Q. Please provide all available 2013 Quarterly Reports to the PUB as well as the fourth quarter reports for 2007 to 2012 inclusive.

A. Please see LWHN-NLH-042 Attachments 1 through 9 for the requested Quarterly Reports to the PUB.

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

QUARTERLY REGULATORY REPORT

FOR THE YEAR ENDED
DECEMBER 31, 2007

HYDRO
THE POWER OF COMMITMENT

NEWFOUNDLAND AND LABRADOR HYDRO

NEWFOUNDLAND & LABRADOR HYDRO
QUARTERLY REGULATORY REPORT
FOR THE YEAR ENDED
December 31, 2007

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NEWFOUNDLAND & LABRADOR HYDRO

QUARTERLY HIGHLIGHTS

CORPORATE SALES AND NET INCOME (Revised)

REGULATED	2007 ACTUAL	2007 FORECAST	2006 ACTUAL
Sales including Wheeling (GWh)	6,765.6	6,862.8	6,318.9
Revenue (millions $)	431.8	436.4	332.9
Expenses (millions $)	428.9	431.1	339.6
Net Operating Income (millions $) [1]	2.9	5.3	(6.7)
Interest Coverage - Corporate[1]	1.49	1.50	1.36
Current Rate Stabilization Plan Balance (millions $):	(38.3)	(6.4)	(49.7)
Retail	(14.7)	(5.3)	(19.3)
Industrial	(8.8)	(1.1)	(14.4)
Hydraulic	(14.8)	0.0	(16.0)
Rate Stabilization Plan Balance (millions $):	12.1	10.3	63.1
Retail	12.1	13.2	53.9
Industrial	0.0	(2.9)	9.2
Full Time Equivalent (FTE) Employees [2] - Regulated	832	841	824
- Non-Regulated	34	33	10

[1] Does not include any earnings associated with Churchill Falls (Labrador) Corporation Ltd. (CF(L)Co)

[2] FTE equates to the actual paid regular hours within the organization, which is 2,080 hours per year in an operating environment and 1,950 hours per year in Hydro's head office environment.

CORPORATE HIGHLIGHTS

SAFETY

Hydro achieved strong safety performance in the fourth quarter
During the fourth quarter of 2007, Hydro had no disabling or loss time incidents, and only one medical aid incident. In addition, through Hydro's Safe Workplace Observation Program (SWOP) 1,045 SWOP observations were reported. SWOP focuses on the importance of reporting to make the workplace safer by preventing major incidents.

REGULATED OPERATIONS

Severe weather caused increased customer outages
During the fourth quarter, there were a number of weather-related outages which lead to a significant increase in the frequency of outages experienced by customers. Although the frequency of outages increased, the interruption time decreased over the same period of the previous year.

Noteworthy events included:

There were seven major unscheduled outages in Labrador West this quarter. Three were caused by loss of supply due to transmission system problems; two were due to equipment failures on the distribution system and two with the cause unknown. Power interruption durations ranged from 45 to 90 minutes. The significant increase in the frequency of the outages is a major concern to Hydro which has prompted a thorough review of the distribution system. The town councils and customers in the area have also raised concerns with the frequency of the interruptions. As a result, senior Hydro officials are meeting with the councils to discuss Hydro's plans to address the reliability issues and load growth in the communities. This meeting is scheduled for the middle of February.

A major wind storm on the Northern Peninsula from November 4th to 7th caused power outages in the Hawke's Bay and Port Saunders areas. The storm caused heavy salt contamination on transmission line TL 221. Customers experienced 12 momentary and 10 sustained power interruptions ranging from one to 14 minutes.

On Sunday, December 2nd, a snow storm with severe winds caused an overhead ground wire on transmission line TL 203 to fail and the line to trip. An incorrect protection operation for this on the adjacent line (TL 237 from Come-by-Chance to Western Avalon) caused TL 237 to trip and the Avalon Peninsula to be isolated from the remainder of the Island electricity system. Two units at the Holyrood plant were in service at the time of the event, but with the two transmission lines out the Avalon load was in excess of Holyrood capability, resulting in a trip of the two units and a complete black-out to the Avalon area for approximately 100,000 customers. Customers had their power restored within 30 minutes to two hours. Restoration efforts were coordinated with Newfoundland Power to help maintain the integrity of the transmission network while units at Holyrood were brought back into service. The units at Holyrood were returned to service without incident and within the timeframe expected for such a sudden trip.

Hydro filed 2008 electricity rates for customers
On December 11th, Hydro filed an application with the Board of Commissioners of Public Utilities (PU Board) for 2008 electricity rates for Labrador Interconnected customers. The phase-in of rates for Labrador Interconnected Rural customers was approved by the PU Board during Hydro's 2006 General Rate Application. The original equalization of rates, approved in 2004 to be phased in from 2004-2008 was suspended in 2007 and the phase-in is extended an additional three years from 2009 through 2011.

Hydro also filed an application for rates for Island Interconnected customers, L'Anse au Loup customers, and Isolated Rural customers (excluding Government Departments) based on the 2008 rates approved for Newfoundland Power.

Power purchase agreement (PPA) signed for 27 MW wind project
In December, Hydro signed a 20-year PPA with SkyPower Corp. to provide wind power to the Island from its Fermeuse wind project. The 27 MW wind project in Fermeuse will consist of nine 3 MW wind turbines and is expected to be in full operation by the end of 2008.

Early in 2007, Hydro signed a 20-year PPA with NeWind Group for a 27 MW wind project in St. Lawrence. When compared to the cost of burning oil at the Holyrood Thermal Generating Station, the wind projects in Fermeuse and St. Lawrence will save consumers approximately $7 million per year over the 20-year life of the contract. Together, these projects will displace 300,000 barrels of oil annually at the Holyrood plant, reduce sulphur dioxide emissions by over 900 tonnes, reduce carbon dioxide emissions by over 140,000 tonnes and generate green energy for the equivalent of 14,000 homes.

Hydro's Holyrood Generating Station issued its first community newsletter
The first edition of *Generating News*, Hydro's new community newsletter from the Holyrood plant, was distributed to Holyrood area residents, Community Liaison Committee members, municipalities and Holyrood staff in December. The goal of *Generating News* is to provide news and information about the plant, its operations and employees to the community in a balanced manner. The first edition covered safety at the Holyrood plant, provided information about the provincial Energy Plan and scrubbers and precipitators, highlighted Hydro's local community investments and gave an update on the recommendations from the human health risk assessment on air emissions at the Holyrood Thermal Generating Station, conducted by Cantox Environmental Inc. The next edition of *Generating News* will be published in June 2008.

ENVIRONMENT AND CONSERVATION

Environmental emergency response exercises held
In October, the Materials Control and Operations staff in Bay d'Espoir and Bishop's Falls successfully completed tests of their Environmental Emergency Response Plans (EERPs). EERPs were developed for all operating areas within Hydro to outline responsibilities and actions to be taken in the event of an accidental release of oil or other hazardous materials into the environment. Hydro undertakes regular testing of its EERPs to ensure a state of readiness.

To test the EERPs, the Materials Control and Operations staff were presented with two mock scenarios. The first scenario involved personnel responding to a leaking jet fuel line. The second scenario was responding to two toppled transformers in the warehouse yard. The staff performed extremely well in responding to these mock emergencies, safely and quickly reacting to control the incident, and notifying the appropriate authorities.

Customers doubling up with Wrap Up for Savings
During the fourth quarter of 2007, Hydro extended its double rebates for the Wrap Up for Savings program from October 31st to November 30th. The HYDROWISE Wrap Up for Savings Program provides rebates and financing for insulation upgrades in electrically-heated homes. Hydro offered double rebates to customers between July 1st and November 30th, 2007 with 42 customers receiving double rebates through the Wrap Up for Savings program.

SAVE energy event brought to Labrador West
During the fourth quarter, Hydro, Newfoundland Power, the Department of Natural Resources and the Iron Ore Company of Canada partnered to deliver a SAVE (Shared Atlantic Vision for Energy Efficiency) Energy Event in Labrador West. This energy conservation event distributed 14,800 compact fluorescent bulbs (CFLs) to over 3,700 homes. The estimated energy savings in Labrador West from this energy conservation initiative is 256,000 kilowatt-hours annually. The SAVE Energy Event kicked off in Labrador West with a trade show on October 25th. Approximately 200 people attended the trade show to learn about energy conservation and ways to save energy in their homes and businesses.

Holiday Lightswitch launched to help consumers save energy during the holidays
The Department of Natural Resources, Hydro and Newfoundland Power launched Holiday Lightswitch in November to help Newfoundlanders and Labradorians become more energy efficient during the holiday season. Holiday Lightswitch exchanged 10,000 sets of LED holiday lights for traditional outdoor holiday lights in 17 municipalities across the province. This energy conservation initiative will result in estimated annual reductions of:

- 410,000 kWh per year;
- 650 barrels of oil from the Holyrood plant; and
- 315 tonnes of greenhouse gas emissions.

1st Annual HYDROWISE Energy Conservation Week launched
From October 22nd to the 26th, 2007, Hydro celebrated the first annual HYDROWISE Energy Efficiency Week. The activities encouraged residents and business owners to take simple steps to reduce their energy usage. Each day of the week featured a different energy conservation theme, such as purchasing ENERGY STAR® labelled products, switching to CFL bulbs, and challenging residents to a Turn it Off Day.

Glenburnie-Birchy Head-Shoal Brook partnered with HYDROWISE
Glenburnie-Birchy Head-Shoal Brook is the first community in Canada to take on the David Suzuki Nature Challenge as an entire community. David Suzuki's Nature Challenge identifies the most effective ways to conserve nature. Energy conservation is one of the four ways identified to achieve this goal.

HYDROWISE representatives delivered a half-day energy efficiency workshop to 25 fire brigade volunteers to prepare them for their fire safety and energy conservation walkthroughs of the 200 homes in their community. Through a partnership with the neighboring Woody Point fire brigade, the initiative has expanded to reach an additional 200 homes. Through the HYDROWISE program, each home will be supplied with a CFL, water conservation kit and HYDROWISE energy efficiency information kit. The total annual potential savings from this distribution is:

- 138,800 kWh per year;
- 220 barrels of oil from the Holyrood plant; and
- 110 tonnes of greenhouse gas emissions.

Conservation and Demand Management (CDM) Potential study continued
As one of the final inputs to the CDM Potential study, workshops were held with stakeholders working in the residential, commercial and industrial sectors. The barriers and opportunities for reaching the Newfoundland and Labrador marketplace with specific technologies were discussed and a view of the achievable energy conservation potential in this province was provided to the consultant. Using the local market information from these workshops and previous experience in other marketplaces, the consultant will develop recommendations of the range of conservation potential deemed achievable. The achievable potential will form the basis for next steps providing initial guidance for target setting and providing insight to the barriers to technology uptake that exist in the marketplace. The final CDM Potential study is expected early in the first quarter of 2008.

RAMEA WIND-HYDROGEN-DIESEL PROJECT

On November 30th, 2007, the PU Board approved Hydro's application for the Ramea Wind-Hydrogen-Diesel Project. This approval allows Hydro to proceed with the construction and installation of the project. At the end of the fourth quarter, Hydro was waiting for a release from the provincial and federal environmental registration processes to proceed with construction. The release is expected early in the first quarter of 2008.

COMMUNITY SUPPORT

Hydro pledged $250,000 for the Seniors Resource Centre
In December, Hydro made a five-year, $250,000 pledge to the Seniors Resource Centre through its Community Investment Program. One of Hydro's key areas of focus for its Community Investment Program is safety and health. Hydro's contribution over the next five years will help the Seniors Resource Centre expand its safety, health and wellness initiatives across the province.

Helped kids stay safe
In October, Hydro employees in St. Anthony helped more than 120 children become bike safe. Hydro teamed up with the RCMP, the Town of St. Anthony, local businesses and parents to bring a bike rodeo to youth and parents in St. Anthony and St. Lunaire-Griquet. In addition to employees helping to run the event, Hydro purchased bike helmets and other protective equipment for children in the area.

Employees took a hike for the East Coast Trail Association
More than 30 Hydro employees, family members and friends participated in the East Coast Trail Association's (ECTA) annual Tely Challenge in October raising $5,000. Two teams competed in their fundraising efforts and raised $2,500. Hydro, through its Community Investment Program, donated an additional $2,500 to the event. Each year the ECTA hosts the Tely Challenge Hike as their main fundraising event to help with the development and maintenance of the 540 kilometre trail system.

Employees volunteered at local food bank
Over a two week period in December, employees with System Operations and Customer Services, in St. John's, volunteered their time at the Community Food Sharing Association. Employees helped sort food which was collected during the St. John's Downtown Christmas Parade. This was one of many volunteer initiatives which employees took part in over the year.

NEWFOUNDLAND & LABRADOR HYDRO
REGULATED FINANCIAL PERFORMANCE
FOR THE YEAR ENDED DECEMBER 31

REGULATED	2007 ACTUAL	2007 FORECAST	2006 ACTUAL
Sales including Wheeling (GWh)	6,765.6	6,862.8	6,318.9
Revenue (millions $)	431.8	436.4	332.9
Expenses (millions $)	428.9	431.1	339.6
Net Operating Income (loss) (millions $) (1)	2.9	5.3	(6.7)
Interest Coverage - Corporate(1)	1.49	1.50	1.36
(1) Does not include any earnings associated with Churchill Falls (Labrador) Corporation Ltd.			

FINANCE

Energy Sales
Total sales for 2007 were 6,765.6 GWh as outlined in Tab 2, page 9, 97.2 GWh lower than the forecast. Sales to Newfoundland Power Inc. were 1.1 GWh lower than forecast. Sales to Industrial Customers were 61.2 GWh lower than forecast. Sales to CFB Goose Bay were 9.2 GWh lower than forecast. Sales to Rural Customers were 25.7 GWh lower than forecast.

Revenue
Total revenue for 2007 was $431.8 million, $4.6 million lower than the forecast.

Expenses
Total expenses for 2007 amounted to $428.9 million, a decrease of $2.2 million from the forecast. The main variances are due to a decrease in fuels ($3.1 million), loss on disposal of assets ($0.9 million) and interest ($0.2 million), offset by increases in net operating costs ($1.2 million), and power purchase costs ($0.8 million).

Net Operating Income
Net Operating Income for 2007 was $2.9 million, a decrease of $2.4 million from the forecast.

Financial Statements
As directed by Board Order No. P.U. 7 (2002 - 2003), separate financial statements have been prepared for Hydro's regulated and non-regulated operations.

Rate Stabilization Plan
The Rate Stabilization Plan Report contained at Tab 3 consists of two parts. The first part outlines the activity in the current plan which commenced January 1, 2004. The second part shows the activity related to the plan balance as of December 31, 2003 that will be recovered over a four-year period starting 2004.

The recovery period for the Industrial Customer portion of the December 31, 2003 (historic) plan ended on December 31, 2007 and the remaining balance was transferred to the current plan. The recovery period for the Utility Customer portion of the historic plan will end on June 30, 2008.

NEWFOUNDLAND AND LABRADOR HYDRO
REGULATED BALANCE SHEET
(UNAUDITED)
AS AT DECEMBER 31
($000)

	2007	2006
Assets		
Current Assets		
Cash and Cash Equivalents	9	5,100
Short-term Investments	0	560
Receivables	69,114	59,416
Current Portion of Regulatory Assets	12,054	45,336
Fuel & Supplies at Average Cost	60,925	45,443
Prepaid Expenses	841	1,085
	142,943	156,940
Property, Plant and Equipment		
Property, Plant and Equipment in Service	2,016,315	1,976,200
Less Contributions in Aid	96,396	93,740
Less Accumulated Depreciation	570,225	536,691
	1,349,694	1,345,769
Construction in Progress	2,535	10,191
	1,352,229	1,355,960
Sinking Funds	151,765	117,092
Regulatory Assets	86,408	102,870
	1,733,345	1,732,862
Liabilities & Shareholder's Equity		
Current Liabilities		
Bank Indebtedness	8,025	6,029
Accounts Payable & Accrued Liabilities	65,295	38,081
Accrued Interest	30,566	30,565
Current Portion of Regulatory Liabilities	23,488	0
Long-term Debt Due in One Year	208,315	8,307
Due to Related Parties	182	3,470
Promissory Notes	(33,601)	16,062
	302,270	102,514
Long-term Debt	1,145,198	1,338,601
Employee Future Benefits	39,805	35,537
Regulatory Liabilities	15,499	50,369
Shareholder's Equity/Retained Earnings	211,038	205,841
Accumulated Other Comprehensive Income	19,535	0
	1,733,345	1,732,862

NEWFOUNDLAND & LABRADOR HYDRO
REGULATED STATEMENT OF INCOME
(UNAUDITED)
FOR THE YEAR ENDED DECEMBER 31
($000)

	YEAR TO DATE		
	2007 ACTUAL	2007 FORECAST	2006 ACTUAL
Revenue			
Energy Sales	429,794	434,335	330,412
Other Revenue	1,983	2,033	2,494
	431,777	436,368	332,906
Expenses			
Operations & Administration			
Net Operating	97,513	96,307	89,484
Loss on Disposal of Assets	902	1,792	1,564
Fuels	150,281	153,348	70,651
Power Purchased	38,606	37,761	38,902
Depreciation & Amortization	38,342	38,380	36,644
Interest	103,242	103,487	102,350
	428,886	431,075	339,595
Net Operating Income	2,891	5,293	(6,689)

NEWFOUNDLAND & LABRADOR HYDRO
REGULATED STATEMENT OF RETAINED EARNINGS
(UNAUDITED)
FOR THE YEAR ENDED DECEMBER 31
($000)

	2007	2006
Balance, Beginning of the Period	205,841	212,530
Adjustment to Opening Retained Earnings	2,306	0
Net Income	2,891	(6,689)
Balance, End of the Period	211,038	205,841

* Hydro has adopted CICA Section 3855, "Financial Instruments Recognition and Measurement". Outstanding long-term debt is now measured at amortized cost, using the effective interest method. This resulted in an adjustment to Retained Earnings of $2,306,000.

NEWFOUNDLAND & LABRADOR HYDRO
REGULATED STATEMENT OF COMPREHENSIVE INCOME
(UNAUDITED)
FOR THE YEAR ENDED DECEMBER 31
($000)

	2007	2006
Net Income (Loss)	2,891	(6,689)
Other Comprehensive Income		
Change in Fair Value of Sinking Fund Investments	177	0
Comprehensive Income (Loss)	3,068	(6,689)

* Hydro has adopted CICA Section 1530, "Comprehensive Income". This new financial statement captures unrealized gains and losses on financial instruments. Changes in the fair market value of sinking fund investments designated as available for sale constitute the sole item in Accumulated Other Comprehensive Income.

NEWFOUNDLAND & LABRADOR HYDRO
REGULATED STATEMENT OF CASH FLOWS
(UNAUDITED)
FOR THE YEAR ENDED DECEMBER 31
($000)

	2007	2006
Operating Activities		
Net Income from Operations	2,891	(6,689)
Add (Deduct) Items not involving Cash Flow		
Depreciation and Amortization	38,342	36,644
Other Amortization	675	914
Loss on Disposal of Property, Plant and Equipment	902	1,564
Other	(92)	498
	42,718	32,931
Changes in Non-Cash Balances related to Operations		
Receivables	(9,698)	(2,147)
Fuels and Supplies	(15,482)	5,799
Prepaid Expenses	244	774
Accounts Payable and Accrued Liabilities	27,214	(10,488)
Accrued Interest	0	1,281
Due (from) to Related Parties	(3,288)	268
Regulatory Assets	49,744	39,094
Regulatory Liabilities	(11,382)	37,695
Employee Future Benefits	4,268	3,271
	84,338	108,478
Financing Activities		
Long-Term Debt Issued	0	225,000
Long-Term Debt Retired	12,691	(190,582)
Decrease in Promissory Notes	(49,663)	(77,123)
	(36,972)	(42,705)
Investing Activities		
Increase in Sinking Funds	(19,592)	(18,506)
Proceeds on Disposal of Property, Plant and Equipment	602	464
Additions to Regulatory Assets	0	(1,856)
Additions to Property, Plant and Equipment	(36,023)	(41,648)
Decrease (Increase) in Short-Term Investments	560	(15)
	(54,453)	(61,561)
Net (Decrease) Increase in Cash	(7,087)	4,212
Cash Position, Beginning of the Year	(929)	(5,141)
Cash Position, end of the Year	(8,016)	(929)

NEWFOUNDLAND & LABRADOR HYDRO
REGULATED STATEMENT OF REVENUE BY MAJOR SOURCE
FOR THE YEAR ENDED DECEMBER 31
($000)

	2007 ACTUAL	2007 FORECAST	2006 ACTUAL
North Atlantic Refining Ltd.	11,560	11,890	8,834
Canadian Forces Base Goose Bay	3,951	4,383	4,903
Newfoundland Power Inc.	324,229	324,346	241,781
Abitibi Consolidated - Grand Falls	4,937	5,553	4,158
Abitibi Consolidated - Stephenville	285	292	3,915
Corner Brook Pulp & Paper Ltd.	19,857	21,999	15,172
AUR Resources Inc.	2,812	2,934	497
Rural Revenue	62,163	62,938	51,152
	429,794	434,335	330,412

NEWFOUNDLAND & LABRADOR HYDRO
REGULATED RURAL REVENUE BY MAJOR SOURCE
FOR THE YEAR ENDED DECEMBER 31
($000)

	2007 ACTUAL	2007 FORECAST	2006 ACTUAL
Happy Valley	7,818	7,961	5,587
Island Diesel	1,498	1,459	1,155
Island Interconnected	38,907	39,231	32,212
Labrador City/Wabush	6,427	6,965	6,015
Labrador Diesel	5,737	5,714	4,735
Southern Labrador	1,776	1,608	1,448
	62,163	62,938	51,152

NEWFOUNDLAND & LABRADOR HYDRO
SUPPLEMENTARY SCHEDULE
FOR THE YEAR ENDED DECEMBER 31
($000)

	2007 ACTUAL	2007 FORECAST	2006 ACTUAL
Other Revenue			
Sundry	443	493	1,011
Pole Attachments	1,444	1,444	1,399
Suppliers' Discount	96	96	84
Total Other Revenue	1,983	2,033	2,494
Interest			
Gross Interest	100,850	101,007	102,379
Accretion of Long-Term Debt	675	675	914
Amortization of Foreign Exchange Losses	2,157	2,157	2,165
Allowance for Funds used during Construction	(646)	(685)	(610)
Interest Earned Including RSP	(12,939)	(12,812)	(16,492)
Debt Guarantee Fee	13,145	13,145	13,994
Total Interest	103,242	103,487	102,350

NEWFOUNDLAND & LABRADOR HYDRO
REGULATED ENERGY SALES (MWh) ANALYSIS
FOR THE YEAR ENDED DECEMBER 31

		2007 ACTUAL	2007 FORECAST	2006 ACTUAL
INDUSTRY				
Corner Brook Pulp & Paper Ltd.	- Firm	383,075	403,571	392,641
Corner Brook Pulp & Paper Ltd.	- Interruptible	11,392	25,201	918
Corner Brook Pulp & Paper Ltd.	- Generation Outage Power	2,207	2,195	4,622
Abitibi Consolidated - Stephenville	- Firm	3,088	3,273	6,769
Abitibi Consolidated - Stephenville	- Wheeled	920	1,017	688
Abitibi Consolidated - Grand Falls	- Firm	90,556	107,438	98,066
Abitibi Consolidated - Grand Falls	- Compensation	31,000	29,348	31,000
Abitibi Consolidated - Grand Falls	- Interruptible	2	2	0
Abitibi Consolidated - Grand Falls	- Generation Outage Power	74	74	85
Abitibi Consolidated - Grand Falls	- Wheeled	9,719	8,665	11,350
AUR Resources Inc.		51,364	54,687	12,866
North Atlantic Refining Ltd.	- Firm	243,142	252,352	238,758
North Atlantic Refining Ltd.	- Interruptible	280	206	166
TOTAL INDUSTRY		826,819	888,029	797,929
Canadian Forces Base Goose Bay		62,938	72,185	69,796
Utility - Newfoundland Power Inc.		4,990,719	4,991,820	4,616,864
Rural - Interconnected and Diesel		885,158	910,811	834,307
TOTAL SALES		6,765,634	6,862,845	6,318,896

INTER-COMPANY

For the past number of years Newfoundland and Labrador Hydro has been providing the following services to Churchill Falls (Labrador) Corporation Ltd. (CF(L)Co):

- Management
- Accounting & Financial Reporting
- Information Systems
- Treasury
- General Counsel
- Financial Planning
- Human Resources
- Engineering Services
- Environment
- Internal Audit
- Administration
- Risk & Insurance
- Corporate Communications

The cost of these services is recovered from CF(L)Co. through a cost recoveries agreement which is based on various methods of cost allocation to CF(L)Co. The agreement is modified annually to reflect changes in the services provided. The charges for services are estimated at the beginning of each year based on the approved operating budgets for each department, and at year-end an adjustment is made based on a review of actual services and costs.

NEWFOUNDLAND & LABRADOR HYDRO
COST RECOVERIES
FOR THE YEAR ENDED DECEMBER 31
($000)

CF(L)Co

	2007 ACTUAL	2007 FORECAST	2006 ACTUAL
Executive Leadership and Associates	140	122	95
Human Resources and Organizational Effectiveness	239	125	140
Finance/CFO	1,699	1,633	1,564
Engineering Services	78	67	103
Regulated Operations	0	0	45
	2,156	1,947	1,947

Lower Churchill Project

Internal costs incurred on the Lower Churchill Project are directly charged to the capital job. These would include salaries, materials, supplies, etc. In addition, the project is charged monthly for financing charges.

NEWFOUNDLAND AND LABRADOR HYDRO
NON-REGULATED BALANCE SHEET
(UNAUDITED)
AS AT DECEMBER 31
($000)

	2007	2006
Assets		
Property, Plant and Equipment	2,314	2,314
Less: Accumulated Depreciation	52	33
	2,262	2,281
Construction in Progress	114,919	69,240
	117,181	71,521
Long-Term Receivable	23,347	18,098
Investment in CF(L)Co.	350,472	338,205
LCDC & GIPCo.	2,675	2,675
	493,675	430,499
Liabilities & Shareholder's Equity		
Long-term Debt	5,960	18,807
Promissory Notes	40,601	43,293
Shareholder's Equity		
Share Capital		
Common Shares Par $1 each Authorized 25,000,000 Issued 22,503,942 Shares	22,504	22,504
Contributed Capital		
Lower Churchill Development	15,400	15,400
Muskrat Falls Project	2,165	2,165
Retained Earnings	407,045	328,330
	447,114	368,399
	493,675	430,499

NEWFOUNDLAND & LABRADOR HYDRO
NON-REGULATED STATEMENT OF INCOME
(UNAUDITED)
FOR THE YEAR ENDED DECEMBER 31
($000)

	2007 ACTUAL	2007 FORECAST	2006 ACTUAL
Revenue			
Energy Sales	58,530	58,141	57,440
Expenses			
Operations & Administration			
Net Operating	6,056	6,252	4,198
Fuels	29	0	363
Power Purchased	3,825	3,799	3,885
Depreciation & Amortization	18	16	16
Interest	(4,999)	(4,996)	(1,277)
	4,929	5,071	7,185
Net Operating Income	53,601	53,070	50,255
Other Revenue			
Equity in CF(L)Co.	15,553	17,212	18,097
Preferred Dividends	10,472	10,473	10,075
Interest Share Purch. Debt	(911)	(908)	(1,738)
Total Other Revenue	25,114	26,777	26,434
Net Income	78,715	79,847	76,689

NEWFOUNDLAND & LABRADOR HYDRO
NON-REGULATED STATEMENT OF RETAINED EARNINGS
(UNAUDITED)
FOR THE YEAR ENDED DECEMBER 31
($000)

	2007	2006
Balance, Beginning of the Period	328,330	254,302
Net Income	78,715	76,689
Dividends		
Hydro	0	2,661
	0	2,661
Balance, End of the Period	407,045	328,330

NEWFOUNDLAND & LABRADOR HYDRO
NON-REGULATED STATEMENT OF CASH FLOWS
(UNAUDITED)
FOR THE YEAR ENDED DECEMBER 31
($000)

	2007	2006
Operating Activities		
Net income	78,715	76,689
Add (Deduct) Items not involving Cash Flow		
Depreciation and Amortization	18	16
Equity in CF(L)Co.	(15,553)	(18,097)
	63,180	58,608
Changes in Non-Cash Balances related to Operations		
Long-Term Receivables	(5,249)	(18,098)
Dividends from CF(L)Co.	3,286	1,326
	61,217	41,836
Financing Activities		
Long-Term Debt Retired	(12,847)	(9,663)
Decrease in Promissory Notes	(2,692)	(14,817)
Dividends	0	(2,661)
	(15,539)	(27,141)
Investing Activities		
Additions to Property, Plant and Equipment	(45,678)	(14,695)
Net Increase in Cash	0	0
Cash Position, Beginning of the 'Period	0	0
Cash Position, End of the Period	0	0

NEWFOUNDLAND AND LABRADOR HYDRO

RATE STABILIZATION PLAN REPORT

DECEMBER 2007

RATE STABILIZATION PLAN REPORT

Summary of Key Facts

The Rate Stabilization Plan of Newfoundland and Labrador Hydro (Hydro), as amended by Board Order No. P.U. 40 (2003) and Order No. P.U. 8 (2007), is established for Hydro's Utility customer, Newfoundland Power, and Island Industrial customers to smooth rate impacts for variations between actual results and Test Year Cost of Service estimates for:

- Hydraulic production;
- No. 6 fuel cost used at Hydro's Holyrood generating station;
- Customer load (Utility and Island Industrial); and
- Rural rates.

The Test Year Cost of Service Study was approved by Board Order No. P.U. 8 (2007) and is based on projections of events and costs that are forecast to happen during a test year. Finance charges are calculated on the balances using the test year Weighted Average Cost of Capital which is currently 7.529% per annum. Holyrood's operating efficiency is 630 kWh/barrel.

	2007 Test Year Cost of Service			
	Net Hydraulic Production	No. 6 Fuel Cost	Utility Load	Industrial Load
	(kWh)	($Can/bbl.)	(kWh)	(kWh)
January	427,100,000	54.17	574,800,000	78,300,000
February	388,680,000	54.73	518,600,000	70,900,000
March	415,080,000	55.46	524,700,000	76,600,000
April	355,520,000	55.46	429,200,000	75,600,000
May	324,240,000	55.46	358,700,000	69,500,000
June	328,500,000	54.49	298,400,000	73,800,000
July	386,790,000	54.49	293,400,000	77,500,000
August	379,140,000	54.49	287,000,000	77,900,000
September	363,560,000	54.49	297,700,000	73,000,000
October	340,510,000	54.56	360,200,000	74,400,000
November	364,390,000	54.56	439,300,000	74,100,000
December	398,560,000	58.98	543,800,000	72,700,000
Total	4,472,070,000		4,925,800,000	894,300,000

Plan Highlights

Hydraulic Production

Year-to-date hydraulic production is 217.4 GWh more than the Cost of Service production of 4,472.1 GWh resulting in a fuel savings of $20,884,529 in the hydraulic variation account. (See page 4)

No. 6 Fuel Cost

The No.6 fuel cost for the month of December was $66.01, $7.03 more than the Cost of Service. Lower year-to-date average fuel costs have resulted in a year-to-date amount of $5,771,537 due to Customers. (See page 5)

Customer Load

Utility sales are up 64.5 GWh year-to-date compared with the Cost of Service Sales of 4,925.8 GWh resulting in $253,840 due from the utility customer. (See page 8)

Industrial sales are down 123.1 GWh year-to-date compared with the Cost of Service Sales of 894.3 GWh resulting in $6,262,077 due to industrial customers. (See page 9)

Rural Rates

A net amount of $42,585 assigned to Labrador Interconnected Customers is removed from the plan and written off to Hydro's net income (loss). This year-to-date amount is calculated as follows:

Rural rate alteration (RRA)	$ 1,861,804	charge [1]
Less RRA to utility customer	1,658,868	charge (see page 10)
RRA to Labrador Interconnected	202,936	charge
Fuel variance to Labrador Interconnected	(40,840)	savings (see page 6)
Hydraulic variance allocation adjustment	(118,398)	savings (see schedule A)
Net Labrador Interconnected	$ 43,698	net charge

[1] Beginning January 2007, the RRA includes a monthly amount of $92,560. This amount relates to the phase in of the application of the credit from secondary energy sales to CFB Goose Bay to the Rural deficit as stated in Section B, Clause 1.3(b) of the approved Rate Stabilization Plan Regulations which received final approval in Order No. P.U. 14 (2007) issued August 17, 2007.

Plan Highlights Continued

Current Plan Summary

Balances below from utility and industrial customers are expected to be recovered in one year. In addition, at December 31, 25% of the hydraulic variance and 100% of the related financing charges was allocated between industrial ($758,949 due to Customers) and utility customers ($5,262,203 due to Customers) and to be repaid in one year. The balances are comprised of the following:

Utility Customer	$	(9,397,169)	due to customer (3)
Utility Customer – 25% Hydraulic balance		(5,262,203)	due to customer
Sub-total Utility		**(14,659,372)**	
Industrial Customers		(6,687,095)	due to customer
Industrial Customers – 25% Hydraulic variance		(758,949)	due to customer
Industrial Customers: - 2003 balance		(1,382,924)	due to customers (4)
Sub-total Industrial		**(8,828,968)**	
Hydraulic Balance:		(14,820,468)	fuel savings (2)
Total Plan Balance:	**$**	**(38,308,808)**	

December 2003 Plan Balance

The plan balances as at December 31, 2003 were consolidated and are being recovered over four years. Year-to-date recoveries for utility and industrial customers are $24,093,414 and $8,746,071 respectively. As of December 31, 2007 the balance of $1,382,924 due to Industrial Customers has been transferred to the current plan in accordance with Section E of the Rate Stabilization Plan rules. The remaining balance of $12,053,450[3] is due from the Utility Customer.

(2) The amount represents the hydraulic balance for the current year to-date as the hydraulic balance at December 31, 2006 was allocated to industrial and utility customers as per P.U. 8. (2007).

(3) December 2006 balances were adjusted in accordance with the provisions of the special adjustment to the RSP Hydraulic Production Variation as set out in Schedule B attached to Order P.U. 8 (2007).

(4) The balance of the December 2003 Plan related to industrial customers will be recovered during 2008 as a component of the Current Plan in accordance with Section E of the Rate Stabilization Plan rules.

NEWFOUNDLAND AND LABRADOR HYDRO **December 2007**
RATE STABILIZATION PLAN

Net Hydraulic Production Variation

	A	B	C	D	E	F	G
	Cost of Service Net Hydraulic Production (kWh)	Actual Net Hydraulic Production (kWh)	Monthly Net Hydraulic Production Variance (kWh)	Cost of Service No. 6 Fuel Cost ($Can/bbl.)	Net Hydraulic Production Variation ($)	Financing Charges ($)	Cumulative Variation and Financing Charges ($)
			(A - B)		**(C / O[1] X D)**		**(E + F)** **(to page 12)**
Opening balance [3]							0
January	427,100,000	531,972,339	(104,872,339)	54.17	(9,017,357)	0	(9,017,357)
February	388,680,000	490,775,513	(102,095,513)	54.73	(8,869,345)	(54,713)	(17,941,415)
March	415,080,000	467,302,785	(52,222,785)	55.46	(4,597,263)	(108,860)	(22,647,538)
April	355,520,000	400,656,711	(45,136,711)	55.46	(3,973,463)	(137,414)	(26,758,415)
May	324,240,000	335,838,684	(11,598,684)	55.46	(1,021,052)	(162,357)	(27,941,824)
June	328,500,000	281,234,508	47,265,492	54.49	4,088,090	(169,537)	(24,023,271)
July	386,790,000	275,130,963	111,659,037	54.49	9,657,621	(145,761)	(14,511,411)
August	379,140,000	344,850,651	34,289,349	54.49	2,965,757	(88,048)	(11,633,702)
September	363,560,000	355,535,026	8,024,974	54.49	694,097	(70,587)	(11,010,192)
October	340,510,000	322,786,684	17,723,316	54.56	1,534,895	(66,804)	(9,542,101)
November	364,390,000	371,392,165	(7,002,165)	54.56	(606,410)	(57,897)	(10,206,408)
December	398,560,000	511,957,801	(113,397,801)	58.98	(10,616,194)	(61,927)	(20,884,529)
	4,472,070,000	4,689,433,830	(217,363,830)		(19,760,624)	(1,123,905)	(20,884,529)
Hydraulic Allocation [2]					4,940,156	1,123,905	6,064,061
Hydraulic variation at year end					(14,820,468)	-	(14,820,468)

(1) O is the Holyrood Operating Efficiency of 630 kWh/barrel.
(2) At year end 25% of the hydraulic variation balance and 100% of the annual financing charges are allocated to customers.

	(from page 6) 12 month kWh	% of kWh to total	Allocation	Reallocate Rural	**(to pages 11 & 12)** Net
Utility	4,990,718,593	81.0%	4,911,447	350,756	5,262,203
Industrial	771,198,558	12.5%	758,949		758,949
Rural	400,018,423	6.5%	393,665	(393,665)	-
Total	6,161,935,574	100.0%	6,064,061	(42,909)	6,021,152
Labrador Inteconnected (write-off to income)				42,909	42,909
				-	6,064,061

(3) In accordance with PUB Order P.U. 8 (2007), the December 31, 2006 Hydraulic Variation balance was allocated to the Industrial and Utility Customers as detailed in Schedule A of this report.

NEWFOUNDLAND AND LABRADOR HYDRO
RATE STABILIZATION PLAN
No. 6 Fuel Variation

December 2007

	A	B	C	D	E	F	G
	Actual Quantity No. 6 Fuel	Actual Quantity No. 6 Fuel for Non-Firm Sales	Net Quantity No. 6 Fuel	Cost of Service No. 6 Fuel Cost	Actual Average No. 6 Fuel Cost	Cost Variance	No.6 Fuel Variation
	(bbl.)	(bbl.)	(bbl.)	($Can/bbl.)	($Can/bbl.)	($Can/bbl.)	($)
			(A - B)			**(E - D)**	**(C X F)**
							(to page 6)
January	211,209	184	211,025	54.17	46.53	(7.64)	(1,612,231)
February	231,852	585	231,267	54.73	46.25	(8.48)	(1,961,147)
March	269,147	1,901	267,246	55.46	46.60	(8.86)	(2,367,797)
April	222,349	2,320	220,029	55.46	47.47	(7.99)	(1,758,031)
May	215,328	6,409	208,919	55.46	51.73	(3.73)	(779,268)
June	170,607	6,259	164,348	54.49	52.65	(1.84)	(302,399)
July	124,765	2,786	121,979	54.49	54.85	0.36	43,912
August	17,736	1,429	16,307	54.49	54.90	0.41	6,686
September	231	145	86	54.49	56.10	1.61	139
October	154,238	18	154,220	54.56	56.11	1.55	239,041
November	181,235	0	181,235	54.56	60.03	5.47	991,357
December	245,950	118	245,832	58.98	66.01	7.03	1,728,201
	2,044,648	22,154	2,022,494	55.47	52.51	(2.96)	(5,771,537)

NEWFOUNDLAND AND LABRADOR HYDRO

December 2007

RATE STABILIZATION PLAN

Allocation of Fuel Variance – Year-to-Date

	A	B	C	D	E	F	G	H	I	J
	Twelve Months-to-Date				Year-to-Date Fuel Variance				Reallocate Rural Island Customers [(1)]	
	Utility	Industrial Customers	Rural Island Customers	Total	Utility	Industrial Customers	Rural Island Interconnected	Total	Utility	Labrador Interconnected
	(kWh)	(kWh)	(kWh)	(kWh)	($)	($)	($)	($)	($)	($)
				(A+B+C)	**(A/D X H)**	**(B/D X H)**	**(C/D X H)**		**(G X 88.58%)**	**(G X 11.42%)**
					(to page 7)			**(from page 5)**	**(to page 7)**	
January	4,661,863,479	749,734,721	374,020,081	5,785,618,281	(1,299,083)	(208,922)	(104,226)	(1,612,231)	(92,865)	(11,361)
February	4,699,613,239	756,787,987	375,955,265	5,832,356,491	(2,879,367)	(463,670)	(230,341)	(3,573,378)	(205,234)	(25,107)
March	4,715,725,889	773,537,749	379,723,680	5,868,987,318	(4,773,729)	(783,052)	(384,394)	(5,941,175)	(342,495)	(41,899)
April	4,779,221,431	780,435,589	382,343,048	5,942,000,068	(6,192,563)	(1,011,231)	(495,412)	(7,699,206)	(441,412)	(54,000)
May	4,834,932,413	792,423,226	386,603,082	6,013,958,721	(6,816,284)	(1,117,158)	(545,032)	(8,478,474)	(485,624)	(59,408)
June	4,868,431,946	795,936,264	390,313,494	6,054,681,704	(7,060,500)	(1,154,316)	(566,057)	(8,780,873)	(504,357)	(61,700)
July	4,881,848,366	796,326,557	391,675,595	6,069,850,518	(7,026,947)	(1,146,235)	(563,779)	(8,736,961)	(502,327)	(61,452)
August	4,878,879,744	804,630,152	393,535,158	6,077,045,054	(7,008,992)	(1,155,931)	(565,352)	(8,730,275)	(503,729)	(61,623)
September	4,890,302,421	802,684,146	394,303,282	6,087,289,849	(7,013,467)	(1,151,176)	(565,493)	(8,730,136)	(503,854)	(61,639)
October	4,915,887,352	792,629,130	394,486,611	6,103,003,093	(6,839,463)	(1,102,783)	(548,849)	(8,491,095)	(489,024)	(59,825)
November	4,945,742,586	777,878,124	396,548,060	6,120,168,770	(6,060,580)	(953,222)	(485,936)	(7,499,738)	(432,969)	(52,967)
December	4,990,718,593	771,198,558	400,018,423	6,161,935,574	(4,674,524)	(722,338)	(374,675)	(5,771,537)	(333,835)	(40,840)

(1) The Fuel Variance initially allocated to Rural Island Interconnected is re-allocated between Utility and Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the approved Cost of Service Study, which is 89.10% and 10.90% respectively. The Labrador Interconnected amount is then removed from the plan and written off to net income (loss).

NEWFOUNDLAND AND LABRADOR HYDRO

December 2007

RATE STABILIZATION PLAN

Allocation of Fuel Variance - Monthly

	A	B	C	D	E	F	G
	Utility					**Industrial**	
	Fuel Variance		Rural Allocation		Total Fuel Variance	Fuel Variance	
	Year-to-Date Activity	Current Month Activity [(1)]	Year-to-Date Activity	Current Month Activity [(1)]	Activity for the month	Year-to-Date Activity	Current Month Activity [(1)]
	($)	($)	($)	($)	($)	($)	($)
					(B + D)		
	(from page 6)		**(from page 6)**		**(to page 10)**	**(from page 6)**	**(to page 11)**
January	(1,299,083)	(1,299,083)	(92,865)	(92,865)	(1,391,948)	(208,922)	(208,922)
February	(2,879,367)	(1,580,284)	(205,234)	(112,369)	(1,692,653)	(463,670)	(254,748)
March	(4,773,729)	(1,894,362)	(342,495)	(137,261)	(2,031,623)	(783,052)	(319,382)
April	(6,192,563)	(1,418,834)	(441,412)	(98,917)	(1,517,751)	(1,011,231)	(228,179)
May	(6,816,284)	(623,721)	(485,624)	(44,212)	(667,933)	(1,117,158)	(105,927)
June	(7,060,500)	(244,216)	(504,357)	(18,733)	(262,949)	(1,154,316)	(37,158)
July	(7,026,947)	33,553	(502,327)	2,030	35,583	(1,146,235)	8,081
August	(7,008,992)	17,955	(503,729)	(1,402)	16,553	(1,155,931)	(9,696)
September	(7,013,467)	(4,475)	(503,854)	(125)	(4,600)	(1,151,176)	4,755
October	(6,839,463)	174,004	(489,024)	14,830	188,834	(1,102,783)	48,393
November	(6,060,580)	778,883	(432,969)	56,055	834,938	(953,222)	149,561
December	(4,674,524)	1,386,056	(333,835)	99,134	1,485,190	(722,338)	230,884
		(4,674,524)		(333,835)	(5,008,359)		(722,338)

(1) The current month activity is calculated by subtracting year-to-date activity for the prior month from year-to-date activity for the current month.

NEWFOUNDLAND AND LABRADOR HYDRO **December 2007**

RATE STABILIZATION PLAN

Load Variation - Utility

	A	B	C	D	E	F	G	H	I	J	K
	Firm Energy						Secondary Energy				
	Cost of Service Sales	Actual Sales	Sales Variance	Cost of Service No. 6 Fuel Cost	Firm Energy Rate (2)	Load Variation	Cost of Service Sales	Actual Sales	Firming Up Charge	Load Variation	Total Load Variation
	(kWh)	(kWh)	(kWh)	($Can/bbl.)	($/kWh)	($)	(kWh)	(kWh)	($/kWh)	($)	($)
			(B - A)			**C x {(D/O[1]) - E}**				**(G - H) x I**	**(F + J)** **(to page 10)**
January	574,800,000	567,548,424	(7,251,576)	54.17	0.08805	14,981	0	928	0.00841	(8)	14,973
February	518,600,000	537,906,741	19,306,741	54.73	0.08805	(22,724)	0	7,253	0.00841	(61)	(22,785)
March	524,700,000	532,869,039	8,169,039	55.46	0.08805	(149)	0	0	0.00841	0	(149)
April	429,200,000	451,710,468	22,510,468	55.46	0.08805	(411)	0	0	0.00841	0	(411)
May	358,700,000	381,600,871	22,900,871	55.46	0.08805	(418)	0	0	0.00841	0	(418)
June	298,400,000	310,533,933	12,133,933	54.49	0.08805	(18,904)	0	0	0.00841	0	(18,904)
July	293,400,000	284,654,277	(8,745,723)	54.49	0.08805	13,625	0	0	0.00841	0	13,625
August	287,000,000	264,188,089	(22,811,911)	54.49	0.08805	35,540	0	0	0.00841	0	35,540
September	297,700,000	285,046,055	(12,653,945)	54.49	0.08805	19,714	0	364,212	0.00841	(3,063)	16,651
October	360,200,000	370,753,163	10,553,163	54.56	0.08805	(15,269)	0	6,332	0.00841	(53)	(15,322)
November	439,300,000	422,560,646	(16,739,354)	54.56	0.08805	24,219	0	1,334	0.00841	(11)	24,208
December	543,800,000	580,955,987	37,155,987	58.98	0.08805	206,923	0	10,841	0.00841	(91)	206,832
	4,925,800,000	4,990,327,693	64,527,693			257,127	0	390,900		(3,287)	253,840

(1) O is the Holyrood Operating Efficiency of 630 kWh/barrel.

NEWFOUNDLAND AND LABRADOR HYDRO **December 2007**

RATE STABILIZATION PLAN

Load Variation - Industrial

	A	B	C	D	E	F
	Cost of Service Sales	Actual Sales	Sales Variance	Cost of Service No. 6 Fuel Cost	Firm Energy Rate	Load Variation
	(kWh)	(kWh)	(kWh)	($)	($/kWh)	($)
			(B - A)			**C x {(D/O[1]) - E}** **(to page 11)**
January	78,300,000	64,661,303	(13,638,697)	54.17	0.03676	(671,353)
February	70,900,000	64,524,850	(6,375,150)	54.73	0.03676	(319,478)
March	76,600,000	75,618,369	(981,631)	55.46	0.03676	(50,330)
April	75,600,000	68,492,990	(7,107,010)	55.46	0.03676	(364,389)
May	69,500,000	75,131,721	5,631,721	55.46	0.03676	288,748
June	73,800,000	72,593,859	(1,206,141)	54.49	0.03676	(59,984)
July	77,500,000	71,183,392	(6,316,608)	54.49	0.03676	(314,138)
August	77,900,000	72,987,173	(4,912,827)	54.49	0.03676	(244,325)
September	73,000,000	56,815,786	(16,184,214)	54.49	0.03676	(804,874)
October	74,400,000	49,072,646	(25,327,354)	54.56	0.03676	(1,262,396)
November	74,100,000	46,331,086	(27,768,914)	54.56	0.03676	(1,384,091)
December	72,700,000	53,785,383	(18,914,617)	58.98	0.03676	(1,075,467)
	894,300,000	771,198,558	(123,101,442)			(6,262,077)

(1) O is the Holyrood Operating Efficiency of 630 kWh/barrel.

NEWFOUNDLAND AND LABRADOR HYDRO **December 2007**
RATE STABILIZATION PLAN
Summary of Utility Customer

	A	B	C	D	E	F	G
	Load Variation	Allocation Fuel Variance	Allocation Rural Rate Alteration [1]	Subtotal Monthly Variances	Financing Charges	Adjustment [2]	Cumulative Net Balance
	($)	($)	($)	($)	($)	($)	($)
				(A + B + C)			
	(from page 8)	**(from page 7)**					**(to page 12)**
Opening Balance [3]							(13,541,887)
January	14,973	(1,391,948)	104,050	(1,272,925)	(82,165)	164,589	(14,732,388)
February	(22,785)	(1,692,653)	102,324	(1,613,114)	(89,389)	155,995	(16,278,896)
March	(149)	(2,031,623)	100,826	(1,930,946)	(98,772)	154,532	(18,154,082)
April	(411)	(1,517,751)	101,241	(1,416,921)	(110,150)	130,996	(19,550,157)
May	(418)	(667,933)	99,708	(568,643)	(118,621)	110,664	(20,126,757)
June	(18,904)	(262,949)	100,834	(181,019)	(122,119)	90,055	(20,339,840)
July	13,625	35,583	119,807	169,015	(123,412)	990,597	(19,303,640)
August	35,540	16,553	182,434	234,527	(117,125)	919,375	(18,266,863)
September	16,651	(4,600)	180,937	192,988	(110,834)	993,228	(17,191,481)
October	(15,322)	188,834	174,219	347,731	(104,309)	1,290,243	(15,657,816)
November	24,208	834,938	191,024	1,050,170	(95,004)	1,470,516	(13,232,134)
December	206,832	1,485,190	201,464	1,893,486	(80,286)	2,021,765	(9,397,169)
Year to date	253,840	(5,008,359)	1,658,868	(3,095,651)	(1,252,186)	8,492,555	4,144,718
Hydraulic allocation **(from page 4)**							(5,262,203)
Total	253,840	(5,008,359)	1,658,868	(3,095,651)	(1,252,186)	8,492,555	(14,659,372)

(1) The Rural Rate Alteration is allocated between Utility and Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the approved Cost of Service Study, which is 89.10% and 10.90% respectively. The Labrador Interconnected amount is then removed from the plan and written off to net income (loss).

(2) The RSP adjustment rate for Utility is 0.029 cents per kWh effective January 1, 2007 to June 30, 2007 and 0.348 per kWh effective July 1, 2007.

(3) In accordance with Board Order P.U. 8 (2007), the December 31, 2006 Hydraulic Variation balance was allocated to the Industrial and Utility Customers as detailed in Schedule A of this report. This resulted in an adjustment of $5,726,000 to the opening balance due to Utility Customer.

NEWFOUNDLAND AND LABRADOR HYDRO

December 2007

RATE STABILIZATION PLAN

Summary of Industrial Customers

	A	B	C	D	E	F
	Load Variation	Allocation Fuel Variance	Subtotal Monthly Variances	Financing Charges	Adjustment [1]	Cumulative Net Balance
	($)	($)	($)	($)	($)	($)
			(A + B)			
	(from page 9)	**(from page 7)**				**(to page 12)**
Opening Balance						(14,406,474)
January	(671,353)	(208,922)	(880,275)	(87,411)	1,293,226	(14,080,934)
February	(319,478)	(254,748)	(574,226)	(85,436)	1,291,104	(13,449,492)
March	(50,330)	(319,382)	(369,712)	(81,605)	1,512,367	(12,388,442)
April	(364,389)	(228,179)	(592,568)	(75,167)	1,369,860	(11,686,317)
May	288,748	(105,927)	182,821	(70,907)	1,502,634	(10,071,769)
June	(59,984)	(37,158)	(97,142)	(61,110)	1,451,877	(8,778,144)
July	(314,138)	8,081	(306,057)	(53,261)	1,423,668	(7,713,794)
August	(244,325)	(9,696)	(254,021)	(46,803)	1,459,743	(6,554,875)
September	(804,874)	4,755	(800,119)	(39,772)	1,136,316	(6,258,450)
October	(1,262,396)	48,393	(1,214,003)	(37,973)	981,453	(6,528,973)
November	(1,384,091)	149,561	(1,234,530)	(39,615)	926,622	(6,876,496)
December	(1,075,467)	230,884	(844,583)	(41,724)	1,075,708	(6,687,095)
Year to date	(6,262,077)	(722,338)	(6,984,415)	(720,784)	15,424,578	7,719,379
Hydraulic allocation - page 4						(758,949)
2003 industrial plan balance Note 2						(1,382,924)
Total	(6,262,077)	(722,338)	(6,984,415)	(720,784)	15,424,578	(8,828,968)

(1) The RSP adjustment rate for Industrial Customers is 2.000 cents per kWh effective January 1, 2007.

(2) The balance of the December 2003 Plan related to Industrial customers will be recovered during 2008 as a component of the Current Plan in accordance with the Section E of the Rate Stabilization Plan Rules.

NEWFOUNDLAND AND LABRADOR HYDRO
RATE STABILIZATION PLAN
Overall Summary

December 2007

	A	B	C	D
	Hydraulic Balance	Utility Balance	Industrial Balance	Total To Date
	($)	($)	($)	($) **(A + B + C)**
	(from page 4)	**(from page 10)**	**(from page 11)**	
December 2006 [1]	0	(13,541,887)	(14,406,474)	(27,948,361)
January	(9,017,357)	(14,732,388)	(14,080,934)	(37,830,679)
February	(17,941,415)	(16,278,896)	(13,449,492)	(47,669,803)
March	(22,647,538)	(18,154,082)	(12,388,442)	(53,190,062)
April	(26,758,415)	(19,550,157)	(11,686,317)	(57,994,889)
May	(27,941,824)	(20,126,757)	(10,071,769)	(58,140,350)
June	(24,023,271)	(20,339,840)	(8,778,144)	(53,141,255)
July	(14,511,411)	(19,303,640)	(7,713,794)	(41,528,845)
August	(11,633,702)	(18,266,863)	(6,554,875)	(36,455,440)
September	(11,010,192)	(17,191,481)	(6,258,450)	(34,460,123)
October	(9,542,101)	(15,657,816)	(6,528,973)	(31,728,890)
November	(10,206,408)	(13,232,134)	(6,876,496)	(30,315,038)
December	(14,820,468)	(14,659,372)	(8,828,968)	(38,308,808)

(1) In accordance with Board Order P.U. 8 (2007), the December 31, 2006 Hydraulic Variation balance was allocated to the Industrial and Utility Customers as detailed in Schedule A of this report. This resulted in an adjustment of $5,726,000 to the current plan opening utility balance and a reduction of the hydraulic balance to 0.

NEWFOUNDLAND AND LABRADOR HYDRO **December 2007**

RATE STABILIZATION PLAN

Recovery of December 2003 Balance

	A	B	C	D	E	F	G
	Utility Customer			Island Industrial Customers			Total To Date
	Recovery [1]	Financing Charges	Total To Date	Recovery [2]	Financing Charges	Total To Date	Due From (To) Customers
	($)	($)	($)	($)	($)	($)	($)
			(A + B)			**(D + E)**	**(C + F)**
Opening Balance [3] [4]			34,393,834.05			7,144,242.96	41,538,077.01
January	(2,576,674.06)	208,684.59	32,025,844.58	(745,993.86)	43,347.69	6,441,596.79	38,467,441.37
February	(2,442,129.53)	194,316.81	29,778,031.86	(736,593.78)	39,084.39	5,744,087.40	35,522,119.26
March	(2,419,225.44)	180,678.21	27,539,484.63	(863,002.68)	34,852.25	4,915,936.97	32,455,421.60
April	(2,050,765.52)	167,095.82	25,655,814.93	(783,103.27)	29,827.45	4,162,661.15	29,818,476.08
May	(1,732,467.95)	155,666.66	24,079,013.64	(858,888.60)	25,256.95	3,329,029.50	27,408,043.14
June	(1,409,824.06)	146,099.42	22,815,289.00	(832,875.91)	20,198.89	2,516,352.48	25,331,641.48
July	(1,477,355.70)	138,431.77	21,476,365.07	(811,381.30)	15,267.97	1,720,239.15	23,196,604.22
August	(1,371,136.18)	130,307.85	20,235,536.74	(834,554.27)	10,437.55	896,122.43	21,131,659.17
September	(1,481,279.29)	122,779.12	18,877,036.57	(638,450.06)	5,437.22	263,109.59	19,140,146.16
October	(1,924,241.78)	114,536.42	17,067,331.21	(537,998.83)	1,596.42	(273,292.82)	16,794,038.39
November	(2,193,096.68)	103,556.03	14,977,790.56	(507,122.64)	(1,658.20)	(782,073.66)	14,195,716.90
December	(3,015,217.84)	90,877.74	12,053,450.46	(596,105.35)	(4,745.23)	(1,382,924.24)	10,670,526.22
Plan Expiry [5]						1,382,924.24	
Total	(24,093,414.03)	1,753,030.44	12,053,450.46	(8,746,070.55)	218,903.35	0.00	12,053,450.46

(1) The recovery rate for Utility is 0.454 cents per kWh effective January 1, 2007 to June 30, 2007 and 0.519 per kWh effective July 1, 2007.
(2) The recovery rate for Industrial Customers is 1.215 cents per kWh effective January 1, 2007.

(3) In accordance with Board Order P.U. 8 (2007), the December 31, 2006 Hydraulic Variation balance was allocated to the Industrial and Utility Customers as detailed in Schedule A of this report. This resulted in a reduction of $19,499,507 to the opening Utility Customer balance and a reduction of $2,085,787 to the Industrial Customers balance.

(4) In accordance with Board Order P.U. 1 (2007) AUR Resources was granted exclusion from the Historical Plan Balance effective January 20,2006. The 2007 opening balance has been increased by $129,103.36 to reflect a refund of $125,726.59 to AUR Resources for amounts collected from January 20 to December 31, 2006 and the associated financing charges of $3,376.77.

(5) The balance in plan for industrial customers will be recovered during 2008 as a component of the current plan in accordance with Section E of the Rate Stabilization Plan rules.

NEWFOUNDLAND AND LABRADOR HYDRO **December 2007**

RATE STABILIZATION PLAN

RATE STABILIZATION PLAN, DECEMBER 31, 2006 ADJUSTMENTS'

Line No.		Balance December 2006 RSP Report	Adjustment	Revised Balance	Comments - Adjustment	
1	Hydraulic Production Variation Balance	(15,977,692)	15,977,692	-	Line 6	
2	Summary of Utility Customer	(19,267,887)	5,726,000	(13,541,887)	Hydraulic allocation moved to Historic Plan	
3	Summary of Industrial Customers	(14,406,474)		(14,406,474)	No Change	
4	Recovery of December 2003 Balance - Utility	53,893,341	(19,499,507)	34,393,834	Line 2 Adjustment plus Line 7 Net	
5	Recovery of December 2003 Balance - Industrial Customers	9,100,931	(2,085,787)	7,015,143	Line 8 Net	
	Hydraulic Production Variation Balance Adjustment					
6	Balance December 31, 2006	15,977,692				
	Allocation:					
		12 month (Dec 2006) kWh	% of kWh to total	Allocation	Reallocate Rural	Net
7	Utility	4,616,864,312	80.5%	12,855,149	918,358	13,773,507
8	Industrial	749,100,463	13.1%	2,085,787		2,085,787
9	Rural	372,345,900	6.5%	1,036,756	(1,036,756)	-
10		5,738,310,675	100.0%	15,977,692	(118,398)	15,859,294
11	Labrador Interconnected (write-off to income)				118,398	118,398
12					-	15,977,692

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NEWFOUNDLAND & LABRADOR HYDRO
CAPITAL EXPENDITURES - OVERVIEW
FOR THE YEAR ENDED DECEMBER 31
($000)

This section will be filed as a

Separate Document

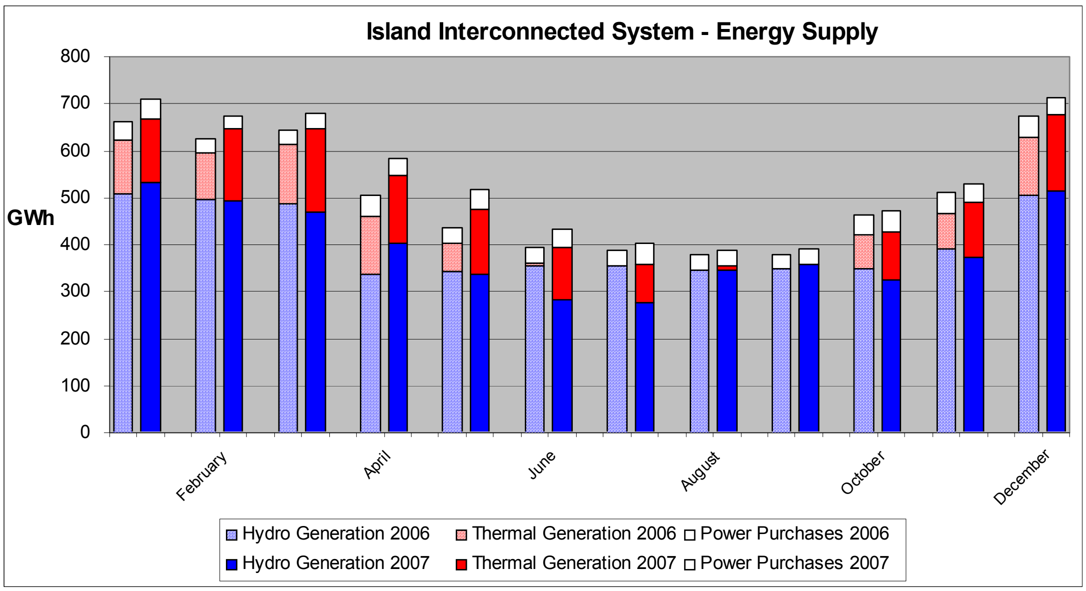
Energy Supply - Island Interconnected System

Production and Purchases

Annual production from Hydro's hydroelectric plants was lower than 2006 due to lower than average inflows. However, it was above the long-term average because of the high storage position at the beginning of the year.

Power purchases were higher than 2006 and the long-term average, due primarily to unusually high secondary energy purchases from Abitibi Bowater in Grand Falls. That paper mill experienced a fire in June which caused a shutdown of paper production. Also in October, the mill took some production downtime. During both periods, the hydro plant operations remained in service resulting in secondary sales to Hydro.

Thermal production was higher than 2006 due to lower hydraulic production and higher system load requirements.

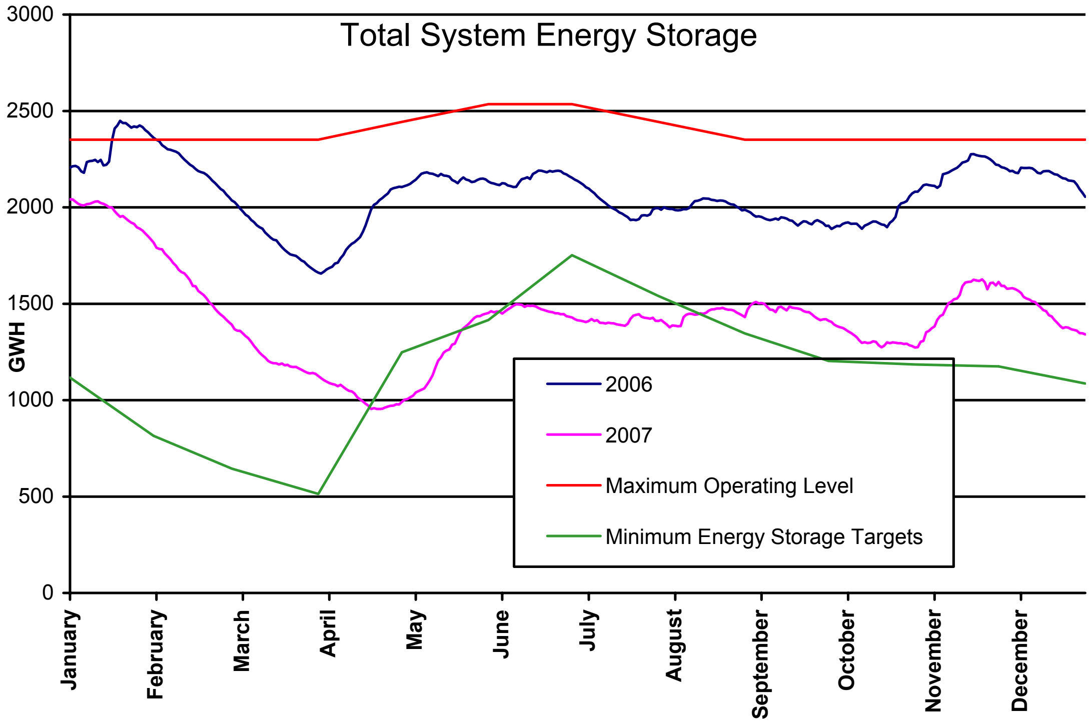


Island Interconnected System Production and Purchases
For the Year Ended December 31

	YTD 2007 {GWh}	YTD Forecast {GWh}	YTD 2006 {GWh}	Annual Forecast {GWh}
Production (NET)				
Hydro	4,689.4	4,655.3	4,802.5	4,655.3
Thermal	1,255.6	1,363.4	740.1	1,363.4
Gas Turbines	(10.1)	(4.4)	(9.1)	(4.4)
Diesels	0.1	0.1	(0.3)	0.2
Total Production	**5,935.0**	**6,014.5**	**5,533.2**	**6,014.5**
Purchases				
NUGS	389.4	398.3	426.5	383.2
Secondary and Other	64.6	54.3	22.2	54.3
Total Purchases	**454.0**	**452.6**	**448.7**	**437.4**
Island Interconnected Total Produced and Purchased	**6,389.0**	**6,467.1**	**5,981.9**	**6,451.9**

System Hydrology

Reservoir storage levels declined during 2007 due to low inflows and lower minimum storage requirements. At the end of the year, storage levels remained well above the minimum targets which will enable continued above-average hydroelectric production in the early part of 2008.



Energy Supply - Labrador Interconnected System

The purchased and produced energy on the Labrador Interconnected System to the end of December 2007 was consistent with the forecast and with the same period of 2006.

Labrador Interconnected System Production and Purchases

For the Year Ended December 31

	YTD 2007 {GWh}	YTD Forecast {GWh}	YTD 2006 {GWh}	Annual Forecast {GWh}
Production (NET)				
Gas Turbines	(2.2)	0.1	(1.7)	0.1
Diesels	(0.7)	(0.2)	(0.5)	(0.2)
Total Production Lab.	**(2.9)**	**(0.1)**	**(2.2)**	**(0.1)**
Purchases				
CF(L)Co. (at border)	**2,362.0**	**2,362.0**	**2,362.0**	**2,362.0**
Labrador Interconnected Total Produced and Purchased	**2,359.1**	**2,361.9**	**2,359.8**	**2,361.9**

Fuel Prices

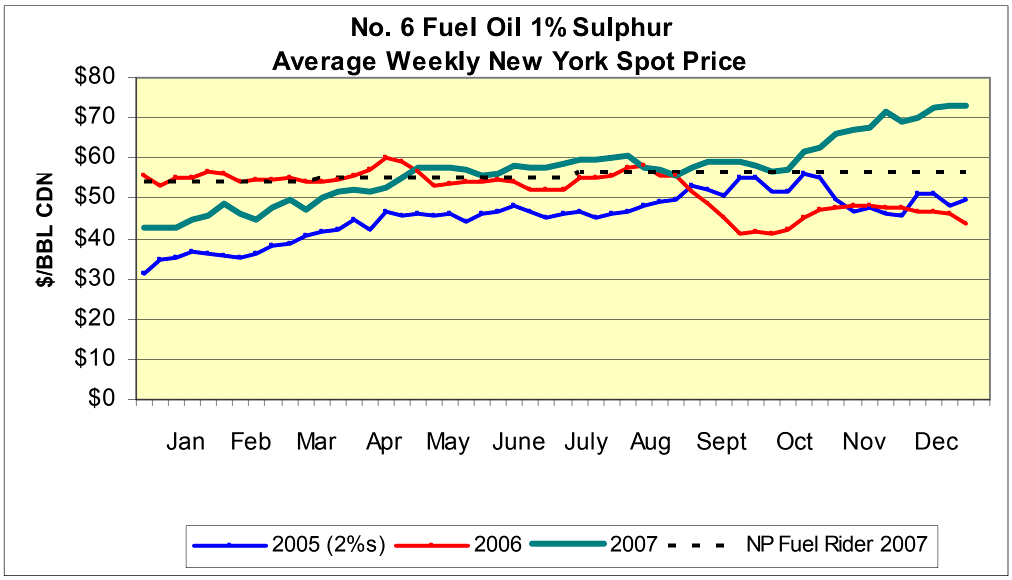
The fourth quarter market prices for No. 6 fuel increased substantially from approximately $56/bbl to $73/bbl. At the end of the quarter, the average inventory cost was $66.64/bbl compared to the current Newfoundland Power fuel price rider of $56.60/bbl. There is no Industrial Customer fuel price rider for 2007.

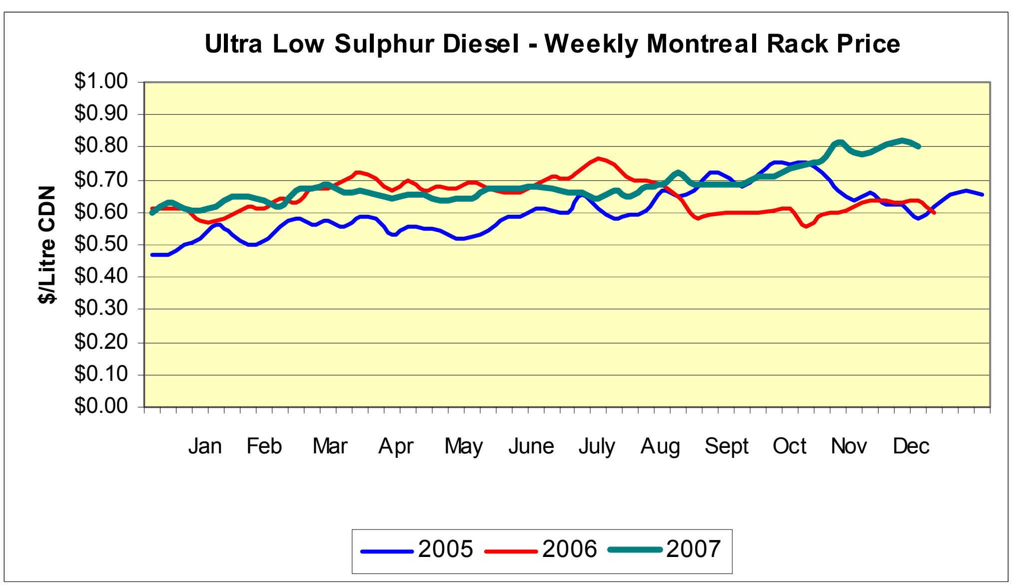
There were two shipments during the fourth quarter of 2007:

November 18	272,031 bbls	$63.23/bbl
December 15	275,289 bbls	$66.64/bbl

The inventory on December 31 was 498,388 barrels.

The following charts show the No. 6 and Low Sulphur Diesel No. 1 fuel prices year to date compared to 2005 and 2006.





The following table provides the monthly forecast price of No. 6 fuel (1.0% sulphur) up to December 2008, landed on the Avalon Peninsula.

Month	Price ($Cdn/bbl)	Month	Price ($Cdn/bbl)
January 2008	74.90	July 2008	55.30
February 2008	66.90	August 2008	55.70
March 2008	63.70	September 2008	55.60
April 2008	62.30	October 2008	58.70
May 2008	60.70	November 2008	61.60
June 2008	56.10	December 2008	58.50

Note: The forecast is based on the PIRA Energy Group short-term price forecast of December 26, 2007, and a spot market exchange on December 31, 2007.

Energy Supply - Isolated Systems

In 2007, net isolated electricity supply (production and purchases) increased by 4.2% from 2006. The increase is largely attributed to colder weather. However, the Labrador isolated systems continue to experience modest customer and load growth.

Isolated Systems Production
For the Year Ended December 31

	YTD 2007 {GWh}	YTD Forecast {GWh}	YTD 2006 {GWh}	Annual Forecast {GWh}
Production (NET)				
Diesels	43.52	43.96	42.23	43.96
Purchases				
NUGS	0.55	0.96	0.65	0.96
Hydro Quebec	16.95	17.09	15.66	17.09
Total Purchases	**17.50**	**18.05**	**16.31**	**18.05**
Total Produced and Purchased	**61.02**	**62.01**	**58.54**	**62.01**

Bulk Power System Delivery Point Interruption Performance

The frequency of sustained outages in the fourth quarter of 2007 increased about 80% over those in the same quarter of the previous year due to increases in forced outages. Forced outages increased by over 400% and planned outages decreased by 44%.

The increase in forced outages was mainly due to weather related problems. A snow and wind storm on December 2nd caused an interruption to the Avalon and Burin Peninsulas. The St. John's area experienced outages ranging from 30 minutes to two hours. Other areas on the Avalon experienced momentary and short duration outages. Problems on the Hydro Québec system resulted in two interruptions to Happy Valley for about 45 minutes in total. These interruptions were caused by severe weather east of Montreal causing the Churchill Falls Plant to trip. A major wind storm on the Great Northern Peninsula resulted in heavy salt contamination on TL221 on November 4th to 7th. There were ten interruptions ranging from one to 14 minutes to customers in the Hawke's Bay and Port Saunders areas.

VOLTAGE CLASS	SAIFI (Number per Delivery Point in Period)				
	FOURTH QUARTER 2007	FOURTH QUARTER 2006	12 MTHS TO DATE 2007	12 MTHS TO DATE 2006	5 YEAR AVERAGE* (2002-2006)
66 kV	0.71	0.75	4.04	3.00	3.18
138 kV	1.13	0.25	3.25	1.25	2.08
230 kV	0.22	0.00	0.64	0.21	0.40
Forced Only	**0.53**	**0.12**	**1.75**	**0.88**	**1.37**
Planned Only	**0.14**	**0.25**	**0.99**	**0.75**	**0.60**
Total	**0.67**	**0.37**	**2.74**	**1.63**	**1.95**

Note: System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per delivery point. It is calculated by dividing the number of delivery point interruptions by the total number of delivery points of the appropriate voltage class(es).

The total interruption time per delivery point decreased by 64%. The improvement in the duration of interruptions over the same quarter as last year was due to a reduction in both forced and planned outage durations. In 2006, a major storm in St. Anthony and Roddickton resulted in a multi-hour outage that greatly affected the SAIDI performance.

VOLTAGE CLASS	SAIDI (Hours per Delivery Point per Period)				
	FOURTH QUARTER 2007	FOURTH QUARTER 2006	12 MTHS TO DATE 2007	12 MTHS TO DATE 2006	5 YEAR AVERAGE* (2002-2006)
66 kV	0.13	1.21	5.71	5.06	3.48
138 kV	0.55	0.52	2.40	1.54	3.15
230 kV	0.07	0.00	0.41	0.14	0.88
Forced Only	**0.12**	**0.23**	**1.75**	**0.94**	**1.40**
Planned Only	**0.10**	**0.40**	**1.37**	**1.58**	**1.13**
Total	**0.23**	**0.63**	**3.12**	**2.52**	**2.52**

Note: System Average Interruption Duration Index (SAIDI) is the time power was not available to a typical delivery point.

The average interruption restoration time index improvement reflects the increased outage frequency and lower interruption time.

VOLTAGE CLASS	SARI (Hours per Interruption)				
	FOURTH QUARTER 2007	FOURTH QUARTER 2006	12 MTHS TO DATE 2007	12 MTHS TO DATE 2006	5 YEAR AVERAGE* (2002-2006)
66 kV	0.19	1.61	1.41	1.69	1.09
138 kV	0.49	2.09	0.74	1.23	1.51
230 kV	0.33	0.00	0.64	0.68	2.20
Forced Only	**0.23**	**1.97**	**1.00**	**1.07**	1.02
Planned Only	**0.76**	**1.57**	**1.39**	**2.12**	1.88
Total	**0.34**	**1.70**	**1.14**	**1.55**	1.29

Note: System Average Restoration Index (SARI) is the average duration of each interruption experienced during the period. It is calculated by dividing the period SAIDI value by the period SAIFI value.

*5 year average includes both forced and planned outages unless noted.

System Underfrequency Load Shedding Performance

Three underfrequency events occurred during this quarter. The following section outlines the details of each event.

The first occurred on October 12th at 1228 hours, when Holyrood Unit #3 tripped due to a fuel control problem. The sudden loss of 77 MW of generation caused the system frequency to drop to 58.68 Hz and load shedding at Newfoundland Power, Deer Lake Power, and for Hydro's rural customers.

Event Characteristics		
	Load Shed (MW)	Duration (Minutes)
NP	25	5
DLP	15	5
NLH Rural	2	2

The second occurred on November 26th at 1208 hours, when Holyrood Unit #1 tripped due to a drum level problem. The sudden loss of 133 MW of generation caused the system frequency to drop to 58.39 Hz and load shedding at Newfoundland Power, Deer Lake Power, Abitibi Bowater at Grand Falls and for Hydro's rural customers.

Event Characteristics		
	Load Shed (MW)	Duration (Minutes)
NP	95	5
AB GF	15	5
DLP	15	5
NLH Rural	8	1

The third occurred on December 28th at 1421 hours, when Holyrood Unit #1 tripped due to a lube oil pump failure. The sudden loss of 120 MW of generation caused the system frequency to drop to 58.44 Hz and load shedding at Newfoundland Power, Deer Lake Power, and for Hydro's rural customers.

Event Characteristics		
	Load Shed (MW)	Duration (Minutes)
NP	75	5
DLP	20	5
NLH Rural	5	3

Underfrequency Load Shedding Number of Events					
CUSTOMERS	**FOURTH QUARTER 2007**	**FOURTH QUARTER 2006**	**YEAR TO DATE 2007**	**YEAR TO DATE 2006**	**5 YEAR AVERAGE 2002-2006**
Nfld. Power	3	2	6	6	8.6
Industrials	3	2	6	6	9.4
Hydro Rural*	3	1	6	5	5.8
Total Events	3	2	6	6	9.4

Underfrequency Load Shedding Unsupplied Energy (MW-min)					
CUSTOMERS	**FOURTH QUARTER 2007**	**FOURTH QUARTER 2006**	**YEAR TO DATE 2007**	**YEAR TO DATE 2006**	**5 YEAR AVERAGE 2002-2006**
Nfld. Power	975	120	1,503	338	2,683
Industrials	280	180	450	1,029	4,502
Hydro Rural*	25	3	69	51	163
Total	1,280	303	2,022	1,418	7,348

* Underfrequency activity affecting Hydro Rural Customers may also result in a number of delivery point outages. Outage frequency and duration are also included in totals shown in the delivery point statistics section of the report for these areas. These areas are the Connaigre Peninsula and Bonne Bay.

Rural Systems Service Continuity Performance by Area

The frequency of outages in the fourth quarter of 2007 increased approximately 81% when compared to the same quarter of the previous year. This increase was mainly due to problems in Labrador West.

Labrador West experienced seven major outages this quarter. Four interruptions affected both the towns of Labrador City and Wabush. Three of these interruptions were caused by loss of supply as the result of problems with the transmission system from Churchill Falls, each with a duration of approximately one hour. The other outage occurred after an insulator failed on a 46 kV feeder during maintenance work at the Wabush Terminal Station; both towns were being fed from one supply point at the time of the trip. This outage had duration of one hour and 30 minutes.

There were two outages which affected the town of Wabush with duration of 45 minutes each. One outage had an unknown cause and the other was the result of a problem with a circuit breaker at the Wabush Substation. An outage to Labrador City, duration of 55 minutes, was caused by an unknown problem which occurred during switching operations at the Labrador City Switching Station.

	SAIFI (Number per Period)				
AREA	FOURTH QUARTER 2007	FOURTH QUARTER 2006	12 MTHS TO DATE 2007	12 MTHS TO DATE 2006	5 YEAR AVERAGE
CENTRAL					
Interconnected	0.90	0.52	3.40	2.92	4.41
Isolated	0.84	0.95	2.36	5.53	4.85
NORTHERN					
Interconnected	1.32	1.16	4.55	4.74	4.91
Isolated	1.59	2.41	8.52	7.65	14.08
LABRADOR					
Interconnected	4.45	1.62	11.46	8.32	8.41
Isolated	1.86	1.08	7.90	9.27	10.57
Totals	2.01	1.11	6.22	5.38	6.34

Note: System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers in an area.

The duration of outages increased by 2% relative for the same quarter of last year.

	SAIDI (Hours per Period)				
AREA	FOURTH QUARTER 2007	FOURTH QUARTER 2006	12 MTHS TO DATE 2007	12 MTHS TO DATE 2006	5 YEAR AVERAGE
CENTRAL					
Interconnected	2.15	1.57	7.70	6.79	10.93
Isolated	0.49	5.28	1.54	8.52	4.53
NORTHERN					
Interconnected	1.76	3.04	7.42	7.72	8.70
Isolated	2.12	3.33	6.84	6.17	13.54
LABRADOR					
Interconnected	3.30	1.69	11.53	9.84	9.49
Isolated	0.97	1.50	14.92	11.01	11.53
Totals	2.24	2.18	8.72	8.02	9.95

Note: System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.

Rural Systems Service Continuity Performance by Origin

The following table shows that the increase in the frequency of outages was mainly due to Loss of Supply, Transmission type outages that increased some 200% over the same quarter last year.

AREA	SAIFI (Number per Period) FOURTH QUARTER 2007	FOURTH QUARTER 2006	12 MTHS TO DATE 2007	12 MTHS TO DATE 2006	5 YEAR AVERAGE
Loss of Supply - Transmission	1.24	0.44	3.12	2.12	2.06
Loss of Supply - Nfld. Power	0.00	0.00	0.00	0.00	0.01
Loss of Supply - Isolated	0.11	0.11	0.49	0.66	0.63
Loss of Supply - L'Anse au Loup	0.00	0.03	0.00	0.08	0.17
Distribution	0.65	0.53	2.60	2.53	3.47
Totals	2.01	1.11	6.22	5.38	6.34

Note: System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers in an area.

The slight increase in outage duration resulted from an increase in distribution related outages of 12%.

AREA	SAIDI (Hours per Period) FOURTH QUARTER 2007	FOURTH QUARTER 2006	12 MTHS TO DATE 2007	12 MTHS TO DATE 2006	5 YEAR AVERAGE
Loss of Supply - Transmission	0.74	0.79	2.54	2.60	2.20
Loss of Supply - Nfld. Power	0.00	0.00	0.00	0.00	0.06
Loss of Supply - Isolated	0.04	0.08	0.18	0.31	0.23
Loss of Supply - L'Anse au Loup	0.00	0.01	0.00	0.02	0.05
Distribution	1.47	1.30	6.00	5.09	7.40
Totals	2.24	2.18	8.72	8.02	9.95

Note: System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.

Rural Systems Service Continuity Performance by Type

The following table provides a breakdown of the totals in the previous tables for the latest quarter by scheduled and unscheduled interruptions.

	SCHEDULED		UNSCHEDULED		TOTAL	
AREA	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI
CENTRAL						
Interconnected	0.22	0.67	0.68	1.48	0.90	2.15
Isolated	0.00	0.00	0.84	0.49	0.84	0.49
NORTHERN						
Interconnected	0.24	1.11	1.09	0.65	1.32	1.76
Isolated	0.01	0.03	1.58	2.09	1.59	2.12
LABRADOR						
Interconnected	0.11	0.04	4.22	3.18	4.33	3.21
Isolated	0.19	0.07	1.67	0.90	1.86	0.97
Totals	0.18	0.55	1.80	1.67	1.98	2.22

Note:

1. System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers in an area.

2. System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g., a two hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.

Generation Equipment Performance

The table below highlights the various performance indices for Hydro's generation facilities. Indices for 2006 and for the latest Canadian Electricity Association (CEA) national average for the period 2001 to 2005 are included for comparison.

Index		Hydraulic	Thermal	Gas Turbine
Failure Rate (Forced Outages per 8760 operating hours)	NLH 2007	2.63	11.64	384.33
	NLH 2006	1.61	14.00	155.09
	CEA '01-'05	2.31	10.56	10.12
Incapability Factor (Percent of Time)	NLH 2007	6.21	46.68	15.39
	NLH 2006	7.15	35.82	17.61
	CEA '01-'05	8.77	18.91	10.63
Derating Adjusted Forced Outage Rate (Percent of Time)	NLH 2007	0.34	23.98	
	NLH 2006	0.67	13.17	
	CEA '01-'05	1.85	11.07	
Utilization Forced Outage Probability	NLH 2007			9.06
	NLH 2006			17.93
	CEA '01-'05			9.72

Hydraulic Unit Performance

Hydraulic unit performance improved in 2007 as compared to 2006, except for failure rate. Failure rate decreased below the national average in 2007 due to an increase in forced outages on Cat Arm Unit #1 and the Upper Salmon plant. Hydraulic unit incapability and derating adjusted forced outage rate continues to be better than the national average.

Thermal Unit Performance

Thermal unit performance decreased in 2007. The incapability factor and forced outage rates both increased due a series of failures. The failure rate improved slightly in 2007 and is getting closer to the national average.

Gas Turbine Unit Performance

Hydro's gas turbines failure rate increased significantly in 2007 from 2006. However, as previously reported, due to the nature of the calculation of failure rate, units with very low operating factors, such as those operated by Hydro, tend to have high failure rates. The incapability factor for Hydro's gas turbines had a slight improvement in 2007.

Of particular importance to Hydro's use of gas turbines is the Utilization Forced Outage Probability. The measure describes the degree to which a standby unit can be called upon to supply load when requested. In 2007, the rate improved significantly and is now better than the national average.

NEWFOUNDLAND AND LABRADOR HYDRO
CONTRIBUTION IN AID OF CONSTRUCTION
FOR YEAR ENDED DECEMBER 31

The table below summarizes Contribution in Aid of Construction (CIAC) activity for this quarter. The table is divided into three sections.

The first section outlines the type of service for which a CIAC has been calculated, either Domestic or General Service.

The second section indicates the number of CIAC's quoted during the quarter as well as the number of CIAC quotes that remained outstanding at the end of the previous quarter. This format facilitates a reconciliation of the total number of CIAC's that were active during the quarter.

The third section provides information as to the disposition of the total CIAC's quoted. A CIAC is considered accepted when a customer indicates they wish to proceed with construction of the extension and has agreed to pay any charge that may be applicable. A CIAC is considered outdated after six months has elapsed and the customers have not indicated their intention to proceed with the extension. A quoted CIAC is outstanding if it is neither accepted nor outdated.

TYPE OF SERVICE	CIAC'S QUOTED	CIAC'S OUTSTANDING PREVIOUS QTR.	TOTAL CIAC'S QUOTED	CIAC'S ACCEPTED	CIAC'S OUTDATED	TOTAL CIAC'S OUTSTANDING
Domestic						
Within Plan. Boundary	2	0	2	1	0	1
Outside Plan. Boundary	7	8	15	3	3	9
Sub-total	9	8	17	4	3	10
General Service	6	8	14	2	5	7
Total	15	16	31	6	8	17

NEWFOUNDLAND AND LABRADOR HYDRO
CIAC QUARTERLY ACTIVITY REPORT
FOR THE YEAR ENDED DECEMBER 31

DATE QUOTED	CUSTOMER NAME	SERVICE LOCATION	CIAC NO.	CIAC AMOUNT ($)	ESTIMATED CONST. COST ($)	ACCEPTED
DOMESTIC - WITHIN RESIDENTIAL PLANNING BOUNDARIES						
Oct 2, 2007	Guy MacDonald	Conne River	605648	$1,425.00	$3,550.00	
Oct 2, 2007	Tyson John	Conne River	603812	$1,400.00	$3,525.00	Yes
DOMESTIC - OUTSIDE RESIDENTIAL PLANNING BOUNDARIES						
Oct 2, 2007	Arthur Weir	Knight's Development	607752	$2,460.00	$3,060.00	
Oct 17, 2007	Levi Reid	Northwest Arm Sect C[1]	605831	$2,235.00	$2,388.00	Yes
Oct 17, 2007	Rennie Normore	Burnt Berry Pond III [1]	611163	$1,898.10	$2,548.10	Yes
Oct 23, 2007	Roger Patey	Western Brook	608997	$1,900.00	$2,525.00	Yes
Nov 13, 2007	Paul Dunphy	Western Brook Road [2]	614352	$2,050.00	$2,675.00	
Nov 14, 2007	Bruce Heath	Knight's Development	423616	$2,800.00	$3,425.00	
Dec 13, 2007	Nicole Crocker	Shoal Cove Pond	618524	$1,162.00	$2,537.00	
GENERAL SERVICE						
Oct 1, 2007	Labrador Fur Farms	Capstan Island	571008	$8,951.90	$11,436.90	
Oct 18, 2007	Brian Gill	Trout River	609509	$875.00	$3,000.00	
Oct 23, 2007	Birch Brook Ski Club	Happy Valley-Goose Bay	556681	$3,185.00	$6,400.00	
Nov 7, 2007	Labrador Fur Farms	Capstan Island	571008	$13,861.90	$21,836.90	Yes
Nov 8, 2007	Town of Rocky Harbour	Waste Management Site	612854	$1,993.00	$8,820.00	Yes
Dec 4, 2007	Dept of Trans. & Works	Lab City Hosp.- proposed	603626	$99,578.60	$539,553.60	

[1] An existing serviced cottage area

[2] CIAC per customer based on 6 potential customers.

NEWFOUNDLAND & LABRADOR HYDRO
CUSTOMER PROPERTY DAMAGE CLAIMS REPORT
FOR YEAR ENDED DECEMBER 31

Introduction

The Customer Property Damage Claims Report contains an overview of all damage claims activity summarized on a quarterly basis. The information contained in the report is broken down by cause as well as by the operating region where the claims originated.

The report is divided into four sections as follows:

1. The first section indicates the number of claims received during the quarter coupled with claims outstanding from the previous quarter.

2. The second section shows the number of claims for which the Company has accepted responsibility and the amount paid to claimants versus the amount originally claimed.

3. The third section shows the number of claims rejected and the dollar value associated with those claims.

4. The fourth section indicates those claims that remain outstanding at the end of the current quarter and the dollar value associated with such claims.

Definitions of Causes of Damage Claims

1. System Operations: Claims arising from system operations. Examples include normal reclosing or switching.

2. Power Interruptions: Claims arising from interruption of power supply. Examples include all scheduled or unscheduled interruptions.

3. Improper Workmanship: Claims arising from failure of electrical equipment caused by improper workmanship or methods. Examples include improper crimping of connections, insufficient sealing and taping of connections, improper maintenance, inadequate clearance or improper operation of equipment.

4. Weather Related: Claims arising from weather conditions. Examples include wind, rain, ice, lighting or corrosion caused by weather.

5. Equipment Failure: Claims arising from failure of electrical equipment not caused by improper workmanship. Examples include broken neutrals, broken tie wires, transformer failure, insulator failure or broken service wire.

6. Third Party: Claims arising from equipment failure caused by acts of third parties. Examples include motor vehicle accidents and vandalism.

7. Miscellaneous: All claims not related to electrical service.

8. Waiting Investigation: Cause to be determined.

NEWFOUNDLAND & LABRADOR HYDRO
CUSTOMER PROPERTY DAMAGE CLAIMS REPORT
BY CAUSE:

FOR THE QUARTER ENDED DECEMBER 31, 2007										
CAUSE	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	AMT. CLAIMED	AMT. PAID	#	AMOUNT	#	AMOUNT
System Operations	3	0	3	0	$0.00	$0.00	3	$470.00	0	$0.00
Power Interruptions	3	5	8	0	$0.00	$0.00	6	$9,163.23	2	$5,516.33
Improper Workmanship[1]	7	1	8	6	$6,340.83	$4,973.00	0	$0.00	2	$323.63
Weather Related	3	0	3	0	$0.00	$0.00	3	$387.60	0	$0.00
Equipment Failure	26	16	42	31	$19,137.00	$13,314.53	0	$0.00	11	$23,368.85
Third Party	0	0	0	0	$0.00	$0.00	0	$0.00	0	$0.00
Miscellaneous	0	1	1	0	$0.00	$0.00	0	$0.00	1	$0.00
Waiting Investigation	0	0	0	0	$0.00	$0.00	0	$0.00	0	$0.00
Total	42	23	65	37	$25,477.83	$18,287.53	12	$10,020.83	16	$29,208.81

FOR THE QUARTER ENDED DECEMBER 31, 2006										
CAUSE	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	AMT. CLAIMED	AMT. PAID	#	AMOUNT	#	AMOUNT
System Operations	0	0	0	0	$0.00	$0.00	0	$0.00	0	$0.00
Power Interruptions	8	7	15	0	$0.00	$0.00	8	$10,729.68	7	$8,919.99
Improper Workmanship	1	2	3	1	$14,188.61	$14,188.61	1	$190.00	1	$0.00
Weather Related	2	2	4	0	$0.00	$0.00	1	$784.00	3	$10,070.51
Equipment Failure	5	5	10	5	$4,187.17	$3,312.42	2	$454.95	3	$1,555.00
Third Party	0	0	0	0	$0.00	$0.00	0	$0.00	0	$0.00
Miscellaneous	0	0	0	0	$0.00	$0.00	0	$0.00	0	$0.00
Waiting Investigation	0	0	0	0	$0.00	$0.00	0	$0.00	0	$0.00
Total	16	16	32	6	$18,375.78	$17,501.03	12	$12,158.63	14	$20,545.50

Note:
[1] Includes a pending claim for the St. Anthony Hospital incident. No amount is yet available.

NEWFOUNDLAND AND LABRADOR HYDRO
CUSTOMER PROPERTY DAMAGE CLAIMS REPORT
BY REGION:

FOR THE QUARTER ENDED DECEMBER 31, 2007										
REGION	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	AMT. CLAIMED	AMT. PAID	#	AMOUNT	#	AMOUNT
Central Region	9	4	13	4	$5,740.75	$4,372.92	3	$2,443.97	6	$6,659.96
Northern Region	8	5	13	6	$3,195.31	$1,765.89	3	$5,915.59	4	$2,877.87
Labrador Region	25	14	39	27	$16,541.77	$12,148.72	6	$1,661.27	6	$19,670.98
Total	42	23	65	37	$25,477.83	$18,287.53	12	$10,020.83	16	$29,208.81

FOR THE QUARTER ENDED DECEMBER 31, 2006										
REGION	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	AMT. CLAIMED	AMT. PAID	#	AMOUNT	#	AMOUNT
Central Region	3	7	10	2	$825.00	$683.75	3	$614.53	5	$9,710.99
Northern Region	9	3	12	2	$1,847.17	$1,492.17	4	$4,494.00	6	$8,525.00
Labrador Region	4	6	10	2	$15,703.61	$15,325.11	5	$7,050.10	3	$2,309.51
Total	16	16	32	6	$18,375.78	$17,501.03	12	$12,158.63	14	$20,545.50

NEWFOUNDLAND AND LABRADOR HYDRO
MAINTENANCE PLAN & ASSOCIATED RELIABILITY STANDARDS UPDATE
FOR YEAR ENDED DECEMBER 31

Hydro is developing a maintenance plan, which is a formal consolidation, validation and documentation of Hydro's established maintenance plans, including recommendations for required changes. It is an ongoing and continuous process which started in 2007.

The goal for 2007 was to review maintenance plans for 50% of Hydro's gas turbines and 25% of the Holyrood thermal plant.

2007 Schedule

Gas Turbines
Work for 50% of gas turbines is substantially complete.

Holyrood Plant
Consolidation of Holyrood maintenance plans has begun.

2008 Work Plan

First Quarter:
Final documentation of the targeted gas turbine systems will be available.
Scope and extent of the work for Holyrood systems will be established, and a timeline established.
Identify future priority focus areas for reviews.

Second Quarter:
Review remaining gas turbines.

NEWFOUNDLAND AND LABRADOR HYDRO
RAMEA WIND-HYDROGEN-DIESEL SYSTEM UPDATE
FOR YEAR ENDED DECEMBER 31

In Order No. P.U. 31 (2007), The Board of Commissioners of Public Utilities directed Hydro to provide a quarterly update on the status of the Wind-Hydrogen-Diesel System in each quarterly report, setting out details as to implementation and operation of this system, capital and operating costs, variances from budget, reliability and safety issues.

Implementation and Operation
There is nothing to report for this period as implementation and operation are planned for December 2008.

Capital Costs

($000)

Actual to Dec. 2007	Budget to Dec. 2008
361	8,794

Operating Costs
There is nothing to report for this period as operation is planned to start in December 2008.

Variances from Budget
There are no variances from budget to report for this period.

Reliability and Safety Issues
There are no reliability or safety issues to report for this period.

NEWFOUNDLAND & LABRADOR HYDRO
STATEMENT OF ENERGY SOLD (GWh)
FOR THE YEAR ENDED DECEMBER 31

	YEAR TO DATE			2007*
	2007 ACTUAL	2007* FORECAST	2006 ACTUAL	ANNUAL FORECAST
Island Interconnected				
Newfoundland Power	4,991	4,992	4,617	4,992
Island Industrials	827	888	798	888
Rural				
Domestic	217	223	209	223
General Service	144	144	134	144
Streetlighting	3	3	3	3
Sub-total Rural	364	370	346	370
Sub-Total Island Interconnected	6,182	6,250	5,761	6,250
Island Isolated				
Domestic	6	6	6	6
General Service	2	2	2	2
Streetlighting	0	0	0	0
Sub-Total Island Isolated	8	8	8	8
Labrador Interconnected				
Labrador Industrials	257	253	289	253
CFB Goose Bay	63	72	70	72
Hydro Quebec	1,502	1,492	1,483	1,492
Rural				
Domestic	263	271	241	271
General Service	202	211	191	211
Streetlighting	2	2	2	2
Sub-total Rural	467	484	434	484
Sub-Total Lab. Interconnected	2,289	2,301	2,276	2,301
Labrador Isolated				
Domestic	19	20	19	20
General Service	14	13	13	13
Streetlighting	0	0	0	0
Sub-Total Labrador Isolated	33	33	32	33
L'Anse au Loup				
Domestic	9	9	9	9
General Service	6	6	6	6
Streetlighting	0	0	0	0
Sub-Total L'Anse au Loup	15	15	15	15
Total Energy Sold (Before Rural Accrual)	8,527	8,607	8,092	8,607
Rural Accrual	-	-	-	-
Total Energy Sold	8,527	8,607	8,092	8,607

* Rural GWh - Based on 2007 Load forecast.
Non-rural GWh - Based on October 23, 2007 and May 28, 2007 Load forecasts.

TAB Appendix

NEWFOUNDLAND & LABRADOR HYDRO
CUSTOMER STATISTICS
FOR THE YEAR ENDED DECEMBER 31

	FOURTH QUARTER		ANNUAL	
	2007 ACTUAL	2006 ACTUAL	2007 FORECAST	2006 ACTUAL
Customers				
Rural	35,610	35,371	35,885	35,371
Industrial	6	7	7	7
CFB Goose Bay	1	1	1	1
Utility	1	1	1	1
Hydro Quebec	1	1	1	1
Reading Days	29.7	29.7	N/A	30.0

NEWFOUNDLAND & LABRADOR HYDRO
SAFETY STATISTICS
FOR THE YEAR ENDED DECEMBER 31

Safety & Health Index Values

ACCIDENTS	YTD FOURTH QUARTER 2007	YTD FOURTH QUARTER 2006
All Injury Frequency Rate	1.36	2.03
Disabling Frequency Rate	0.62	1.14
Severity Rate	2.97	4.06

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

QUARTERLY REGULATORY REPORT

FOR THE YEAR ENDED DECEMBER 31, 2008

NEWFOUNDLAND AND LABRADOR HYDRO

Table of Contents

1 HIGHLIGHTS

HIGHLIGHTS
For the Year ended December 31, 2008

REGULATED	2008 Actual YTD	2008 Target/ Budget	2007 Actual YTD
Safety			
Lead:Lag Ratio[1]	294:1	250:1	259:1
All Injury Frequency Rate[1,2]	1.32	N/A	1.36
Production			
Quarter End Reservoir Storage (GWh)	1,757	1,086	1,419
Hydraulic Production (GWh)[3]	4,771	4,757	4,689
Holyrood Fuel Cost per barrel ($)[3]	72	59	53
Electricity Delivery			
Sales including Wheeling (GWh)	6,666	6,759	6,766
Financial*			
Revenue ($millions)*	427.4	430.0	431.8
Expenses ($millions)*	418.5	434.3	429.1
Net Operating Income ($millions)[4*]	8.9	(4.3)	2.7
Current Rate Stabilization Plan (RSP) Balance ($millions)	(53.2)	(29.4)	(38.3)
Hydraulic	(30.9)	(9.8)	(14.8)
Utility	(10.3)	(6.8)	(14.7)
Industrial	(12.0)	(12.8)	(8.8)
Historic RSP Balance ($millions)	-	-	12.1
Utility	-	-	12.1
Industrial	-	-	-
Full Time Equivalent (FTE) Employees[5 6]			
Regulated[7]	805.9	865.6	832.0
Non Regulated	50.2	26.8	34.0

[1] Annual Target, and 2007 Actual
[2] Per 200,000 hours
[3] Target based on approved 2007 Test Year forecast
[4] Does not include any earnings from CF(L)Co
[5] One FTE is the equivalent of actual paid regular hours - 2,080 hours per year in the operating environment and 1,950 hours per year in Hydro's head office environment.
[6] Annual Budget and 2007 Actual values
[7] In 2007, salaries transferred to non-regulated activities were not converted to FTEs and Hydro FTEs were therefore higher than in 2008. On January 1, 2008, some employees were transferred to the Energy Corporation and the FTE number above includes only the portion related to Hydro.

* Revised to reflect the results of audited financial statements.

- 2008 safety initiatives were successful (Pages 3-4)
- Hydro and Newfoundland Power team up for conservation (Page 8)
- December 31, 2008 reservoir storage GWh 62% above target (Pages 11-12)
- No. 6 fuel price decreased by $55 this quarter (Page 12)
- First wind power received from St. Lawrence (Page 26)
- Nalcor Energy named (Page 27)
- Provincial Government waived Hydro's debt guarantee in 2008 in the amount of $12.4 million (Budget $12.9 million).

2 SAFETY

Goal - To be a Safety Leader

Safety is Hydro's number one priority. Hydro remains committed to being a world class leader in safety performance. As indicated by the measures identified below, Hydro did not meet all targets and there remain opportunities to improve. It should be noted that the reorganization of Hydro in 2008 does not permit easy access to Hydro only corporate data on the data tracking systems, and the reported statistics are related to the Regulated Operations Division only, except for the all injury frequency ratio. It is expected that Hydro only corporate data will be available in 2009.

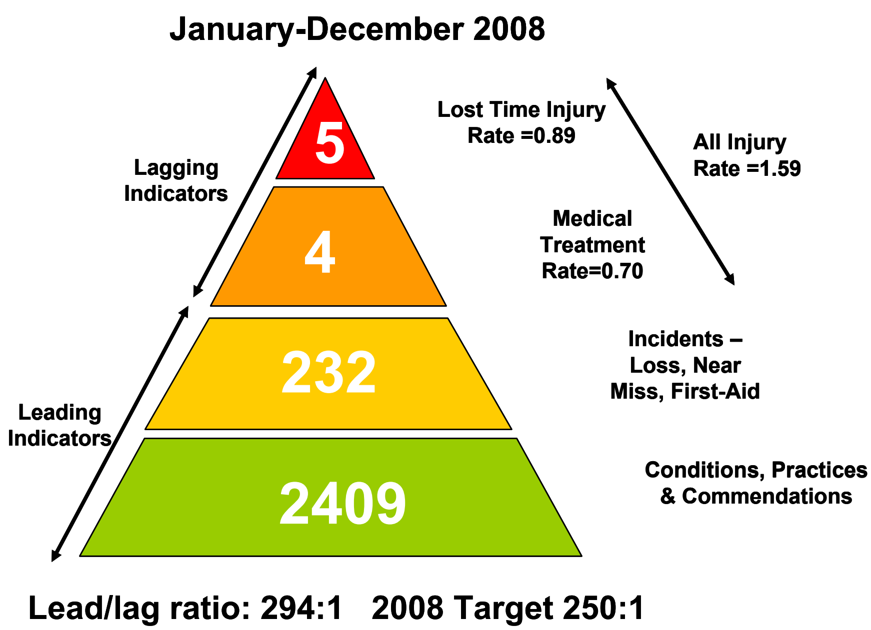
Measurement	Annual		
	2008 Actual	2008 Plan	2007 Actual[2]
Number of lost time injuries - Regulated Operations Division (RO)	5	< 50% 2007	4
Number of medical treatment injuries (RO)	4	< 50% 2007	6
Ratio of condition and incident reports to lost time and medical treatment injuries (lead/lag ratio) (RO)	294:1	250:1	259:1
All injury frequency ratio[1] Regulated Operations Division	1.32 1.59	N/A N/A	1.36 1.79

[1] Corporate excluding CF(L)Co and Lower Churchill group.
[2] Regulated Operations Division only, 2007 Hydro corporate Lost Time 10; Medical Aid 10; Lead/Lag Ratio 280:1. 2008 Hydro corporate Lost Time 6; Medical Aid 5; Lead/Lag Ratio 302:1.

The number of lost time injuries in Regulated Operations was higher than both the 2008 plan and 2007 actual numbers. The number of medical treatment injuries was slightly higher than the plan, but one-third less than the number that occurred in 2007. The lead/lag ratio of incidents and condition reports to injuries remains better than the 2008 plan and 2007 actual activity, reflecting the continuing emphasis Hydro places on safety observation and reporting. The all injury frequency rate for 2008 was an improvement over 2007. It should be noted that with one exception, the types of injuries were minor and the lost time was of short duration. The reporting of incidents and conditions provides Hydro with significant lessons learned, which will lead to a safer workplace over time.

Hydro's leadership team and employees promote the reporting of all conditions, incidents and behaviors that could lead to injury or loss, using the Safe Workplace Observation Program (SWOP).

The following safety triangle summarizes Regulated Operations Division reporting performance for 2008.



To further support and enhance safety, the following strategic initiatives were initiated in 2008.

1. Work Protection Code Improvement Plan
   - Updating Work Protection Code Training
     - Completed additional training session on Canadian Standards Association (CSA) standard Z 460
   - Improving Work Protection Code training delivery media to improve consistency
     - Use of DVD's and preferred session facilitators
     - Reduce areas of the code open to interpretation
   - Investigating enhancements to the Work Protection Code
     - Pilot process at Holyrood using automation – In service and positive feedback
     - Investigating application using in-house resources for other operating areas
   - Establishing a process to unify Work Protection Codes in Hydro
     - Reviewing suitability of using Holyrood Work Protection Code enhancements as template for compliance with emerging legislative requirements

2. Prevention of Injuries through SWOPs
   - Enhancing near miss observations (See March 2008 Quarterly Report)
   - Following up on SWOPs during regional meetings
   - Reviewing some recent high potential near misses to identify possible safety changes

3. Promotion of Safety Culture Changes
   - Refreshing supervisors on “Stepback 5x5” to deliver to staff
     - Take five minutes for five tasks:
       1. THINK through the task;
       2. LOOK for hazards;
       3. ASSESS the risk(s);
       4. MAKE required changes; and
       5. DO the task safely.
   - Reinforcing the Safety Credo

4. Emergency Preparedness
   - Emergency response training for Holyrood (See September 2008 Quarterly Report)

2.1 Emergency Preparedness – Are we ready for an emergency?

Emergency preparedness was tested by a mock disaster involving the Bishop’s Falls Fire Department and Hydro employees on November 26.

The scenario was as follows: An after hours work crew, consisting of two workers, was involved in an explosion. The janitorial staff called in the emergency and response time to the facility was five minutes. The Fire Department had to:

- Determine where the explosion happened.
- Determine what had happened.
- Determine who was involved and what the injuries were, if any.
- Determine where the workers were.
- Determine what precautions to take.
- Extinguish a live fire.
- Determine whether there were any hazardous materials.

In the scenario, one of the workers suffered from smoke inhalation, was disoriented and had a possible concussion. The other worker had back injuries and a concussion. Both workers fled the explosion site and a search had to be initiated. Information received from the janitor was limited as he only heard an explosion and called it in. He was not orientated in the local emergency procedure protocol.

The Bishop's Falls Fire Department was very efficient in putting out the fire. From the little information they had received from the janitor, they quickly found both injured workers. The workers were in a small side building that was in total darkness. Paramedics quickly assessed them, administered first aid, placed them on back boards and dispatched both in an ambulance for transfer to the hospital.

Afterwards both the Bishop's Falls Fire Department and Hydro representatives met at the fire hall to debrief. Everyone agreed that this was a very informative drill and discussions have started to have another emergency preparedness scenario in place for the summer of 2009.

2.2 Holyrood Emergency Response Team Receives Valuable Training

The Holyrood Thermal Generating Station's Emergency Response and Firefighting Team is a group of Holyrood employees who volunteered to serve on the team. Recently, the group participated in fire safety training in which they learned to extinguish different types of fires including gas pressure and structural oil fires. This training was extremely beneficial and provided them with the skills necessary to safely tackle a real fire, should their services ever be needed.

It should be noted that it is Hydro's plan to assign dedicated resources to Emergency Response. These resources will be trained to respond to many situations, such as fire and falls.

3 ENVIRONMENT AND CONSERVATION

Goal - To be an Environmental Leader

Hydro recognizes its commitment and responsibility to protect the environment.

In 2008, Hydro's focus was on achieving an ideal production schedule at Holyrood, and continuing to improve environmental performance by setting and achieving targets related to its Environmental Management System (EMS) and ISO 14001 certification.

Measurement	Annual		
	2008 Actual	2008 Target	2007 Actual
Variance from ideal production schedule at Holyrood Thermal Generating Station[1]	23.8%	Not more than 12%	N/A
Achievement of EMS targets	89%[1]	95%	83%
Achievement of EMS milestones	94%[1]	95%	90%

[1] An EMS target is an initiative undertaken to improve environmental performance. Percentages are based on number of targets/milestones completed to December 31 divided by target for completion to December 31.

Production Schedule at Holyrood

Throughout 2008, the primary decision driver for Holyrood utilization was minimizing total unit hours. Hydro's hydraulic production, energy purchases and lower load in 2008 (see Section 4) resulted in fewer barrels of oil being consumed at Holyrood – a positive environmental impact.

Hydro was unable to meet its target variance from an ideal Holyrood production schedule due primarily to unforeseen equipment failures on the Holyrood units. The age of the Holyrood plant continued to cause operational issues in 2008. Among the contributing factors are:

- First Quarter superheater tube leak and safety valve replacement; and
- Fourth Quarter forced outage due to a forced draft fan failure.

Environmental Targets

There were 66 EMS targets with 234 individual milestones identified in Hydro for completion in 2008. Of these, 59 targets and 220 milestones were successfully completed, for percentages completed of 89% and 94% respectively.

The 59 EMS targets that were completed related generally to improvements in the following areas:

- Reducing risks associated with fuel and oil handling systems;
- Reducing risks associated with handling PCBs and other hazardous materials;
- Environmental risk reduction associated with vegetation control programs;
- Waste management;
- Minimizing disturbance to land and water habitats;
- Internal energy efficiency;
- Air emission management;
- Conservation and demand management; and
- Environmental awareness and training.

Three of the missed targets involved changes to computer software in the Energy Management System that would provide improvements to: short term generation scheduling decision support; reservoir inflow forecasting; and optimization of power flow on transmission systems. In each case, problems were identified during testing of the software that delayed implementation. These issues are still being addressed and the new software improvements may be implemented in early 2009.

One of the missed targets involved installation of four new meteorological stations at reservoirs to improve inflow forecasting. Three of the four stations were successfully installed, however, problems with remote communications equipment and resource availability delayed the installation of the fourth station.

A target to review marine spill risk potential at the Holyrood Thermal Generating Station, to identify potential improvements, was not completed because of changes to key personnel that occurred in mid-2008.

Three of six milestones were not fully completed in a target to develop partnerships with external stakeholders regarding better coordination of efforts to protect listed endangered species potentially affected by operational activities. Difficulties in coordinating with the external parties delayed discussion and agreement. These efforts are continuing.

The other EMS target not fully completed involved finalization of a report from the results of study test plots in which an alternative herbicide application technology, with the potential to reduce overall herbicide application rates, was tested. Although test results were compiled, a final report was not completed as a result of resource issues. This report is to be completed in early 2009.

Other accomplishments in the environmental initiatives include:

- Conservation and Demand Management (CDM) report and five year plan completed (See March Quarterly Report);
- Corporate procedures implemented to reduce energy use (See September Quarterly Report); and
- Conservation efforts expanded, in partnership with Newfoundland Power.

3.1 Hydro and Newfoundland Power Team Up for Conservation

Hydro and Newfoundland Power have teamed up to develop a new provincial energy conservation and efficiency brand "Take Charge. Saving Energy Starts Here" which launched publicly on November 13.

3.2 New Energy Initiatives Announced for Coastal Labrador

On October 6, 2008, the Provincial Government announced $500,000 for Hydro to conduct an alternative energy study and an energy efficiency community pilot project in select coastal Labrador communities. The funding is part of the $13 million allocated in the 2008 Provincial Budget for implementing key Energy Plan initiatives.

The alternative energy study is being conducted in seven communities – Cartwright, Charlottetown, Hopedale, Makkovik, Mary's Harbour, Nain and Port Hope Simpson. It will determine the potential for alternative energy sources to complement existing diesel generation systems. This will include investigating solar, wind and mini-hydroelectric facility developments. The information collected through the study will be used to help identify the best alternative energy options, and to conduct more detailed studies that focus only on the most attractive options.

Hydro is also conducting a pilot project to explore conservation and efficiency opportunities in two coastal Labrador communities – Hopedale and Port Hope Simpson. Guided energy reviews will be conducted with residents and commercial customers to identify opportunities for improvements in energy efficiency to reduce energy costs. The community pilot project will provide residents and business owners with hands-on advice and energy efficiency tools to help them reduce their energy consumption.

4 OPERATIONAL EXCELLENCE

Goal - Through operational excellence provide exceptional value to all consumers of energy.

Hydro strives to deliver operational excellence by maintaining safe, reliable delivery of power and energy to customers in a cost-effective manner while maintaining high customer satisfaction. The 2008 key focus areas were:

- Energy Supply;
- Asset Management; and
- Financial Performance.

Measurement	Annual		
	2008 Actual	2008 Target	2007 Actual
Energy Supply			
Winter Availability	87.6%	97%	94.1%
Unserved Energy (MW minutes)	8,874	17,373	20,616
Asset Management			
Long-term asset replacement strategy and plan	Final Holyrood and Stephenville Gas Turbines manuals	Finalized & signed off	N/A
20-year asset replacement/ enhancement outlook	Completed	Complete	N/A
Long-term asset management plan for critical systems - four gas turbines - Holyrood synchronous condenser	Data collected	Develop & execute	N/A
System assets to be reviewed under asset management strategy plan	Completed	Identify & prioritize	N/A
Critical systems at Holyrood	Completed	Identify	N/A
Financial Targets			
*Operating Budget	+1%	Maintain cost to ± 2% of budget	+4%
*Capital Plan	84%	Achieve >95% progress against original project schedule	N/A
*Capital Plan	-14%	Achieve variance of 5% or less within total budget	-18%

Winter availability was less than target, primarily due to the Holyrood performance issues discussed in Section 3. Unserved energy was substantially better than target, due to forced transmission interruptions and underfrequency interruptions being less severe in terms of the amount and duration of load interruptions.

The Asset Maintenance Plan targets were primarily achieved. As a result, there are revised manuals in place for the maintenance of the Holyrood and Stephenville gas turbines, and some critical systems at Holyrood (see Section 4.4). As well, Hydro has prepared a 20-year asset replacement and/or enhancement outlook, and substantial work has been completed on preparing a long term asset maintenance strategy for the gas turbines and Holyrood's critical systems. The Asset Maintenance Plan will result in comprehensive replacement and maintenance strategies for Hydro's entire critical infrastructure.

Financial target data is not yet available.

4.1 Energy Supply

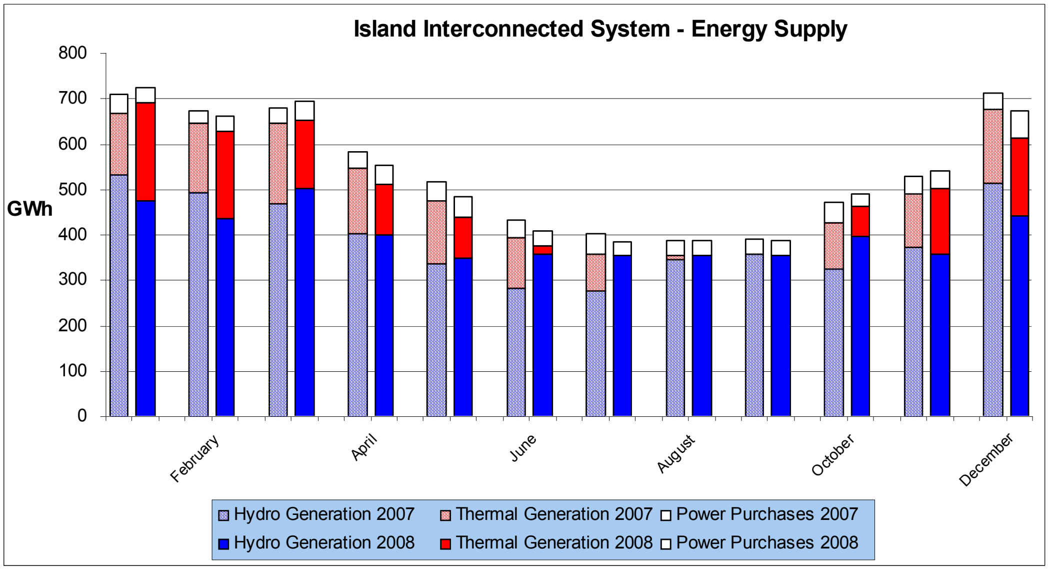
4.1.1 Energy Supply - Island Interconnected System

Energy requirements from the Holyrood Thermal Generating Station were low during the fourth quarter due to the storage in the hydroelectric reservoir system being above the minimum storage levels (as seen on the Total System Energy Storage Chart in Section 4.1.2). Individual units at Holyrood were brought into service as customers' demand increased through the quarter. Unit 2, was put into operation on October 6 and Unit 1 was brought on line on October 31. All three units were not in operation together until December 23. In December, following the return to service of Unit 3 on December 1, repair and maintenance work was carried out on Units 1 and 2.

Annual hydroelectric production was above 2007 by 1.8% due to a strong storage position at the start of 2008 and above average inflows during the year. Purchases from non-utility generators were 420 GWh, up 8% from 2007. This increase was caused by increased purchases from the Exploits River Hydro Partnership. Purchases of secondary energy from Abitibi-Consolidated Company of Canada – Grand Falls (Abitibi) were less than 2007. Thermal production was less than 2007 due to the increased purchases and reduced overall energy supply requirements.

Wind power became available in 2008, and Hydro purchased 7.8 GWh.

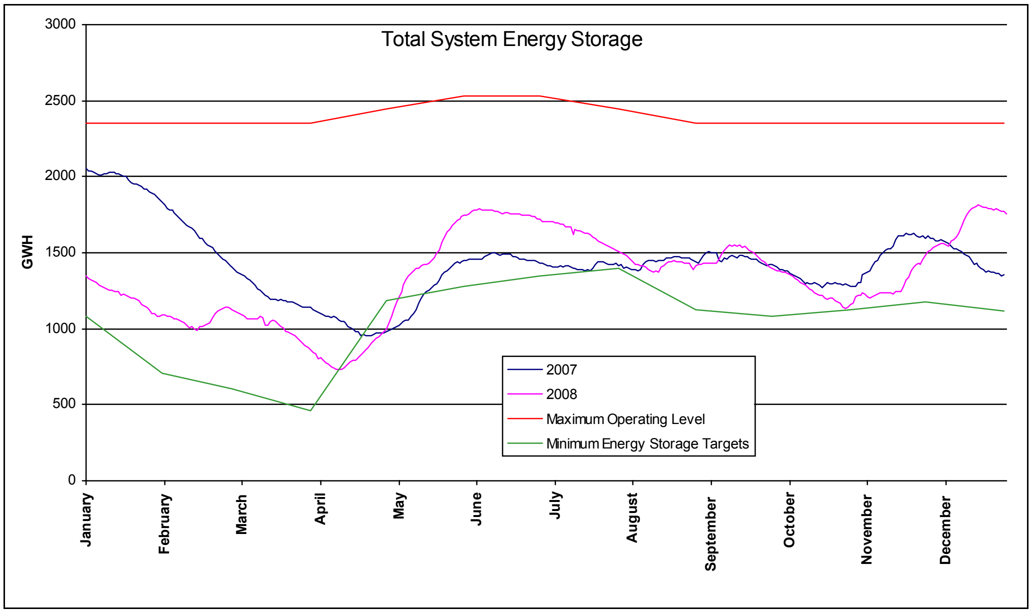
The energy supply for the Island Interconnected system is shown in the following charts and tables.



Island Interconnected System Production For the Year ended December 31			
	Annual		
	2008 (GWh)	2007 (GWh)	Forecast (GWh)
Production (net)			
Hydro	4,771.0	4,689.4	4,756.8
Thermal	1,080.2	1,255.6	1,108.5
Gas Turbines	(7.5)	(10.1)	(5.4)
Diesels	(0.6)	0.1	(0.3)
Total Production	**5,843.1**	**5,935.0**	**5,859.6**
Purchases			
Non Utility Generators	420.5	389.4	448.7
Secondary and Other	30.1	64.6	25.1
Total Purchases	**450.6**	**454.0**	**473.8**
Island Interconnected Total Produced and Purchased	**6,293.7**	**6,389.0**	**6,333.4**

4.1.2 System Hydrology

The reservoir storage level rose significantly in November and December due to above normal inflows in both months. In November the inflows were 44% above the 58 year average and in December they were 62% above.



4.1.3 Energy Supply – Labrador Interconnected System

The purchased and produced energy on the Labrador Interconnected System to the end of December 2008 was consistent with the forecast and with the same period of 2007.

Labrador Interconnected System Production
For the Year ended December 31

	Year-to-date			Annual Forecast (GWh)
	2008 (GWh)	2007 (GWh)	Forecast (GWh)	
Production (net)				
Gas Turbines	(1.7)	(2.2)	(0.5)	(0.3)
Diesels	(0.7)	(0.7)	(1.3)	(1.3)
Total Production	**(2.4)**	**(2.9)**	**(1.8)**	**(1.6)**
Purchases				
CF(L)Co (at border)	**2,362.0**	**2,362.0**	**2,362.0**	**2,362.0**
Labrador Interconnected Total Produced and Purchased	**2,359.6**	**2,359.1**	**2,360.2**	**2,360.4**

4.1.4 Fuel Prices

The fourth quarter market prices for No. 6 fuel decreased significantly from approximately $95/bbl at the start of the quarter to just under $40/bbl at the end of the quarter. The average inventory cost was $52.56/bbl at the end of the quarter, lower than the current Newfoundland

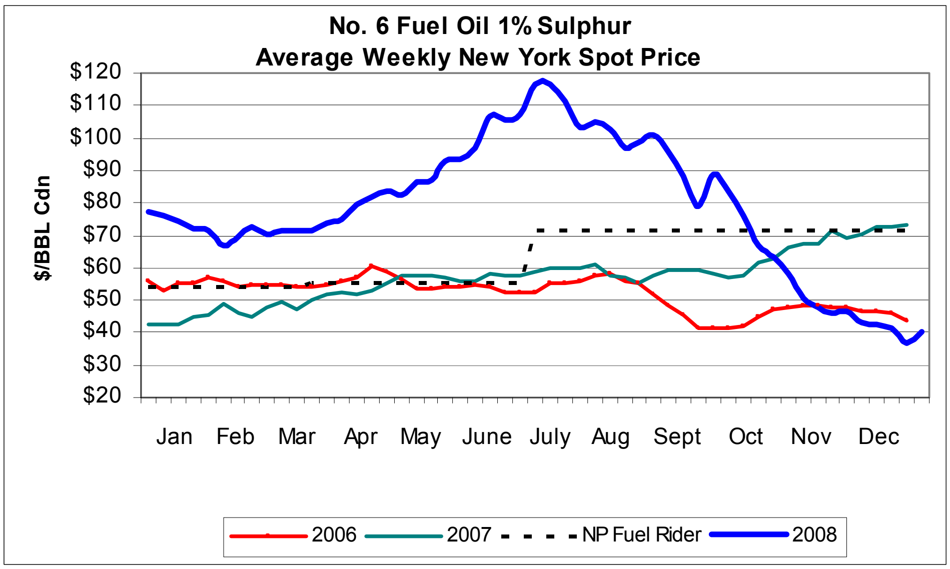
Power fuel price rider of $71.45/bbl. There is no Industrial Customer fuel price rider for 2008.

There were two shipments during the fourth quarter of 2008.

November 23	220,900 bbls	$49.00/bbl
December 15	207,852 bbls	$40.11/bbl

The inventory on December 31 was 264,003 barrels.

The following chart shows the No. 6 fuel prices year-to-date compared to 2006 and 2007, and the Newfoundland Power fuel price rider of $71.45/bbl.



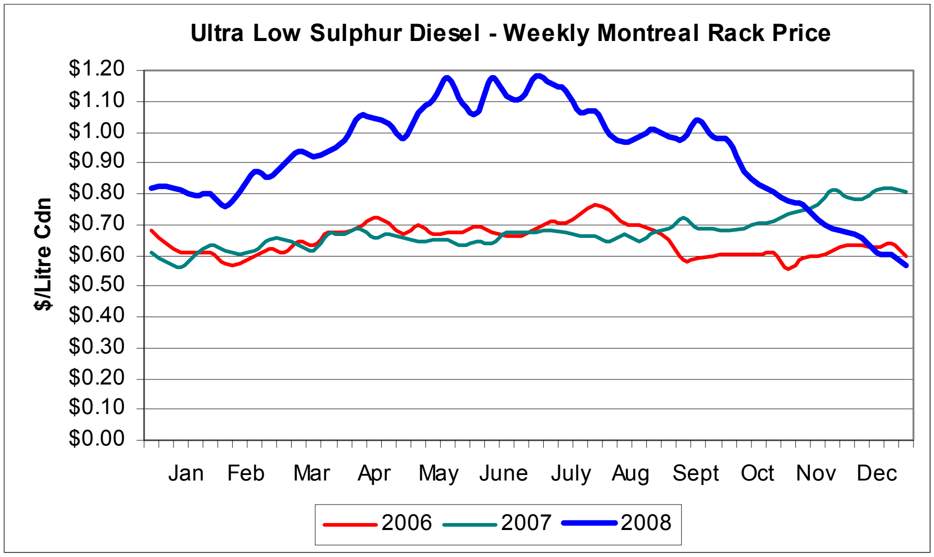
The following table provides the monthly forecast price of No. 6 fuel (1.0% sulphur) up to December 2009, landed on the Avalon Peninsula.

No. 6 Fuel Oil 1% Sulphur
Forecast Price January 2009 – December 2009

Month	Price ($Cdn/bbl)	Month	Price ($Cdn/bbl)
January 2009	35.80	July 2009	47.40
February 2009	35.80	August 2009	51.70
March 2009	35.80	September 2009	53.70
April 2009	36.70	October 2009	57.30
May 2009	38.10	November 2009	61.80
June 2009	42.60	December 2009	67.00

Note: The forecast is based on the PIRA Energy Group short-term price forecast of January 6, 2009 and the spot market exchange rate on December 31, 2008.

The following chart shows Low Sulphur Diesel No. 1 fuel prices year-to-date compared to 2006 and 2007.



4.1.5 Energy Supply - Isolated Systems

Net isolated electricity supply - production and purchases - increased by 4.1% from 2007. The increase is largely attributed to continuing growth on the Labrador isolated systems and the resumption of processing at the Little Bay Islands fish plant.

Isolated Systems Production
For the Year ended December 31

	Annual		
	2008 (GWh)	**2007 (GWh)**	**Forecast (GWh)**
Production (net)			
Diesels	46.5	43.5	46.3
Purchases			
Non Utility Generators	0.4	0.6	0.4
Hydro Québec	16.7	17.0	18.2
Total Purchases	**17.1**	**17.6**	**18.6**
Isolated Systems Total Produced and Purchased	**63.6**	**61.1**	**64.9**

Due to low water levels at Hydro Québec's (HQ) Lac Robertson reservoir, purchases from HQ were largely curtailed in November and December. This resulted in an increase in diesel generation to meet the requirements of the L'Anse au Loup system.

4.1.5.1 L'Anse au Loup Fuel Requirements

Hydro typically purchases almost all of the energy required for the L'Anse au Loup system from HQ's Lac Robertson Hydro Plant, as secondary energy. In October, HQ informed Hydro that the level of the reservoir supplying the Lac Robertson Hydro Plant was well below normal and that they would not be able to supply the entire energy requirement of the L'Anse au Loup system this winter.

On October 28, HQ representatives requested that Hydro generate 60% of the energy required for November using the L'Anse au Loup Diesel Plant. On December 21, reservoir levels had recovered to the point where HQ was again able to supply 100% of the L'Anse au Loup system load. During October, November and December, approximately 65% of the energy used on the L'Anse au Loup system was supplied by HQ and approximately 35% by Hydro.

There is a high possibility that HQ will not be able to supply 100% of the energy for the L'Anse au Loup system for the remainder of the winter and that for some period, diesel production from the L'Anse au Loup Diesel Plant will be required. Adding to the need for diesel generation is measurable load growth in the area. The purchase price of energy from HQ is approximately one-half the cost of producing that energy from the diesel plant. Energy supply costs are therefore expected to remain high.

4.2 Performance Indices

4.2.1 Bulk Power System Delivery Point Interruption Performance

The net frequency of sustained outages in the fourth quarter of 2008 decreased approximately 61% from the same quarter of the previous year. The reduction was due to a 95% reduction in the number of forced outages this quarter, while planned outages increased 71% this quarter from 2007.

There were only two forced outages this quarter. These interruptions were less than one hour combined and had limited customer effects.

The increase in planned outages this quarter was due primarily to work of an urgent nature. On October 7 and 8, customers in White Bay experienced two seven-hour outages to replace rotten poles on TL-251 and TL-252. On October 30, customers on Fogo Island experienced a one hour and 40 minute interruption to replace damaged insulators on transmission line TL-254. On November 27, Newfoundland Power customers in Buchans experienced a four-hour planned outage to replace a faulty relay on transformer T2 at the Buchans Terminal Station. On December 7, these same customers experienced a planned 26-minute outage to restore transformer GT1 back to service after damage was found on November 27. There were additional planned outages in Daniel's Harbour and the Hawkes Bay/Port au Choix area to facilitate completion of the 2008 capital upgrade program.

T-SAIFI (Number per Delivery point in Period)

Voltage Class	Fourth Quarter 2008	Fourth Quarter 2007	12 Mths to Date 2008	12 Mths to Date 2007	5 Year Average (2003–2007)
66 kV	0.58	0.71	3.25	4.04	3.23
138 kV	0.13	1.13	1.19	3.25	2.10
230 kV	0.00	0.22	0.06	0.64	0.46
Forced Only	0.03	0.53	0.95	1.75	1.36
Planned Only	0.24	0.14	0.74	0.99	0.67
Total	0.28	0.67	1.69	2.74	2.03

Note: System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per delivery point. It is calculated by dividing the number of delivery point interruptions by the total number of delivery points of the appropriate voltage class(es).

The total interruption time per delivery point increased by 360% from the same quarter in 2007. The increase this quarter was largely the result of an increase in planned outages on the 66 kV system.

T-SAIDI (Hours per Delivery point in Period)

Voltage Class	Fourth Quarter 2008	Fourth Quarter 2007	12 Mths to Date 2008	12 Mths to Date 2007	5 Year Average (2003–2007)
66 kV	2.53	0.13	10.36	5.71	3.82
138 kV	0.06	0.55	1.27	2.40	2.70
230 kV	0.00	0.07	0.00	0.41	0.64
Forced Only	0.02	0.12	1.05	1.75	1.37
Planned Only	1.05	0.10	3.58	1.37	1.12
Total	1.06	0.23	4.64	3.12	2.50

Note: System Average Interruption Duration Index (SAIDI) is the time power was not available to a typical delivery point.

The average interruption restoration time index reflects the effect of an increase in planned outages duration.

T-SARI (Hours per Interruption)

Voltage Class	Fourth Quarter 2008	Fourth Quarter 2007	12 Mths to Date 2008	12 Mths to Date 2007	5 Year Average (2003–2007)
66 kV	4.33	0.19	3.19	1.41	1.18
138 kV	0.49	0.49	1.07	0.74	1.29
230 kV	0.00	0.33	0.03	0.64	1.39
Forced Only	0.49	0.23	1.11	1.00	1.01
Planned Only	4.33	0.76	4.83	1.39	1.67
Total	3.85	0.34	2.74	1.14	1.23

Note: System Average Restoration Index (SARI) is the average duration of each interruption experienced during the period. It is calculated by dividing the period SAIDI value by the period SAIFI value.

4.2.2 System Underfrequency Load Shedding Performance

No underfrequency events occurred during this quarter.

Underfrequency Load Shedding Number of Events

Customers	Fourth Quarter		Year-to-date		Average
	2008	2007	2008	2007	(2003–2007)
NF Power	0	3	6	6	6.4
Industrials	0	3	6	6	7.2
Hydro Rural*	0	3	6	6	5.8
Total Events	0	3	6	6	7.4

Underfrequency Load Shedding Unsupplied Energy (MW-min)

Customers	Fourth Quarter		Year-to-date		Average
	2008	2007	2008	2007	(2003–2007)
NF Power	0	975	2,861	1,503	2,160
Industrials	0	280	510	450	3,784
Hydro Rural*	0	25	69	69	159
Total Events	0	1,280	3,440	2,022	6,103 **

* Underfrequency activity affecting Hydro Rural Customers may also result in a number of delivery point outages. Outage frequency and duration are also included in totals shown in the delivery point statistics section of the report for these areas, namely the Connaigre Peninsula and Bonne Bay.
** The 6,103 MW-min represents 69% of the total unserved energy shown on Page 9.

4.2.3 Rural Systems Service Continuity Performance by Area

The Rural Systems Service Continuity data was not available for the third quarter report and is therefore included in this report. Problems with the data collection have been corrected and steps are in place to prevent this from happening again. Only outages which originated on the distribution system are described in this section. Loss of supply outages to the distribution system are described in the previous Bulk Power System Delivery Point Interruption section.

Third Quarter Review
The frequency of outages in the third quarter of 2008 increased 53% when compared to the same quarter of the previous year. The duration of outages increased by 112% relative to the same quarter last year.

Customers in Nain experienced an outage between 37 and 82 hours in August. This outage was caused by a major fire in the diesel plant which resulted in all diesel units being damaged and one unit being destroyed. All customers in Black Tickle experienced a 13-hour outage due to a failure of a distribution transformer resulted in tripping of the main recloser in July. Conne River customers experienced a seven hour outage in September due to a vehicle breaking off a pole on the main feeder supplying the community.

Planned outages accounted for the remaining significant interruptions in the third quarter. A planned outage to all customers in the Town of Hermitage occurred in July for six hours to make improvements to the feeder. All customers on Feeder 3 in St. Anthony and Goose Cove experienced a series of planned outages in August and September of up to five hours each. These outages were required for improvements to the feeder.

SAIFI (Number per Period)

Area	Third Quarter 2008	Third Quarter 2007	12 Mths to Date 2008	12 Mths to Date 2007	Average (2003–2007)
Central					
Interconnected	2.27	1.15	4.80	3.05	4.31
Isolated	0.60	0.10	2.73	2.48	4.85
Northern					
Interconnected	3.33	1.18	7.78	4.39	5.22
Isolated	1.99	2.32	5.87	9.35	10.20
Labrador					
Interconnected	2.65	3.38	10.05	8.58	8.28
Isolated	3.03	0.61	10.62	7.13	10.39
Total	2.63	1.74	7.22	5.32	6.15

Note: System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers in an area.

SAIDI (Hours per Period)

Area	Third Quarter 2008	Third Quarter 2007	12 Mths to Date 2008	12 Mths to Date 2007	5 Year (2003–2007)
Central					
Interconnected	7.24	3.09	13.82	7.23	10.49
Isolated	0.92	0.03	2.32	6.34	4.53
Northern					
Interconnected	5.38	0.27	11.84	8.70	9.01
Isolated	1.05	1.19	6.14	8.05	12.18
Labrador					
Interconnected	0.88	3.80	5.13	9.84	9.08
Isolated	11.01	1.18	15.95	15.47	10.63
Total	4.77	2.25	10.43	8.68	9.67

Note: System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.

Fourth Quarter Review

The frequency of outages in the fourth quarter of 2008 decreased 44% when compared to the same quarter of the previous year. The duration of outages increased by 25% relative to the same quarter last year.

All customers in Conche experienced a six hour outage in November after a vehicle damaged three poles on the main feeder. Blizzard conditions resulted in a broken pole on the main feeder in Mary's Harbour in December resulting in a five hour outage to all customers.

Customers in the South Brook area experienced six planned outage of five to six hours each in October. The outages were required for pole replacement on the feeders. All customers in Port Saunders and Hawke's Bay experienced a five hour outage in November to permit improvement to the distribution system and to the terminal station supplying the area. All customers in Labrador City and Wabush experienced a four hour and 45 minute interruption to repair a damaged disconnect switch at the Wabush Terminal Station and to replace insulators on Feeders L9 and L11.

SAIFI (Number per Period)

Area	Fourth Quarter 2008	Fourth Quarter 2007	12 Mths to Date 2008	12 Mths to Date 2007	Average (2003–2007)
Central					
Interconnected	0.79	0.90	4.69	3.40	3.87
Isolated	2.06	0.84	3.95	2.36	5.10
Northern					
Interconnected	0.48	1.32	6.94	4.55	4.95
Isolated	1.28	1.59	5.57	8.52	9.75
Labrador					
Interconnected	1.45	4.45	7.06	11.46	8.30
Isolated	5.07	1.86	13.84	7.90	10.50
Total	1.13	2.01	6.34	6.22	5.92

Note: System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers in an area.

SAIDI (Hours per Period)

Area	Fourth Quarter 2008	Fourth Quarter 2007	12 Mths to Date 2008	12 Mths to Date 2007	5 Year (2003–2007)
Central					
Interconnected	2.79	2.15	14.45	7.70	9.88
Isolated	1.64	0.49	3.47	1.54	4.47
Northern					
Interconnected	1.33	1.76	11.40	7.42	8.57
Isolated	1.88	2.12	5.91	6.84	11.89
Labrador					
Interconnected	2.87	3.30	4.75	11.53	9.41
Isolated	12.85	0.97	27.87	14.92	10.66
Total	2.79	2.24	10.98	8.72	9.40

Note: System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.

4.2.4 Rural Systems Service Continuity Performance by Origin

The following table provides a breakdown by source. In the third quarter the total SAIFI was 59% lower than the same quarter last year. Loss of Supply outages due to transmission increased by 63%, while on the isolated systems there was a 125% increase in outages originating in the diesel plants. There was a 20% increase in distribution related outages.

SAIFI (Number per Period)					
Area	Third Quarter		12 Mths to Date		Average
	2008	2007	2008	2007	(2003–2007)
Loss of Supply – Transmission	1.71	1.05	3.88	2.44	2.07
Loss of Supply – NF Power	0.00	0.00	0.00	0.00	0.01
Loss of Supply – Isolated	0.18	0.08	0.61	0.49	0.62
Loss of Supply – L'Anse au Loup	0.00	0.00	0.00	0.03	0.11
Distribution	0.72	0.60	2.72	2.36	3.01
Total	0.72	1.74	4.91	5.32	5.82

Note: System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers.

In the fourth quarter the total SAIFI was 64% lower than the same quarter last year. Loss of Supply outages due to transmission decreased by 80%, while on the isolated systems there was a 127% increase in outages originating in the diesel plants. There was a 20% decrease in distribution related outages.

SAIFI (Number per Period)					
Area	Fourth Quarter		12 Mths to Date		Average
	2008	2007	2008	2007	(2003–2007)
Loss of Supply – Transmission	0.21	1.24	2.98	3.12	2.07
Loss of Supply – NF Power	0.00	0.00	0.00	0.00	0.01
Loss of Supply – Isolated	0.25	0.11	0.75	0.49	0.62
Loss of Supply – L'Anse au Loup	0.03	0.00	0.03	0.00	0.11
Distribution	0.64	0.65	2.58	2.60	3.01
Total	0.72	2.01	4.91	6.22	5.82

Note: System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers.

The following table provides a breakdown by the source of the contributors to the outage duration of customer interruptions. In the third quarter the duration of outages for distribution related causes increased 75% from last year. Loss of supply from transmission increased 158% from the same quarter in 2007.

SAIDI (Hours per Period)					
Area	**Third Quarter**		**12 Mths to Date**		**Average**
	2008	**2007**	**2008**	**2007**	**(2003–2007)**
Loss of Supply – Transmission	2.61	1.01	3.64	2.92	2.09
Loss of Supply – NF Power	0.00	0.00	0.00	0.00	0.02
Loss of Supply – Isolated	0.07	0.03	0.25	0.23	0.23
Loss of Supply – L'Anse au Loup	0.00	0.00	0.00	0.01	0.04
Distribution	2.10	1.20	6.54	5.52	6.84
Total	1.28	2.25	7.79	8.68	9.22

Note: System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers.

In the fourth quarter, duration of outages for distribution related causes increased 40% from last year. Loss of supply from transmission decreased 42% from the same quarter in 2007. The duration of outages due to Loss of Supply in the isolated systems increased 300% from 2007.

SAIDI (Hours per Period)					
Area	**Fourth Quarter**		**12 Mths to Date**		**Average**
	2008	**2007**	**2008**	**2007**	**(2003–2007)**
Loss of Supply – Transmission	0.36	0.74	3.38	2.54	2.09
Loss of Supply – NF Power	0.00	0.00	0.00	0.00	0.02
Loss of Supply – Isolated	0.16	0.04	0.38	0.18	0.23
Loss of Supply – L'Anse au Loup	0.04	0.00	0.04	0.00	0.04
Distribution	2.22	1.47	7.17	6.00	6.84
Total	1.28	2.24	7.79	8.72	9.22

Note: System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers.

4.2.5 Rural Systems Service Continuity Performance by Type

The following table provides a breakdown of the regional interconnected and isolated systems for the third and fourth quarters by scheduled and unscheduled interruptions. Scheduled outages were not a significant contributor to interruptions during the third quarter, but had more of an effect in the fourth quarter.

Third Quarter

Area	Scheduled SAIFI	Scheduled SAIDI	Unscheduled SAIFI	Unscheduled SAIDI	Total SAIFI	Total SAIDI
Central						
Interconnected	0.37	1.07	1.90	6.17	2.27	7.24
Isolated	0.00	0.00	0.60	0.92	0.60	0.92
Northern						
Interconnected	0.76	1.80	2.58	3.59	3.33	5.38
Isolated	0.24	0.34	1.74	0.71	1.99	1.05
Labrador						
Interconnected	0.10	0.36	2.55	0.52	2.65	0.88
Isolated	0.12	0.41	2.91	10.60	3.03	11.01
Total	0.38	0.99	2.25	3.78	2.63	4.77

Fourth Quarter

Area	Scheduled SAIFI	Scheduled SAIDI	Unscheduled SAIFI	Unscheduled SAIDI	Total SAIFI	Total SAIDI
Central						
Interconnected	0.32	1.38	0.47	1.41	0.79	2.79
Isolated	0.46	1.02	1.60	0.63	2.06	1.64
Northern						
Interconnected	0.21	1.05	0.27	0.28	0.48	1.33
Isolated	0.29	0.73	0.99	1.15	1.29	1.88
Labrador						
Interconnected	1.07	2.85	0.38	0.02	1.45	2.87
Isolated	0.28	0.78	4.79	12.07	5.07	12.85
Total	0.49	1.61	0.64	1.18	1.13	2.79

Note:
1. System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers in an area.
2. System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.

4.2.6 Generation Equipment Performance

The table below highlights the various performance indices for Hydro's generation facilities. Indices for 2007 and for the latest Canadian Electricity Association (CEA) national average for the period 2002-2006 are included for comparison.

Generation Performance Indices

Index		Hydraulic	Thermal	Gas Turbine
Failure Rate (Forced Outages per 8760 operating hours)	NLH 2008	2.59	7.58	119.39
	NLH 2007	2.63	11.64	384.33
	CEA '02-'06	2.30	10.36	10.82
Incapability Factor (Percent of Time)	NLH 2008	8.92	32.68	19.80
	NLH 2007	6.21	46.68	15.39
	CEA '02-'06	8.98	18.45	11.38
Derating Adjusted Forced Outage Rate (Percent of Time)	NLH 2008	1.06	15.60	
	NLH 2007	0.34	23.98	
	CEA '02-'06	2.03	10.74	
Utilization Forced Outage Probability (Percent of Time)	NLH 2008			13.58
	NLH 2007			9.06
	CEA '02-'06			8.11

4.2.6.1 Hydraulic Unit Performance

Hydraulic unit performance decreased slightly in 2008 as compared to 2007, except for the failure rate which improved slightly. Hydraulic unit incapability and derating adjusted forced outage rates continue to be better than the national average. The 14 week outage at Cat Arm to upgrade the spherical valves and replace the governor on Unit 2 was the main contributor to the increase in incapability factor.

4.2.6.2 Thermal Unit Performance

On an annual basis, the thermal unit performance improved in 2008. Significant improvements can be seen in all of the above performance measures. Holyrood's performance improved in 2008 over relatively poor performance in 2007. The failure rate improved in 2008 and is better than the national average.

4.2.6.3 Gas Turbine Unit Performance

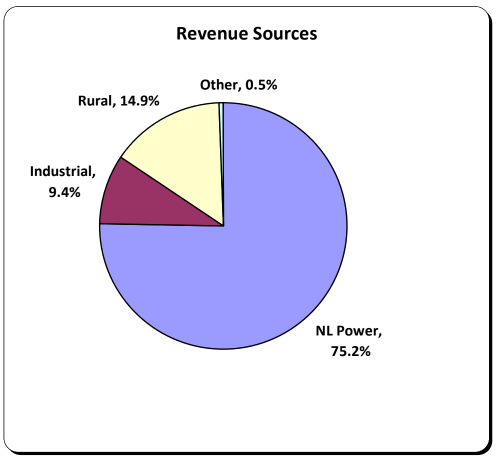
Hydro's gas turbines failure rate improved significantly in 2008 compared to 2007. However, due to the nature of the calculation of the failure rate, units with very low operating factors, such as those operated by Hydro, tend to have high failure rates. The incapability factor for Hydro's gas turbines declined from the improvement trend in 2007. The major contribution to the decline in performance was the Stephenville Gas Turbine, due to one turbine being out of service all year.

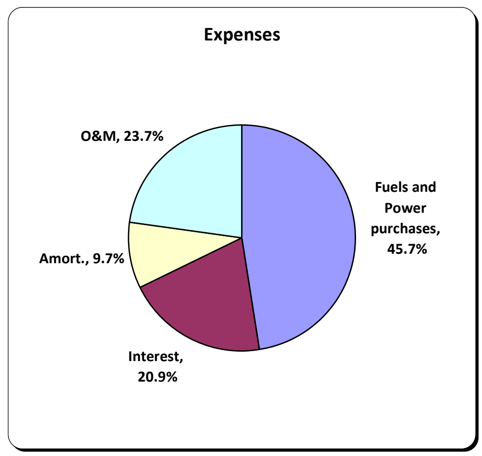
Of particular importance to Hydro's use of gas turbines is the utilization forced outage probability (UFOP). The measure describes the degree to which a standby unit can be called upon to supply load when requested. In 2008, the rate declined significantly and is below the national average.

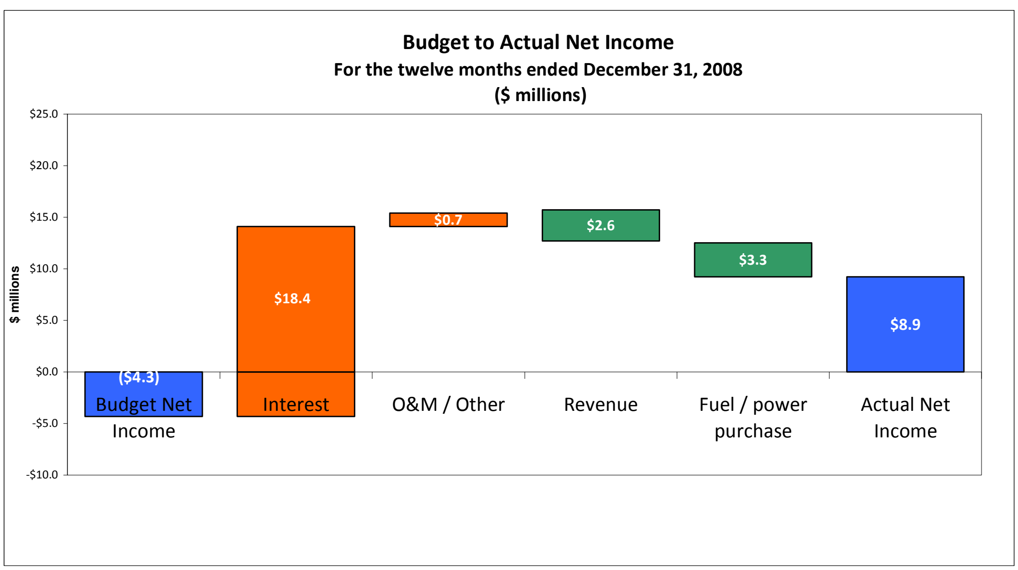
4.3 Financial

Below are charts of Hydro's (regulated) Statement of Income for the quarter ended December 31, 2008. Please see Appendix C for the remainder of the financial statements.

Regulated Utility
For the twelve months ended December 31, 2008







Statement of Income - Regulated Utility
For the twelve months ended December 31, 2008
($000's)

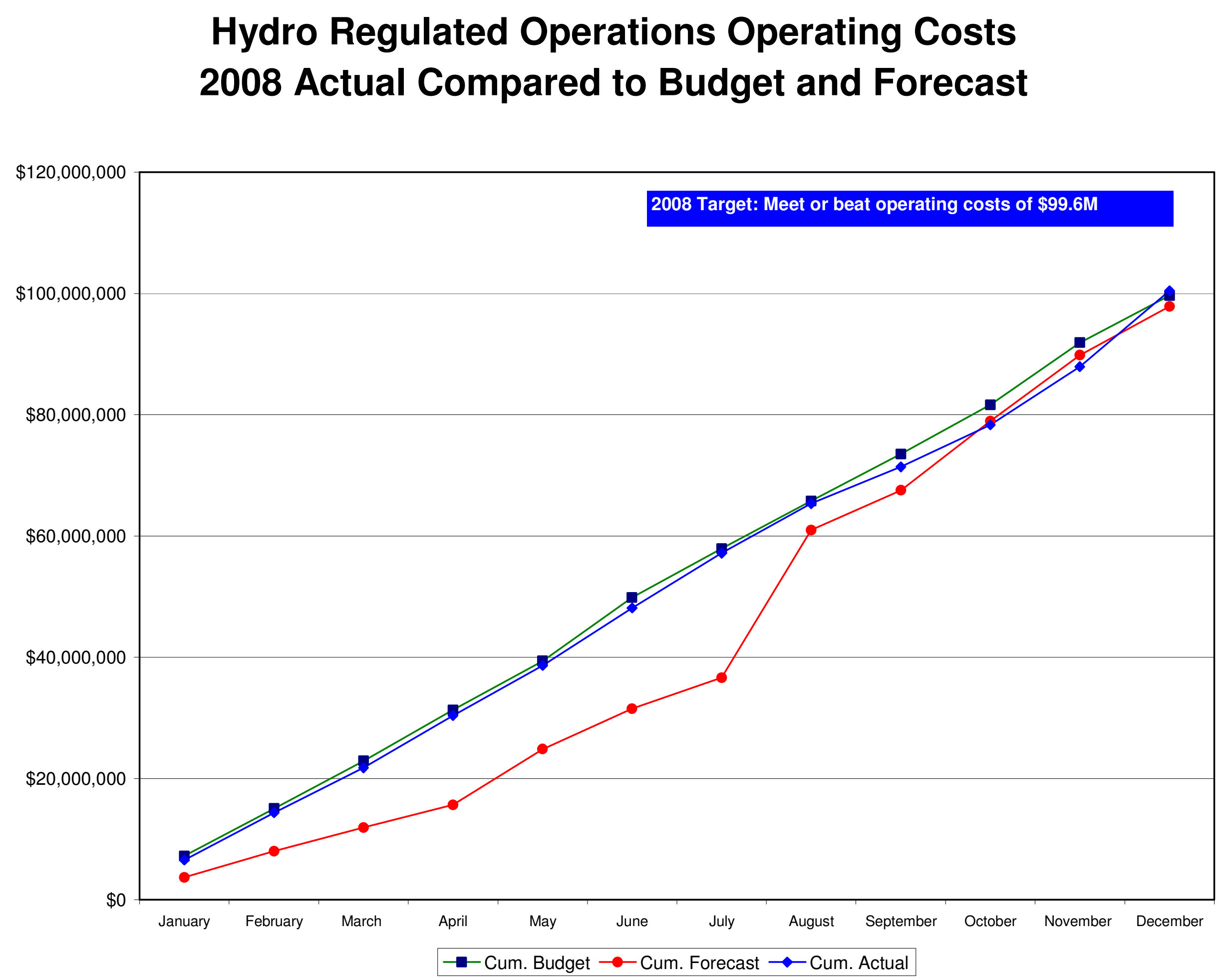
Fourth Quarter 2008 Actual	Fourth Quarter 2008 Budget	Fourth Quarter 2007 Actual		Year-to-date 2008 Actual	Year-to-date 2008 Budget	Year-to-date 2007 Actual
			Revenue			
113,330	117,658	117,366	Energy sales	425,196	428,010	429,794
641	508	452	Other revenue	2,197	2,033	1,983
113,971	118,166	117,818		427,393	430,043	431,777
			Expenses			
28,175	25,876	25,472	Operations and maintenance (1)	96,694	98,636	97,693
1,432	282	814	Loss on disposal of property,plant,and equipment	2,580	1,126	902
47,499	46,180	49,230	Fuels	149,854	148,090	150,281
11,404	12,616	11,202	Power purchases	41,388	39,841	38,606
10,534	10,154	9,985	Amortization	40,393	40,615	38,342
21,518	26,118	25,954	Interest (2)	87,610	106,035	103,242
120,562	121,226	122,657		418,519	434,343	429,066
(6,591)	(3,060)	(4,839)	**Net income (loss) (1)**	8,874	(4,300)	2,711

(1) Note:
Operations and maintenance costs for 2008 increased by $0.2 million (2007 - $0.2 million) for IOCC actual costs.

(2) Note:
Actual interest expense is less than budget primarily due to:

Debt Guarantee Fee	12,862
Capitalized Interest	10,700
Short-term interest	4,233
Non - Regulated	(8,948)
Other	(422)
Total	18,425

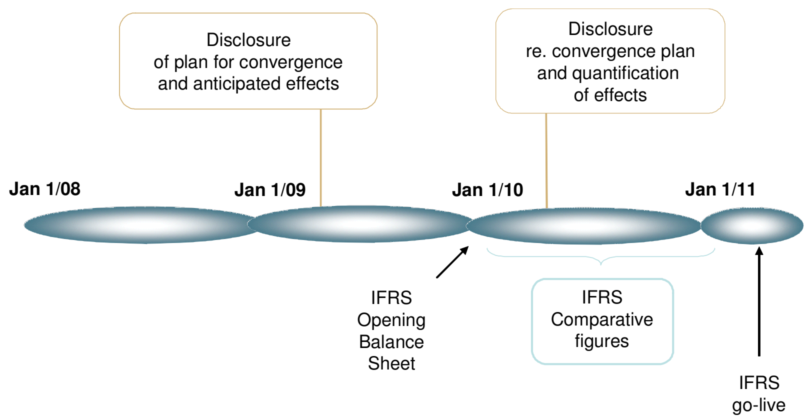
The chart below illustrates the controllable cost results for the year-to-date, which are consistent with the 2008 target of ±2% of budget.



4.3.1 International Financial Reporting Standards (IFRS)

In 2006, the Canadian Accounting Standards Board (AcSB) of the Canadian Institute of Chartered Accountants (CICA) announced a plan to replace Canadian Generally Accepted Accounting Principles (cGAAP) with International Financial Reporting Standards (IFRS) for publicly accountable entities. On February 13, 2008, the CICA confirmed that all publicly accountable entities in Canada will be required to adopt IFRS for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011.

IFRS MILESTONES



Hydro commenced its IFRS conversion project in 2008. It established a project team and commenced a process to identify differences between cGAAP and IFRS which will affect the company. The project team will ensure the impacts of the transition are fully understood and assessed, and that each of the disclosure requirements and other milestones as shown above, between now and 2011 are achieved.

Hydro has established a formal project governance structure which includes a steering committee consisting of senior levels of management from finance and treasury which will be expanded to include representatives from information technology, operations, and others as the project progresses. In addition to dedicated internal resources, the company has also engaged an external advisor to assist in the IFRS conversion project. Regular reporting is provided to Hydro's leadership team and the Audit Committee of the Board of Directors.

The conversion project consists of three phases – scoping, solution development and implementation. During 2008, Hydro completed the scoping phase which involved a high level review of the major differences between current cGAAP and IFRS. The differences which have the highest potential to impact Hydro are regulatory assets and liabilities - a significant portion of

(Continued on page 25 of the Quarterly Regulatory Report for the Year Ended December 31, 2008 as filed with the PUB on February 3, 2009)

which is the Rate Stabilization Plan, property, plant and equipment, impairment of assets, provisions, contingent assets and contingent liabilities, and employee benefits. As well, Hydro will assess the exceptions and exemptions available upon conversion under the provisions of IFRS 1, *First-time Adoption of IFRS*. The impact of these differences, exceptions, and exemptions on Hydro's future financial position and result of operations is not reasonably estimable or determinable at this time.

Regular reporting to the Board of Commissioners of Public Utilities will be made through the Quarterly Report and any other appropriate means. Hydro has also commenced engagement with Newfoundland Power to coordinate a joint approach to IFRS issues related to regulated utilities.

The solution development phase to be undertaken in 2009 will involve a more thorough review of the accounting differences and issues identified during the scoping phase, including an analysis of options and alternatives. System and process impacts will be assessed and comprehensive communications and training plans will be developed.

Hydro will continue to review all proposed and continuing projects of the International Accounting Standards Board (IASB), closely monitor any International Financial Reporting Interpretations Committee (IFRIC) initiatives with potential to impact the company's financial reporting and will participate in related processes as appropriate.

4.4 Maintenance Plan

Hydro is developing a maintenance plan, which is a formal consolidation, validation and documentation of Hydro's established maintenance plans, including recommendations for required changes. It is an ongoing and continuous process which started in 2007. Following the initial reviews of the individual systems, there will be a requirement to review and update the documentation to stay current with operating experiences, aging assets and new technologies.

2008 Year-to-Date
Gas Turbines
The manual for the Hardwoods and Stephenville gas turbines has been completed.

Preparation of the manuals for the Happy Valley and Holyrood gas turbines was targeted to be finished by year-end. This target was delayed due to emergency issues including the Nain Diesel Plant fire. The manuals are now targeted to be delivered to Regulated Operations during the first quarter of 2009.

Holyrood Plant
The analysis of information on the synchronous condenser systems at Holyrood has been completed. The manuals will be completed in the first quarter of 2009. Operations will proceed with implementation immediately. This task was also delayed due to the emergency issues identified above.

The identification of the critical generation systems at Holyrood was completed. The plan for review of these systems will be developed in the first quarter of 2009.

Other Plant
The identification and prioritization of the other system assets is complete. A plan and schedule for the review of these other system assets will be developed in January/February of 2009.

4.5 Capital Expenditures

Capital Expenditures for the year ended December 31, 2008 will be reported in a separate document.

4.6 First Commercial Wind Power for Newfoundland

Wednesday, October 29, 2008 marked a first for Newfoundland and Labrador! At 11:00 a.m. the first commercial wind energy was delivered to the Island Interconnected system from two turbines at the St. Lawrence Wind Farm.

St. Lawrence

5 OTHER ITEMS

5.1 Significant Issues

5.1.1 New Corporate Structure and Branding Launched for Nalcor Energy

On December 11, 2008, Nalcor Energy was named as the parent company of Newfoundland and Labrador Hydro and four other Nalcor Energy lines of business. Nalcor Energy's five lines of business are: Newfoundland and Labrador Hydro, Churchill Falls, Lower Churchill Project, Oil and Gas, and Bull Arm Fabrication.

5.1.2 Ramea Wind-Hydrogen-Diesel Project Update

In accordance with Order No. P.U. 31 (2007), the following update is provided on the Wind-Hydrogen-Diesel Project for Ramea.

Implementation and Operation
Most major equipment is on order and civil works are approximately 95% complete. Commissioning and operations are planned for mid-2009.

Capital Costs

($000)

Actual Cost to Dec. 2008	Actual Cost Recoveries to Dec. 2008	Net Cost to Dec. 2008	Budget to Dec. 2008	Budget Reforecast to July 2009[1]
4,082	**4,082**	**0**	**8,794**	**2,486**

[1] Project change order was completed to reflect a new completion date of July 2009 due to late delivery of H2 Electrolyser, delays in civil construction of wind turbine foundations and consequent decision to delay wind turbine installation to April 2009. The project change order also included cost increases associated with major equipment purchases, civil construction and consultants; and cost recoveries from Natural Resources Canada, ACOA and the Government of Newfoundland and Labrador totaling $7.14M.

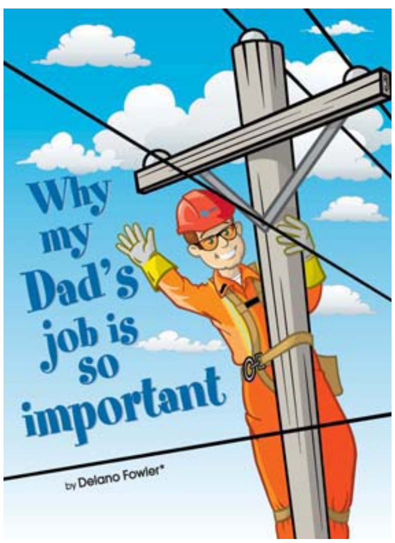
Operating Costs
There is nothing to report for this period as operation is planned to start in mid-2009.

Reliability and Safety Issues
All activities have been executed with no safety issues in this period.

5.2 Community

5.2.1 Hydro Launches Children's Electrical Safety Book

On Thursday, December 4, Hydro's Vice President Regulated Operations launched Hydro's children's safety book "*Why my Dad's job is so important*" to grade one students at Hazelwood Elementary. Ingemar Dean, a line worker from Whitbourne, read the book to the students and the author, Delano Fowler, a retired Hydro line worker, was given a token of appreciation for his dedication to promoting electrical safety. Hydro published the book for distribution to schools across Newfoundland and Labrador.



5.2.2 Collecting Food, Money and Awards during Christmas Parades

Members of the Silver Lights along with Hydro Place and Holyrood employees took to the streets for the Conception Bay South (CBS) Christmas Parade. Working with the CBS Kinsmen, $1,765 in cash and over $4,000 in food donations was collected for the CBS Food Bank. Hydro also donated $1,000 to the cause.

Hydro's Rolie Polie Olie float received an Honorary Mention by the Downtown Development Commission for the St. John's Christmas Parade. The organizers presented Hydro's parade team with a special award at the award's ceremony.

5.2.3 Gathering Place

On November 19 and 20, the System Operations and Customer Services Department volunteered their time for the Gathering Place in St. John's. Over the two days, staff from the Department helped sort winter clothes so they could be distributed to the community.

5.2.4 Employees Take a Hike

In October more than 20 Hydro Place employees, along with some family members, participated in the East Coast Trail Association's (ECTA) Annual Tely Challenge Hike. The hike took place on Saturday on the Sugarloaf Trail (Quidi Vidi to Logy Bay). The teams raised $1,000 in pledges, and Hydro also sponsored the event with a $2,000 contribution. Each year the ECTA hosts the Tely Challenge Hike as their main fundraising event to help with the development and maintenance of the 540 km trail system.

5.2.5 Treasury Department Penny-Pinching for Charity

For months now, the Treasury Department has been collecting pennies for charity. They placed a glass jar on the counter with a sign to catch everyone's attention as they walked by. So far, the department has collected four jars of pennies. The department has decided to donate all the money collected this year to Epilepsy Newfoundland and Labrador. They are also encouraging other departments and area offices to start their own collection.

5.2.6 Hydro Employees Run for the Cure

On Sunday, October 5, 170,000 Canadians in 55 communities across the country laced up their sneakers to participate in the Canadian Breast Cancer Foundation CIBC Run for the Cure. In total, $28.5 million was raised for breast cancer research, education, and awareness programs. This year, Hydro's team raised $1,554 and Hydro made a $1,000 contribution.

5.3 Statement of Energy Sold

Statement of Energy Sold (GWh)
For the Quarter ended December 31

	Annual		
	2008 ACTUAL	2007 ACTUAL	2008* FORECAST
Island Interconnected			
Newfoundland Power	4,960	4,991	5,015
Island Industrials (including Wheeling)	737	827	718
Rural			
Domestic	224	217	227
General Service	156	144	161
Streetlighting	3	3	3
Sub-total Rural	383	364	391
Sub-Total Island Interconnected	6,080	6,182	6,124
Island Isolated			
Domestic	6	6	6
General Service	2	2	2
Streetlighting	0	0	0
Sub-Total Island Isolated	8	8	8
Labrador Interconnected			
Labrador Industrials	337	257	347
CFB Goose Bay	61	63	71
Hydro Quebec (includes Menihek)	1,434	1,502	1,397
Rural			
Domestic	264	263	285
General Service	204	202	217
Streetlighting	2	2	2
Sub-total Rural	470	467	504
Sub-Total Lab. Interconnected	2,302	2,289	2,319
Labrador Isolated			
Domestic	19	19	21
General Service	14	13	14
Streetlighting	0	0	0
Sub-Total Labrador Isolated	33	32	35
L'Anse au Loup			
Domestic	11	9	11
General Service	7	6	6
Streetlighting	0	0	0
Sub-Total L'Anse au Loup	18	15	17
Total Energy Sold (Before Rural Accrual)	8,441	8,526	8,503
Rural Accrual **	8	(2)	-
Total Energy Sold	8,449	8,524	8,503

* Rural and non rural GWh - Based on June 4, 2008 Load forecast.
** The 2007 Rural Accrual amount was inadvertantly omitted from the 4th quarter report for 2007.

5.4 Customer Statistics

Customer Statistics
For the Quarter ended December 31

	FOURTH QUARTER		ANNUAL	
	2008 ACTUAL	2007 ACTUAL	2008 FORECAST	2007 ACTUAL
Customers				
Rural	35,965	35,610	35,568	35,610
Industrial	6	6	6	6
CFB Goose Bay	1	1	1	1
Utility	1	1	1	1
Hydro Quebec	1	1	1	1
Reading Days	29.5	29.7	N/A	29.9

APPENDICES

TYPE OF SERVICE	CIAC'S QUOTED	CIAC'S OUTSTANDING PREVIOUS QTR.	TOTAL CIAC'S QUOTED	CIAC'S ACCEPTED	CIAC'S OUTDATED	TOTAL CIAC'S OUTSTANDING
CIAC QUARTERLY ACTIVITY REPORT For the Quarter ended December 31, 2008						
Domestic						
Within Plan. Boundary	4	3	7	3	0	4
Outside Plan. Boundary	7	7	14	8	2	4
Sub-total	11	10	21	11	2	8
General Service	0	7	7	5	0	2
Total	11	17	28	16	2	10

Note: The Third Quarter report for outstanding CIACs was incorrectly reported as three. There was only one outstanding CIAC for the General Service Area. This will result in the current report having seven outstanding CIACs instead of the five indicated in the CIACs outstanding column in the third quarter 2008 report.

The table above summarizes Contribution in Aid of Construction (CIAC) activity for this quarter. The table is divided into three sections, as follows:

- The first section outlines the type of service for which a CIAC has been calculated, either Domestic or General Service.

- The second section indicates the number of CIACs quoted during the quarter as well as the number of CIAC quotes that remained outstanding at the end of the previous quarter. This format facilitates a reconciliation of the total number of CIACs that were active during the quarter.

- The third section provides information as to the disposition of the total CIACs quoted. A CIAC is considered accepted when a customer indicates they wish to proceed with construction of the extension and has agreed to pay any charge that may be applicable. A CIAC is considered outdated after six months has elapsed and the customers have not indicated their intention to proceed with the extension. A quoted CIAC is outstanding if it is neither accepted nor outdated.

CIAC QUARTERLY ACTIVITY REPORT
For the Quarter ended December 31, 2008

DATE QUOTED	CUSTOMER NAME	SERVICE LOCATION	CIAC NO.	CIAC AMOUNT ($)	ESTIMATED CONST. COST ($)	ACCEPTED
DOMESTIC - WITHIN RESIDENTIAL PLANNING BOUNDARIES						
Oct 3,2008	John Rumbolt	Happy Valley Goose Bay	674643	$1,328.75	$1,953.75	Yes
Nov 5, 2008	Rudy Burridge	Rocky Harbour	675725	$4,900.00	$7,025.00	Yes
Nov 6, 2008	Perry Shea	Fleur de Lys	675715	$1,250.00	$2,375.00	
Dec 17, 2008	Gregory Jeddore	Conne River	686305	$250.00	$2,375.00	
DOMESTIC - OUTSIDE RESIDENTIAL PLANNING BOUNDARIES						
Oct 14, 2008	Lawrence Huxter	South Brook	657597	$2,895.00	$3,520.00	
Oct 14, 2008	Guy Wellman	Knights Development	648368	$5,197.50	$5,822.50	
Oct 22, 2008	Joe Kennedy	West Pond	677597	$60,230.00	$80,380.00	Yes
Oct 29, 2008	Ralph Hedderson	St Anthony	676780	$0.00	$575.00	Yes
Oct 29, 2008	Woodrow Pilgrim	St Anthony	673367	$1,266.20	$1,266.20	Yes
Nov 13, 2008	Leslie C. Branton	Red Bay, Labrador	681853	$1,825.00	$2,450.00	Yes
Dec 1, 2008	Pauline Bartlett	St Anthony	681853	$992.50	$992.50	Yes
GENERAL SERVICE						
	None					

CUSTOMER PROPERTY DAMAGE CLAIMS REPORT
For the Quarter ended December 31

Introduction

The Customer Property Damage Claims Report contains an overview of all damage claims activity summarized on a quarterly basis. The information contained in the report is broken down by cause as well as by the operating region where the claims originated.

The report is divided into four sections as follows:

1. The first section indicates the number of claims received during the quarter coupled with claims outstanding from the previous quarter.

2. The second section shows the number of claims for which the Company has accepted responsibility and the amount paid to claimants versus the amount originally claimed.

3. The third section shows the number of claims rejected and the dollar value associated with those claims.

4. The fourth section indicates those claims that remain outstanding at the end of the current quarter and the dollar value associated with such claims.

Definitions of Causes of Damage Claims

1. System Operations: Claims arising from system operations. Examples include normal reclosing or switching.

2. Power Interruptions: Claims arising from interruption of power supply. Examples include all scheduled or unscheduled interruptions.

3. Improper Workmanship: Claims arising from failure of electrical equipment caused by improper workmanship or methods. Examples include improper crimping of connections, insufficient sealing and taping of connections, improper maintenance, inadequate clearance or improper operation of equipment.

4. Weather Related: Claims arising from weather conditions. Examples include wind, rain, ice, lighting or corrosion caused by weather.

5. Equipment Failure: Claims arising from failure of electrical equipment not caused by improper workmanship. Examples include broken neutrals, broken tie wires, transformer failure, insulator failure or broken service wire.

6. Third Party: Claims arising from equipment failure caused by acts of third parties. Examples include motor vehicle accidents and vandalism.

7. Miscellaneous: All claims not related to electrical service.

8. Waiting Investigation: Cause to be determined.

CUSTOMER PROPERTY DAMAGE CLAIMS REPORT - BY CAUSE

For the Quarter Ended December 31, 2008

CAUSE	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	AMT. CLAIMED	AMT. PAID	#	AMOUNT	#	AMOUNT
System Operations	2	2	4	0	$750.00	$0.00	1	$0.00	3	$795.00
Power Interruptions	0	3	3	2	$6,500.00	$5,915.00	0	$0.00	1	$0.00
Improper Workmanship	2	2	4	1	$350.00	$350.00	0	$0.00	3	$0.00
Weather Related	2	2	4	0	$850.00	$0.00	2	$0.00	2	$850.00
Equipment Failure	12	24	36	17	$6,292.03	$9,051.16	10	$2,517.98	9	$2,739.22
Third Party	1	0	1	0	$113.00	$0.00	0	$0.00	1	$113.00
Miscellaneous	3	0	3	1	$2,140.00	$350.00	1	$1,950.00	1	$0.00
Waiting Investigation	5	1	6						6	$38,860.00
Total	27	34	61	21	$16,995.03	$15,666.16	14	$4,467.98	26	$43,357.22

For the Quarter Ended December 31, 2007

CAUSE	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	AMT. CLAIMED	AMT. PAID	#	AMOUNT	#	AMOUNT
System Operations	3	0	3	0	$0.00	$0.00	3	$470.00	0	$0.00
Power Interruptions	3	5	8	0	$0.00	$0.00	6	$9,163.23	2	$5,516.33
Improper Workmanship	7	1	8	6	$6,340.83	$4,973.00	0	$0.00	2	$323.63
Weather Related	3	0	3	0	$0.00	$0.00	3	$387.60	0	$0.00
Equipment Failure	26	16	42	31	$19,137.00	$13,314.53	0	$0.00	11	$23,368.85
Third Party	0	0	0	0	$0.00	$0.00	0	$0.00	0	$0.00
Miscellaneous	0	1	1	0	$0.00	$0.00	0	$0.00	1	$0.00
Waiting Investigation	0	0	0	0	$0.00	$0.00	0	$0.00	0	$0.00
Total	42	23	65	37	$25,477.83	$18,287.53	12	$10,020.83	16	$29,208.81

CUSTOMER PROPERTY DAMAGE CLAIMS REPORT - BY REGION

For the Quarter Ended December 31, 2008

REGION	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	AMT. CLAIMED	AMT. PAID	#	AMOUNT	#	AMOUNT
Central Region	6	4	10	2	$6,500.00	$5,915.00	2	$1,790.00	6	$1,183.00
Northern Region	15	17	32	18	$10,145.03	$9,401.16	3	$798.00	11	$445.22
Labrador Region	6	13	19	1	$350.00	$350.00	9	$1,879.98	9	$41,729.00
Total	27	34	61	21	$16,995.03	$15,666.16	14	$4,467.98	26	$43,357.22

For the Quarter Ended December 31 2007

REGION	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	AMT. CLAIMED	AMT. PAID	#	AMOUNT	#	AMOUNT
Central Region	9	4	13	4	$5,740.75	$4,372.92	3	$2,443.97	6	$6,659.96
Northern Region	8	5	13	6	$3,195.31	$1,765.89	3	$5,915.59	4	$2,877.87
Labrador Region	25	14	39	27	$16,541.77	$12,148.72	6	$1,661.27	6	$19,670.98
Total	42	23	65	37	$25,477.83	$18,287.53	12	$10,020.83	16	$29,208.81

FINANCIAL – REGULATED

Balance Sheet - Regulated Utility
As at December 31
($000's)

	Dec-08	Dec-07
ASSETS		
Current assets		
Cash and cash equivalents	80	9
Receivables	69,495	69,114
Current portion of regulatory assets	5,000	17,154
Fuel and supplies	42,993	60,925
Prepaid expenses	1,156	841
	118,724	148,043
Property, plant, and equipment	1,354,348	1,352,229
Sinking funds	163,881	151,765
Regulatory assets	74,626	81,308
Total assets	1,711,579	1,733,345
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Bank indebtedness	4,637	8,025
Accounts payable and accrued liabilities	46,212	65,295
Accrued interest	28,667	30,566
Deferred capital contribution	470	-
Current portion of long-term debt	8,322	208,315
Current portion of regulatory liabilities	22,324	23,488
Due to related parties	450	182
Promissory notes	139,490	(33,421)
	250,572	302,450
Long-term debt	1,151,928	1,145,198
Regulatory liabilities	31,546	15,499
Employee future benefits	41,881	39,805
Shareholder's equity / retained earnings	219,732	210,858
Accumulated other comprehensive income	15,920	19,535
Total liabilities and shareholder's equity	1,711,579	1,733,345

Statement of Retained Earnings - Regulated Utility
For the twelve months ended December 31, 2008
($000's)

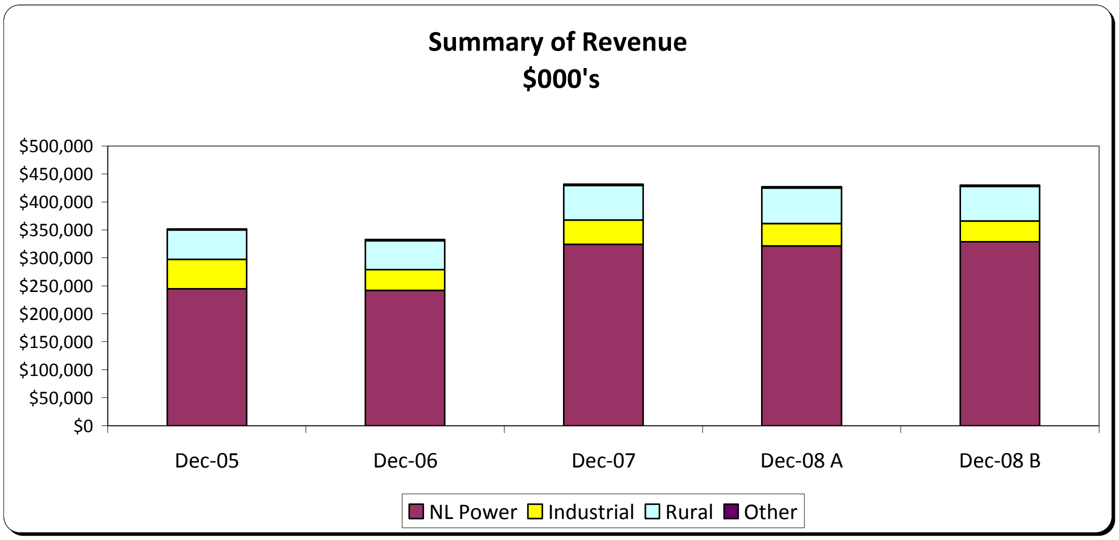
Fourth Quarter 2008 Actual	Fourth Quarter 2007 Actual		Year-to-date 2008 Actual	Year-to-date 2007 Actual
226,323	215,697	Balance, beginning of period [1]	210,858	205,841
-	-	Adjustment to long-term debt	-	2,306
(6,591)	(4,839)	Net income	8,874	2,711
219,732	210,858	Balance, end of period	219,732	210,858

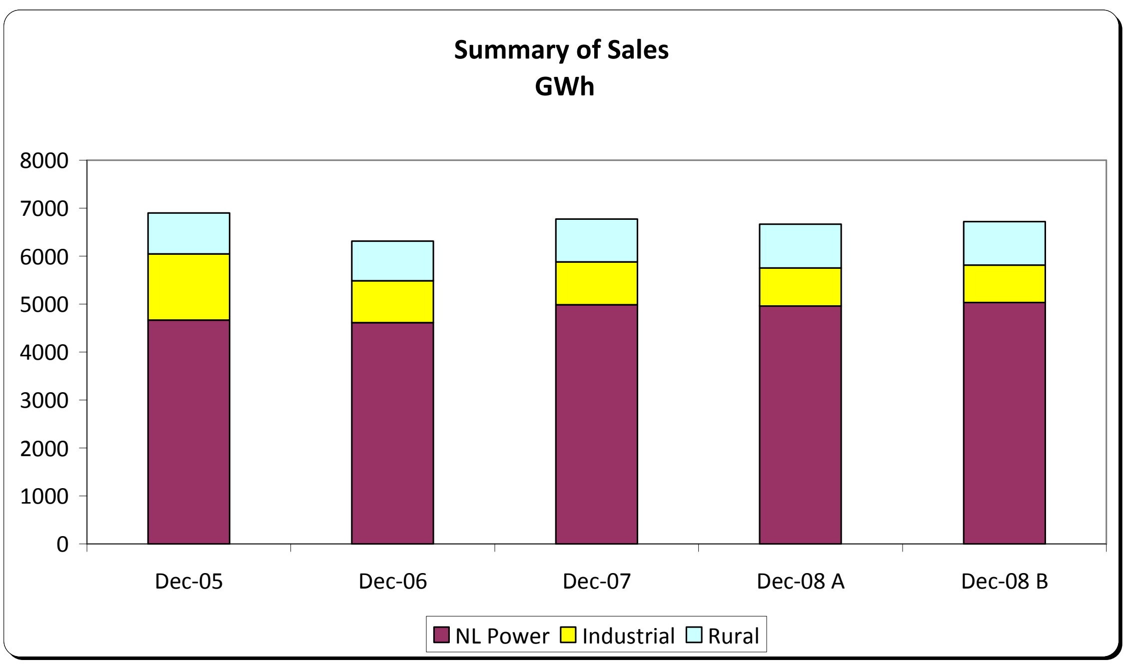
[1] Opening balance for 2008 includes an increase in costs of $180K associated with IOCC cost allocation.

Statement of Comprehensive Income - Regulated Utility
For the twelve months ended December 31, 2008
($000's)

Fourth Quarter 2008 Actual	Fourth Quarter 2008 Budget	Fourth Quarter 2007 Actual		Year-to-date 2008 Actual	Year-to-date 2008 Budget	Year-to-date 2007 Actual
(6,591)	(3,060)	(4,839)	Net income (loss)	8,874	(4,300)	2,711
			Other comprehensive income			
393	-	177	Change in fair value of sinking fund investments	(3,615)	-	177
(6,198)	(3,060)	(4,662)	Total comprehensive income	5,259	(4,300)	2,888

Regulated Utility
For the twelve months ended December 31, 2008





Revenue Summary - Regulated Utility
For the twelve months ended December 31, 2008
($000's)

Fourth Quarter 2008 Actual	Fourth Quarter 2008 Budget	Fourth Quarter 2007 Actual		Year-to-date 2008 Actual	Year-to-date 2008 Budget	Year-to-date 2007 Actual
			REVENUE BY MAJOR SOURCE			
			Industrial			
3,817	2,926	3,511	Corner Brook Pulp and Paper Ltd.	13,762	11,841	19,857
-	-	-	Abitibi Stephenville	-	-	285
1,421	1,548	1,032	Abitibi Grand Falls	5,151	6,385	4,937
2,969	2,994	2,622	North Atlantic Refinery	12,044	10,988	11,560
850	1,470	1,157	C.F.B. Goose Bay	5,719	4,680	3,951
842	840	756	Teck Cominco Limited	3,198	3,337	2,812
9,899	9,778	9,078	**Total Industrial**	39,874	37,231	43,402
			Utility			
87,782	91,423	92,209	Newfoundland Power Inc.	321,519	328,780	324,229
			Rural			
15,649	16,457	16,079	Interconnected and diesel	63,803	61,999	62,163
641	508	452	**Other revenue**	2,197	2,033	1,983
113,971	118,166	117,818	**Total**	427,393	430,043	431,777
			ENERGY SALES VOLUME ANALYSIS GWh			
			Industrial			
83.6	59.8	64.8	Corner Brook Pulp and Paper Ltd.	282.9	242.9	396.7
-	-	-	Abitibi Stephenville	-	-	4.0
35.0	40.8	29.1	Abitibi Grand Falls	136.7	170.1	131.3
63.1	63.8	53.5	North Atlantic Refinery	256.0	228.3	243.4
9.9	23.8	14.8	C.F.B. Goose Bay	60.7	75.8	62.9
16.5	16.4	14.1	Teck Cominco Limited	61.2	65.0	51.4
208.1	204.6	176.3	**Total Industrial**	797.5	782.1	889.7
			Utility			
1,324.0	1,362.8	1,374.2	Newfoundland Power Inc.	4,959.8	5,032.0	4,990.7
			Rural			
217.0	253.0	222.6	Interconnected and diesel	909.1	912.3	890.0
1,749.1	1,820.4	1,773.1	**Total**	6,666.4	6,726.4	6,770.4

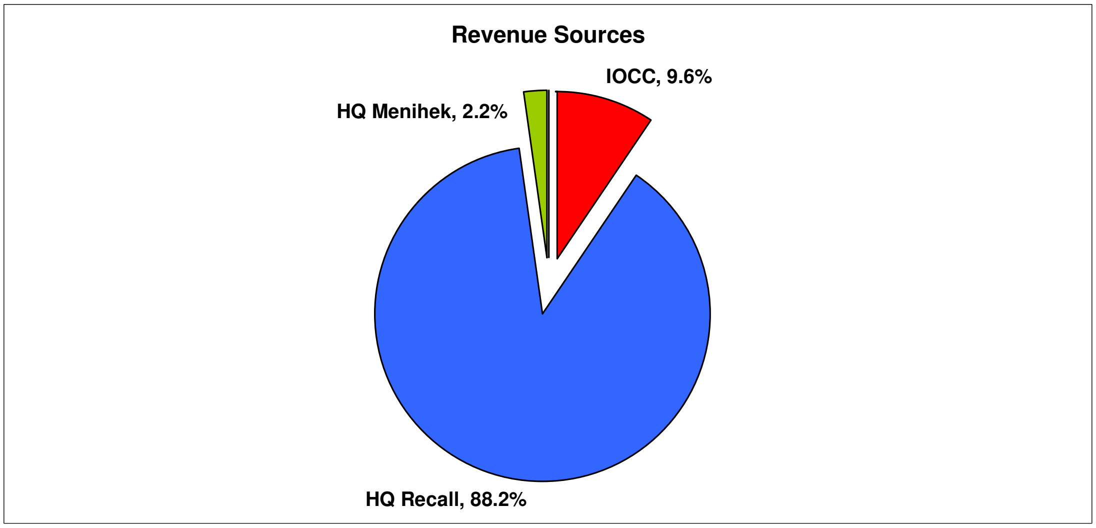
Statement of Cash Flows - Regulated Utility
For the twelve months ended December 31, 2008
($000's)

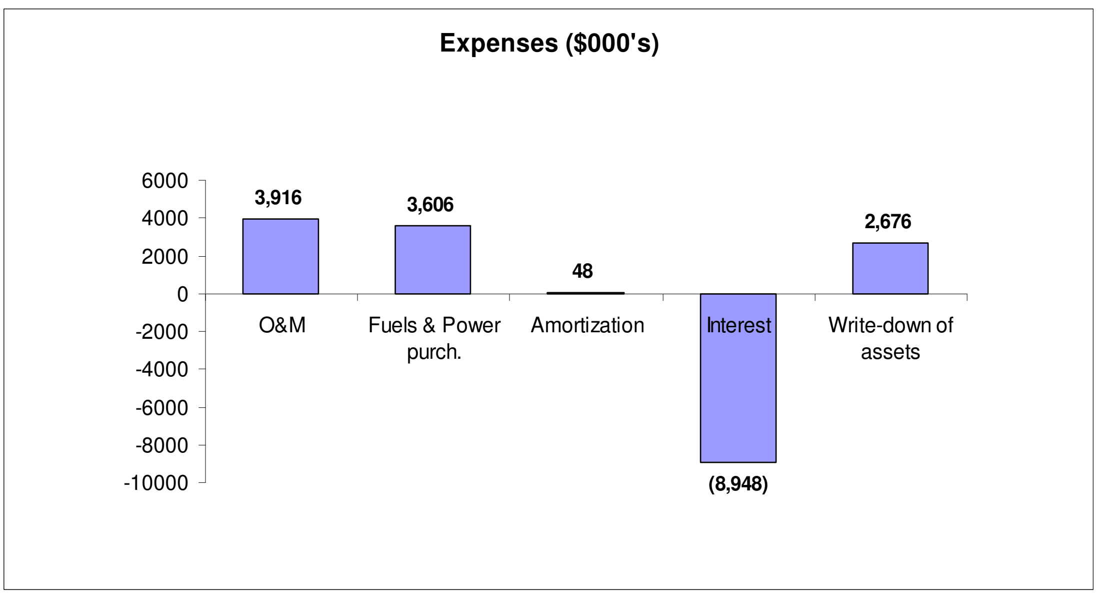
	Year-to-date 2008	Year-to-date 2007
Cash provided by (used in)		
Operating activities		
Net income	8,874	2,711
Adjusted for items not involving cash flow		
Amortization	40,393	38,342
Accretion of long-term debt	479	675
Loss on disposal of property, plant and equipment	2,580	902
Other	-	(92)
	52,326	42,538
Changes in non-cash balances related to operations		
Receivables	(381)	(9,698)
Fuel and supplies	17,932	(15,482)
Prepaid expenses	(315)	244
Regulatory assets	18,836	49,744
Regulatory liabilities	14,883	(11,382)
Accounts payable and accrued liabilities	(19,083)	27,214
Accrued interest	(1,899)	-
Due to related parties	268	(3,288)
Employee future benefits	2,560	4,268
	85,127	84,158
Financing activities		
(Decrease) increase in long-term debt	(188,692)	12,691
Increase in deferred capital contribution	470	-
Increase (decrease) in promissory notes	172,911	(49,483)
Transfer of employee future benefits to Non-Regulated	(484)	-
	(15,795)	(36,792)
Investing activities		
Additions to property, plant and equipment	(45,785)	(36,023)
Proceeds on disposal of property, plant and equipment	693	602
Increase in sinking funds	(20,781)	(19,592)
Decrease in short-term investments	-	560
	(65,873)	(54,453)
Net increase (decrease) in cash	3,459	(7,087)
Cash position, beginning of period	(8,016)	(929)
Cash position, end of period	(4,557)	(8,016)

Balance Sheet - Non-Regulated Activities
As at December 31
($000's)

	Dec-08	Dec-07
ASSETS		
Property, plant, and equipment	-	117,181
Long-term receivable	25,416	23,347
Investment in CF(L)Co.	359,813	350,472
Investment in LCDC & GIPCO	-	2,675
Total assets	385,229	493,675
LIABILITIES AND SHAREHOLDER'S EQUITY		
Long-term debt	(5,514)	5,960
Deferred capital contribution	1,726	-
Due to related party	3,067	-
Promissory notes	23,510	40,421
Share capital	22,504	22,504
Lower Churchill Development	15,400	15,400
Muskrat Falls Project	-	2,165
Retained earnings	324,536	407,225
	362,440	447,294
Total liabilities and shareholder's equity	385,229	493,675

Non-Regulated Activities
For the twelve months ended December 31, 2008





Statement of Income - Non-Regulated Activities
For the twelve months ended December 31, 2008
($000's)

Fourth Quarter 2008 Actual	Fourth Quarter 2008 Budget	Fourth Quarter 2007 Actual		Year-to-date 2008 Actual	Year-to-date 2008 Budget	Year-to-date 2007 Actual
			Revenue			
13,706	-	13,156	Energy sales	58,164	-	58,530
13,706	-	13,156		58,164	-	58,530
			Expenses			
860	218	1,913	Operating Costs [(1)]	3,715	972	5,876
28	-	12	Fuels	44	-	29
842	-	808	Power purchases	3,562	-	3,825
34	4	4	Amortization	48	16	18
(2,667)	-	(1,669)	Interest	(8,948)	-	(4,999)
2,675	-	-	Write down of investment	2,675	-	-
1,772	222	1,068		1,096	988	4,749
11,934	(222)	12,088	Net operating income (loss)	57,068	(988)	53,781
			Other revenue			
(2,659)	-	6,055	Equity in CF(L)Co	11,763	-	15,553
932	-	2,200	Preferred dividends	9,016	-	10,472
93	-	(135)	Interest share purchase debt	36	-	(911)
(1,634)	-	8,120	Total other revenue	20,815	-	25,114
10,300	(222)	20,208	Net income (loss)	77,883	(988)	78,895

(1) Note:
Operations and maintenance costs for 2008 decreased by $0.2 million (2007 - $0.2 million) for IOCC actual costs.

Statement of Retained Earnings - Non-Regulated Activties
For the twelve months ended December 31, 2008
($000's)

Fourth Quarter 2008 Actual	Fourth Quarter 2007 Actual		Year-to-date 2008 Actual	Year-to-date 2007 Actual
471,808	387,017	Balance, beginning of period (1)	407,225	328,330
10,300	20,208	Net income	77,883	78,895
(160,572)	-	Retained earnings transfer (2)	(160,572)	-
3,000	-	Dividends	-	-
324,536	407,225	Balance, end of period	324,536	407,225

(1) Opening balance for 2008 includes a decrease in costs of $180K associated with IOCC cost allocation.

(2) Transfer associated with restructuring activities.

Statement of Cash Flows - Non-Regulated Activities
For the twelve months ended December 31, 2008
($000's)

	Year-to-date 2008	Year-to-date 2007
Cash provided by (used in)		
Operating activities		
Net income	77,883	78,895
Adjusted for items not involving cash flow		
Amortization	48	18
Equity in CF(L)Co	(11,763)	(15,553)
Write-down of investment	2,675	-
	68,843	63,360
Dividends from CF(L)Co	2,422	3,286
Change in long-term receivable	(2,069)	(5,249)
Transfer of employee future benefits from Regulated	484	-
	69,680	61,397
Financing activities		
Decrease in long-term debt	(11,474)	(12,847)
Decrease in promissory notes	(16,911)	(2,872)
Increase in deferred capital contribution	1,726	-
Advance to Nalcor	(3,000)	-
	(29,659)	(15,719)
Investing activities		
Additions to property, plant and equipment	(40,021)	(45,678)
	(40,021)	(45,678)
Net change in cash	-	-
Cash position, beginning of period	-	-
Cash position, end of period	-	-

FINANCIAL – SUPPLEMENTARY

Supplementary Schedule - Regulated Activities
For the twelve months ended December 31, 2008
($000's)

Fourth Quarter 2008 Actual	Fourth Quarter 2008 Budget	Fourth Quarter 2007 Actual		Year-to-date 2008 Actual	Year-to-date 2008 Budget	Year-to-date 2007 Actual
			Other revenue			
263	123	82	Sundry	634	493	443
366	361	361	Pole attachments	1,464	1,444	1,444
12	24	9	Supplier's discount	99	96	96
641	508	452	**Total other revenue**	2,197	2,033	1,983
			Interest			
26,792	25,451	32,076	Gross interest	107,269	102,501	100,850
95	97	172	Accretion of long-term debt	479	497	675
539	539	539	Amortization of foreign exchange losses	2,157	2,157	2,157
(2,799)	(356)	(162)	Allowance for funds used during construction	(9,628)	(771)	(646)
(3,109)	(2,829)	(9,957)	Interest earned including RSP	(12,667)	(11,211)	(12,939)
-	3,216	3,286	Debt guarantee fee	-	12,862	13,145
21,518	26,118	25,954	**Total interest**	87,610	106,035	103,242

Cost Recoveries - Regulated Activities
For the twelve months ended December 31, 2008
($000's)

Fourth Quarter 2008 Actual	Fourth Quarter 2008 Budget	Fourth Quarter 2007 Actual		Year-to-date 2008 Actual	Year-to-date 2008 Budget	Year-to-date 2007 Actual
			CF(L)CO			
4	31	48	Executive Leadership	4	122	140
37	31	147	Human Resources and Organizational Effectiveness	251	125	239
404	421	473	Finance / CFO	1,547	1,686	1,699
(23)	17	28	Engineeering Services	36	67	78
422	500	696		1,838	2,000	2,156

Rate Stabilization Plan Report

Rate Stabilization Plan Report
December 31, 2008

Summary of Key Facts

The Rate Stabilization Plan of Newfoundland and Labrador Hydro (Hydro), as amended by Board Order No. P.U. 40 (2003) and Order No. P.U. 8 (2007), is established for Hydro's utility customer, Newfoundland Power, and Island Industrial customers to smooth rate impacts for variations between actual results and Test Year Cost of Service estimates for:

- Hydraulic production;
- No. 6 fuel cost used at Hydro's Holyrood generating station;
- Customer load (Utility and Island Industrial); and
- Rural rates.

The Test Year Cost of Service Study was approved by Board Order No. P.U. 8 (2007) and is based on projections of events and costs that are forecast to happen during a test year. Finance charges are calculated on the balances using the test year Weighted Average Cost of Capital which is currently 7.529% per annum. Holyrood's operating efficiency is 630 kWh/barrel.

	2007 Test Year Cost of Service			
	Net Hydraulic Production	No. 6 Fuel Cost	Utility Load	Industrial Load
	(kWh)	($Can/bbl.)	(kWh)	(kWh)
January	427,100,000	54.17	574,800,000	78,300,000
February	388,680,000	54.73	518,600,000	70,900,000
March	415,080,000	55.46	524,700,000	76,600,000
April	355,520,000	55.46	429,200,000	75,600,000
May	324,240,000	55.46	358,700,000	69,500,000
June	328,500,000	54.49	298,400,000	73,800,000
July	386,790,000	54.49	293,400,000	77,500,000
August	379,140,000	54.49	287,000,000	77,900,000
September	363,560,000	54.49	297,700,000	73,000,000
October	340,510,000	54.56	360,200,000	74,400,000
November	364,390,000	54.56	439,300,000	74,100,000
December	398,560,000	58.98	543,800,000	72,700,000
Total	4,472,070,000		4,925,800,000	894,300,000

Rate Stabilization Plan
Plan Highlights
December 31, 2008

	Actual	Cost of Service	Variance	Year-to-Date Due (To) From customers	Reference
Hydraulic production year-to-date	4,771. GWh	4,472.1 GWh	299. GWh	$ (26,383,315)	Page 4
No 6 fuel cost - Current month	$ 59.25	$ 58.98	$ 0.27	$ 27,745,268	Page 5
Year-to-date customer load - Utility	4,959.7 GWh	4,925.8 GWh	33.9 GWh	$ (26,253)	Page 8
Year-to-date customer load - Industrial	690.2 GWh	894.3 GWh	-204.12 GWh	$ (10,315,182)	Page 9
				$ (8,979,482)	

Rural rates		
Rural Rate Alteration (RRA) [(1)]	$ (245,481)	
Less : RRA to utility customer	$ (218,723)	Page 10
RRA to Labrador interconnected	(26,758)	
Fuel variance to Labrador interconnected	$ 205,395	Page 6
Net Labrador interconnected	$ 178,637	

Current plan summary		
One year recovery		
Due (to) from utility customer	$ (10,329,890)	Page 10
Due (to) from Industrial customers	$ (11,994,442)	Page 11
Sub total	(22,324,333)	
Four year recovery		
Hydraulic balance	$ (30,902,837)	Page 4
Total plan balance	$ (53,227,170)	

[(1)] Beginning January 2008, the RRA includes a monthly amount of $32,433. This amount relates to the phase in of the application of the credit from secondary energy sales to CFB Goose Bay to the Rural deficit as stated in Section B, Clause 1.3(b) of the approved Rate Stabilization Plan Regulations which received final approval in Order No. P.U. 33 (2007) issued December 21, 2007.

Rate Stabilization Plan
Net Hydraulic Production Variation
December 31, 2008

	A	B	C	D	E	F	G
	Cost of Service Net Hydraulic Production (kWh)	Actual Net Hydraulic Production (kWh)	Monthly Net Hydraulic Production Variance (kWh) **(A - B)**	Cost of Service No. 6 Fuel Cost ($Can/bbl.)	Net Hydraulic Production Variation ($) **(C / O[1] X D)**	Financing Charges ($)	Cumulative Variation and Financing Charges ($) **(E + F)** **(to page 12)**
Opening balance							(14,820,468)
January	427,100,000	477,077,144	(49,977,144)	54.17	(4,297,241)	(89,923)	(19,207,632)
February	388,680,000	437,972,596	(49,292,596)	54.73	(4,282,196)	(116,542)	(23,606,370)
March	415,080,000	503,744,129	(88,664,129)	55.46	(7,805,258)	(143,232)	(31,554,860)
April	355,520,000	390,350,281	(34,830,281)	55.46	(3,066,170)	(191,459)	(34,812,489)
May	324,240,000	347,865,812	(23,625,812)	55.46	(2,079,821)	(211,225)	(37,103,535)
June	328,500,000	358,079,359	(29,579,359)	54.49	(2,558,380)	(225,126)	(39,887,041)
July	386,790,000	353,156,726	33,633,274	54.49	2,909,011	(242,015)	(37,220,045)
August	379,140,000	354,560,633	24,579,367	54.49	2,125,920	(225,833)	(35,319,958)
September	363,560,000	355,244,466	8,315,534	54.49	719,228	(214,304)	(34,815,034)
October	340,510,000	395,269,826	(54,759,826)	54.56	(4,742,375)	(211,240)	(39,768,649)
November	364,390,000	357,071,095	7,318,905	54.56	633,840	(241,296)	(39,376,105)
December	398,560,000	440,644,093	(42,084,093)	58.98	(3,939,873)	(238,915)	(43,554,893)
	4,472,070,000	4,771,036,160	(298,966,160)		(26,383,315)	(2,351,110)	(43,554,893)
Hydraulic Allocation [2]					10,300,946	2,351,110	12,652,056
Hydraulic variation at year end					(16,082,369)	-	(30,902,837)

(1) O is the Holyrood Operating Efficiency of 630 kWh/barrel.
(2) At year end 25% of the hydraulic variation balance and 100% of the annual financing charges are allocated to customers.

	(from page 6) 12 month kWh	% of kWh to total	Allocation	Reallocate Rural	**(to pages 11 & 12)** Net
Utility	4,959,752,852	81.8%	10,352,198	765,618	11,117,816
Industrial	690,182,871	11.4%	1,440,578		1,440,578
Rural	411,682,211	6.8%	859,280	(859,280)	-
Total	6,061,617,934	100.0%	12,652,056	(93,662)	12,558,394
Labrador Interconnected (write-off to income)				93,662	93,662
				-	12,652,056

Rate Stabilization Plan
No. 6 Fuel Variation
December 31, 2008

	A	B	C	D	E	F	G
	Actual Quantity No. 6 Fuel	Actual Quantity No. 6 Fuel for Non-Firm Sales	Net Quantity No. 6 Fuel	Cost of Service No. 6 Fuel Cost	Actual Average No. 6 Fuel Cost	Cost Variance	No.6 Fuel Variation
	(bbl.)	(bbl.)	(bbl.) **(A - B)**	($Can/bbl.)	($Can/bbl.)	($Can/bbl.) **(E - D)**	($) **(C X F) (to page 6)**
January	315,296	1,267	314,029	54.17	69.17	15.00	4,710,435
February	278,439	3,118	275,321	54.73	70.34	15.61	4,297,761
March	231,653	1,240	230,413	55.46	71.09	15.63	3,601,351
April	169,327	583	168,744	55.46	71.52	16.06	2,710,036
May	134,027	329	133,698	55.46	71.52	16.06	2,147,194
June	26,533	258	26,275	54.49	79.33	24.84	652,660
July	339	337	2	54.49	89.89	35.40	55
August	0	408	(408)	54.49	89.89	35.40	(14,443)
September	135	369	(234)	54.49	89.95	35.46	(8,296)
October	102,573	256	102,317	54.56	90.06	35.50	3,632,242
November	215,331	1	215,330	54.56	82.18	27.62	5,947,416
December	255,028	2	255,026	58.98	59.25	0.27	68,857
	1,728,681	8,168	1,720,513	55.47	71.59	16.12	27,745,268

Rate Stabilization Plan
Allocation of Fuel Variance - Year-to-Date
December 31, 2008

	A	B	C	D	E	F	G	H	I	J
	Twelve Months-to-Date				Year-to-Date Fuel Variance				Reallocate Rural Island Customers [(1)]	
	Utility	Industrial Customers	Rural Island Customers	Total	Utility	Industrial Customers	Rural Island Interconnected	Total	Utility	Labrador Interconnected
	(kWh)	(kWh)	(kWh)	(kWh)	($)	($)	($)	($)	($)	($)
				(A+B+C)	**(A/D X H)**	**(B/D X H)**	**(C/D X H)**		**(G X 88.58%)**	**(G X 11.42%)**
					(to page 7)			**(from page 5)**	**(to page 7)**	
January	5,013,930,402	757,617,115	402,636,925	6,174,184,442	3,825,249	578,004	307,182	4,710,435	273,699	33,483
February	5,010,687,516	745,479,713	405,359,469	6,161,526,698	7,325,661	1,089,897	592,638	9,008,196	528,040	64,598
March	5,037,540,915	725,101,495	407,923,188	6,170,565,598	10,294,212	1,481,744	833,591	12,609,547	742,730	90,861
April	5,021,579,114	715,981,053	407,769,144	6,145,329,311	12,518,206	1,784,857	1,016,520	15,319,583	905,719	110,801
May	5,010,732,890	698,078,679	407,998,011	6,116,809,580	14,308,334	1,993,390	1,165,053	17,466,777	1,038,062	126,991
June	4,998,998,529	681,489,225	409,750,041	6,090,237,795	14,872,825	2,027,540	1,219,072	18,119,437	1,086,193	132,879
July	4,991,379,950	667,970,308	410,477,609	6,069,827,867	14,900,137	1,994,008	1,225,347	18,119,492	1,091,784	133,563
August	5,008,640,188	651,211,542	411,239,047	6,071,090,777	14,936,636	1,942,026	1,226,387	18,105,049	1,092,711	133,676
September	5,010,044,656	648,919,073	411,961,865	6,070,925,594	14,934,385	1,934,355	1,228,013	18,096,753	1,094,160	133,853
October	5,012,364,843	661,618,615	412,275,567	6,086,259,025	17,895,007	2,362,093	1,471,895	21,728,995	1,311,458	160,437
November	5,004,210,952	684,182,648	412,005,514	6,100,399,114	22,703,203	3,104,013	1,869,195	27,676,411	1,665,453	203,742
December	4,959,752,852	690,182,871	411,682,211	6,061,617,934	22,701,806	3,159,108	1,884,354	27,745,268	1,678,959	205,395

(1) The Fuel Variance initially allocated to Rural Island Interconnected is re-allocated between Utility and Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the approved Cost of Service Study, which is 89.10% and 10.90% respectively. The Labrador Interconnected amount is then removed from the plan and written off to net income (loss).

Rate Stabilization Plan
Allocation of Fuel Variance - Monthly
December 31, 2008

	A	B	C	D	E	F	G
	Utility					**Industrial**	
	Fuel Variance		Rural Allocation		Total Fuel Variance	Fuel Variance	
	Year-to-Date Activity	Current Month Activity (1)	Year-to-Date Activity	Current Month Activity (1)	Activity for the month	Year-to-Date Activity	Current Month Activity (1)
	($)	($)	($)	($)	($)	($)	($)
					(B + D)		
	(from page 6)		**(from page 6)**		**(to page 10)**	**(from page 6)**	**(to page 11)**
January	3,825,249	3,825,249	273,699	273,699	4,098,948	578,004	578,004
February	7,325,661	3,500,412	528,040	254,341	3,754,753	1,089,897	511,893
March	10,294,212	2,968,551	742,730	214,690	3,183,241	1,481,744	391,847
April	12,518,206	2,223,994	905,719	162,989	2,386,983	1,784,857	303,113
May	14,308,334	1,790,128	1,038,062	132,343	1,922,471	1,993,390	208,533
June	14,872,825	564,491	1,086,193	48,131	612,622	2,027,540	34,150
July	14,900,137	27,312	1,091,784	5,591	32,903	1,994,008	(33,532)
August	14,936,636	36,499	1,092,711	927	37,426	1,942,026	(51,982)
September	14,934,385	(2,251)	1,094,160	1,449	(802)	1,934,355	(7,671)
October	17,895,007	2,960,622	1,311,458	217,298	3,177,920	2,362,093	427,738
November	22,703,203	4,808,196	1,665,453	353,995	5,162,191	3,104,013	741,920
December	22,701,806	(1,397)	1,678,959	13,506	12,109	3,159,108	55,095
		22,701,806		1,678,959	24,380,765		3,159,108

(1) The current month activity is calculated by subtracting year-to-date activity for the prior month from year-to-date activity for the current month.

Rate Stabilization Plan
Load Variation - Utility
December 31, 2008

	A	B	C	D	E	F	G	H	I	J	K
	Firm Energy						Secondary Energy				
	Cost of Service Sales (kWh)	Actual Sales (kWh)	Sales Variance (kWh) **(B - A)**	Cost of Service No. 6 Fuel Cost ($Can/bbl.)	Firm Energy Rate ($/kWh)	Load Variation ($) **C x {(D/O[1]) - E}**	Cost of Service Sales (kWh)	Actual Sales (kWh)	Firming Up Charge ($/kWh)	Load Variation ($) **(G - H) x I**	Total Load Variation ($) **(F + J)** **(to page 10)**
January	574,800,000	590,752,934	15,952,934	54.17	0.08805	(32,957)	0	8,227	0.00841	(69)	(33,026)
February	518,600,000	534,671,108	16,071,108	54.73	0.08805	(18,915)	0	0	0.00841	0	(18,915)
March	524,700,000	559,719,845	35,019,845	55.46	0.08805	(639)	0	2,593	0.00841	(22)	(661)
April	429,200,000	435,748,667	6,548,667	55.46	0.08805	(120)	0	0	0.00841	0	(120)
May	358,700,000	370,754,647	12,054,647	55.46	0.08805	(220)	0	0	0.00841	0	(220)
June	298,400,000	298,799,572	399,572	54.49	0.08805	(623)	0	0	0.00841	0	(623)
July	293,400,000	276,980,859	(16,419,141)	54.49	0.08805	25,580	0	54,839	0.00841	(461)	25,119
August	287,000,000	281,448,327	(5,551,673)	54.49	0.08805	8,649	0	0	0.00841	0	8,649
September	297,700,000	286,814,735	(10,885,265)	54.49	0.08805	16,959	0	0	0.00841	0	16,959
October	360,200,000	373,078,329	12,878,329	54.56	0.08805	(18,633)	0	1,353	0.00841	(11)	(18,644)
November	439,300,000	414,408,089	(24,891,911)	54.56	0.08805	36,014	0	0	0.00841	0	36,014
December	543,800,000	536,495,923	(7,304,077)	58.98	0.08805	(40,677)	0	12,805	0.00841	(108)	(40,785)
	4,925,800,000	4,959,673,035	33,873,035			(25,582)	0	79,817		(671)	(26,253)

(1) O is the Holyrood Operating Efficiency of 630 kWh/barrel.

Rate Stabilization Plan
Load Variation - Industrial
December 31, 2008

	A	B	C	D	E	F
	Cost of Service Sales	Actual Sales	Sales Variance	Cost of Service No. 6 Fuel Cost	Firm Energy Rate	Load Variation
	(kWh)	(kWh)	(kWh)	($)	($/kWh)	($)
			(B - A)			**C x {(D/O[1]) - E}**
						(to page 11)
January	78,300,000	51,079,860	(27,220,140)	54.17	0.03676	(1,339,888)
February	70,900,000	52,387,448	(18,512,552)	54.73	0.03676	(927,720)
March	76,600,000	55,240,151	(21,359,849)	55.46	0.03676	(1,095,157)
April	75,600,000	59,372,548	(16,227,452)	55.46	0.03676	(832,010)
May	69,500,000	57,229,347	(12,270,653)	55.46	0.03676	(629,138)
June	73,800,000	56,004,405	(17,795,595)	54.49	0.03676	(885,012)
July	77,500,000	57,664,475	(19,835,525)	54.49	0.03676	(986,462)
August	77,900,000	56,228,407	(21,671,593)	54.49	0.03676	(1,077,773)
September	73,000,000	54,523,317	(18,476,683)	54.49	0.03676	(918,884)
October	74,400,000	61,772,188	(12,627,812)	54.56	0.03676	(629,410)
November	74,100,000	68,895,119	(5,204,881)	54.56	0.03676	(259,428)
December	72,700,000	59,785,606	(12,914,394)	58.98	0.03676	(734,300)
	894,300,000	690,182,871	(204,117,129)			(10,315,182)

(1) O is the Holyrood Operating Efficiency of 630 kWh/barrel.

Rate Stabilization Plan
Summary of Utility Customer
December 31, 2008

	A	B	C	D	E	F	G	H
	Load Variation	Allocation Fuel Variance	Allocation Rural Rate Alteration (1)	Subtotal Monthly Variances	Financing Charges	Adjustment (2)	Transfer from Old Plan	Cumulative Net Balance
	($)	($)	($)	($)	($)	($)		($)
				(A + B + C)				
	(from page 8)	**(from page 7)**						**(to page 12)**
Opening Balance (3)								(14,652,165)
January	(33,026)	4,098,948	126,133	4,192,055	(88,902)	2,055,849		(8,493,163)
February	(18,915)	3,754,753	42,481	3,778,319	(51,532)	1,860,655		(2,905,721)
March	(661)	3,183,241	42,112	3,224,692	(17,630)	1,947,834		2,249,175
April	(120)	2,386,983	59,898	2,446,761	13,647	1,516,405		6,225,988
May	(220)	1,922,471	64,030	1,986,281	37,776	1,290,226		9,540,271
June	(623)	612,622	57,595	669,594	57,886	1,039,823		11,307,574
2003 Utility plan balance (4)							(2,238,025)	9,069,549
July	25,119	32,903	8,966	66,988	55,029	(2,083,308)		7,108,258
August	8,649	37,426	(115,302)	(69,227)	43,129	(2,116,491)		4,965,669
September	16,959	(802)	(110,476)	(94,319)	30,129	(2,156,847)		2,744,632
October	(18,644)	3,177,920	(108,416)	3,050,860	16,653	(2,805,559)		3,006,586
November	36,014	5,162,191	(127,946)	5,070,259	18,242	(3,116,349)		4,978,738
December	(40,785)	12,109	(157,798)	(186,474)	30,208	(4,034,546)		787,926
Year to date	(26,253)	24,380,765	(218,723)	24,135,789	144,635	(6,602,308)	(2,238,025)	15,440,091
Hydraulic allocation **(from page 4)**								(11,117,816)
Total	(26,253)	24,380,765	(218,723)	24,135,789	144,635	(6,602,308)	(2,238,025)	(10,329,890)

(1) The Rural Rate Alteration is allocated between Utility and Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the approved Cost of Service Study, which is 89.10% and 10.90% respectively. The Labrador Interconnected amount is then removed from the plan and written off to net income (loss).

(2) The RSP adjustment rate for Utility is $0.348 cents per kWh effective July 1, 2007 to June 30, 2008 and $0.752 effective July 1, 2008.

(3) The December 2007 closing balance of $14,659,375 payable was reduced by $7,210 related to a Rural Rate Alteration adjustment in July 2007.

(4) The balance in plan for utility customers will be recovered as a component of the current plan in accordance with Section E of the Rate Stabilization Plan.

Rate Stabilization Plan
Summary of Industrial Customers
December 31, 2008

	A	B	C	D	E	F
	Load Variation	Allocation Fuel Variance	Subtotal Monthly Variances	Financing Charges	Adjustment [(1)]	Cumulative Net Balance
	($)	($)	($)	($)	($)	($)
			(A + B)			
	(from page 9)	**(from page 7)**				**(to page 12)**
Opening Balance						(8,828,968)
January	(1,339,888)	578,004	(761,884)	(53,570)	462,206	(9,182,216)
February	(927,720)	511,893	(415,827)	(55,713)	468,080	(9,185,676)
March	(1,095,157)	391,847	(703,310)	(55,734)	499,003	(9,445,717)
April	(832,010)	303,113	(528,897)	(57,312)	529,906	(9,502,020)
May	(629,138)	208,533	(420,605)	(57,654)	514,376	(9,465,903)
June	(885,012)	34,150	(850,862)	(57,434)	502,326	(9,871,873)
July	(986,462)	(33,532)	(1,019,994)	(59,898)	510,304	(10,441,461)
August	(1,077,773)	(51,982)	(1,129,755)	(63,354)	497,280	(11,137,290)
September	(918,884)	(7,671)	(926,555)	(67,576)	482,977	(11,648,444)
October	(629,410)	427,738	(201,672)	(70,677)	551,743	(11,369,050)
November	(259,428)	741,920	482,492	(68,982)	608,393	(10,347,147)
December	(734,300)	55,095	(679,205)	(62,782)	535,270	(10,553,864)
Year to date	(10,315,182)	3,159,108	(7,156,074)	(730,686)	6,161,864	(1,724,896)
Hydraulic allocation - page 4						(1,440,578)
						0
Total	(10,315,182)	3,159,108	(7,156,074)	(730,686)	6,161,864	(11,994,442)

(1) The RSP adjustment rate for Industrial Customers excluding Teck Cominco is 0.785 cents per kWh effective January 1, 2008. The rate for Teck Cominco is 2.000 cents per kWh.

Rate Stabilization Plan
Overall Summary
December 31, 2008

	A	B	C	D
	Hydraulic Balance	Utility Balance	Industrial Balance	Total To Date
	($)	($)	($)	($)
				(A + B + C)
	(from page 4)	**(from page 10)**	**(from page 11)**	
December 2007	(14,820,468)	(14,652,165)	(8,828,968)	(38,301,602)
January	(19,207,632)	(8,493,163)	(9,182,216)	(36,883,012)
February	(23,606,370)	(2,905,721)	(9,185,676)	(35,697,768)
March	(31,554,860)	2,249,175	(9,445,717)	(38,751,403)
April	(34,812,489)	6,225,988	(9,502,020)	(38,088,522)
May	(37,103,535)	9,540,271	(9,465,903)	(37,029,168)
June	(39,887,041)	11,307,574	(9,871,873)	(38,451,341)
July	(37,220,045)	7,108,258	(10,441,461)	(40,553,249)
August	(35,319,958)	4,965,669	(11,137,290)	(41,491,580)
September	(34,815,034)	2,744,632	(11,648,444)	(43,718,847)
October	(39,768,649)	3,006,586	(11,369,050)	(48,131,114)
November	(39,376,105)	4,978,738	(10,347,147)	(44,744,515)
December	(30,902,837)	(10,329,890)	(11,994,442)	(53,227,170)

Rate Stabilization Plan
Recovery of December 2003 Balance
December 31, 2008

	A	B	C	G
	Utility Customer			Total To Date
		Financing	Total	Due From (To)
	Recovery [1]	Charges	To Date	Customers
	($)	($)	($)	($)
			(A + B)	**(C + F)**
Opening Balance			12,053,450.46	12,053,450.46
January	(3,066,050.43)	73,134.31	9,060,534.34	9,060,534.34
February	(2,774,943.05)	54,974.79	6,340,566.08	6,340,566.08
March	(2,904,959.45)	38,471.38	3,474,078.01	3,474,078.01
April	(2,261,535.58)	21,078.97	1,233,621.40	1,233,621.40
May	(1,924,216.62)	7,485.00	(683,110.22)	(683,110.22)
June	(1,550,769.78)	(4,144.77)	(2,238,024.77)	(2,238,024.77)
Plan expiry [2]				2,238,024.77
July	0.00			0.00
August	0.00	0.00	0.00	0.00
September	0.00	0.00	0.00	0.00
October	0.00	0.00	0.00	0.00
November	0.00	0.00	0.00	0.00
December	0.00	0.00	0.00	0.00
Total	(14,482,474.91)	190,999.68	(2,238,024.77)	0.00

(1) The recovery rate for Utility is 0.519 cents per kWh effective July 1, 2007 to June 30, 2008.
(2) The balance in plan for utility customers will be included as a component of the current plan in accordance with Section E of the Rate Stabilization Plan.

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

QUARTERLY REGULATORY REPORT FOR THE YEAR ENDED DECEMBER 31, 2009

Newfoundland and Labrador Hydro

Table of Contents

1 HIGHLIGHTS

REVISED May 2010

HIGHLIGHTS
For the twelve months ended December 31, 2009

REGULATED	2009 Actual YTD	2009 Target/ Budget	2008 Actual YTD[7]
Safety			
Lead:Lag Ratio[1]	341:1	350:1	294:1
All Injury Frequency Rate[1,2]	1.44	≤1.0	1.44
Production			
Quarter End Reservoir Storage (GWh)	2,368	824	1,754
Hydraulic Production (GWh)[3]	4,200	4,214	4,771
Holyrood Fuel Cost per barrel, current month ($)[3]	67	59	59
Electricity Delivery			
Sales including Wheeling (GWh)	6,450.4	6,852.5	6,666.4
Financial[8]			
Revenue ($millions)	427.7	443.4	427.4
Expenses ($millions)	410.5	434.6	418.5
Net Operating Income ($millions)[4]	17.2	8.8	8.9
Current Rate Stabilization Plan (RSP) Balance ($millions)	(122.0)	(4.3)	(53.2)
Hydraulic	(32.2)	(10.1)	(30.9)
Utility	(52.9)	15.7	(10.3)
Industrial	(36.9)	(9.9)	(12.0)
Full Time Equivalent (FTE) Employees[5, 6]			
Regulated[2]	813.5	849.6	805.9
Non-Regulated	21.9	4.0	50.2

[1] Annual Target, and 2008 Actual
[2] Per 200,000 hours
[3] Target based on approved 2007 Test Year forecast
[4] Does not include any earnings from CF(L)Co
[5] One FTE is the equivalent of actual paid regular hours - 2,080 hours per year in the operating environment and 1,950 hours per year in Hydro's head office environment.
[6] Annual Budget and 2008 Actual values
[7] Certain of the 2008 comparative figures were restated to conform with the 2009 presentation.
[8] Finance Statement will be available after year end

- Work methods and work permit codes have been standardized (Page 3)
- Back-it-up Safety campaign established (Page 4)
- 2009 Winter Availability exceeds target (Page 12)
- System Hydrology Storage 2,368 GWh (Page 15)
- 2009 Key Performance Indicators Annual Report (Appendix E)

2 SAFETY

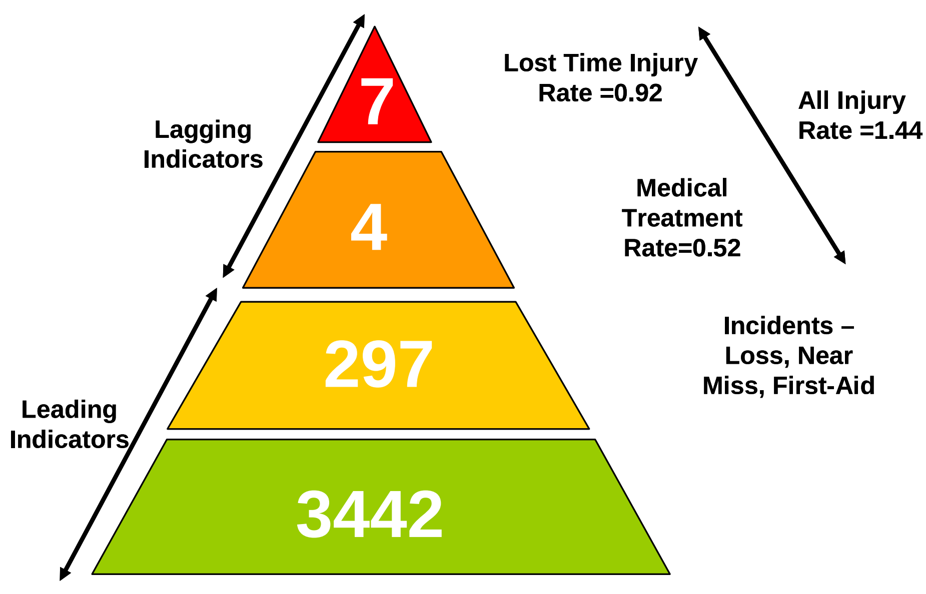
Goal - To be a Safety Leader

Safety is Hydro's number one priority. Hydro remains committed to being a world class leader in safety performance.

Measurement	Year-to-date 2009 Actual	Annual 2009 Plan	Annual 2008 Actual
All Injury Frequency (AIF)	1.44	$\leq$1.0	1.44
Lost Time Injury Frequency (LTIF)	0.92	$\leq$0.5	0.78
Ratio of condition and incident reports to lost time and medical treatment injuries (lead/lag ratio)	341:1	350:1	294:1
Work Permit Code Standardization and Improvement	Completed [1]		N/A
Work Methods Standardized	Completed [2]		N/A

[1] Training has been completed for approximately 85% of Hydro's employees.
[2] A process for completing work methods was finalized and targets established for 2009 to 2011.

The following safety triangle summarizes Hydro's year-to-date performance.



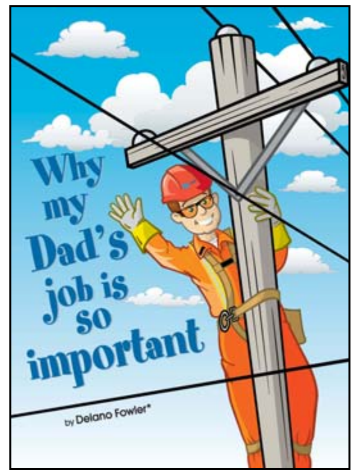
Lead/lag ratio: 341:1 2009 Target 350:1

2.1 Hydro Encourages Contractors to Work Safely Around Power Lines

Hydro and Newfoundland Power are partnering to address concerns surrounding the number of electrical contacts that contractors have made with power lines over the summer and fall. The majority of incidents have involved contractors using large equipment such as booms, cranes, tractor-trailers, snow clearing equipment and dump trucks. There is now a campaign to educate contractors on the dangers of electricity and remind them to take the necessary precautions when working near power lines. Accidents can be prevented with proper planning, worksite evaluation and adhering to safe distances. The company is getting this message out to contractors through updated website material, targeted mailing campaigns, advertising, media engagement and direct communication with contractors. Hydro plans to continue this campaign on contractor power line safety in 2010.

2.2 Hydro Educating Children on Electrical Safety

This fall, for the second year, Hydro distributed its children's electrical safety book called "Why my Dad's job is so important" to schools across the province for distribution to grade one students. The concept of the book was first brought to Hydro by Delano Fowler, a retired lineworker. The company believes everyone has a responsibility for their own safety and health, as well as the safety of others, and you are never too young to learn the importance of electrical safety. Downloadable copies of the book are available at www.nlh.nl.ca/safetybook.



Hydro's Safety Book

2.3 Testing the Work Method Database

During the week of November 23, employees met in Deer Lake to demonstrate and test the new Work Method database. The Work Methods Program systematically examines occupational tasks to identify requirements necessary to perform tasks safely, with minimum risk to people, equipment, materials, and environment. It involves developing and maintaining a task inventory; completing task analysis on the task inventory to identify critical tasks, as well as to identify safety and health requirements for tasks; completing task based risk assessments for critical tasks; and developing work methods for critical tasks. Keith Saunders (Work Methods Specialist) conceived the concept for the database and Patricia Ly (Systems Analyst) developed it. To ensure the functionality of the database, employees throughout Nalcor met to perform a variety of processes with the database. This database is in the same class as the SWOP database and will ensure the safety and health of workers, contractors, visitors, and the public.

2.4 Hydro Launches New Public Safety Campaign – Back it Up

In December, Hydro launched a new safety campaign called Back it Up. Back it Up is designed to give people important information they need to make safer decisions at work and at home. The concept is based on Hydro's policy to reverse into parking spots at all its locations, an action which all Hydro and Nalcor Energy employees embrace. "Backing in is a small safety act, but for Hydro, safety is as big as it gets." said Jim Haynes, Hydro's Vice President of Regulated Operations. "We believe that small steps can make a big difference in keeping you and your family safe. We challenge everyone to take the time to step back and make every situation safe." For more information visit www.HydroSafety.ca.

3 ENVIRONMENT AND CONSERVATION

Goal - To be an Environmental Leader

Hydro recognizes its commitment and responsibility to protect the environment.

Measurement	Year-to-date 2009 Actual	Annual 2009 Target	Annual 2008 Actual
Variance from ideal production schedule at Holyrood Thermal Generating Station	9.1%	$\leq$ 16%	23.8%
Achievement of EMS targets[1]	93% of Planned	95%	89%
Annual energy savings from Conservation and Demand Management and internal energy efficiency initiatives	5.28 GWh	4.65 GWh	N/A
0.7% Sulphur fuel in Holyrood	Completed	Attain direction	N/A
Emission compliance for stack emissions with 0.7% Sulphur fuel	In progress	100%	N/A

[1] An EMS target is an initiative undertaken to improve environmental performance.

- Variance from ideal production schedule at Holyrood Thermal Generating Station:
  - i. In 2009, the year end variance is 9.1%.
  - ii. The biggest improvements are in the forced outage time at Holyrood. These were also gains made through improved System Operations decisions.
  - iii. The conversion of Holyrood Unit 3 to and from synchronous condenser operations was the biggest contribution to the variance.

- Achievement of EMS initiatives:
  - i. 66 initiatives were completed out of 71 planned for completion in 2009.
  - ii. 98%, or 246 out of 252, planned milestones associated with those initiatives were completed.
  - iii. The remaining initiatives are expected to be completed in early 2010.

- Annual energy savings from Conservation and Demand Management and internal energy efficiency initiatives:
    i. There were two components of this target, Customer Facing and Internal Efficiency. Customer Facing initiatives met the target of 3 GWh, with a final total of 3.05 GWh. Internal Efficiency exceeded the target of 1.65 GWh with a total of 2.23 GWh of savings. The savings beyond target were primarily driven by the identification of operational opportunities in heating and lighting systems at Holyrood, both in the plant and surrounding buildings.

- Holyrood Sulphur Emissions Compliance:
    i. Receipt of fuel with a maximum sulphur content of 0.7% began in March 2009.

- Sulphur Emissions Compliance Testing:
    i. Emission rate test using 0.7% sulphur fuel occurred in late March and early April.
    ii. The report on emission rate testing was received in late July.
    iii. Agreement was reached with the Department of Environment on the approach and scenarios for determination of compliance in October.
    iv. Air emission dispersion modeling using the agreed approach and scenarios is ongoing and is expected to be completed in February 2010.

3.1 TakeCHARGE Launches Energy Efficiency Week

Members of Hydro's takeCHARGE Energy Efficiency team. L-R: Dawn Dunn, Simone Browne, Brad Coady, Elaine Cole, Wade Lucas and Barry Brophy

From November 14 to 20, 2009, Hydro and Newfoundland Power held the first takeCHARGE Energy Efficiency Week in Newfoundland and Labrador. TakeCHARGE Energy Efficiency Week provided homeowners with the advice they need to become more energy efficient at home to save energy and save money.

TakeCHARGE produced a five-part television series to show homeowners how to improve the energy efficiency of their homes. Each day from November 16 to November 20, the series presented the takeCHARGE Team visiting a homeowner to discuss ways to make their homes more energy efficient, helping them save money while creating a more comfortable home. The two-minute segments, aired during the week on the nightly NTV and CBC news and focused on insulation, windows, thermostats, weather proofing and saving energy during the holiday season.

3.2 Conservation and Demand Management (CDM)

3.2.1 Introduction

In 2009, Hydro expanded staff resources focused on energy efficiency, launched an expanded portfolio of rebate programs for residential and commercial customers, further developed an efficiency program targeting Industrial Customers, and continued work with Newfoundland Power on the development of the provincial delivery of the takeCHARGE program.

Work has continued with government partners, community groups and individual customers to engage on energy efficiency and to create energy savings.

3.2.2 Energy Efficiency Planning and Coordination

Hydro and Newfoundland Power worked closely to develop and implement the takeCHARGE program for energy efficiency.

In June 2009, the first rebate programs offered jointly by the two utilities were launched:

- Residential
    i. Insulation
    ii. Energy Star Windows
    iii. Thermostats
- Commercial
    i. Lighting

In order to provide these programs, late in 2008 and early in 2009, staffing levels were increased for Hydro's Energy Efficiency group. The group was increased to include technical and marketing skills, a support role and a focused resource on the development of the industrial program.

As well, training and orientation on new programs, processes and specific technologies were delivered to staff involved in customer services. This included Customer Services Representatives, Customer Services Technologists and Meter Readers.

3.2.3 Customer Awareness

As the takeCHARGE brand was launched to the public in November 2008, promotional activities for 2009 were focused on developing awareness and understanding of the takeCHARGE brand and program to ensure customers became aware of the utilities' efforts to assist them to conserve with rebates and information.

This was achieved through a mass market approach providing television, web, radio and print ads on the brand and the specific rebated technologies. The preliminary numbers from research conducted on the effectiveness of this campaign show very strong results, with nearly 80% awareness of the takeCHARGE initiative.

Hydro also participated in ten trade show events across the province, promoting the takeCHARGE brand to residential and commercial audiences.

As takeCHARGE is a joint utility program, mass marketing efforts were focused on getting customers to visit the website for information. The website was launched in 2008 with the brand and activity for 2009 was very strong. Provincially, there were web and bill insert-based contests to encourage customers to visit the website. Hydro also independently launched a customer promotion that will continue into 2010, providing customers with the additional incentive of an energy efficiency kit for a limited time to encourage participation in the rebate programs.

Industrial customers have also been engaged in discussions on efficiency through the development of the Industrial Customer Efficiency Program which will launch in 2010.

3.2.4 Community Outreach

Community based promotions and marketing are critical to creating awareness of the program and providing rebate program detailed information. The launch events for the Energy Savers Rebates focused on bringing the information to retail locations where customers would be purchasing the windows, thermostats and insulation. The events were outdoor hot dog giveaways to encourage a relaxed environment for customers to speak with takeCHARGE representatives about the programs. These events were also the first to be conducted in partnership with retailers, helping to forge a network of retailer relationships to bring the programs to customers.

Work continued with retailers for the remainder of the year, providing them education on the rebate programs and assisting to inform their floor staff on the benefits of the specific technologies. Retailers are a critical piece in the decision making process for customers doing home improvements and Hydro spent time visiting key retailers and providing all retailers in the Hydro service areas with promotional materials for display.

In addition to a mass marketing approach to create strong awareness of the takeCHARGE program, November 14 to 20 was designated Energy Efficiency Week. Television spots were aired nightly, demonstrating ways to save energy at home. Hydro also targeted awareness with families through activities at skating rinks in target communities. A contest was also held through the website, with a chance to win Energy Star windows. These efforts demonstrated a clear spike in website activity, with an increase in website visits of 83% over the previous week. The average time spent on the website also increased 27%, possibly a result of customers investigating the rebates and tips mentioned in the week's promotional campaigns. These are both positive indicators of the success of these types of outreach methods.

3.2.5 Energy Efficiency Programs

Rebates

Hydro relaunched the Wrap Up for Savings insulation upgrade rebate program in 2006 and ended this program in June 2009 when it was replaced with the takeCHARGE portfolio of Energy Savers Rebates.

As described earlier, rebate programs addressing both residential and commercial customers were launched in June 2009. The following table provides an overview of all rebate activities for 2009.

2009	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
Wrap Up for Savings	1	2	2	2	2							
Residential												
Insulation							1	3	2	2	8	2
Window							2	1	5		7	3
Thermostat									2	3	5	3
Commercial												
Lighting										2	12	7
Total	**1**	**2**	**2**	**2**	**2**	**0**	**3**	**4**	**9**	**7**	**32**	**15**

Internal Energy Efficiency

Hydro has been taking active steps to encourage behaviour change and improve technology and control systems in its own facilities. Activities across the regions include installation of programmable thermostats at the Bay d'Espoir training centre, removal of some heating load at the Holyrood Thermal Generating Station, and a variety of activities encouraging employees to turn off lights and turn back heaters, among others. The largest effort for 2009 was a retrofit of the Hydro Place building including the heating and air conditioning, lighting and control systems. Energy efficiency opportunities were identified in an energy audit completed in 2008 and work was completed throughout 2009. The project is expected to result in a reduction of approximately 1 GWh/yr or 25% of the annual energy use of the building.

Further steps were taken to strengthen the tracking and monitoring of energy use at facilities across the province and this data is provided to employees as part of the internal communications efforts to engage employees in energy conservation in the workplace.

Partner and Special Projects

The provincial Department of Natural Resources provided funding to Hydro to conduct a pilot project to explore conservation and efficiency opportunities in two coastal Labrador communities. Port Hope Simpson and Hopedale were selected from a community application process. The Conservation Corps Newfoundland and Labrador were contracted to deliver home and commercial energy walkthroughs and conduct public awareness events. The walkthrough agents were hired and trained locally. Participation numbers were high for the program, with 61% and 81% of homeowners participating in Hopedale and Port Hope Simpson, respectively. Additional outreach was conducted in schools to bring information to all members of the family.

Rural delivery of programs is often challenging, coordinating supply and demand in an economical and customer focused manner. Hydro worked with the Department of Natural Resources and Amerispec on a focused promotion for EcoEnergy home audit bookings on the south coast of Labrador. This effort resulted in more than 20 leads for bookings provided to the Hydro call centre. This was a pilot project to explore methods of promotions within a targeted geography in a short term campaign. Discussions are ongoing for similar initiatives in 2010.

Hydro also undertook an LED holiday light promotion through the Canadian Blood Services' *Light up a Life* campaign, distributing approximately 6,000 sets of LED lights and takeCHARGE information to people who made a blood donation during the holiday season at blood collection sites across the province.

3.2.6 Costs

Hydro's 2009 CDM costs are outlined in the table below. Costs related directly to the delivery of the takeCHARGE Rebate programs are included in the CDM Program Portfolio costs. Costs associated with general awareness, planning functions and partnership programs and initiatives that would be incurred regardless of the specific rebate programs currently being offered are included in the Support Costs.

Hydro's CDM Costs by Category ($000s)

	2009
CDM Program Portfolio	
Residential Insulation	40
Residential Windows	44
Residential Thermostat	13
Commercial Lighting	13
Industrial	57
Support Costs	
Education	262
Support	53
Planning	176
Total	**658**

3.2.7 Energy Savings

Delays in the launch of the takeCHARGE rebate programs until mid-year resulted in less than anticipated participation. Participation did increase into the home heating season and is expected to continue to increase. In addition to the takeCHARGE rebates, Hydro was involved in a number of other initiatives and projects to create awareness of efficiency opportunities and to promote a wide range of technologies and behaviours to help consumers save. These initiatives also created considerable savings during 2009. All savings are shown in the table below.

Hydro Energy Savings (MWh) 2009	
takeCHARGE Program Portfolio	
Residential Insulation	31
Residential Windows	12
Residential Thermostat	6
Commercial Lighting	3
Industrial	0
Other Initiatives	
Hydro existing [1]	1,309
Wrap Up for Savings 2009[2]	38
Coastal Labrador Community Energy Efficiency Pilot Project[3]	987
Outreach and Promotions	339
LED Distribution with Canadian Blood Services	334
Total	**3,059**

[1] Reflects savings currently being seen on the system from activities that have taken place prior to 2009. For example, previous rebates issued through the Wrap Up for Savings program would create savings for approximately a 25 year period, whereas a CFL distribution would create savings for approximately 5 years.
[2] Wrap Up for Savings was active until June 2009 when it was replaced with the takeCHARGE Energy Savers Residential Insulation program.
[3] Savings are modeled savings from the technologies included in the energy efficiency kits distributed to participating homeowners.

3.2.8 Outlook

2010 will see growth in the residential and commercial rebate program participation and the launch of the Industrial Customer Efficiency Program. Efforts will continue to strengthen and expand the network of retailers and community groups to further reach customers at a community level.

Hydro will also continue to work with the Department of Natural Resources to promote additional Provincial and Federal Government energy efficiency programs.

4 OPERATIONAL EXCELLENCE

Goal - Through operational excellence provide exceptional value to all consumers of energy.

Hydro strives to deliver operational excellence by maintaining safe, reliable delivery of power and energy to customers in a cost-effective manner while maintaining high customer satisfaction. The 2009 key focus areas were:

- Energy Supply;
- Asset Management; and
- Financial Performance.

Update August 2010

Measurement	Year-to-date 2009 Actual	Annual 2009 Target	Annual 2008 Actual
Energy Supply			
Winter Availability*	97.7%	>93%	87.6%
Asset Management			
Asset Management System (AMS) framework and organization	Approved [1]	Approved by CEO and in place	Final Holyrood and Stephenville Gas Turbines manuals
Financial Targets			
Operating Budget	-2.8%	+2% of budget	1%
Net Income	$17.2 million	$8.8 million	$8.9 million

* Winter Availability is only reported each year for the months of January, February, March and December.

[1] The Asset Management framework has been defined and communicated to key individuals and areas of the organization. The organization design has been developed, with a high level of engagement by impacted areas and individuals. Job assignments will be completed in 2010.

4.1 Energy Supply

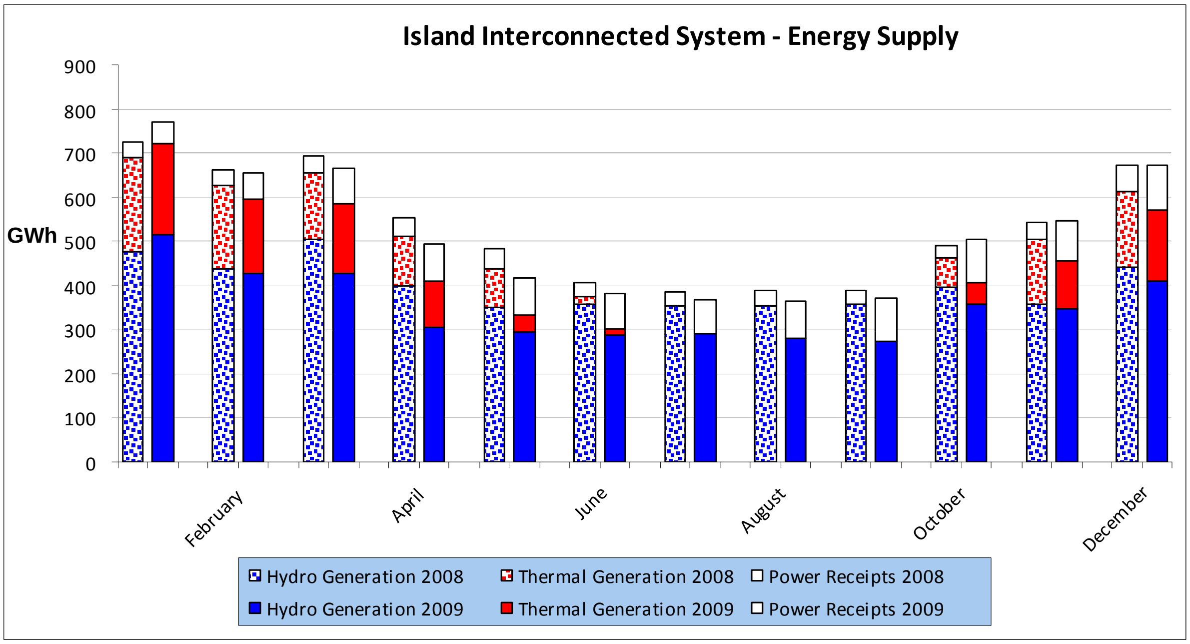
4.1.1 Energy Supply - Island Interconnected System

Energy requirements from the Holyrood Thermal Generating Station were low during the fourth quarter, mainly attributable to lower system requirements and high storage in the hydroelectric storage system. Individual units were brought into service as required to meet customers' demand and for transmission support for the Avalon Peninsula. Unit 2 was put into operation on October 27, and Unit 3 was started on December 6 following conversion from synchronous condenser to generate mode.

Annual hydroelectric production was 12.0 percent below levels in 2008 due to lower system load and higher energy receipts from the Exploits River generation. Total energy receipts were 977.7 GWh, up considerably (117%) from 2008 due to the Exploits River generation and the new wind farm at

Fermeuse. This was offset somewhat by reduced generation at the Corner Brook Pulp and Paper Co-Gen. Thermal production was less than 2008 due to reduced overall plant requirements for system security.

The energy supply for the Island Interconnected System is shown in the following charts and tables.



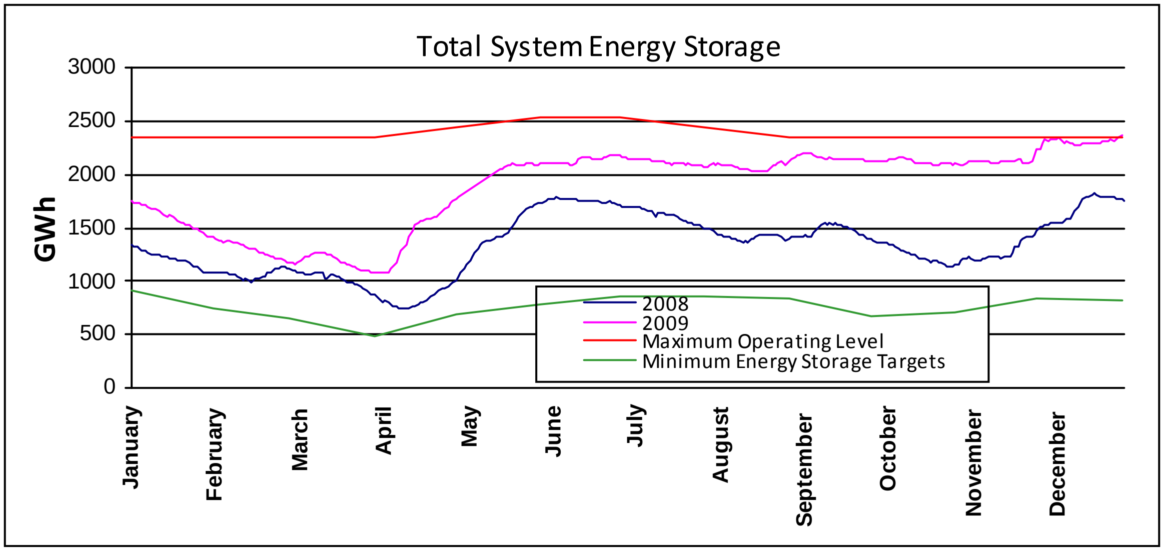
Island Interconnected System Production
For the Year ended December 31, 2009

	Year-to-date			Annual Forecast (GWh)	2009 ($000)
	2009 (GWh)	2008 (GWh)	Forecast (GWh)		
Production (net)					
Hydro	4,199.5	4,771.0	4,214.2	4,214.2	
Thermal	939.9	1,080.2	961.6	961.6	
Gas Turbines	(7.6)	(7.5)	(6.7)	(6.7)	
Diesels	(0.3)	(0.6)	(0.2)	(0.2)	
Total Production	**5,131.5**	**5,843.1**	**5,168.9**	**5,168.9**	
Energy Receipts					
Non Utility Generators					
Rattle Brook	15.6	13.7	14.4	14.4	1,226
Corner Brook Pulp and Paper					
Co-generation	55.7	74.1	65.5	65.5	5,524
St. Lawrence Wind	100.6	7.8	99.6	99.6	7,080
Fermeuse Wind	53.7	0.0	47.8	47.8	4,020
Star Lake Hydro		147.7			
Exploits River Project		177.2			
Total Non Utility Generators	225.6	420.5	227.3	227.3	17,850
Secondary					
Deer Lake Power	9.5	0.1	8.2	8.2	207
Abitibi Consolidated	7.4	29.6			237
Other					
Hydro Request to NP	0.5	0.5			119
Nalcor Energy[1]	735.2		708.8	708.8	25,024
Total Secondary and Other	752.6	30.2	717.0	717.0	25,587
Total Receipts	**978.2**	**450.7**	**944.3**	**944.3**	**43,437**
Island Interconnected Total Produced and Received	**6,109.7**	**6,293.3**	**6,113.2**	**6,113.2**	**43,437**

[1] Hydro has received energy from Exploits River assets operated by Nalcor Energy.

4.1.2 System Hydrology

The reservoir storage rose to near maximum levels by the end of the year primarily due to inflows that were 126.7% of average during the month of December. Year-to-date inflows were 105.7% of average. The effect of higher inflows and higher energy receipts from the Exploits River Generation resulted in a year end storage position that was 97% of the maximum operating level (MOL) and 287% of the minimum storage target.



System Hydrology Storage Levels			
	2009 (GWh)	**2009 Minimum Target**	**2008 (GWh)**
Quarter End Storage Levels	2,368	824	1,754

4.1.3 Energy Supply – Labrador Interconnected System

The purchased and produced energy on the Labrador Interconnected System at the end of the year is down significantly from 2008 (23.9%) primarily due to lower industrial loads and a reduction in sales to Canadian Forces Base (CFB) Goose Bay.

Labrador Interconnected System Production
For the Year ended December 31, 2009

	Year-to-date			Annual Forecast (GWh)
	2009 (GWh)	2008 (GWh)	Forecast (GWh)	
Production (net)				
Gas Turbines	(1.1)	(1.7)	(0.8)	(0.8)
Diesels	(0.8)	(0.7)	(0.1)	(0.1)
Total Production	**(1.9)**	**(2.4)**	**(0.9)**	**(0.9)**
Purchases				
CF(L)Co for Labrador (at border)	**737.2**	**968.8**	**771.7**	**771.7**
Labrador Interconnected Total Produced and Purchased	**735.3**	**966.4**	**770.8**	**770.8**

4.1.4 Fuel Prices

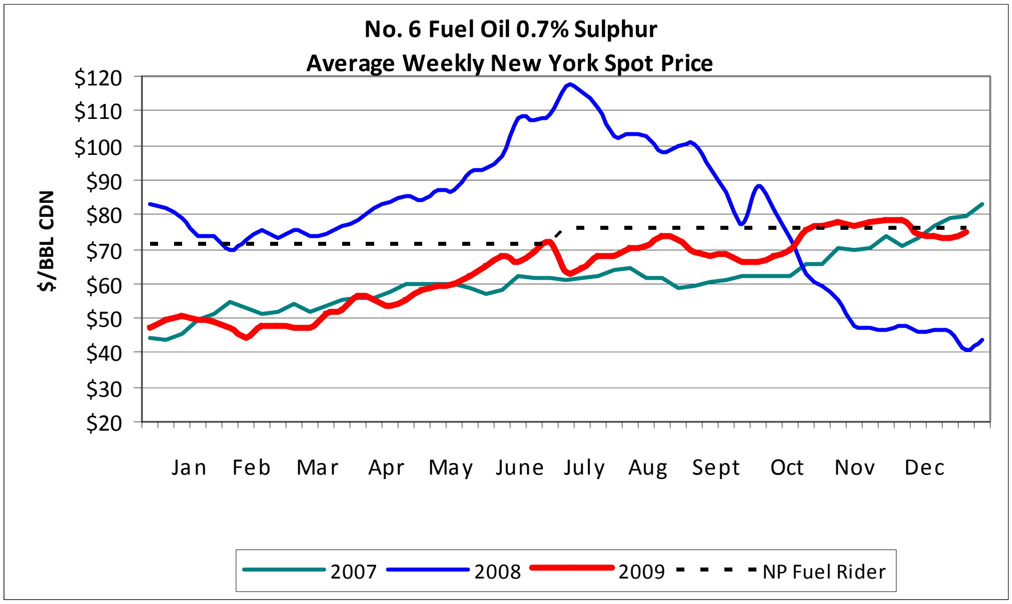
The fuel market prices for No. 6 fuel increased from approximately $66/bbl at the start of the quarter to just above $76/bbl at the end of the quarter. The quarter ending inventory cost was $69.90/bbl, slightly lower than the current Newfoundland Power fuel price rider of $75.95/bbl. There is no Industrial Customer fuel price rider for 2009.

There were two shipments during the fourth quarter of 2009.

November 11	228,329.45 bbls	$78.50/bbl
December 14	232,780.64 bbls	$74.92/bbl

The inventory on December 31 was 297,309 barrels.

The following chart shows the No. 6 fuel prices year-to-date compared to 2007 and 2008, and the Newfoundland Power fuel rider price of $75.95/bbl.



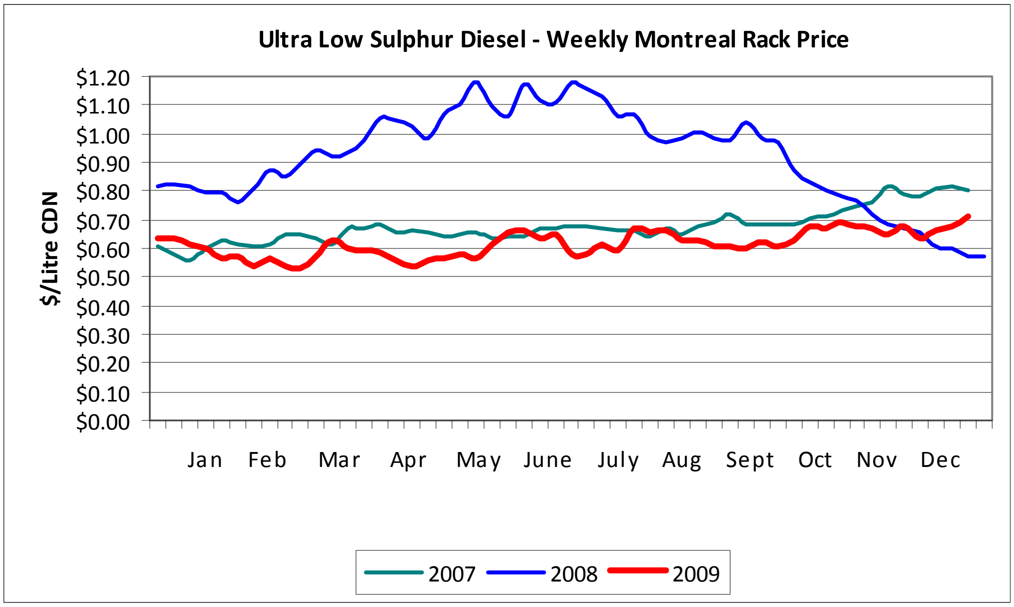
The following table provides the monthly forecast price of No. 6 fuel (0.7% sulphur) up to December 2010, landed on the Avalon Peninsula.

No. 6 Fuel Oil Sulphur
Forecast Price January 2010 –December 2010

Month	Price ($Cdn/bbl) 0.7%	Month	Price ($Cdn/bbl) 0.7%
January 2010	77.30	July 2010	75.90
February 2010	80.20	August 2010	77.60
March 2010	79.80	September 2010	81.40
April 2010	78.10	October 2010	85.00
May 2010	78.40	November 2010	83.40
June 2010	75.80	December 2010	84.10

Note: The forecast is based on the PIRA Energy Group price forecast available January 12, 2010 and an exchange rate forecast by Canadian financial institutions and the Conference Board of Canada.

The following chart shows Low Sulphur Diesel No. 1 fuel prices year-to-date compared to 2007 and 2008.



4.1.5 Energy Supply - Isolated Systems

Net isolated electricity supply - production and purchases - increased by 5.3% in 2009 compared to 2008. The increase is largely attributed to continuing growth on the Labrador Isolated Systems.

Production and purchases for the L'Anse au Loup system grew by 10.1% in 2009. During 2008 and early 2009 approximately 60 homeowners on the L'Anse au Loup system upgraded their electrical panels from 100 amp to 200 amp services. Increased electricity consumption indicates many of these customers have installed some form of electric heat.

Although purchases from Hydro-Québec grew by 16.2% in 2009, expense was reduced by 26.6% reflecting the lower cost of fuel which makes up the basis of Hydro-Québec's pricing.

Isolated Systems Production
For the Year ended December 31, 2009

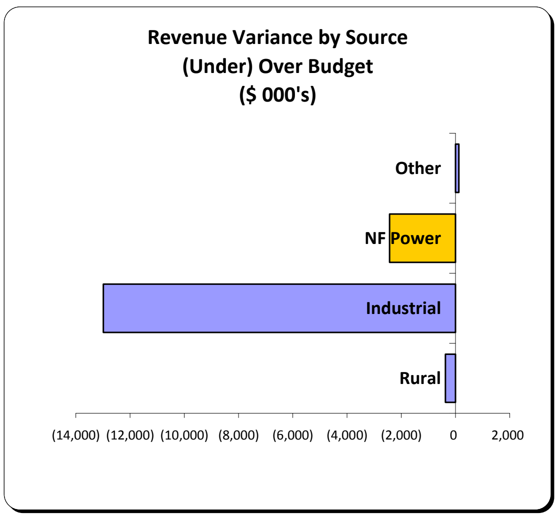
	Year-to-date						Annual Forecast (GWh)	$(000)[1]
	2009 (GWh)	$(000)[1]	2008 (GWh)	$(000)[1]	Forecast (GWh)	$(000)[1]		
Production (net)								
Diesels	47.1		46.5		47.2		47.2	
Purchases								
Non Utility Generators (NUGS)[2]	0.5	94.3	0.4	101.1	0.4	88.2	0.4	88.2
Hydro-Québec	19.4	1,680.2	16.7	2,289.6	18.6	1657.0	18.6	1,657.0
Total Purchases	**19.9**	**1,774.5**	**17.1**	**2,390.7**	**19.0**	**1745.2**	**19.0**	**1,745.2**
Isolated Systems Total Produced and Purchased	**67.0**	**1,774.5**	**63.6**	**2,390.7**	**66.2**	**1745.2**	**66.2**	**1,745.2**

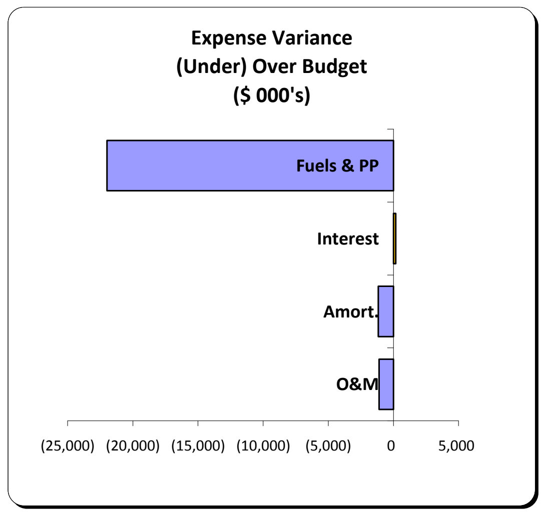
[1] Purchases before taxes.
[2] Frontier Power Systems Inc., Ramea is the only NUG currently included. Mary's Harbour Mini Hydro has not produced any energy since September 2007 and is no longer included in Hydro's forecast of power purchases.

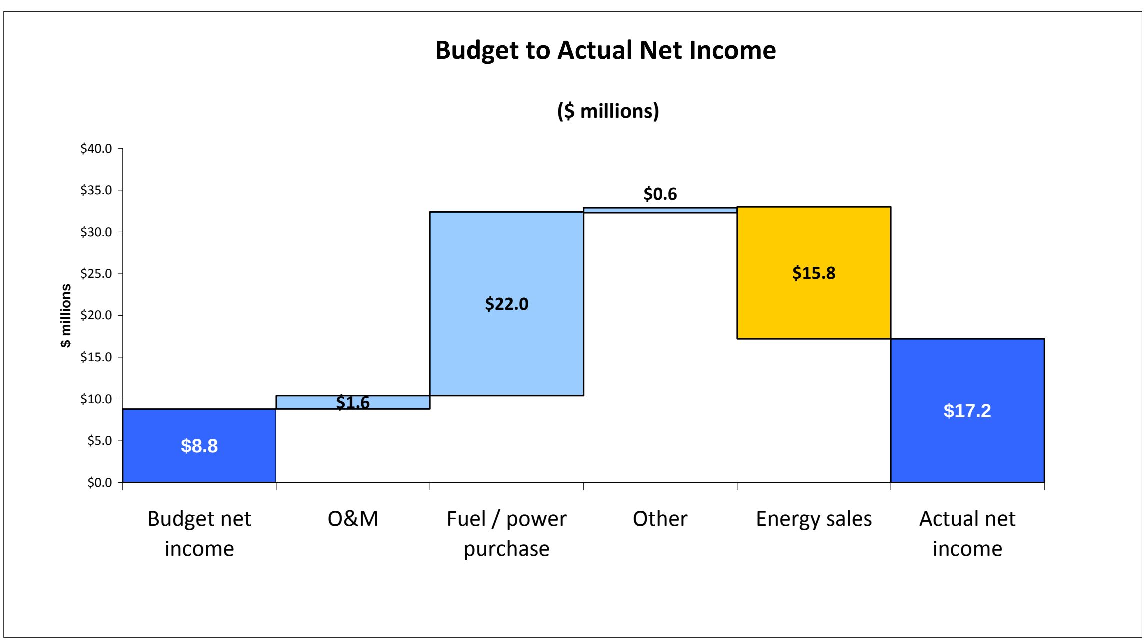
4.2 Financial

Below are charts of Hydro's (regulated) Statement of Income year-to-date. Please see Appendix C for the remainder of the financial statements.

Regulated Operations
For the twelve months ended December 31,2009







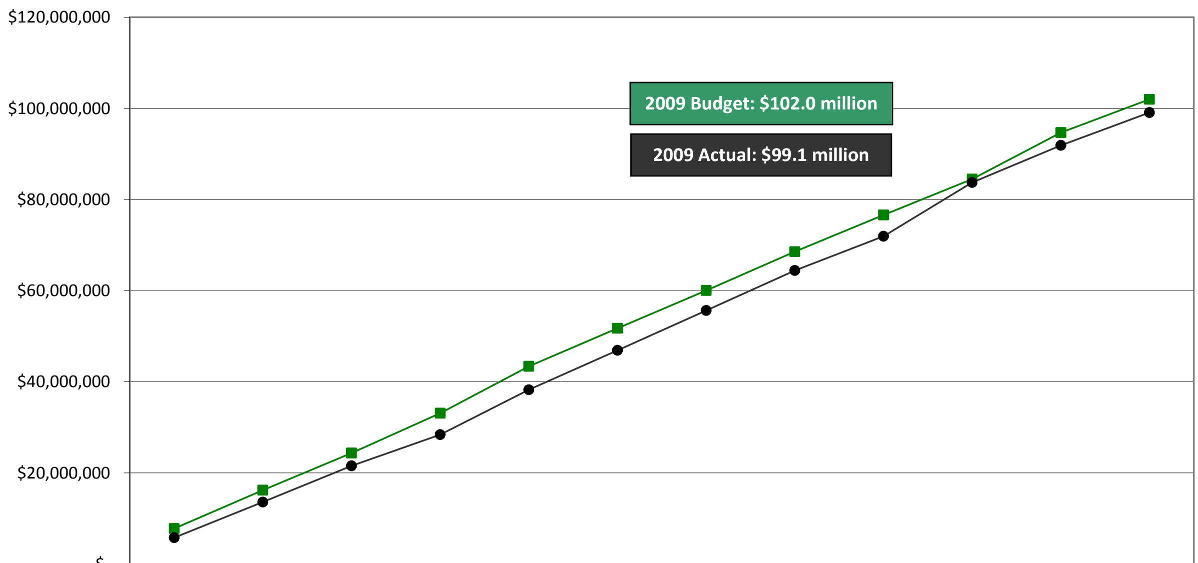
Statement of Income - Regulated Operations
For the twelve months ended December 31, 2009
($ 000's)

Fourth Quarter 2009 Actual	Fourth Quarter 2009 Budget	Fourth Quarter 2008 Actual		Year-to-date 2009 Actual	Year-to-date 2009 Budget	Year-to-date 2008 Actual
			Revenue			
122,675	121,073	113,330	Energy sales	425,528	441,314	425,196
550	523	641	Other revenue	2,218	2,091	2,197
123,225	121,596	113,971		427,746	443,405	427,393
			Expenses			
28,453	25,360	28,175	Operations	100,369	101,970	96,694
918	192	1,432	Loss on disposal of capital assets	1,267	766	2,580
48,937	48,977	47,499	Fuels	136,933	151,454	149,854
13,138	14,839	11,404	Power purchases	46,782	54,242	41,388
10,948	10,727	10,534	Amortization	41,744	42,909	40,393
21,120	20,783	21,518	Interest	83,440	83,268	87,610
123,514	120,878	120,562		410,535	434,609	418,519
(289)	718	(6,591)	**Net income (loss)**	17,211	8,796	8,874

The chart below illustrates the controllable cost results for the year-to-date, which are consistent with the 2009 target of ±2% of budget.

Hydro Regulated Operating Costs

2009 Actual Compared to Budget



	January	February	March	April	May	June	July	August	September	October	November	December
Cumulative Budget	$7,786,999	$16,192,815	$24,332,600	$33,091,655	$43,387,818	$51,725,660	$60,029,154	$68,540,639	$76,609,610	$84,455,567	$94,689,745	$101,969,234
Cumulative Actual	$5,764,126	$13,588,724	$21,536,123	$28,382,960	$38,233,457	$46,889,868	$55,636,121	$64,407,658	$71,916,136	$83,714,398	$91,874,819	$99,065,916

Cumulative Budget **Cumulative Actual**

4.2.1 International Financial Reporting Standards (IFRS)

On November 27, 2009, Hydro and Newfoundland Power made presentations to the Board regarding the status of the implementation of IFRS within their respective organizations. The following is an update regarding activities and events relating to the IFRS project since that presentation.

The IFRS project team continued to work on finalizing the outstanding position papers, completing analysis of the potential impact of changes, and drafting mock financial statements and disclosures, as well as planning the next phases of the IFRS project.

The company continues to review all proposed and continuing projects of the International Accounting Standards Board (IASB) with potential to impact the company's financial reporting. With respect to the Rate Regulated Activities exposure draft, the IASB staff has determined that they will not be taking feedback on the proposed IFRS to the IASB in January as originally scheduled. Instead, the staff will likely present an analysis in February. The delay is due to the large number of responses received (approximately 150) as well as the great diversity in opinions and comments on virtually every critical aspect of the proposed IFRS. The staff's expected February Board presentation may include discussion on the options for the next steps for the project. Potential next steps include:

- Move forward, but with significant changes to the Exposure Draft;
- Move forward by amending the current IFRS, rather than issuing a separate standard;
- Move forward, but only with a disclosure standard; and
- Not issue additional guidance.

Significant matters that the Board expects to discuss in determining the next steps for the project include how the asset/liability framework definitions are met and the scope of the standard.

4.3 Maintenance Plan and Associated Reliability Standards Update

Hydro is developing a maintenance plan, which is a formal consolidation, validation and documentation of Hydro’s established maintenance plans, including recommendations for required changes. It is an ongoing and continuous process which started in 2007.

2009 Year-to-Date
<u>Gas Turbines</u>
The manuals for the Hardwoods, Stephenville and Holyrood gas turbines have been delivered to the managers.

The analysis work for the Happy Valley gas turbine is complete and the manual was targeted to be delivered to Regulated Operations during the third quarter of 2009. This target has been delayed due to other work priorities. The revised schedule is to deliver the manual to Operations by the end of the second quarter of 2010.

<u>Holyrood Plant</u>
The analysis work on the synchronous condenser systems at Holyrood is complete and the manual was originally targeted to be delivered to Regulated Operations in the third quarter of 2009. However, since

the review work on the generation and common systems at Holyrood progressed faster than anticipated, it was decided to combine all three reviews into one manual for the Holyrood plant.

The review and analysis of the critical generation systems and common systems at Holyrood was completed by the end of the fourth quarter of 2009.

Work is underway to review all tactics and compile the manuals. The combined manual for the synchronous condenser, generation and common systems for the Holyrood plant is targeted to be delivered to Operations in the second quarter of 2010.

2010
Maintenance review work planned for 2010 will cover: hydraulic structures; hydraulic units; diesel plants; and energy management systems.

Work teams have been assigned to these efforts and schedules for the different milestones in the review processes will be established during the first quarter of 2010.

4.4 Capital Expenditures

Capital Expenditures for the year ended December 31, 2009 will be reported in a separate document.

5 OTHER ITEMS

5.1 Significant Issues

5.1.1 Ramea Wind-Hydrogen-Diesel Project Update

Overall Project Site showing (L-R): diesel plant/storage tanks, meteorological tower, hydrogen electrolyser, three hydrogen storage tanks, distribution box structure, three wind turbines, and Quonset hut housing the hydrogen genset.

In accordance with Order No. P.U. 31 (2007), the following update is provided on the Wind-Hydrogen-Diesel Project for Ramea.

Implementation and Operation
All major equipment is on site, and detailed design is complete. The electrical services contract is 95% complete. The wind turbine equipment has been commissioned and is in service in manual mode. The meteorological tower has been installed. The hydrogen electrolyser has been commissioned and is awaiting interconnection to the hydrogen storage tanks in early 2010. The hydrogen genset and storage tanks have been delivered to and installed at site. Commissioning completion is planned for the second quarter of 2010 and operations are planned to commence in the second quarter of 2010.

Capital Costs

($000)

Actual Cost to Dec. 2009	Actual Cost Recoveries to Dec. 2009	Net Cost to Dec. 2009	Budget to Dec. 2009
8,377	8,377	0	8,794

* Project Change Order #2 was completed to reflect a new completion date of May 2010 due to delays in starting commissioning activities.

Operating Costs
There is nothing to report for this period as operation is planned to start the second quarter of 2010.

Reliability and Safety Issues
All activities have been executed with no safety issues in this period.

5.2 Community

5.2.1 Employees Run for the Cure

On Sunday, October 4, the CIBC Run for the Cure was held at Quidi Vidi Lake. Employees, friends and family joined together to create a 16 member team who raised $1,288.52, and Nalcor matched up to $1,000 for a total donation of $2,288.52.

5.2.2 Hydro Supports the Boys and Girls Club of St. John's

In November, Jim Haynes, Hydro's Vice President of Regulated Operations, presented the Boys and Girls Club of St. John's with a $5,000 donation from Hydro's Community Investment Program. The donation will support the Boys and Girls Club Wellness Program, which is designed to educate and actively engage children in the areas of healthy eating, physical activity, and healthy lifestyle for today and the future. This program will ensure all club members and their families have the opportunity to enjoy a healthy lifestyle by engaging our youth in various physical activities, educational sessions and a positive environment in which to grow into healthy adults.

5.2.3 Donation to Stella Burry Foundation

Employees of Nalcor Energy and Hydro (a Nalcor Energy company) in St. John's recently raised $1,650 for the Stella Burry Foundation. The money was raised through Capital Hydro Social Club employee fundraising activities and was then matched by the corporate Community Investment Program.

5.2.4 Light up a Life

The Canadian Blood Services (CBS) and takeCHARGE teamed up to encourage residents across the province to give blood this holiday season. The takeCHARGE team donated 4,000 sets of LED energy efficient holiday lights to the Light Up A Life campaign for CBS that was given out at donor clinics until the end of November. The LED holiday lights were available for free to blood donors while supplies lasted.

5.2.5 Celebrating a Family Christmas

The Hydro/Silverlights Club float "A Bearentsein Bear Family Christmas" made its way through the streets of downtown St. John's past 60,000 spectators. The float placed second in the best float over 20 feet category. The float was also included in the Mount Pearl, Torbay, and Conception Bay South Christmas parades.

5.2.6 Libra House Receives Land Donation

Libra House is currently embarking on a major expansion and renovation of its existing emergency crisis shelter in Happy Valley-Goose Bay. To assist Libra House in this undertaking, Hydro recently donated two parcels of land to the shelter. Libra House plans to sell the land and use the proceeds to fund its upcoming building renovations and expansion. The donated land, located on Corte Real Road, is no longer required by Hydro. The two parcels of land are approximately 100 x 200 square feet each.

L-R: Jim Haynes, Vice President, Regulated Operations, Hydro; Janet O'Donnell, Executive Director; and Shaun MacLean, Board of Directors of Libra House.

5.2.7 Nalcor Energy and Hydro Employees Supporting Charities during the Holidays

Chris O'Brien, President of Capital Hydro Social Club makes a donation to VOCM Cares Foundation Happy Tree.

L-R: Gerry Hynes, CBS Food Bank; Don Butler, CBS Kinsmen; Herb Butler, Holyrood Thermal Generating Station and Grandson Cameron Petten; Dave Stone, CBS Kinsmen; and Wayne Fitzpatrick, CBS Kinsmen.

Hydro and Nalcor Energy employees deliver Christmas hampers to the St. John's Women's Centre.

This year Nalcor and Hydro employees teamed up to support the St. John's Women's Centre, Community Food Sharing Association, Labrador Friendship Centre and the VOCM Cares Foundation's Happy Tree.

Sixteen families in St. John's were supported through the Women's Centre Christmas program. Employees delivered 42 boxes of food to the food bank in Happy Valley-Goose Bay and food and presents were also donated to the Labrador Friendship Centre. In addition, a casual day in support of the Happy Tree VOCM Cares Foundation raised $1,500 plus dozens of Christmas presents for children.

5.2.8 Over $6,300 Raised for CBS Food Bank

During the Conception Bay South Christmas parade on Saturday, December 12, volunteers from the Holyrood Thermal Generating Station and CBS Kinsmen collected $3,500 worth of food and $1,845 in aid of the CBS Food Bank. Hydro's Community Investment Program made an additional donation of $1,000 to the local food bank.

5.2.9 Ramea

This fall was busy in the small community of Ramea. Construction is more than 90 percent complete on the over $8.5 million Ramea Wind-Hydrogen-Diesel Project and the team is now gearing up for commissioning activities. This project is a research and development project that will use wind and hydrogen technology to supplement the diesel requirements of the isolated community. On December 12, hydrogen was produced for the very first time by the new hydrogenics electrolyser and on December 14 one of the new wind turbines produced power for the first time.

5.3 Statement of Energy Sold

Statement of Energy Sold (GWh)

For the Year ended December 31

	YEAR TO DATE 2009 ACTUAL	YEAR TO DATE 2008 ACTUAL	YEAR TO DATE 2009* FORECAST	2009* ANNUAL FORECAST
Island Interconnected				
Newfoundland Power	5,111	4,960	5,078	5,078
Island Industrials	394	737	431	431
Rural				
Domestic	232	224	236	236
General Service	140	156	142	142
Streetlighting	3	3	3	3
Sub-total Rural	375	383	381	381
Sub-Total Island Interconnected	5,880	6,080	5,890	5,890
Island Isolated				
Domestic	6	6	7	7
General Service	2	2	2	2
Streetlighting	0	0	0	0
Sub-Total Island Isolated	8	8	9	9
Labrador Interconnected				
Labrador Industrials	162	337	165	165
CFB Goose Bay	19	61	21	21
Hydro Quebec (includes Menihek)	373	1,434	374	374
Recall	1,187	0	1,118	1,118
Rural				
Domestic	273	264	288	288
General Service	211	204	221	221
Streetlighting	2	2	2	2
Sub-total Rural	486	470	511	511
Sub-Total Lab. Interconnected	2,227	2,302	2,189	2,189
Labrador Isolated				
Domestic	22	19	23	23
General Service	15	14	14	14
Streetlighting	0	0	0	0
Sub-Total Labrador Isolated	37	33	37	37
L'Anse au Loup				
Domestic	12	11	12	12
General Service	7	7	7	7
Streetlighting	0	0	0	0
Sub-Total L'Anse au Loup	19	18	19	19
Total Energy Sold (Before Rural Accrual)	8,171	8,441	8,144	8,144
Rural Accrual	(5)	8	-	-
Total Energy Sold	8,166	8,449	8,144	8,144
Sales to Non-Regulated Customers **	1,722	1,771	1,657	1,657

* Rural GWh - Based on 2009 Forecast, Fall 2008 Rural Load Forecast, Actuals to August 31, 2009
Non-rural GWh - Based on 2009 Revenue Budget Island Load Forecast July 29, 2009, Labrador Load Forecast September 15, 2009

** Included in Total Energy Sold

5.4 Customer Statistics

Customer Statistics
For the Year ended December 31

	FOURTH QUARTER		ANNUAL	
	2009 ACTUAL	2008 ACTUAL	2009 FORECAST	2008 ACTUAL
Customers				
Rural	36,307	35,965	35,895	35,965
Industrial	5	6	5	6
CFB Goose Bay	1	1	1	1
Utility	1	1	1	1
Emera	1	0	1	0
NB Power	1			
Hydro Quebec	1	1	1	1
Reading Days	29.6	29.6	N/A	29.7

APPENDICES

CIAC QUARTERLY ACTIVITY REPORT
For the Quarter ended December 31, 2009

TYPE OF SERVICE	CIAC'S QUOTED	CIAC'S OUTSTANDING PREVIOUS QTR.	TOTAL CIAC'S QUOTED	CIAC'S ACCEPTED	CIAC'S EXPIRED	TOTAL CIAC'S OUTSTANDING
Domestic						
Within Plan. Boundary	3	2	5	1	1	3
Outside Plan. Boundary	8	10	18	6	2	10
Sub-total	11	12	23	7	3	13
General Service	1	9	10	4	4	2
Total	12	21	33	11	7	15

The table above summarizes Contribution in Aid of Construction (CIAC) activity for this quarter. The table is divided into three sections, as follows:

- The first section outlines the type of service for which a CIAC has been calculated, either Domestic or General Service.
- The second section indicates the number of CIACs quoted during the quarter as well as the number of CIAC quotes that remained outstanding at the end of the previous quarter. This format facilitates a reconciliation of the total number of CIACs that were active during the quarter.
- The third section provides information as to the disposition of the total CIACs quoted. A CIAC is considered accepted when a customer indicates they wish to proceed with construction of the extension and has agreed to pay any charge that may be applicable. A CIAC is considered outdated after six months has elapsed and the customers have not indicated their intention to proceed with the extension. A quoted CIAC is outstanding if it is neither accepted nor outdated.

CIAC QUARTERLY ACTIVITY REPORT
For the Quarter ended December 31, 2009

CIAC NO.	CIAC AMOUNT ($)	ESTIMATED CONST. COST ($)	ACCEPTED
DOMESTIC - WITHIN RESIDENTIAL PLANNING BOUNDARIES			
740413	$ 2,346.10	$ 2,971.10	
740739	$ 1,225.00	$ 3,350.00	Yes
748700	$ 350.00	$ 2,475.00	
DOMESTIC - OUTSIDE RESIDENTIAL PLANNING BOUNDARIES			
728932	$ 550.00	$ 1,175.00	Yes
738520	$ 23,760.00	$ 28,510.00	
742581	$ 2,900.00	$ 3,525.00	Yes
742629	$ 2,132.00	$ 2,757.00	Yes
740711	$ 2,521.24	$ 3,146.24	Yes
728936	$ 2,463.31	$ 3,088.31	
745882	$ 2,420.89	$ 3,045.89	
751447	$ 2,475.20	$ 3,100.20	
GENERAL SERVICE			
715478	$ 241,284.20	$ 410,743.20	

CUSTOMER PROPERTY DAMAGE CLAIMS REPORT
For the Quarter ended December 31, 2009

Introduction

The Customer Property Damage Claims Report contains an overview of all damage claims activity summarized on a quarterly basis. The information contained in the report is broken down by cause as well as by the operating region where the claims originated.

The report is divided into four sections as follows:

1. The first section indicates the number of claims received during the quarter coupled with claims outstanding from the previous quarter.

2. The second section shows the number of claims for which the Company has accepted responsibility and the amount paid to claimants versus the amount originally claimed.

3. The third section shows the number of claims rejected and the dollar value associated with those claims.

4. The fourth section indicates those claims that remain outstanding at the end of the current quarter and the dollar value associated with such claims.

Definitions of Causes of Damage Claims

1. System Operations: Claims arising from system operations. Examples include normal reclosing or switching.

2. Power Interruptions: Claims arising from interruption of power supply. Examples include all scheduled or unscheduled interruptions.

3. Improper Workmanship: Claims arising from failure of electrical equipment caused by improper workmanship or methods. Examples include improper crimping of connections, insufficient sealing and taping of connections, improper maintenance, inadequate clearance or improper operation of equipment.

4. Weather Related: Claims arising from weather conditions. Examples include wind, rain, ice, lighting or corrosion caused by weather.

5. Equipment Failure: Claims arising from failure of electrical equipment not caused by improper workmanship. Examples include broken neutrals, broken tie wires, transformer failure, insulator failure or broken service wire.

6. Third Party: Claims arising from equipment failure caused by acts of third parties. Examples include motor vehicle accidents and vandalism.

7. Miscellaneous: All claims not related to electrical service.

8. Waiting Investigation: Cause to be determined.

CUSTOMER PROPERTY DAMAGE CLAIMS REPORT - BY CAUSE

For the Quarter ended December 31, 2009

CAUSE	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	AMT. CLAIMED	AMT. PAID	#	AMOUNT	#	AMOUNT
System Operations	2	0	2	0	$ -	$ -	2	$ 23.00	0	$ -
Power Interruptions	3	0	3	0	$ -	$ -	1	$ 950.00	2	$ 700.00
Improper Workmanship	5	1	6	2	$ 4,180.61	$ 4,230.61	0	$ -	3	$ 4,569.83
Weather Related	0	1	1	0	$ -	$ -	0	$ -	1	$ 660.00
Equipment Failure	5	2	7	2	$ 1,115.23	$ 1,115.23	1	$ 38,840.27	5	$ 30,231.79
Third Party	1	0	1	0	$ -	$ -	0	$ -	1	$ -
Miscellaneous	3	0	3	1	$ 180.39	$ 180.39	1	$ 471.19	1	$ -
Waiting Investigation	3	0	3	0	$ -	$ -	0	$ -	3	$ -
Total	22	4	26	5	$ 5,476.23	$ 5,526.23	5	$ 40,284.46	16	$ 36,161.62

For the Quarter ended December 31, 2008

CAUSE	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	AMT. CLAIMED	AMT. PAID	#	AMOUNT	#	AMOUNT
System Operations	2	2	4	0	$ 750.00	$ -	1	$ -	3	$ 795.00
Power Interruptions	0	3	3	2	$ 6,500.00	$ 5,915.00	0	$ -	1	$ -
Improper Workmanship	2	2	4	1	$ 350.00	$ 350.00	0	$ -	3	$ -
Weather Related	2	2	4	0	$ 850.00	$ -	2	$ -	2	$ 850.00
Equipment Failure	12	24	36	17	$ 6,292.03	$ 9,051.16	10	$ 2,517.98	9	$ 2,739.22
Third Party	1	0	1	0	$ 113.00	$ -	0	$ -	1	$ 113.00
Miscellaneous	3	0	3	1	$ 2,140.00	$ 350.00	1	$ 1,950.00	1	$ -
Waiting Investigation	5	1	6						6	$ 38,860.00
Total	27	34	61	21	$ 16,995.03	$ 15,666.16	14	$ 4,467.98	26	$ 43,357.22

CUSTOMER PROPERTY DAMAGE CLAIMS REPORT - BY REGION

For the Quarter ended December 31, 2009

REGION	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	AMT. CLAIMED	AMT. PAID	#	AMOUNT	#	AMOUNT
Central Region	5	0	5	1	$ 180.39	$ 180.39	0	$ -	4	$ 5,049.82
Northern Region	7	2	9	4	$ 5,295.84	$ 5,345.84	1	$ -	4	$ 18,629.92
Labrador Region	10	2	12	0	$ -	$ -	4	$ 40,284.46	8	$ 12,481.88
Total	22	4	26	5	$ 5,476.23	$ 5,526.23	5	$ 40,284.46	16	$ 36,161.62

For the Quarter ended December 31, 2008

REGION	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	AMT. CLAIMED	AMT. PAID	#	AMOUNT	#	AMOUNT
Central Region	6	4	10	2	$ 6,500.00	$ 5,915.00	2	$ 1,790.00	6	$ 1,183.00
Northern Region	15	17	32	18	$ 10,145.03	$ 9,401.16	3	$ 798.00	11	$ 445.22
Labrador Region	6	13	19	1	$ 350.00	$ 350.00	9	$ 1,879.98	9	$ 41,729.00
Total	27	34	61	21	$ 16,995.03	$ 15,666.16	14	$ 4,467.98	26	$ 43,357.22

FINANCIAL – REGULATED

Balance Sheet - Regulated Operations
As at December 31
($ 000's)

	Dec-09	Dec-08
ASSETS		
Current assets		
Cash and cash equivalents	10,942	-
Short-term investments	20,000	-
Receivables	65,703	69,495
Current portion of regulatory assets	4,789	5,000
Fuel and supplies	49,964	42,993
Prepaid expenses	1,492	1,156
	152,890	118,644
Property, plant, and equipment	1,364,205	1,354,348
Sinking funds	179,613	163,881
Regulatory assets	69,324	74,626
Total assets	1,766,032	1,711,499
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Bank indebtedness	-	4,557
Accounts payable and accrued liabilities	51,115	46,212
Accrued interest	28,667	28,667
Current portion of long-term debt	8,150	8,322
Current portion of regulatory liabilities	89,814	22,324
Deferred capital contribution	165	470
Due to related parties	21,441	450
Promissory notes	(3,531)	145,004
	195,821	256,006
Long-term debt	1,141,618	1,146,414
Regulatory liabilities	32,788	31,546
Employee future benefits	44,060	41,881
Contributed capital	100,000	-
Shareholder's equity / retained earnings	236,943	219,732
Accumulated other comprehensive income	14,802	15,920
Total liabilities and shareholder's equity	1,766,032	1,711,499

Note: *Certain of the 2008 comparative figures were restated to conform with the 2009 presentation.*

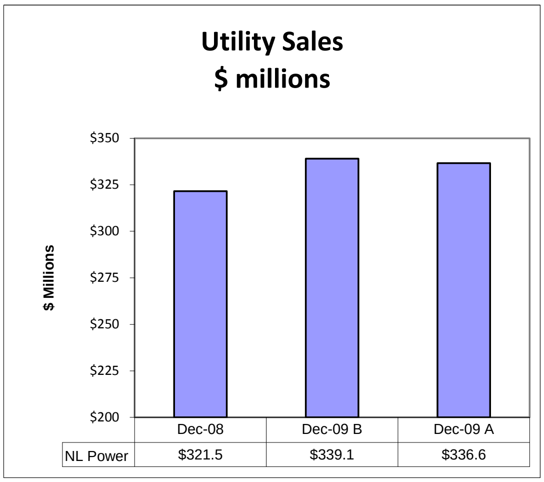
Statement of Retained Earnings - Regulated Operations
For the twelve months ended December 31, 2009
($ 000's)

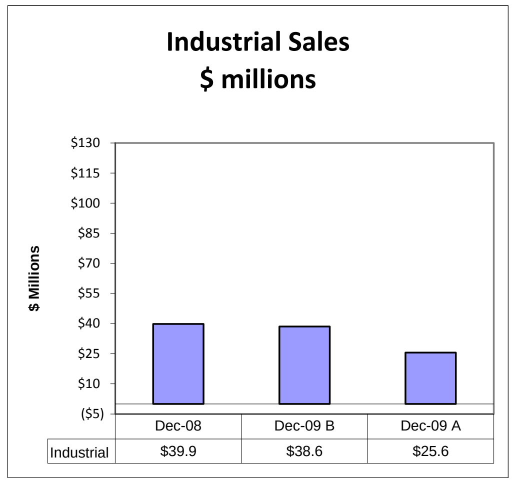
Fourth Quarter 2009 Actual	Fourth Quarter 2008 Actual		Year-to-date 2009 Actual	Year-to-date 2008 Actual
237,232	226,323	Balance, beginning of period	219,732	210,858
(289)	(6,591)	Net income (loss)	17,211	8,874
236,943	219,732	Balance, end of period	236,943	219,732

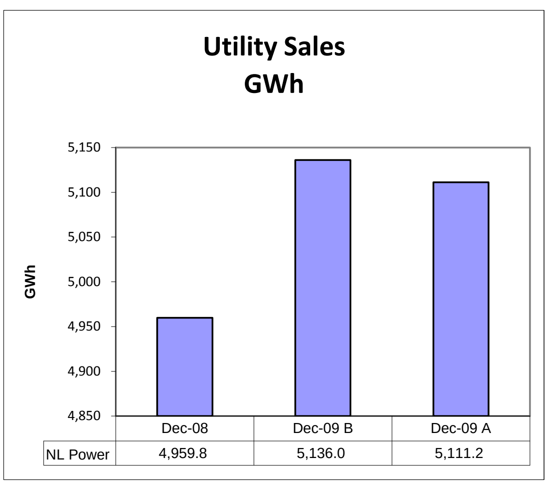
Statement of Comprehensive Income - Regulated Operations
For the twelve months ended December 31, 2009
($ 000's)

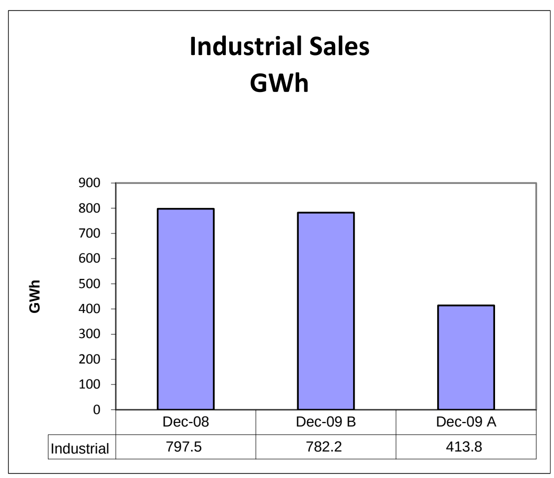
Fourth Quarter 2009 Actual	Fourth Quarter 2009 Budget	Fourth Quarter 2008 Actual		Year-to-date 2009 Actual	Year-to-date 2009 Budget	Year-to-date 2008 Actual
(289)	718	(6,591)	Net income (loss)	17,211	8,796	8,874
			Other comprehensive income (loss)			
(4,646)	-	393	Change in fair value of sinking fund investments	(1,118)	-	(3,615)
(4,935)	718	(6,198)	Total comprehensive income (loss)	16,093	8,796	5,259

Regulated Operations
For the twelve months ended December 31,2009









Revenue Summary - Regulated Operations
For the twelve months ended December 31, 2009
($ 000's)

Fourth Quarter 2009 Actual	Fourth Quarter 2009 Budget	Fourth Quarter 2008 Actual		Year-to-date 2009 Actual	Year-to-date 2009 Budget	Year-to-date 2008 Actual
			REVENUE			
			Industrial			
1,202	3,109	3,817	Corner Brook Pulp and Paper Ltd.	6,940	12,366	13,762
2,705	1,523	1,421	Abitibi Grand Falls	3,351	5,804	5,151
2,802	3,004	2,969	North Atlantic Refinery	10,669	11,686	12,044
1,180	1,744	850	C.F.B. Goose Bay	1,350	5,583	5,719
854	786	842	Teck Cominco Limited	3,282	3,139	3,198
8,743	10,166	9,899	**Total Industrial**	25,592	38,578	39,874
			Utility			
98,183	94,000	87,782	Newfoundland Power Inc.	336,626	339,055	321,519
			Rural			
15,749	16,907	15,649	Interconnected and diesel	63,310	63,681	63,803
550	523	641	**Other**	2,218	2,091	2,197
123,225	121,596	113,971	**Total**	427,746	443,405	427,393
			ENERGY SALES (GWh)			
			Industrial			
10.7	64.0	83.6	Corner Brook Pulp and Paper Ltd.	97.3	256.4	282.9
0.0	40.1	35.0	Abitibi Grand Falls	12.8	154.3	136.7
58.6	63.7	63.1	North Atlantic Refinery	219.6	245.8	256.0
17.0	20.3	9.9	C.F.B. Goose Bay	19.5	65.0	60.7
17.1	15.2	16.5	Teck Cominco Limited	64.6	60.7	61.2
103.4	203.3	208.1	**Total Industrial**	413.8	782.2	797.5
			Utility			
1,435.2	1,388.9	1,324.0	Newfoundland Power Inc.	5,111.2	5,136.0	4,959.8
			Rural			
228.0	257.8	217.0	Interconnected and diesel	925.4	934.3	909.1
1,766.6	1,850.0	1,749.1	**Total**	6,450.4	6,852.5	6,666.4

Statement of Cash Flows - Regulated Operations
For the twelve months ended December 31, 2009
($ 000's)

	Year-to-date 2009	Year-to-date 2008
Cash provided by (used in)		
Operating activities		
Net income	17,211	8,874
Adjusted for items not involving cash flow		
Amortization	41,744	40,393
Accretion of long-term debt	394	479
Loss on disposal of property, plant and equipment	1,267	2,580
	60,616	52,326
Changes in non-cash balances		
Receivables	3,792	(381)
Fuel and supplies	(6,971)	17,932
Prepaid expenses	(336)	(315)
Regulatory assets	5,513	18,836
Regulatory liabilities	68,732	14,883
Accounts payable and accrued liabilities	4,903	(19,083)
Accrued interest	-	(1,899)
Due to related parties	20,991	268
Employee future benefits	2,179	2,560
	159,419	85,127
Financing activities		
Decrease in long-term debt	(172)	(188,692)
Decrease in deferred capital contribution	(305)	470
Increase in contributed capital	100,000	-
(Decrease) increase in promissory notes	(148,535)	172,911
Transfer of employee future benefits to Non-Regulated Activities	-	(484)
	(49,012)	(15,795)
Investing activities		
Additions to property, plant and equipment	(54,097)	(45,785)
Increase in short term investments	(20,000)	-
Proceeds on disposal of property, plant and equipment	1,229	693
Increase in sinking funds	(22,040)	(20,781)
	(94,908)	(65,873)
Net increase in cash	15,499	3,459
Cash position, beginning of period	(4,557)	(8,016)
Cash position, end of period	10,942	(4,557)

Note: *Certain of the 2008 comparative figures were restated to conform with the 2009 presentation.*

FINANCIAL - NON-REGULATED

Balance Sheet - Non-Regulated Activities
As at December 31
($ 000's)

	Dec-09	Dec-08
ASSETS		
Accounts receivable	4,001	-
Long-term receivable	23,935	25,416
Forward contracts	7,045	-
Investment in CF(L)Co.	367,693	359,813
Total assets	402,674	385,229
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	1,834	-
Due to related party	-	3,067
Deferred capital contribution	-	1,726
Promissory notes	3,531	17,996
	5,365	22,789
Long term note payable	23,934	-
Share capital	22,504	22,504
Lower Churchill Development Corp	15,400	15,400
Retained earnings	329,226	324,536
Accumulated other comprehensive income	6,245	-
Total liabilities and shareholder's equity	402,674	385,229

Note: *Certain of the 2008 comparative figures were restated to conform with the 2009 presentation.*

Statement of Income - Non-Regulated Activities
For the twelve months ended December 31, 2009
($ 000's)

Fourth Quarter 2009 Actual	Fourth Quarter 2009 Budget	Fourth Quarter 2008 Actual		Year-to-date 2009 Actual	Year-to-date 2009 Budget	Year-to-date 2008 Actual
			Revenue			
14,461	-	13,706	Energy sales	60,687	-	58,164
252	-	-	Other revenue	743	-	-
14,713	-	13,706		61,430	-	58,164
			Expenses			
5,525	225	860	Operations	19,758	991	3,715
-	-	28	Fuels	21	-	44
1,086	-	842	Power purchases	4,226	-	3,562
-	-	34	Amortization	-	-	48
-	-	(2,667)	Interest	-	-	(8,948)
-	-	2,675	Write down of investment	-	-	2,675
6,611	225	1,772		24,005	991	1,096
8,102	(225)	11,934	Net operating income (loss)	37,425	(991)	57,068
7,774	-	(2,659)	Equity in CF(L)Co	7,880	-	11,763
744	-	932	Preferred dividends	3,858	-	9,016
(155)	-	92	Interest share purchase debt	-	-	35
8,413	-	(1,635)	Total other revenue	11,738	-	20,814
16,465	(225)	10,299	**Net income (loss)**	49,163	(991)	77,882

Statement of Retained Earnings - Non-Regulated Activties
For the twelve months ended December 31, 2009
($ 000's)

Fourth Quarter 2009 Actual	Fourth Quarter 2008 Actual		Year-to-date 2009 Actual	Year-to-date 2008 Actual
320,985	471,808	Balance, beginning of period	324,536	407,225
16,465	10,299	Net income	49,163	77,882
-	(160,571)	Retained earnings transfer	-	(160,571)
(8,224)	3,000	Dividends	(44,473)	-
329,226	324,536	Balance, end of period	329,226	324,536

Statement of Comprehensive Income - Non-Regulated Activities
For the twelve months ended December 31, 2009
($ 000's)

Fourth Quarter 2009 Actual	Fourth Quarter 2009 Budget	Fourth Quarter 2008 Actual		Year-to-date 2009 Actual	Year-to-date 2009 Budget	Year-to-date 2008 Actual
16,465	(546)	10,299	Net income (loss)	49,163	(991)	77,882
			Other comprehensive income			
179	-	-	Change in fair value of derivative instruments	6,245	-	-
16,644	(546)	10,299	Total comprehensive income (loss)	55,408	(991)	77,882

Statement of Cash Flows - Non-Regulated Activities
For the twelve months ended December 31, 2009
($ 000's)

	Year-to-date 2009	Year-to-date 2008
Cash provided by (used in)		
Operating activities		
Net income	49,163	77,882
Adjusted for items not involving cash flow		
Amortization	-	48
Unrealized gain on derivatives	(800)	-
Unrealized foreign exchange loss	13	-
Equity in CF(L)Co	(7,880)	(11,763)
Write-down of investment	-	2,675
	40,496	68,842
Dividends from CF(L)Co	-	2,422
Decrease in due to related party	(3,067)	-
Increase in accounts payable and accrued liabilities	1,834	-
Increase in long-term note payable	23,934	-
Increase in accounts receivable	(4,014)	-
Decrease (increase) in long-term receivable	1,481	(2,069)
Transfer of employee future benefits from Regulated Operations	-	484
	60,664	69,679
Financing activities		
Decrease in long-term debt	-	(11,474)
Decrease in promissory notes	(14,465)	(16,911)
(Decrease) increase in deferred capital contribution	(1,726)	1,726
Dividends	(44,473)	-
Advance to Nalcor	-	(3,000)
	(60,664)	(29,659)
Investing activities		
Additions to property, plant and equipment	-	(40,020)
	-	(40,020)
Net change in cash	-	-
Cash position, beginning of period	-	-
Cash position, end of period	-	-

Note: *Certain of the 2008 comparative figures were restated to conform with the 2009 presentation.*

FINANCIAL – SUPPLEMENTARY

Supplementary Schedule - Regulated Operations
For the twelve months ended December 31, 2009
($ 000's)

Fourth Quarter				Year-to-date		
2009 Actual	2009 Budget	2008 Actual		2009 Actual	2009 Budget	2008 Actual
			Other revenue			
155	128	263	Sundry	593	510	634
379	366	366	Pole attachments	1,515	1,464	1,464
16	29	12	Supplier's discount	110	117	99
550	523	641	**Total other revenue**	2,218	2,091	2,197
			Interest			
25,016	24,335	26,792	Gross interest	98,065	96,145	107,269
100	85	95	Accretion of long-term debt	393	370	479
545	539	539	Amortization of foreign exchange losses	2,163	2,157	2,157
(348)	(512)	(2,799)	Allowance for funds used during construction	(811)	(1,282)	(9,628)
(4,193)	(3,664)	(3,109)	Interest earned	(16,370)	(14,122)	(12,667)
21,120	20,783	21,518	**Total interest**	83,440	83,268	87,610

Cost Recoveries - Regulated Operations
For the twelve months ended December 31, 2009
($ 000's)

Fourth Quarter 2009 Actual	Fourth Quarter 2009 Budget	Fourth Quarter 2008 Actual		Year-to-date 2009 Actual	Year-to-date 2009 Budget	Year-to-date 2008 Actual
(2)	-	4	Executive Leadership	6	-	4
88	73	39	Human Resources and Organizational Effectiveness	276	306	256
634	551	575	Finance / CFO	2,450	2,202	2,230
27	20	(23)	Engineeering Services	54	78	36
12	5	-	Regulated Operations	43	21	-
759	649	595		2,829	2,607	2,526

2008 Actual balances were adjusted to reflect regulated activities only.

Rate Stabilization Plan Report

Rate Stabilization Plan Report
December 31, 2009

Summary of Key Facts

The Rate Stabilization Plan of Newfoundland and Labrador Hydro (Hydro), as amended by Board Order No. P.U. 40 (2003) and Order No. P.U. 8 (2007), is established for Hydro's utility customer, Newfoundland Power, and Island Industrial customers to smooth rate impacts for variations between actual results and Test Year Cost of Service estimates for:

- Hydraulic production;
- No. 6 fuel cost used at Hydro's Holyrood generating station;
- Customer load (Utility and Island Industrial); and
- Rural rates.

The Test Year Cost of Service Study was approved by Board Order No. P.U. 8 (2007) and is based on projections of events and costs that are forecast to happen during a test year. Finance charges are calculated on the balances using the test year Weighted Average Cost of Capital which is currently 7.529% per annum. Holyrood's operating efficiency is set, for RSP purposes, at 630 kWh/barrel regardless of the actual conversion rate experienced.

	2007 Test Year Cost of Service			
	Net Hydraulic Production (kWh)	No. 6 Fuel Cost ($Can/bbl.)	Utility Load (kWh)	Industrial Load (kWh)
January	427,100,000	54.17	574,800,000	78,300,000
February	388,680,000	54.73	518,600,000	70,900,000
March	415,080,000	55.46	524,700,000	76,600,000
April	355,520,000	55.46	429,200,000	75,600,000
May	324,240,000	55.46	358,700,000	69,500,000
June	328,500,000	54.49	298,400,000	73,800,000
July	386,790,000	54.49	293,400,000	77,500,000
August	379,140,000	54.49	287,000,000	77,900,000
September	363,560,000	54.49	297,700,000	73,000,000
October	340,510,000	54.56	360,200,000	74,400,000
November	364,390,000	54.56	439,300,000	74,100,000
December	398,560,000	58.98	543,800,000	72,700,000
Total	4,472,070,000		4,925,800,000	894,300,000

Rate Stabilization Plan
Plan Highlights
December 31, 2009

	Actual	Cost of Service	Variance	Year-to-Date Due (To) From customers	Reference
Hydraulic production year-to-date	4,606.2 GWh	4,472.1 GWh	-134.2 GWh	$ (12,005,544)	Page 4
No 6 fuel cost - Current month	$ 67.33	$ 58.98	$ 8.35	$ (4,523,041)	Page 5
Year-to-date customer load - Utility	5,111.2 GWh	4,925.8 GWh	185.4 GWh	$ (152,989)	Page 8
Year-to-date customer load - Industrial	384.8 GWh	894.3 GWh	-(509.5) GWh	$ (25,874,401)	Page 9
				$ (42,555,975)	

Rural rates		
Rural Rate Alteration (RRA) [1]	$ (1,152,150)	
Less : RRA to utility customer	$ (1,026,565)	Page 10
RRA to Labrador interconnected	(125,585)	
Fuel variance to Labrador interconnected	$ (34,638)	Page 6
Net Labrador interconnected	$ (160,223)	

Current plan summary [2]		
One year recovery		
Due (to) from utility customer [2]	$ (52,940,017)	Page 10
Due (to) from Industrial customers [2]	$ (36,874,648)	Page 11
Sub total	(89,814,665)	
Four year recovery		
Hydraulic balance	$ (32,181,286)	Page 4
Total plan balance	$ (121,995,951)	

[1] Beginning January 2009, the RRA includes a monthly credit of $5,766. This amount relates to the phase in of the application of the credit from secondary energy sales to CFB Goose Bay to the Rural deficit as stated in Section B, Clause 1.3(b) of the approved Rate Stabilization Plan Regulations which received final approval in Order No. P.U. 34 (2008) issued December 22, 2008.

[2] Disposition of the load variation is one of the issues to be considered by the Public Utilities Board in a pending hearing. This may impact the balances owing to customers in the current plan.

Rate Stabilization Plan
Net Hydraulic Production Variation
December 31, 2009

	A	B	C	D	E	F	G
	Cost of Service Net Hydraulic Production (kWh)	Actual Net Hydraulic Production (3) (kWh)	Monthly Net Hydraulic Production Variance (kWh)	Cost of Service No. 6 Fuel Cost ($Can/bbl.)	Net Hydraulic Production Variation ($)	Financing Charges ($)	Cumulative Variation and Financing Charges ($)
			(A - B)		**(C / O[1] X D)**		**(E + F)** **(to page 12)**
Opening balance							(30,902,837)
January	427,100,000	511,622,865	(84,522,865)	54.17	(7,267,625)	(187,503)	(38,357,965)
February	388,680,000	444,266,356	(55,586,356)	54.73	(4,828,954)	(232,737)	(43,419,656)
March	415,080,000	466,091,401	(51,011,401)	55.46	(4,490,623)	(263,449)	(48,173,728)
April	355,520,000	337,983,715	17,536,285	55.46	1,543,750	(292,294)	(46,922,272)
May	324,240,000	332,602,567	(8,362,567)	55.46	(736,171)	(284,701)	(47,943,144)
June	328,500,000	324,109,389	4,390,611	54.49	379,753	(290,895)	(47,854,286)
July	386,790,000	330,916,410	55,873,590	54.49	4,832,622	(290,356)	(43,312,020)
August	379,140,000	320,246,634	58,893,366	54.49	5,093,809	(262,796)	(38,481,007)
September	363,560,000	312,369,147	51,190,853	54.49	4,427,603	(233,484)	(34,286,888)
October	340,510,000	393,718,444	(53,208,444)	54.56	(4,608,020)	(208,036)	(39,102,944)
November	364,390,000	384,679,928	(20,289,928)	54.56	(1,757,172)	(237,257)	(41,097,373)
December	398,560,000	447,636,721	(49,076,721)	58.98	(4,594,516)	(249,358)	(45,941,247)
	4,472,070,000	4,606,243,577	(134,173,577)		(12,005,544)	(3,032,866)	(45,941,247)
Hydraulic Allocation [2]					10,727,095	3,032,866	13,759,961
Hydraulic variation at year end					(1,278,449)	-	(32,181,286)

(1) O is the Holyrood Operating Efficiency of 630 kWh/barrel.

(2) At year end 25% of the hydraulic variation balance and 100% of the annual financing charges are allocated to customers.

	(from page 6) 12 month kWh	% of kWh to total	Allocation	Reallocate Rural	**(to pages 11 & 12)** Net
Utility	5,111,194,217	86.5%	11,897,543	861,378	12,758,921
Industrial	384,777,985	6.5%	895,664		895,664
Rural	415,318,157	7.0%	966,754	(966,754)	-
Total	5,911,290,359	100.0%	13,759,961	(105,376)	13,654,585
Labrador Inteconnected (write-off to income)				105,376	105,376
				-	13,759,961

(3) Restated February to August to include the impact of hydraulic production for storing surplus generation energy in Hydro's reservoirs.

Rate Stabilization Plan
No. 6 Fuel Variation
December 31, 2009

	A	B	C	D	E	F	G
	Actual Quantity No. 6 Fuel	Actual Quantity No. 6 Fuel for Non-Firm Sales	Net Quantity No. 6 Fuel	Cost of Service No. 6 Fuel Cost	Actual Average No. 6 Fuel Cost	Cost Variance	No.6 Fuel Variation
	(bbl.)	(bbl.)	(bbl.)	($Can/bbl.)	($Can/bbl.)	($Can/bbl.)	($)
			(A - B)			**(E - D)**	**(C X F)** **(to page 6)**
January	310,422	690	309,732	54.17	52.20	(1.97)	(610,172)
February	256,185	2,424	253,761	54.73	47.68	(7.05)	(1,789,015)
March	238,388	1,139	237,249	55.46	47.70	(7.76)	(1,841,052)
April	163,842	0	163,842	55.46	46.57	(8.89)	(1,456,555)
May	59,632	0	59,632	55.46	46.46	(9.00)	(536,691)
June	23,342	0	23,342	54.49	46.29	(8.20)	(191,404)
July	0	0	0	54.49	46.29	(8.20)	0
August	0	2	(2)	54.49	46.29	(8.20)	16
September	799	8	791	54.49	46.29	(8.20)	(6,489)
October	75,309	0	75,309	54.56	46.24	(8.32)	(626,570)
November	165,711	0	165,711	54.56	57.71	3.15	521,990
December	241,076	10	241,066	58.98	67.33	8.35	2,012,901
	1,534,707	4,273	1,530,434	55.47	52.51	(2.96)	(4,523,041)

Rate Stabilization Plan
Allocation of Fuel Variance - Year-to-Date
December 31, 2009

	A	B	C	D	E	F	G	H	I	J
	Twelve Months-to-Date				Year-to-Date Fuel Variance				Reallocate Rural Island Customers [(1)]	
	Utility	Industrial Customers	Rural Island Customers	Total	Utility	Industrial Customers	Rural Island Interconnected	Total	Utility	Labrador Interconnected
	(kWh)	(kWh)	(kWh)	(kWh)	($)	($)	($)	($)	($)	($)
				(A+B+C)	**(A/D X H)**	**(B/D X H)**	**(C/D X H)**		**(G X 89.10%)**	**(G X 10.90%)**
					(to page 7)			**(from page 5)**	**(to page 7)**	
January	5,005,151,512	689,749,882	414,470,780	6,109,372,174	(499,888)	(68,889)	(41,395)	(610,172)	(36,883)	(4,512)
February	5,010,856,454	680,296,222	412,537,210	6,103,689,886	(1,969,625)	(267,405)	(162,157)	(2,399,187)	(144,482)	(17,675)
March	5,003,195,483	666,365,030	412,541,893	6,082,102,406	(3,488,061)	(464,567)	(287,611)	(4,240,239)	(256,261)	(31,350)
April	4,989,239,677	625,317,933	413,558,514	6,028,116,124	(4,715,017)	(590,949)	(390,828)	(5,696,794)	(348,228)	(42,600)
May	4,968,395,779	587,975,854	413,195,928	5,969,567,561	(5,188,051)	(613,971)	(431,463)	(6,233,485)	(384,434)	(47,029)
June	4,973,908,918	562,003,055	409,782,881	5,945,694,854	(5,374,782)	(607,298)	(442,809)	(6,424,889)	(394,543)	(48,266)
July	4,987,839,609	535,491,993	408,086,623	5,931,418,225	(5,402,808)	(580,043)	(442,038)	(6,424,889)	(393,856)	(48,182)
August	4,989,721,971	512,632,364	407,951,793	5,910,306,128	(5,424,140)	(557,263)	(443,470)	(6,424,873)	(395,132)	(48,338)
September	4,999,960,523	488,905,941	408,071,177	5,896,937,641	(5,453,094)	(533,214)	(445,054)	(6,431,362)	(396,543)	(48,511)
October	5,041,831,300	457,254,549	412,332,579	5,911,418,428	(6,019,689)	(545,939)	(492,304)	(7,057,932)	(438,643)	(53,661)
November	5,077,674,472	415,239,050	415,532,992	5,908,446,514	(5,616,939)	(459,339)	(459,664)	(6,535,942)	(409,561)	(50,103)
December	5,111,194,217	384,777,985	415,318,157	5,911,290,359	(3,910,845)	(294,414)	(317,782)	(4,523,041)	(283,144)	(34,638)

(1) The Fuel Variance initially allocated to Rural Island Interconnected is re-allocated between Utility and Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the approved Cost of Service Study, which is 89.10% and 10.90% respectively. The Labrador Interconnected amount is then removed from the plan and written off to net income (loss).

Rate Stabilization Plan
Allocation of Fuel Variance - Monthly
December 31, 2009

	A	B	C	D	E	F	G
	Utility					**Industrial**	
	Fuel Variance		Rural Allocation		Total Fuel Variance	Fuel Variance	
	Year-to-Date Activity	Current Month Activity (1)	Year-to-Date Activity	Current Month Activity (1)	Activity for the month	Year-to-Date Activity	Current Month Activity (1)
	($)	($)	($)	($)	($)	($)	($)
					(B + D)		
	(from page 6)		**(from page 6)**		**(to page 10)**	**(from page 6)**	**(to page 11)**
January	(499,888)	(499,888)	(36,883)	(36,883)	(536,771)	(68,889)	(68,889)
February	(1,969,625)	(1,469,737)	(144,482)	(107,599)	(1,577,336)	(267,405)	(198,516)
March	(3,488,061)	(1,518,436)	(256,261)	(111,779)	(1,630,215)	(464,567)	(197,162)
April	(4,715,017)	(1,226,956)	(348,228)	(91,967)	(1,318,923)	(590,949)	(126,382)
May	(5,188,051)	(473,034)	(384,434)	(36,206)	(509,240)	(613,971)	(23,022)
June	(5,374,782)	(186,731)	(394,543)	(10,109)	(196,840)	(607,298)	6,673
July	(5,402,808)	(28,026)	(393,856)	687	(27,339)	(580,043)	27,255
August	(5,424,140)	(21,332)	(395,132)	(1,276)	(22,608)	(557,263)	22,780
September	(5,453,094)	(28,954)	(396,543)	(1,411)	(30,365)	(533,214)	24,049
October	(6,019,689)	(566,595)	(438,643)	(42,100)	(608,695)	(545,939)	(12,725)
November	(5,616,939)	402,750	(409,561)	29,082	431,832	(459,339)	86,600
December	(3,910,845)	1,706,094	(283,144)	126,417	1,832,511	(294,414)	164,925
		(3,910,845)		(283,144)	(4,193,989)		(294,414)

(1) The current month activity is calculated by subtracting year-to-date activity for the prior month from year-to-date activity for the current month.

Rate Stabilization Plan
Load Variation - Utility
December 31, 2009

	A	B	C	D	E	F	G	H	I	J	K
	Firm Energy						Secondary Energy				
	Cost of Service Sales	Actual Sales	Sales Variance	Cost of Service No. 6 Fuel Cost	Firm Energy Rate	Load Variation	Cost of Service Sales	Actual Sales	Firming Up Charge	Load Variation	Total Load Variation
	(kWh)	(kWh)	(kWh)	($Can/bbl.)	($/kWh)	($)	(kWh)	(kWh)	($/kWh)	($)	($)
			(B - A)			**C x {(D/O[1]) - E}**				**(G - H) x I**	**(F + J)**
											(to page 10)
January	574,800,000	636,159,821	61,359,821	54.17	0.08805	(126,762)	0	0	0.00841	0	(126,762)
February	518,600,000	540,373,649	21,773,649	54.73	0.08805	(25,627)	0	2,401	0.00841	(20)	(25,647)
March	524,700,000	552,059,084	27,359,084	55.46	0.08805	(499)	0	2,383	0.00841	(20)	(519)
April	429,200,000	421,770,620	(7,429,380)	55.46	0.08805	136	0	22,241	0.00841	(187)	(51)
May	358,700,000	347,556,066	(11,143,934)	55.46	0.08805	203	0	2,354,683	0.00841	(19,803)	(19,600)
June	298,400,000	299,536,918	1,136,918	54.49	0.08805	(1,771)	0	4,775,793	0.00841	(40,164)	(41,935)
July	293,400,000	290,190,644	(3,209,356)	54.49	0.08805	5,000	0	775,745	0.00841	(6,524)	(1,524)
August	287,000,000	284,106,434	(2,893,566)	54.49	0.08805	4,508	0	(775,745)	0.00841	6,524	11,032
September	297,700,000	297,053,287	(646,713)	54.49	0.08805	1,008	0	0	0.00841	0	1,008
October	360,200,000	414,950,459	54,750,459	54.56	0.08805	(79,214)	0	0	0.00841	0	(79,214)
November	439,300,000	450,251,261	10,951,261	54.56	0.08805	(15,845)	0	0	0.00841	0	(15,845)
December	543,800,000	570,028,473	26,228,473	58.98	0.08805	146,068	0	0	0.00841	0	146,068
	4,925,800,000	5,104,036,716	178,236,716			(92,795)	0	7,157,501		(60,194)	(152,989)

(1) O is the Holyrood Operating Efficiency of 630 kWh/barrel.

Rate Stabilization Plan
Load Variation - Industrial
December 31, 2009

	A	B	C	D	E	F
	Cost of Service Sales	Actual Sales	Sales Variance	Cost of Service No. 6 Fuel Cost	Firm Energy Rate	Load Variation
	(kWh)	(kWh)	(kWh)	($)	($/kWh)	($)
			(B - A)			**C x {(D/O[1]) - E}**
						(to page 11)
January	78,300,000	50,646,871	(27,653,129)	54.17	0.03676	(1,361,201)
February	70,900,000	42,933,788	(27,966,212)	54.73	0.03676	(1,401,471)
March	76,600,000	41,308,959	(35,291,041)	55.46	0.03676	(1,809,433)
April	75,600,000	18,325,451	(57,274,549)	55.46	0.03676	(2,936,566)
May	69,500,000	19,887,268	(49,612,732)	55.46	0.03676	(2,543,731)
June	73,800,000	30,031,606	(43,768,394)	54.49	0.03676	(2,176,693)
July	77,500,000	31,153,413	(46,346,587)	54.49	0.03676	(2,304,911)
August	77,900,000	33,368,778	(44,531,222)	54.49	0.03676	(2,214,630)
September	73,000,000	30,796,894	(42,203,106)	54.49	0.03676	(2,098,848)
October	74,400,000	30,120,796	(44,279,204)	54.56	0.03676	(2,207,016)
November	74,100,000	26,879,620	(47,220,380)	54.56	0.03676	(2,353,614)
December	72,700,000	29,324,541	(43,375,459)	58.98	0.03676	(2,466,287)
	894,300,000	384,777,985	(509,522,015)			(25,874,401)

(1) O is the Holyrood Operating Efficiency of 630 kWh/barrel.

Rate Stabilization Plan
Summary of Utility Customer
December 31, 2009

	A	B	C	D	E	F	G
	Load Variation	Allocation Fuel Variance	Allocation Rural Rate Alteration (1)	Subtotal Monthly Variances	Financing Charges	Adjustment (2)	Cumulative Net Balance
	($)	($)	($)	($)	($)	($)	($)
				(A + B + C)			
	(from page 8)	**(from page 7)**					**(to page 12)**
Opening Balance							(10,329,890)
January	(126,762)	(536,771)	(260,611)	(924,144)	(62,677)	(4,783,922)	(16,100,633)
February	(25,647)	(1,577,336)	(319,568)	(1,922,551)	(97,691)	(4,063,628)	(22,184,503)
March	(519)	(1,630,215)	(207,444)	(1,838,178)	(134,604)	(4,151,502)	(28,308,787)
April	(51)	(1,318,923)	(192,147)	(1,511,121)	(171,764)	(3,171,882)	(33,163,554)
May	(19,600)	(509,240)	(160,450)	(689,290)	(201,220)	(2,631,329)	(36,685,393)
June	(41,935)	(196,840)	(142,567)	(381,342)	(222,589)	(2,288,432)	(39,577,756)
July	(1,524)	(27,339)	(73,949)	(102,812)	(240,138)	(128,025)	(40,048,731)
August	11,032	(22,608)	57,023	45,447	(242,996)	(124,666)	(40,370,946)
September	1,008	(30,365)	67,908	38,551	(244,951)	(130,703)	(40,708,049)
October	(79,214)	(608,695)	71,071	(616,838)	(246,996)	(182,578)	(41,754,461)
November	(15,845)	431,832	75,668	491,655	(253,345)	(198,111)	(41,714,262)
December	146,068	1,832,511	58,501	2,037,080	(253,101)	(250,813)	(40,181,096)
Year to date	(152,989)	(4,193,989)	(1,026,565)	(5,373,543)	(2,372,072)	(22,105,591)	(29,851,206)
Hydraulic allocation							(12,758,921)
(from page 4)							
Total	(152,989)	(4,193,989)	(1,026,565)	(5,373,543)	(2,372,072)	(22,105,591)	(52,940,017)

(1) The Rural Rate Alteration is allocated between Utility and Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the approved Cost of Service Study, which is 89.10% and 10.90% respectively. The Labrador Interconnected amount is then removed from the plan and written off to net income (loss).

(2) The RSP adjustment rate for Utility is 0.752 cents per kwh effective July 1, 2008 to June 30, 2009 and 0.044 cents per kwh effective July 1, 2009.

Rate Stabilization Plan
Summary of Industrial Customers
December 31, 2009

	A	B	C	D	E	F
	Load Variation	Allocation Fuel Variance	Subtotal Monthly Variances	Financing Charges	Adjustment (1)	Cumulative Net Balance
	($)	($)	($)	($)	($)	($)
			(A + B)			
	(from page 9)	**(from page 7)**				**(to page 12)**
Opening Balance						(11,994,442)
January	(1,361,201)	(68,889)	(1,430,090)	(72,776)	466,209	(13,031,099)
February	(1,401,471)	(198,516)	(1,599,987)	(79,066)	398,964	(14,311,188)
March	(1,809,433)	(197,162)	(2,006,595)	(86,833)	388,867	(16,015,749)
April	(2,936,566)	(126,382)	(3,062,948)	(97,176)	208,165	(18,967,708)
May	(2,543,731)	(23,022)	(2,566,753)	(115,087)	222,774	(21,426,774)
June	(2,176,693)	6,673	(2,170,020)	(130,007)	296,273	(23,430,528)
July	(2,304,911)	27,255	(2,277,656)	(142,165)	309,768	(25,540,581)
August	(2,214,630)	22,780	(2,191,850)	(154,967)	327,668	(27,559,730)
September	(2,098,848)	24,049	(2,074,799)	(167,219)	301,775	(29,499,973)
October	(2,207,016)	(12,725)	(2,219,741)	(178,991)	303,811	(31,594,894)
November	(2,353,614)	86,600	(2,267,014)	(191,702)	279,156	(33,774,454)
December	(2,466,287)	164,925	(2,301,362)	(204,927)	301,759	(35,978,984)
Year to date	(25,874,401)	(294,414)	(26,168,815)	(1,620,916)	3,805,189	(23,984,542)
Hydraulic allocation **(from page 4)**						(895,664)
Total	(25,874,401)	(294,414)	(26,168,815)	(1,620,916)	3,805,189	(36,874,648)

(1) The RSP adjustment rate for Industrial Customers excluding Teck Resources is 0.785 cents per kWh effective January 1, 2008. The rate for Teck Cominco is 2.000 cents per kWh.

Rate Stabilization Plan
Overall Summary
December 31, 2009

	A	B	C	D
	Hydraulic Balance	Utility Balance	Industrial Balance	Total To Date
	($)	($)	($)	($)
				(A + B + C)
	(from page 4)	**(from page 10)**	**(from page 11)**	
December 2008	(30,902,837)	(10,329,890)	(11,994,442)	(53,227,169)
January	(38,357,965)	(16,100,633)	(13,031,099)	(67,489,697)
February	(43,419,656)	(22,184,503)	(14,311,188)	(79,915,347)
March	(48,173,728)	(28,308,787)	(16,015,749)	(92,498,264)
April	(46,922,272)	(33,163,554)	(18,967,708)	(99,053,534)
May	(47,943,144)	(36,685,393)	(21,426,774)	(106,055,311)
June	(47,854,286)	(39,577,756)	(23,430,528)	(110,862,570)
July	(43,312,020)	(40,048,731)	(25,540,581)	(108,901,332)
August	(38,481,007)	(40,370,946)	(27,559,730)	(106,411,683)
September	(34,286,888)	(40,708,049)	(29,499,973)	(104,494,910)
October	(39,102,944)	(41,754,461)	(31,594,894)	(112,452,299)
November	(41,097,373)	(41,714,262)	(33,774,454)	(116,586,089)
December	(32,181,286)	(52,940,017)	(36,874,648)	(121,995,951)

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

2009 ANNUAL REPORT
ON
KEY PERFORMANCE INDICATORS

Pursuant to Order No. P.U. 14 (2004)

NEWFOUNDLAND AND LABRADOR HYDRO

newfoundland labrador hydro
a nalcor energy company

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1 Introduction

In Order No. P.U. 14 (2004), the Board required Hydro to file appropriate historic, current and forecast comparisons of reliability, operating, financial and other Key Performance Indicators (KPIs). These were ordered to be filed with Hydro's annual financial report, commencing in 2004.

In compliance with the above Order, Hydro has 16 individual KPIs within the following four general categories: Reliability; Operating; Financial; and Customer-Related.

Within each of these categories, KPI data is reported on an historic basis for Hydro. Where appropriate, KPIs are subcategorized based on whether they relate to generation, transmission, distribution or overall corporate activity. For most of the Reliability KPIs, data from the Canadian Electricity Association (CEA) is provided in this report, as has been the case in prior years. CEA data has been published only to 2007. CEA data is unavailable for underfrequency load shedding, a reliability KPI, as this measure is unique to Hydro's Island Interconnected System. In the Operating category, the KPIs used to measure performance relate to two specific facilities within Hydro's system: Bay d'Espoir and Holyrood. For these two generation plants, performance is measured and compared on a year-over-year basis.

Section 2 of this report provides an overview of Hydro's KPI performance in 2009 compared with the prior year as well as a comparison of actual KPI results compared with targets. This is followed by a detailed analysis of each individual KPI within the four categories named above in Section 3.

In October 2007, Hydro filed a report entitled "Peer Group Benchmarking" relating to several financial KPIs. Financial KPI's are not yet available, but should be filed within the first quarterly report for 2010.

2 Overview of Key Performance Indicator Results

2.1 Performance in 2009 versus 2008

Hydro faced several challenges in 2009 that impacted unit availability which was mainly attributable to equipment failures at the Holyrood Thermal Generating Station (Holyrood). Unit 1 and Unit 3 experienced a series of vibration issues and additional maintenance outages to complete required equipment repairs. Unit 2 experienced a few minor forced outages and the regular annual maintenance program outage. Transmission reliability improved significantly over 2008 performance in all areas. Distribution reliability also improved slightly due to a reduction in the transmission issues.

The operating KPIs for energy conversion showed a decline in the Holyrood fuel conversion rate. This was driven by lower average load on the operating units in 2009. There was some improvement due to scheduling of thermal production resulting in higher unit loading in the fall. The hydraulic conversion factor was down slightly from 2008.

Hydro's 2009 operating and maintenance costs are not available at this time. Financial KPI data will be provided at a later date.

The final category of KPIs called "Customer-Related" deals with Hydro's residential customer satisfaction. Customer satisfaction remained high, showing some improvement over past performance.

2.2 Performance in 2009 versus 2009 Target

The table below summarizes Hydro's KPI performance in 2009 compared to targets set for each measure. Targets were met with respect to the frequency and duration of transmission events and the frequency of distribution customer outages. Other targets were not met due to a number of challenges further described in this report.

The rationale for the 2009 targets was summarized in the September 2009 report to the Board entitled *2008 Annual Report on Key Performance Indicators*. The 2009 rationale is included in this report as Appendix A.

Hydro's KPI Targets and Operating Results for 2009

Category	KPI	Units	2009 Target	2009 Results	Target Achieved
Reliability	Capability Factor (CF)	%	86.8	82.0	No
	DAFOR	%	4.0	4.5	No
	T-SAIDI	Minutes/Point	191.0[1]	100.3[2]	Yes
	T-SAIFI	Number/Point	1.9[1]	0.9	Yes
	T-SARI	Minutes/Outage	102.1	111.4	No
	D-SAIDI	Hours/Customer	7.7	9.4	No
	D-SAIFI	Number/Customer	4.7	4.3	Yes
	Underfrequency Load Shedding	# of events	6	7	No
Operating	Hydraulic CF	GWh/MCM	0.434	0.436	Yes
	Thermal CF	kWh/BBL	630	612	No
Financial	Controllable Unit Cost	$/MWh		Not Available	
Other	Customer Satisfaction (Residential)	Max=100%	89%	91%	Yes

[1] Transmission reliability targets were set on combined planned and unplanned outages.
[2] The transmission reliability indicator shown is for planned and unplanned outages.

3 Performance Indices

The following defines and describes detailed Key Performance Indicator (KPI) data within four general categories: Reliability, Operating, Financial, and Customer-Related.

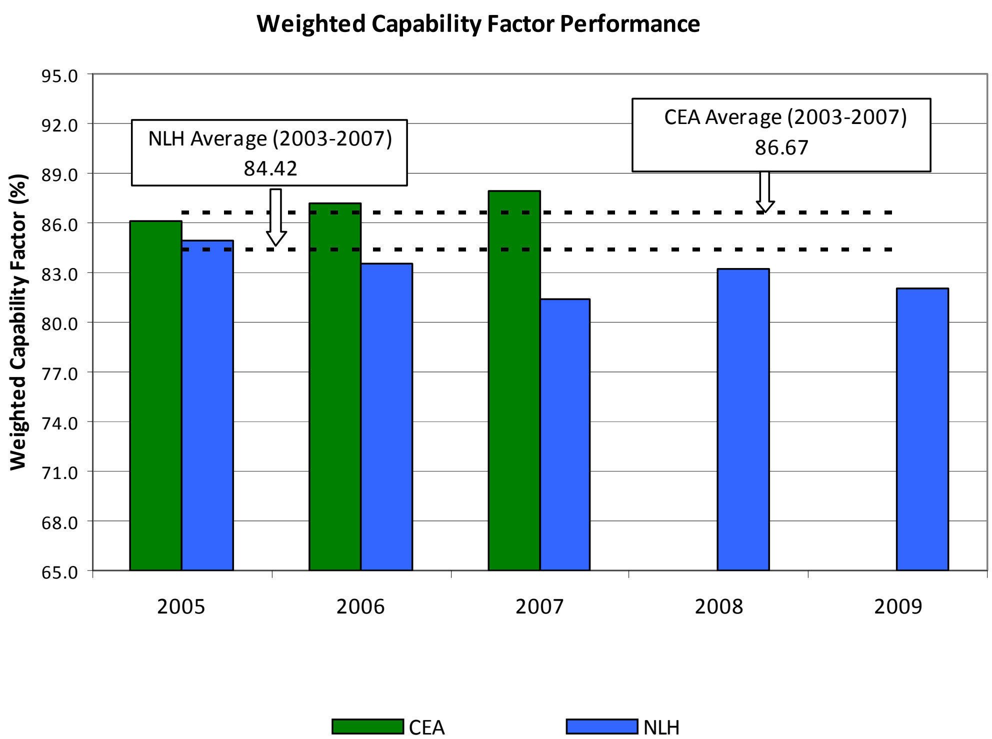
3.1 Reliability Performance Indicators

Hydro monitors reliability performance with eight separate metrics. These metrics have been divided into the following subcategories: Generation, Transmission, Distribution, and Other.

3.1.1 Reliability KPI: Generation

3.1.1 a) Weighted Capability Factor (WCF) – *a reliability KPI for generation assets that includes Hydro's thermal, gas turbine and hydroelectric generation assets on the Island and Labrador Interconnected Systems. The WCF measures the percentage of the time that a unit or a group of units is available to supply power at maximum continuous generating capacity. The factor is weighted to reflect the difference in generating unit sizes, meaning larger units have a greater impact on this measure.*

In 2009, Hydro's WCF was 82.0%, versus a target of 86.8%.



Thermal unit performance was affected by issues with Holyrood Unit 3, which had a capability factor of 54 percent in 2009, and some what by Holyrood Unit 1, which had a capability of 61 percent in 2009. Holyrood Unit 2 was in the expected range at 71 percent. Holyrood Unit 3 had an issue with high vibration when operating in synchronous condenser mode during the summer. This required a number of extended outages to realign the unit. Holyrood Unit 1 had issues with vibration on a forced draft fan motor on the boiler. This was repaired during its annual maintenance shutdown.

Hydraulic performance improved in 2009 over 2008. There were no major issues with hydraulic generation. Gas turbine performance decreased slightly from the improvement in 2008. Both the Hardwoods and Stephenville gas turbine plants continued to be derated since 2007. Each plant normally has two gas turbine engines operating a single generator. However, one of the engines was removed from Stephenville and installed in Hardwoods in 2007 to replace a failed Hardwoods engine. The Stephenville plant was reduced to a capacity of 25 MW pending the repairs to the failed engine removed from Hardwoods. The Hardwoods plant capacity was reduced in 2007 to 48 MW due to high exhaust gas temperature problems. Other than the gas turbines, all units were available at full capacity at the end of the year. Calculation details for weighted capability as well as a list of factors that may impact KPI performance are in Appendix B.

Hydro's 2003 to 2007[3] overall weighted capability was slightly better than the comparable weighted national average using CEA data for the same period for hydraulic and gas turbine units. The average is slightly lower for thermal – oil fired units. The weighted national average was developed by using national average capabilities values for the unit types in Hydro's system (hydraulic, oil-fired thermal and gas turbine) and applying weightings to these based upon the maximum continuous ratings of Hydro's generation. The quoted CEA value is therefore not a CEA published value but a re-stated value to facilitate a comparison to Hydro. The table below provides a direct comparison by unit type along with the weighting applied to the CEA values to provide an overall comparison.

Capability Factor Performance

	CEA (2003-2007)	Hydro (2003-2007)	Weighting Factor
Hydraulic	91.00	93.74	50%
Thermal - Oil Fired	79.09	67.75	33%
Gas Turbine	88.75	89.63	17%

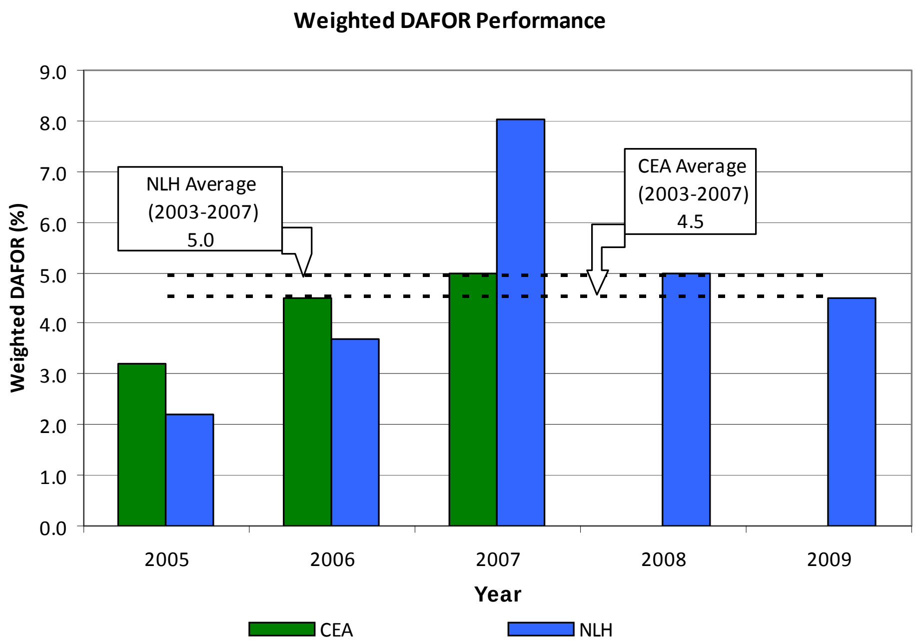
3.1.1 b) Weighted Derating-Adjusted Forced Outage Rate (DAFOR) - *a reliability KPI for generation assets that includes Hydro's thermal and hydroelectric generation assets on the interconnected systems[4]. DAFOR measures the percentage of the time that a unit or group of units is unable to generate at its Maximum Continuous Rating (MCR) due to forced outages. The KPI is weighted to reflect differences in generating unit sizes.*

In 2009, Hydro's weighted DAFOR was 4.51% versus a target of 4.02%. DAFOR was impacted by the vibration issues on Holyrood Unit 1 and Unit 3. Hydro's weighted DAFOR from 2003 to 2007 was

[3] The CEA has not yet published its Annual Generation Equipment Performance Reports for 2008.
[4] DAFOR is not applicable to the gas turbines because of the gas turbines' low operating hours.

slightly above the equivalently weighted national average up to 2007[5]. However, Hydro's performance has improved in 2009 to 4.5% compared to 2008 DAFOR results of 5.0%. The following table provides a direct comparison by unit type:

DAFOR Performance			
	CEA (2003-2007)	Hydro (2003-2007)	Weighting Factor
Hydraulic	2.70	0.58	60%
Thermal - Oil Fired	7.27	11.56	40%



[5] The CEA has not yet published its Annual Generation Equipment Performance Reports for 2008.

3.1.1.1 Generation Equipment Performance

The table below highlights the various performance indices for Hydro's generation facilities. Indices for 2008 and for the latest Canadian Electricity Association (CEA) national average for the period 2003-2007 are included for comparison.

Generation Performance Indices

Index		Hydraulic	Thermal	Gas Turbine
Failure Rate (Forced Outages per 8760 operating hours)	NLH 2009 NLH 2008 CEA '03-'07	3.53 2.59 2.25	7.07 7.58 9.85	172.14 119.39 12.44
Incapability Factor (Percent of Time)	NLH 2009 NLH 2008 CEA '03-'07	5.61 8.92 9.00	38.05 32.68 17.60	23.78 19.80 11.25
Derating Adjusted Forced Outage Rate (Percent of Time)	NLH 2009 NLH 2008 CEA '03-'07	0.69 1.06 2.19	13.79 15.60 9.40	
Utilization Forced Outage Probability (Percent of Time)	NLH 2009 NLH 2008 CEA '03-'07			15.38 13.58 7.76

3.1.1.1 (a) Hydraulic Unit Performance

As is shown in the above Generation Performance Indices table, the hydraulic unit failure rate increased in 2009 to 3.53 as compared to 2.59 in 2008. The 2009 hydraulic unit incapability of 5.61 and derating adjusted forced outage rate of 0.69 continues to be better than the national average for these indices of 9.00 and 2.19, respectively.

3.1.1.1 (b) Thermal Unit Performance

Thermal unit performance improved in 2009 in all measures except for Incapability Factor, as is shown in the Generation Performance Indices table above. The failure rate improved in 2009 to 7.07 as compared to 7.58 in 2008, and is better than the national average of 9.85. The derating adjusted forced outage rate of 13.79 in 2009 improved from 15.60 in 2008. The 2009 Incapability Factor of 38.05 increased from 32.68 in 2008.

3.1.1.1 (c) Gas Turbine Unit Performance

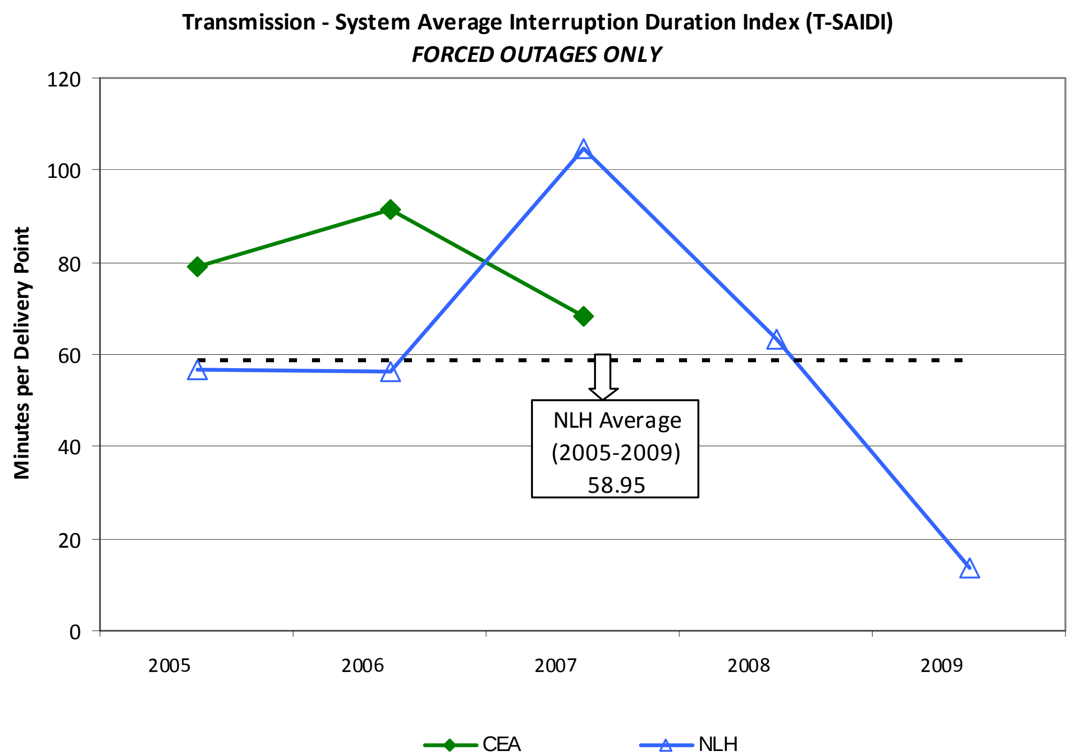
The Generation Performance Indices table above also shows that Hydro's gas turbines failure rate increased in 2009 to 172.14 from 119.39 in 2008. However, as previously reported, due to the nature of the calculation of failure rate, units with very low operating factors, such as those operated by Hydro, tend to have high failure rates. The 2009 incapability factor for Hydro's gas turbines of 23.78 indicates a decline in improvement from the trend in the past few years.

Of particular importance to Hydro's use of gas turbines is the utilization forced outage probability (UFOP). The measure describes the degree to which a standby unit can be called upon to supply load when requested. In 2009, the rate worsened to 15.38 as compared to 13.58 in 2008, and is significantly worse than the national average.

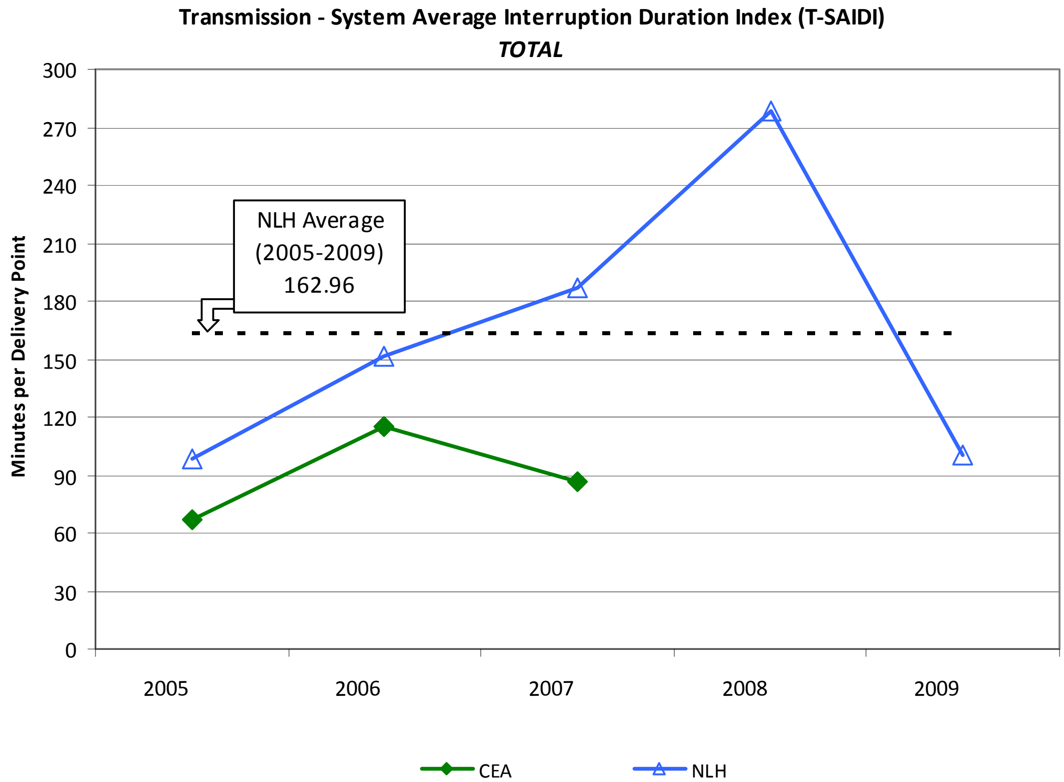
3.1.2 Reliability KPI: Transmission

3.1.2 a) Transmission System Average Interruption Duration Index (T-SAIDI) - *a reliability KPI for bulk transmission assets which measures the average duration of outages in minutes per delivery point.*

The fourth quarter T-SAIDI was 53.40 minutes per delivery point. The total 2009 T-SAIDI was 100.19 minutes per delivery point. This contrasts against the 2009 target[6] of 191.00 minutes per delivery point, and is 48% better than target performance. The 2008 total was 278.10 minutes per delivery point. This improvement is mainly attributable to the 2009 forced outage duration of 13.53 minutes which is down 79% from 2008. Planned outage durations are also down 60% from the previous year's average. Of note is that for this quarter 99% of the total outage duration was related to planned outages.



[6] "Target" means less than or equal to the value set as a performance outcome.



The 2009 outage duration of 86.76 minutes for planned interruptions accounted for approximately 87% of the total outage time. When compared to the 2009 target of 133 minutes a 35% decrease was achieved. The planned outage time was heavily influenced by several lengthy maintenance outages in the White Bay area and on the Great Northern Peninsula (GNP). The outages on the GNP were necessary for critical maintenance in the Bear Cove, Cow Head, Daniels' Harbour, Glenburnie, Hawke's Bay, Parson's Pond, and Plum Point terminal stations and on transmission lines. Those in the White Bay area were for replacement of a circuit breaker used to feed White Bay. Planned outages this quarter were as follows:

- On November 10, customers in Howley and the White Bay area experienced a planned outage of six hours duration. The outage was required to reconfigure the bus at Howley Terminal Station to allow for replacement of circuit breaker L51T2. These same customers experienced another planned outage on December 11 of four hours in duration, to energize and commission this new circuit breaker.

- Customers supplied by the Bear Cove and Plum Point Terminal Stations experienced a planned outage of three hours in duration on October 4. This outage was required to complete a connection off transmission line TL-241 to the Hawke's Bay Terminal Station for future connection of the mobile substation. On December 4, these same customers experienced a planned outage of 29 minutes in duration to connect the mobile substation to TL-241 at Hawke's Bay.

- There was a planned outage of 2 ½ hours in duration on December 1 to customers served by the Glenburnie Terminal Station. This outage was required to replace broken insulators on a voltage regulator and for general maintenance in the terminal station.

- There were three other planned outages ranging from six to 15 minutes; all were for switching proposes.

Forced outages this quarter were as follows:

- On December 2, customers served by the Glenburnie, Rocky Harbour and Wiltondale Terminal Stations experienced an outage of one minute in duration. The outage occurred after transformer T1 tripped at Deer Lake Terminal Station due to overload. This was during a disturbance on Deer Lake Power's system that resulted in both DLP 60Hz lines and TL-225 tripping.

- From December 3 to December 4, customers served by the Parson's Pond Terminal Station experienced five outages ranging from one to seven minutes in duration and one planned outage of six minutes in duration. These outages were all the result of salt contamination on transmission line TL-227 between Daniel's Harbour and Parson's Pond.

As previously reported, Hydro's planned outage durations tend to be longer than the national average. This is due to the relatively high number of delivery points on the Hydro system that do not have alternative supply options such as multiple station transformers or greater distribution system integration. This was a contributing factor to the planned outages on the GNP where station maintenance required customer outages for which there is no alternate supply point or local generation.

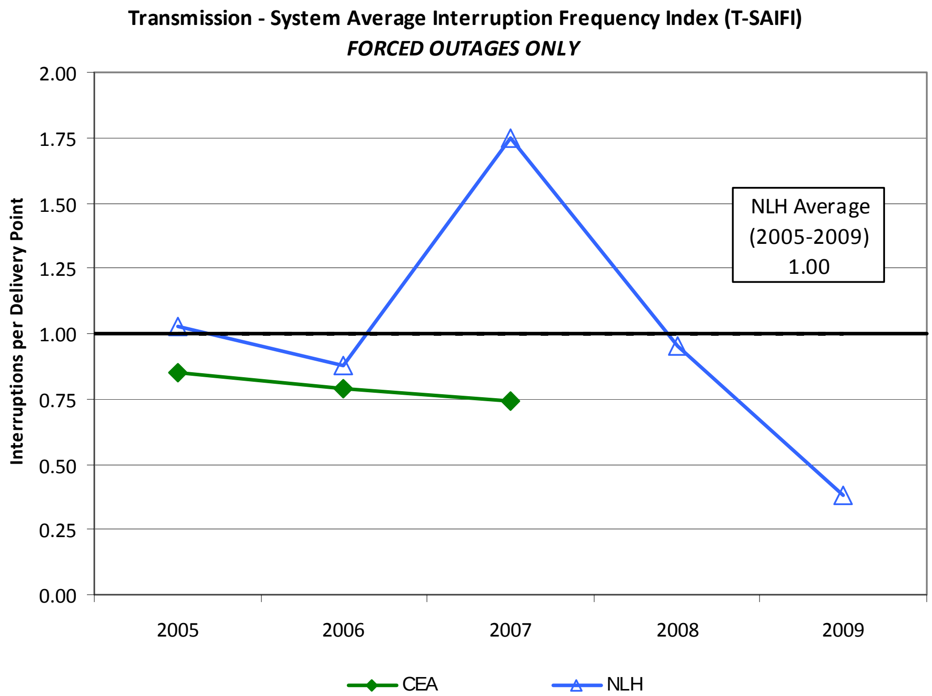
3.1.2 b) Transmission System Average Interruption Frequency Index (T-SAIFI) - *a reliability KPI for bulk transmission assets that measures the average number of sustained outages per delivery point*.

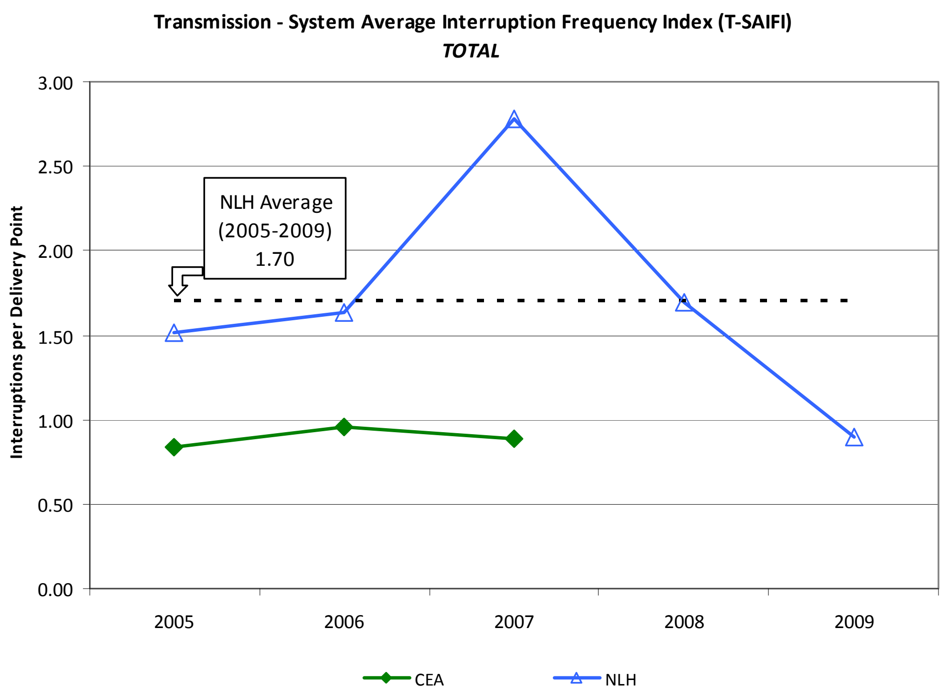
The fourth quarter T-SAIFI was 0.45 outages per bulk delivery point. This quarter the breakdown between forced and planned outages was split as follows: 0.14 for forced and 0.31 for planned outages. The 2008 fourth quarter T-SAIFI was 0.28 outages per bulk delivery point. Forced outages increased over 300% and planned outages increased 29% from the fourth quarter of 2008.

The overall 2009 T-SAIFI was 0.90 outages per bulk delivery point, which is lower than last year's average of 1.69 outages per delivery point, a decrease of 47%. This decrease can be attributed to a significant reduction in outage frequency in all areas. The 2009 target was 1.87 outages per bulk delivery point. The 2009 outcome was 52% better than target. This improvement is the result of a reduction in forced outages due to weather conditions, including high winds, salt contamination, and lightning. The number of forced outages per delivery point decreased from the 2008 level by 60% to 0.38 in 2009. The planned outages per delivery point decreased by 30% to 0.52 in 2009.

The frequency of Hydro's forced delivery point outages has been generally higher than the national average. This result is expected and can generally be attributed to the number of delivery points that are supplied by a single transmission line. The most severe example is on the Great Northern

Peninsula, where one line, TL-239, supplies up to eight delivery points. There are a number of other locations where a single line supplies three delivery points.



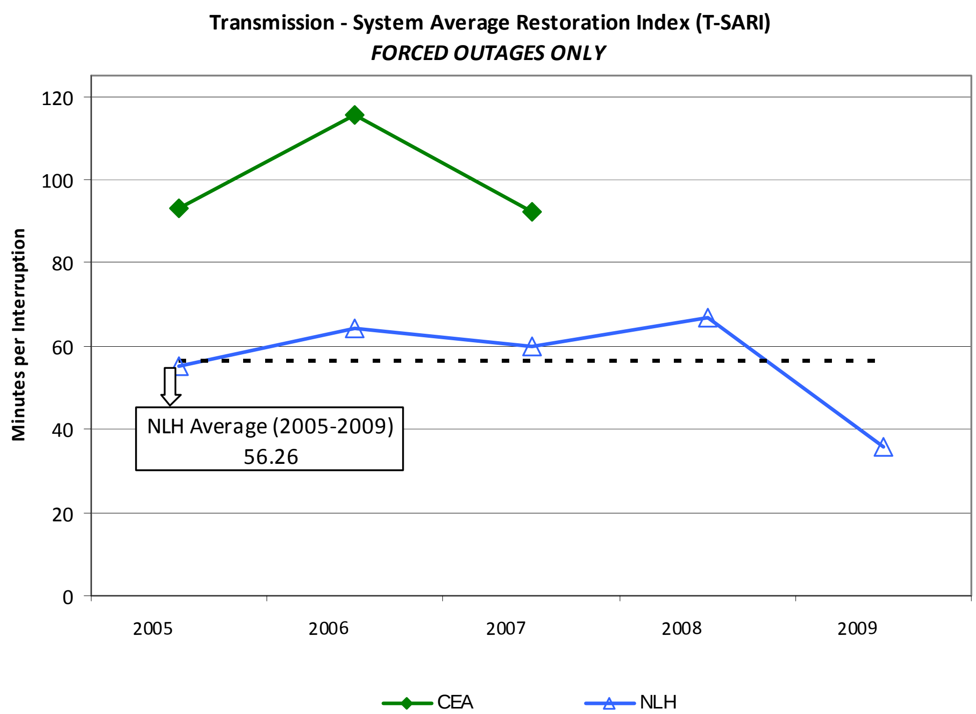


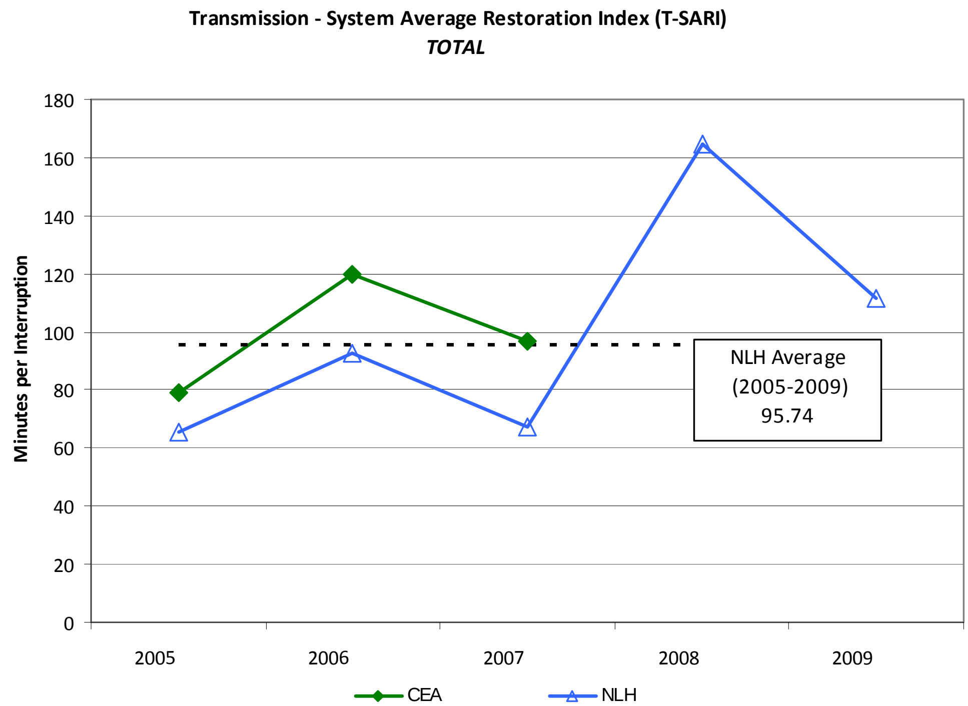
3.1.2 c) Transmission System Average Restoration Index (T-SARI) - *a reliability KPI for bulk transmission assets which measures the average duration per transmission interruption. T-SARI is calculated by dividing T-SAIDI by T-SAIFI.*

Hydro's total transmission T-SARI was 1.98 minutes per interruption for the fourth quarter 2009 versus 3.85 minutes per interruption for the fourth quarter 2008, a 49% decrease. The forced outage component of T-SARI was 0.03 minutes per interruption, a 94% decrease from the same quarter last year. The planned outage component of T-SARI was 2.84 minutes per interruption, a 34% decrease from the same quarter last year. Since the T-SARI is the ratio of T-SAIDI to T-SAIFI, this decrease is the result of decreases in both values.

Hydro's 2009 total transmission SARI was 111.4 minutes per interruption versus 164.5 minutes in 2008 and a target of 102.1 minutes for the year. The forced outage component of T-SARI was 35.61 minutes per interruption, a decrease of 46 percent over 2008. The planned outage component of T-SARI was 166.85 minutes per interruption, a decrease of 43 percent over 2008. Since T-SARI is the ratio of T-SAIDI to T-SAIFI, this decrease is driven by a lower T-SAIDI and T-SAIFI.

Up to the end of 2007 Hydro's T-SARI performance was in line with the national average. However, as can be seen in the chart below, it shows a significant increase in 2008 and a significant decrease in 2009. Performance is starting to come back in line with the national average.

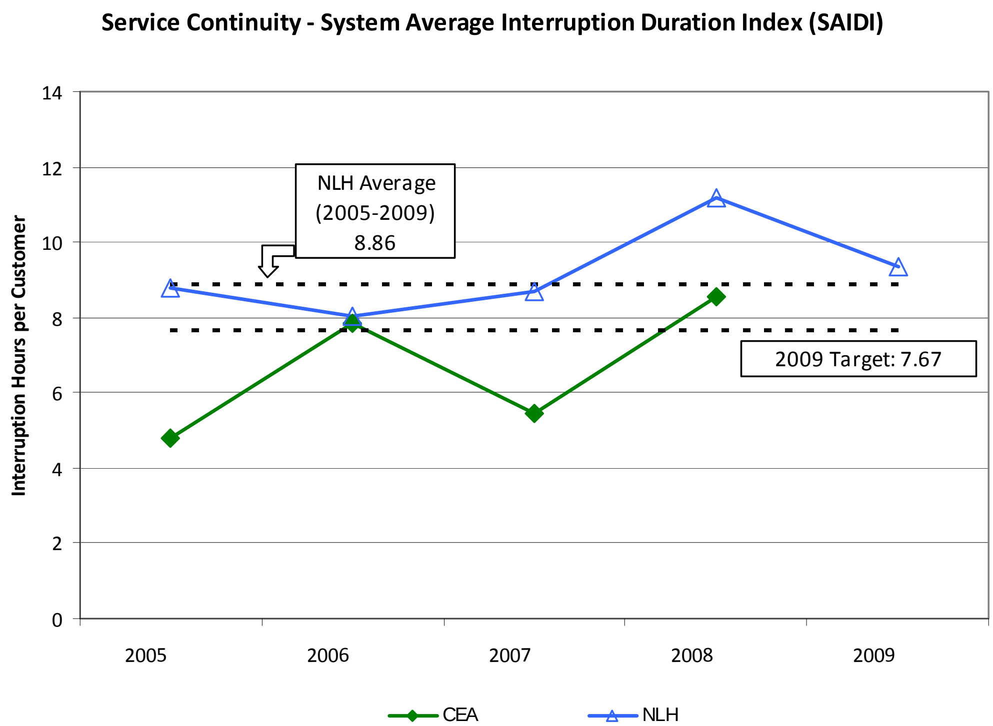




3.1.3 Reliability KPI: Distribution

3.1.3 a) System Average Interruption Duration Index (SAIDI) - *a reliability KPI for distribution service and it measures service continuity in terms of the average cumulative duration of outages per customer served during the year.*

In the fourth quarter, the SAIDI was 1.32 hours per customer compared to 2.80 hours per customer in the same quarter of 2008, a 53% decrease. The 2009 SAIDI was 9.35 hours per customer compared to 11.18 hours per customer in 2008, a 16% decrease. The 2009 target for SAIDI was 7.67, which was exceeded by 22%.



The duration of outages was negatively impacted by an increase in outage durations in the Labrador Interconnected System and the GNP portion of the Island Interconnected System. Outages on the GNP were generally the result of planned outages to both the transmission and distribution systems. On the transmission system, these outages were for regular maintenance on terminal station equipment and transmission lines, while the distribution outages were to make repairs and upgrade sections of the feeders.

There was an increase in planned outage duration in the towns of Labrador City and Wabush due to planned maintenance at the Wabush Terminal Station. There were a series of mostly planned and some forced outages in the third quarter of 2009 that totaled to 31 hours of outage time. In addition, customers in Labrador City experienced distribution equipment failures and experienced additional outage durations of six hours. Customers on Fogo Island experienced two outages totaling approximately 14 hours, the first due a failure of the submarine cable termination and then a planned outage to replace the cable terminations.

Customers in Hopedale experienced a forced outage in December totaling 25 hours after a blizzard caused damage to the distribution system. Restoration was delayed due to weather conditions.

Outages this quarter were as follows:

- The longest duration outage this quarter occurred in Hopedale after a blizzard. There was storm damage to the distribution system that to repair required a work crew from Happy Valley. Due to the weather conditions, this crew was delayed from leaving Happy Valley and all customers experienced a 25 hour outage.

- Customers fed from feeder line 1 at St. Anthony experienced a six hour planned outage. This planned outage was required to install the mobile substation at Hawke's Bay into the 138 kV transmission system. The St. Anthony diesel could not supply all three feeders in St. Anthony.

- Approximately 3,600 customers fed by the South Brook Terminal Station experienced a power outage after a tree fell across the main feeder. This tree contact resulted in the phase conductor burning off and falling to the ground. Repairs to the conductor took five hours to complete.

- All customers in Labrador City experienced an outage on December 20 ranging from two hours to six hours. An in-line disconnect switch failed on the main 46 kV feeder to the town. A backup 46 kV feeder could only carry 25% of the customers until the main feeder line was repaired.

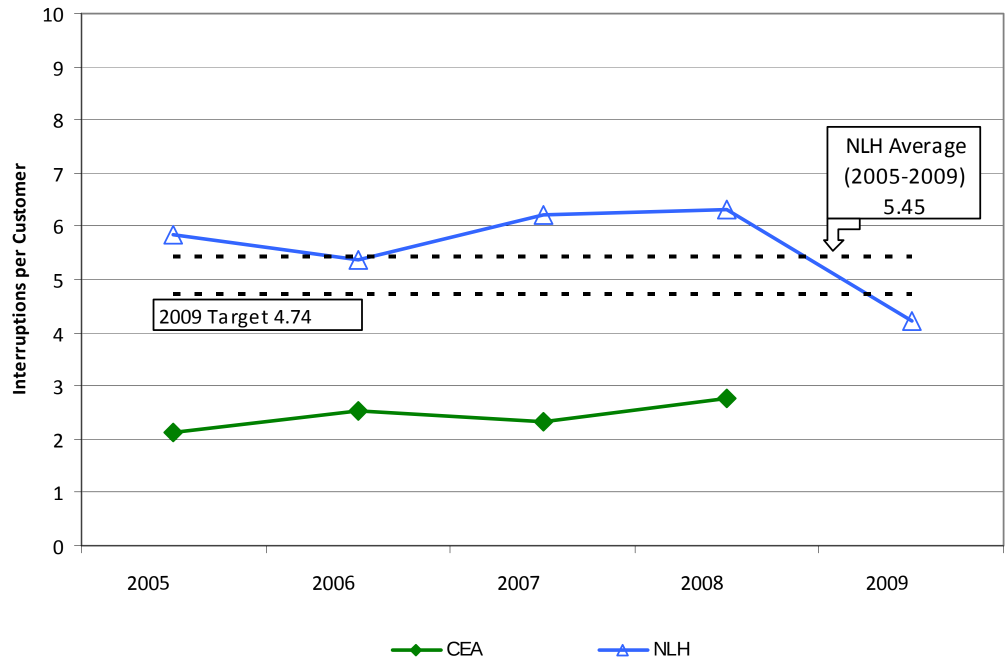
- In December, customers in Cartwright experienced two planned outages of four hours and 3 ½ hours to upgrade the distribution system.

3.1.3 b) System Average Interruption Frequency Index (SAIFI) - *a reliability KPI for distribution service which measures the average cumulative number of sustained interruptions per customer per year.*

In the fourth quarter, the SAIFI was 0.76 interruptions per customer compared to 1.16 interruptions per customers in the same quarter in 2008, a 35% decrease. The 2009 SAIFI was 4.21 interruptions per customer compared to 6.31 interruptions per customer in 2008, a 33% decrease. This is an 11% improvement over the 2009 target of 4.74 interruptions per customer. The 2009 results show an improvement in the five year average for Hydro, which is approaching the latest national average for utilities without a predominant urban customer base[7]. The decrease in 2009 was the result of a reduction in outages in all areas.

[7] The CEA data is not yet available for 2009.

Service Continuity - System Average Interruption Frequency Index (SAIFI)



3.1.3.1 Additional Information

This section provides more detailed information in three tables with performance broken down by Area, Origin, and Type.

Rural Systems Service Continuity Performance by Area

SAIFI (Number per Period)					
Area	**Fourth Quarter 2009**	**Fourth Quarter 2008**	**12 Mths to Date 2009**	**12 Mths to Date 2008**	**5 Year Average (2004–2008)**
Central					
Interconnected	0.39	0.79	2.80	4.69	3.91
Isolated	0.91	2.06	2.18	3.95	4.88
Northern					
Interconnected	0.91	0.57	2.62	6.79	4.81
Isolated	0.88	1.45	4.24	5.74	8.62
Labrador					
Interconnected	0.51	1.45	6.22	7.06	8.20
Isolated	3.93	5.07	13.87	13.84	10.20
Total	0.76	1.16	4.21	6.31	5.80

Note: System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers in an area

SAIDI (Hours per Period)					
Area	**Fourth Quarter 2009**	**Fourth Quarter 2008**	**12 Mths to Date 2009**	**12 Mths to Date 2008**	**5 Year Average (2004–2008)**
Central					
Interconnected	0.75	2.79	5.93	14.45	9.58
Isolated	0.20	1.64	1.34	3.47	4.22
Northern					
Interconnected	0.57	1.34	4.40	12.13	8.40
Isolated	1.48	1.96	3.97	5.99	6.26
Labrador					
Interconnected	1.90	2.87	20.15	4.75	9.28
Isolated	7.14	12.85	12.75	27.87	13.94
Total	1.32	2.80	9.35	11.18	9.06

Note: System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.

Rural Systems Service Continuity Performance by Origin

SAIFI (Number per Period)

Area	Fourth Quarter 2009	Fourth Quarter 2008	12 Mths to Date 2009	12 Mths to Date 2008	5 Year Average (2004–2008)
Loss of Supply – Transmission	0.22	0.21	1.82	2.95	2.34
Loss of Supply – NF Power	0.00	0.00	0.01	0.00	0.01
Loss of Supply – Isolated	0.19	0.25	0.55	0.75	0.64
Loss of Supply – L'Anse au Loup	0.00	0.03	0.04	0.03	0.08
Distribution	0.35	0.67	1.79	2.58	2.73
Total	0.72	1.16	4.91	6.31	5.80

Note: System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers.

SAIDI (Hours per Period)

Area	Fourth Quarter 2009	Fourth Quarter 2008	12 Mths to Date 2009	12 Mths to Date 2008	5 Year Average (2004–2008)
Loss of Supply – Transmission	0.04	0.36	4.79	3.49	2.57
Loss of Supply – NF Power	0.00	0.00	0.02	0.00	0.02
Loss of Supply – Isolated	0.11	0.16	0.22	0.38	0.24
Loss of Supply – L'Anse au Loup	0.00	0.04	0.02	0.04	0.03
Distribution	1.16	2.23	4.31	7.27	6.20
Total	1.28	2.80	7.79	11.18	9.06

Note: System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.

Rural Systems Service Continuity Performance by Type

Area	Scheduled		Unscheduled		Total	
	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI
Central						
Interconnected	0.14	0.34	0.25	0.41	0.39	0.75
Isolated	0.00	0.00	0.91	0.20	0.91	0.20
Northern						
Interconnected	0.11	0.31	0.81	0.26	0.91	0.57
Isolated	0.00	0.00	0.88	1.49	0.88	1.49
Labrador						
Interconnected	0.12	0.27	0.39	1.63	0.51	1.90
Isolated	0.78	1.91	3.16	5.24	3.93	7.15
Total	0.14	0.36	0.61	0.96	0.76	1.32

Note:
1. System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers in an area.
2. System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.

3.1.4 Reliability KPI: Other

3.1.4 a) Under Frequency Load Shedding (UFLS) - *reliability KPI that measures the number of events in which shedding of a customer load is required to counteract a generator trip. Customer loads are shed automatically depending upon the generation lost.*

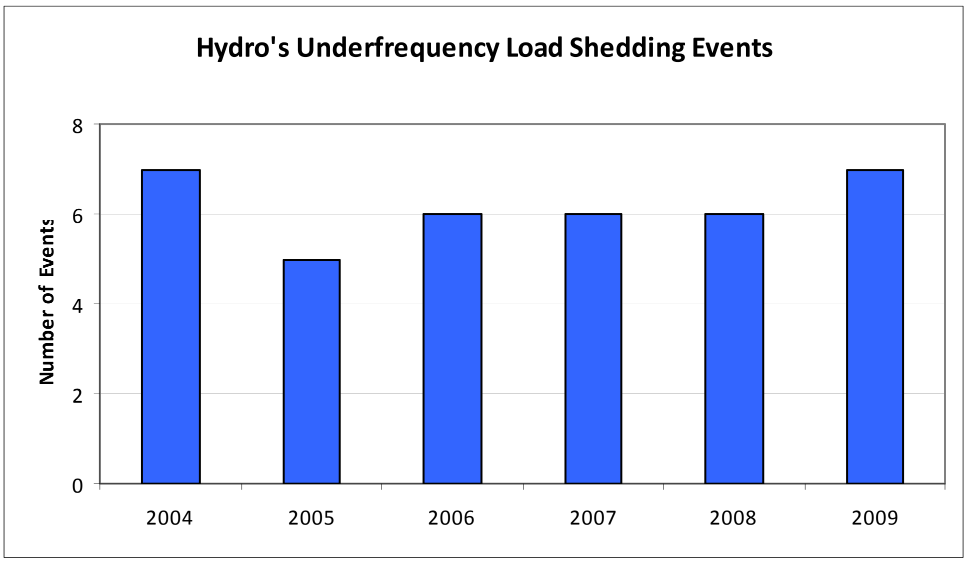
There were three underfrequency events during this quarter. The details are as follows:

- On November 6 at 1941 hours, a broken linkage on a feedwater valve caused a high drum level and a trip of Holyrood Unit 2. The frequency fell to 58.33 Hz. An underfrequency event occurred in which 15,149 Newfoundland Power customers, 1,247 Hydro rural customers, and Corner Brook Pulp and Paper (CBPP) were impacted. Approximately 489 MW-mins of energy went unserviced. Service was restored to all Newfoundland Power and Hydro rural customers within six minutes, and to CBPP in five minutes.

- On December 2 at 0033 hours, a trip of Deer Lake Power's Lines 1 and 2 resulted in an overload on TL-225 which resulted in 70 MW becoming separated from the system. The frequency fell to 58.58 Hz. An underfrequency event occurred in which 12,537 Newfoundland Power customers, 3,138 Hydro rural customers, and CBPP were impacted. Approximately 481 MW-mins of energy went unserviced. Service was restored to all Newfoundland Power customers within 20 minutes. Service was restored to Hydro rural customers in two minutes and to CBPP in five minutes.

- On December 6 at 1627 hours, Holyrood Unit 3 tripped due an issue that resulted in a high drum level. The frequency fell to 58.75 Hz. An underfrequency event occurred in which 4,879 Newfoundland Power customers were impacted. Approximately 57 MW-mins of energy went unserviced. Service was restored to all Newfoundland Power customers within three minutes.

In total, there were seven UFLS events in 2009. This was one more event then the number of events experienced from 2006 to 2008 and reflects a slight change in the stable performance of the past five years. Refer to the graph below which compares the UFLS events over the past five years to this year's performance.



Four of the seven events in 2009 had a significant impact on customers. The other three events resulted in minor customer load loss and interruption durations of less than five minutes. The details of the four significant events are:

1. Transmission line TL-248 was opened at Massey Drive Terminal Station for planned maintenance. The opening of this transmission line resulted in Deer Lake Power's generation being removed from the system at CBPP. Before TL-248 was opened, Deer Lake Power had one of two main transmission lines out of service between the Deer Lake power plant and Corner Brook. When TL-248 was opened it caused the other transmission line to become overloaded and trip. An underfrequency event occurred in which 10,061 Newfoundland Power customers, 1,247 Hydro rural customers, and CBPP were impacted. Service was restored to all Newfoundland Power customers within 7 minutes. Service was restored to Hydro rural customers in three minutes and to CBPP in five minutes.

2. A slow clearing fault developed on transmission line TL-202 which resulted in the frequency dragging. An underfrequency event occurred in which 5,424 Newfoundland Power customers and CBPP were impacted. Service was restored to all Newfoundland Power customers within 9 minutes and to CBPP in five minutes.

3. A second slow clearing fault developed on transmission line TL-202 which resulted in the frequency dragging. An underfrequency event occurred in which 16,941 Newfoundland Power customers and 1,247 Hydro rural customers were impacted. Service was restored to all Newfoundland Power and Hydro rural customers within four minutes.

4. A trip of Deer Lake Power's Lines 1 and 2 resulted in an overload on TL-225 which resulted in Deer Lake Power's generation becoming separated from the system. An underfrequency event occurred in which 12,537 Newfoundland Power customers, 3,138 Hydro rural customers, and CBPP were impacted. Service was restored to all Newfoundland Power customers within 20 minutes. Service was restored to Hydro rural customers in two minutes and to CBPP in five minutes.

The table below compares the UFLS events this quarter to last quarter.

Underfrequency Load Shedding Number of Events

Customers	Fourth Quarter		Year-to-date		5 Year Average
	2009	2008	2009	2008	(2004–2008)
NF Power	3	0	7	6	5.6
Industrials	2	0	5	6	6.0
Hydro Rural*	2	0	5	6	5.6
Total Events	3	0	7	6	6.2

Underfrequency Load Shedding Unsupplied Energy (MW-min)

Customers	Fourth Quarter		Year-to-date		5 Year Average
	2009	2008	2009	2008	(2004–2008)
NF Power	847	0	1,503	2,861	2,095
Industrials	150	0	317	510	2,378
Hydro Rural*	30	0	63	69	87
Total Events	1,027	0	1,883	3,440	4,560

* Underfrequency activity affecting Hydro Rural Customers may also result in a number of delivery point outages. Outage frequency and duration are also included in totals shown in the delivery point statistics section of the report for these areas, namely the Connaigre Peninsula and Bonne Bay.

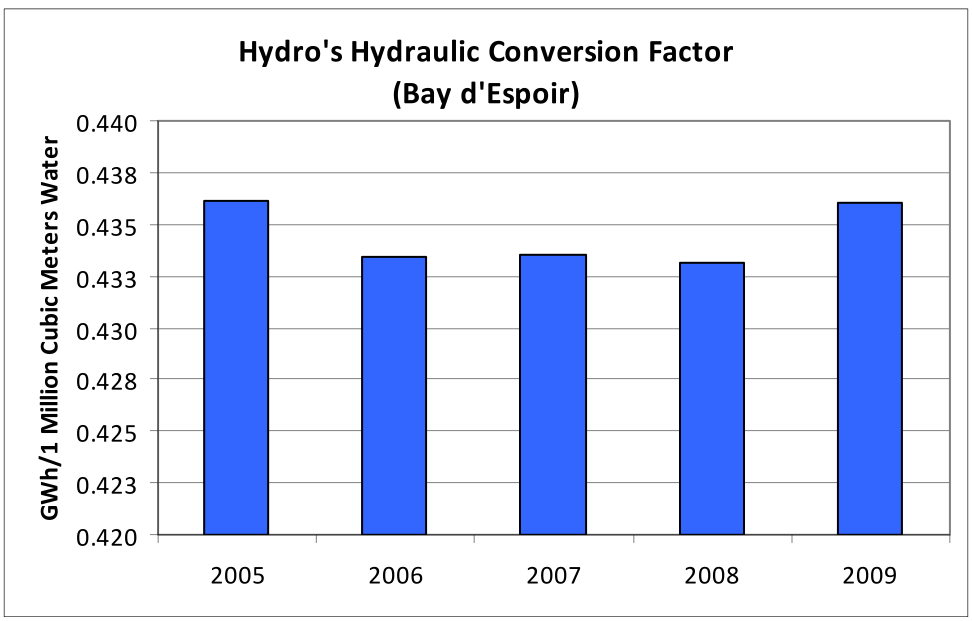
3.2 Operating Performance Indicators

This section presents information on two indicators of operating performance, both of which deal with generation.

3.2.1 Operating KPI: Generation

3.2.1 a) Hydraulic conversion factor (Bay d'Espoir) - *a representative performance KPI for the principal hydroelectric generation assets located at Bay d'Espoir. This KPI tracks the efficiency in converting water to energy and it is calculated as the ratio of Net GWh generated for every one million cubic metres (MCM) of water consumed.*

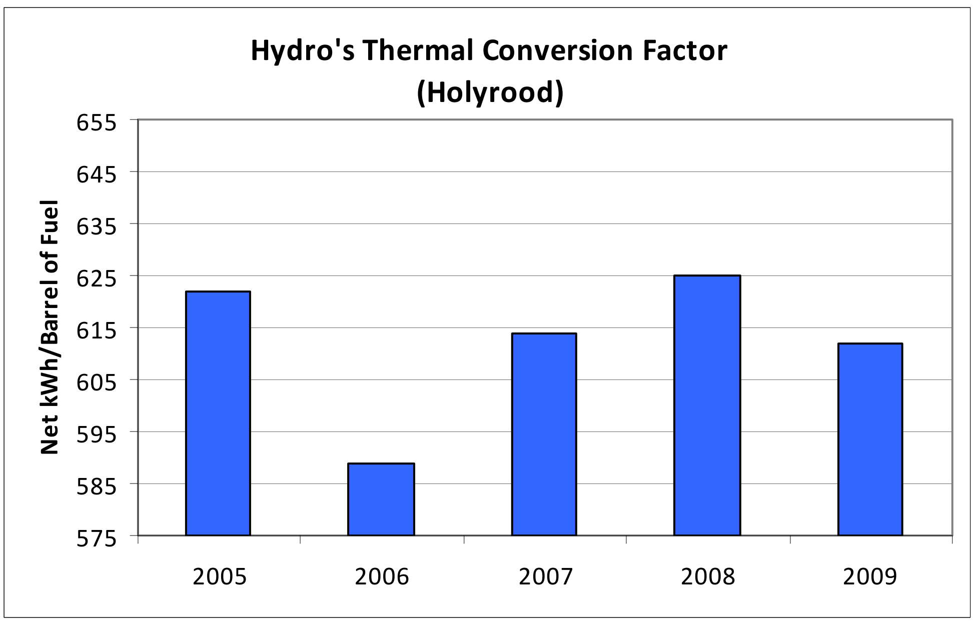
In 2009, Hydro's hydraulic conversion factor for Bay d'Espoir was 0.436 GWh/MCM. The lower performance in recent years is due to fewer operating hours on Unit 7 due to a lower night time load which results in the unit being operated in synchronous condenser mode.



3.2.1 b) Thermal conversion factor - *a representative performance KPI for the oil-fired thermal generation assets located at Holyrood. This KPI tracks the efficiency in converting heavy fuel oil into electrical energy and is measured as the ratio of the net kWhs generated to the number of barrels of No. 6 fuel oil consumed.*

The thermal conversion factor for Holyrood is directly proportional to the output level of the three units, with higher average and sustained loadings resulting in higher conversion factors. In turn, the output level of the Holyrood Thermal Generating Station will vary depending on hydraulic production, quantity of power purchases, customer energy requirements and system security requirements.

In 2009, Hydro's thermal conversion factor was 612 kWh per barrel, which is below the 2009 target of 630 kWh per barrel. This reduction is related to operating the plant at lower generating levels due to the high volume of water resources. In addition to this impact, effort was made to reduce the number of units operating whenever system security constraints permitted, so that the unit loading on operating units could be raised to meet the energy production requirements. The average unit loading while operating was 81 MW, down from 100 MW in 2008. Overall production from Holyrood for 2009 was 1,005 GWh, a 13% decrease from 2008 production levels.



3.3 Financial Performance Indicators

The financial KPIs reported annually to the Board are:

1. Corporate operating, maintenance and administrative expense (OM&A) per MWh delivered;
2. Generation OM&A per MW installed capacity;
3. Generation OM&A per GWh generated;
4. Transmission OM&A per transmission circuit km; and
5. Distribution OM&A per distribution circuit km.[8]

In Order No. P.U. 8 (2007), the Board ordered that Hydro file a report no later than October 31, 2007 outlining an appropriate peer group with which Hydro's financial performance at the generation and transmission level could be compared. In compliance with Board Order No. P.U. 8 (2007), Hydro filed a report titled "Peer Group Benchmarking" dated October 31, 2007 which summarized Hydro's findings regarding development of a peer group for financial KPIs related to generation and transmission. In that report, Hydro identified separate peer groups for generation KPIs and transmission KPIs and proposed that, subject to data availability, the selected peers remain constant to allow for meaningful trend comparisons over time. This is the second year of reporting generation and transmission financial KPI peer data. The list of peers used for KPI benchmarking for Financial Performance Indicators is included as Appendix C. This peer group benchmarking data is sourced from the U.S. Federal Energy Regulatory Commission (FERC) database, to which Hydro has a subscription. All financial data for the U.S.-based peer group is in $US and all financial data for Hydro is in $Cdn.

With respect to the Corporate and Distribution KPIs (items 1 and 5 above), in its 2007 Annual Report on KPIs Hydro had incorporated peer benchmarking data from the Canadian Electricity Association's (CEA) Committee on Performance Excellence (COPE) as published in the "Peer Group Performance Measures for Newfoundland Power" report. However, the CEA has informed Newfoundland Power that the composite information for these measures is no longer available, nor are any other cost-related CEA composite indicators available for benchmarking purposes.[9] As a result, Newfoundland Power is now using a peer group of U.S. companies. This group of US companies is not an appropriate group for Hydro due to Hydro's relatively small distribution component. In order to maintain consistency for year over year comparisons, Hydro is using the same peer group of U.S. companies for the Corporate Controllable Unit Cost KPI that Hydro uses for its generation financial benchmarking.

3.3.1 Financial KPI: Corporate

3.3.1 a) Controllable Unit Cost - *a high level corporate KPI that tracks Hydro's OM&A expenses in relation to its total energy delivered, expressed as dollars per MW hour. Total Corporate OM&A includes all operating labour and materials for Hydro's generation, transmission, distribution, customer-related and administrative costs. Energy deliveries have been normalized for weather, customer hydrology, and industrial strikes.*

[8] This KPI is not available for benchmarking from 2007 onwards. It will continue to be reported for Hydro for annual comparison purposes. Please see section 3.3.4 a) Distribution Controllable Cost for a discussion of the alternate KPI to be used for peer benchmarking.

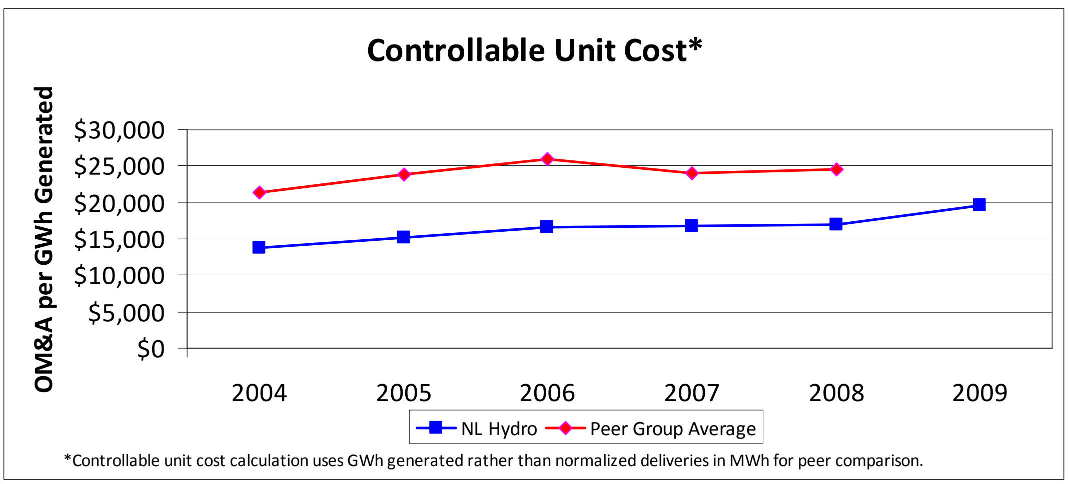
[9] "Peer Group Performance Measures for Newfoundland Power", December 23, 2008, p.2.

Hydro's OM&A costs increased slightly from $99.3 million in 2008 to $101.7 million in 2009, resulting in a Controllable Unit Cost of $14.91 per MWh delivered for 2009.

Up to 2006, Hydro's Controllable Unit Cost was compared to the average Controllable Unit Cost for participants in the CEA COPE program as reported by Newfoundland Power. As of 2008, however, Newfoundland Power no longer uses CEA COPE benchmarking data for cost-related measures, because the composite information for these measures is no longer available for publication. Peer group results for the period 2004-2008 herein have therefore been restated using the same U.S. Peer Group Hydro uses for generation financial KPIs.

For computation of Hydro's Corporate Controllable Unit Cost, normalized energy delivered is used. However, the available peer group data from the FERC database is based on net energy generated. Thus, for better comparison against the peer group, Hydro's data will also be calculated and charted on this basis. Hydro's Corporate OM&A per unit of net generation is $19.66 per MWh, higher than the computed Controllable Unit Cost, because normalized deliveries are higher than net generation due to the effect of Hydro's energy purchases.

Hydro's Corporate Controllable Unit Cost is following a very similar slow and steady upward trend as compared to the peer group. However, it is difficult to determine specifically what factors might be impacting the expenses of the peer group participants without detailed information regarding their operations and finances.

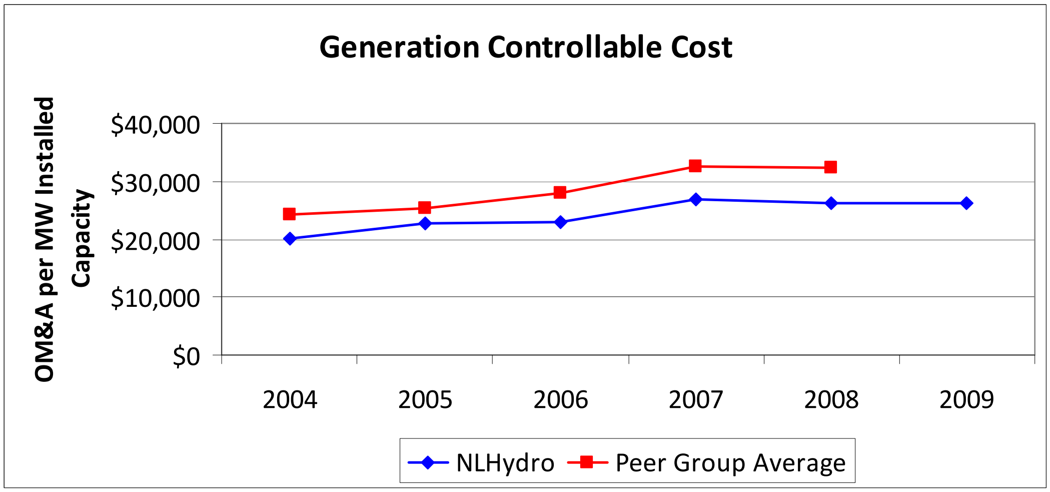


3.3.2 Financial KPI: Generation

3.3.2 a) Generation Controllable Cost - *a functional corporate KPI that tracks Hydro's generation costs in relation to its installed generation. It is computed by dividing generation OM&A by installed capacity as measured in MW.*

Generation Controllable Cost was $26,138 per MW for 2009 compared with $26,217 in 2008, a slight decrease. As mentioned in prior annual KPI reports, an asbestos abatement program was undertaken at Holyrood in 2005 through 2007. Amortization of costs associated with this program will continue through to 2012.

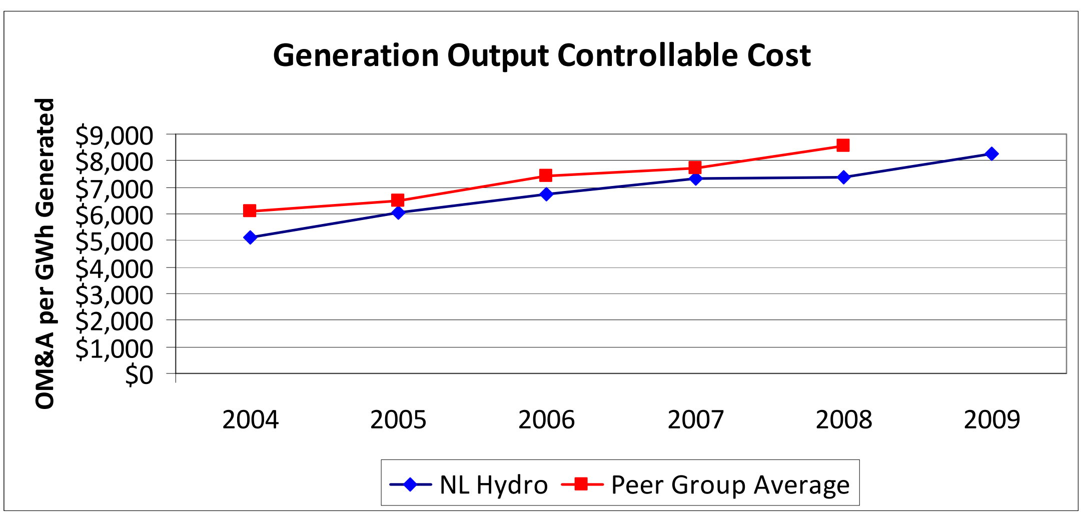
The peer group used to benchmark Generation Controllable Costs appears to be experiencing a similar cost trend as Hydro.



3.3.2 b) Generation Output Controllable Cost - *a functional corporate KPI that tracks Hydro's generation OM&A expenses in relation to its net generation measured in GWh.*

In 2009, Hydro's Generation Output Controllable Cost, at $8,267 per GWh, was higher than the $7,362 in 2008. Despite a decrease in the Generation Costs component of approximately $0.6 million from 2008 to 2009 there the Generation Output Controllable Cost increased because there was a proportionately greater decrease in the Net Energy Generated of 714. The decrease in Net Energy Generated was a result of the combined reduction in industrial load and increases in energy from other sources.

From 2004 through 2008, Hydro's Generation Output Controllable Costs were in line with and trending in a similar direction as those of the peer group.

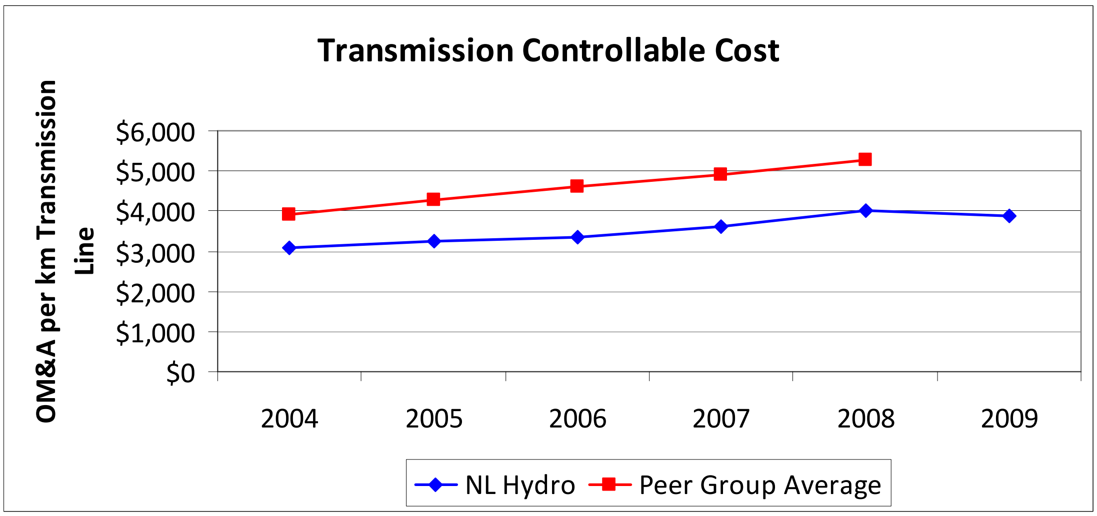


3.3.3 Financial KPI: Transmission

3.3.3 a) Transmission Controllable Cost - *a KPI that tracks Hydro's transmission OM&A expenses in relation to the 230 kV equivalent length of its transmission circuits (69 kV lines and above).*

In 2009, Hydro's Transmission Controllable Cost was $3,870 per km of transmission, a decrease of 4% over 2008.

Hydro's costs per km of transmission circuit are trending in a similar pattern as the peer group, although per unit cost increases appear to be increasing at a slower rate within Hydro. A direct cost per unit km within the peer group is not meaningful due to differences in accounting and corporate cost allocations; however comparisons over time can highlight relevant trends.



3.3.4 Financial KPI: Distribution

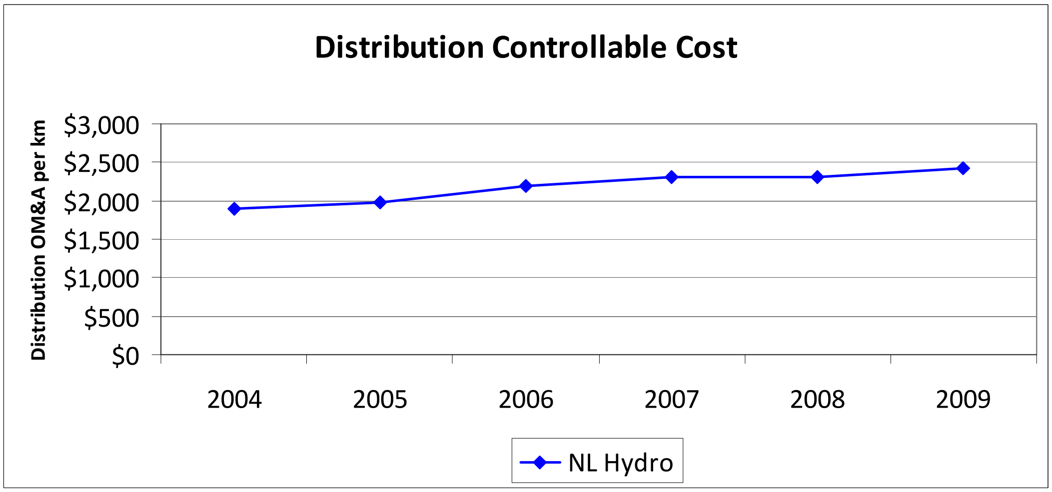
3.3.4 a) Distribution Controllable Cost - *a functional corporate KPI that tracks Hydro's distribution OM&A expenses in relation to the length of its equivalent 230 kV distribution circuits in kilometres[10].*

The Distribution Controllable Cost KPI had previously been reported as dollars per km of distribution using the CEA COPE data. As discussed, the CEA COPE data is no longer available for benchmarking of financial KPIs. Additionally, although distribution cost data is available for the U.S.-based peer group used by Hydro for Transmission Controllable Cost, the associated km of distribution data is unavailable. In the absence of the CEA COPE data, Newfoundland Power has chosen to use a KPI that divides total Distribution OM&A by MWh of retail sales. Hydro will therefore use this same data set. However, given Hydro's relatively small quantity of retail sales, combined with the rural and remote locations of these sales, it is expected that Hydro's Distribution cost per MWh will be significantly higher than Newfoundland Power's and the peer group average.

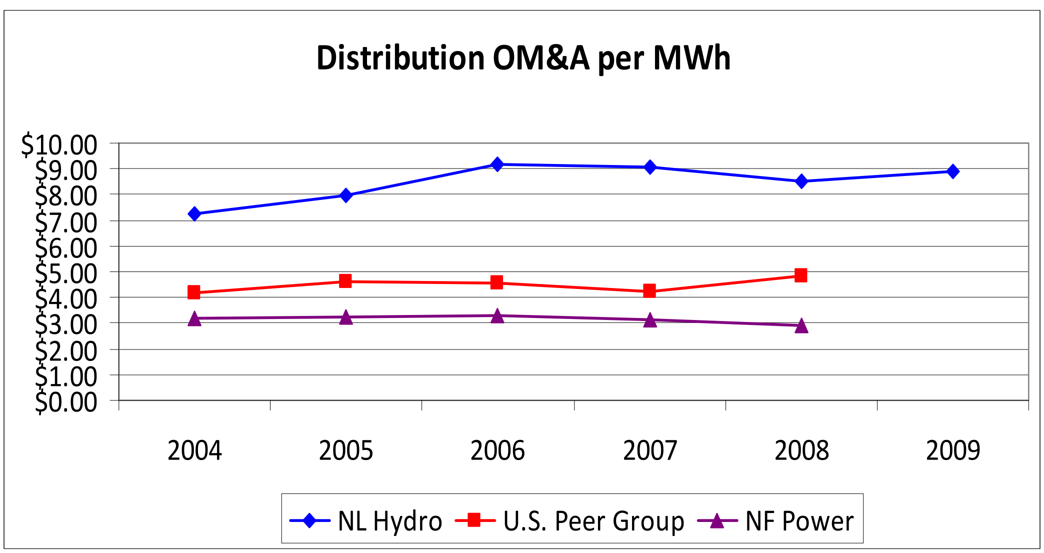
The distribution cost per km of circuit length will continue to be reported for year over year trend analysis.

[3] CEA COPE peer data used up to 2007 excluded circuit s less than 1 kV. Hydro's data has also been adjusted to exclude circuits less than 1 kV from 2003 onward.

At $2,429 per circuit km Hydro's Distribution Controllable Cost of 2009 increased from the $2,305 that was recorded in 2008. This is in line with in the slight upward trend in this cost that was seen between 2004 and 2008.



As expected, Hydro's distribution costs trend higher than those of its peers. The distribution systems are a relatively small component of Hydro's total plant compared to generation and transmission plant and also compared to Newfoundland Power's distribution assets. Thus, Hydro's higher costs are likely due to the rural and geographically dispersed nature of its distribution systems and the resultant inability to achieve cost economies.



3.4 Customer-Related Performance Indicators

3.2.4 a) Residential Customer Satisfaction - *an indicator of Hydro's residential customers overall satisfaction level with service, which is tracked by the Percent Satisfied Customers KPI*[11]*.*

The Percent Satisfied Customers measure is also a corporate performance KPI that tracks the satisfaction of rural residential customers with Hydro's performance. The Percent Satisfied Customers measure is produced via an annual survey of Hydro's residential customers.

In 2009, 91% of Hydro's residential customers were satisfied with Hydro's service. The satisfaction rating has improved since 2008.

[11] As of 2009, the Customer Satisfaction index (CSI) is no longer being calculated as a Customer-Related Performance Indicator.

4 Data Table of Key Performance Indicators

Key Performance Indicators' targets for 2010 were established in the same manner as in previous years. Any future changes in methodology will be included as such a change occurs.

Newfoundland and Labrador Hydro
Key Performance Indicators (KPI)
Results to December 31, 2009 plus Target/Budget for 2010

KPI	Measure Definition	Units	2005	2006	2007	2008	2009	2010F[4]
Reliability								
Generation								
Weighted Capability Factor	Availability of Units for Supply	%	84.9	83.5	81.4	87.4	82.0	86.8
Weighted DAFOR	Unavailability of Units due to Forced Outage	%	2.2	3.7	8.0	3.9	4.5	3.2
Transmission								
SAIDI	Outage Duration per Delivery Point	Minutes / Point	99	151	187	191	100	233
SAIFI	Number of Outages per Delivery Point	Number / Point	1.5	1.6	2.7	1.7	0.9	1.8
SARI	Outage Duration per Interruption	Minutes / Outage	65	93	68	165	111	129
Distribution								
SAIDI	Average Outage Duration for Customers	Hours / Customer	8.8	8.0	8.7	6.3	9.4	6.9
SAIFI	Number of Outages for Customers	Number / Customer	5.8	5.4	6.2	6.3	4.3	4.3
Under Frequency Load Shedding								
UFLS	Customer Load Interruptions Due to Generator Trip	Number of Events	5	6	6	6	7	6
Operating								
Hydraulic Conversion Factor[1]	Net Generation / 1 Million m^3 Water	GWh / MCM	0.436	0.433	0.433	0.434	0.434	0.433
Thermal Conversion Factor[2]	Net kWh / Barrel No. 6 HFO	kWh / BBL	622	589	614	624	612	630
Financial (Regulated)								
Controllable Unit Cost[3]	Controllable OM&A$ / Energy Deliveries	$/MWh	12.49	13.23695475	14.15	14.05	14.91	N/A[5]
Generation Controllable Costs	Generation OM&A$ / Installed MW	$ / MW	$22,641	$22,887	$26,836	$26,217	$26,138	N/A[5]
	Generation OM&A$ / Net Generation	$ / GWh	$6,040	$6,719	$7,342	$7,362	$8,267	N/A[5]
Transmission Controllable Costs	Transmission OM&A$ / 230 kV Eqv Circuit Km	$ / Km	$3,235	$3,358	$3,625	$4,023	$3,870	N/A[5]
Distribution Controllable Costs	Distribution OM&A$ / Circuit Km	$ / Km	$1,983	$2,198	$2,307	$2,305	$2,429	N/A[5]
Other								
Percent Satisfied Customers4	Satisfaction Rating	Max = 100%	88%	89%	88%	89%	89%	89%

Notes:
1. For Bay d'Espoir hydroelectric plant.
2. For Holyrood Thermal Generating Station
3. Energy deliveries have been normalized for weather, customer hydrology, and industrial strikes. No adjustments have been made for Abitibi Consolidated Stephenville mill closure.
4. Residential customers only
5. Forecasts are unavailable because 2010 is not a test year for a General Rate Application; therefore Cost of Service data is unavailable on a projected basis.

Appendices

APPENDIX A: Rationale for Hydro's 2009 KPI Targets

KPI	Comment on KPI 2009 Target
Reliability	Hydro has adopted a target setting approach wherein known factors that affect reliability performance are incorporated into the target setting process wherever practical. This approach also uses percentage improvements and past performance levels to set target levels for continuous improvements.
Weighted Capability Factor	The 2009 target is set using the expected annual generation unit outage schedule combined with performance improvements relative to recent history.
Weighted DAFOR	The 2009 target is set using the expected annual generation unit outage schedule combined with performance improvements relative to recent history.
Transmission SAIDI, SAIFI, and SARI	The 2009 targets for forced outage performance are set based upon recent performance improvements. The planned outage contribution to total performance is currently under development and will be incorporated into the final performance targets upon completion of the annual transmission terminals maintenance outage plan.
Distribution SAIDI & SAIFI	Improvements relative to the most recent five-year average.
Underfrequency Load Shedding	The 2009 target is based upon improvement over the most recent five-year average.
Operating	
Hydraulic Conversion Factor	Hold at the previous target value.
Thermal Conversion Factor	Per Board Order No. P.U. 14 (2004)
Financial	
Controllable Unit Cost	Unavailable
Generation, Transmission & Distribution Controllable Cost	Unavailable
Other	
Customer Satisfaction	Targeting continuous improvement.

Appendix B: Computation of Weighted Capability Factor and Factors Impacting Performance

Weighted Capability Factor is calculated using the following formula:

$$1-\frac{\sum_{all\ units}\left(\frac{unit\ total\ equivalent\ outage\ time \times unit\ MCR}{unit\ hours}\right)}{\sum_{all\ units} unit\ MCR}$$

Where,

MCR = Maximum Continuous Rating, the gross maximum electrical output, measured in megawatts, for which a generating unit has been designed and/or has been shown capable of producing continuously. MCR would only change if the generating capability of a unit is permanently altered by virtue of equipment age, regulation, or capital modifications. Such changes to MCR are infrequent and have not actually taken place within Hydro since the 1980's when two units at Holyrood were uprated due to modifications made to these units.

Unit hours = the sum of hours that a unit is in commercial service. This measure includes time that a unit is operating, shut down, on maintenance, or operating under some form of derating. Unit hours will only be altered in the infrequent event that a unit is removed from commercial service for an extended period of time.

Unit total equivalent outage time = the period of time a unit is wholly or partially unavailable to generate at its MCR. For the purposes of calculating outage time, the degree to which a unit is derated is converted to an outage equivalency. Thus, a unit that is able to generate at 75% load for four days would have an equivalent outage time of one full day out of four. Factors that can affect unit total equivalent outage time are classified by CEA under nine categories, which are outlined in Appendix A to this Report. Hydro tracks the time that each unit spends in each of these nine states and calculates the weighted capability accordingly.

Unit total equivalent outage time is the measure that is most likely to impact Weighted Capability Factor on a year-to-year basis, since MCR and unit hours are unlikely to change.

Factors that Affect Unit Total Equivalent Outage Time

1. **Sudden Forced Outage.** An occurrence wherein a unit trips or becomes immediately unavailable.
2. **Immediately Deferrable Forced Outage**. An occurrence wherein a unit must be made unavailable within a very short time (10 minutes).
3. **Deferrable Forced Outage**. An occurrence or condition wherein a unit must be made unavailable within the next week.
4. **Starting Failure**. A condition wherein a unit is unable to start.
5. **Planned Outage**. A condition where a unit is unavailable because it is on its annual inspection and maintenance.
6. **Maintenance Outage**. A condition where a unit is unavailable due to repair work. Maintenance outage time covers outages that can be deferred longer than a week, but cannot wait until the next annual planned maintenance period.
7. **Forced Derating**. A condition that limits the usable capacity of a unit to something less than MCR. The derating is forced in nature, typically because of the breakdown of a subsystem on the unit.
8. **Scheduled Derating**. A condition that limits the usable capacity of a unit to something less than MCR, but is done by virtue of the decision of the unit operator. Scheduled deratings are less common than forced deratings, but can arise, for example, when a unit at Holyrood is derated to remove a pump from service.
9. **Common Mode Outages**. Common mode outages are rare, and arise when an event causes multiple units to become unavailable. An example might be the operation of multiple circuit breakers in a switchyard at Holyrood due to a lightning strike, rendering up to three units unavailable.

Note: There are hundreds of CEA equipment codes for generator subsystems that track the cause for the time spent in each of the above categories.

Appendix C: List of U.S.-Based Peers for Financial KPI Benchmarking

Generation and Corporate Peer Group:

Alcoa Power Generating Inc.
Allete, Inc.
Aquila, Inc.
Avista Corporation
Buckeye Power, Inc.
Cleco Power LLC
Electric Energy, Inc.
Entergy Mississippi, Inc.
Hawaiian Electric Company, Inc.
Indiana-Kentucky Electric Corporation
Kentucky Power Company
Ohio Valley Electric Corporation
Portland General Electric Company
Public Service Company of New Hampshire
Puget Sound Energy, Inc.
Savannah Electric and Power Company
Sierra Pacific Power Company
Southern Electric Generating Company
Southern Indiana Gas and Electric Company
The Empire District Electric Company

Transmission Peer Group:

AEP Texas North Company
Allete, Inc.
Aquila, Inc.
Avista Corporation
Central Illinois Public Service Company
Delmarva Power & Light Company
Entergy Mississippi, Inc.
Kentucky Utilities Company
MDU Resources Group, Inc.
Mississippi Power Company
New York State Electric & Gas Corporation
Northern Indiana Public Service Company
Northern States Power Company (Wisconsin)
Oklahoma Gas and Electric Company
Public Service Company of Colorado
Public Service Company of Oklahoma
Sierra Pacific Power Company
Southwestern Electric Power Company
Tucson Electric Power Company
Westar Energy, Inc.

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

QUARTERLY REGULATORY REPORT FOR THE YEAR ENDED DECEMBER 31, 2010

Newfoundland and Labrador Hydro

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1 HIGHLIGHTS

REVISED JUNE 2011

HIGHLIGHTS
For the twelve months ended December 31, 2010

REGULATED	2010 Actual YTD	2010 Target/ Budget	2009 Actual YTD[6]
Safety			
Lead:Lag Ratio[1]	358:1	350:1	341:1
All Injury Frequency Rate[1,2]	1.39	≤1.0	1.44
Production			
Quarter End Reservoir Storage (GWh)	2,445	640	2,368
Hydraulic Production (GWh)[3]	4,274	4,300	4,200
Holyrood Fuel Cost per barrel, current month ($)[3]	79	55	67
Holyrood Efficiency Factor	589	630	612
Electricity Delivery			
Sales including Wheeling (GWh)	6,324.1	6,758.9	6,450.4
Financial			
Revenue ($millions)	417.1	447.6	427.7
Expenses ($millions)	410.5	441.6	410.5
Net Operating Income ($millions)[4]	6.6	6.0	17.2
Current Rate Stabilization Plan (RSP) Balance ($millions)	(159.2)	(112.7)	(122.0)
Hydraulic	(40.4)	(17.8)	(32.2)
Utility	(56.2)	(41.1)	(52.9)
Industrial	(62.6)	(53.8)	(36.9)
Full Time Equivalent (FTE) Employees[5]			
Regulated	820.1	854.5	813.5
Non-Regulated	28.3	12.5	21.9

[1] Annual Target, and Actual
[2] Per 200,000 hours
[3] Target based on approved 2007 Test Year forecast
[4] Does not include any earnings from CF(L)Co
[5] One FTE is the equivalent of actual paid regular hours - 2,080 hours per year in the operating environment and 1,950 hours per year in Hydro's head office environment.
6 Certain of the 2009 comparative figures were restated to conform with the 2010 presentation.

2010 targets met or exceeded include:

- Lost time injury frequency (page 2)
- Variance from ideal production schedule at Holyrood Thermal Generating Station (page 6)
- Achievement of environmental targets (page 7)
- Winter availability of energy supply (page 13)

2 SAFETY

Goal - To be a Safety Leader

Safety is Hydro's number one priority. Hydro remains committed to being a world class leader in safety performance.

Measurement	Year-to-date 2010 Actual	Annual 2010 Plan	Annual 2009 Actual
All Injury Frequency (AIF)	1.39	$\leq$1.0	1.44
Lost Time Injury Frequency (LTIF)	0.38	$\leq$0.5	0.92
Ratio of condition and incident reports to lost time and medical treatment injuries (lead/lag ratio)	358:1	350:1	341:1
Work Permit Code Standardization and Improvement	Completed	-	N/A
Work Methods Standardized	Completed	-	N/A

The fourth quarter of 2010 has seen the continuation and completion of many important safety initiatives launched earlier in the year. Newfoundland and Labrador Hydro (Hydro) has continued to focus on the structural as well as the behavioral side of safety management to ensure that all employees are well equipped to play their part in reducing incidents both in the workplace as well as at home.

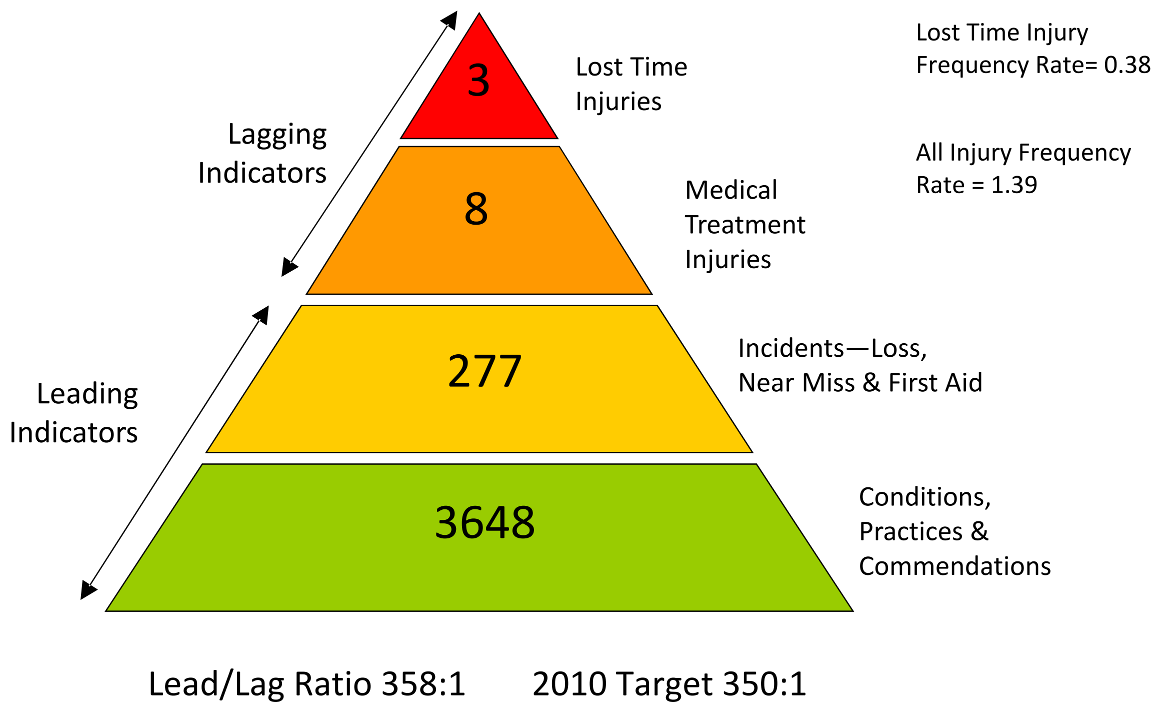
The Work Protection Code and the development of Work Methods continued to be a priority in the fourth quarter. Other standardization programming that was revised included Confined Space, Fall Protection, Electrical Safety and Grounding and Bonding.

Online training programs were finalized which included refresher Work Protection Code training as well as Hazard Recognition, Evaluation and Control. Implementation is scheduled for Q1 2011.

Promotion of the Wellness Works Program continued with broader engagement of regional groups, called Wellness Councils, to develop regional wellness plans that will support the corporate safety and health wellness strategic plan.

These continued efforts contributed to Hydro meeting the criteria for, and the successful completion of, the PRIME audit in 2008 and 2009 as established and conducted by the Workplace, Health, Safety and Compensation Commission.

The following safety triangle summarizes Hydro's year-to-date performance.



2.1 Back it Up Safety Challenge Launched

In November, Hydro launched a Back it Up Safety Challenge to continue to raise awareness of the importance of following safe practices at work and at home. Throughout the month, employees delivered safety presentations to primary and elementary schools across Newfoundland and Labrador talking about various safety topics, from electrical to bike safety.

The Back it Up Safety Challenge was a contest for the public to visit the HydroSafety.ca website to win an iPad. Visitors to the HydroSafety.ca website were asked to upload a picture, video or short essay on their safety moment. The Challenge was advertised through school presentations, mall displays and print advertisements.

2.2 Hydro Encourages Contractors to Work Safely Around Power Lines

Hydro, in cooperation with Newfoundland Power, published a Power Line Hazards safety information pamphlet and vehicle decal. In December, the booklet, decal and letter were mailed by Workplace Health and Safety Compensation Commission (WHSCC) to companies who work around electrical equipment. The information was also posted on Hydro's, Newfoundland Power's and WHSCC's websites. Significant positive feedback has been received from WHSCC and companies who received the booklets and decals. Both utilities have also received requests for additional copies of the material.

2.3 Hydro Educating Children on Electrical Safety

This fall for the third consecutive year, Hydro distributed its children's electrical safety book called "Why my Dad's job is so important" to schools across the province for distribution to grade one students. The company believes everyone has a responsibility for their own safety and health, as well as the safety of others, and one is never too young to learn the importance of electrical safety. Downloadable copies of the book are available at www.nlh.ca/safetybook.

3 ENVIRONMENT AND CONSERVATION

Goal - To be an Environmental Leader

Hydro recognizes its commitment and responsibility to protect the environment.

Measurement	Year-to-date 2010 Actual	Annual 2010 Target	Annual 2009 Actual
Variance from ideal production schedule at Holyrood Thermal Generating Station	9.5%	$\leq$ 14%	9.1%
Achievement of EMS targets[1]	99% of Planned	95%	93%
Annual energy savings from Conservation and Demand Management and internal energy efficiency initiatives	6.7 GWh	>= 5.8 GWh	5.28 GWh
Five year rolling average number of reportable spills	Seven reportable spill incidents; 40% reduction from the five year rolling average	Achieve $\geq$ 20% reduction in the five year rolling average number of reportable spills	N/A
Completion of waste reduction opportunity study	Completed	Reduction in the selected waste streams entering landfills to be identified following study	N/A

[1] An EMS target is an initiative undertaken to improve environmental performance.

3.1 Variance from Ideal Production Schedule at Holyrood Thermal Generating Station

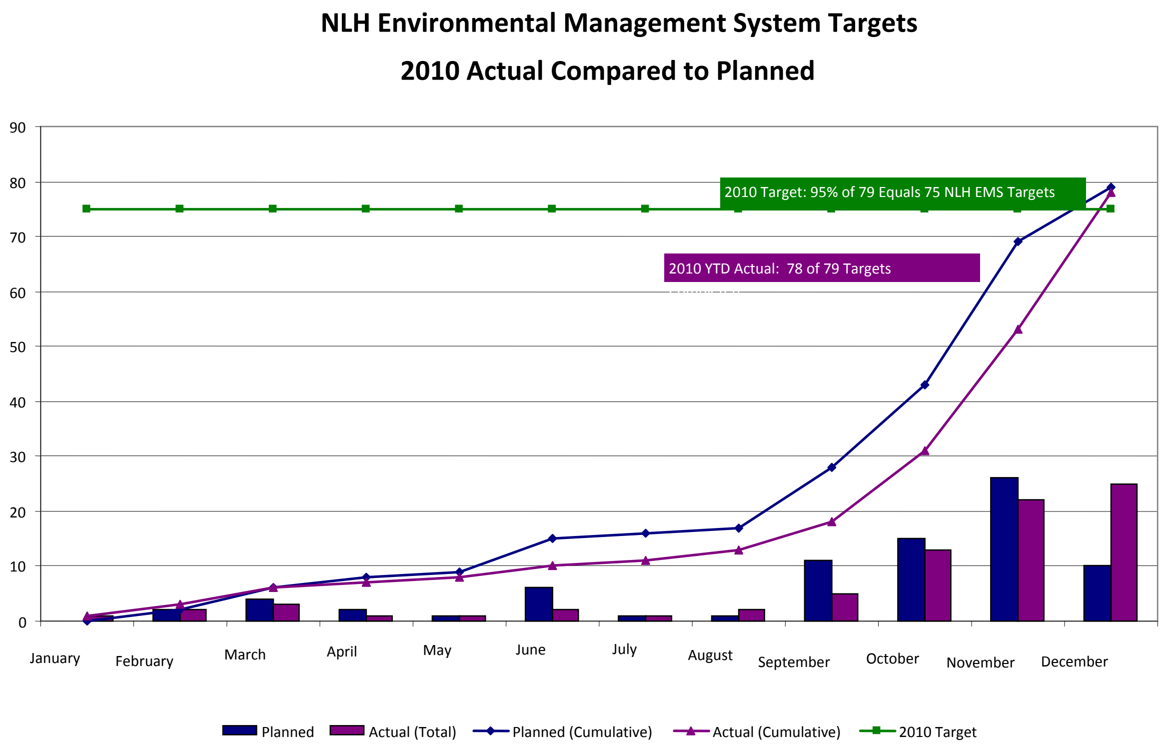
The annual 2010 target of ≤ 14% was achieved.

Minimum Hours						
2010	**Variance[1]**		**Ideal**		**Variance**	
Month	**Unit-Hours**	**Cumulative**	**Unit-Hours**	**Cumulative**	**Percent**	**Cumulative**
January	50	50	2,067	2,067	2.4%	2.4%
February	61	111	1,464	3,531	4.2%	3.1%
March	234	345	1,611	5,142	14.5%	6.7%
April	345	690	938	6,080	36.8%	11.3%
May	6	696	696	6,776	0.9%	10.3%
June	10	706	107	6,883	9.3%	10.3%
July	0	706	0	6,883		10.3%
August	0	706	0	6,883		10.3%
September	18	724	144	7,027	12.5%	10.3%
October	48	772	624	7,651	7.7%	10.1%
November	187	959	1,296	8,947	14.4%	10.7%
December	55	1,014	1,708	10,655	3.2%	9.5%

[1] Variance is the number of hours greater than or less than the ideal. Hours greater than the ideal represent hours of operation that ideally could have been avoided. Hours less than the ideal represent hours of operation where a single contingency could have resulted in a load interruption.

3.2 Achievement of EMS Targets

The annual target of 95% achievement was met, with 78 of the 79 planned initiatives completed.



3.3 Conservation Demand Management (CDM)

3.3.1 Introduction

This section outlines the major activities undertaken in 2010 by Hydro to address energy efficiency opportunities with Hydro's customers and internal facilities.

2010 was the first full year of activity for the new takeCHARGE rebate programs for residential and commercial customers. The joint utility program saw an increase in both participation and community engagement on conservation and efficiency opportunities in general. Hydro also launched the Industrial Energy Efficiency Program (IEEP), providing a customized approach to energy savings for Hydro's industrial customers.

Work has continued with government partners, community groups, individual customers to engage on energy efficiency and to create energy savings, and with those who sell and distribute energy saving technologies to assist in their promotions to the marketplace.

3.3.2 Energy Efficiency Planning and Coordination

Hydro and Newfoundland Power continue to work closely to develop and implement the takeCHARGE program for energy efficiency. There are three rebate programs currently offered provincially to residential customers and one program for commercial customers. These programs offer a prescriptive rebate for eligible technologies. They are:

- Residential
    i. Insulation
    ii. Energy Star Windows
    iii. High Efficiency and Programmable Thermostats
- Commercial
    i. Lighting

Hydro launched two additional programs in 2010 to address the unique nature of Hydro's customer base. The IEEP provides a customized approach to identification of savings opportunities for Hydro's Industrial Customers. This program provides support for opportunity identification through energy audits and feasibility studies as well as capital projects. There are also additional resources available to assist in employee training and awareness on efficiency.

The second program is an "at cash" coupon program offering discounts on smaller technologies including compact fluorescent light bulbs (CFLs), hot water tank wraps and low flow showerheads. Hydro is working with retailers in ten locations throughout its service area to deliver this program with the assistance of an energy efficiency engagement consultant, Summerhill. In addition to the coupons, there are rebates on two Energy Star appliances available to all Hydro customers. This new program is a pilot to determine the interest level in smaller efficiency technologies, explore the challenges of working on an "at cash" program directly with retailers and to determine the applicability of these types of initiatives as a cost effective ongoing component of the takeCHARGE portfolio. The pilot is scheduled to end February 28, 2011.

The continued expansion of the rebate programs has meant a continued effort on training, orientation and efficiency awareness for Hydro employees involved in the direct administration of the rebates as well as those external to the program.

3.3.3 Customer Awareness

As a provincial initiative, takeCHARGE promotions are primarily through mass market media with TV, internet and print campaigns. The program promotes cost savings of the rebated technologies as well as the energy and comfort of having a more efficient home or workspace.

Hydro also participated in ten trade show events across the province, promoting the takeCHARGE brand to residential and commercial audiences.

As takeCHARGE is a joint utility program, mass marketing efforts were focused on getting customers to visit the website for information. With an increasing number of customers online, takeCHARGE has also begun using social media to promote the rebates and community initiatives through facebook. This new approach has created positive discussion among customers on energy efficiency.

3.3.4 Community Outreach

Community based promotions and marketing are critical to creating awareness of the program and providing rebate program detailed information. Hydro participated in a number of community sporting and social events to promote the takeCHARGE program with positive response. In working with local volunteers with the Seniors Resource Centre and Canadian Blood Services, energy efficient products and information has been distributed to a wide geographic area. Engagement of retailers also continues, with training sessions available to assist in keeping floor staff knowledgeable on products and rebates.

As part of Energy Efficiency Week 2010, during the week of October 2 to 8, takeCHARGE launched the takeCHARGE of Your Town Challenge challenging municipalities to find ways to save and win prizes. Participating towns will work to reduce their consumption over a three month period as compared to the same period the previous year. The takeCHARGE team has been working with municipalities to provide suggested ways to encourage conservation in their residents and business owners. With 33 communities in Hydro’s service area signed on to the Challenge, there has been significant effort and awareness created on the many ways to conserve.

3.3.5 Energy Efficiency Programs

Rebates
Rebate activity has been steadily increasing since the launch in 2009. The residential rebate programs that provide home heating savings have shown increases in participation through the home heating season as customers become more aware of heat loss during the cold winter months. The Energy Star Appliance rebate launch was timed to take advantage of Christmas purchases and the limited time nature of the program should encourage uptake. Understanding the purchase patterns in the markets for the technologies involved is critical to ensuring success.

The following table shows Hydro’s rebate activity by month:

Rebate Activity

	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total
Residential													
Insulation	6	3	8	2	5	5	0	2	1	0	3	3	38
Window	2	0	6	2	4	1	6	2	2	2	2	5	34
Thermostat	5	2	5	3	3	4	0	0	0	9	5	9	45
Appliance												4	4
Commercial													
Lighting					9				55			10	74
Total:	13	5	19	7	21	10	6	4	58	11	10	31	195

Internal Energy Efficiency
Hydro continues to take active steps to encourage behaviour change and improve technology and control systems in its own facilities. Installation of variable speed drives, high efficiency lighting, programmable thermostats and other technologies are having energy savings impacts across Hydro's facilities. Employees have been engaged through internal communications efforts promoting tips for home and office energy savings.

Walkthrough energy audits have been conducted at the following facilities:
- Happy Valley, Goose Bay diesel plant and facilities, old warehouse and line shop;
- Port Saunders office building and warehouse; and
- Bishop's Falls office building, warehouse and salvage stores facilities.

These walkthroughs provide the first identification of low and no cost options as well as provide justifications for more formal energy audits and analysis of potential capital projects. Employees have been supportive of the efforts and work has been progressing with retrofits conducted to Hydro Place and planning for other sites.

Additional energy management information has been provided to employees who manage buildings and to the general employee population. Through providing tracking information, promoting activities and training opportunities for designated energy champions in the regions, the network of energy aware employees at Hydro continues to grow.

Partner and Special Projects
Hydro continues to be an active participant in discussions with the provincial government regarding the development of plans and initiatives for energy efficiency and conservation across all sectors. During 2010 Hydro partnered with the Department of Natural Resources to promote the Provincial EnerGuide home energy retrofit program in concert with the takeCHARGE rebates.

3.3.6 Costs

Hydro's 2010 CDM program costs are outlined in the table below.

Hydro's CDM Program Costs 2010 ($000's)

Residential	**2010**
Insulation	60
Windows	48
Thermostat	19
Hydro Customer Coupon Program	140
Subtotal	*267*
Commercial	
Lighting	12
Industrial	221
Total	500

Costs associated with general awareness, planning functions and partnership programs and initiatives that would be incurred regardless of the specific rebate programs currently being offered are shown in the following table of Support Costs.

Hydro's Support Costs 2010 ($000's) 2010	
Education	106
Support	48
Planning	180
Total	334

3.3.7 Energy Savings

Savings for the takeCHARGE rebates has had steady growth. The below table demonstrates the energy savings realized in 2010.

Hydro Energy Savings (MWh) 2010	
takeCHARGE Program Portfolio	
Residential Insulation	84
Residential Windows	27
Residential Thermostat	25
Coupon Program	64
Commercial Lighting	10
Industrial	0
Other Hydro Initiatives[1]	3,777
Total	**3,987**

Hydro Energy Savings (MWh) 2009	
takeCHARGE Program Portfolio	
Residential Insulation	31
Residential Windows	12
Residential Thermostat	6
Commercial Lighting	3
Industrial	0
Other Initiatives	
Hydro existing[2]	1,309
Wrap Up for Savings 2009[3]	38
Coastal Labrador Community Energy Efficiency Pilot Project[4]	987
Outreach and Promotions	339
LED Distribution with Canadian Blood Services	334
Total	**3,059**

[1] Includes savings currently on the system from previous year's activities, as well as outreach activities.
[2] Reflects savings currently being seen on the system from activities that have taken place previous to 2009. For example, previous rebates issued through the Wrap Up for Savings program would create savings for approximately 25 year period, whereas a CFL distribution would create savings for approximately five years.
[3] Wrap Up for Savings was active until June 2009 when it was replaced with the takeCHARGE Energy Savers Residential Insulation program.
[4] Savings are modeled savings from the technologies included in the energy efficiency kits distributed to participating homeowners.

We have surpassed the overall target of 5.8 GWh of savings, with 6.7 GWh of annual savings in place to the end of 2010.

3.3.8 Outlook

2011 will see growth in the residential and commercial rebate program participation and the implementation of the first Industrial Custom Efficiency Program projects. Efforts will continue to strengthen and expand the network of retailers and community groups to further reach customers on a community level.

Hydro will also continue to work with the Department of Natural Resources to promote additional provincial and Federal Government energy efficiency programs.

3.4 Five Year Rolling Average Number of Reportable Spills

The table below identifies the number of reportable spills for Hydro in each year since 2005.

Reportable Spills						
Year	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Number of Reportable Spills	15	8	22	5	9	7

The five year rolling average to 2009 is 12 reportable spills. The seven reportable spills in 2010 represent a 40% reduction from this average.

3.5 Completion of Waste Reduction Opportunity Study

Waste reduction potential is dependent on local area opportunities. Potential initiatives identified for offices in Holyrood, Bishop's Falls and Bay d'Espoir were implemented. Additional initiatives to reduce selected waste streams entering landfills have been identified and will be pursued subject to budgetary approvals in future years.

3.6 takeCHARGE Celebrates Energy Efficiency Week

During Energy Efficiency Week, the takeCHARGE teams went to various areas of the province providing homeowners with hands-on advice and practical tips to make their homes more energy efficient. The takeCHARGE teams also hosted energy efficiency events at building supply stores providing energy efficiency tips and details on the takeCHARGE Energy Savers Rebate Programs. Customers who purchased programmable thermostats at these events doubled their savings and received a $20 rebate per thermostat.

4 OPERATIONAL EXCELLENCE

Goal - Through operational excellence provide exceptional value to all consumers of energy.

Hydro strives to deliver operational excellence by maintaining safe, reliable delivery of power and energy to customers in a cost-effective manner while maintaining high customer satisfaction. The key focus areas are:

- Energy Supply;
- Asset Management; and
- Financial Performance.

REVISED JUNE 2011

Measurement	Year-to-date 2010 Actual	Annual 2010 Target	Annual 2009 Actual
Energy Supply			
Winter Availability[1]	97.87%	≥94.6%	97.7%
Asset Management[2]			
Asset Management System (AMS) Phase II – roles, alignment, plan	Completed as per target	Fill positions, align and educate participants, gap analysis and closure plan – for current state versus future state	Framework and organization completed
Financial Targets			
Annual Controllable Costs	-8.7%[3]	±2% of budget	-2.8%
Net Income	$6.6 million	$6.0 million	$17.2 million

4.1 Energy Supply

4.1.1 Energy Supply - Island Interconnected System

Energy requirements for the Holyrood Thermal Generating Station were low during the fourth quarter, mainly attributable to lower system load requirements and high water levels in the hydroelectric storage system. Individual units were brought into service as required to meet customers' demand and for transmission support for the Avalon Peninsula. Total thermal production was 136.7 GWh lower in 2010 than in 2009, representing a 14.5% decrease.

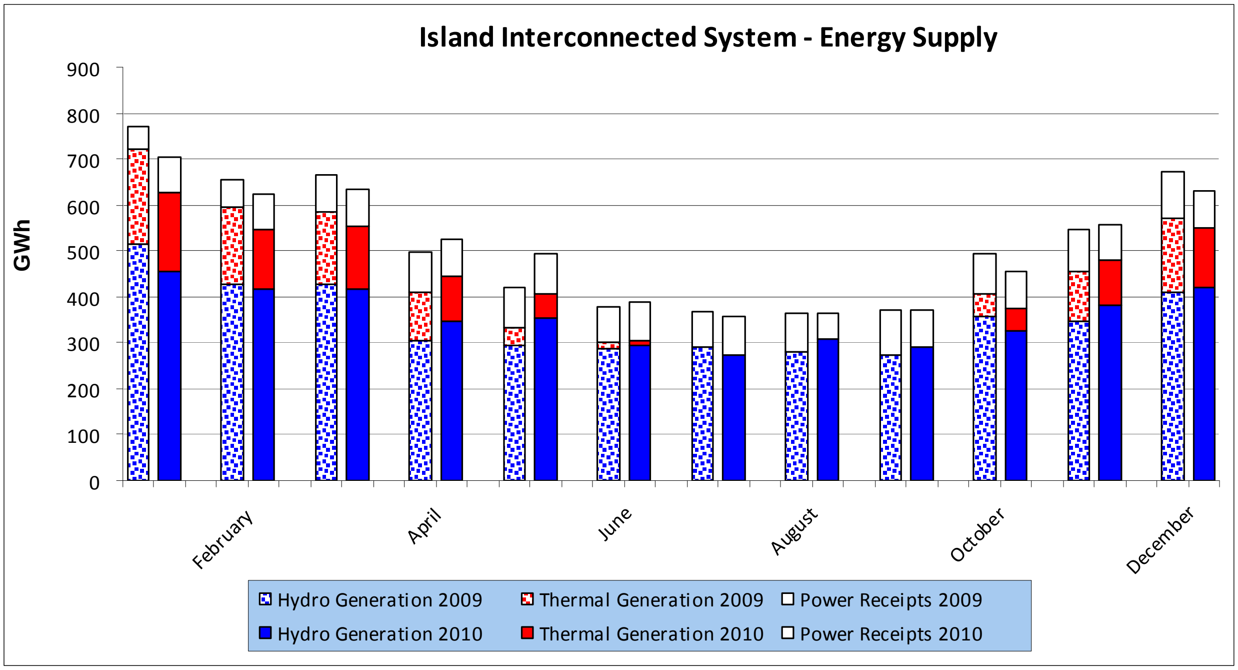
[1] Winter Availability is applicable for the months of January, February, March and December.

[2] The Asset Management framework has been defined and communicated to key individuals and areas of the organization. The organization design has been developed, with a high level of engagement by impacted areas and individuals. Job assignments will be completed in 2010.

[3] Actual 2010 annual controllable costs are favourable from budget by 8.7%. This is mainly attributable to capital labour, boiler overhaul deferral and timing of other expenses.

Annual hydroelectric production was 1.8% above levels in 2009, primarily due to reduced requirements from Holyrood for Avalon transmission support and reduced energy receipts. Total energy receipts were down by 33 GWh or 3.4% in 2010. The decrease was primarily due to decreased generation from the facilities at Exploits and Star Lake. This was offset somewhat by increased generation from the wind farms. The wind operation at Fermeuse did not come into service until April 2009.

The energy supply for the Island Interconnected System is shown in the following charts and tables.



Island Interconnected System Production
For the Year ended December 31, 2010

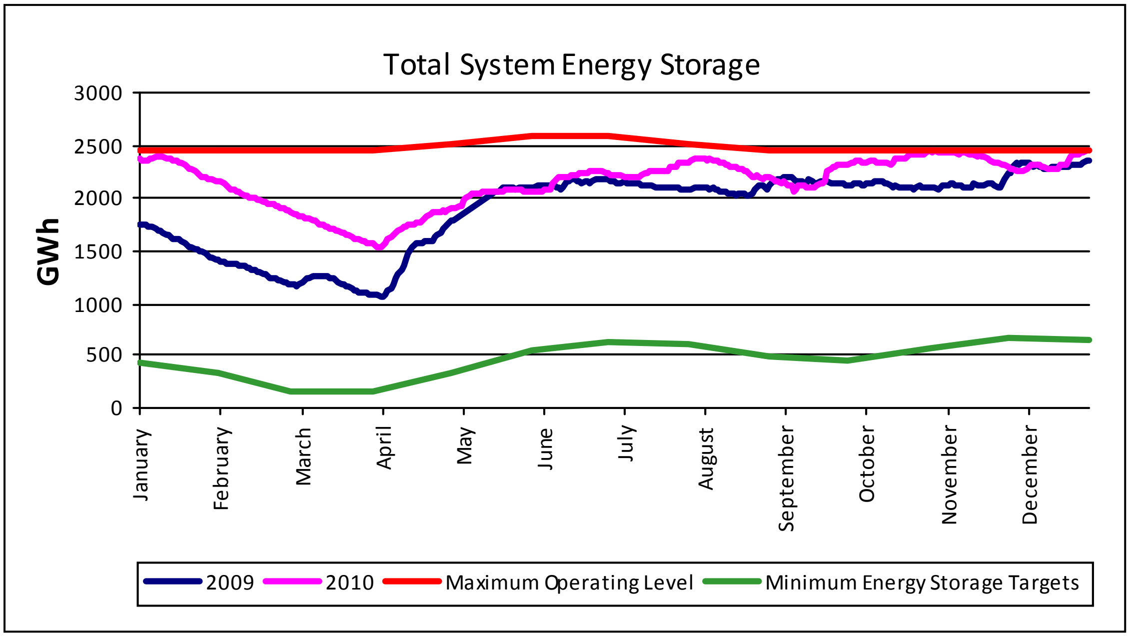
	Year-to-date			Annual Forecast (GWh)	2010 ($ 000)
	2010 (GWh)	2009 (GWh)	Forecast (GWh)		
Production (net)					
Hydro	4,273.8	4,199.5	4,299.8	4,299.8	-
Thermal	803.1	939.8	881.4	881.4	-
Gas Turbines	(10.2)	(7.6)	(6.6)	(6.6)	-
Diesels	(0.4)	(0.3)	(0.2)	(0.2)	-
Total Production	**5,066.3**	**5,131.4**	**5,174.4**	**5,174.3**	**-**
Energy Receipts					
Non Utility Generators					
Rattle Brook	17.4	15.6	16.4	16.4	1,367
Corner Brook Pulp and Paper					
Co-generation	51.5	55.7	54.2	54.2	5,468
St. Lawrence Wind	100.5	100.6	98.0	98.0	7,072
Fermeuse Wind	82.8	53.7	81.2	81.2	6,193
Total Non Utility Generators	**252.2**	**225.6**	**249.8**	**249.8**	**20,101**
Secondary and Others					
Deer Lake Power	4.5	7.0	2.4	2.4	-
Abitibi Consolidated	0.0	7.4	0.0	0.0	-
Hydro Request to NP	0.2	0.5	0.0	0.0	-
Nalcor Energy[1]	691.5	740.9	723.1	723.1	
Total Secondary and Other	**696.2**	**755.8**	**725.5**	**725.5**	**-**
Total Purchases	**948.4**	**981.4**	**975.3**	**975.3**	**20,101**
Island Interconnected Total Produced and Purchased	**6,014.7**	**6,112.8**[2]	**6,149.7**	**6,149.6**	**20,101**

[1] Nalcor Energy includes Star Lake Hydro, Exploits River Project, Grand Falls, Bishop's Falls and Buchans generation.
[2] Metering error in 2009 data.

4.1.2 System Hydrology

Reservoir storage levels continue to be high. Inflows into the aggregate reservoir system were 110.7% of average during the fourth quarter of 2010. Annual inflows were 98.1% of average. Milder temperatures have resulted in lighter system loads and precipitation in late November and December that was primarily rain. This has contributed to an aggregate storage position that was 100% of maximum operating level and 382% of minimum target levels at year end.

There was additional spill at the Cat Arm reservoir during the fourth quarter, representing a lost energy equivalent of 127.7 GWh. Total spill for the year at Cat Arm and the Granite Bypass was 134.6 GWh.



System Hydrology Storage Levels			
	2010 (GWh)	2010 Minimum Target	2009 (GWh)
Quarter End Storage Levels	2,445	640	2,368

4.1.3 Energy Supply – Labrador Interconnected System

The purchased and produced energy on the Labrador Interconnected System is up significantly from 2009 (156.8 GWh or 21.4%) primarily due to the higher industrial sales to the Iron Ore Company of Canada (IOCC) and increased secondary sales to CFB Goose Bay. This has been offset somewhat by decreased Hydro Rural requirements in Labrador east and west.

Labrador Interconnected System Production
For the Year ended December 31, 2010

	Year-to-date			Annual Forecast (GWh)
	2010 (GWh)	2009 (GWh)	Forecast (GWh)	
Production (net)				
Gas Turbines	(1.2)	(1.1)	(0.5)	(0.5)
Diesels	(0.7)	(0.8)	(0.4)	(0.4)
Total Production	**(1.9)**	**(1.9)**	**(0.9)**	**(0.9)**
Purchases				
CF(L)Co for Labrador (at border)	**892.1**	**735.3**	**950.7**	**950.7**
Labrador Interconnected Total Produced and Purchased	**890.2**	**733.4**[1]	**949.8**	**949.8**

4.1.4 Fuel Prices

The fuel market prices for No. 6 fuel increased from approximately $75/bbl at the start of the quarter to just above $82/bbl at the end of the quarter. The quarter ending inventory cost was $79.08/bbl, higher than the current Newfoundland Power fuel price rider of $75.45/bbl. There is no Industrial Customer fuel price rider for 2010.

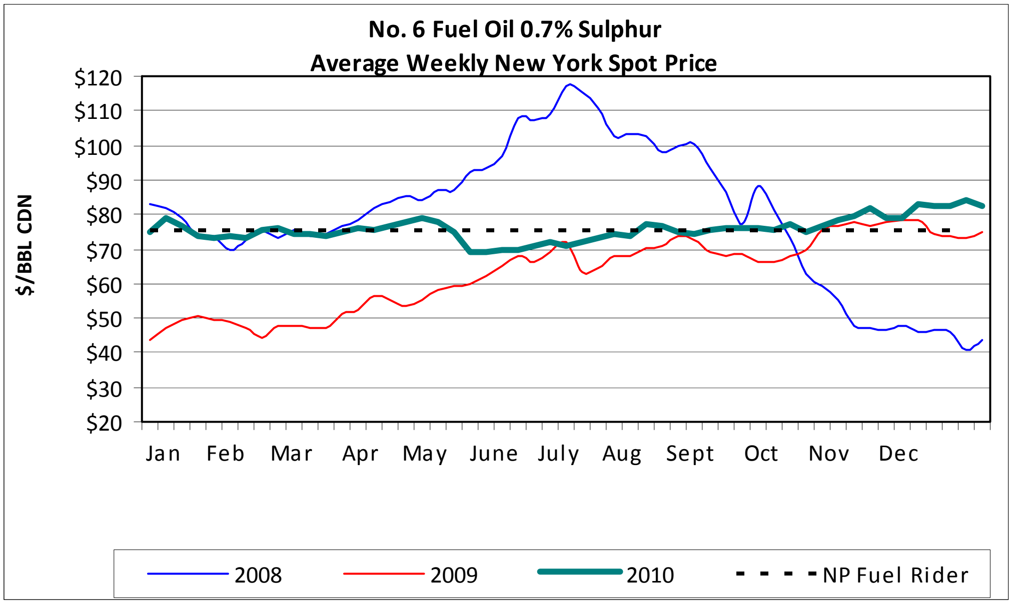
There were two shipments during the fourth quarter of 2010.

November 8	222,528 bbls	$79.82/bbl
December 9	200,603 bbls	$82.90/bbl

The inventory on December 31 was 305,283 barrels.

[1] Metering report error in 2009

The following chart shows the No. 6 fuel prices year-to-date compared to 2008 and 2009, and the Newfoundland Power fuel rider price of $75.45/bbl.



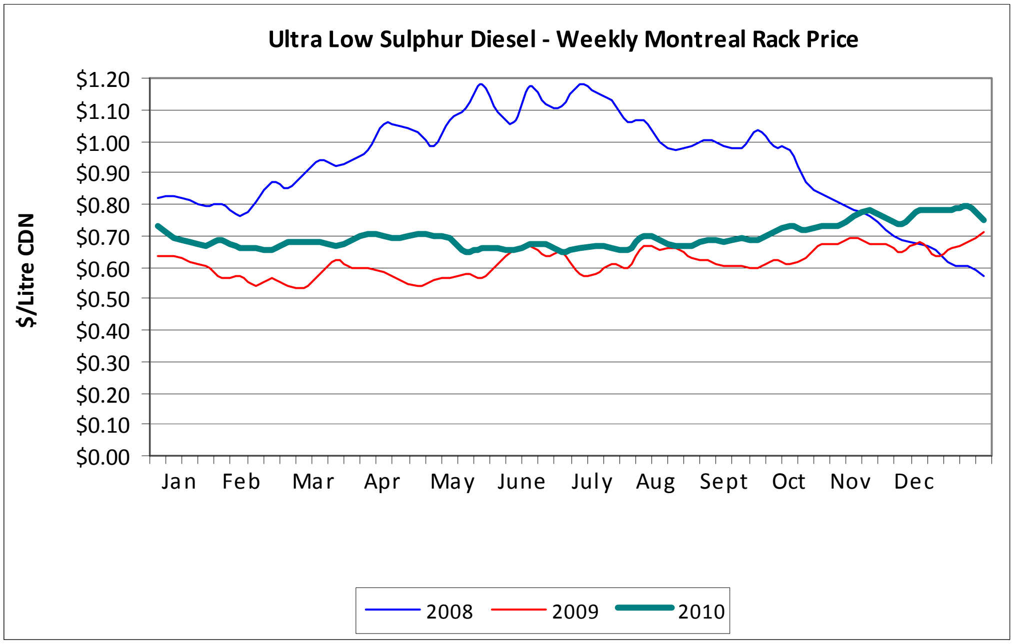
The following table provides the monthly forecast price of No. 6 fuel (0.7% sulphur) up to December 2011, landed on the Avalon Peninsula.

No. 6 Fuel Oil Sulphur
Forecast Price January 2011 – December 2011

Month	Price ($Cdn/bbl) 0.7%	Month	Price ($Cdn/bbl) 0.7%
January 2011	80.30	July 2011	84.30
February 2011	81.40	August 2011	82.60
March 2011	80.30	September 2011	85.20
April 2011	83.00	October 2011	87.60
May 2011	81.30	November 2011	88.20
June 2011	83.60	December 2011	91.30

Note: The forecast is based on the PIRA Energy Group price forecast available December 23, 2010 and an exchange rate forecast by Canadian financial institutions and the Conference Board of Canada.

The following chart shows Low Sulphur Diesel No. 1 fuel prices year-to-date compared to 2008 and 2009.



4.1.5 Energy Supply - Isolated Systems

When compared to 2009, total isolated energy supply for 2010 declined by almost 2%. Supply requirements were forecast to be higher than in 2009, but have been stagnated by milder weather in Hydro's operating areas.

Purchases from Hydro Québec in 2010 have increased by 7% over 2009. This is partly due to purchase curtailments in 2009 and partly due to increased 2010 electricity consumption. In February 2009 purchases from Hydro Québec were curtailed because of low water levels at Lac Robertson. Increased consumption levels on the L'Anse au Loup system are attributed to increased reliance on electricity for heating purposes.

Average cost of power purchased from Hydro Québec, based on Montreal rack fuel prices, has increased from $88 per megawatt hour in 2009 to $100 per megawatt hour in 2010.

Average cost of power purchased from the non-utility generator at Ramea, based on average diesel fuel price, has increased from $0.20 per kilowatt hour in 2009 to $0.23 per kilowatt hour in 2010.

The decrease in diesel production (2.7 GWh) is a reflection of the increase in purchases from Hydro Québec at L'Anse au Loup, milder weather in 2010, and the closure of the crab processing plant in Little Bay Islands. Production in Little Bay Islands has decreased by 0.7 GWh.

Isolated Systems Production For the Year ended December 31, 2010								
	Year-to-date						Annual Forecast (GWh)	\$(000)[1]
	2010 (GWh)	\$(000)[1]	2009 (GWh)	\$(000)[1]	Forecast (GWh)	\$(000)[1]		
Production (net)								
Diesels	44.4		47.1		48.5		48.5	
Purchases								
Non Utility Generators (NUGS)[2]	0.5	114.3	0.5	94.3	0.5	115.1	0.5	115.1
Hydro Québec	20.8	2,091.3	19.4	1,680.2	21.2	2,144.3	21.2	2,144.3
Total Purchases	**21.3**	**2,205.6**	**19.9**	**1,774.5**	**21.7**	**2,259.4**	**21.7**	**2,259.4**
Isolated Systems Total Produced and Purchased	**65.7**	**2,205.6**	**67.0**	**1,774.5**	**70.2**	**2,259.4**	**70.2**	**2,259.4**

4.2 Asset Management

Annual 2010 Target

Develop/complete organization design to support asset management and fill positions; complete planned alignment/education activities; complete current state/desired state by division/unit; develop gap closure plans and determine execution status.

Year-to-date 2010

The design of the organizational structure to support asset management is complete. All specific long term Asset Planning roles have been filled, however a retirement is expected during 2011 and there are some related positions to fill. These positions, when filled, will allow the Asset Planning personnel to dedicate more effort to the asset management strategy, as some are or were serving dual roles at present or for much of 2010. Planned alignment and education activities have occurred, and gap analysis is in progress, with closure plans to be developed. Hydro is pleased with the progress to date, and 2011 activities will enhance the strategy.

4.3 Financial

Financial data for December 31, 2010 will follow when audited Financial Statements become available.

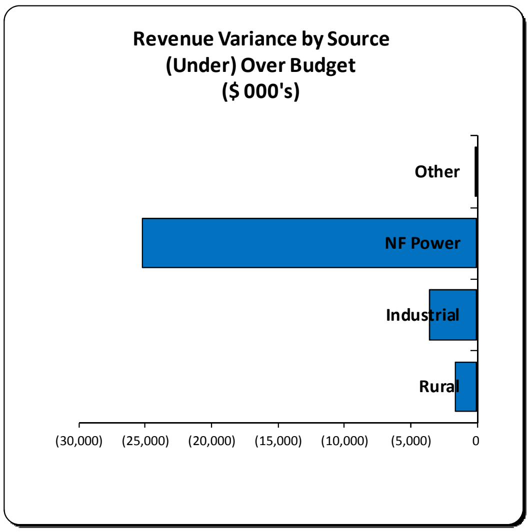
Hydro Regulated Operating Costs
(Chart)

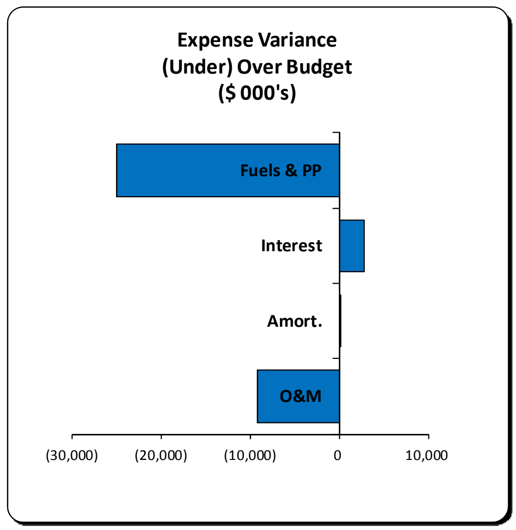
This chart will not be available until the audited Financial Statements become available.

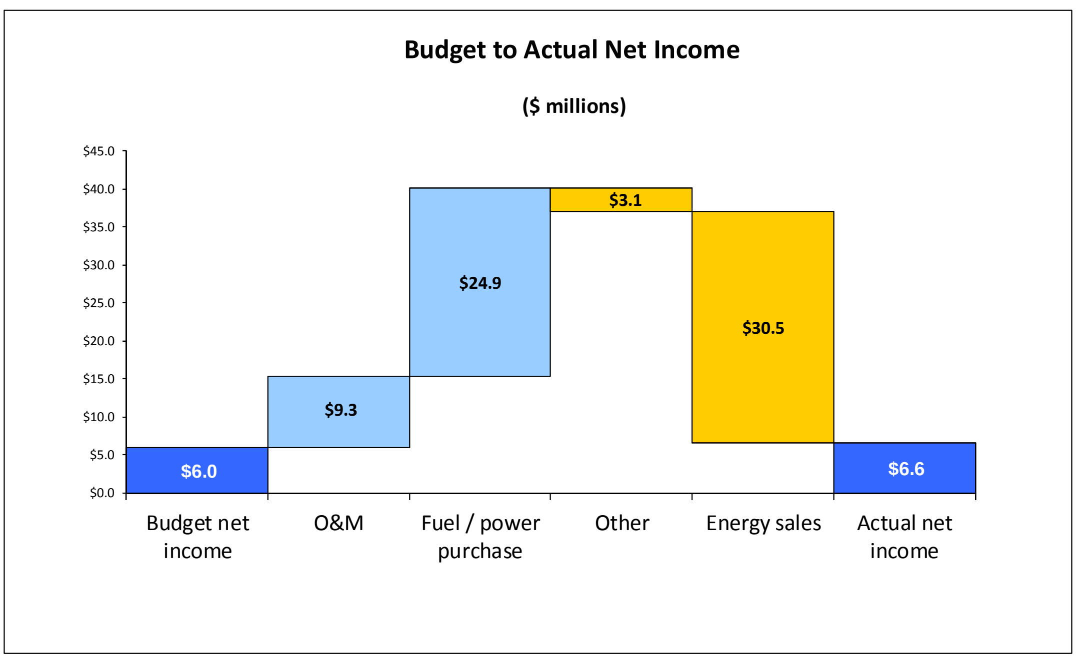
[1] Purchases before taxes.
[2] Ramea wind generation by Frontier Power Systems Inc.

4.3 Financial

Regulated Operations
For the twelve months ended December 31, 2010







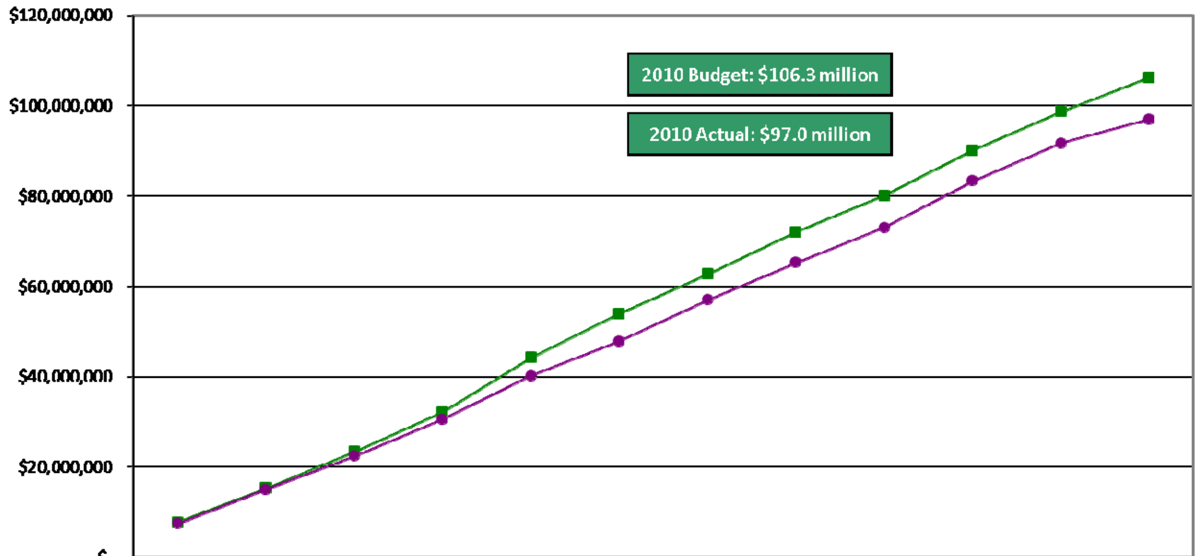
Statement of Income - Regulated Operations
For the twelve months ended December 31, 2010
($ 000's)

Fourth Quarter				Year-to-date		
2010 Actual	2010 Budget	2009 Actual		2010 Actual	2010 Budget	2009 Actual
			Revenue			
112,099	121,665	122,675	Energy sales	414,774	445,253	425,528
585	583	550	Other revenue	2,287	2,332	2,218
112,684	122,248	123,225		417,061	447,585	427,746
			Expenses			
24,000	26,211	28,453	Operations	96,976	106,279	100,369
538	130	918	Loss on disposal of capital assets	687	521	1,267
45,893	50,038	48,937	Fuels	137,994	155,511	136,933
12,469	14,485	13,138	Power purchased	44,244	51,652	46,782
11,299	10,919	10,948	Amortization	43,790	43,757	41,744
21,796	20,621	21,275	Interest	86,766	83,872	83,440
115,995	122,404	123,669		410,457	441,592	410,535
(3,311)	(156)	(444)	**Net income (loss)**	6,604	5,993	17,211

Note: *Certain of the 2009 comparative figures were restated to conform with the 2010 presentation.*

Hydro Regulated Operating Costs

2010 Actual Compared to Budget



	January	February	March	April	May	June	July	August	September	October	November	December
Cumulative Budget	$7,653,762	$15,263,646	$23,330,727	$32,125,585	$44,136,151	$53,392,553	$62,639,041	$71,989,697	$80,057,760	$90,114,176	$98,659,652	$106,279,489
Cumulative Actual	$7,426,299	$14,935,171	$22,394,044	$30,512,490	$40,136,777	$47,790,640	$56,955,439	$65,279,460	$72,975,801	$83,265,671	$91,698,956	$96,975,000

Cumulative Budget — Cumulative Actual

4.4 Maintenance Plan

Hydro is developing a maintenance plan, which is a formal consolidation, validation and documentation of Hydro's established maintenance plans. This includes recommendations for required changes.

2010
<u>Gas Turbines</u>
Work on the manual for Happy Valley gas turbine was delayed due to other priorities. This manual will be finished in 2011.

<u>Holyrood Plant</u>
The manual for the Holyrood plant was completed during the second quarter of 2010 and the maintenance strategies are being implemented.

<u>Other Systems</u>
Maintenance manuals for Hydraulic Structures, Hydraulic Units and Diesel Systems are all complete.

2011
<u>Other Systems</u>
Maintenance review work planned for completion in 2011 is as follows:

Energy Management Systems
Hydraulic Powerhouse Auxiliaries
Terminal Stations and Substations
Distribution Systems
Communications Systems
Corner Brook Frequency Converter

Review teams for each manual have been assigned and targeted completion dates towards the end of the second quarter in 2011 have been set.

<u>Gas Turbines</u>
The manual for Happy Valley gas turbine will be completed by the end of the third quarter in 2011.

4.5 Capital Expenditures

Capital Expenditures for the year ended December 31, 2010 will be reported as a separate document.

4.6 Other

4.6.1 Wind-exposed Transmission Line Gets Capital Upgrade

In mid-October, line and terminal crews from Bishop's Falls, Burgeo and Stephenville and contractors geared up for a major capital project on the transmission line from Doyles to Grand Bay, located in the southwest part of Newfoundland near Port aux Basque.

Capital work on this transmission line has occurred over a five-year period. In 2010, Hydro replaced the guy wires on approximately 60 structures over a 15 kilometre span. This guywire was replaced due to excessive wear resulting from extreme wind exposure which is common in the area. The work included the replacement of all guy wires and associated anchor hardware which keeps the wires in place.

In addition to the guy wire replacement on this transmission line, 11 transmission poles were replaced, as identified in 2009 through Hydro's Wood Pole Line Management Program as needing replacement.

4.6.2 Holyrood Publishes Bi-Annual Community Newsletter

Hydro issued its community newsletter from the Holyrood Generating Station in December. *Generating News*, Hydro's community newsletter from the Holyrood plant, was distributed to Holyrood staff, Community Liaison Committee members, municipalities and over 2,200 area residents. This edition discussed the announcement of the Lower Churchill Project, profiled a President's Award recipient from the Holyrood plant, introduced Holyrood's Environmental Technologist Team and highlighted Hydro's local community investments. The next edition of Generating News will be published in June 2011.

GeneratingNews

A Community Update from the Holyrood Generating Station

Newfoundland and Labrador Hydro — December 2010

Hydro Thanks Dedicated Volunteer

At the end of December 2010, Hydro bids farewell to Calvin Morgan – a dedicated member of the Holyrood Community Liaison Committee (CLC). With Cal's retirement from the Department of Health and Community Services and Eastern Region Health Authority, he will also retire after more than 10 years on the CLC. The Committee has truly benefitted from Cal's dedication and insight during his tenure. Members of the CLC look forward to Cal's replacement from the Department of Health and Community Services who will also bring the same level of dedication and background knowledge of thermal generation.

The Committee also welcomes its newest member – Charles Clarke. Charles was appointed in September 2010 as the youth representative.

Lower Churchill Project Gets Green Light

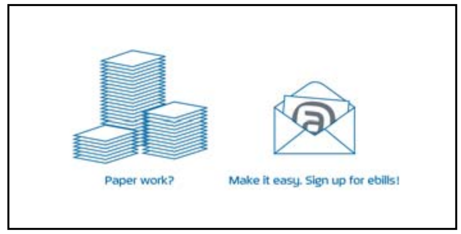
L-R: Danny Williams, Premier of Newfoundland and Labrador; Kathy Dunderdale, Minister of Natural Resources; Ed Martin, President and CEO of Nalcor Energy; Darrell Dexter, Premier of Nova Scotia; Chris Huskilson, Chair and CEO of Emera; Joseph Riche, Grand Chief of the Innu Nation; and Sebastien Benuen, Chief, Sheshatshiu Innu First Nation announce details of the Lower Churchill Project.

4.6.3 Improved Service Features for Customers

This past fall, Hydro replaced its Customer Services Billing and Outage website and customer telephone system. The new site, located under "Outage Information" on the Hydro website, www.nlh.nl.ca, has a more user-friendly interface and is easier to navigate than the previous site. It allows customers to subscribe to outage notifications, and Hydro's customers set up on Automatic Meter Reading technology are now able to view their daily energy consumption for the previous three billing periods.

4.6.4 Ebills Promotion to Encourage Customers to Sign up for Electronic Billing

In October, Hydro launched a six-week contest to encourage customers to sign up for electronic billing (ebills). This was the second contest Hydro ran during 2010 promoting Hydro's new ebilling service which was implemented in April. Hydro will continue to promote ebills to customers on its website, through the customer call centre and bill inserts. During 2010, 675 customers signed up for ebilling.



5 OTHER ITEMS

5.1 *Significant Issues*

5.1.1 Ramea Wind-Hydrogen-Diesel Project Update

Overall Project Site Showing (l-r) the Diesel Plant/Storage Tanks, Meteorological Tower, Hydrogen Electrolyser, 3 Hydrogen Storage Tanks, Distribution Box Structure, 3 Wind Turbines, and Quonset Hut Housing the Hydrogen Genset.

In accordance with Order No. P.U. 31 (2007), the following update is provided on the Wind-Hydrogen-Diesel Project for Ramea.

Implementation and Operation
Commissioning activities resumed during the third week in October 2010. The commissioning phase identified equipment issues requiring troubleshooting before the project could be put in service, such as tank repairs and wind turbine break pad noise. Resolution of the issues is ongoing. Commissioning is planned for completion during the first quarter of 2011. Operations are planned to commence during the second quarter of 2011.

Capital Costs

($000)

Actual Cost to December 2010	Actual Cost Recoveries to December 2010	Net Cost to December 2010	Budget to December 2008	Budget Reforecast to May 2010[1]
11,092	**11,092**	**0**	**8,794**	**2,486**

[1] Project Change Order #3 is under preparation to reflect various cost increases and schedule delays associated with incomplete commissioning activities and equipment problems.

Operating Costs
There is nothing to report for this period as operation is planned to start during the second quarter of 2011.

Reliability and Safety Issues
All activities have been executed with no major safety issues in this period.

5.2 Community

5.2.1 Giving Kids an Energy Boost

Hydro is proud to be a partner with the Kids Eat Smart Foundation (KES), contributing $50,000 over the past ten years. To kick-start Kids Eat Smart Week on October 18, employees from Hydro and Nalcor participated in a province-wide volunteer effort. During the Energy breakfast, employees covering 15 areas of the province whipped up a nutritious, delicious breakfast for hundreds of children at KES Clubs in schools and community centres.

5.2.2 Hydro Launches Capital Fundraising Campaign for Libra House

Libra House is embarking on a major expansion and renovation of its existing emergency crisis shelter for women and children in Happy Valley-Goose Bay. To assist Libra House in this undertaking, Hydro is investing $100,000 over two years to this project.

At the Libra House 25th Anniversary Gala in Happy Valley-Goose Bay on November 13, Hydro announced a capital campaign to raise the remaining $270,000 funding required to complete this expansion project. The donation to Libra House is part of Hydro's commitment to giving back to our communities and the work of Libra House is aligned with Hydro's Community Investment Program's commitment to safety and health.

5.2.3 Nalcor Energy and Hydro Employees Support Charities During the Holidays

Again this year Nalcor and Hydro employees teamed up to support the St. John's Women's Centre, the Labrador Friendship Centre Food Bank and the VOCM Cares Foundation's Happy Tree.

Sixteen families in the St. John's area were supported through the Women's Centre Christmas program through the generous support of Nalcor and Hydro employees who purchased presents worth $4,700 for parents who otherwise would not have been able to afford Christmas gifts for their children. Employees also collected donations for the Labrador Friendship Centre food bank located in Happy Valley-Goose Bay. In addition, a casual day in support of the Happy Tree-VOCM Cares Foundation raised $1,200 plus dozens of Christmas presents for children.

5.2.4 $10,000 Raised for CBS Food Bank

Giving back to communities in Newfoundland and Labrador is a priority for Hydro and we support organizations in the communities where we operate and where our employees work and live. During the CBS Christmas parade on December 11, volunteers from the Holyrood plant and CBS Kinsmen collected food worth $7,000 and $2,000 in aid of the CBS Food Bank. Hydro's Community Investment Program made an additional donation of $1,000.

5.2.5 Investing in Our Youth

Each year, Hydro and its parent company Nalcor Energy, support educational and academic achievements by providing scholarships to students at Memorial University, College of the North Atlantic and to children of Nalcor Energy and Hydro employees and retirees who achieve high academic standings. The scholarship program represents the company's commitment to help the province's youth further their educational studies. In 2010, $40,000 was awarded in scholarships to Newfoundland and Labrador students.

5.2.6 Customers Continue to Give Hydro an 'A+' in Customer Satisfaction

In October, Hydro contracted a research agency to conduct its annual residential customer satisfaction survey. The primary objectives of this research are to assess customer satisfaction with the service provided by Hydro and identify any changes in customer satisfaction over time.

Over the past five years, Hydro has maintained a consistently high rating for overall Residential Customer Satisfaction: 89% (2006 through 2008); 91% (2009) and in 2010 Hydro achieved a 92% rating. Bills that are easy to read and understand, concern for public safety, and friendly and courteous employees were noted as the top three key strengths for customer satisfaction for Hydro in 2010.

5.3 Statement of Energy Sold

Statement of Energy Sold (GWh)
For the Year ended December 31

	YEAR TO DATE			2010*
	2010 ACTUAL	2009 ACTUAL	2010* FORECAST	ANNUAL FORECAST
Island Interconnected				
Newfoundland Power	5,013 [1]	5,111	5,149	5,149
Island Industrials	370 [2]	394	380	380
Rural				
Domestic	227	232	236	236
General Service	143	140	146	146
Streetlighting	3	3	3	3
Sub-total Rural	373	375	385	385
Sub-Total Island Interconnected	5,756	5,880	5,914	5,914
Island Isolated				
Domestic	6	6	6	6
General Service	1	2	2	2
Streetlighting	0	0	0	0
Sub-Total Island Isolated	7	8	8	8
Labrador Interconnected				
Labrador Industrials	303	162	332	332
CFB Goose Bay	56	19	54	54
Hydro Quebec (includes Menihek)	40	373	40	40
Export	1,398	1,187	1,398	1,398
Rural				
Domestic	251	273	273	273
General Service	197	211	212	212
Streetlighting	2	2	2	2
Sub-total Rural	450	486	487	487
Sub-Total Lab. Interconnected	2,247	2,227	2,311	2,311
Labrador Isolated				
Domestic	20	22	22	22
General Service	15	14	14	14
Streetlighting	0	0	0	0
Sub-Total Labrador Isolated	35	36	36	36
L'Anse au Loup				
Domestic	12	12	13	13
General Service	7	7	7	7
Streetlighting	0	0	0	0
Sub-Total L'Anse au Loup	19	19	20	20
Total Energy Sold (Before Rural Accrual)	8,064	8,170	8,289	8,289
Rural Accrual	(1)	-	-	-
Total Energy Sold	8,063	8,170	8,289	8,289
Sales to Non-Regulated Customers**	1,741	1,722	1,770	1,770

* Rural GWh - Based on 2010 Forecast August 31, 2010 (Actuals to August 31)
Non-rural GWh - Based on 2010 Wholesale Industrial Revenue Forecast August 31, 2010 (actuals to August 31)
** Included in Total Energy Sold
[1] Reflects an adjustment on November's bill of -3,215,668 kWhs for June 2009.
[2] Refects an adjustment on Corner Brook Pulp & Paper's December bill of 643,367 kWhs for June 2009.

5.4 Customer Statistics

Customer Statistics
For the Year ended December 31

	FOURTH QUARTER		ANNUAL	
	2010 ACTUAL	2009 ACTUAL	2010 FORECAST	2009 ACTUAL
Customers				
Rural	36,722	36,307	36,039	36,307
Industrial	5	5	5	5
CFB Goose Bay	1	1	1	1
Utility	1	1	1	1
Non-Regulated	3	3	3	3
Reading Days	29.7	29.6	N/A	29.6

APPENDICES

Appendix A - Contributions in Aid of Construction (CIAC)
Appendix B - Damage Claims
Appendix C - Financial
Appendix D - Rate Stabilization Plan Report
Appendix E – 2010 Key Performance Indices Annual Report

CIAC QUARTERLY ACTIVITY REPORT
For the Quarter ended December 31, 2010

TYPE OF SERVICE	CIAC'S QUOTED	CIAC'S OUTSTANDING PREVIOUS QTR.	TOTAL CIAC'S QUOTED	CIAC'S ACCEPTED	CIAC'S EXPIRED	TOTAL CIAC'S OUTSTANDING
Domestic						
Within Plan. Boundary	6	7	13	3	3	7
Outside Plan. Boundary	4	7	11	0	1	10
Sub-total	10	14	24	3	4	17
General Service	12	5	17	5	3	9
Total	22	19	41	8	7	26

The table above summarizes Contribution in Aid of Construction (CIAC) activity for this quarter. The table is divided into three sections, as follows:

- The first section outlines the type of service for which a CIAC has been calculated, either Domestic or General Service.
- The second section indicates the number of CIACs quoted during the quarter as well as the number of CIAC quotes that remained outstanding at the end of the previous quarter. This format facilitates a reconciliation of the total number of CIACs that were active during the quarter.
- The third section provides information as to the disposition of the total CIACs quoted. A CIAC is considered accepted when a customer indicates they wish to proceed with construction of the extension and has agreed to pay any charge that may be applicable. A CIAC is considered outdated after six months has elapsed and the customers have not indicated their intention to proceed with the extension. A quoted CIAC is outstanding if it is neither accepted nor outdated.

CIAC QUARTERLY ACTIVITY REPORT
For the Quarter ended December 31, 2010

CIAC NO.	CIAC AMOUNT ($)	ESTIMATED CONST. COST ($)	ACCEPTED
DOMESTIC - WITHIN RESIDENTIAL PLANNING BOUNDARIES			
791535	$ 500.00	$ 3,350.00	
791157	$ 420.00	$ 2,970.00	Yes
808826	$ 5,063.75	$ 5,813.75	
807217	$ 2,600.00	$ 4,250.00	
813637	$ 350.00	$ 2,000.00	
812358	$ 350.00	$ 1,670.00	
DOMESTIC - OUTSIDE RESIDENTIAL PLANNING BOUNDARIES			
800927	$ 912.50	$ 1,662.50	
803262	$ 13,062.50	$ 14,412.50	
780426	$ 2,130.00	$ 2,880.00	
812167	$ 1,087.50	$ 1,837.50	
GENERAL SERVICE			
807454	$ -	$ 5,445.00	
786203	$ 5,300.00	$ 8,750.00	Yes
799712	$ 5,900.00	$ 8,450.00	
791518	$ -	$ 20,560.50	
808384	$ 2,500.00	$ 9,625.00	Yes
810844	$ 2,550.00	$ 5,100.00	Yes
810016	$ 947.50	$ 9,580.00	Yes
704604	$ 13,599.52	$ 28,992.52	
792284	$ 4,050.00	$ 7,500.00	
801206	$ -	$ 10,755.00	
813149	$ 3,240.00	$ 12,775.00	
801209	$ -	$ 3,600.00	

CUSTOMER PROPERTY DAMAGE CLAIMS REPORT
For the Quarter ended December 31, 2010

Introduction

The Customer Property Damage Claims Report contains an overview of all damage claims activity summarized on a quarterly basis. The information contained in the report is broken down by cause as well as by the operating region where the claims originated.

The report is divided into four sections as follows:

1. The first section indicates the number of claims received during the quarter coupled with claims outstanding from the previous quarter.

2. The second section shows the number of claims for which the Company has accepted responsibility and the amount paid to claimants versus the amount originally claimed.

3. The third section shows the number of claims rejected and the dollar value associated with those claims.

4. The fourth section indicates those claims that remain outstanding at the end of the current quarter and the dollar value associated with such claims.

Definitions of Causes of Damage Claims

1. System Operations: Claims arising from system operations. Examples include normal reclosing or switching.

2. Power Interruptions: Claims arising from interruption of power supply. Examples include all scheduled or unscheduled interruptions.

3. Improper Workmanship: Claims arising from failure of electrical equipment caused by improper workmanship or methods. Examples include improper crimping of connections, insufficient sealing and taping of connections, improper maintenance, inadequate clearance or improper operation of equipment.

4. Weather Related: Claims arising from weather conditions. Examples include wind, rain, ice, lighting or corrosion caused by weather.

5. Equipment Failure: Claims arising from failure of electrical equipment not caused by improper workmanship. Examples include broken neutrals, broken tie wires, transformer failure, insulator failure or broken service wire.

6. Third Party: Claims arising from equipment failure caused by acts of third parties. Examples include motor vehicle accidents and vandalism.

7. Miscellaneous: All claims not related to electrical service.

8. Waiting Investigation: Cause to be determined.

CUSTOMER PROPERTY DAMAGE CLAIMS REPORT - BY CAUSE

For the Quarter ended December 31, 2010

CAUSE	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	AMT. CLAIMED	AMT. PAID	#	AMOUNT	#	AMOUNT
System Operations	2	1	3	0	$ -	$ -	3	$ 3,523.98	0	$ -
Power Interruptions	1	1	2	0	$ -	$ -	0	$ -	2	$ 2,383.76
Improper Workmanship	5	10	15	10	$ 628,561.62	$ 618,713.79	1	$ -	4	$ 7,988.66
Weather Related	2	3	5	0	$ -	$ -	1	$ 3,052.00	4	$ 6,358.55
Equipment Failure	2	3	5	1	$ 700.00	$ 700.00	2	$ 18,051.00	2	$ 1,837.00
Third Party	0	0	0	0	$ -	$ -	0	$ -	0	$ -
Miscellaneous	0	0	0	0	$ -	$ -	0	$ -	0	$ -
Waiting Investigation	3	2	5	0	$ -	$ -	0	$ -	5	$ 6,113.40
Total	15	20	35	11	$ 629,261.62	$ 619,413.79	7	$ 24,626.98	17	$ 24,681.37

For the Quarter ended December 31, 2009

CAUSE	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	AMT. CLAIMED	AMT. PAID	#	AMOUNT	#	AMOUNT
System Operations	2	0	2	0	$ -	$ -	2	$ 23.00	0	$ -
Power Interruptions	3	0	3	0	$ -	$ -	1	$ 950.00	2	$ 700.00
Improper Workmanship	5	1	6	2	$ 4,180.61	$ 4,230.61	0	$ -	3	$ 4,569.83
Weather Related	0	1	1	0	$ -	$ -	0	$ -	1	$ 660.00
Equipment Failure	5	2	7	2	$ 1,115.23	$ 1,115.23	1	$ 38,840.27	5	$ 30,231.79
Third Party	1	0	1	0	$ -	$ -	0	$ -	1	$ -
Miscellaneous	3	0	3	1	$ 180.39	$ 180.39	1	$ 471.19	1	$ -
Waiting Investigation	3	0	3	0	$ -	$ -	0	$ -	3	$ -
Total	22	4	26	5	$ 5,476.23	$ 5,526.23	5	$ 40,284.46	16	$ 36,161.62

CUSTOMER PROPERTY DAMAGE CLAIMS REPORT - BY REGION

For the Quarter ended December 31, 2010

REGION	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	AMT. CLAIMED	AMT. PAID	#	AMOUNT	#	AMOUNT
Central Region	7	3	10	3	$ 3,804.22	$ 3,848.46	1	$ 60.00	6	$ 2,559.51
Northern Region	7	7	14	4	$ 578,443.60	$ 589,841.71	5	$ 24,566.98	5	$ 12,028.55
Labrador Region	1	10	11	4	$ 47,013.80	$ 25,723.62	1	$ -	6	$ 10,093.31
Total	15	20	35	11	$ 629,261.62	$ 619,413.79	7	$ 24,626.98	17	$ 24,681.37

For the Quarter ended December 31, 2009

REGION	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	AMT. CLAIMED	AMT. PAID	#	AMOUNT	#	AMOUNT
Central Region	5	0	5	1	$ 180.39	$ 180.39	0	$ -	4	$ 5,049.82
Northern Region	7	2	9	4	$ 5,295.84	$ 5,345.84	1	$ -	4	$ 18,629.92
Labrador Region	10	2	12	0	$ -	$ -	4	$ 40,284.46	8	$ 12,481.88
Total	22	4	26	5	$ 5,476.23	$ 5,526.23	5	$ 40,284.46	16	$ 36,161.62

FINANCIAL – REGULATED

Balance Sheet - Regulated Operations
As at December 31
($ 000's)

	Dec-10	Dec-09
ASSETS		
Current assets		
Cash and cash equivalents	37,760	10,942
Short-term investments	8,992	20,000
Accounts receivable	61,678	65,703
Current portion of regulatory assets	3,851	4,789
Inventory	53,390	49,964
Prepaid expenses	2,322	1,492
	167,993	152,890
Property, plant, and equipment	1,386,061	1,364,205
Sinking funds	208,381	179,613
Regulatory assets	65,885	69,324
Total assets	1,828,320	1,766,032
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	65,237	51,115
Accrued interest	28,667	28,667
Current portion of long-term debt	8,150	8,150
Current portion of regulatory liabilities	118,849	89,814
Deferred capital contribution	123	165
Due to related parties	37,224	21,441
Promissory notes	(5,521)	(3,531)
	252,729	195,821
Long-term debt	1,136,755	1,141,618
Regulatory liabilities	40,931	32,788
Asset retirement obligations	11,395	-
Employee future benefits	48,348	44,060
Contributed capital	100,000	100,000
Shareholder's equity / retained earnings	212,647	236,943
Accumulated other comprehensive income	25,515	14,802
Total liabilities and shareholder's equity	1,828,320	1,766,032

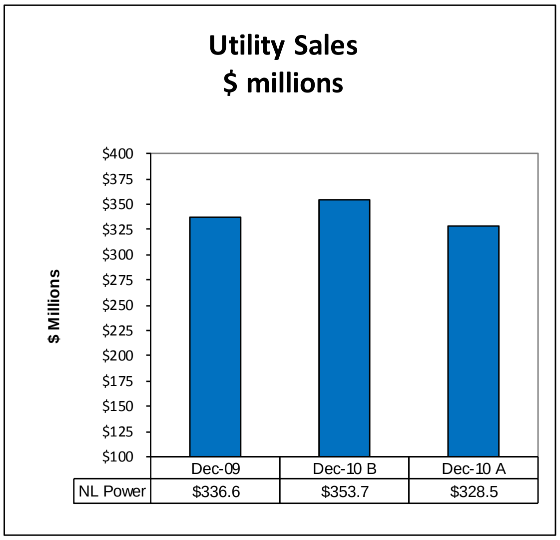
Statement of Retained Earnings - Regulated Operations
For the twelve months ended December 31, 2010
($ 000's)

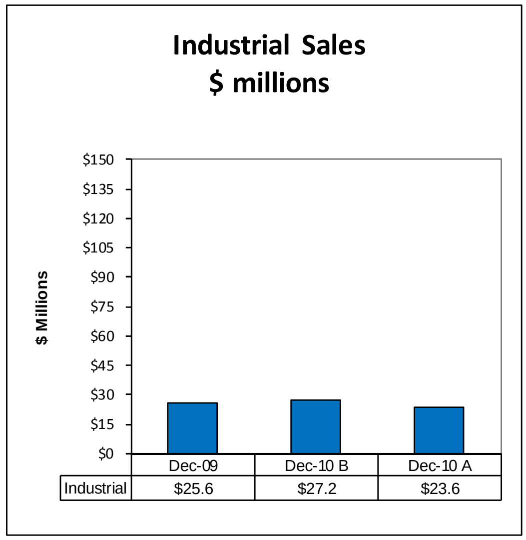
Fourth Quarter 2010 Actual	Fourth Quarter 2009 Actual		Year-to-date 2010 Actual	Year-to-date 2009 Actual
215,958	237,387	Balance, beginning of year	236,943	219,732
(3,311)	(444)	Net income (loss)	6,604	17,211
-	-	Dividends	(30,900)	-
212,647	236,943	Balance, end of year	212,647	236,943

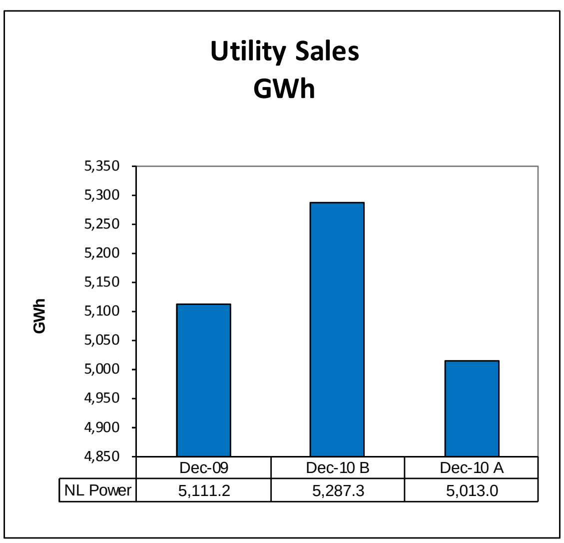
Statement of Comprehensive Income - Regulated Operations
For the twelve months ended December 31, 2010
($ 000's)

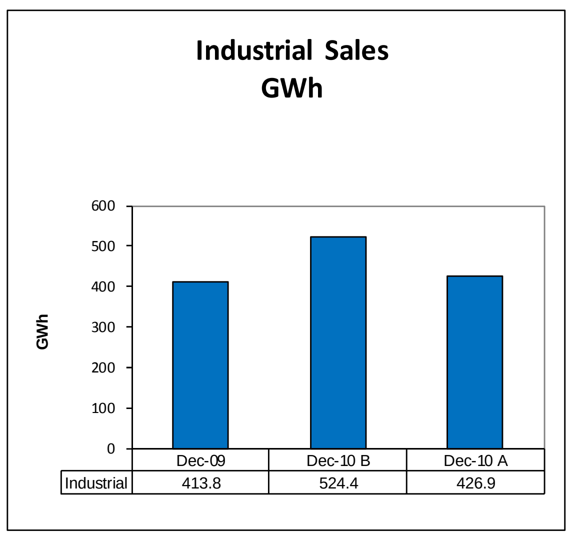
Fourth Quarter 2010 Actual	Fourth Quarter 2010 Budget	Fourth Quarter 2009 Actual		Year-to-date 2010 Actual	Year-to-date 2010 Budget	Year-to-date 2009 Actual
(3,311)	(156)	(444)	Net income (loss)	6,604	5,993	17,211
			Other comprehensive income (loss)			
(1,423)	-	(4,646)	Change in fair value of sinking fund investments	10,713	-	(1,118)
(4,734)	(156)	(5,090)	Total comprehensive income (loss)	17,317	5,993	16,093

Sales - Regulated Operations
For the twelve months ended December 31, 2010









Revenue Summary - Regulated Operations
For the twelve months ended December 31, 2010
($ 000's)

Fourth Quarter 2010 Actual	Fourth Quarter 2010 Budget	Fourth Quarter 2009 Actual		Year-to-date 2010 Actual	Year-to-date 2010 Budget	Year-to-date 2009 Actual
			REVENUE			
			Industrial			
1,260	1,962	1,202	Corner Brook Pulp and Paper Ltd.	5,842	8,037	6,940
-	-	2,705	Abitibi Grand Falls	-	-	3,351
3,018	3,021	2,802	North Atlantic Refinery	10,189	11,999	10,669
1,499	1,200	1,180	C.F.B. Goose Bay	4,025	3,926	1,350
910	841	854	Teck Cominco Limited	3,530	3,205	3,282
6,687	7,024	8,743	**Total Industrial**	23,586	27,167	25,592
			Utility			
89,789	97,524	98,183	Newfoundland Power Inc.	328,492	353,725	336,626
			Rural			
15,623	17,117	15,749	Interconnected and diesel	62,696	64,361	63,310
585	583	550	**Other**	2,287	2,332	2,218
112,684	122,248	123,225	**Total**	417,061	447,585	427,746
			ENERGY SALES (GWh)			
			Industrial			
17.8	36.3	10.7	Corner Brook Pulp and Paper Ltd.	92.8	147.5	97.3
-	-	-	Abitibi Grand Falls	-	-	12.8
64.5	64.2	58.6	North Atlantic Refinery	206.6	254.7	219.6
20.9	17.1	17.0	C.F.B. Goose Bay	56.4	59.7	19.5
18.4	16.7	17.1	Teck Cominco Limited	71.1	62.5	64.6
121.6	134.3	103.4	**Total Industrial**	426.9	524.4	413.8
			Utility			
1,337.6	1,425.1	1,435.2	Newfoundland Power Inc.	5,013.0	5,287.3	5,111.2
			Rural			
214.4	261.6	228.0	Interconnected and diesel	884.2	947.2	925.4
1,673.6	1,821.0	1,766.6	**Total**	6,324.1	6,758.9	6,450.4

Statement of Cash Flows - Regulated Operations
For the twelve months ended December 31, 2010
($ 000's)

	Year-to-date 2010	Year-to-date 2009
Cash provided by (used in)		
Operating activities		
Net income	6,604	17,211
Adjusted for items not involving cash flow		
Amortization	43,790	41,744
Accretion of long-term debt	426	394
Loss on disposal of property, plant and equipment	687	1,267
	51,507	60,616
Changes in non-cash balances		
Accounts receivable	4,025	3,792
Inventory	(3,426)	(6,971)
Prepaid expenses	(830)	(336)
Regulatory assets	4,377	5,513
Regulatory liabilities	37,178	68,732
Accounts payable and accrued liabilities	14,122	4,903
Due to related parties	15,783	20,991
Employee future benefits	4,288	2,179
	127,024	159,419
Financing activities		
Decrease in long-term debt	-	(172)
Decrease in deferred capital contribution	(42)	(305)
Increase in contributed capital	-	100,000
Dividends	(30,900)	-
Decrease in promissory notes	(1,990)	(148,535)
	(32,932)	(49,012)
Investing activities		
Additions to property, plant and equipment	(55,401)	(54,097)
Decrease (increase) in short term investments	11,008	(20,000)
Proceeds on disposal of property, plant and equipment	463	1,229
Increase in sinking funds	(23,344)	(22,040)
	(67,274)	(94,908)
Net increase in cash	26,818	15,499
Cash position, beginning of year	10,942	(4,557)
Cash position, end of year	37,760	10,942

FINANCIAL - NON-REGULATED

Balance Sheet - Non-Regulated Activities
As at December 31
($ 000's)

	Dec-10	Dec-09
ASSETS		
Current assets		
Accounts receivable	5,403	4,001
Derivative assets	1,981	7,045
	7,384	11,046
Long-term receivable	25,407	23,935
Investment in CF(L)Co.	384,265	367,693
Total assets	417,056	402,674
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	1,926	1,834
Promissory notes	5,521	3,531
Derivative liabilities	294	-
	7,741	5,365
Long-term note payable	25,315	23,934
Share capital	22,504	22,504
Lower Churchill Development Corp	15,400	15,400
Retained earnings	344,828	329,226
Accumulated other comprehensive income	1,268	6,245
Total liabilities and shareholder's equity	417,056	402,674

Statement of Income - Non-Regulated Activities
For the twelve months ended December 31, 2010
($ 000's)

Fourth Quarter 2010 Actual	Fourth Quarter 2010 Budget	Fourth Quarter 2009 Actual		Year-to-date 2010 Actual	Year-to-date 2010 Budget	Year-to-date 2009 Actual
			Revenue			
18,023	18,814	14,461	Energy sales	83,068	76,535	60,687
(434)	-	252	Other revenue (loss)	(2,610)	-	743
17,589	18,814	14,713		80,458	76,535	61,430
			Expenses			
6,590	6,165	5,458	Operations	25,494	25,053	19,150
52	-	-	Fuels	68	-	21
886	738	1,086	Power purchased	4,064	3,438	4,226
123	-	67	Interest	476	-	608
7,651	6,903	6,611		30,102	28,491	24,005
9,938	11,911	8,102	Net operating income	50,356	48,044	37,425
4,624	9,326	7,774	Equity in CF(L)Co	16,572	15,960	7,880
3,866	2,400	744	Preferred dividends	10,159	10,100	3,858
8,490	11,726	8,518	Total other revenue	26,731	26,060	11,738
18,428	23,637	16,620	**Net income**	77,087	74,104	49,163

Note: *Certain of the 2009 comparative figures were restated to conform with the 2010 presentation.*

Statement of Retained Earnings - Non-Regulated Activties
For the twelve months ended December 31, 2010
($ 000's)

Fourth Quarter 2010 Actual	Fourth Quarter 2009 Actual		Year-to-date 2010 Actual	Year-to-date 2009 Actual
342,326	320,830	Balance, beginning of year	329,226	324,536
18,428	16,620	Net income	77,087	49,163
(15,926)	(8,224)	Dividends	(61,485)	(44,473)
344,828	329,226	Balance, end of year	344,828	329,226

Statement of Comprehensive Income - Non-Regulated Activities
For the twelve months ended December 31, 2010
($ 000's)

Fourth Quarter 2010 Actual	Fourth Quarter 2010 Budget	Fourth Quarter 2009 Actual		Year-to-date 2010 Actual	Year-to-date 2010 Budget	Year-to-date 2009 Actual
18,428	23,637	16,620	Net income	77,087	74,104	49,163
			Other comprehensive income (loss)			
(959)	-	179	instruments	(4,976)	-	6,245
17,469	23,637	16,799	Total comprehensive income	72,111	74,104	55,408

Statement of Cash Flows - Non-Regulated Activities
For the twelve months ended December 31, 2010
($ 000's)

	Year-to-date 2010	Year-to-date 2009
Cash provided by (used in)		
Operating activities		
Net income	77,087	49,163
Adjusted for items not involving cash flow		
Unrealized loss (gain) on derivatives	381	(800)
Unrealized foreign exchange loss	-	13
Equity in CF(L)Co	(16,572)	(7,880)
	60,896	40,496
Changes in non-cash balances		
Due to related party	-	(3,067)
Accounts payable and accrued liabilities	92	1,834
Accounts receivable	(1,402)	(4,014)
	59,586	35,249
Financing activities		
Increase (decrease) in promissory notes	1,990	(14,465)
(Increase) decrease in long-term receivable	(1,472)	1,481
Increase in long-term note payable	1,381	23,934
Decrease in deferred capital contribution	-	(1,726)
Dividends	(61,485)	(44,473)
	(59,586)	(35,249)
Net change in cash	-	-
Cash position, beginning of year	-	-
Cash position, end of year	-	-

Note: *Certain of the 2009 comparative figures were restated to conform with the 2010 presentation.*

FINANCIAL – SUPPLEMENTARY

Supplementary Schedule - Regulated Operations
For the twelve months ended December 31, 2010
($ 000's)

Fourth Quarter 2010 Actual	Fourth Quarter 2010 Budget	Fourth Quarter 2009 Actual		Year-to-date 2010 Actual	Year-to-date 2010 Budget	Year-to-date 2009 Actual
			Other revenue			
183	183	155	Sundry	612	731	593
388	379	379	Pole attachments	1,573	1,515	1,515
14	21	16	Supplier's discount	102	86	110
585	583	550	**Total other revenue**	2,287	2,332	2,218
			Interest			
25,845	24,756	25,171	Gross interest	101,455	98,602	98,065
109	106	100	Accretion of long-term debt	426	426	393
539	539	545	Amortization of foreign exchange losses	2,157	2,157	2,163
(457)	(730)	(348)	Allowance for funds used during construction	(1,161)	(1,699)	(811)
(4,240)	(4,050)	(4,193)	Interest earned	(16,111)	(15,614)	(16,370)
21,796	20,621	21,275	**Total interest**	86,766	83,872	83,440

Cost Recoveries - Regulated Operations
For the twelve months ended December 31, 2010
($ 000's)

Fourth Quarter 2010 Actual	Fourth Quarter 2010 Budget	Fourth Quarter 2009 Actual		Year-to-date 2010 Actual	Year-to-date 2010 Budget	Year-to-date 2009 Actual
11	1	(2)	Executive Leadership	13	3	6
290	190	83	Human Resources and Organizational Effectiveness	878	760	276
890	643	634	Finance / CFO	2,706	2,572	2,450
32	17	27	Engineeering Services	85	70	54
46	17	12	Regulated Operations	97	67	43
1,269	868	754		3,779	3,472	2,829

Newfoundland and Labrador Hydro
Rate Stabilization Plan
December 31, 2010

Rate Stabilization Plan Report
December 31, 2010

Summary of Key Facts

The Rate Stabilization Plan of Newfoundland and Labrador Hydro (Hydro), as amended by Board Order No. P.U. 40 (2003) and Order No. P.U. 8 (2007), is established for Hydro's utility customer, Newfoundland Power, and Island Industrial customers to smooth rate impacts for variations between actual results and Test Year Cost of Service estimates for:

- Hydraulic production;
- No. 6 fuel cost used at Hydro's Holyrood generating station;
- Customer load (Utility and Island Industrial); and
- Rural rates.

The Test Year Cost of Service Study was approved by Board Order No. P.U. 8 (2007) and is based on projections of events and costs that are forecast to happen during a test year. Finance charges are calculated on the balances using the test year Weighted Average Cost of Capital which is currently 7.529% per annum. Holyrood's operating efficiency is set, for RSP purposes, at 630 kWh/barrel regardless of the actual conversion rate experienced.

	2007 Test Year Cost of Service			
	Net Hydraulic Production	No. 6 Fuel Cost	Utility Load	Industrial Load
	(kWh)	($Can/bbl.)	(kWh)	(kWh)
January	427,100,000	54.17	574,800,000	78,300,000
February	388,680,000	54.73	518,600,000	70,900,000
March	415,080,000	55.46	524,700,000	76,600,000
April	355,520,000	55.46	429,200,000	75,600,000
May	324,240,000	55.46	358,700,000	69,500,000
June	328,500,000	54.49	298,400,000	73,800,000
July	386,790,000	54.49	293,400,000	77,500,000
August	379,140,000	54.49	287,000,000	77,900,000
September	363,560,000	54.49	297,700,000	73,000,000
October	340,510,000	54.56	360,200,000	74,400,000
November	364,390,000	54.56	439,300,000	74,100,000
December	398,560,000	58.98	543,800,000	72,700,000
Total	4,472,070,000		4,925,800,000	894,300,000

Rate Stabilization Plan
Plan Highlights
December 31, 2010

	Actual	Cost of Service	Variance	Year-to-Date Due (To) From customers	Reference
Hydraulic production year-to-date	4,711.0 GWh	4,472.1 GWh	-(238.9) GWh	$ (21,252,231)	Page 4
No 6 fuel cost - Current month	$ 78.87	$ 58.98	$ 19.89	$ 25,111,625	Page 5
Year-to-date customer load - Utility	5,012.9 GWh	4,925.8 GWh	87.1 GWh	$ (273,346)	Page 8
Year-to-date customer load - Industrial	370.3 GWh	894.3 GWh	-(524.0) GWh	$ (26,494,534)	Page 9
				$ (22,908,486)	

Rural rates		
Rural Rate Alteration (RRA) [1]	$ (1,312,329)	
Less : RRA to utility customer	$ (1,169,286)	Page 10
RRA to Labrador interconnected	(143,043)	
Fuel variance to Labrador interconnected	$ 192,156	Page 6
Net Labrador interconnected	$ 49,113	

Current plan summary [2]		
One year recovery		
Due (to) from utility customer [2]	$ (56,238,247)	Page 10
Due (to) from Industrial customers [2]	$ (62,610,998)	Page 11
Sub total	(118,849,245)	
Four year recovery		
Hydraulic balance	$ (40,360,369)	Page 4
Total plan balance	$ (159,209,614)	

[1] Beginning January 2010, the RRA includes a monthly credit of $47,847. This amount relates to the phase in of the application of the credit from secondary energy sales to CFB Goose Bay to the Rural deficit as stated in Section B, Clause 1.3(b) of the approved Rate Stabilization Plan Regulations which received final approval in Order No. P.U. 45 (2009) issued December 21, 2009.

[2] Disposition of the load variation is one of the issues to be considered by the Public Utilities Board in a pending hearing. This may impact the balances owing to customers in the current plan.

Rate Stabilization Plan
Net Hydraulic Production Variation
December 31, 2010

	A	B	C	D	E	F	G
	Cost of Service Net Hydraulic Production (kWh)	Actual Net Hydraulic Production (kWh)	Monthly Net Hydraulic Production Variance (kWh)	Cost of Service No. 6 Fuel Cost ($Can/bbl.)	Net Hydraulic Production Variation ($)	Financing Charges ($)	Cumulative Variation and Financing Charges ($)
			(A - B)		**(C / O[1] X D)**		**(E + F)** **(to page 12)**
Opening balance							(32,561,595) [2]
January	427,100,000	484,303,693	(57,203,693)	54.17	(4,918,610)	(197,567)	(37,677,772)
February	388,680,000	452,586,240	(63,906,240)	54.73	(5,551,728)	(228,610)	(43,458,110)
March	415,080,000	453,058,007	(37,978,007)	55.46	(3,343,270)	(263,682)	(47,065,062)
April	355,520,000	385,699,364	(30,179,364)	55.46	(2,656,742)	(285,567)	(50,007,371)
May	324,240,000	394,615,611	(70,375,611)	55.46	(6,195,288)	(303,420)	(56,506,079)
June	328,500,000	334,152,315	(5,652,315)	54.49	(488,880)	(342,851)	(57,337,810)
July	386,790,000	311,115,568	75,674,432	54.49	6,545,238	(347,897)	(51,140,469)
August	379,140,000	335,159,327	43,980,673	54.49	3,803,979	(310,295)	(47,646,785)
September	363,560,000	328,376,695	35,183,305	54.49	3,043,077	(289,097)	(44,892,805)
October	340,510,000	365,975,438	(25,465,438)	54.56	(2,205,388)	(272,387)	(47,370,580)
November	364,390,000	416,061,428	(51,671,428)	54.56	(4,474,910)	(287,421)	(52,132,911)
December	398,560,000	449,935,325	(51,375,325)	58.98	(4,809,709)	(346,665) [4]	(57,289,285)
	4,472,070,000	4,711,039,011	(238,969,011)		(21,252,231)	(3,475,459)	(57,289,285)
Hydraulic Allocation [3]					13,453,457	3,475,459	16,928,916
Hydraulic variation at year end					(7,798,774)	-	(40,360,369)

(1) O is the Holyrood Operating Efficiency of 630 kWh/barrel.

(2) Opening balance adjusted to reflect a correction in the calculation of 2009 station service load.

(3) At year end 25% of the hydraulic variation balance and 100% of the annual financing charges are allocated to customers.

	(from page 6) 12 month kWh	% of kWh to total	Allocation	Reallocate Rural	**(to pages 11 & 12)** Net
Utility	5,012,937,578	86.6%	14,657,662	1,058,910	15,716,572
Industrial	370,319,827	6.4%	1,082,803		1,082,803
Rural	406,451,869	7.0%	1,188,451	(1,188,451)	-
Total	5,789,709,274	100.0%	16,928,916	(129,541)	16,799,375
Labrador Inteconnected (write-off to income)				129,541	129,541
				-	16,928,916

(4) Hydraulic adjustment for financing charges dating back to 2009

Rate Stabilization Plan
No. 6 Fuel Variation
December 31, 2010

	A	B	C	D	E	F	G
	Actual Quantity No. 6 Fuel (bbl.)	Actual Quantity No. 6 Fuel for Non-Firm Sales (bbl.)	Net Quantity No. 6 Fuel (bbl.) **(A - B)**	Cost of Service No. 6 Fuel Cost ($Can/bbl.)	Actual Average No. 6 Fuel Cost ($Can/bbl.)	Cost Variance ($Can/bbl.) **(E - D)**	No.6 Fuel Variation ($) **(C X F)** **(to page 6)**
January	270,320	30	270,290	54.17	71.99	17.82	4,816,570
February	196,962	3	196,959	54.73	73.45	18.72	3,687,076
March	216,322	24	216,298	55.46	72.92	17.46	3,776,563
April	151,632	1	151,631	55.46	72.41	16.95	2,570,146
May	80,820	2	80,818	55.46	72.41	16.95	1,369,860
June	13,630	0	13,630	54.49	72.41	17.92	244,242
July	0	0	0	54.49	72.41	17.92	0
August	0	0	0	54.49	72.41	17.92	0
September	1,449	1	1,448	54.49	72.50	18.01	26,083
October	75,734	15	75,719	54.56	72.50	17.94	1,358,400
November	150,319	6	150,313	54.56	75.63	21.07	3,167,096
December	205,991	79	205,912	58.98	78.87	19.89	4,095,589
	1,363,179	161	1,363,018	55.47	73.90	18.43	25,111,625

Rate Stabilization Plan
Allocation of Fuel Variance - Year-to-Date
December 31, 2010

	A	B	C	D	E	F	G	H	I	J
	Twelve Months-to-Date				Year-to-Date Fuel Variance				Reallocate Rural Island Customers [1]	
	Utility	Industrial Customers	Rural Island Customers	Total	Utility	Industrial Customers	Rural Island Interconnected	Total	Utility	Labrador Interconnected
	(kWh)	(kWh)	(kWh)	(kWh)	($)	($)	($)	($)	($)	($)
				(A+B+C)	**(A/D X H)**	**(B/D X H)**	**(C/D X H)**		**(G X 89.10%)**	**(G X 10.90%)**
					(to page 7)			**(from page 5)**	**(to page 7)**	
January	5,078,580,595	356,855,371	412,135,791	5,847,571,757	4,183,162	293,937	339,471	4,816,570	302,469	37,002
February	5,070,589,365	332,741,777	411,544,888	5,814,876,030	7,415,205	486,600	601,841	8,503,646	536,240	65,601
March	5,053,421,331	322,048,427	408,158,375	5,783,628,133	10,729,782	683,796	866,631	12,280,209	772,168	94,463
April	5,058,923,607	343,197,465	406,652,834	5,808,773,906	12,933,334	877,398	1,039,623	14,850,355	926,304	113,319
May	5,110,933,100	361,310,432	406,932,886	5,879,176,418	14,100,688	996,829	1,122,698	16,220,215	1,000,324	122,374
June	5,113,821,599	362,751,798	409,914,840	5,886,488,237	14,303,315	1,014,614	1,146,528	16,464,457	1,021,556	124,972
July	5,107,364,735	359,226,221	412,153,276	5,878,744,232	14,304,073	1,006,076	1,154,308	16,464,457	1,028,488	125,820
August	5,112,223,432	357,102,237	411,616,806	5,880,942,475	14,312,329	999,754	1,152,374	16,464,457	1,026,765	125,609
September	5,110,621,482	356,106,545	411,523,784	5,878,251,811	14,337,070	999,003	1,154,467	16,490,540	1,028,630	125,837
October	5,062,021,064	359,343,390	409,636,762	5,831,001,216	15,495,059	1,099,965	1,253,916	17,848,940	1,117,239	136,677
November	5,071,210,553	363,430,112	409,091,903	5,843,732,568	18,237,786	1,307,017	1,471,233	21,016,036	1,310,869	160,364
December	5,012,937,578	370,319,827	406,451,869	5,789,709,274	21,742,544	1,606,183	1,762,898	25,111,625	1,570,742	192,156

(1) The Fuel Variance initially allocated to Rural Island Interconnected is re-allocated between Utility and Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the approved Cost of Service Study, which is 89.10% and 10.90% respectively. The Labrador Interconnected amount is then removed from the plan and written off to net income (loss).

Rate Stabilization Plan
Allocation of Fuel Variance - Monthly
December 31, 2010

	A	B	C	D	E	F	G
	Utility					**Industrial**	
	Fuel Variance		Rural Allocation		Total Fuel Variance	Fuel Variance	
	Year-to-Date Activity	Current Month Activity (1)	Year-to-Date Activity	Current Month Activity (1)	Activity for the month	Year-to-Date Activity	Current Month Activity (1)
	($)	($)	($)	($)	($)	($)	($)
					(B + D)		
	(from page 6)		**(from page 6)**		**(to page 10)**	**(from page 6)**	**(to page 11)**
January	4,183,162	4,183,162	302,469	302,469	4,485,631	293,937	293,937
February	7,415,205	3,232,043	536,240	233,771	3,465,814	486,600	192,663
March	10,729,782	3,314,577	772,168	235,928	3,550,505	683,796	197,196
April	12,933,334	2,203,552	926,304	154,136	2,357,688	877,398	193,602
May	14,100,688	1,167,354	1,000,324	74,020	1,241,374	996,829	119,431
June	14,303,315	202,627	1,021,556	21,232	223,859	1,014,614	17,785
July	14,304,073	758	1,028,488	6,932	7,690	1,006,076	(8,538)
August	14,312,329	8,256	1,026,765	(1,723)	6,533	999,754	(6,322)
September	14,337,070	24,741	1,028,630	1,865	26,606	999,003	(751)
October	15,495,059	1,157,989	1,117,239	88,609	1,246,598	1,099,965	100,962
November	18,237,786	2,742,727	1,310,869	193,630	2,936,357	1,307,017	207,052
December	21,742,544	3,504,758	1,570,742	259,873	3,764,631	1,606,183	299,166
		21,742,544		1,570,742	23,313,286		1,606,183

(1) The current month activity is calculated by subtracting year-to-date activity for the prior month from year-to-date activity for the current month.

Rate Stabilization Plan
Load Variation - Utility
December 31, 2010

	A	B	C	D	E	F	G	H	I	J	K
	Firm Energy						Secondary Energy				
	Cost of Service Sales	Actual Sales	Sales Variance	Cost of Service No. 6 Fuel Cost	Firm Energy Rate	Load Variation	Cost of Service Sales	Actual Sales	Firming Up Charge	Load Variation	Total Load Variation
	(kWh)	(kWh)	(kWh)	($Can/bbl.)	($/kWh)	($)	(kWh)	(kWh)	($/kWh)	($)	($)
			(B - A)			**C x {(D/O[1]) - E}**				**(G - H) x I**	**(F + J)**
											(to page 10)
January	574,800,000	603,546,199	28,746,199	54.17	0.08805	(59,386)	0	0	0.00841	0	(59,386)
February	518,600,000	532,384,820	13,784,820	54.73	0.08805	(16,225)	0	0	0.00841	0	(16,225)
March	524,700,000	534,893,433	10,193,433	55.46	0.08805	(186)	0	0	0.00841	0	(186)
April	429,200,000	427,295,137	(1,904,863)	55.46	0.08805	35	0	0	0.00841	0	35
May	358,700,000	401,920,242	43,220,242	55.46	0.08805	(789)	0	0	0.00841	0	(789)
June	298,400,000	307,201,210	8,801,210	54.49	0.08805	(13,712)	0	0	0.00841	0	(13,712)
July	293,400,000	284,509,525	(8,890,475)	54.49	0.08805	13,851	0	0	0.00841	0	13,851
August	287,000,000	288,189,386	1,189,386	54.49	0.08805	(1,853)	0	0	0.00841	0	(1,853)
September	297,700,000	295,451,337	(2,248,663)	54.49	0.08805	3,503	0	0	0.00841	0	3,503
October	360,200,000	366,350,041	6,150,041	54.56	0.08805	(8,898)	0	0	0.00841	0	(8,898)
November	439,300,000	462,013,050	22,713,050	54.56	0.08805	(32,862)	0	(2,572,300) [2]	0.00841	21,633	(11,229)
December	543,800,000	511,755,498	(32,044,502)	58.98	0.08805	(178,457)	0	0	0.00841	0	(178,457)
	4,925,800,000	5,015,509,878	89,709,878			(294,979)	0	(2,572,300)		21,633	(273,346)

(1) O is the Holyrood Operating Efficiency of 630 kWh/barrel.
(2) Adjustment related to June 2009 sales.

Rate Stabilization Plan
Load Variation - Industrial
December 31, 2010

	A	B	C	D	E	F
	Cost of Service Sales	Actual Sales	Sales Variance	Cost of Service No. 6 Fuel Cost	Firm Energy Rate	Load Variation
	(kWh)	(kWh)	(kWh)	($)	($/kWh)	($)
			(B - A)			**C x {(D/O[1]) - E}**
						(to page 11)
January	78,300,000	22,724,257	(55,575,743)	54.17	0.03676	(2,735,667)
February	70,900,000	18,820,194	(52,079,806)	54.73	0.03676	(2,609,876)
March	76,600,000	30,615,609	(45,984,391)	55.46	0.03676	(2,357,700)
April	75,600,000	39,474,489	(36,125,511)	55.46	0.03676	(1,852,218)
May	69,500,000	38,000,235	(31,499,765)	55.46	0.03676	(1,615,048)
June	73,800,000	31,472,972	(42,327,028)	54.49	0.03676	(2,105,010)
July	77,500,000	27,627,836	(49,872,164)	54.49	0.03676	(2,480,246)
August	77,900,000	31,244,794	(46,655,206)	54.49	0.03676	(2,320,260)
September	73,000,000	29,801,202	(43,198,798)	54.49	0.03676	(2,148,365)
October	74,400,000	33,357,641	(41,042,359)	54.56	0.03676	(2,045,681)
November	74,100,000	30,966,342	(43,133,658)	54.56	0.03676	(2,149,918)
December	72,700,000	36,214,256	(36,485,744)	58.98	0.03676	(2,074,545)
	894,300,000	370,319,827	(523,980,173)			(26,494,534)

(1) O is the Holyrood Operating Efficiency of 630 kWh/barrel.

Rate Stabilization Plan
Summary of Utility Customer
December 31, 2010

	A	B	C	D	E	F	G
	Load Variation	Allocation Fuel Variance	Allocation Rural Rate Alteration [1]	Subtotal Monthly Variances	Financing Charges	Adjustment [2]	Cumulative Net Balance
	($)	($)	($)	($)	($)	($)	($)
				(A + B + C)			
	(from page 8)	**(from page 7)**					**(to page 12)**
Opening Balance							(53,069,391) [3]
January	(59,386)	4,485,631	(30,254)	4,395,991	(321,999)	(265,560)	(49,260,959)
February	(16,225)	3,465,814	(118,286)	3,331,303	(298,891)	(234,249)	(46,462,796)
March	(186)	3,550,505	(105,551)	3,444,768	(281,913)	(235,353)	(43,535,294)
April	35	2,357,688	(91,578)	2,266,145	(264,150)	(188,010)	(41,721,309)
May	(789)	1,241,374	(74,087)	1,166,498	(253,144)	(176,845)	(40,984,800)
June	(13,712)	223,859	(65,017)	145,130	(248,675)	(135,169)	(41,223,514)
July	13,851	7,690	(85,262)	(63,721)	(250,124)	(628,766)	(42,166,125)
August	(1,853)	6,533	(104,543)	(99,863)	(255,843)	(636,899)	(43,158,730)
September	3,503	26,606	(102,366)	(72,257)	(261,866)	(652,947)	(44,145,800)
October	(8,898)	1,246,598	(108,567)	1,129,133	(267,855)	(809,634)	(44,094,156)
November	(11,229)	2,936,357	(125,676)	2,799,452	(267,541)	(998,289)	(42,560,534)
December	(178,457)	3,764,631	(158,099)	3,428,075	(258,236)	(1,130,980)	(40,521,675)
Year to date	(273,346)	23,313,286	(1,169,286)	21,870,654	(3,230,237)	(6,092,701)	12,547,716
Hydraulic allocation **(from page 4)**							(15,716,572)
Total	(273,346)	23,313,286	(1,169,286)	21,870,654	(3,230,237)	(6,092,701)	(56,238,247)

(1) The Rural Rate Alteration is allocated between Utility and Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the approved Cost of Service Study, which is 89.10% and 10.90% respectively. The Labrador Interconnected amount is then removed from the plan and written off to net income (loss).

(2) The RSP adjustment rate for Utility is 0.221 cents per kwh effective July 1, 2010 to June 30, 2011.

(3) Opening balance adjusted to reflect a correction in the calculation of 2009 station service load.

Rate Stabilization Plan
Summary of Industrial Customers
December 31, 2010

	A	B	C	D	E	F
	Load Variation	Allocation Fuel Variance	Subtotal Monthly Variances	Financing Charges	Adjustment [(1)]	Cumulative Net Balance
	($)	($)	($)	($)	($)	($)
			(A + B)			
	(from page 9)	**(from page 7)**				**(to page 12)**
Opening Balance						(36,883,730) [(2)]
January	(2,735,667)	293,937	(2,441,730)	(223,792)	254,640	(39,294,612)
February	(2,609,876)	192,663	(2,417,213)	(238,420)	215,644	(41,734,601)
March	(2,357,700)	197,196	(2,160,504)	(253,225)	314,991	(43,833,339)
April	(1,852,218)	193,602	(1,658,616)	(265,959)	381,585	(45,376,329)
May	(1,615,048)	119,431	(1,495,617)	(275,321)	371,121	(46,776,146)
June	(2,105,010)	17,785	(2,087,225)	(283,814)	316,468	(48,830,717)
July	(2,480,246)	(8,538)	(2,488,784)	(296,280)	283,885	(51,331,896)
August	(2,320,260)	(6,322)	(2,326,582)	(311,456)	314,741	(53,655,193)
September	(2,148,365)	(751)	(2,149,116)	(325,553)	304,263	(55,825,599)
October	(2,045,681)	100,962	(1,944,719)	(338,722)	333,889	(57,775,151)
November	(2,149,918)	207,052	(1,942,866)	(350,551)	316,148	(59,752,420)
December	(2,074,545)	299,166	(1,775,379)	(362,549)	362,153	(61,528,195)
Year to date	(26,494,534)	1,606,183	(24,888,351)	(3,525,642)	3,769,528	(24,644,465)
Hydraulic allocation **(from page 4)**						(1,082,803)
Total	(26,494,534)	1,606,183	(24,888,351)	(3,525,642)	3,769,528	(62,610,998)

(1) The RSP adjustment rate for Industrial Customers excluding Teck Resources is 0.785 cents per kWh effective January 1, 2008. The rate for Teck Resources is 2.000 cents per kWh.

(2) Opening balance adjusted to reflect a correction in the calculation of 2009 station service load.

Rate Stabilization Plan
Overall Summary
December 31, 2010

	A	B	C	D
	Hydraulic Balance ($)	Utility Balance ($)	Industrial Balance ($)	Total To Date ($) **(A + B + C)**
	(from page 4)	**(from page 10)**	**(from page 11)**	
Opening Balance	(32,561,595)	(53,069,391)	(36,883,730)	(122,514,716) [(1)]
January	(37,677,772)	(49,260,959)	(39,294,612)	(126,233,343)
February	(43,458,110)	(46,462,796)	(41,734,601)	(131,655,507)
March	(47,065,062)	(43,535,294)	(43,833,339)	(134,433,695)
April	(50,007,371)	(41,721,309)	(45,376,329)	(137,105,009)
May	(56,506,079)	(40,984,800)	(46,776,146)	(144,267,025)
June	(57,337,810)	(41,223,514)	(48,830,717)	(147,392,041)
July	(51,140,469)	(42,166,125)	(51,331,896)	(144,638,490)
August	(47,646,785)	(43,158,730)	(53,655,193)	(144,460,708)
September	(44,892,805)	(44,145,800)	(55,825,599)	(144,864,204)
October	(47,370,580)	(44,094,156)	(57,775,151)	(149,239,887)
November	(52,132,911)	(42,560,534)	(59,752,420)	(154,445,865)
December	(40,360,369)	(56,238,247)	(62,610,998)	(159,209,614)

(1) Opening balance adjusted to reflect a correction in the calculation of 2009 station service load.

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

2010 ANNUAL REPORT
ON
KEY PERFORMANCE INDICATORS

Pursuant to Order No. P.U. 14 (2004)

NEWFOUNDLAND AND LABRADOR HYDRO

newfoundland labrador hydro
a nalcor energy company

TABLE OF CONTENTS

1 Introduction

In Order No. P.U. 14 (2004), the Board required Hydro to file appropriate historic, current and forecast comparisons of reliability, operating, financial and other Key Performance Indicators (KPIs). These were ordered to be filed with Hydro's annual financial report, commencing in 2004.

In compliance with the above Order, Hydro has 16 individual KPIs within the following four general categories: Reliability; Operating; Financial; and Customer-Related.

Within each of these categories, KPI data is reported on a historic basis for Hydro. Where appropriate, KPIs are subcategorized based on whether they relate to generation, transmission, distribution or overall corporate activity. For most of the Reliability KPIs, data from the Canadian Electricity Association (CEA) is provided in this report, as has been the case in prior years. CEA data has been published only to 2009. CEA data is unavailable for underfrequency load shedding, a reliability KPI, as this measure is unique to Hydro's Island Interconnected System. In the Operating category, the KPIs used to measure performance relate to two specific facilities within Hydro's system: Bay d'Espoir and Holyrood. For these two generation plants, performance is measured and compared on a year-over-year basis.

Section 2 of this report provides an overview of Hydro's KPI performance in 2010 compared with the prior year as well as a comparison of actual KPI results compared with targets. This is followed by a detailed analysis of each individual KPI within the four categories named above in Section 3.

Section 3.3 Financial Performance Indicators are not yet available but will follow after the audited financial statements are available.

Section 4 Data Table of Key Performance Indicators is not available at this time. This section will be filed after the financial data is available and the 2011 target levels have been established.

2 Overview of Key Performance Indicator Results

2.1 Performance in 2010 versus 2009

Hydro faced several challenges in 2010 that impacted unit availability and overall, the Capability Factor was slightly worse than target. There was a decline in hydraulic capability performance in 2010, primarily a result of extended outages to Unit 2 at Bay d'Espoir and the Hinds Lake unit. The capability performance at the Holyrood Generating Station improved in 2010, however, Units 1 and 3 did experience a series of lengthy outages due to burner management issues, fuel pump failures, and a broken turning gear. The performance at Holyrood did not impact on the reliability of supply because of the low production requirements in 2010. This reduced requirement enabled flexibility for the extended maintenance time to complete repairs. Transmission reliability declined over the excellent performance in 2009. Distribution reliability improved slightly in 2010 due to a general reduction in problems in all areas.

The operating KPIs for energy conversion showed a decline in the Holyrood fuel conversion rate. This was driven by lower average load on the operating units in 2010. Holyrood was operated at minimum levels throughout the year, only as required for Avalon transmission and to support system peak loading. Another contributor to the decline in fuel conversion rate is the lower density fuel received in 2010 compared to 2009.

The hydraulic conversion factor improved slightly from 2009, primarily a result of increased operating head on the Bay d'Espoir plant, particularly during the winter months of 2010.

Hydro's 2010 operating and maintenance costs are not available at this time. Financial KPI data will be provided at a later date.

The final category of KPIs called "Customer-Related" deals with Hydro's residential customer satisfaction. Customer satisfaction remains high, improving over previous years.

2.2 Performance in 2010 versus 2010 Target

The table below summarizes Hydro's KPI performance in 2010 compared to targets set for each measure. Targets were met with respect to the frequency and duration of distribution customer outages, duration of transmission events, and generation forced outage rates. Other targets were not met due to a number of challenges further described in this report.

The rationale for the 2010 targets was summarized in the July 2010 report to the Board entitled *2009 Annual Report on Key Performance Indicators*. The 2010 rationale is included in this report as Appendix A.

Hydro's KPI Targets and Operating Results for 2010

Category	KPI	Units	2010 Target	2010 Results	Target Achieved
Reliability	Capability Factor (CF)	%	86.8	85.1	No
	DAFOR	%	3.2	1.8	Yes
	T-SAIDI	Minutes/Point	233.0[1]	173.45[2]	Yes
	T-SAIFI	Number/Point	1.8[1]	2.3	No
	T-SARI	Minutes/Outage	129	75	Yes
	D-SAIDI	Hours/Customer	6.9	6.4	Yes
	D-SAIFI	Number/Customer	4.3	3.5	Yes
	Underfrequency Load Shedding	# of events	6	6	Yes
Operating	Hydraulic CF	GWh/MCM	0.433	0.436	Yes
	Thermal CF	kWh/BBL	630	589	No
Financial	Controllable Unit Cost	$/MWh	Not Available	Not Available	
Other	Customer Satisfaction (Residential)	Max=100%	>90%	92%	Yes

[1] Transmission reliability targets were set on combined planned and unplanned outages.
[2] The transmission reliability indicator shown is for planned and unplanned outages.

3 Performance Indices

The following defines and describes detailed Key Performance Indicator (KPI) data within four general categories: Reliability, Operating, Financial, and Customer-Related.

Note: *Some of the reliability performance outcomes measures for 2009 in this section have changed slightly from the data which was filed in the 2009 KPI Report. The changes were the result of data correction and verification of the 2009 data which occurred after the KPI report was filed. This has been completed for the 2010 data.*

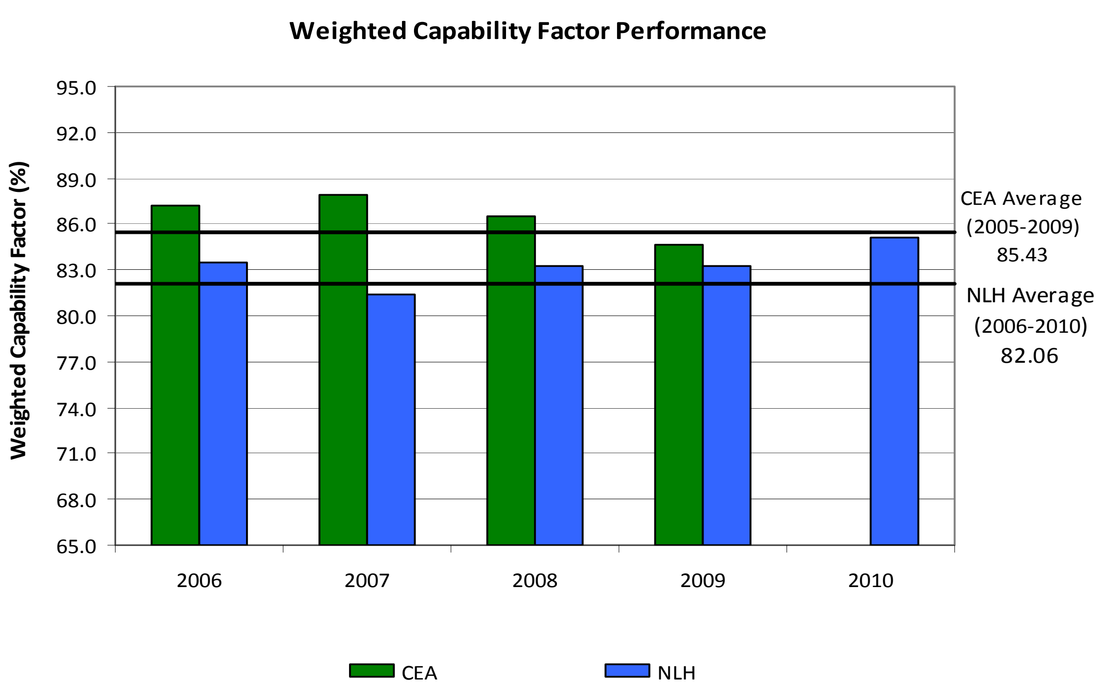
3.1 Reliability Performance Indicators

Hydro monitors reliability performance with eight separate metrics. These metrics have been divided into the following subcategories: Generation, Transmission, Distribution, and Other.

3.1.1 Reliability KPI: Generation

3.1.1 a) Weighted Capability Factor (WCF) – *a reliability KPI for generation assets that includes Hydro's thermal, gas turbine and hydroelectric generation assets on the Island and Labrador Interconnected Systems. The WCF measures the percentage of the time that a unit or a group of units is available to supply power at maximum continuous generating capacity. The factor is weighted to reflect the difference in generating unit sizes, meaning larger units have a greater impact on this measure.*

In 2010, Hydro's WCF was 85.7%, slightly lower than the target of 86.8%.



Thermal unit performance was affected by issues with Holyrood Unit 3, which had a capability factor of 61% in 2010, and somewhat by Holyrood Unit 1 with a 77% capability factor. Holyrood Unit 3 experienced burner management issues and the failure of a main fuel pump. Holyrood Unit 1 experienced a starting failure due to broken turning gear.

Hydraulic performance declined in 2010 over 2009. Bay d'Espoir Unit 2 had a 73% capability factor in 2010 due to an extended outage required for a winding replacement. The Hinds Lake unit also experienced an extended outage for generator maintenance. There were no other major issues with hydraulic generation. Gas turbine performance decreased slightly from the improvement shown in 2009. Each of the Hardwoods and Stephenville gas turbine plants normally has two gas turbine engines operating a single generator. However, one of the engines was removed from Stephenville and installed in Hardwoods in 2007 to replace a failed Hardwoods engine. The Stephenville plant was reduced to a capacity of 25 MW pending the repairs to the failed engine removed from Hardwoods. The Hardwoods plant capacity was reduced to 48 MW in 2007 due to high exhaust gas temperature problems. The Hardwoods unit capacity was increased to 50 MW in November 2010 after a rebuilt engine was installed as a replacement for one end. The Holyrood gas turbine has been shut down since November 2010 by an order of Government Services to cease operation. Other than the gas turbines, all units were available at full capacity at the end of the year. Calculation details for weighted capability as well as a list of factors that may impact KPI performance are in Appendix B of this report.

The table below provides a comparison by unit type along with the weightings applied to the CEA values to provide for the comparison to Hydro for the period 2005-2009. Hydro's hydraulic generation capability was slightly better than the comparable weighted national average. The average is slightly lower for thermal-oil fired units and gas turbines.

Capability Factor Performance

	CEA (2005-2009)	NLH (2005-2009)	Weighting Factor
Hydraulic	91.60	93.37	50%
Thermal - Oil Fired	74.74	60.04	33%
Gas Turbine	88.32	78.69	17%

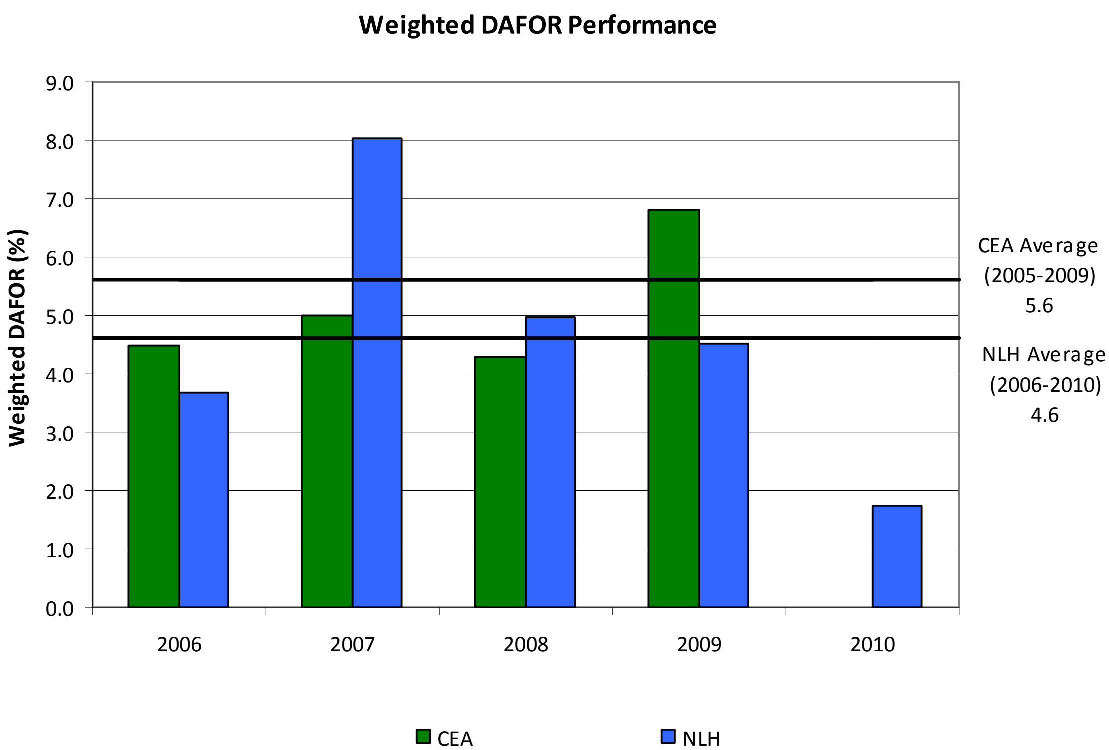
The weighted national average was developed by using national average capabilities values for the unit types in Hydro's system (hydraulic, oil-fired thermal and gas turbine) and applying weightings to these based upon the maximum continuous ratings of Hydro's generation. The quoted CEA value is therefore not a CEA published value but a re-stated value to facilitate a comparison to Hydro.

3.1.1 b) Weighted Derating-Adjusted Forced Outage Rate (DAFOR) - *a reliability KPI for generation assets that includes Hydro's thermal and hydroelectric generation assets on the interconnected systems[3]. DAFOR measures the percentage of the time that a unit or group of units is unable to generate at its Maximum Continuous Rating (MCR) due to forced outages. The KPI is weighted to reflect differences in generating unit sizes.*

In 2010, Hydro's weighted DAFOR was 1.8% versus a target of 3.2%. DAFOR was impacted by the previously identified starting failures on Holyrood Unit 1, miscellaneous equipment issues on Holyrood Unit 2 (cooling water pump, economizer inlet valve, bearing oil leak, boiler stop valve) and previously identified burner management issues on Holyrood Unit 3. Hydro's weighted DAFOR from 2005 to 2009 is better than the equivalently weighted national average for the same period. Hydro's performance has improved in 2010 to 1.8% compared to 2009 DAFOR results of 4.5%. The following table provides a 2005-2009 comparison by unit type:

DAFOR Performance

	CEA (2005-2009)	NLH (2005-2009)	Weighting Factor
Thermal - Oil Fired	10.31	14.43	40%
Hydraulic	2.41	0.75	60%



[3] DAFOR is not applicable to the gas turbines because of the gas turbines' low operating hours.

3.1.1.1 Generation Equipment Performance

The table below highlights the various performance indices for Hydro's generation facilities. Indices for 2009 and for the latest Canadian Electricity Association (CEA) national average for the period 2005-2009 are included for comparison.

Generation Performance Indices

Index		**Hydraulic**	**Thermal**	**Gas Turbine**
Failure Rate	NLH 2010	3.33	6.27	32.94
(Forced Outages per 8760	NLH 2009	3.53	7.07	214.90
operating hours)	CEA '05-'09	2.31	8.91	16.92
Incapability	NLH 2010	8.58	26.98	25.55
Factor	NLH 2009	5.61	38.05	24.14
(Percent of Time)	CEA '05-'09	8.40	25.26	11.49
Derating Adjusted Forced	NLH 2010	0.64	5.07	
Outage Rate	NLH 2009	0.69	13.79	
(Percent of Time)	CEA '05-'09	2.41	10.31	
Utilization	NLH 2010			7.60
Forced Outage	NLH 2009			15.38
Probability (Percent of Time)	CEA '05-'09			23.91

3.1.1.1 (a) Hydraulic Unit Performance

As is shown in the above Generation Performance Indices table, the hydraulic unit failure rate and derating adjusted forced outage rate performance improved slightly in 2010 as compared to 2009. The hydraulic unit derating adjusted forced outage rate continues to be significantly better than the national average. The incapability factor, which deteriorated in 2010, is close to the national average while the failure rate continues to be worse than the national average.

3.1.1.1 (b) Thermal Unit Performance

Thermal unit performance improved in 2010 in all measures with significant improvement in the incapability factor and derating adjusted forced outage rate. The failure rate and derating adjusted forced outage rate are both significantly better than the national average.

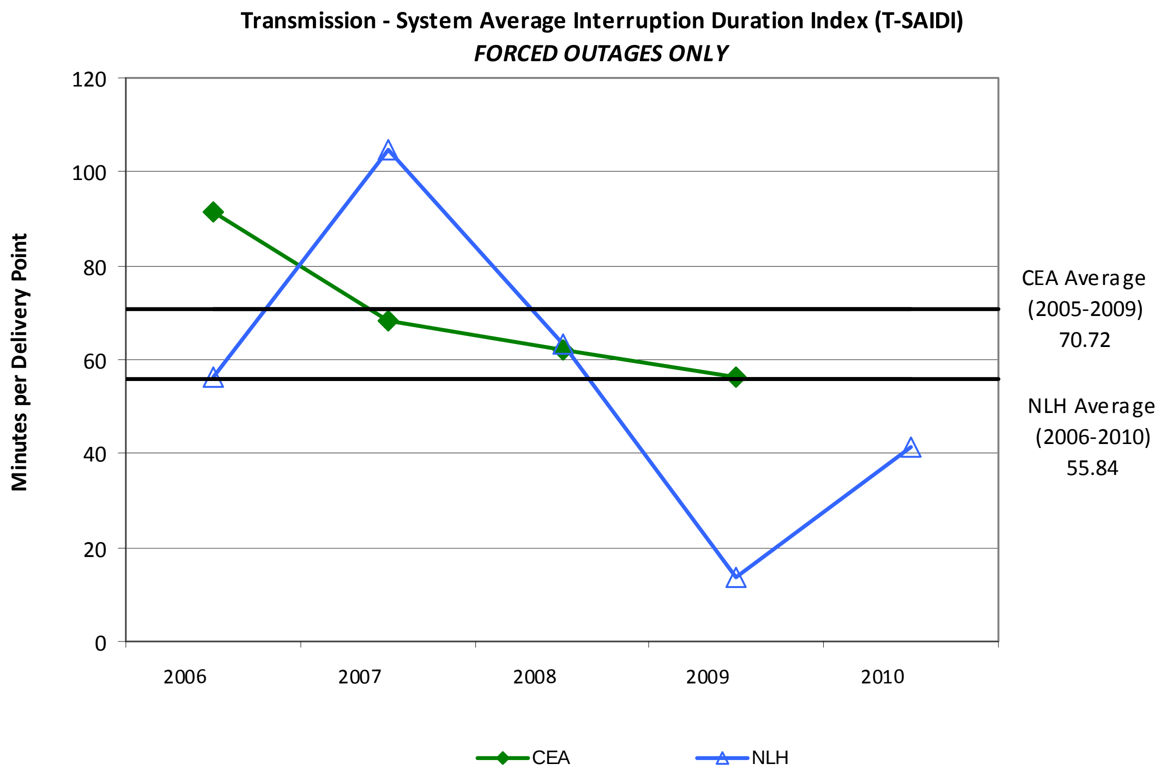
3.1.1.1 (c) Gas Turbine Unit Performance

The Generation Performance Indices table also indicates that Hydro's gas turbines failure rate improved significantly in 2010 from 2009. The incapability factor performance for Hydro's gas turbines declined slightly from the improvement trend in the past few years. Of particular importance to Hydro's use of gas turbines is the utilization forced outage probability (UFOP). The measure describes the degree to which a standby unit can be called upon to supply load when requested. In 2010, the rate improved also significantly and is significantly better than the national average.

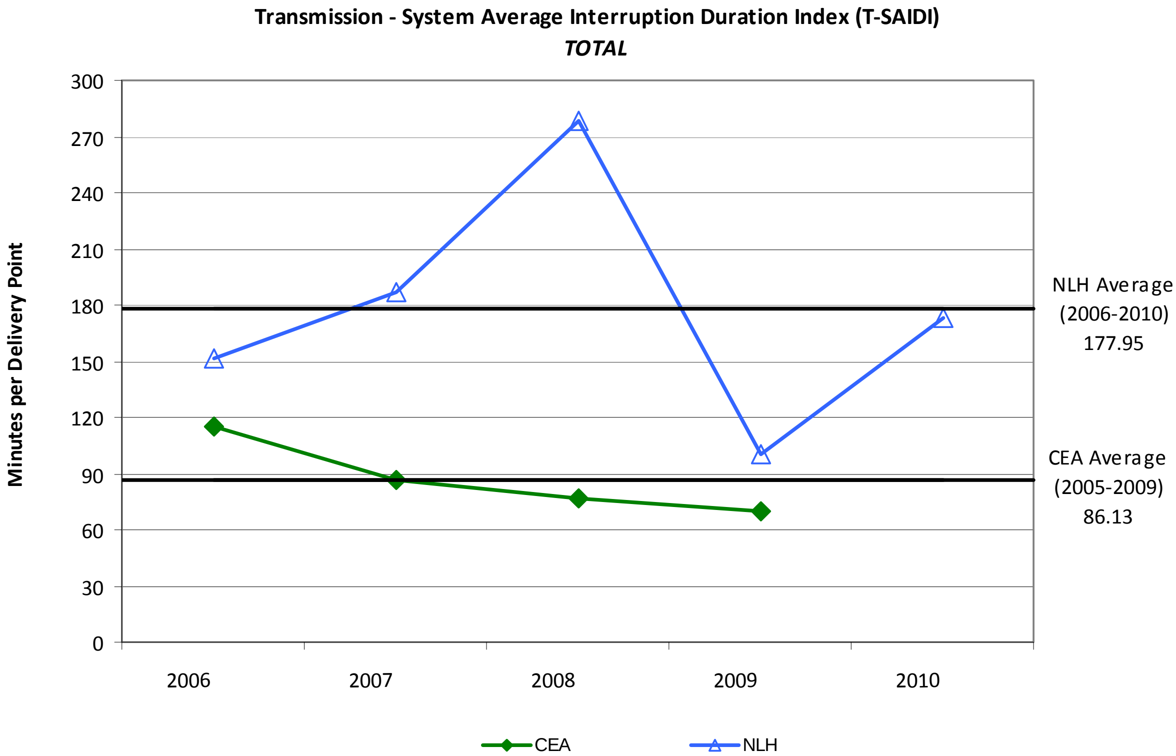
3.1.2 Reliability KPI: Transmission

3.1.2 a) Transmission System Average Interruption Duration Index (T-SAIDI) - *a reliability KPI for bulk transmission assets which measures the average duration of outages in minutes per delivery point.*

The fourth quarter T-SAIDI was 73.2 minutes per delivery point (forced and planned combined). The total 2010 T-SAIDI was 173.45 minutes per delivery point. This contrasts against the 2010 target[4] of 233 minutes per delivery point, and is 26% better than target performance. The 2009 total was 100.29 minutes per delivery point. Forced outage duration in 2010 increased to 41.27 minutes from 13.53 in 2009. Planned outage durations increased by 52% from the previous year's average. Of note is that for the fourth quarter, 99% of the total outage duration was related to planned outages.



[4] "Target" means less than or equal to the value set as a performance outcome.



There were 13 planned outages and two forced outages in the fourth quarter. A summary of the forced and the notable planned outages follows:

<u>Forced</u>

On October 31, all customers served by Parson's Pond, Daniel's Harbour, Hawke's Bay, Plum Point and Bear Cove Terminal Stations experienced an outage of one minute. Customers served by the Main Brook, Roddickton and St. Anthony Diesel Plant Terminal Station experienced an outage of two minutes. The outages were caused by an inadvertent operation of the breaker B1L59 at Berry Hill Terminal Station while removing an electronic hold off caution tag from TL-259 at the Energy Control Centre in St. John's.

On December 15, Newfoundland Power customers supplied by transmission line TL-215 in the Port aux Basques area experienced a power outage of one minute. The outage was caused by salt contamination on TL-215 due to very high winds in the area.

<u>Planned</u>

Customers served by Parson's Pond Terminal Station experienced a planned outage of four hours and ten minutes on October 17. The outage was required to perform emergency welding and repairs on the main power transformer T1.

On October 24, all customers supplied by the Bottom Waters Terminal Station experienced a planned power outage of five hours and 34 minutes. The outage was required for Newfoundland Power to perform maintenance on their main transmission line to the area, 363L, and Hydro's crews to work on circuit switcher L60T1 at the Bottom Waters Station.

There were three planned outages that affected customers supplied by the Bay d'Espoir 69 kV Terminal Station, in the towns of St. Alban's, Milltown, and Conne River, all towns in the English Harbour West Distribution system, and all towns in the Barachoix Distribution system. The outages were required to install the mobile substation to bypass transformer T11 at Bay d'Espoir. This transformer required radiator replacements. The first planned outage occurred on November 3 for four hours and 34 minutes. This outage was cancelled before the switching was completed due to safety issues with the switching arrangements. On November 4, another planned outage occurred to install the mobile substation. This outage had a duration of five hours. The third planned outage occurred on December 3, with a duration of three hours and 44 minutes. The mobile substation was removed and transformer T11 was restored at this time.

Newfoundland Power customers supplied by the Buchans Terminal Station experienced a planned power outage of two hours and 38 minutes on December 5. The outage was required to investigate a problem with a potential transformer in the revenue metering circuit on Buchans Bus B3.

The other planned outages during the fourth quarter had outage durations of less than 30 minutes.

As previously reported, Hydro's planned outage durations tend to be longer than the national average. This is due to the relatively high number of delivery points on the Hydro system that do not have alternative supply options such as multiple station transformers or greater distribution system integration. This was a contributing factor to the planned outages on the GNP where station maintenance required customer outages for which there is no alternate supply point or local generation.

The following is a listing of all 2010 transmission significant events. Significant events are indentified as those resulting in forced outages with an unsupplied energy of greater than 1,000 MW-mins. Unsupplied energy is a calculation of the outage duration times the load, in MW, at the delivery point before it was interrupted. This measures the energy that could have been supplied if the delivery had not been interrupted. These events are:

- On March 7 at 16:47 hours customers served by the Bottom Waters Terminal Station experienced an outage of 785 minutes (13 hours and five minutes). A line patrol of TL-260 observed that the total length of TL-260 was covered in ice. The most likely cause of the trip was ice bridging that formed between the ground wire on the crossarm to the line end of the insulators, resulting in a short to ground. The line was restored with no further action required. **Forced Outage: 3,140 MW-Mins**

- On September 7 at 13:49 hours, all Newfoundland Power customers supplied from the Stephenville Terminal Station in the towns of Stephenville, Stephenville Crossing, St. George's and Robinson's areas and all towns on the Port Au Port Peninsula experienced a power outage of 334 minutes. The outage was caused by the failure of two bus support insulators on the 66 kV bus at the Stephenville Terminal Station. The failure of these two support insulators and damage to a third resulted in the overhead bus falling to ground. Initial investigation has determined that the support insulator failures were related to a heavy build up of salt contamination caused by Post-Tropical Storm Earl. This storm passed through the area on September 5 and the high winds continued on September 6 and 7. Transmission line 400L also failed due to damaged insulators as a result of salt contamination caused by the storm. Work crews repaired the damage and restored all customers at 19:23 hours. **Forced Outage: 6,513 MW-Mins**

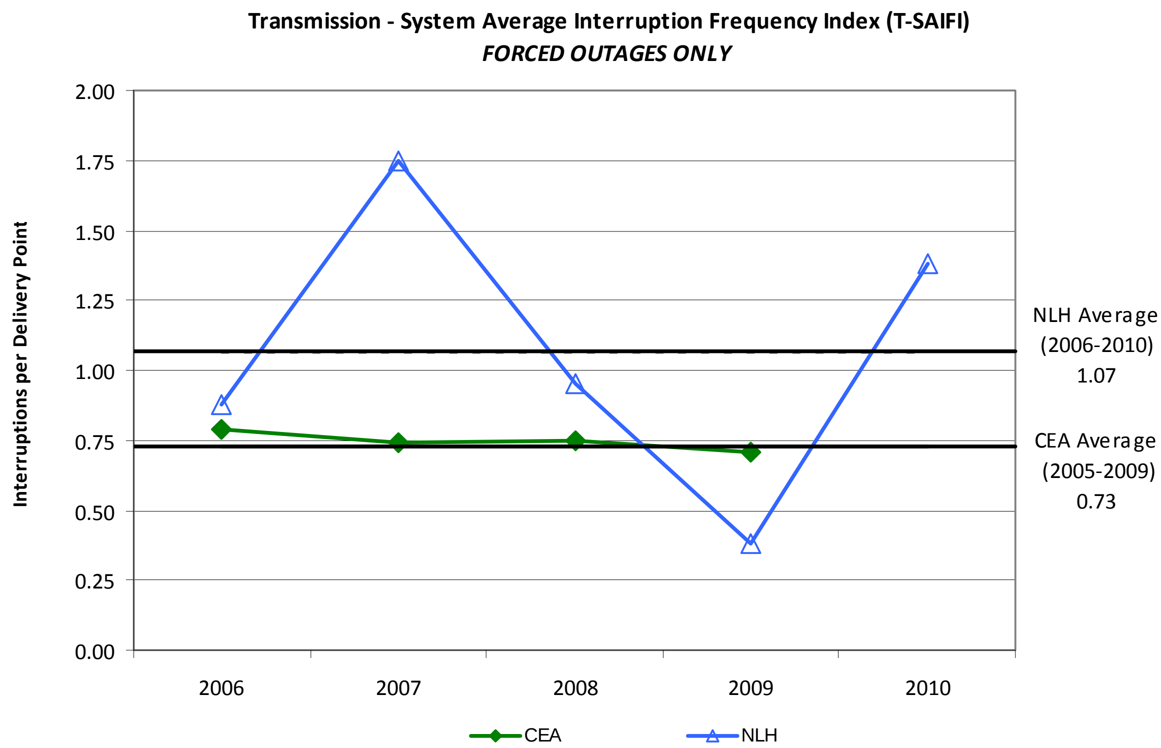
- On September 26 at 09:37 hours customers supplied by the Happy Valley Terminal Station experienced an outage ranging from 170 to 188 minutes. Transmission line L1301 was out of service for maintenance and the gas turbine was being used to supply customers. A problem with the fuel system caused the gas turbine to trip. Customers were restored after L1301 work was completed and the line restored. **Forced Outage: 3,622 MW-Mins**

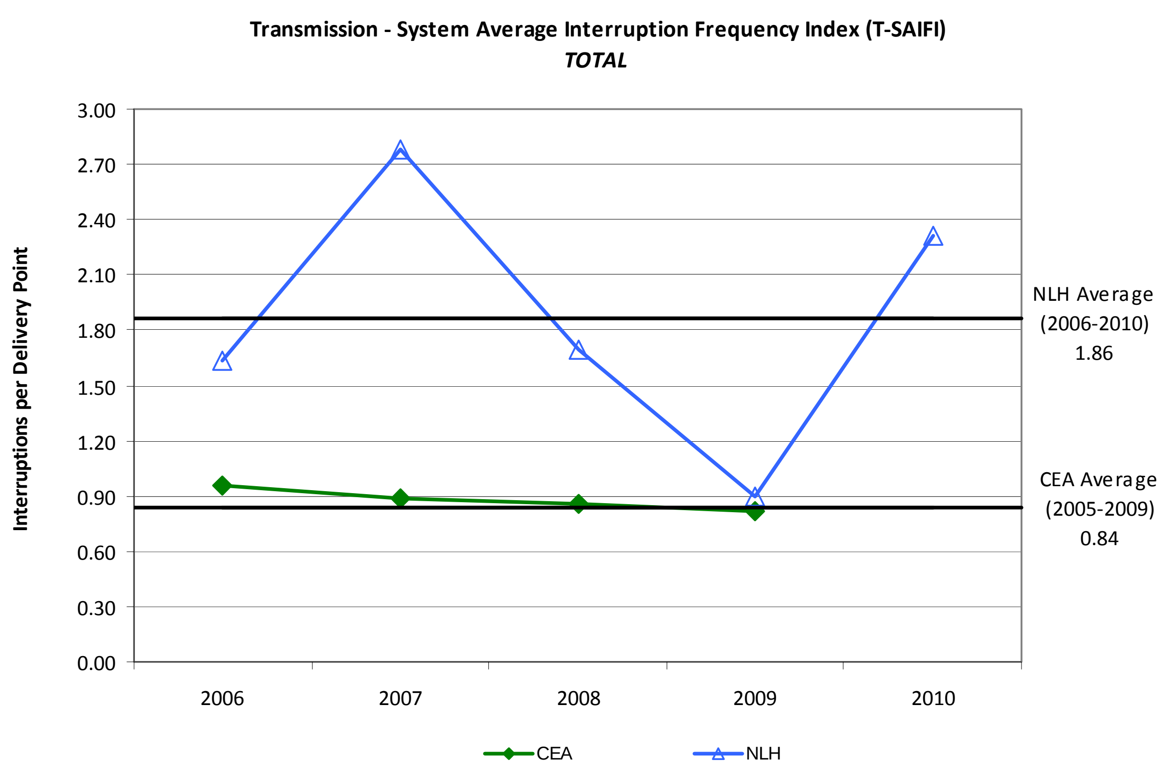
3.1.2 b) Transmission System Average Interruption Frequency Index (T-SAIFI) - *a reliability KPI for bulk transmission assets that measures the average number of sustained outages per delivery point*.

The fourth quarter T-SAIFI was 0.59 outages per bulk delivery point. The breakdown between forced and planned outages frequency was split as follows: 0.16 for forced and 0.43 for planned. The 2009 fourth quarter T-SAIFI was 0.45 outages per bulk delivery point. Forced outages frequency increased 14% and planned outages frequency increased 39% from the fourth quarter of 2009. The forced outage rate was lower than the planned outage rate. In 2009 the split was very similar between forced and planned outages. Overall the increase in outage frequency was the result of planned outages on the 66 kV transmission system.

The overall 2010 T-SAIFI was 2.30 outages per bulk delivery point which is significantly higher than last year's average of 0.90 outages per delivery point, an increase of 155%. This increase can be attributed to a significant increase in outage frequency in all areas. The 2010 target was 1.76 outages per bulk delivery point. The 2010 outcome was 30% above target. This is the result of an increase in short duration outages due to weather conditions, including high winds, salt contamination, and lightning. The number of forced outages per delivery point increased significantly from the 2009 level by 253% to 1.38 in 2010. The planned outages per delivery point increased by 79% to 0.93 in 2010.

The frequency of Hydro's forced delivery point outages has been generally higher than the national average. This result is expected and can generally be attributed to the number of delivery points that are supplied by a single transmission line. The most severe example is on the Great Northern Peninsula, where one line, TL-239, supplies up to nine delivery points. There are a number of other locations where a single line supplies three delivery points.


Transmission - System Average Interruption Frequency Index (T-SAIFI)
FORCED OUTAGES ONLY
Interruptions per Delivery Point
2.00
1.75
1.50
1.25
1.00
0.75
0.50
0.25
0.00
2006
2007
2008
2009
2010
NLH Average (2006-2010) 1.07
CEA Average (2005-2009) 0.73
CEA
NLH

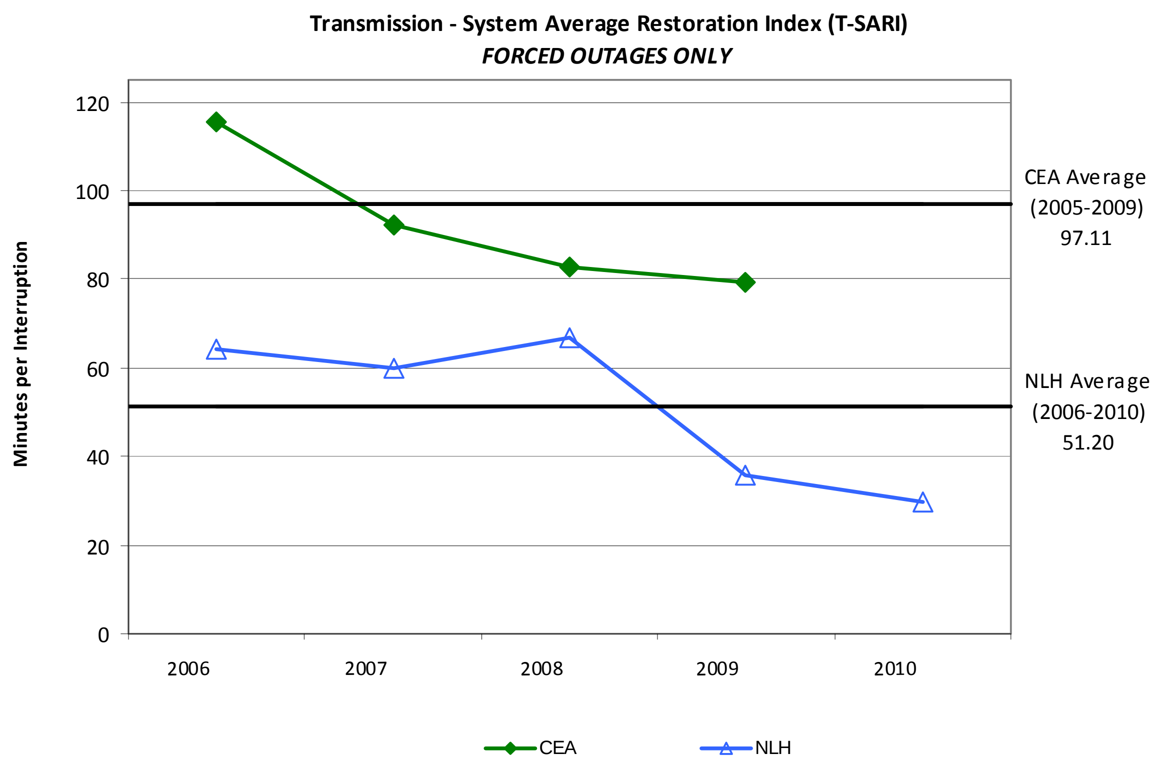

Transmission - System Average Interruption Frequency Index (T-SAIFI)
TOTAL
Interruptions per Delivery Point
3.00
2.70
2.40
2.10
1.80
1.50
1.20
0.90
0.60
0.30
0.00
2006
2007
2008
2009
2010
NLH Average (2006-2010) 1.86
CEA Average (2005-2009) 0.84
CEA
NLH

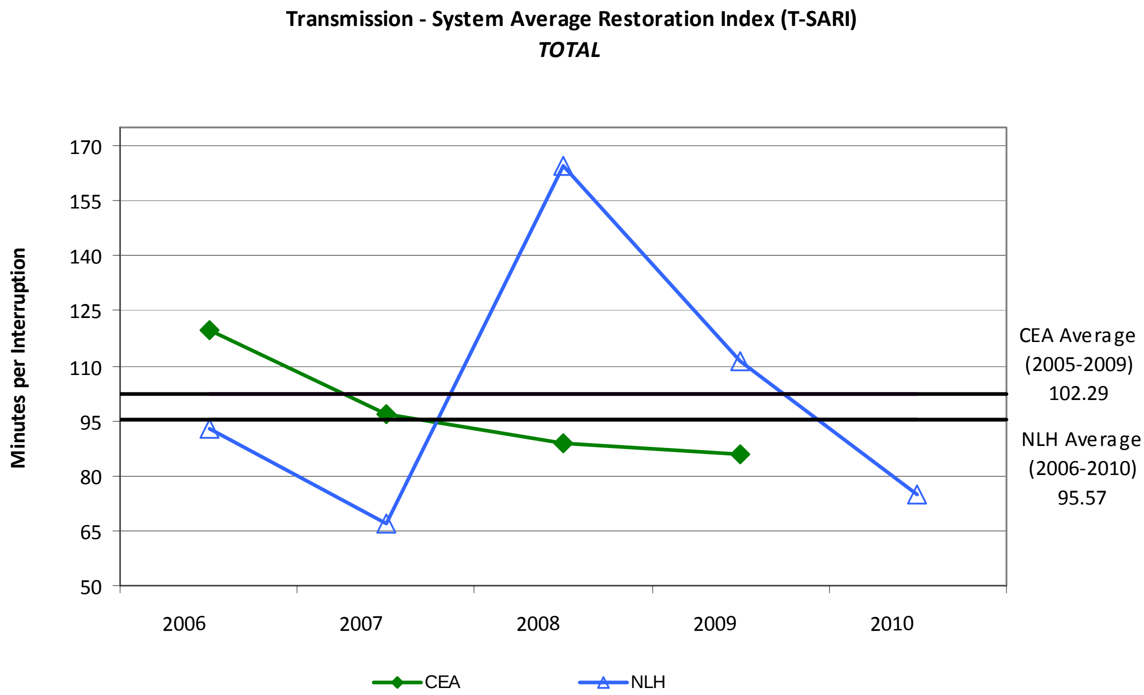
3.1.2 c) Transmission System Average Restoration Index (T-SARI) - *a reliability KPI for bulk transmission assets which measures the average duration per transmission interruption. T-SARI is calculated by dividing T-SAIDI by T-SAIFI.*

Hydro's total transmission T-SARI was 123.6 minutes per interruption for the fourth quarter of 2010 versus 118.8 minutes per interruption for the fourth quarter of 2009, a 4% increase. The forced outage component of T-SARI was 1.2 minutes per interruption, while the planned outage component of T-SARI was 169.8 minutes per interruption, approximately the same numbers as in 2009.

Hydro's 2010 total transmission T-SARI was 75 minutes per interruption versus 114.43 minutes in 2009 and a 2010 target of 129 minutes. The forced outage component of T-SARI was 30 minutes per interruption, a decrease of 15% over 2009. The planned outage component of T-SARI was 142.2 minutes per interruption, which is also a decrease of 15% over 2009. Since T-SARI is the ratio of T-SAIDI to T-SAIFI, this decrease is driven by greater increase in T-SAIFI relate to T-SAIDI.

Hydro's overall T-SARI performance was better than the national average in 2010. This can be seen in the chart below.



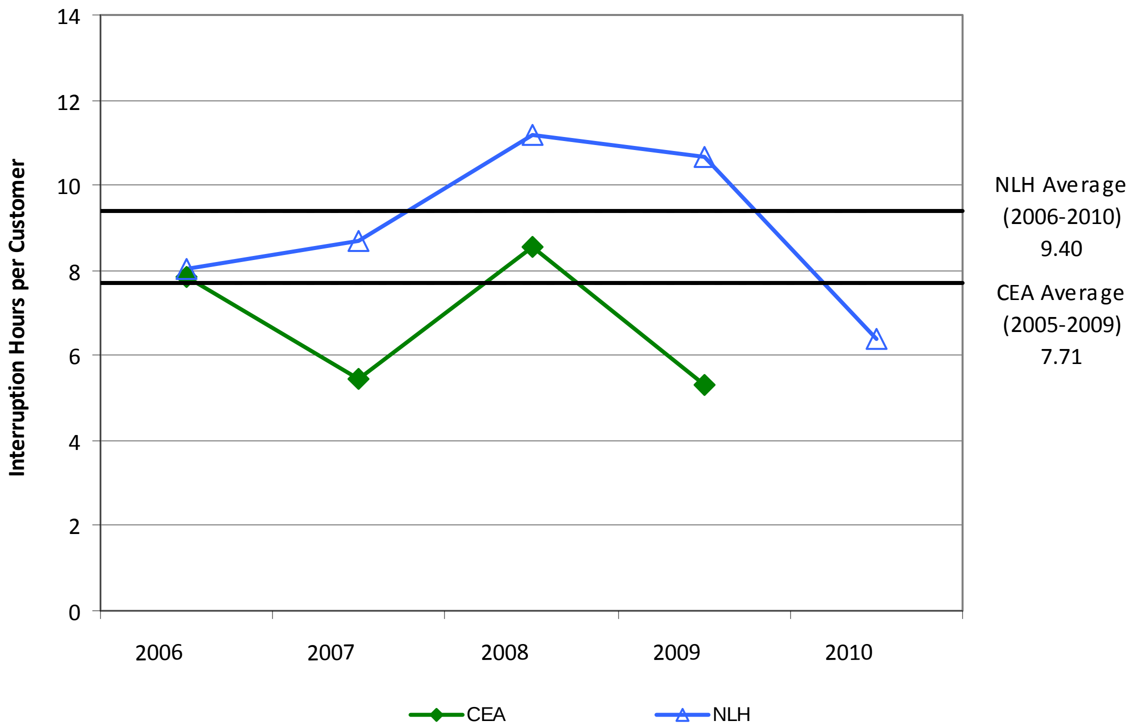


3.1.3 Reliability KPI: Distribution

3.1.3 a) System Average Interruption Duration Index (SAIDI) - *a reliability KPI for distribution service and it measures service continuity in terms of the average cumulative duration of outages per customer served during the year.*

In the fourth quarter, the SAIDI was 1.32 hours per customer compared to 1.86 hours per customer in the same quarter of 2009, a 29% decrease. The total 2010 SAIDI was 6.38 hours per customer compared to 10.67 hours per customer in 2009, a 40% decrease. The 2010 target for SAIDI was 6.9, which was bettered by 8%.

Service Continuity - System Average Interruption Duration Index (SAIDI)



A summary of the major interruptions during the fourth quarter follows:

- On October 5, a backhoe hooked a Bell Aliant telephone cable on the first structure on the main feeder in the town of Rigolet, Labrador. This resulted in damage to the structure causing a power outage of seven hours and 29 minutes to the entire community. The pole was replaced and power was restored to all customers. The backhoe is owned by the Town of Rigolet.

- On October 24, customers on the Baie Verte Peninsula experienced a six hour and 25 minute interruption due to a planned outage by Newfoundland Power on their main transmission line to the area, 363L.

- On October 30, there was a 43 hour outage to Pinsent's Arm area near Charlottetown, Labrador. A winter storm caused nine poles to break off and weather conditions delayed the repair and replacement of these poles. Weather conditions also resulted in broken poles and crossarms on October 30 in St. Lewis. These customers experienced an average of 20 hours of interruption. On October 31, this same storm resulted in a six hour outage to all customers in Mary's Harbour. There was damage to the distribution system that required repairs prior to restoration.

- All 106 customers in Black Tickle experienced an outage of 11 hours and 30 minutes on November 22. Eighty-two of these customers experienced an additional outage of 38 hours and 15 minutes. These outages were caused by a winter storm with blowing snow, freezing rain and high winds. Weather conditions delayed repair crews from arriving in Black Tickle to make repairs.

- A tree contacted the main feeder to Jackson's Arm on December 27 resulting in damage to the conductor. Repairs took ten hours to complete before customers could be restored.

Following are the remainder of the 2010 distribution significant events (outages generally to complete system with a duration of greater than five hours).

- On March 7, customers served by the Bottom Waters Terminal Station in the communities of La Scie, Ming's Bight, Brent's Cove, Nipper's Harbour, Burlington, and Middle Arm experienced a forced outage of 13 hours. The outage occurred after a severe ice storm passed over transmission line TL-260. This ice storm resulted in ice bridging between the ground wire and insulator causing a short to ground. The line was restored with no further action required.

- Customers in Nipper's Harbour, Burlington, and Middle Arm also experienced a series of outages caused by icing conditions from March 5 to March 7. These outage durations ranged from three to ten hours while ice was removed and minor repairs completed to distribution lines.

- Customers in Coachman's Cove and Fleur De Lys experienced a six hour and 33 minute outage on April 15, after a crossarm burnt off near the town of Fleur de Lys. On May 20, Hydro's customers in Coachman's Cove and Fleur De Lys experienced another power outage when feeder SCR-02 tripped at Newfoundland Power's Seal Cove Road Substation. The first nine km of this feeder is owned and maintained by Newfoundland Power. A line patrol by Newfoundland Power found no damage and the line was restored. The outage duration was four hours.

- All customers in Cartwright experienced a planned outage on May 13 for five hours. This outage was required to make improvements to the distribution system in the town.

- On May 23, Hydro's customers in Coachman's Cove and Fleur De Lys experienced a power outage when feeder SCR-02 tripped at Newfoundland Power's Seal Cove Road Substation. An investigation into the trip was initiated by both Newfoundland Power and Hydro's crews, and it was determined the problem was on the Newfoundland Power section of the feeder. Newfoundland Power reported that this feeder could not be safely patrolled in the dark due to its close location to the old Baie Verte Mine site. It was decided that a line patrol would be started in the morning at dawn. On May 24, a line patrol was conducted by Newfoundland Power and it was determined that the problem was on a section of the feeder that once supplied the old Baie Verte Mine site. This section was isolated from the main feeder by Newfoundland Power and all customers were restored. The outage duration was 13 hours and 55 minutes.

- On June 11, Feeder 3 at the St. Anthony diesel plant station tripped, resulting in an outage to half of the town of St. Anthony and the town of Goose Cove. A tractor trailer transporting a piece of heavy equipment came in contact with an overhead guy wire which caused two poles to crack off and damaged a third pole. There were no injuries. The poles were replaced and the lines repaired. The outage duration was six hours and 46 minutes. The incident also affected the St. Anthony Hospital which operated on its own emergency backup power during the outage.

- On August 11, customers served by the South Brook Terminal Station in the Green Bay area experienced a planned outage of five hours. The outage was required to install the mobile substation and perform maintenance on terminal station equipment. On August 18 the same customers experienced an unplanned outage of two hours 20 minutes. There was a lightning strike on transmission line TL-222 which caused a loss of AC power to the mobile substation that required a manual reset. A worker had to travel to site and reset the mobile. On August 26, the same customers experienced a planned outage of two hours 30 minutes. This outage was required to remove the mobile substation.

- On September 2, customers served by Glenburnie Terminal Station (towns of Glenburnie, Woody Point and Trout River) experienced a planned outage of five hours 14 minutes. The outage was required to perform preventive maintenance on the transformer and terminal station equipment.

- Customers in Trout River and Woody Point experienced a six hour planned outage on September 2 in order to make improvements to the terminal station equipment. These same customers experienced a four hour and 30 minute forced outage after a lightning strike in the distribution system on August 18.

- There was a nine hour outage to the Town of Gaultois on September 14 related to blown power fuses on the main feeder.

- On September 10, a tractor-trailer transporting a shed hooked Bell Aliant telephone cables crossing a road in the town of St. Anthony. This resulted in damage to structure 342 on Feeder 2 in the St. Anthony Distribution system causing a power outage to customers on the east side of St. Anthony. To access structure number 342, 24 loads of blast rock were required to fill in a bog for Hydro's workers to safely access the damaged pole. The outage duration was six hours and 22 minutes.

The following the major events were related to Hurricane Igor:

- On September 21, approximately 40 customers in St. Brendan's experienced a power outage. The outage occurred after an insulator was damaged on the feeder which supplies these customers. The road to Eastport was not passable and a helicopter had to be used to transport the line crew. The affected customers were restored on September 22. Total outage time was 22 hours ten minutes. The repairs were delayed due to a road washout that prevented personnel from travelling to the area.

- On September 22 and 23, there were three power outages affecting all customers on Fogo Island. All were initiated by a trip of the main recloser FH1-R2 located at Change Islands. The outage times, number of customers affected and outage descriptions are as indicated in the table below.

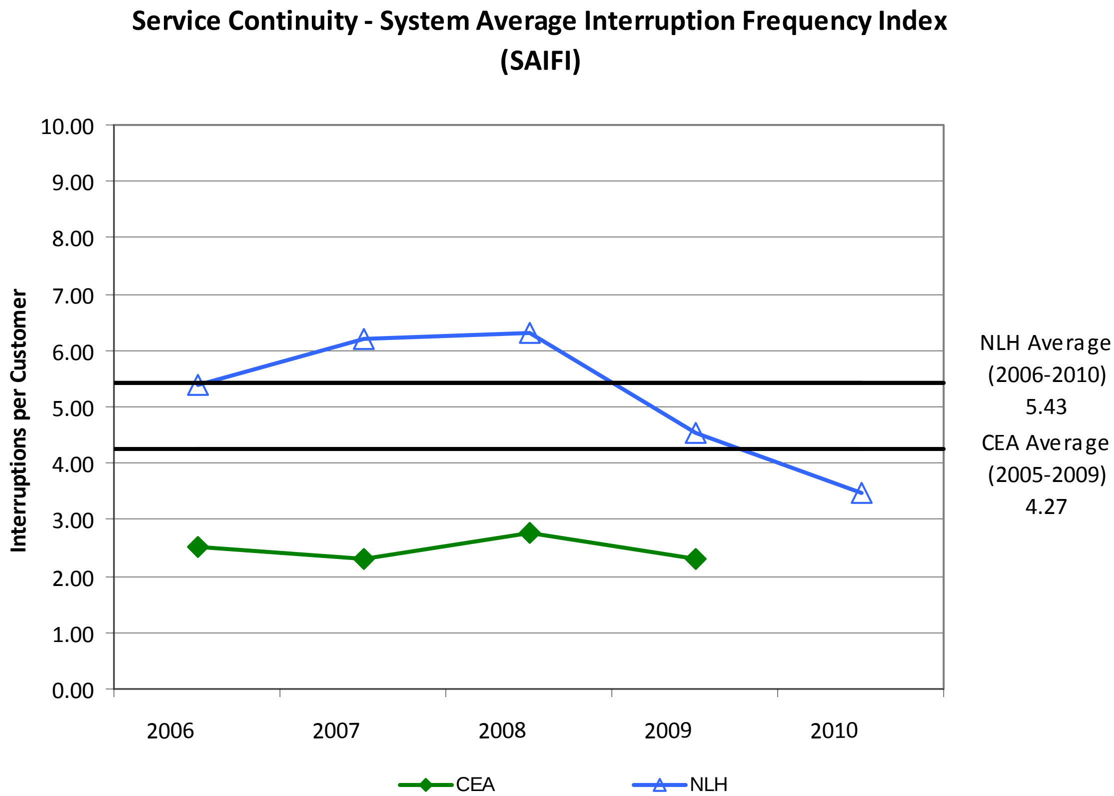
Fogo Island Outages - September 22 and 23, 2010

Outage Start Time Date	Time	Outage End Time Date	Time	Duration	Affected Area	No. Customers	Comments
22-Sep-10	20:48	23-Sep-10	00:03	3 hours 15 min	Fogo Island	1,501	A 25 KV CT failure at the Fogo Substation was determined to be the cause. The CT was isolated and all customers restored except those on feeder F6. There was a delay in restoring feeder F6 customers (362) to 0111 hours due to severe salt contamination.
23-Sep-10	01:43	23-Sep-10	03:31	1 hour 48 min	Fogo Island	1,501	Severe salt contamination is suspected to be the cause.
23-Sep-10	04:48	23-Sep-10	06:15	1 hour 27 min	Fogo Island	1,501	The A phase and C phase CTs at the Fogo Substation were isolated and customers restored.

3.1.3 b) System Average Interruption Frequency Index (SAIFI) - *reliability KPI for distribution service which measures the average cumulative number of sustained interruptions per customer per year.*

In the fourth quarter, the SAIFI was 0.74 interruptions per customer compared to 0.94 interruptions per customer in the same quarter in 2009, a 21% decrease. The 2010 SAIFI was 3.48 interruptions per customer compared to 4.53 interruptions per customer in 2009, a 23% decrease. This is a 19% improvement over the 2010 target of 4.3 interruptions per customer. The 2010 results contribute to an improvement in the five year average for Hydro, which is approaching the latest national average for utilities without a predominant urban customer base[5]. The improvement in 2010 was the result of a reduction in the number of outage in all areas.

[5] The CEA data is not yet available for 2010.


Service Continuity - System Average Interruption Frequency Index (SAIFI)
Interruptions per Customer
10.00
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
2006
2007
2008
2009
2010
NLH Average (2006-2010) 5.43
CEA Average (2005-2009) 4.27
CEA
NLH

3.1.3.1 Additional Information

This section provides more detailed information in three tables with performance broken down by Area, Origin, and Type.

Rural Systems Service Continuity Performance by Area

SAIFI (Number per Period)

Area	Fourth Quarter 2010	Fourth Quarter 2009	12 Mths to Date 2010	12 Mths to Date 2009	5 Year Average (2005–2009)
Central					
Interconnected	0.69	0.50	2.35	2.91	3.44
Isolated	0.20	1.15	2.25	2.42	4.21
Northern					
Interconnected	0.36	0.91	2.39	2.68	4.62
Isolated	2.48	0.89	7.94	4.24	7.27
Labrador					
Interconnected	0.43	1.01	3.85	7.24	8.43
Isolated	3.59	3.93	11.90	13.87	10.83
Total	0.74	0.94	3.48	4.53	5.59

Note: System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers in an area.

SAIDI (Hours per Period)

Area	Fourth Quarter 2010	Fourth Quarter 2009	12 Mths to Date 2010	12 Mths to Date 2009	5 Year Average (2005–2009)
Central					
Interconnected	1.84	0.84	7.79	6.02	8.93
Isolated	0.07	0.41	0.91	1.55	3.89
Northern					
Interconnected	0.34	0.58	3.53	4.41	8.05
Isolated	4.36	1.48	9.44	3.97	5.97
Labrador					
Interconnected	0.68	3.83	6.32	24.99	12.40
Isolated	4.15	7.14	12.26	12.75	15.25
Total	1.32	1.86	6.38	10.67	9.58

Note: System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.

Rural Systems Service Continuity Performance by Origin

SAIFI (Number per Period)					
Area	Fourth Quarter		12 Mths to Date		5 Year Average
	2010	2009	2010	2009	(2005–2009)
Loss of Supply – Transmission	0.06	0.24	0.56	1.91	2.53
Loss of Supply – NF Power	0.01	0.00	0.02	0.01	0.01
Loss of Supply – Isolated	0.15	0.19	0.54	0.56	0.63
Loss of Supply – L'Anse au Loup	0.05	0.00	0.11	0.04	0.05
Distribution	0.47	0.50	2.25	2.02	2.38
Total	0.74	0.94	3.48	4.53	5.59

Note: System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers.

SAIDI (Hours per Period)					
Area	Fourth Quarter		12 Mths to Date		5 Year Average
	2010	2009	2010	2009	(2005–2009)
Loss of Supply – Transmission	0.12	0.05	1.36	5.02	3.47
Loss of Supply – NF Power	0.08	0.00	0.18	0.02	0.02
Loss of Supply – Isolated	0.08	0.12	0.24	0.22	0.26
Loss of Supply – L'Anse au Loup	0.02	0.00	0.04	0.02	0.03
Distribution	1.02	1.70	4.56	5.39	5.81
Total	1.32	1.86	6.38	10.67	9.58

Note: System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.

Rural Systems Service Continuity Performance by Type

Area	Scheduled		Unscheduled		Total	
	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI
Central						
Interconnected	0.15	0.18	0.55	1.66	0.69	1.84
Isolated	0.00	0.00	0.20	0.07	0.20	0.07
Northern						
Interconnected	0.19	0.21	0.17	0.13	0.36	0.34
Isolated	0.42	0.94	2.06	3.43	2.48	4.36
Labrador						
Interconnected	0.37	0.58	0.07	0.10	0.43	0.68
Isolated	1.02	0.93	2.57	3.21	3.59	4.15
Total	0.27	0.37	0.48	0.95	0.74	1.32

Note:
1. System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers in an area.
2. System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.

3.1.4 Reliability KPI: Other

3.1.4 a) Under Frequency Load Shedding (UFLS) - *reliability KPI that measures the number of events in which shedding of a customer load is required to counteract a generator trip. Customer loads are shed automatically depending upon the generation lost.*

There were three underfrequency events during the fourth quarter of 2010. The details are as follows:

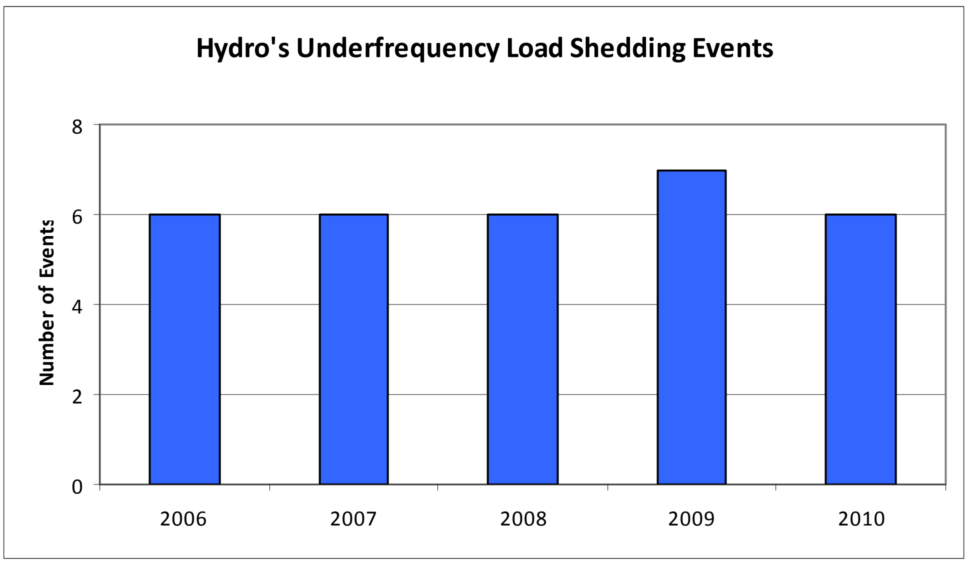
- On November 14 at 22:33 hours, Unit 3 at the Bay d'Espoir Generating station tripped when an operator at the plant inadvertently opened the field breaker during switching. The breaker for Unit 5 (which was offline) was supposed to be opened instead. With the removal of generation (approximately 53 MW) the drop in system frequency resulted in the activation of the underfrequency protection. Total system load at the time of the incident was 743 MW. The frequency fell to 58.73 Hz. An underfrequency event occurred in which 5,057 Newfoundland Power customers were impacted. Approximately 30 MW-mins of energy went unserviced. Service was restored to all Newfoundland Power customers within three minutes.

- On December 22 at 21:19 hours, the Upper Salmon Generating station tripped due to low air pressure at the governor. With the removal of generation (approximately 75 MW) the drop in system frequency resulted in the activation of the underfrequency protection. Total system load at the time of the incident was 1,056 MW. The frequency fell to 58.7 Hz. An underfrequency event occurred in which 5,272 Newfoundland Power customers and Corner

Brook Pulp & Paper (CBPP) was impacted. Approximately 134 MW-mins of energy went unserviced. Service was restored to all customers within three minutes.

- On December 30 at 12:57 hours, Unit 3 at the Holyrood Generating station tripped due to a problem with the unit's fuel pressure system. With the removal of generation (approximately 70 MW) the drop in system frequency resulted in the activation of the underfrequency protection. Total system load at the time of the incident was 1,059 MW. The frequency fell to 58.7 Hz. An underfrequency event occurred in which 7,845 Newfoundland Power customers and CBPP was impacted. Approximately 162 MW-mins of energy went unserviced. Service was restored to CBPP within three minutes. Newfoundland Power customers were restored in stages between three and seven minutes.

In total, there were six UFLS events in 2010. This was one less event than what was experienced in 2009 and equal to the number in all the other years since 2005. Refer to the graph below which compares the UFLS events over the past five years to this year's performance.



The details of the previous three UFLS events in 2010 are:

- On July 13 at 12:30 hours, a slow clearing fault developed on transmission line TL-233 which resulted in the frequency rapidly dropping to 59.07 Hz and activation of the rate-of-change underfrequency load shedding. An underfrequency event occurred in which 3,560 Newfoundland Power customers were impacted. Approximately, 56 MW-mins of energy went unserviced. Service was restored to all Newfoundland Power customers within seven minutes.

- On July 18 at 19:18 hours, the Hinds Lake unit tripped due a lightning strike on TL-243, the 138 kV line that connects the plant to the grid. The frequency fell to 58.73 Hz. An underfrequency event occurred in which 6,488 Newfoundland Power customers were impacted. Approximately 30 MW-mins of energy went unserviced. Service was restored to all Newfoundland Power customers within three minutes.

- On July 18 at 22:54 hours, a lightning strike on transmission line 363L resulted in the frequency rapidly dropping to 59.2 Hz and activated the rate-of-change underfrequency load shedding. An underfrequency event occurred in which 3,530 Newfoundland Power customers were impacted. Approximately 16 MW-mins of energy went unserviced. Service was restored to all Newfoundland Power customers within two minutes.

The table below compares the UFLS events fourth quarter to same quarter in 2009.

Underfrequency Load Shedding Number of Events

Customers	Fourth Quarter		Year-to-date		5 Year Average
	2010	2009	2010	2009	(2005–2009)
NF Power	3	3	6	7	5.8
Industrials	2	2	2	5	5.6
Hydro Rural*	0	2	0	5	5.4
Total Events	3	3	6	7	6.2

Underfrequency Load Shedding Unsupplied Energy (MW-min)

Customers	Fourth Quarter		Year-to-date		5 Year Average
	2010	2009	2010	2009	(2005–2009)
NF Power	230	847	332	1,503	2,182
Industrials	120	150	120	317	2,233
Hydro Rural*	0	30	0	63	78
Total Events	350	1,027	452	1,883	4,493

* Underfrequency activity affecting Hydro Rural Customers may also result in a number of delivery point outages. Outage frequency and duration are also included in totals shown in the delivery point statistics section of the report for these areas, namely the Connaigre Peninsula and Bonne Bay.

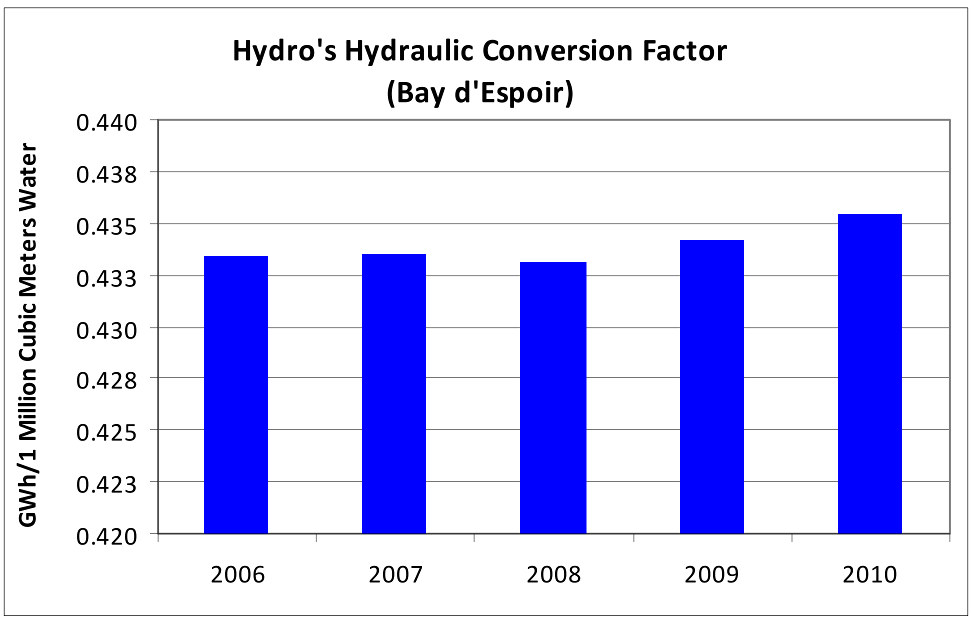
3.2 Operating Performance Indicators

This section presents information on two indicators of operating performance, both of which deal with generation.

3.2.1 Operating KPI: Generation

3.2.1 a) Hydraulic Conversion Factor (Bay d'Espoir) - *a representative performance KPI for the principal hydroelectric generation assets located at Bay d'Espoir. This KPI tracks the efficiency in converting water to energy and it is calculated as the ratio of Net GWh generated for every one million cubic metres (MCM) of water consumed.*

In 2010, Hydro's hydraulic conversion factor for Bay d'Espoir was 0.436 GWh/MCM. Performance has been improving since 2008, with 2010 experiencing the best performance in the previous five year period.



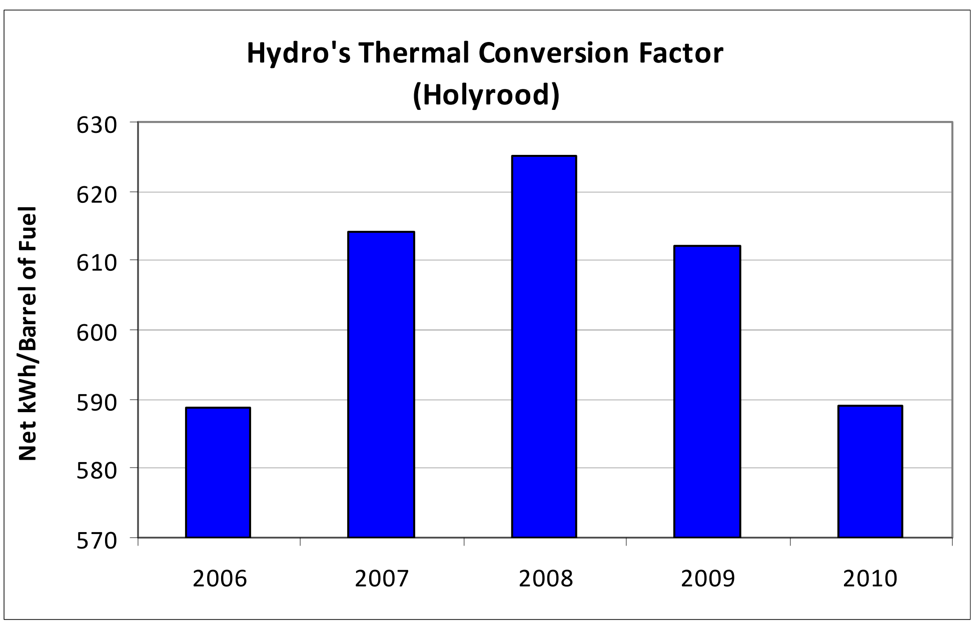
The improvement in 2010 over that experienced in 2009 is primarily a result of increased operating head at the Bay d'Espoir plant, particularly during the winter months (January – March). On average, Long Pond elevation was approximately one meter higher during this period in 2010.

3.2.1 b) Thermal Conversion Factor - *a representative performance KPI for the oil-fired thermal generation assets located at Holyrood. This KPI tracks the efficiency in converting heavy fuel oil into electrical energy and is measured as the ratio of the net kWhs generated to the number of barrels of No. 6 fuel oil consumed.*

The thermal conversion factor for Holyrood is directly proportional to the output level of the three units, with higher averages and sustained loadings resulting in higher conversion factors. In turn, the output level of the Holyrood Thermal Generating Station will vary depending on hydraulic production, quantity of power purchases, customer energy requirements and system security requirements.

In 2010, Hydro's thermal conversion factor was 589 kWh per barrel, which is significantly below the 2010 target of 630 kWh per barrel. This reduction is primarily related to operating the plant at lower generating levels due to the high volume of water resources and energy receipts relative to the system load requirements. Production at Holyrood was kept to a minimum in 2010 with units dispatched only as required for Avalon transmission support and system peak load considerations. The average unit load while operating was 77 MW, down from 81 MW in 2009. Overall, gross production from Holyrood for 2010 was 862 GWh, a 14% decrease from 2009 production levels.

Another contributor to the decreased conversion rate is the lower density fuel shipments in 2010 relative to what was received in 2009.



3.3 Financial Performance Indicators

The financial KPIs reported annually to the Board are:

1. Corporate operating, maintenance and administrative expense (OM&A) per MWh delivered;
2. Generation OM&A per MW installed capacity;
3. Generation OM&A per GWh generated;
4. Transmission OM&A per transmission circuit km; and
5. Distribution OM&A per distribution circuit km.[1]

In Order No. P.U. 8 (2007), the Board ordered that Hydro file a report no later than October 31, 2007 outlining an appropriate peer group with which Hydro's financial performance at the generation and transmission levels could be compared. In compliance with Board Order No. P.U. 8 (2007), Hydro filed a report titled "Peer Group Benchmarking" dated October 31, 2007 which summarized Hydro's findings regarding development of a peer group for financial KPIs related to generation and transmission. In that report, Hydro identified separate peer groups for generation KPIs and transmission KPIs and proposed that, subject to data availability, the selected peers remain constant to allow for meaningful trend comparisons over time. This is the third year of reporting generation and transmission financial KPI peer data. The list of peers used for KPI benchmarking for Financial Performance Indicators is included as Appendix C. This peer group benchmarking data is sourced from the U.S. Federal Energy Regulatory Commission (FERC) database, to which Hydro has a subscription. All financial data for the U.S.-based peer group is in $US and all financial data for Hydro is in $Cdn.

With respect to the Corporate and Distribution KPIs (items 1 and 5 above), in its 2007 Annual Report on KPIs Hydro had incorporated peer benchmarking data from the Canadian Electricity Association's (CEA) Committee on Performance Excellence (COPE) as published in the "Peer Group Performance Measures for Newfoundland Power" report. However, the CEA has informed Newfoundland Power that the composite information for these measures is no longer available, nor are any other cost-related CEA composite indicators available for benchmarking purposes.[2] As a result, Newfoundland Power is now using a peer group of U.S. companies. This group of US companies is not an appropriate group for Hydro due to Hydro's relatively small distribution component. In order to maintain consistency for year over year comparisons, Hydro is using the same peer group of U.S.

[1] This KPI is not available for benchmarking from 2007 onwards. It will continue to be reported for Hydro for annual comparison purposes. Please see section 3.3.4 a) Distribution Controllable Cost for a discussion of the alternate KPI to be used for peer benchmarking.
[2] "Peer Group Performance Measures for Newfoundland Power", December 23, 2008, p.2.

companies for the Corporate Controllable Unit Cost KPI that Hydro uses for its generation financial benchmarking.

3.3.1 Financial KPI: Corporate

3.3.1 a) Controllable Unit Cost - *a high level corporate KPI that tracks Hydro's OM&A expenses in relation to its total energy delivered, expressed as dollars per MW hour. Total Corporate OM&A includes all operating labour and materials for Hydro's generation, transmission, distribution, customer-related and administrative costs loss on disposal of capital assets. Energy deliveries have been normalized for weather, customer hydrology, and industrial strikes.*

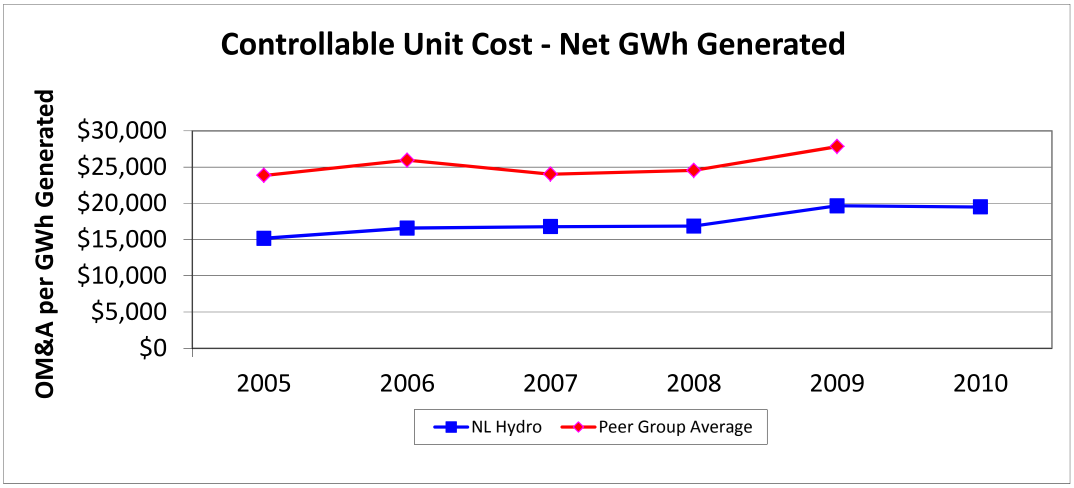
Hydro's OM&A costs decreased from $101.7 million in 2009 to $99.6 million[3] in 2010, resulting in a Controllable Unit Cost of $14.25 per MWh delivered for 2010.

Up to 2006, Hydro's Controllable Unit Cost was compared to the average Controllable Unit Cost for participants in the CEA COPE program as reported by Newfoundland Power. As of 2008, however, Newfoundland Power no longer uses CEA COPE benchmarking data for cost-related measures, because the composite information for these measures is no longer available for publication. Peer group results for the period 2005-2009 have therefore been herein restated using the same U.S. Peer Group that Hydro uses for generation financial KPIs.

For computation of Hydro's Corporate Controllable Unit Cost, normalized energy delivered is used. However, the available peer group data from the FERC database is based on net energy generated. Thus, for better comparison against the peer group, Hydro's data will also be calculated and charted on this basis. Hydro's Corporate OM&A per unit of net generation was $19.50 per MWh during 2010, higher than the computed Controllable Unit Cost, because normalized deliveries are higher than net generation due to the effect of Hydro's energy purchases.

Hydro's Corporate Controllable Unit Cost is following a very similar slow and steady upward trend as compared to the peer group. However, it is difficult to determine specifically what factors might be impacting the expenses of the peer group participants without detailed information regarding their operations and finances.

[3] This $99.6 million was calculated in the 2010 Cost of Service study and includes a $2.7 million cost to Hydro that was incurred to service an unregulated Industrial Customer. The $2.7 million was excluded when the $97.0 million regulated amount was reported on the Statement of Income – Regulated Operations for 2010, filed as part of the December 31, 2010 Quarterly Regulatory Report.

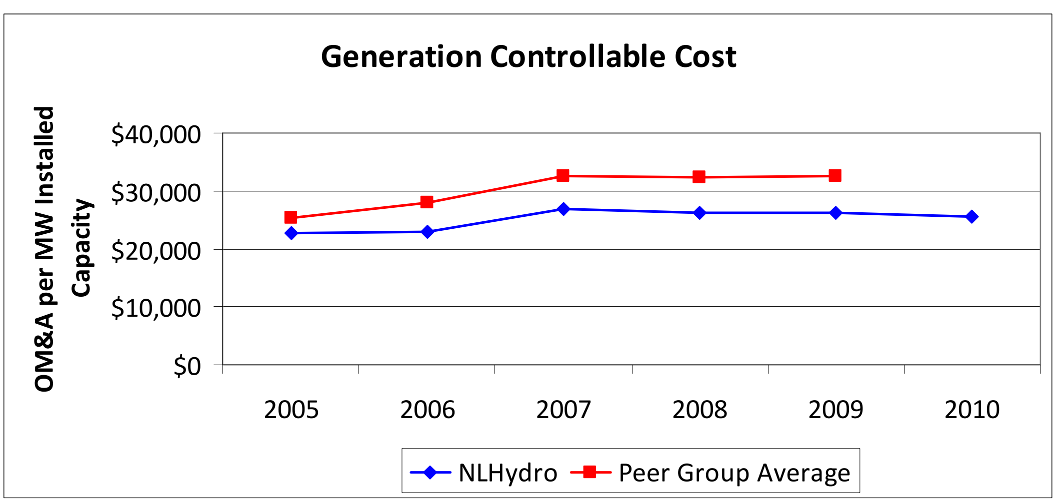


3.3.2 Financial KPI: Generation

3.3.2 a) Generation Controllable Cost - *a functional corporate KPI that tracks Hydro's generation costs in relation to its installed generation. It is computed by dividing generation OM&A by installed capacity as measured in MW.*

Generation Controllable Cost was $25,465 per MW for 2010 compared with $26,138 in 2009, a slight decrease. As mentioned in prior annual KPI reports, an asbestos abatement program was undertaken at Holyrood in 2005 through 2007. Amortization of costs associated with this program will continue through to 2012.

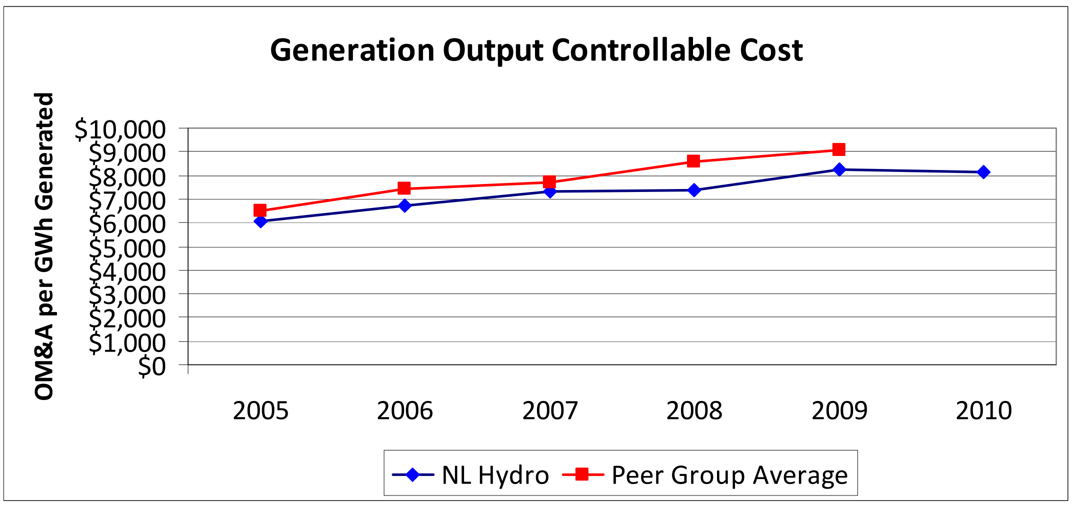
The peer group used to benchmark Generation Controllable Costs appears to be experiencing a similar cost trend as Hydro.



3.3.2 b) Generation Output Controllable Cost - *a functional corporate KPI that tracks Hydro's generation OM&A expenses in relation to its net generation measured in GWh.*

In 2010, Hydro's Generation Output Controllable Cost of $8,159 per GWh, was lower than the $8,267 in 2009. There was a decrease in the Generation Costs component of approximately $1.1 million from 2009 to 2010 and a decrease in the Net Energy Generated by 67 GWh.

From 2005 through 2009, Hydro's Generation Output Controllable Costs were in line with and trending in a similar direction as those of the peer group.

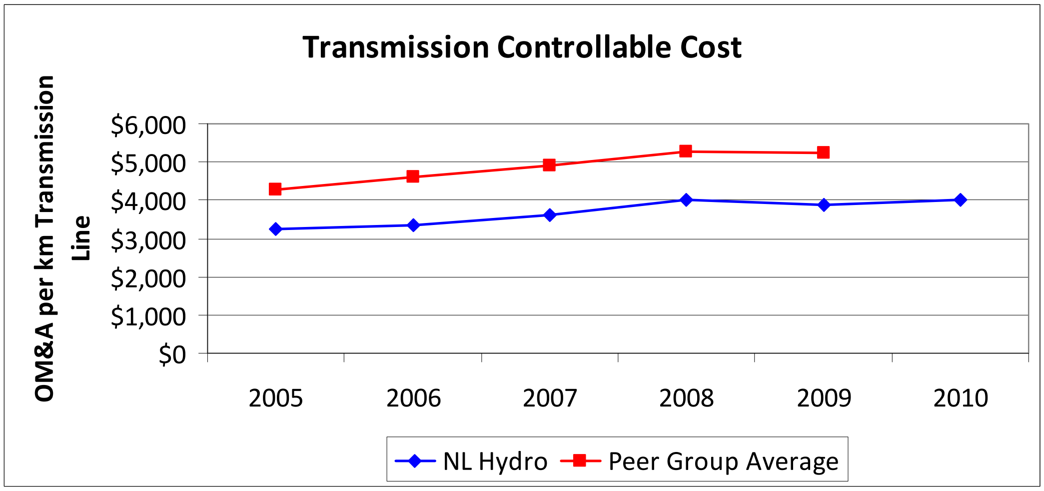


3.3.3 Financial KPI: Transmission

3.3.3 a) Transmission Controllable Cost - *a KPI that tracks Hydro's transmission OM&A expenses in relation to the 230 kV equivalent length of its transmission circuits (69 kV lines and above).*

In 2010, Hydro's Transmission Controllable Cost was $4,021 per km of transmission, an increase of 4% over 2009.

Hydro's costs per km of transmission circuit are trending in a similar pattern as the peer group, although per unit cost increases appear to be increasing at a slower rate within Hydro. A direct cost per unit km within the peer group is not meaningful due to differences in accounting and corporate cost allocations; however comparisons over time can highlight relevant trends.



3.3.4 Financial KPI: Distribution

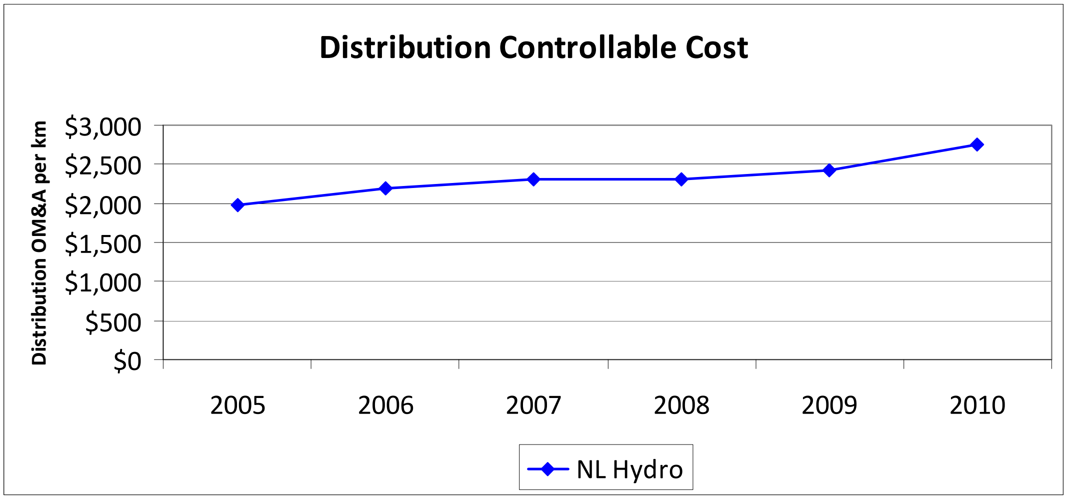
3.3.4 a) Distribution Controllable Cost - *a functional corporate KPI that tracks Hydro's distribution OM&A expenses in relation to the length of its equivalent 230 kV distribution circuits in kilometres[4].*

The Distribution Controllable Cost KPI had previously been reported as dollars per km of distribution using the CEA COPE data. As discussed, the CEA COPE data is no longer available for benchmarking of financial KPIs. Additionally, although distribution cost data is available for the U.S.-based peer group used by Hydro for Transmission Controllable Cost, the associated km of distribution data is unavailable. In the absence of the CEA COPE data, Newfoundland Power has chosen to use a KPI that divides total Distribution OM&A by MWh of retail sales. Hydro will therefore use this same data set. However, given Hydro's relatively small quantity of retail sales, combined with the rural and remote locations of these sales, it is expected that Hydro's Distribution cost per MWh will be significantly higher than Newfoundland Power's and the peer group average.

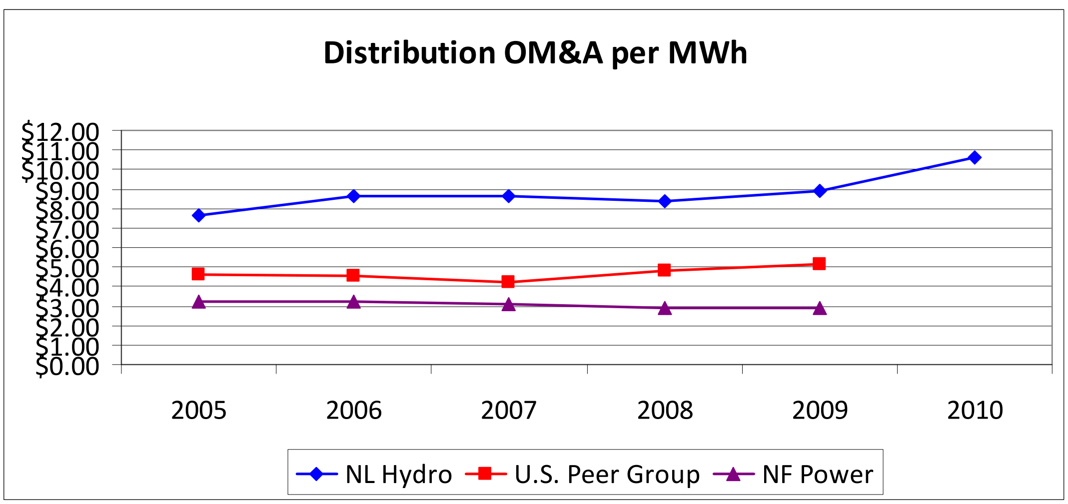
The distribution cost per km of circuit length will continue to be reported for year over year trend analysis.

At $2,755 per circuit km Hydro's Distribution Controllable Cost of 2010 increased from the $2,429 that was recorded in 2009. This is in line with the slight upward trend in this cost that was seen between 2005 and 2009.

[4] CEA COPE peer data used up to 2007 excluded circuit s less than 1 kV. Hydro's data has also been adjusted to exclude circuits less than 1 kV from 2003 onward.



As expected, Hydro's distribution costs trend higher than those of its peers. The distribution systems are a relatively small component of Hydro's total plant compared to generation and transmission plant and also compared to Newfoundland Power's distribution assets. Thus, Hydro's higher costs are likely due to the rural and geographically dispersed nature of its distribution systems and the resultant inability to achieve cost economies.



3.4 Customer-Related Performance Indicators

3.2.4 a) Residential Customer Satisfaction - *an indicator of Hydro's residential customers overall satisfaction level with service, which is tracked by the Percent Satisfied Customers KPI[6].*

The Percent Satisfied Customers measure is also a corporate performance KPI that tracks the satisfaction of rural residential customers with Hydro's performance. The Percent Satisfied Customers measure is produced via an annual survey of Hydro's residential customers.

In 2010, 92% of Hydro's residential customers were satisfied with Hydro's service. The satisfaction rating has improved annually since 2008.

[6] As of 2009, the Customer Satisfaction index (CSI) is no longer being calculated as a Customer-Related Performance Indicator.

4 Data Table of Key Performance Indicators

Key Performance Indicators' targets for 2010 were established in the same manner as in previous years. Any future changes in methodology will be included as such a change occurs.

Newfoundland and Labrador Hydro
Key Performance Indicators (KPI)
Results for 2010 plus Target/Budget for 2011

KPI	Measure Definition	Units	2006	2007	2008	2009	2010	2011T
Reliability								Target
Generation								
Weighted Capability Factor[2]	Availibility of Units for Supply	%	83.2	80.5	82.3	82.0	83.4	86.3
Weighted DAFOR[2]	Unavailibility of Units due to Forced Outage	%	3.7	7.9	5.0	4.5	1.8	3.1
Transmission[6,7]								
T-SAIDI	Outage Duration per Delivery Point	Minutes / Point	151	187	278	100	173	259
T-SAIFI	Number of Outages per Delivery Point	Number / Point	1.6	2.7	1.7	0.9	2.3	2.0
T-SARI	Outage Duration per Interuption	Minutes / Outage	94	69	164	111	75	130
Distribution								
SAIDI	Average Outage Duration for Customers	Hours / Customer	8	8.7	11.2	9.4	6.6	6.2
SAIFI	Number of Outages for Customers	Number / Customer	5.3	6.2	6.3	4.3	3.5	3.8
Under Frequency Load Shedding								
UFLS	Customer Load Interruptions Due to Generator Trip	Number of Events	6	6	6	7	6	6
Operating								
Hydraulic Conversion Factor[4]	Net Generation / 1 Million m^3 Water	GWh / MCM	0.433	0.433	0.433	0.434	0.436	0.433
Thermal Conversion Factor[5]	Net kWh / Barrel No. 6 HFO	kWh / BBL	589	614	625	612	589	630
Financial (Regulated)								
Controllable Unit Cost[6]	Controllable OM&A$ / Energy Deliveries	$/MWh	$13.24	$14.15	$14.05	$14.91	$14.25	N/A
Generation Controllable Costs	Generation OM&A$ / Installed MW	$ / MW	$22,887	$26,836	$26,217	$26,138	$25,465	N/A
	Generation OM&A$ / Net Generation	$ / GWh	$6,719	$7,342	$7,362	$8,267	$8,159	N/A
Transmission Controllable Costs	Transmission OM&A$ / 230 kV Eqv Circuit Km	$ / Km	$3,358	$3,625	$4,023	$3,870	$4,021	N/A
Distribution Controllable Costs	Distribution OM&A$ / Circuit Km	$ / Km	$2,198	$2,307	$2,305	$2,429	$2,755	N/A
Other								
Percent Satisfied Customers (Residential)	Satisfaction Rating	Max = 100%	89%	88%	89%	91%[1]	92%	90%

Notes:
1. Historical data has been updated and/or corrected where applicable.
2. The 2011 targets for weighted capability factor and DAFOR are based on the annual generation outage schedule.
3. For Bay d'Espoir hydroelectric plant.
4. For Holyrood thermal plant.
5. Energy deliveries have been normalized for weather, customer hydrology, and industrial strikes. No adjustments have been made for AC Stephenmille mill closure.
6.. The 2011 targets for T-SAIFI and T-SAIDI are based on the combination of forced and planned outage performance.
7.The T-SAIDI target for 2011 is higher than the previous five year outcomes. This is due to the aggressive work plan in 2011 which involves a significant number of customer outages.

Appendices

APPENDIX A: Rationale for Hydro's 2010 KPI Targets

KPI	Comment on KPI 2009 Target
Reliability	Hydro has adopted a target setting approach wherein known factors that affect reliability performance are incorporated into the target setting process wherever practical. This approach also uses percentage improvements and past performance levels to set target levels for continuous improvements.
Weighted Capability Factor	The 2010 target is set using the expected annual generation unit outage schedule combined with performance improvements relative to recent history.
Weighted DAFOR	The 2010 target is set using the expected annual generation unit outage schedule combined with performance improvements relative to recent history.
Transmission SAIDI, SAIFI, and SARI	The 2010 targets for forced outage performance are set based upon recent performance improvements. The planned outage contribution to total performance is currently under development and will be incorporated into the final performance targets upon completion of the annual transmission terminals maintenance outage plan.
Distribution SAIDI & SAIFI	Improvements relative to the most recent five-year average.
Underfrequency Load Shedding	The 2010 target is based upon improvement over the most recent five-year average.
Operating	
Hydraulic Conversion Factor	Hold at the previous target value.
Thermal Conversion Factor	Per Board Order No. P.U. 14 (2004)
Financial	
Controllable Unit Cost	Unavailable
Generation, Transmission & Distribution Controllable Cost	Unavailable
Other	
Customer Satisfaction	Targeting continuous improvement.

Appendix B: Computation of Weighted Capability Factor and Factors Impacting Performance

Weighted Capability Factor is calculated using the following formula:

$$1 - \frac{\sum_{all\ units} \left(\frac{unit\ total\ equivalent\ outage\ time \times unit\ MCR}{unit\ hours} \right)}{\sum_{all\ units} unit\ MCR}$$

Where,

MCR = Maximum Continuous Rating, the gross maximum electrical output, measured in megawatts, for which a generating unit has been designed and/or has been shown capable of producing continuously. MCR would only change if the generating capability of a unit is permanently altered by virtue of equipment age, regulation, or capital modifications. Such changes to MCR are infrequent and have not actually taken place within Hydro since the 1980’s when two units at Holyrood were uprated due to modifications made to these units.

Unit hours = the sum of hours that a unit is in commercial service. This measure includes time that a unit is operating, shut down, on maintenance, or operating under some form of derating. Unit hours will only be altered in the infrequent event that a unit is removed from commercial service for an extended period of time.

Unit total equivalent outage time = the period of time a unit is wholly or partially unavailable to generate at its MCR. For the purposes of calculating outage time, the degree to which a unit is derated is converted to an outage equivalency. Thus, a unit that is able to generate at 75% load for four days would have an equivalent outage time of one full day out of four. Factors that can affect unit total equivalent outage time are classified by CEA under nine categories, which are outlined in Appendix A to this Report. Hydro tracks the time that each unit spends in each of these nine states and calculates the weighted capability accordingly.

Unit total equivalent outage time is the measure that is most likely to impact Weighted Capability Factor on a year-to-year basis, since MCR and unit hours are unlikely to change.

Factors that Affect Unit Total Equivalent Outage Time

1. **Sudden Forced Outage.** An occurrence wherein a unit trips or becomes immediately unavailable.
2. **Immediately Deferrable Forced Outage**. An occurrence wherein a unit must be made unavailable within a very short time (10 minutes).
3. **Deferrable Forced Outage**. An occurrence or condition wherein a unit must be made unavailable within the next week.
4. **Starting Failure**. A condition wherein a unit is unable to start.
5. **Planned Outage**. A condition where a unit is unavailable because it is on its annual inspection and maintenance.
6. **Maintenance Outage**. A condition where a unit is unavailable due to repair work. Maintenance outage time covers outages that can be deferred longer than a week, but cannot wait until the next annual planned maintenance period.
7. **Forced Derating**. A condition that limits the usable capacity of a unit to something less than MCR. The derating is forced in nature, typically because of the breakdown of a subsystem on the unit.
8. **Scheduled Derating**. A condition that limits the usable capacity of a unit to something less than MCR, but is done by virtue of the decision of the unit operator. Scheduled deratings are less common than forced deratings, but can arise, for example, when a unit at Holyrood is derated to remove a pump from service.
9. **Common Mode Outages**. Common mode outages are rare, and arise when an event causes multiple units to become unavailable. An example might be the operation of multiple circuit breakers in a switchyard at Holyrood due to a lightning strike, rendering up to three units unavailable.

Note: There are hundreds of CEA equipment codes for generator subsystems that track the cause for the time spent in each of the above categories.

Appendix C: List of U.S.-Based Peers for Financial KPI Benchmarking

Generation and Corporate Peer Group:

Alcoa Power Generating Inc.
Allete, Inc.
Aquila, Inc.
Avista Corporation
Buckeye Power, Inc.
Cleco Power LLC
Electric Energy, Inc.
Entergy Mississippi, Inc.
Hawaiian Electric Company, Inc.
Indiana-Kentucky Electric Corporation
Kentucky Power Company
Ohio Valley Electric Corporation
Portland General Electric Company
Public Service Company of New Hampshire
Puget Sound Energy, Inc.
Savannah Electric and Power Company
Sierra Pacific Power Company
Southern Electric Generating Company
Southern Indiana Gas and Electric Company
The Empire District Electric Company

Transmission Peer Group:

AEP Texas North Company
Allete, Inc.
Aquila, Inc.
Avista Corporation
Central Illinois Public Service Company
Delmarva Power & Light Company
Entergy Mississippi, Inc.
Kentucky Utilities Company
MDU Resources Group, Inc.
Mississippi Power Company
New York State Electric & Gas Corporation
Northern Indiana Public Service Company
Northern States Power Company (Wisconsin)
Oklahoma Gas and Electric Company
Public Service Company of Colorado
Public Service Company of Oklahoma
Sierra Pacific Power Company
Southwestern Electric Power Company
Tucson Electric Power Company
Westar Energy, Inc.

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

QUARTERLY REGULATORY REPORT FOR THE QUARTER ENDED DECEMBER 31, 2011

Newfoundland and Labrador Hydro

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1 HIGHLIGHTS

REVISED MAY 31, 2012

HIGHLIGHTS
For the twelve months ended December 31, 2011

REGULATED	2011 Actual YTD	2011 Target/ Budget	2010 Actual YTD
Safety			
Lead:Lag Ratio[1]	578:1	450:1	358:1
All Injury Frequency Rate[1]	0.91	$\leq$1.0	1.39
Production			
Quarter End Reservoir Storage (GWh)	2,260	N/A	2,445
Hydraulic Production (GWh)	4,512	4,572	4,274
Holyrood Fuel cost per barrel, current month ($) [2]	107	55	79
Holyrood Efficiency [2]	603	630	589
Electricity Delivery			
Sales including Wheeling (GWh)	6,628.7	6,792.8	6,324.1
Financial			
Revenue ($millions)	446.1	455.4	417.1
Expenses ($millions)	425.5	432.2	410.5
Net Operating (Loss) Income ($millions)[3]	20.6	23.2	6.6
Current Rate Stabilization Plan (RSP) Balance ($millions)	(170.3)	(166.8)	(159.2)
Hydraulic	(32.7)	(37.6)	(40.4)
Utility	(55.9)	(53.3)	(56.2)
Industrial	(81.7)	(75.9)	(62.6)
Full Time Equivalent (FTE) Employees[4, 5]			
Regulated	819.6	862.0	820.1
Non-Regulated	23.7	8.4	28.3

[1] Annual Target, and 2010 Actual
[2] Target based on approved 2007 Test Year forecast
[3] Does not include any earnings from CF(L)Co
[4] One FTE is the equivalent of actual paid regular hours - 2,080 hours per year in the operating environment and 1,950 hours per year in Hydro's head office environment.
[5] Annual Budget and 2010 Actual values

- All injury frequency and lost time injury frequency rates better than target (page 2)
- Share the Air campaign launched (page 4)
- Winter Availability better than target (page 14)

2 SAFETY

Goal - To be a Safety Leader

Safety is Hydro's number one priority. Hydro remains committed to being a world class leader in safety performance.

Measurement	Year-to-date 2011 Actual	Annual 2011 Plan	Annual 2010 Actual
All Injury Frequency (AIF)	0.91	≤1.0	1.39
Lost Time Injury Frequency (LTIF)	0.13	≤0.3	0.38
Ratio of condition and incident reports to lost time and medical treatment injuries (lead/lag ratio)	578:1	450:1	358:1
Continue progressing Work Methods for high risk tasks and integration of Work Permit Code	Completed	-	N/A

The 2011 safety targets have all been exceeded. Most notably, the AIF and LTIF are better than both the target and last year's performance.

The final quarter of 2011 continued building on the accomplishments of the year's earlier objectives specifically in the following areas:

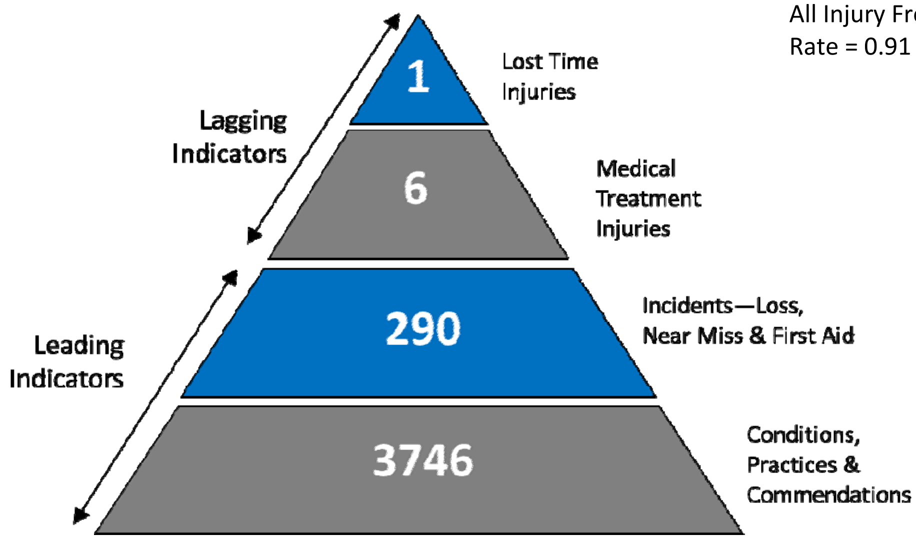
From a program perspective, consistent with the 2012 requirement for provincial Fall Protection programs to be compliant with the Workplace Health, Safety and Compensation Commission (WHSCC) requirements, the Company submitted its program for WHSCC review. In addition to the submission of the program, Hydro identified eight internal trainers for external certification and is poised to commence training as soon as the program receives final approval from the WHSCC.

Safety coaching workshops continued in the fourth quarter with an initial focus on safety leadership. A two-day session for safety leaders will be followed by another session for all employees designed to further enhance the work already done to ensure employees at all levels fully understand and fulfill their obligations with respect to safety and health in the workplace.

Program development continued concerning Hydro's new and younger workers, with specific focus on reducing safety exposures. Initiatives included the implementation of a New Worker Hard Hat program as well as enhanced orientation programs. The programs have received positive feedback from new and more experienced workers alike and will serve to complement other initiatives planned for 2012.

Lost Time Injury
Frequency Rate= 0.13

All Injury Frequency
Rate = 0.91



Lead/Lag Ratio 578:1 2011 Target 450:1

2.1 Public Safety – Power Line Safety Campaign

During the fourth quarter, there were five public incidents where direct contact with energized power lines occurred. The majority of these have involved contractors and operators using large equipment such as excavators, dump trucks, booms, cranes, tractors and trailers.

Public safety emphasis continued in the fourth quarter with a strengthening of the organization's Power Line Hazards protocol through the development of a comprehensive corporate standard outlining the process for how Power Line Hazards permits are obtained. Complementing this was the involvement of staff in several speaking engagements throughout the province regarding the dangers of working around energized power lines. This message was also communicated using radio/internet advertisements, media interviews, social media blogs, and posting information to Hydro's Back it Up website.

2.2 Nalcor and Hydro launch Share the Air Campaign

In October, Nalcor and Hydro launched a new corporate-wide, scent-free campaign called Share the Air. A growing number of employees have serious allergies or sensitivities to scented products. Such sensitivities can cause employees to experience a number of short-term and long-term symptoms. Share the Air encourages employees to do their part in creating a respectful and healthy environment by coming to work scent-free.

Cathy Bradbury (right) shows Hydro Place employee, Margaret Neal (left) a scent-free cleaning product during the launch of Share the Air.

3 ENVIRONMENT AND CONSERVATION

Goal - To be an Environmental Leader

Hydro recognizes its commitment and responsibility to protect the environment.

Measurement	Year-to-date 2011 Actual	Annual 2011 Target	Annual 2010 Actual
Achievement of EMS targets[1]	91%	95%	99% of planned
Variance from ideal production schedule at Holyrood Thermal Generating Station	9.8%	≤12.5%	9.5%
Annual energy savings from Conservation and Demand Management and internal energy efficiency initiatives	10.2 GWh	11.85 GWh	6.7 GWh
Minimized environmental risks and emissions from diesel generation systems	Information system limitations identified. Four-year plan prepared to address.	Acquire production data from all Diesel Plants for automating production monthly reporting	N/A

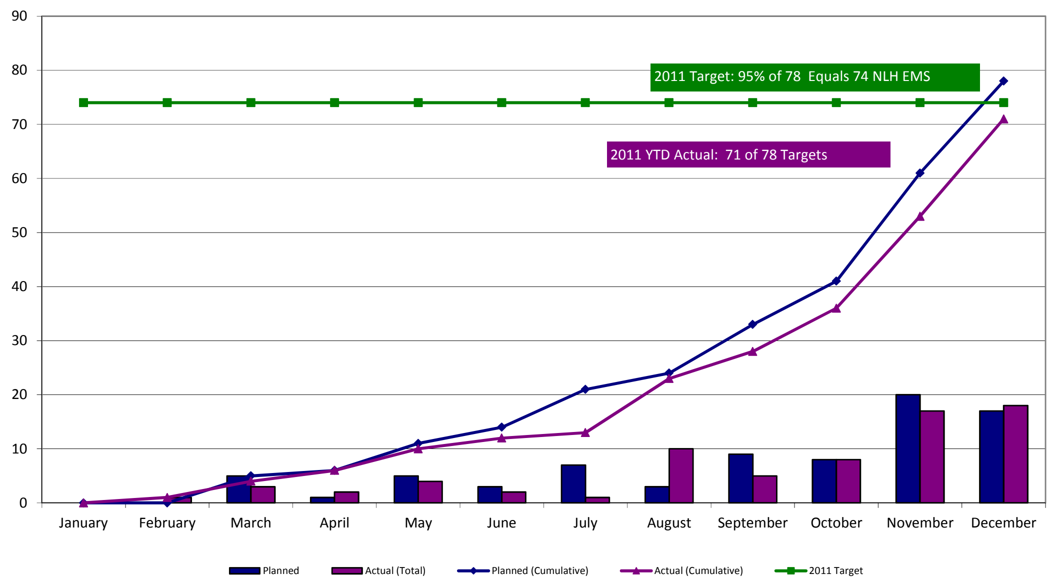
For 2011, environmental results, other than the variance from the ideal production schedule at Holyrood, were slightly under target. Competing work priorities and long lead times resulted in some EMS targets being progressed but not completed by year end.

[1] An EMS target is an initiative undertaken to improve environmental performance.

3.1 Achievement of EMS Targets

See graph below displaying planned target completion schedules and actual to-date.

NLH Environmental Management System Targets
2011 Actual Compared to Planned



3.2 Variance from Ideal Production Schedule at Holyrood Thermal Generating Station

Minimum Hours						
2011	**Variance[1]**		**Ideal**		**Variance**	
Month	**Unit-Hours**	**Cumulative**	**Unit-Hours**	**Cumulative**	**Percent**	**Cumulative**
January	77.0	77.0	2,184	2,184	3.5%	3.5%
February	1.5	78.5	2,016	4,200	0.1%	1.9%
March	179.5	258.0	2,016	6,216	8.9%	4.2%
April	192.5	450.5	1,296	7,512	14.9%	6.0%
May	98.0	548.5	720	8,232	13.6%	6.7%
June	123.0	671.5	384	8,616	32.0%	7.8%
July	24.0	695.5	24	8,640	100.0%	8.0%
August	24.0	719.5	24	8,664	100.0%	8.3%
September	120.0	839.5	120	8,784	100.0%	9.6%
October	120.0	959.5	792	9,576	15.2%	10.0%
November	274.0	1,233.5	1,440	11,016	19.0%	11.2%
December	48.0	1,281.5	2,088	13,104	2.3%	9.8%

[1] Variance is the number of hours greater than or less than the ideal. Hours greater than the ideal represent hours of operation that ideally could have been avoided. Hours less than the ideal represent hours of operation where a single contingency could have resulted in a load interruption.

3.3 Annual Energy Savings from Conservation and Demand Management and Internal Energy Efficiency Initiatives

3.3.1 Introduction

This section outlines the major activities undertaken in 2011 by Hydro to address energy efficiency opportunities with Hydro's customers and internal facilities.

There were many successes in 2011, including the first activity in the Industrial Energy Efficiency Program (IEEP), strong growth of the residential rebate programs, new efforts to engage builders and retailers and continued efforts on the internal energy efficiency of Hydro facilities.

Key audiences for 2011 included Labrador isolated communities, retailers of energy efficient products, homebuilders, lighting distributors and Industrial Customers, to increase the range of programs and impact across Hydro's service area. Within Hydro, employees were engaged in outreach efforts, building walkthroughs and info sessions to educate and inform on the opportunities for energy and cost savings.

3.3.2 Energy Efficiency Planning and Coordination

Hydro and Newfoundland Power continue to work closely to develop and implement the takeCHARGE program for energy efficiency. There are three rebate programs currently offered provincially to residential customers, one program for commercial customers and an Industrial program offered under the takeCHARGE banner for Hydro's transmission level Industrial Customers. These programs are:

- Residential
    i. Insulation
    ii. Energy Star Windows
    iii. High Efficiency and Programmable Thermostats
- Commercial
    i. Lighting
- Industrial Energy Efficiency Program (IEEP)

Three IEEP projects were approved and are in various stages of completion. For all three, feasibility study assistance was approved and project development agreements were signed for the capital upgrades. A lighting retrofit was due to be completed in December, with 165 MWh/yr savings. When all projects are completed, currently scheduled for installation in the first quarter of 2012, energy savings will total 3.6 GWh/yr. These projects are all with Corner Brook Pulp and Paper, however progress has been made in the planning and prioritizing of opportunities at the other Industrial Customers and projects are expected for submission in 2012. Hydro has increased CDM service provision to the Industrial Customers in identifying opportunities and supporting the application requirements to bring new projects to the program.

Also in 2011, Hydro administered the Coastal Labrador Energy Efficiency Program (Phase II), providing audits in Mary's Harbour and Nain homes and businesses and the direct installation of a number of energy savings technologies including lighting and water savings items. Building on the work completed in Phase I in 2009, Hydro also provided promotion of the Provincial EnerGuide for homes and

Newfoundland and Labrador Housing's Residential Energy Efficiency Program (REEP) home energy audit and rebate programs. This programming was funded by the Provincial Department of Natural Resources.

The Coupon Program Pilot also closed in 2011. Launched in November 2010 as a Hydro customer program, the pilot provided data on the administration requirements of this approach and the interest level from customers. The program was extended from the original date - end of February 2011 to April 2011 and offered coupons on eight small technologies and two appliances, redeemable at 14 retailers in Hydro service areas. The Coupon Program was able to achieve success by adapting to feedback and uptake figures, and by trying new, innovative methods for executing energy efficiency programs. As a result, not only did the Coupon Program meet its goals, but it gathered important information that will help build future program successes.

The continued expansion of the rebate programs has meant a continued effort on training, orientation and efficiency awareness for Hydro employees involved in the direct administration of the rebates as well as those external to the program.

Significant effort was given to the preparation of an update to the joint utility Five Year Plan. Unfortunately, the document was not completed, due to coordinating issues with Hydro's partner, Newfoundland Power. Hydro continues to work with Newfoundland Power and expects to have the updated plan filed in 2012. Instead of this updated plan, Hydro did submit, as part of its 2012 application for deferral of CDM expenses, expansion of programming for Hydro's customers as well as a continuation of the existing rebate programs.

3.3.3 Customer Awareness

takeCHARGE activities raise awareness of the importance of using energy wisely and encourages more people to take action today to reduce their energy usage. Mass media, online advertising, social media and specialized offerings are used to increase customer awareness of takeCHARGE. The website received an increase in visits from 50,000 in 2009 to 73,000 in 2011. The takeCHARGE Facebook page has had a significant increase in traffic in 2011, going from 600 to over 6,000 likes in one year. A variety of targeted activities, contests and creative postings lead to the increase and allowed for great customer interaction and increased awareness of program offerings. These new ways of reaching a wide customer base add value to our existing traditional media campaigns and event offerings.

3.3.4 Community Outreach

Community based promotions and marketing are critical to creating awareness of the program and providing rebate program detailed information. Engagement of retailers also continues, with training sessions available to assist in keeping floor staff knowledgeable on products and rebates.

Hydro launched a pilot incentive program for retailers to encourage them to sell Energy Star Windows and promote the takeCHARGE Energy Star Window program. The pilot allows select retailers to receive a small fee for each eligible rebate they submit on behalf of their customer. The pilot runs until May and further retailer partnerships will be explored.

A challenge was issued to all municipalities or local service districts to reduce their energy consumption between November 1, 2010 and January 31, 2011 (compared to the same period the previous year) with the highest percentage reduction winning a $10,000 energy efficient upgrade/retrofit for a municipal building(s) in their town. The program was a joint utility initiative and an overwhelming success with 106 municipalities signing up for the challenge. Admiral's Beach, St. Mary's Bay, was the winner. They had residents come together as a community and show that making wise energy choices in their homes and businesses results in saving energy, saving money and saving our environment. The town will continue to save energy after their energy efficiency upgrades to their municipal building.

3.3.5 Energy Efficiency Program Activity

Rebates

Rebate activity followed the expected pattern, with a drop in the summer months. There was a significant increase in the Insulation program rebates due to a limited time offering of an increased rebate offered.

Residential Rebate Activity

2011	Jan - Mar	Apr - June	July - Sept	Oct. - Dec.	Total
Insulation	15	10	7	105	137
Windows	21	10	8	14	53
Thermostats	14	3	5	26	48
Appliances	84	20	2	0	106
Total	**134**	**43**	**22**	**145**	**344**

The Commercial program is operated through lighting distributors to customers and as such the transactions can differ greatly in size, so rebate numbers are not tracked, but instead numbers of eligible products incented are calculated.

Commercial Activity

Product	# Incented
Ballast	3,264
Lamps	5,446
Exit Signs	247

Industrial Program

There are three projects currently approved for capital incentive, with one project accounting for savings in 2011 of 165 MWh/yr.

Internal Energy Efficiency

Hydro continues to take active steps to encourage behaviour change and implement energy conservation measures in its own facilities. In 2010, walkthrough energy audits were conducted at a number of facilities with several energy conservation measures (ECM's) identified from the audits, varying from low/no cost to potential capital projects.

Actions have been taken throughout the system as a follow up on that work. Transmission and Rural Operations areas completed five of the seven low cost ECM's identified in the energy audits as 2011 EMS targets. The Thermal Generation division identified an ECM to place variable frequency drives

(VFD's) on their boiler combustion fan motors and the project is currently undergoing review for capital funding. Hydro Generation division retrofitted some of their standard exterior lighting to LED fixtures as a trial. So far feedback regarding the new fixtures is very positive. In addition to using less energy, the new LED fixtures provide a better light quality in the area and also do not require frequent relamping.

New internal efficiency gains for 2011 were 172 MWh/yr with steps taken towards stronger savings in 2012.

3.3.6 Costs

Hydro's 2011 CDM program costs are outlined in the table below.

Hydro's CDM Program Costs 2011 ($000's)	
Residential	
Insulation	140
Windows	80
Thermostat	31
Hydro Customer Coupon Program	135
Subtotal	*386*
Commercial	
Lighting	59
Industrial	103
Total	548

Costs associated with general awareness, planning functions and partnership programs and initiatives that would be incurred regardless of the specific rebate programs currently being offered are shown in the following table of Support Costs.

Hydro's Support Costs 2011 ($000's)	
Education	212
Support	43
Planning	304
Total	559

3.3.7 Energy Savings

Savings for the takeCHARGE rebates has had steady growth. The below table demonstrates the energy savings realized in 2010.

Hydro Energy Savings (MWh) 2011	
takeCHARGE Program Portfolio	
Residential Insulation	407
Residential Windows	61
Residential Thermostat	27
Coupon Program	256
Commercial Lighting	227
Industrial	165
Coastal Labrador Program (Phase II)	978
Other Hydro Initiatives[1]	5,968
Total	**8,089**

The target of 9.9 GWh from customer facing programs was not met in 2011, due to the large expected savings for the IEEP that did not occur in 2011. Overall residential and commercial energy savings did meet target.

3.3.8 Outlook

Hydro expects to see continued growth and expansion in the residential and commercial rebate programs in 2012, as new program concepts were filed with the PUB for approval in December. As well, indications are that it will be a very successful year for participation in the IEEP. Efforts will continue to strengthen and expand the network of retailers and community groups to further reach customers on a community level. Hydro will also continue to monitor, plan and engage employees in energy efficiency on behavior changes and long term capital improvements.

3.4 Minimize Environmental Risks and Emissions from Diesel Generation Systems

Work began on acquiring production data in the third quarter. At present, many of the plants are connected to a common server in St. John's. With this system there is a requirement for the server to connect to a modem at a particular plant and there are technical issues with the connection. A new internet protocol device to help improve the ability to get data is planned. Based on the results of the work completed in 2011, a four-year improvement program has been proposed to define and establish data transfer requirements from all diesel plants, and implement hardware and software improvements required to ensure data transfer capability.

[1] Includes savings currently on the system from previous year's activities, as well as outreach activities.

3.5 Hydro's Participation in Protection of the Limestone Barrens of the West Coast of the Island of Newfoundland - A Globally Unique Ecosystem

Geographically, the Limestone Barrens of the west coast of the Island of Newfoundland occupy two primary areas. The Northern Limestone Barrens is an extensive area comprising a disjointed string of mostly small, often widely separated patches and slivers of unforested land extending for approximately 200 km in a north-northeasterly direction along the extreme western and northwestern margins of the Great Northern Peninsula, from Table Head near Bellburns in the south, to the Burnt Cape Ecological Reserve in the north. The Southern Limestone Barrens is a more compact area comprising the summit of Table Mountain, west of Stephenville, and several exposed sections of the nearby Port au Port Peninsula. The primary area of concern to Hydro has become the Northern Limestone Barrens.

Chemically, the Limestone Barrens are underlain by both limestone and dolomite bedrock of Ordovician age. Ecologically, they are consistently subjected to challenging climatic conditions; in general because of their exposed barren aspect but more specifically towards the north because of increasingly colder conditions. Biologically, they harbour a rich and unique flora and fauna. Anthropologically, they tend to occur in close proximity to human habitation and are therefore subject to the many potential dangers and impacts of this close association.

Knowledge of the Limestone Barrens and their unique physical and biological characteristics has existed since the early 1800's, but the area wasn't significantly acknowledged locally until the late 1990's when the area attracted international as well as local interest and the Limestone Barrens became a tourist attraction with related business opportunities in the local areas increasing. There are numerous unique characteristics to this habitat but of particular interest and concern are three plants that grow only on these barrens and nowhere else in the world. These plants are Long's Braya, Fernald's Braya and Barrens Willow. In the mid 2000's each species was listed under Federal and Provincial legislation as endangered species and afforded the protection of these regulations.

Not only do the Limestone Barrens provide habitat for flora and fauna but it also provides stable ground for equipment travel and the installation of infrastructure necessary to support the communities in the area. Roads, airports, quarries, commercial and domestic dwellings and transmission line (TL) and distribution line (DL) facilities are just some of the infrastructure developed within and adjacent to the Limestone Barrens over the years.

Hydro's first significant exposure to the need for special work restrictions for activities associated with Limestone Barrens was during the planning process for upgrading the DL to the Point Riche Light House in 2000. Through discussions with Gros Morne National Park and the Provincial Endangered Species Biologist, Hydro became aware of the potential for Fernald's Braya to exist along the DL right-of-way and associated access trail. Hydro retained a botanist to assess the area and work with internal Environmental Services Department and Transmission and Rural Operations Maintenance personnel to plan the work such that plants and associated critical habitat were not impacted. This experience identified a significant concern regarding the potential for Hydro to impact these plants, or their critical habitats, as part of our annual maintenance and capital upgrade programs. A decision was taken by Hydro to conduct an assessment for these plants during the planning of any work on infrastructure within or adjacent to the Northern Limestone Barrens, and identify appropriate protection measures such that plants and their critical habitat would not be impacted.

Hydro also commenced an annual program involving assessments by a qualified botanist of its entire infrastructure located within or adjacent to the Northern Limestone Barrens. As these plants grow only to approximately eight cm in height, can only be identified when in flower and only flower approximately three weeks a year, this program took ten years to complete and was completed in 2011. This information is now included on Hydro's TL and DL Site Sensitivity Maps and used to plan work in areas where Limestone Barrens may be present.

For the past ten years, Hydro has been a partner with and supported the Memorial University of Newfoundland Botanical Gardens (MUNBG) in their efforts to implement a Limestone Barrens Species at Risk Recovery Strategy. This support has enabled the banking of Braya seeds in the National Seed Bank for endangered species and supported local laboratory and field research associated with the re-establishment of Braya species in their natural environments.

As well, since 2000, Hydro has annually supported Conservation Core Green Team Projects managed by local community groups intended to educate people about the Limestone Barrens or clean up and improve sections of barrens habitat previously impacted.

Hydro's Environmental Services Department personnel participate in the Limestone Barrens Stewardship Program Annual Workshop which provides an opportunity to discuss the status of the barrens and recent activities by government, industry and local interest groups. Through initiatives such as those outlined above, Hydro has been recognized by the Limestone Barrens Stewardship Program members, Parks Canada, and Provincial Wildlife Division as a Corporate leader regarding its approach to planning and undertaking work within and adjacent to the Limestone Barrens, and the protection of this unique habitat and its endangered species for future generations.

Barrens Willow – Cape Norman, Newfoundland

Longs Braya, Yankee Point, Newfoundland

4 OPERATIONAL EXCELLENCE

Goal - Through operational excellence provide exceptional value to all consumers of energy.

Hydro strives to deliver operational excellence by maintaining safe, reliable delivery of power and energy to customers in a cost-effective manner while maintaining high customer satisfaction. The key focus areas are:

- Energy Supply;
- Asset Management; and
- Financial Performance.

REVISED MAY 31, 2012

Measurement	Year-to-date 2011 Actual	Annual 2011 Target	Annual 2010 Actual
Asset Management and Reliability			
Winter Availability[1]	98.3%	>96.3%	97.9%
Office of Asset Management established and functional	Completed	-	
Financial Targets			
Annual Controllable Costs	-3.2%[2]	+1% of budget	-8.7%
Net Income	$20.6 million	$23.2 million	$6.6 million
Return on Capital Employed	7.9%	8.0%	N/A
Project Execution			
Completion rate of capital projects by year end	83%	>95%	86%
All-project variance from original budget	5%	8%	12%
Project/Program management implemented in Project Execution Technical Services	Completed	-	N/A
Customer Service			
Rural Residential Customer Satisfaction rate	88%	>90%	92%

[1] Winter Availability is applicable for the months of January, February, March and December.
[2] Actual 2011 annual controllable costs are favorable from budget by 3.2% (2010 – 8.7% favorable).

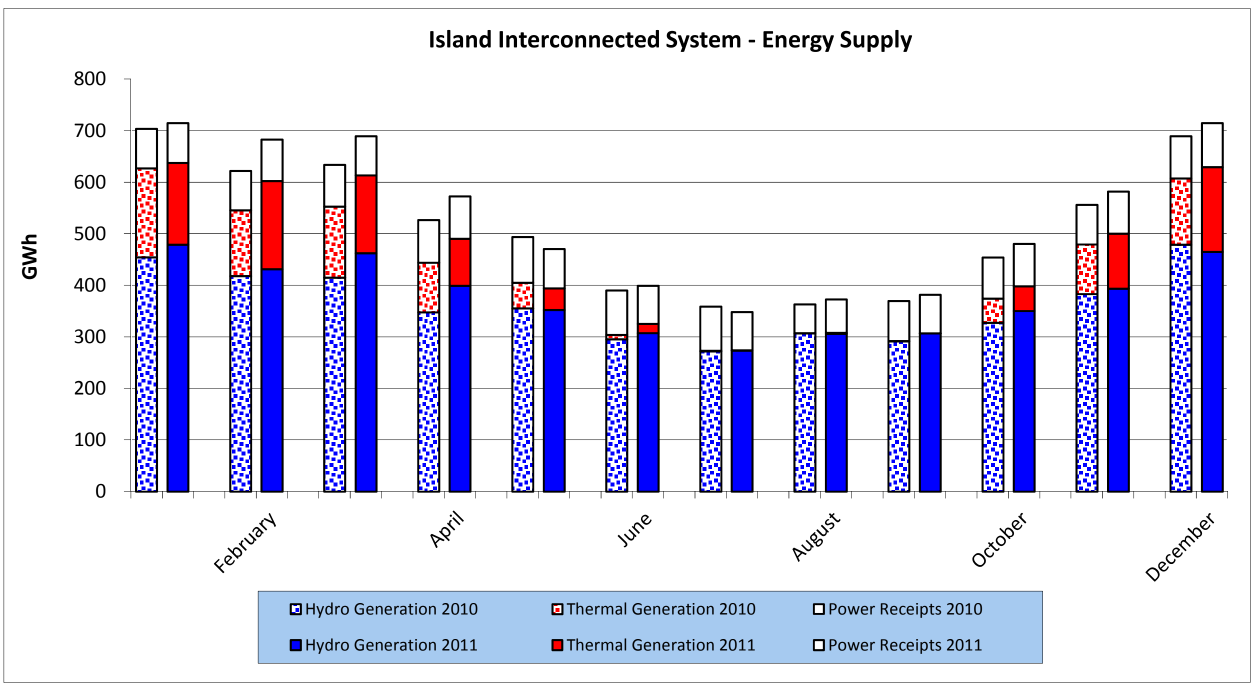
4.1 Energy Supply

4.1.1 Energy Supply - Island Interconnected System

Energy requirements from the Holyrood Generating station were higher during the fourth quarter of 2011 when compared to the same period in 2010. This was primarily due to colder temperatures and increased Avalon Peninsula requirements. Individual units were brought into service as required to meet customers' demand and for transmission support to the Avalon Peninsula. For the year, Holyrood thermal production was 82.2 GWh (10.2%) higher in 2011 than in 2010.

Annual hydroelectric production was 239 GWh or 5.6% above the levels in 2010, primarily due to increased system load requirements and a decrease in energy receipts. Total energy receipts were down by 43.0 GWh or 4.5% in 2011 when compared to 2010. This decrease was primarily due to reduced generation from the facilities at Exploits and Star Lake. This was offset somewhat by increased generation at the wind farms (St. Lawrence and Fermeuse).

The energy supply for the Island Interconnected System is shown in the following chart and tables.



Island Interconnected System Production
For the Year ended December 31, 2011

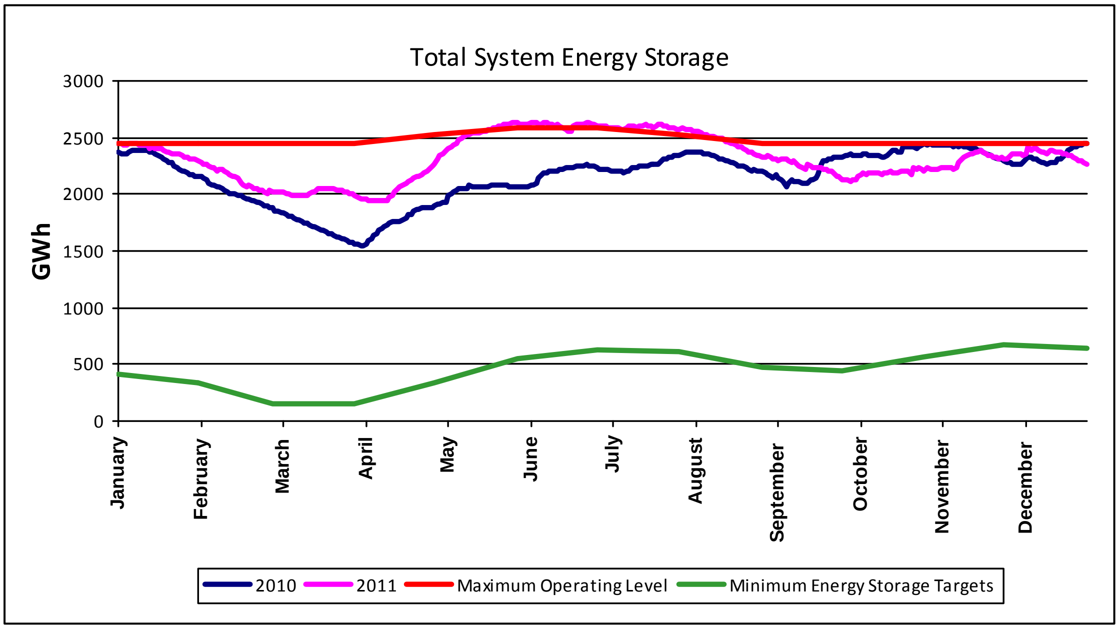
	Year-to-date			Annual Forecast (GWh)	2011 ($000)
	2011 (GWh)	2010 (GWh)	Forecast (GWh)		
Production (net)					
Hydro	4,512.4	4,273.8	4,572.1	4,572.1	-
Thermal	885.3	803.1	897.4	897.4	-
Gas Turbines	(10.2)	(10.2)	(6.0)	(6.0)	-
Diesels	1.7	(0.4)	1.2	1.2	-
Total Production	**5,389.2**	**5,066.3**	**5,464.7**	**5,464.6**	**-**
Energy Receipts					
Non Utility Generators					
Rattle Brook	18.7	17.4	18.0	18.0	1,489.8
Corner Brook Pulp and Paper Co-generation	50.5	51.5	55.8	55.8	5,913.6
St. Lawrence Wind	110.0	100.5	110.1	110.1	7,777.0
Fermeuse Wind	88.0	82.8	84.5	84.5	6,606.1
Total Non Utility Generators	**267.2**	**252.2**	**268.4**	**268.3**	**21,786.5**
Secondary and Others					
Deer Lake Power	3.9	4.5	0.2	0.2	-
Abitibi Consolidated	0.0	0.0	0.0	0.0	-
Hydro Request to NP	0.1	0.2	0.0	0.0	-
Nalcor Energy[1]	634.2	691.5	644.9	644.9	-
Total Secondary and Other	**638.2**	**696.2**	**645.1**	**645.1**	**-**
Total Purchases	**905.4**	**948.4**	**913.5**	**913.4**	
Island Interconnected Total Produced and Purchased	**6,294.6**	**6,014.7**	**6,378.2**	**6,378.0**	

[1] Nalcor Energy includes Star Lake Hydro, Exploits River Project, Grand Falls, Bishop's Falls and Buchans generation.

4.1.2 System Hydrology

Reservoir levels continue to be high. Inflows into the aggregate reservoir system were 109% of average during the fourth quarter of 2011. Annual inflows were 105% of average. The aggregate storage position was 93% of the maximum operating level (MOL) at year end.

There was a spill at the Cat Arm reservoir during the fourth quarter, representing a lost energy equivalent of 10.7 GWh. The total spill for the year, out of several reservoir systems, was 727 GWh.



System Hydrology Storage Levels			
	2011 (GWh)	**2011 Minimum Target**	**2010 (GWh)**
Quarter End Storage Levels	2,260	N/A	2,445

4.1.3 Energy Supply – Labrador Interconnected System

The purchased and produced energy on the Labrador Interconnected System was down significantly in 2011 (127.7 GWh or 14.3%) when compared to 2010. This is primarily due to lower industrial sales at the Iron Ore Company of Canada (IOCC) and reduced secondary sales to CFB Goose Bay. These reductions were offset somewhat by increased Hydro Rural requirements in Labrador East and West.

Labrador Interconnected System Production
For the Year ended December 31, 2011

	Year-to-date			Annual Forecast (GWh)
	2011 (GWh)	2010 (GWh)	Forecast (GWh)	
Production (net)				
Gas Turbines	(2.2)	(1.2)	(1.2)	(1.2)
Diesels	(0.7)	(0.7)	(0.4)	(0.4)
Total Production	**(2.9)**	**(1.9)**	**(1.6)**	**(1.6)**
Purchases				
CF(L)Co for Labrador (at border)	**765.4**	**892.1**	**901.1**	**901.1**
Labrador Interconnected Total Produced and Purchased	**762.5**	**890.2**	**899.5**	**899.5**

4.1.4 Fuel Prices

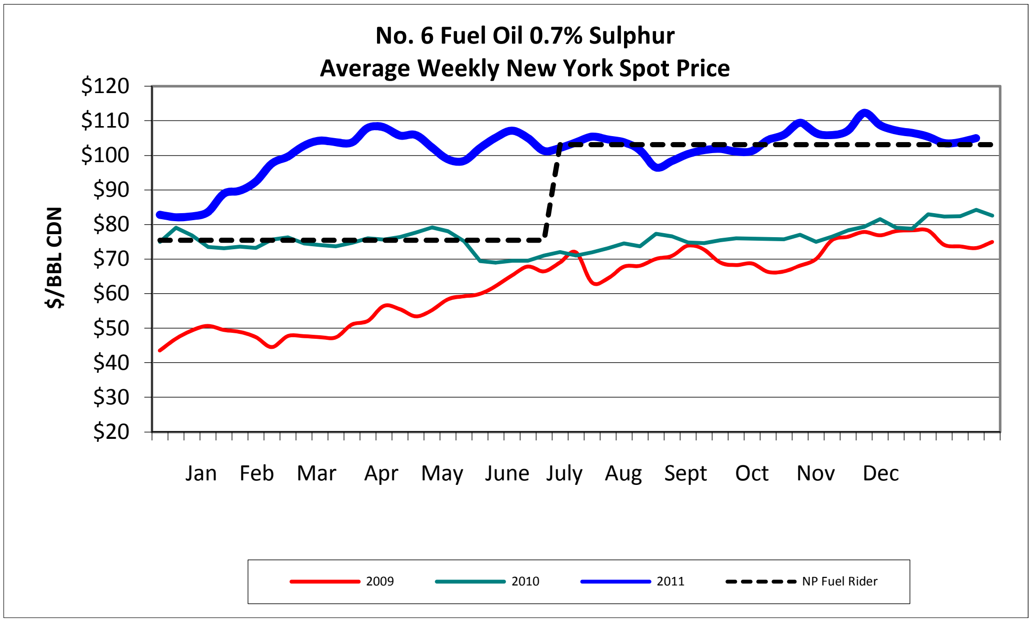
The fuel market prices for No. 6 fuel increased slightly from approximately $103/bbl at the start of the quarter to $104/bbl at the end of the quarter. The quarter ending inventory cost was $108.53/bbl, higher than the current Newfoundland Power fuel price rider of $103.10/bbl. There is no Industrial Customer fuel price rider for 2011.

There were two shipments and a part of another shipment received during the fourth quarter of 2011. The receipt of the remainder of the year-end shipment carried over into the first quarter of 2012.

October 3	207,717 bbls	$101.44
November 23	212,955 bbls	$108.12
December 31	78,055 bbls	$103.80

The inventory on December 31 was 211,474 barrels.

The following chart shows the No. 6 fuel prices year-to-date compared to 2009 and 2010, and the Newfoundland Power fuel rider price of $103.10/bbl.



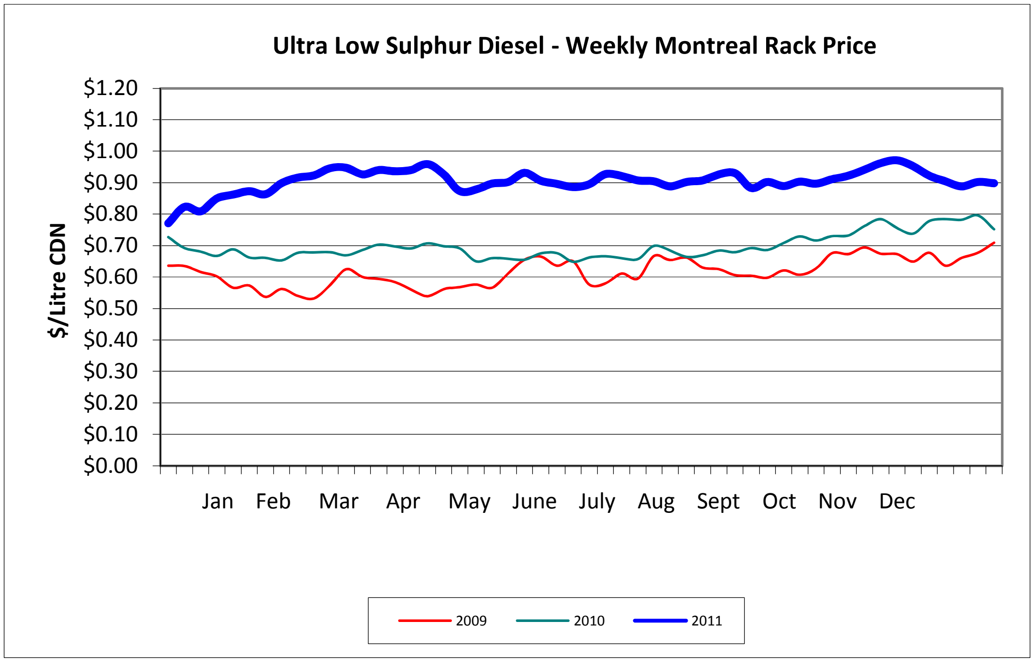
The following table provides the monthly forecast price of No. 6 fuel (0.7% sulphur) up to December 2012, landed on the Avalon Peninsula.

No. 6 Fuel Oil Sulphur
Forecast Price January 2012 – December 2012

Month	Price ($Cdn/bbl) 0.7%	Month	Price ($Cdn/bbl) 0.7%
January 2012	108.40	July 2012	102.90
February 2012	106.70	August 2012	106.10
March 2012	103.50	September 2012	106.30
April 2012	103.80	October 2012	108.10
May 2012	103.60	November 2012	111.50
June 2012	106.60	December 2012	111.60

Note: The forecast is based on the PIRA Energy Group price forecast available January 3, 2012 and an exchange rate forecast by Canadian financial institutions and the Conference Board of Canada.

The following chart shows Low Sulphur Diesel No. 1 fuel prices year-to-date compared to 2009 and 2010.



4.1.5 Energy Supply - Isolated Systems

Total isolated energy supply increased by 6.5% in 2011. Much of the growth can be attributed to colder weather in 2011 than in 2010. The L'Anse au Loup system accounts for 57% of the overall increase in isolated supply. Purchases from Hydro Québec for the L'Anse au Loup system have increased by 6.8%.

Frontier Power, the non-utility generator in Ramea, was out of service for four months due to a fire in their control trailer in March.

Average cost of power, purchased from Hydro Québec and based on Montreal rack fuel prices, was $131 per megawatt hour in 2011 as compared to $100 per megawatt hour in 2010 and the forecast price of $113 per megawatt hour. Average cost of power from NUGS, based on current diesel fuel prices, has increased from $233 per megawatt hour in 2010 to $275 per megawatt hour in 2011 and the forecast price of $282 per megawatt hour.

Isolated Systems Production
For the Year ended December 31, 2011

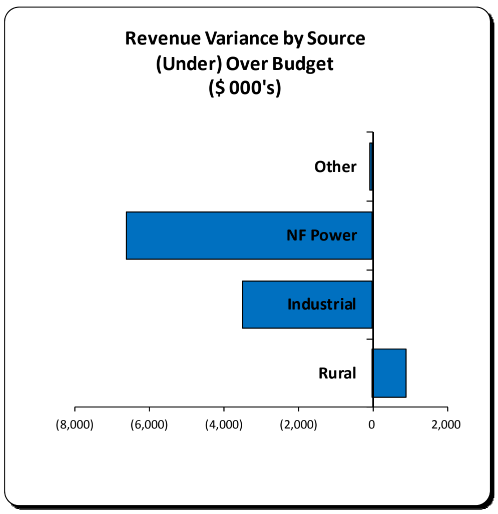
	Year-to-date						Annual Forecast (GWh)	$(000)[1]
	2011 (GWh)	$(000)[1]	2010 (GWh)	$(000)[1]	Forecast (GWh)	$(000)[1]		
Production (net)								
Diesels	47.3		44.4		48.9		48.9	
Purchases								
Non Utility Generators (NUGS)[2]	0.4	108.1	0.5	114.3	0.5	193.6	0.5	193.6
Hydro Québec	22.3	2,926.0	20.8	2,091.3	21.1	2,806.1	21.1	2,806.1
Total Purchases	**22.7**	**3,034.5**	**21.3**	**2,205.6**	**21.6**	**2,999.8**	**21.6**	**2,999.8**
Isolated Systems Total Produced and Purchased	**70.0**		**65.7**		**70.5**		**70.5**	

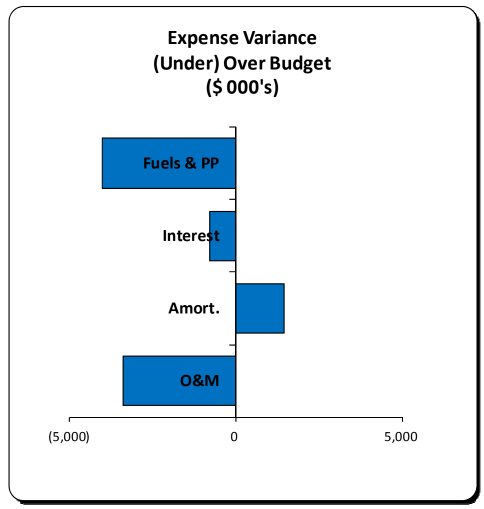
[1] Purchases before taxes.
[2] Ramea wind generation by Frontier Power Systems Inc.

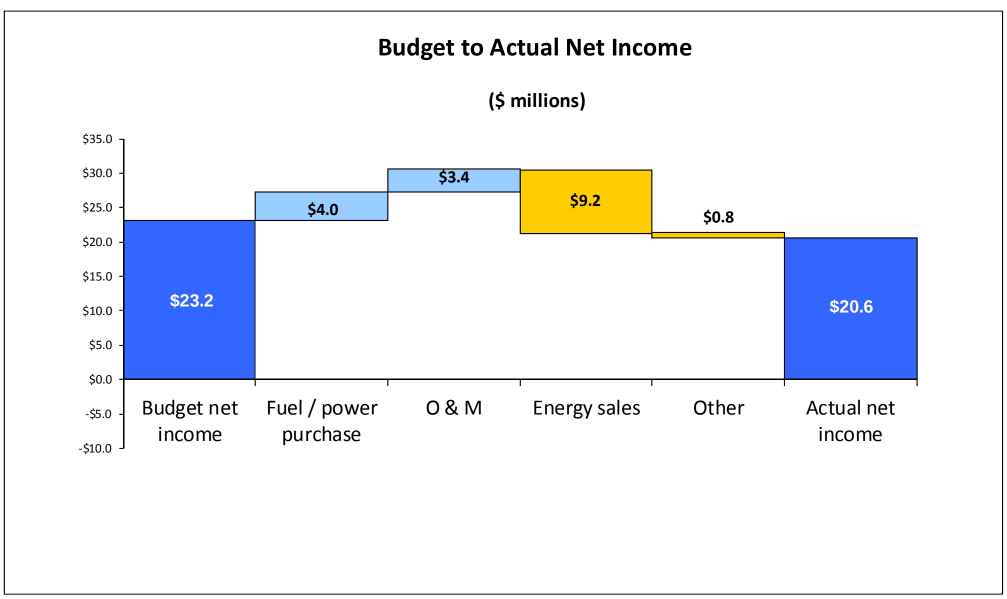
4.2 Financial

Below are charts of Hydro's (Regulated) Statement of Income year to date. Please see Appendix C for the remainder of the financial statements.

Regulated Operations
For the twelve months ended December 31, 2011



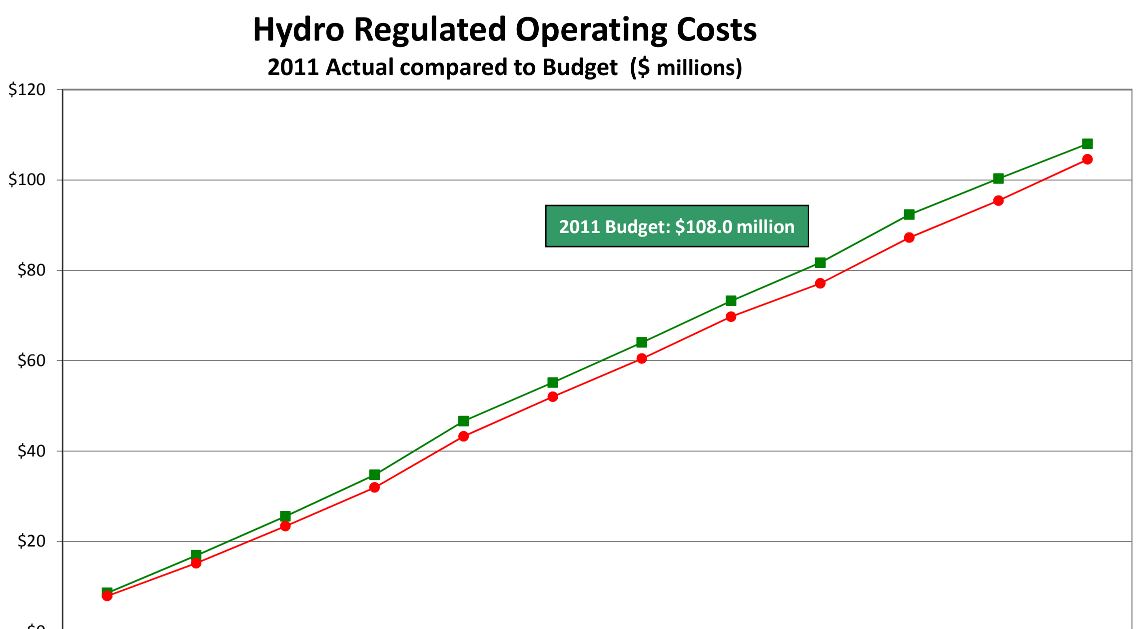




Statement of Income - Regulated Operations
For the twelve months ended December 31, 2011
($ 000's)

Fourth Quarter 2011 Actual	Fourth Quarter 2011 Budget	Fourth Quarter 2010 Actual		Year-to-date 2011 Actual	Year-to-date 2011 Budget	Year-to-date 2010 Actual
			Revenue			
125,842	127,934	112,099	Energy sales	443,796	452,997	414,774
677	600	585	Other revenue	2,317	2,401	2,287
126,519	128,534	112,684		446,113	455,398	417,061
			Expenses			
27,458	26,339	24,000	Operations	104,564	108,021	96,976
583	210	538	Loss on disposal of property, plant, and equipment	925	843	687
35,759	54,225	45,893	Fuels	131,275	133,548	137,994
19,957	11,938	12,469	Power purchased	52,222	53,945	44,244
12,105	11,146	11,299	Amortization	45,684	44,217	43,790
22,750	22,487	21,796	Interest	90,844	91,608	86,766
118,612	126,345	115,995		425,514	432,182	410,457
7,907	2,189	(3,311)	**Net income (loss)**	20,599	23,216	6,604

The chart below illustrates the controllable cost results for the year-to-date, which are consistent with the target of ±1% of budget.



	January	February	March	April	May	June	July	August	September	October	November	December
Cumulative Budget	$8.601	$16.922	$25.560	$34.719	$46.636	$55.168	$64.044	$73.247	$81.682	$92.339	$100.308	$108.021
Cumulative Actual	$7.920	$15.177	$23.376	$31.946	$43.257	$52.036	$60.479	$69.736	$77.106	$87.258	$95.434	$104.564

4.3 Maintenance Plan

Hydro has completed the development and implementation of the maintenance plan as of the third quarter and therefore has concluded its reporting on the status of the plan.

4.4 Asset Management

All planned activities for 2011 were completed. People are functioning in their roles with clarity of accountabilities and responsibilities. Targeted councils were launched for the functions of Long-Term Asset Planning, Short-Term Work Planning and Scheduling, as well as for Management of Change, and Root Cause and Repeat Failure Analysis. Self-assessment scorecards were completed and results compiled to baseline current state maturity. Asset condition data is being collected, analyzed and used to continually improve our long term asset plans. All of these elements will continue to mature with oversight and guidance provided through the Office of Asset Management.

4.5 Capital Expenditures

Capital Expenditures for the year ended December 31, 2011 will be reported as a separate document.

4.6 Other

4.6.1 Crews Work Hard to Complete Maintenance at Cat Arm Generating Station

Above are 19 of the 35 crewmembers that completed the extensive work at the Cat Arm Generating Station.

With the help of more than 30 Hydro employees, major work was completed to improve the overall reliability of the Cat Arm Generating Station. Work crews from the Bay d'Espoir Mechanical, Electrical, Protection and Control, Support Service and General Maintenance departments, along with personnel from the Western Operations team worked together to complete several major projects at the Cat Arm Generating Station from October 11 to November 10.

The work included an inspection scheduled for once every six years of Generator One, an annual inspection on Generator Two, phase one upgrades of cooling water piping, installation of a cooling water flow monitoring system, battery bank replacement, battery charger replacement and an overhaul of the 600 volt station service breakers.

4.6.2 Snow and Ice Storm Causes Power Outages

High winds, rain, ice and snow caused numerous broken structures and downed power lines from October 26 to 30 on the Baie Verte and Northern Peninsulas. Crews had restored power on the Northern Peninsula in two days; however the Baie Verte Peninsula outages extended into four days. The damage was widespread and crews worked mostly in remote areas over rough terrain to make repairs and install new equipment. By October 30, close to 75 personnel, including crews from Newfoundland Power, were in this area to help restore power.

Joe Walsh, Line Superintendent for the Central Region, stands next to a de-energized line on the Baie Verte Peninsula. Up to nine inches of ice stuck to the power lines in the area during a snow and ice storm.

5 OTHER ITEMS

5.1 Significant Issues

5.1.1 Ramea Wind-Hydrogen-Diesel Project Update

Overall Project Site Showing (l-r) the Diesel Plant/Storage Tanks, Meteorological Tower, Hydrogen Electrolyser, 3 Hydrogen Storage Tanks, Distribution Box Structure, 3 Wind Turbines, and Quonset Hut Housing the Hydrogen Genset.

In accordance with Order No. P.U. 31 (2007), the following update is provided on the Wind-Hydrogen-Diesel Project for Ramea.

Implementation and Operation
Delayed repairs/replacements were completed on lightning-damaged equipment (from September 15 lightning storm) by mid-October due to lack of available maintenance resources. System commissioning activities resumed but were problematic due to extreme (too high and too low) wind conditions and failure of all H_2 genset units resulting in more required corrective maintenance. This was delayed until the week of December 5, 2011 due to lack of available maintenance resources. Four out of five units were repaired and commissioning was re-scheduled for the first quarter of 2012.

Capital Costs

($000)

Actual Cost to December 2011	Actual Cost Recoveries to December 2011	Net Cost to December 2011	Budget to December 2008	Budget Reforecast to September 2010[1]
11,773	11,773	0	8,794	2,486

Operating Costs
There is nothing to report for this period as operation is planned to start in the first quarter of 2012.

Reliability and Safety Issues
All activities have been executed with no major safety issues in this period.

5.2 Community

5.2.1 Nalcor and Hydro Employees Support Movember

Movember, which runs through the entire month of November, is responsible for the sprouting of moustaches on thousands of men's faces across Canada. With their "Mos," these men aim to raise vital funds and awareness for men's health, specifically prostate cancer.

This year, two teams of Nalcor and Hydro employees supported the cause. The Nalcor team included Justin Baikie, John Flynn, Jamie Curtis, Matthew Pike, Jon Matchem, Curtis Sturge and Chris O'Brien. Hydro's team included Mike Whalen, Nicholas Gale and Jeff Slaney.

Collectively, both teams raised nearly $2,000. The Community Investment Program recognized employee efforts and provided an additional $1,500 donation to support the cause.

(L-R) Hydro team Movember participants Jeff Slaney and Mike Whalen

5.2.2 Holyrood Plant Donates Equipment to Memorial University

Hydro employees from the Holyrood Generating Station recently donated surplus lab equipment to Memorial University (MUN). The equipment donated from Hydro's Chemical Department Lab, located in Holyrood, included a sulfur analyzer, muffle furnace, lab oven and a 10,000 rpm centrifuge. Ken King, General Maintenance B, Hydro, and Ed Finn, Plant Chemist, Holyrood, delivered the equipment to MUN on Wednesday, September 21.

This equipment is especially beneficial for researcher and PhD student, John Halyard. John is presently conducting research on mine tailings, which is the processed rock left over after the more valuable ore has been removed and extracted. As part of his PhD thesis, he is researching methods to remove and recover sulfur from the tailings. This is a process that could help protect the environment.

[1] Project Change Order #3 is under draft to reflect various cost increases and schedule delays associated with incomplete commissioning activities and equipment problems.

“We are delighted that we are able to donate equipment that will support projects like John's that can help our environment,” said Ed. “It’s also great to give back to our communities and build a relationship with Memorial University.”

5.2.3 Continuing to Support Local Charities Through Facebook

As a key partner to both the Ronald McDonald House Newfoundland and Labrador (RMHNL) and the Kids Eat Smart Foundation of Newfoundland and Labrador (KES), Hydro is constantly looking for ways which they can help these worthwhile causes.

In October, Hydro teamed up with KES to help promote KES Week. Throughout the week, Hydro posted regular updates on Facebook about the activities that KES were presenting and helped KES promote healthy eating and a healthy lifestyle. This partnership was a great opportunity to raise awareness about KES. Hydro is also supported RMHNL through Facebook. For every person who “liked” the RMHNL Facebook page until October 28, Hydro donated $1 to the local charity. This campaign attracted more than 1,500 likes which translates to more than $1,500 raised.

5.2.4 Hydro’s Silver Lights Club Participates in Community Christmas Parades

Each year, Hydro’s Silver Lights Club participates in several local Christmas parades. Silver Lights is a group of Nalcor retirees or employees with 25 years or more of service. This year’s float, called A Backyardigan Christmas, was featured in four Christmas parades, including downtown St. John’s, Mount Pearl, Torbay and Conception Bay South.

It was a Backyardigan Christmas on the Silver Lights float at the 2011 Downtown St. John’s Christmas Parade on Nov. 27.

5.3 Statement of Energy Sold

Statement of Energy Sold (GWh)

For the Year ended December 31

	YEAR TO DATE 2011 ACTUAL	YEAR TO DATE 2010 ACTUAL	YEAR TO DATE 2011* FORECAST	2011* ANNUAL FORECAST	ANNUAL % CHANGE
Island Interconnected					
Newfoundland Power	5,317	5,013	5,317	5,317	6.1%
Island Industrials	311	370	311	311	-15.9%
Rural					
Domestic	239	227	241	241	5.3%
General Service	151	143	149	149	5.6%
Streetlighting	3	3	3	3	0.0%
Sub-total Rural	393	373	393	393	5.4%
Sub-Total Island Interconnected	6,021	5,756	6,021	6,021	4.6%
Island Isolated					
Domestic	6	6	6	6	0.0%
General Service	1	1	1	1	0.0%
Streetlighting	0	0	0	0	0.0%
Sub-Total Island Isolated	7	7	7	7	0.0%
Labrador Interconnected					
Labrador Industrials	129	303	129	129	-57.4%
CFB Goose Bay	51	56	51	51	-8.9%
Hydro Quebec (includes Menihek)	42	40	42	42	5.0%
Export	1,530	1,398	1,530	1,530	9.4%
Rural					
Domestic	272	251	272	272	8.4%
General Service	218	197	218	218	10.7%
Streetlighting	2	2	2	2	0.0%
Sub-total Rural	492	450	492	492	9.3%
Sub-Total Lab. Interconnected	2,244	2,247	2,244	2,244	-0.1%
Labrador Isolated					
Domestic	21	21	21	21	0.0%
General Service	15	14	15	15	7.1%
Streetlighting	0	0	0	0	0.0%
Sub-Total Labrador Isolated	36	35	36	36	2.9%
L'Anse au Loup					
Domestic	13	12	13	13	8.3%
General Service	8	7	8	8	14.3%
Streetlighting	0	0	0	0	0.0%
Sub-Total L'Anse au Loup	21	19	21	21	10.5%
Total Energy Sold (Before Rural Accrual)	8,329	8,064	8,329	8,329	3.3%
Rural Accrual	1	(1)	-	-	-200.0%
Total Energy Sold	8,330	8,063	8,329	8,329	3.3%
Sales to Non-Regulated Customers**	1,700	1,741	1,700	1,700	-2.4%

[1] Forecast numbers now reflect actuals to the current reporting period.
Non-rural GWh - Based on 2011 Wholesale Industrial Revenue Forecast with actuals to the current reporting period.
[2] Included in Total Energy Sold

5.4 Customer Statistics

Customer Statistics
For the Year ended December 31

	FOURTH QUARTER		ANNUAL	
	2011 ACTUAL	2010 ACTUAL	2011 FORECAST	2010 ACTUAL
Customers				
Rural	36,794	36,722	37,915	36,722
Industrial	5	5	5	5
CFB Goose Bay	1	1	1	1
Utility	1	1	1	1
Non-Regulated	3	3	3	3
Reading Days	29.6	29.7	N/A	29.7

APPENDICES

CIAC QUARTERLY ACTIVITY REPORT
For the Quarter ended December 31, 2011

TYPE OF SERVICE	CIAC'S QUOTED	CIAC'S OUTSTANDING PREVIOUS QTR.	TOTAL CIAC'S QUOTED	CIAC'S ACCEPTED	CIAC'S EXPIRED	TOTAL CIAC'S OUTSTANDING
Domestic						
Within Plan. Boundary	3	4	7	3	1	3
Outside Plan. Boundary	8	7	15	5	2	8
Sub-total	11	11	22	8	3	11
General Service	6	10	16	6	3	8
Total	17	21	38	14	6	19

The table above summarizes Contribution in Aid of Construction (CIAC) activity for this quarter. The table is divided into three sections, as follows:

- The first section outlines the type of service for which a CIAC has been calculated, either Domestic or General Service.
- The second section indicates the number of CIACs quoted during the quarter as well as the number of CIAC quotes that remained outstanding at the end of the previous quarter. This format facilitates a reconciliation of the total number of CIACs that were active during the quarter.
- The third section provides information as to the disposition of the total CIACs quoted. A CIAC is considered accepted when a customer indicates they wish to proceed with construction of the extension and has agreed to pay any charge that may be applicable. A CIAC is considered outdated after six months has elapsed and the customers have not indicated their intention to proceed with the extension. A quoted CIAC is outstanding if it is neither accepted nor outdated.

CIAC QUARTERLY ACTIVITY REPORT
For the Quarter ended December 31, 2011

CIAC NO.	CIAC AMOUNT ($)	ESTIMATED CONST. COST ($)	ACCEPTED
DOMESTIC - WITHIN RESIDENTIAL PLANNING BOUNDARIES			
870628	$ 2,562.50	$ 3,042.50	
859883	$ 1,730.00	$ 4,280.00	Yes
878919	$ 2,800.00	$ 5,350.00	Yes
DOMESTIC - OUTSIDE RESIDENTIAL PLANNING BOUNDARIES			
870420	$ 30,780.00	$ 42,480.00	Yes
875800	$ 825.00	$ 1,450.00	Yes
875742	$ 1,521.00	$ 2,271.00	
877482	$ 240.00	$ 840.00	
876736	$ 90,636.00	$ 116,636.00	Yes
880280	$ 2,220.00	$ 3,870.00	
881955	$ 1,110.00	$ 1,860.00	
883032	$ 68,894.00	$ 94,894.00	
GENERAL SERVICE			
869010	$ -	$ 4,890.00	Yes
864680	$ 9,060.00	$ 11,610.00	
864682	$ 4,050.00	$ 6,600.00	
783159	$ 3,005.00	$ 9,705.00	Yes
875483	$ 4,950.00	$ 7,500.00	Yes
868352	$ -	$ 9,975.00	

CUSTOMER PROPERTY DAMAGE CLAIMS REPORT
For the Quarter ended December 31, 2011

Introduction

The Customer Property Damage Claims Report contains an overview of all damage claims activity summarized on a quarterly basis. The information contained in the report is broken down by cause as well as by the operating region where the claims originated.

The report is divided into four sections as follows:

1. The first section indicates the number of claims received during the quarter coupled with claims outstanding from the previous quarter.

2. The second section shows the number of claims for which the Company has accepted responsibility and the amount paid to claimants versus the amount originally claimed.

3. The third section shows the number of claims rejected and the dollar value associated with those claims.

4. The fourth section indicates those claims that remain outstanding at the end of the current quarter and the dollar value associated with such claims.

Definitions of Causes of Damage Claims

1. System Operations: Claims arising from system operations. Examples include normal reclosing or switching.

2. Power Interruptions: Claims arising from interruption of power supply. Examples include all scheduled or unscheduled interruptions.

3. Improper Workmanship: Claims arising from failure of electrical equipment caused by improper workmanship or methods. Examples include improper crimping of connections, insufficient sealing and taping of connections, improper maintenance, inadequate clearance or improper operation of equipment.

4. Weather Related: Claims arising from weather conditions. Examples include wind, rain, ice, lighting or corrosion caused by weather.

5. Equipment Failure: Claims arising from failure of electrical equipment not caused by improper workmanship. Examples include broken neutrals, broken tie wires, transformer failure, insulator failure or broken service wire.

6. Third Party: Claims arising from equipment failure caused by acts of third parties. Examples include motor vehicle accidents and vandalism.

7. Miscellaneous: All claims not related to electrical service.

8. Waiting Investigation: Cause to be determined.

CUSTOMER PROPERTY DAMAGE CLAIMS REPORT - BY CAUSE

For the Quarter ended December 31, 2011

CAUSE	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	AMT. CLAIMED	AMT. PAID	#	AMOUNT	#	AMOUNT
System Operations	4	0	4	0	$ -	$ -	5	$ -	0	$ -
Power Interruptions	4	2	6	0	$ -	$ -	6	$ 4,081.62	0	$ -
Improper Workmanship	7	4	11	2	$ 9,527.63	$ 8,622.13	0	$ -	8	$ 7,642.95
Weather Related	12	9	21	0	$ -	$ -	14	$ 10,326.42	6	$ 4,024.47
Equipment Failure [1]	3	2	5	3	$ 21,680.50	$ 152,582.00	2	$ 372.89	3	$ 8,174.68
Third Party	0	0	0	0	$ -	$ -	0	$ -	0	$ -
Miscellaneous	3	1	4	0	$ -	$ -	5	$ 4,397.89	0	$ -
Waiting Investigation	2	8	10	0	$ -	$ -	0	$ -	5	$ 13,221.77
Total	35	26	61	5	$ 31,208.13	$ 161,204.13	32	$ 19,178.82	22	$ 33,063.87

For the Quarter ended December 31, 2010

CAUSE	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	AMT. CLAIMED	AMT. PAID	#	AMOUNT	#	AMOUNT
System Operations	2	1	3	0	$ -	$ -	3	$ 3,523.98	0	$ -
Power Interruptions	1	1	2	0	$ -	$ -	0	$ -	2	$ 2,383.76
Improper Workmanship [2]	5	10	15	10	$ 628,561.62	$ 618,713.79	1	$ -	4	$ 7,988.66
Weather Related	2	3	5	0	$ -	$ -	1	$ 3,052.00	4	$ 6,358.55
Equipment Failure	2	3	5	1	$ 700.00	$ 700.00	2	$ 18,051.00	2	$ 1,837.00
Third Party	0	0	0	0	$ -	$ -	0	$ -	0	$ -
Miscellaneous	0	0	0	0	$ -	$ -	0	$ -	0	$ -
Waiting Investigation	3	2	5	0	$ -	$ -	0	$ -	5	$ 6,113.40
Total	15	20	35	11	$ 629,261.62	$ 619,413.79	7	$ 24,626.98	17	$ 24,681.37

[1] Claims pd 2011 Equipment Failure
**DC-001315 Ed Humby St. Lunaire-Griquet, claimed $6,335.50; settled Risk & Insurance for $55,074.00
**DC-001316 Chris Humby St. Lunaire-Griquet, claimed $14,245.00; settled Risk & Insurance for $97,268.00

[2] Claims pd 2010 Improper Workmanship
**DC-001219 Grenfell Hospital Northern Region, claimed $570,483.64; settled by Insurance for $581,921.75.
**DC-001167 Bird House Gardens Labrador, claimed $42,768.00; settled by Insurance for $22,900.00.

CUSTOMER PROPERTY DAMAGE CLAIMS REPORT - BY REGION

For the Quarter ended December 31, 2011

REGION	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	AMT. CLAIMED	AMT. PAID	#	AMOUNT	#	AMOUNT
Central Region	11	9	20	2	$ 10,155.00	$ 8,389.50	10	$ 2,304.51	7	$ 9,174.88
Northern Region [1]	18	9	27	2	$ 20,580.50	$ 152,342.00	16	$ 11,217.31	9	$ 5,204.15
Labrador Region	6	8	14	1	$ 472.63	$ 472.63	6	$ 5,657.00	6	$ 18,684.84
Total	35	26	61	5	$ 31,208.13	$ 161,204.13	32	$ 19,178.82	22	$ 33,063.87

For the Quarter ended December 31, 2010

REGION	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	AMT. CLAIMED	AMT. PAID	#	AMOUNT	#	AMOUNT
Central Region	7	3	10	3	$ 3,804.22	$ 3,848.46	1	$ 60.00	6	$ 2,559.51
Northern Region [2]	7	7	14	4	$ 578,443.60	$ 589,841.71	5	$ 24,566.98	5	$ 12,028.55
Labrador Region [3]	1	10	11	4	$ 47,013.80	$ 25,723.62	1	$ -	6	$ 10,093.31
Total	15	20	35	11	$ 629,261.62	$ 619,413.79	7	$ 24,626.98	17	$ 24,681.37

[1] Claims pd 2011 Northern Region **DC-001315 Ed Humby St. Lunaire-Griquet, claimed $6,335.50; settled Risk & Insurance for $55,074.00
**DC-001316 Chris Humby St Lunaire-Griquet, claimed $14,245.00; settled Risk & Insurance for $97,268.00

[2] Claims pd 2010 Northern Region **DC-001219 Grenfell Hospital Northern Region, claimed $570,483.64; settled by Insurance for $581,921.75.

[3] Claims pd 2010 Labrador Region **DC-001167 Bird House Gardens Labrador, claimed $42,768.00; settled by Insurance for $22,900.00.

FINANCIAL – REGULATED

Balance Sheet - Regulated Operations
As at December 31
($ 000's)

	Dec-11	Dec-10
ASSETS		
Current assets		
Cash and cash equivalents	6,685	37,760
Short-term investments	-	8,992
Accounts receivable	79,359	61,429
Current portion of regulatory assets	2,762	3,851
Inventory	54,258	53,390
Prepaid expenses	2,284	2,322
	145,348	167,744
Property, plant, and equipment	1,410,432	1,386,061
Sinking funds	246,966	208,381
Regulatory assets	63,597	65,885
Long-term receivable	210	249
Total assets	1,866,553	1,828,320
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	49,341	65,237
Accrued interest	28,667	28,667
Current portion of long-term debt	8,150	8,150
Current portion of regulatory liabilities	137,593	118,849
Deferred capital contribution	3,497	123
Due to related parties	49,258	37,224
Promissory notes	(5,118)	(5,521)
	271,388	252,729
Long-term debt	1,131,542	1,136,755
Regulatory liabilities	33,271	40,931
Asset retirement obligations	19,593	11,395
Employee future benefits	53,556	48,348
Contributed capital	100,000	100,000
Shareholder's equity / retained earnings	212,096	212,647
Accumulated other comprehensive income	45,107	25,515
Total liabilities and shareholder's equity	1,866,553	1,828,320

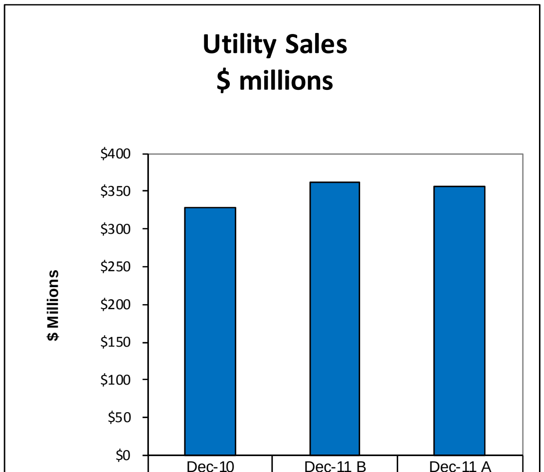
Statement of Retained Earnings - Regulated Operations
For the twelve months ended December 31, 2011
($ 000's)

Fourth Quarter 2011 Actual	Fourth Quarter 2010 Actual		Year-to-date 2011 Actual	Year-to-date 2010 Actual
204,189	215,958	Balance, beginning of year	212,647	236,943
7,907	(3,311)	Net income (loss)	20,599	6,604
-	-	Dividends	(21,150)	(30,900)
212,096	212,647	Balance, end of year	212,096	212,647

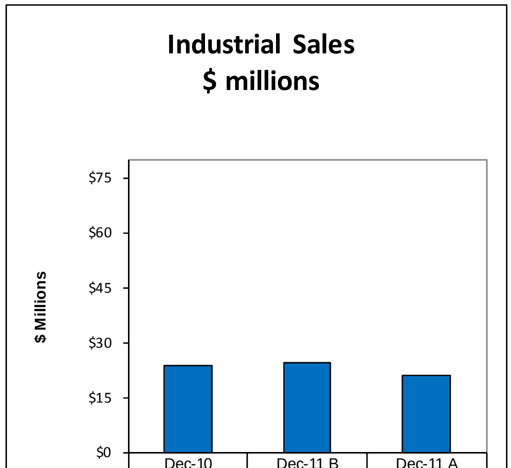
Statement of Comprehensive Income - Regulated Operations
For the twelve months ended December 31, 2011
($ 000's)

Fourth Quarter 2011 Actual	Fourth Quarter 2011 Budget	Fourth Quarter 2010 Actual		Year-to-date 2011 Actual	Year-to-date 2011 Budget	Year-to-date 2010 Actual
7,907	2,189	(3,311)	Net income (loss)	20,599	23,216	6,604
			Other comprehensive income (loss)			
5,936	-	10,713	Change in fair value of sinking fund investments	19,592	-	10,713
13,843	2,189	7,402	Total comprehensive income	40,191	23,216	17,317

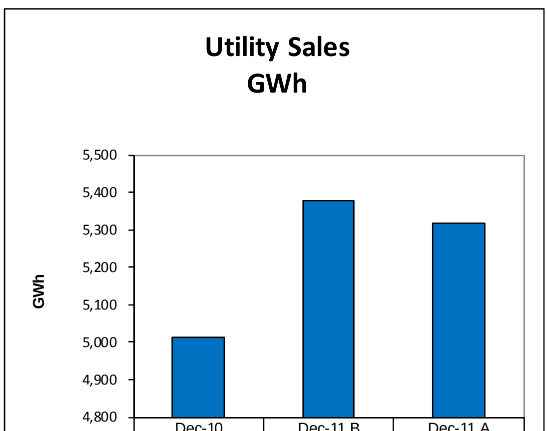
Sales - Regulated Operations
For the twelve months ended December 31, 2011



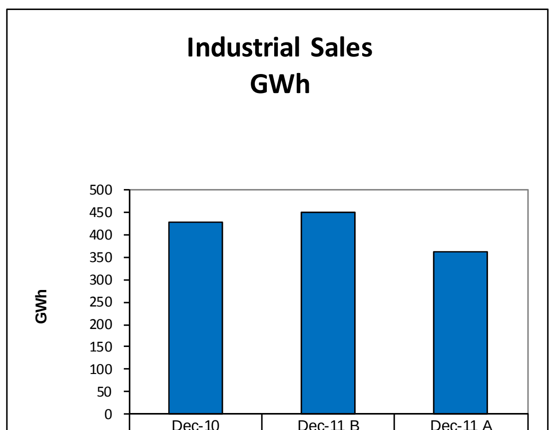
	Dec-10	Dec-11 B	Dec-11 A
NL Power	$328.5	$362.5	$355.9



	Dec-10	Dec-11 B	Dec-11 A
Industrial	$23.6	$24.7	$21.2



	Dec-10	Dec-11 B	Dec-11 A
NL Power	5,013.0	5,376.1	5,317.5



	Dec-10	Dec-11 B	Dec-11 A
Industrial	426.9	451.2	362.3

Revenue Summary - Regulated Operations
For the twelve months ended December 31, 2011
($ 000's)

Fourth Quarter 2011 Actual	Fourth Quarter 2011 Budget	Fourth Quarter 2010 Actual		Year-to-date 2011 Actual	Year-to-date 2011 Budget	Year-to-date 2010 Actual
			REVENUE			
			Industrial			
1,109	1,501	1,260	Corner Brook Pulp and Paper Ltd.	4,197	5,975	5,842
-	137	-	Vale Inco	-	137	-
2,848	2,520	3,018	North Atlantic Refinery	9,381	11,117	10,189
1,393	1,339	1,499	C.F.B. Goose Bay	4,038	4,037	4,025
921	870	910	Teck Cominco Limited	3,585	3,418	3,530
6,271	6,367	6,687	**Total Industrial**	21,201	24,684	23,586
			Utility			
102,581	104,115	89,789	Newfoundland Power Inc.	355,895	362,512	328,492
			Rural			
16,990	17,452	15,623	Interconnected and diesel	66,700	65,801	62,696
677	600	585	**Other**	2,317	2,401	2,287
126,519	128,534	112,684	**Total**	446,113	455,398	417,061
			ENERGY SALES (GWh)			
			Industrial			
15.3	24.3	17.8	Corner Brook Pulp and Paper Ltd.	54.6	96.4	92.8
-	1.0	-	Vale Inco	-	1.0	-
59.9	50.6	64.5	North Atlantic Refinery	184.6	230.6	206.6
15.8	18.2	20.9	C.F.B. Goose Bay	51.4	54.9	56.4
18.6	17.5	18.4	Teck Cominco Limited	71.7	68.3	71.1
109.6	111.6	121.6	**Total Industrial**	362.3	451.2	426.9
			Utility			
1,481.2	1,497.2	1,337.6	Newfoundland Power Inc.	5,317.5	5,376.1	5,013.0
			Rural			
228.5	263.6	214.4	Interconnected and diesel	948.9	965.5	884.2
1,819.3	1,872.4	1,673.6	**Total**	6,628.7	6,792.8	6,324.1

Statement of Cash Flows - Regulated Operations
For the twelve months ended December 31, 2011
($ 000's)

	Year-to-date 2011	Year-to-date 2010
Operating activities		
Net income	20,599	6,604
Adjusted for items not involving cash flow		
Amortization	45,684	43,790
Accretion of long-term debt	460	426
Loss on disposal of property, plant and equipment	925	687
	67,668	51,507
Changes in non-cash balances		
Accounts receivable	(17,930)	4,274
Inventory	(868)	(3,426)
Prepaid expenses	38	(830)
Regulatory assets	3,377	4,377
Regulatory liabilities	11,084	37,178
Accounts payable and accrued liabilities	(15,896)	14,122
Due to related parties	12,034	15,783
Employee future benefits	5,208	4,288
	64,715	127,273
Financing activities		
Increase (decrease) in deferred capital contribution	3,374	(42)
Decrease (increase) in long-term receivable	39	(249)
Dividends	(21,150)	(30,900)
Increase (decrease) in promissory notes	403	(1,990)
	(17,334)	(33,181)
Investing activities		
Additions to property, plant and equipment	(63,083)	(55,401)
Decrease in short term investments	8,992	11,008
Proceeds on disposal of property, plant and equipment	301	463
Increase in sinking funds	(24,666)	(23,344)
	(78,456)	(67,274)
Net (decrease) increase in cash	(31,075)	26,818
Cash position, beginning of period	37,760	10,942
Cash position, end of period	6,685	37,760

FINANCIAL - NON-REGULATED

Balance Sheet - Non-Regulated Activities
As at December 31
($ 000's)

	Dec-11	Dec-10
ASSETS		
Current assets		
Accounts receivable	3,691	5,403
Derivative assets	217	1,981
	3,908	7,384
Long-term receivable	1,398	25,407
Investment in CF(L)Co.	399,155	384,265
Total assets	404,461	417,056
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	3,458	1,926
Promissory notes	5,118	5,521
Derivative liabilities	30	294
	8,606	7,741
Long-term note payable	1,306	25,315
Share capital	22,504	22,504
Lower Churchill Development Corp	15,400	15,400
Retained earnings	356,645	344,828
Accumulated other comprehensive income	-	1,268
Total liabilities and shareholder's equity	404,461	417,056

Statement of Income - Non-Regulated Activities
For the twelve months ended December 31, 2011
($ 000's)

Fourth Quarter 2011 Actual	Fourth Quarter 2011 Budget	Fourth Quarter 2010 Actual		Year-to-date 2011 Actual	Year-to-date 2011 Budget	Year-to-date 2010 Actual
			Revenue			
15,278	13,275	18,023	Energy sales	74,260	65,630	83,068
864	-	(434)	Other (loss) revenue	(1,838)	-	(2,610)
16,142	13,275	17,589		72,422	65,630	80,458
			Expenses			
5,829	6,861	6,590	Operations	24,288	27,541	25,494
13	-	52	Fuels	36	-	68
1,087	1,008	886	Power purchased	4,569	4,977	4,064
327	-	123	Interest	(655)	-	476
7,256	7,869	7,651		28,238	32,518	30,102
8,886	5,406	9,938	Net operating income	44,184	33,112	50,356
3,706	9,326	4,624	Equity in CF(L)Co	14,890	15,785	16,572
2,725	2,317	3,866	Preferred dividends	9,588	9,765	10,159
6,431	11,643	8,490		24,478	25,550	26,731
15,317	17,049	18,428	**Net income**	68,662	58,662	77,087

Statement of Retained Earnings - Non-Regulated Activties
For the twelve months ended December 31, 2011
($ 000's)

Fourth Quarter 2011 Actual	Fourth Quarter 2010 Actual		Year-to-date 2011 Actual	Year-to-date 2010 Actual
354,466	342,326	Balance, beginning of year	344,828	329,226
15,317	18,428	Net income	68,662	77,087
(13,138)	(15,926)	Dividends	(56,845)	(61,485)
356,645	344,828	Balance, end of year	356,645	344,828

Statement of Comprehensive Income - Non-Regulated Activities
For the twelve months ended December 31, 2011
($ 000's)

Fourth Quarter				Year-to-date		
2011 Actual	**2011 Budget**	**2010 Actual**		**2011 Actual**	**2011 Budget**	**2010 Actual**
15,317	17,049	18,428	Net income	68,662	58,662	77,087
			Other comprehensive income (loss)			
-	-	(959)	Change in fair value of derivative instruments	(1,268)	-	(4,976)
15,317	17,049	17,469	Total comprehensive income	67,394	58,662	72,111

Statement of Cash Flows - Non-Regulated Activities
For the twelve months ended December 31, 2011
($ 000's)

	Year-to-date 2011	Year-to-date 2010
Operating activities		
Net income	68,662	77,087
Adjusted for items not involving cash flow		
Unrealized loss (gain) on derivatives	232	381
Equity in CF(L)Co	(14,890)	(16,572)
	54,004	60,896
Changes in non-cash balances		
Accounts payable and accrued liabilities	1,532	92
Accounts receivable	1,712	(1,402)
	57,248	59,586
Financing activities		
(Decrease) increase in promissory notes	(403)	1,990
Decrease (increase) in long-term receivable	24,009	(1,472)
(Decrease) increase in long-term note payable	(24,009)	1,381
Dividends	(56,845)	(61,485)
	(57,248)	(59,586)
Net change in cash	-	-
Cash position, beginning of period	-	-
Cash position, end of period	-	-

FINANCIAL – SUPPLEMENTARY

Supplementary Schedule - Regulated Operations
For the twelve months ended December 31, 2011
($ 000's)

Fourth Quarter 2011 Actual	Fourth Quarter 2011 Budget	Fourth Quarter 2010 Actual		Year-to-date 2011 Actual	Year-to-date 2011 Budget	Year-to-date 2010 Actual
			Other revenue			
225	174	183	Sundry	581	696	612
438	403	388	Pole attachments	1,634	1,612	1,573
14	23	14	Supplier's discount	102	93	102
677	600	585	**Total other revenue**	2,317	2,401	2,287
			Interest			
27,060	26,773	25,845	Gross interest	107,338	106,844	101,455
117	111	109	Accretion of long-term debt	460	445	426
539	539	539	Amortization of foreign exchange losses	2,157	2,157	2,157
(501)	(644)	(457)	Allowance for funds used during construction	(1,546)	(1,188)	(1,161)
(4,465)	(4,292)	(4,240)	Interest earned	(17,565)	(16,650)	(16,111)
22,750	22,487	21,796	**Total interest**	90,844	91,608	86,766

Cost Recoveries - Regulated Operations
For the twelve months ended December 31, 2011
($ 000's)

Fourth Quarter 2011 Actual	Fourth Quarter 2011 Budget	Fourth Quarter 2010 Actual		Year-to-date 2011 Actual	Year-to-date 2011 Budget	Year-to-date 2010 Actual
6	1	11	Executive Leadership	9	4	13
261	222	290	Human Resources and Organizational Effectiveness	940	890	878
672	782	890	Finance / CFO	2,994	3,128	2,706
56	18	32	Engineeering Services	209	72	85
36	22	46	Regulated Operations	95	88	97
1,031	1,045	1,269		4,247	4,182	3,779

Newfoundland and Labrador Hydro
Rate Stabilization Plan –
December 31, 2011

Rate Stabilization Plan Report
December 31, 2011

Summary of Key Facts

The Rate Stabilization Plan of Newfoundland and Labrador Hydro (Hydro), as amended by Board Order No. P.U. 40 (2003) and Order No. P.U. 8 (2007), is established for Hydro's utility customer, Newfoundland Power, and Island Industrial customers to smooth rate impacts for variations between actual results and Test Year Cost of Service estimates for:

- Hydraulic production;
- No. 6 fuel cost used at Hydro's Holyrood generating station;
- Customer load (Utility and Island Industrial); and
- Rural rates.

The Test Year Cost of Service Study was approved by Board Order No. P.U. 8 (2007) and is based on projections of events and costs that are forecast to happen during a test year. Finance charges are calculated on the balances using the test year Weighted Average Cost of Capital which is currently 7.529% per annum. Holyrood's operating efficiency is set, for RSP purposes, at 630 kWh/barrel regardless of the actual conversion rate experienced.

	2007 Test Year Cost of Service			
	Net Hydraulic Production	No. 6 Fuel Cost	Utility Load	Industrial Load
	(kWh)	($Can/bbl.)	(kWh)	(kWh)
January	427,100,000	54.17	574,800,000	78,300,000
February	388,680,000	54.73	518,600,000	70,900,000
March	415,080,000	55.46	524,700,000	76,600,000
April	355,520,000	55.46	429,200,000	75,600,000
May	324,240,000	55.46	358,700,000	69,500,000
June	328,500,000	54.49	298,400,000	73,800,000
July	386,790,000	54.49	293,400,000	77,500,000
August	379,140,000	54.49	287,000,000	77,900,000
September	363,560,000	54.49	297,700,000	73,000,000
October	340,510,000	54.56	360,200,000	74,400,000
November	364,390,000	54.56	439,300,000	74,100,000
December	398,560,000	58.98	543,800,000	72,700,000
Total	4,472,070,000		4,925,800,000	894,300,000

Rate Stabilization Plan
Plan Highlights
December 31, 2011

	Actual	Cost of Service	Variance	Year-to-Date Due (To) From customers	Reference
Hydraulic production year-to-date	4,502.2 GWh	4,472.1 GWh	-(30.1) GWh	$ (3,250,127)	Page 4
No 6 fuel cost - Current month	$ 107.25	$ 58.98	$ 48.27	$ 53,479,336	Page 5
Year-to-date customer load - Utility	5,317.5 GWh	4,925.8 GWh	391.7 GWh	$ 14,437	Page 8
Year-to-date customer load - Industrial	310.9 GWh	894.3 GWh	-(583.4) GWh	$ (29,511,328)	Page 9
				$ 20,732,318	

Rural rates		
Rural Rate Alteration (RRA) [1]	$ (4,380,677)	
Less : RRA to utility customer	$ (3,903,184)	Page 10
RRA to Labrador interconnected	(477,493)	
Fuel variance to Labrador interconnected	$ 420,517	Page 6
Net Labrador interconnected	$ (56,976)	

Current plan summary [2]		
One year recovery		
Due (to) from utility customer [2]	$ (55,939,780)	Page 10
Due (to) from Industrial customers [2]	$ (81,653,349)	Page 11
Sub total	(137,593,129)	
Four year recovery		
Hydraulic balance	$ (32,737,147)	Page 4
Total plan balance	$ (170,330,276)	

[1] Beginning January 2011, the RRA includes a monthly credit of $98,295. This amount relates to the phase in of the application of the credit from secondary energy sales to CFB Goose Bay to the Rural deficit as stated in Section B, Clause 1.3(b) of the approved Rate Stabilization Plan Regulations which received final approval in Order No. P.U. 33 (2010) issued December 15, 2010.

[2] Disposition of the load variation is one of the issues to be considered by the Public Utilities Board in a pending hearing. This may impact the balances owing to customers in the current plan.

Rate Stabilization Plan
Net Hydraulic Production Variation
December 31, 2011

	A	B	C	D	E	F	G
	Cost of Service Net Hydraulic Production (kWh)	Actual Net Hydraulic Production (kWh)	Monthly Net Hydraulic Production Variance (kWh) **(A - B)**	Cost of Service No. 6 Fuel Cost ($Can/bbl.)	Net Hydraulic Production Variation ($) **(C / O(1) X D)**	Financing Charges ($)	Cumulative Variation and Financing Charges ($) **(E + F)** **(to page 12)**
Opening balance							(40,399,402) (2)
January	427,100,000	482,169,679	(55,069,679)	54.17	(4,735,118)	(245,123)	(45,379,643)
February	388,680,000	466,139,588	(77,459,588)	54.73	(6,729,148)	(275,341)	(52,384,132)
March	415,080,000	494,923,948	(79,843,948)	55.46	(7,028,802)	(317,841)	(59,730,775)
April	355,520,000	435,834,951	(80,314,951)	55.46	(7,070,265)	(362,416)	(67,163,456)
May	324,240,000	389,528,347	(65,288,347)	55.46	(5,747,447)	(407,514)	(73,318,417)
June	328,500,000	348,118,618	(19,618,618)	54.49	(1,696,855)	(444,859)	(75,460,131)
July	386,790,000	319,834,069	66,955,931	54.49	5,791,157	(457,854)	(70,126,828)
August	379,140,000	249,827,851	129,312,149	54.49	11,184,475	(425,495)	(59,367,848)
September	363,560,000	249,399,731	114,160,269	54.49	9,873,957	(360,214)	(49,854,105)
October	340,510,000	292,121,163	48,388,837	54.56	4,190,627	(302,490)	(45,965,968)
November	364,390,000	332,422,068	31,967,932	54.56	2,768,524	(278,899)	(43,476,343)
December	398,560,000	441,833,583	(43,273,583)	58.98	(4,051,232)	(263,793)	(47,791,368)
	4,472,070,000	4,502,153,596	(30,083,596)		(3,250,127)	(4,141,839)	(47,791,368)
Hydraulic Allocation (3)					10,912,382	4,141,839	15,054,221
Hydraulic variation at year end					7,662,255	-	(32,737,147)

(1) O is the Holyrood Operating Efficiency of 630 kWh/barrel.
(2) Opening balance adjusted to reflect a correction in the calculation of 2010 station service load.
(3) At year end 25% of the hydraulic variation balance and 100% of the annual financing charges are allocated to customers.

Rate Stabilization Plan
No. 6 Fuel Variation
December 31, 2011

	A	B	C	D	E	F	G
	Actual Quantity No. 6 Fuel	Actual Quantity No. 6 Fuel for Non-Firm Sales	Net Quantity No. 6 Fuel	Cost of Service No. 6 Fuel Cost	Actual Average No. 6 Fuel Cost	Cost Variance	No.6 Fuel Variation
	(bbl.)	(bbl.)	(bbl.) **(A - B)**	($Can/bbl.)	($Can/bbl.)	($Can/bbl.) **(E - D)**	($) **(C X F)** **(to page 6)**
January	247,884	1	247,883	54.17	81.95	27.78	6,886,181
February	263,816	1	263,815	54.73	81.89	27.16	7,165,208
March	233,763	1	233,762	55.46	86.01	30.55	7,141,432
April	141,189	2	141,187	55.46	93.40	37.94	5,356,643
May	66,210	0	66,210	55.46	93.59	38.13	2,524,595
June	28,108	0	28,108	54.49	93.59	39.10	1,099,025
July	0	0	0	54.49	93.59	39.10	0
August	162	0	162	54.49	93.59	39.10	6,324
September	761	0	761	54.49	93.59	39.10	29,743
October	73,507	0	73,507	54.56	97.70	43.14	3,171,074
November	164,647	5	164,642	54.56	103.33	48.77	8,029,609
December	250,045	4	250,041	58.98	107.25	48.27	12,069,502
	1,470,092	14	1,470,078	55.47	91.92	36.45	53,479,336

Rate Stabilization Plan
Allocation of Fuel Variance - Year-to-Date
December 31, 2011

	A	B	C	D	E	F	G	H	I	J
	Twelve Months-to-Date				Year-to-Date Fuel Variance				Reallocate Rural Island Customers [1]	
	Utility	Industrial Customers	Rural Island Customers	Total	Utility	Industrial Customers	Rural Island Interconnected	Total	Utility	Labrador Interconnected
	(kWh)	(kWh)	(kWh)	(kWh)	($)	($)	($)	($)	($)	($)
				(A+B+C)	**(A/D X H)**	**(B/D X H)**	**(C/D X H)**		**(G X 89.10%)**	**(G X 10.90%)**
					(to page 7)			**(from page 5)**	**(to page 7)**	
January	4,984,784,910	380,718,623	406,692,901	5,772,196,434	5,946,806	454,194	485,181	6,886,181	432,296	52,885
February	5,033,586,374	386,795,925	411,250,703	5,831,633,002	12,128,486	931,989	990,914	14,051,389	882,904	108,010
March	5,078,312,315	389,239,371	416,214,437	5,883,766,123	18,291,645	1,402,007	1,499,169	21,192,821	1,335,760	163,409
April	5,121,071,765	381,878,794	421,145,971	5,924,096,530	22,950,624	1,711,430	1,887,410	26,549,464	1,681,682	205,728
May	5,110,586,020	367,058,140	424,590,833	5,902,234,993	25,174,443	1,808,107	2,091,509	29,074,059	1,863,535	227,974
June	5,140,258,901	345,876,811	426,802,581	5,912,938,293	26,230,185	1,764,972	2,177,927	30,173,084	1,940,533	237,394
July	5,146,631,473	327,794,819	428,861,841	5,903,288,133	26,305,635	1,675,436	2,192,013	30,173,084	1,953,084	238,929
August	5,161,145,010	318,924,866	430,010,923	5,910,080,799	26,355,021	1,628,567	2,195,820	30,179,408	1,956,476	239,344
September	5,173,855,690	317,723,422	429,399,043	5,920,978,155	26,397,292	1,621,042	2,190,817	30,209,151	1,952,018	238,799
October	5,203,014,107	314,634,846	428,967,432	5,946,616,385	29,206,152	1,766,144	2,407,929	33,380,225	2,145,465	262,464
November	5,230,154,703	314,623,079	430,831,163	5,975,608,945	36,243,978	2,180,278	2,985,578	41,409,834	2,660,150	325,428
December	5,317,495,075	310,873,875	437,593,508	6,065,962,458	46,880,624	2,740,757	3,857,955	53,479,336	3,437,438	420,517

(1) The Fuel Variance initially allocated to Rural Island Interconnected is re-allocated between Utility and Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the approved Cost of Service Study, which is 89.10% and 10.90% respectively. The Labrador Interconnected amount is then removed from the plan and written off to net income (loss).

Rate Stabilization Plan
Allocation of Fuel Variance - Monthly
December 31, 2011

	A	B	C	D	E	F	G
	Utility					**Industrial**	
	Fuel Variance		Rural Allocation		Total Fuel Variance	Fuel Variance	
	Year-to-Date Activity	Current Month Activity (1)	Year-to-Date Activity	Current Month Activity (1)	Activity for the month	Year-to-Date Activity	Current Month Activity (1)
	($)	($)	($)	($)	($)	($)	($)
					(B + D)		
	(from page 6)		**(from page 6)**		**(to page 10)**	**(from page 6)**	**(to page 11)**
January	5,946,806	5,946,806	432,296	432,296	6,379,102	454,194	454,194
February	12,128,486	6,181,680	882,904	450,608	6,632,288	931,989	477,795
March	18,291,645	6,163,159	1,335,760	452,856	6,616,015	1,402,007	470,018
April	22,950,624	4,658,979	1,681,682	345,922	5,004,901	1,711,430	309,423
May	25,174,443	2,223,819	1,863,535	181,853	2,405,672	1,808,107	96,677
June	26,230,185	1,055,742	1,940,533	76,998	1,132,740	1,764,972	(43,135)
July	26,305,635	75,450	1,953,084	12,551	88,001	1,675,436	(89,536)
August	26,355,021	49,386	1,956,476	3,392	52,778	1,628,567	(46,869)
September	26,397,292	42,271	1,952,018	(4,458)	37,813	1,621,042	(7,525)
October	29,206,152	2,808,860	2,145,465	193,447	3,002,307	1,766,144	145,102
November	36,243,978	7,037,826	2,660,150	514,685	7,552,511	2,180,278	414,134
December	46,880,624	10,636,646	3,437,438	777,288	11,413,934	2,740,757	560,479
		46,880,624		3,437,438	50,318,062		2,740,757

(1) The current month activity is calculated by subtracting year-to-date activity for the prior month from year-to-date activity for the current month.

Rate Stabilization Plan
Load Variation - Utility
December 31, 2011

	A	B	C	D	E	F	G	H	I	J	K
	Firm Energy						Secondary Energy				
	Cost of Service Sales (kWh)	Actual Sales (kWh)	Sales Variance (kWh) **(B - A)**	Cost of Service No. 6 Fuel Cost ($Can/bbl.)	Firm Energy Rate ($/kWh)	Load Variation ($) **C x {(D/O[1]) - E}**	Cost of Service Sales (kWh)	Actual Sales (kWh)	Firming Up Charge ($/kWh)	Load Variation ($) **(G - H) x I**	Total Load Variation ($) **(F + J)** **(to page 10)**
January	574,800,000	575,393,531	593,531	54.17	0.08805	(1,226)	0	0	0.00841	0	(1,226)
February	518,600,000	581,186,284	62,586,284	54.73	0.08805	(73,663)	0	0	0.00841	0	(73,663)
March	524,700,000	579,619,374	54,919,374	55.46	0.08805	(1,002)	0	0	0.00841	0	(1,002)
April	429,200,000	470,054,587	40,854,587	55.46	0.08805	(746)	0	0	0.00841	0	(746)
May	358,700,000	391,434,497	32,734,497	55.46	0.08805	(598)	0	0	0.00841	0	(598)
June	298,400,000	336,874,091	38,474,091	54.49	0.08805	(59,940)	0	0	0.00841	0	(59,940)
July	293,400,000	290,882,097	(2,517,903)	54.49	0.08805	3,923	0	0	0.00841	0	3,923
August	287,000,000	302,702,923	15,702,923	54.49	0.08805	(24,464)	0	0	0.00841	0	(24,464)
September	297,700,000	308,162,017	10,462,017	54.49	0.08805	(16,299)	0	0	0.00841	0	(16,299)
October	360,200,000	395,508,458	35,308,458	54.56	0.08805	(51,085)	0	0	0.00841	0	(51,085)
November	439,300,000	486,581,346	47,281,346	54.56	0.08805	(68,408)	0	0	0.00841	0	(68,408)
December	543,800,000	599,095,870	55,295,870	58.98	0.08805	307,945	0	0	0.00841	0	307,945
	4,925,800,000	5,317,495,075	391,695,075			14,437	0	0		0	14,437

(1) O is the Holyrood Operating Efficiency of 630 kWh/barrel.

Rate Stabilization Plan
Load Variation - Industrial
December 31, 2011

	A	B	C	D	E	F
	Cost of Service Sales	Actual Sales	Sales Variance	Cost of Service No. 6 Fuel Cost	Firm Energy Rate	Load Variation
	(kWh)	(kWh)	(kWh)	($)	($/kWh)	($)
			(B - A)			**C x {(D/O¹) - E}**
						(to page 11)
January	78,300,000	33,123,053	(45,176,947)	54.17	0.03676	(2,223,796)
February	70,900,000	24,897,496	(46,002,504)	54.73	0.03676	(2,305,324)
March	76,600,000	33,059,055	(43,540,945)	55.46	0.03676	(2,232,420)
April	75,600,000	32,113,912	(43,486,088)	55.46	0.03676	(2,229,608)
May	69,500,000	23,179,581	(46,320,419)	55.46	0.03676	(2,374,929)
June	73,800,000	10,291,643	(63,508,357)	54.49	0.03676	(3,158,402)
July	77,500,000	9,545,844	(67,954,156)	54.49	0.03676	(3,379,500)
August	77,900,000	22,374,841	(55,525,159)	54.49	0.03676	(2,761,381)
September	73,000,000	28,599,758	(44,400,242)	54.49	0.03676	(2,208,116)
October	74,400,000	30,269,065	(44,130,935)	54.56	0.03676	(2,199,626)
November	74,100,000	30,954,575	(43,145,425)	54.56	0.03676	(2,150,505)
December	72,700,000	32,465,052	(40,234,948)	58.98	0.03676	(2,287,721)
	894,300,000	310,873,875	(583,426,125)			(29,511,328)

(1) O is the Holyrood Operating Efficiency of 630 kWh/barrel.

Rate Stabilization Plan
Summary of Utility Customer
December 31, 2011

	A	B	C	D	E	F	G
	Load Variation	Allocation Fuel Variance	Allocation Rural Rate Alteration [1]	Subtotal Monthly Variances	Financing Charges	Adjustment [2]	Cumulative Net Balance
	($)	($)	($)	($)	($)	($)	($)
				(A + B + C)			
	(from page 8)	**(from page 7)**					**(to page 12)**
Opening Balance							(56,251,212) [3]
January	(1,226)	6,379,102	(246,535)	6,131,341	(341,304)	(1,271,620)	(51,732,795)
February	(73,663)	6,632,288	(274,839)	6,283,786	(313,889)	(1,284,422)	(47,047,320)
March	(1,002)	6,616,015	(263,101)	6,351,912	(285,460)	(1,280,959)	(42,261,827)
April	(746)	5,004,901	(246,285)	4,757,870	(256,424)	(1,038,821)	(38,799,202)
May	(598)	2,405,672	(211,424)	2,193,650	(235,414)	(865,070)	(37,706,036)
June	(59,940)	1,132,740	(197,367)	875,433	(228,781)	(744,492)	(37,803,876)
July	3,923	88,001	(253,917)	(161,993)	(229,375)	(2,708,112)	(40,903,356)
August	(24,464)	52,778	(403,051)	(374,737)	(248,181)	(2,818,164)	(44,344,438)
September	(16,299)	37,813	(397,541)	(376,027)	(269,060)	(2,868,988)	(47,858,513)
October	(51,085)	3,002,307	(404,167)	2,547,055	(290,382)	(3,682,184)	(49,284,024)
November	(68,408)	7,552,511	(467,859)	7,016,244	(299,031)	(4,530,072)	(47,096,883)
December	307,945	11,413,934	(537,098)	11,184,781	(285,760)	(5,577,583)	(41,775,445)
Year to date	14,437	50,318,062	(3,903,184)	46,429,315	(3,283,061)	(28,670,487)	14,475,767
Hydraulic allocation **(from page 4)**							(14,164,335)
Total	14,437	50,318,062	(3,903,184)	46,429,315	(3,283,061)	(28,670,487)	(55,939,780)

(1) The Rural Rate Alteration is allocated between Utility and Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the approved Cost of Service Study, which is 89.10% and 10.90% respectively. The Labrador Interconnected amount is then removed from the plan and written off to net income (loss).

(2) The RSP adjustment rate for Utility is 0.931 cents per kwh effective July 1, 2011 to June 30, 2012.

(3) Opening balance adjusted to reflect a correction in the calculation of 2010 station service load.

Rate Stabilization Plan
Summary of Industrial Customers
December 31, 2011

	A	B	C	D		E	F
	Load Variation	Allocation Fuel Variance	Subtotal Monthly Variances	Financing Charges	Payment [3]	Adjustment [1]	Cumulative Net Balance
	($)	($)	($)	($)		($)	($)
			(A + B)				
	(from page 9)	**(from page 7)**					**(to page 12)**
Opening Balance							(62,611,891) [2]
Payment					10,000,000		(52,611,891)
January	(2,223,796)	454,194	(1,769,602)	(379,898)		339,552	(54,421,839)
February	(2,305,324)	477,795	(1,827,529)	(330,205)		265,916	(56,313,657)
March	(2,232,420)	470,018	(1,762,402)	(341,683)		336,630	(58,081,112)
April	(2,229,608)	309,423	(1,920,185)	(352,407)		328,009	(60,025,695)
May	(2,374,929)	96,677	(2,278,252)	(364,206)		257,654	(62,410,499)
June	(3,158,402)	(43,135)	(3,201,537)	(378,676)		146,954	(65,843,758)
July	(3,379,500)	(89,536)	(3,469,036)	(399,507)		141,637	(69,570,664)
August	(2,761,381)	(46,869)	(2,808,250)	(422,120)		244,219	(72,556,815)
September	(2,208,116)	(7,525)	(2,215,641)	(440,238)		289,853	(74,922,841)
October	(2,199,626)	145,102	(2,054,524)	(454,594)		311,733	(77,120,226)
November	(2,150,505)	414,134	(1,736,371)	(467,927)		318,007	(79,006,517)
December	(2,287,721)	560,479	(1,727,242)	(479,373)		331,295	(80,881,837)
Year to date	(29,511,328)	2,740,757	(26,770,571)	(4,810,834)	10,000,000	3,311,459	(18,269,946)
Hydraulic allocation **(from page 4)**							(771,512)
Total	(29,511,328)	2,740,757	(26,770,571)	(4,810,834)	10,000,000	3,311,459	(81,653,349)

(1) The RSP adjustment rate for Industrial Customers excluding Teck Resources is 0.785 cents per kWh effective January 1, 2008. The rate for Teck Resources is 2.000 cents per kWh.

(2) Opening balance adjusted to reflect a correction in the calculation of 2010 station service load and interest related to payment as per Board Order No. P.U. 1 (2011)

(3) This payment reflects a distribution of the industrial load variation component of the plan as per Board Order No. P.U. 1 (2011).

Rate Stabilization Plan
Overall Summary
December 31, 2011

	A	B	C	D
	Hydraulic Balance	Utility Balance	Industrial Balance	Total To Date
	($)	($)	($)	($)
				(A + B + C)
	(from page 4)	**(from page 10)**	**(from page 11)**	
Opening Balance	(40,399,402)	(56,251,212)	(62,611,891)	(159,262,505) [(1)]
January	(45,379,643)	(51,732,795)	(54,421,839)	(151,534,277)
February	(52,384,132)	(47,047,320)	(56,313,657)	(155,745,109)
March	(59,730,775)	(42,261,827)	(58,081,112)	(160,073,714)
April	(67,163,456)	(38,799,202)	(60,025,695)	(165,988,353)
May	(73,318,417)	(37,706,036)	(62,410,499)	(173,434,952)
June	(75,460,131)	(37,803,876)	(65,843,758)	(179,107,765)
July	(70,126,828)	(40,903,356)	(69,570,664)	(180,600,848)
August	(59,367,848)	(44,344,438)	(72,556,815)	(176,269,101)
September	(49,854,105)	(47,858,513)	(74,922,841)	(172,635,459)
October	(45,965,968)	(49,284,024)	(77,120,226)	(172,370,218)
November	(43,476,343)	(47,096,883)	(79,006,517)	(169,579,743)
December	(32,737,147)	(55,939,780)	(81,653,349)	(170,330,276)

(1) Opening balance adjusted to reflect a correction in the calculation of 2010 station service load and interest related to payment as per Board Order No. P.U. 1 (2011)

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

2011 ANNUAL REPORT
ON
KEY PERFORMANCE INDICATORS

Pursuant to Order No. P.U. 14 (2004)

NEWFOUNDLAND AND LABRADOR HYDRO

newfoundland labrador hydro
a nalcor energy company

TABLE OF CONTENTS

1 Introduction

In Order No. P.U. 14 (2004), the Board required Hydro to file appropriate historic, current and forecast comparisons of reliability, operating, financial and other Key Performance Indicators (KPIs). These were ordered to be filed with Hydro's annual financial report, commencing in 2004.

In compliance with the above Order, Hydro has 16 individual KPIs within the following four general categories: Reliability, Operating, Financial and Customer Related.

Within each of these categories, KPI data is reported on a historic basis for Hydro. Where appropriate, KPIs are subcategorized based on whether they relate to generation, transmission, distribution or overall corporate activity. For most of the Reliability KPIs, data from the Canadian Electricity Association (CEA) is provided in this report, as has been the case in prior years. CEA data is published only to 2010. CEA data is unavailable for underfrequency load shedding, a reliability KPI, as this measure is unique to Hydro's Island Interconnected System. In the Operating category, the KPIs used to measure performance relate to two specific facilities within Hydro's system: Bay d'Espoir and Holyrood. For these two generation plants, performance is measured and compared on a year-over-year basis.

Section 2 of this report provides an overview of Hydro's KPI performance in 2011 compared with the prior year as well as a comparison of actual KPI results compared with targets. This is followed by a detailed analysis of each individual KPI within the four categories.

Section 4 - Data Table of Key Performance Indicators excludes the 2012 target levels. A revised table will follow once these targets have been established.

2 Overview of Key Performance Indicator Results

2.1 Performance in 2011 versus 2010

Hydro faced several challenges in 2011 that impacted unit availability and overall, the Capability Factor slightly missed the target. Hydraulic capability performance in 2011 was impacted by an extended outage to the Hinds Lake unit. The capability performance at the Holyrood Generating Station decreased in 2011, primarily due to Unit 3 which experienced a series of lengthy outages due to generator excitation equipment issues. The performance at Holyrood did not impact reliability of supply because of low production requirements in 2011. This reduced requirement enabled flexibility for the extended maintenance time to complete repairs.

The underfrequency load shedding performance showed a significant improvement over 2010 and the past five-year average. The three underfrequency events in 2011 represent the best performance since these events started being recorded in 1998.

Transmission and distribution reliability was significantly impacted in 2011 due to a number of severe weather-related events which caused numerous and lengthy outages, primarily in the Northern and Central regions of Newfoundland. The most notable outages occurred during the fourth quarter and affected the Great Northern Peninsula (GNP) and customers served by the Bottom Waters Terminal Station. The distribution performance shows a decline over the past two years. The transmission performance in 2011 reversed what was generally an improving trend over the past four years.

The operating KPIs for energy conversion showed an improvement in the Holyrood fuel conversion rate. This was driven somewhat by a slightly higher average load on the operating units in 2011. Unit operating time continued to be minimized in 2011, with units placed on line only as required to support Avalon transmission and system peak loads.

The hydraulic conversion factor at Bay d'Espoir decreased slightly from 2010, primarily as a result of increased water levels and the requirement to operate the plant to reduce and control the spill of water, particularly during the summer months in 2011.

Hydro's "Financial Performance Indicators" can be found at Section 3.3 on page E28.

The final category of KPIs called "Customer-Related" deals with Hydro's residential customer satisfaction.

2.2 Performance in 2011 versus 2011 Target

The table below summarizes Hydro's KPI performance in 2011 compared to targets set for each measure. Targets were met with respect to the number of underfrequency load shedding events, hydraulic conversion rate, and the generation forced outage rate. Other targets were not met due to a number of challenges further described in this report.

The rationale for the 2011 targets was summarized in the February 2011 report to the Board entitled *2010 Annual Report on Key Performance Indicators*. The 2011 rationale is included in this report as Appendix A.

Hydro's KPI Targets and Operating Results for 2011					
Category	**KPI**	**Units**	**2011 Target**	**2011 Results**	**Target Achieved**
Reliability	Weighted Capability Factor (WCF)	%	86.3	83.3	No
	DAFOR	%	3.1	2.7	Yes
	T-SAIDI	Minutes/Point	258.5[1]	432[2]	No
	T-SAIFI	Number/Point	2.0[1]	4.5[2]	No
	T-SARI	Minutes/Outage	129[1]	96[2]	Yes
	SAIDI	Hours/Customer	6.2	16.3	No
	SAIFI	Number/Customer	3.8	5.7	No
	Underfrequency Load Shedding	# of events	6	3	Yes
Operating	Hydraulic CF	GWh/MCM	0.433	0.434	Yes
	Thermal CF	kWh/BBL	630	603	No
Financial	Controllable Unit Cost	$/MWh	N/A	$14.96	N/A
Other	Customer Satisfaction (Residential)	Max=100%	>90%	88%	No

[1] Transmission reliability targets were set on combined planned and unplanned outages.
[2] The transmission reliability indicator shown is for planned and unplanned outages.

3 Performance Indices

The following defines and describes detailed Key Performance Indicator (KPI) data within four general categories: Reliability, Operating, Financial, and Customer Related.

Note: *Some of the reliability performance outcomes measures for 2009 in this section have changed slightly from the data which was filed in the 2009 KPI Report. The changes were the result of data correction and verification of the 2009 data which occurred after the KPI report was filed. This has been completed for the 2010 data.*

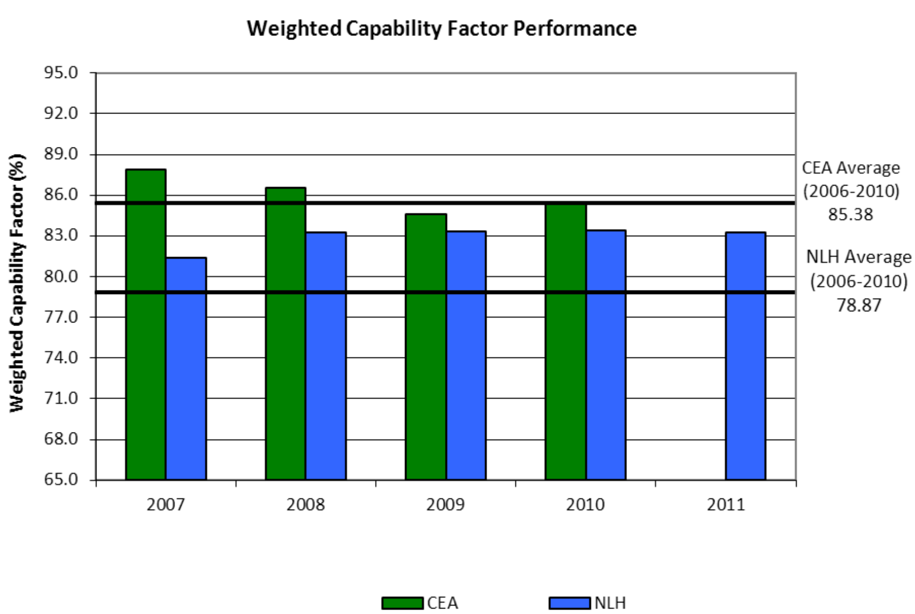
3.1 Reliability Performance Indicators

Hydro monitors reliability performance with eight separate metrics. These metrics have been divided into the following subcategories: Generation, Transmission, Distribution and Other.

3.1.1 Reliability KPI: Generation

3.1.1 a) Weighted Capability Factor (WCF) – *a reliability KPI for generation assets that includes Hydro's thermal, gas turbine and hydroelectric generation assets on the Island and Labrador Interconnected Systems. The WCF measures the percentage of the time that a unit or a group of units is available to supply power at maximum continuous generating capacity. The factor is weighted to reflect the difference in generating unit sizes, meaning larger units have a greater impact on this measure.*

In 2011, Hydro's WCF was 83.3%. This is lower than the target of 86.3%; however it does reflect an improvement over the 2006 to 2010 five year average of 78.9%.



Thermal unit performance was affected by issues with all three of the Holyrood units. Holyrood Unit 3 had a capability factor of only 48% in 2011, primarily due to issues with the generator excitation equipment. Holyrood Units 1 and 2 each experienced capability factors of approximately 75%, attributed mainly to starting failures due to boiler tube leaks.

Overall, the hydraulic unit performance improved in 2011 over 2010. There were no major issues with the hydraulic generation, except at Hinds Lake. The capability factor of this unit was reduced to 85% in 2011 due to an extended outage required for a slip ring repair.

Gas turbine performance improved in 2011 from the 2010 performance. Each of the Hardwoods and Stephenville gas turbine plants normally has two gas turbine engines operating a single generator. However, one of the engines was removed from Stephenville and installed in Hardwoods in 2007 to replace a failed Hardwoods engine. This resulted in a reduction of the Stephenville plant to a capacity of 25 MW, pending the repairs to the failed engine removed from Hardwoods. In December, a stator ground fault was detected and the Stephenville unit is not anticipated to be available until repairs are completed in late 2012. The Hardwoods plant capacity is currently 50 MW. Calculation details for weighted capability as well as a list of factors that may impact KPI performance are in Appendix B of this report.

The table below provides a comparison by unit type along with the weightings applied to the CEA values to provide for the comparison to Hydro for the period 2006-2010. Hydro's hydro generation capability was slightly better than the comparable weighted national average. The weighted average is lower for Hydro's thermal-oil fired units and gas turbines.

Capability Factor Performance

	CEA (2006-2010)	**NLH (2006-2010)**	**Weighting Factor**
Hydro	91.60	93.37	50%
Thermal - Oil Fired	74.39	61.94	33%
Gas Turbine	88.59	74.97	17%

The weighted national average is developed by using national average capabilities values for the unit types in Hydro's system (hydro, oil-fired thermal and gas turbine) and applying weightings to these based upon the maximum continuous ratings of Hydro's generation. The quoted CEA value is therefore not a CEA published value but a re-stated value to facilitate a comparison to Hydro.

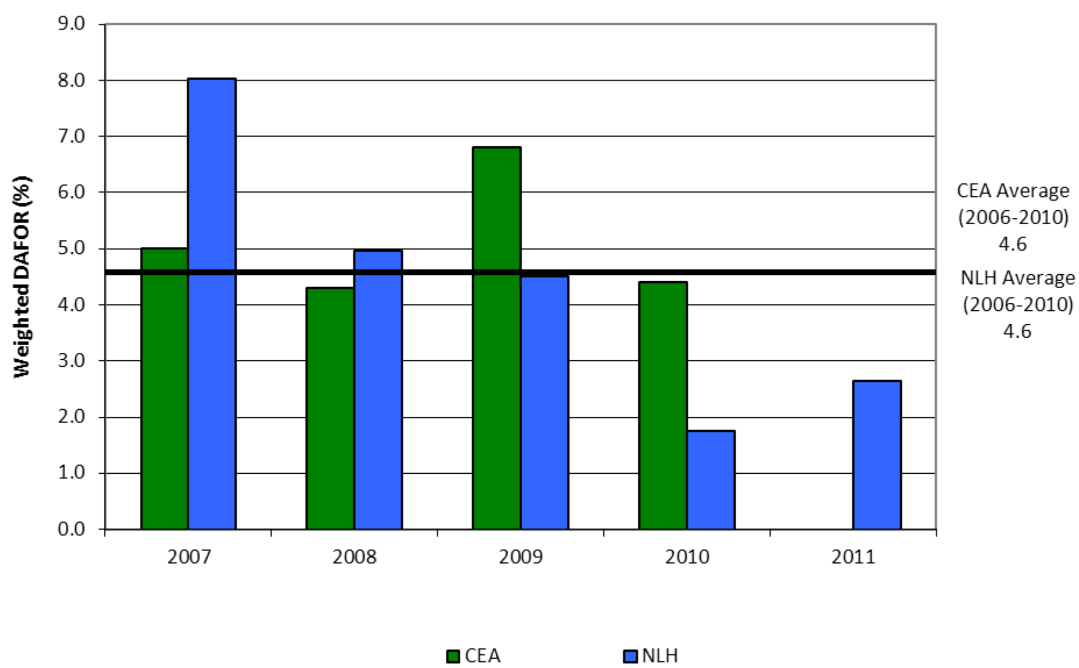
3.1.1 b) Weighted Derating-Adjusted Forced Outage Rate (DAFOR) - *a reliability KPI for generation assets that includes Hydro's thermal and hydroelectric generation assets on the Interconnected systems[3]. DAFOR measures the percentage of the time that a unit or group of units is unable to generate at its Maximum Continuous Rating (MCR) due to forced outages. The KPI is weighted to reflect differences in generating unit sizes.*

In 2011, Hydro's weighted DAFOR was 2.65% versus a target of 3.1%. The DAFOR was impacted by starting failures on Holyrood Units 1 and 2 and generator collector and brush issues on Holyrood Unit 3. Hydro's overall weighted DAFOR from 2006 to 2010 of 4.6%, is comparable to the equivalently weighted national average for the same period. The following table provides a 2006-2010 comparison by unit type:

DAFOR Performance

	CEA (2006-2010)	NLH (2006-2010)	Weighting Factor
Thermal - Oil Fired	7.31	14.43	40%
Hydro	2.74	0.90	60%

Weighted DAFOR Performance



[3] DAFOR is not applicable to the gas turbines because of the gas turbines' low operating hours.

3.1.1.1 Generation Equipment Performance

The table below highlights the various performance indices for Hydro's generation facilities. Indices for 2010 and for the latest CEA national average for the period 2006-2010 are included for comparison.

Generation Performance Indices

Index		Hydro	Thermal	Gas Turbine
Failure Rate	NLH 2011	2.12	2.95	137.66
(Forced Outages per 8,760	NLH 2010	3.33	6.27	32.94
operating hours)	CEA '06-'10	2.15	8.90	18.18
Incapability	NLH 2011	6.56	33.32	24.90
Factor	NLH 2010	8.58	26.98	25.55
(Percent of Time)	CEA '06-'10	8.40	25.61	11.49
Derating Adjusted Forced	NLH 2011	0.82	7.88	
Outage Rate	NLH 2010	0.64	5.07	
(Percent of Time)	CEA '06-'10	2.74	10.22	
Utilization	NLH 2011			10.45
Forced Outage	NLH 2010			7.60
Probability (Percent of Time)	CEA '06-'10			8.09

3.1.1.1 (a) Hydro Unit Performance

As indicated in the above Generation Performance Indices table, the hydro unit failure rate and incapability factor improved in 2011 when compared to 2010. The hydraulic unit derating adjusted forced outage rate deteriorated in 2011 when compared to 2010, however it continues to be significantly better than the latest five-year national average.

3.1.1.1 (b) Thermal Unit Performance

Thermal unit performance improved significantly in 2011 in the failure rate measure. Performance in the derating adjusted forced outage rate measure declined, but is still significantly better than the national five-year average. The incapability factor performance declined in 2011 and continues to trail the national five-year average.

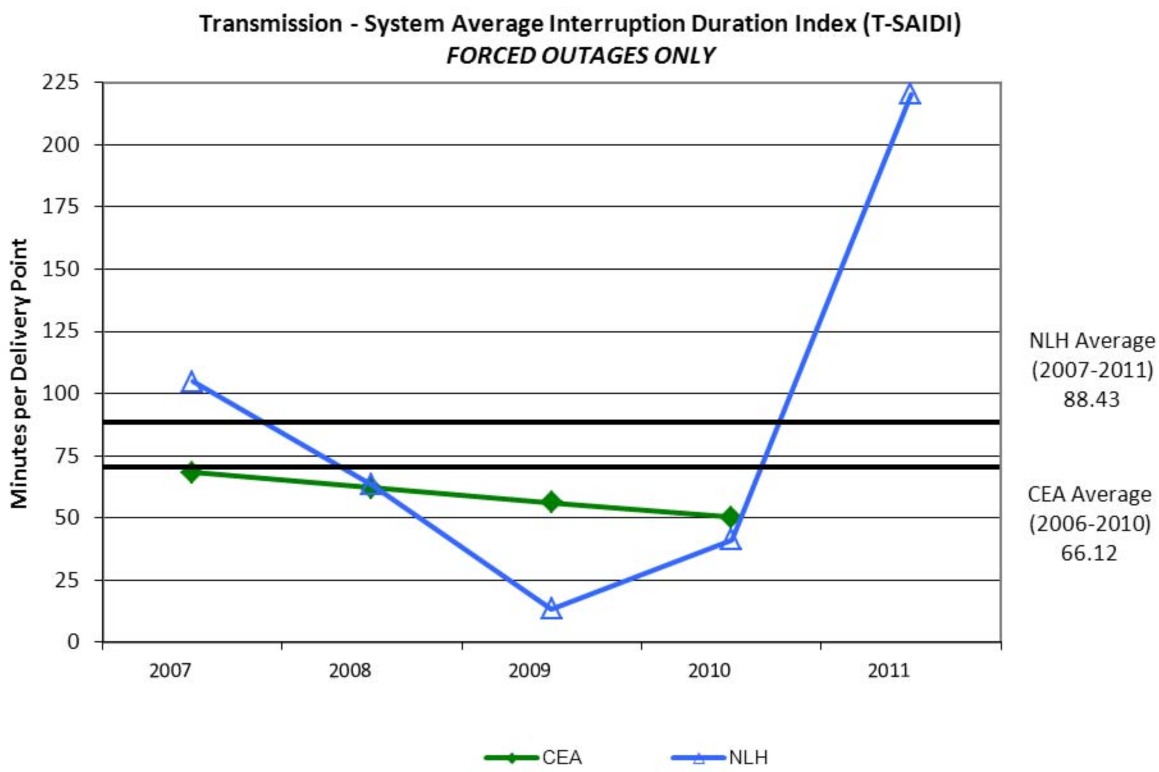
3.1.1.1 (c) Gas Turbine Unit Performance

The Generation Performance Indices table indicates that Hydro's gas turbines failure rate performance declined in 2011 from 2010. The failure rate calculation is very volatile due to the normally low operating hours of Hydro's gas turbines. A major failure at the Stephenville gas turbine in December was the main cause for the decline in performance. The incapability factor performance for Hydro's gas turbines improved slightly from 2010. Of particular importance to Hydro's use of gas turbines is the utilization forced outage probability (UFOP). The measure describes the degree to which a standby unit can be called upon to supply load when requested. In 2011, the performance in this area declined from 2010 and fell below the national average. This was primarily due a failure at the Stephenville gas turbine in December 2011.

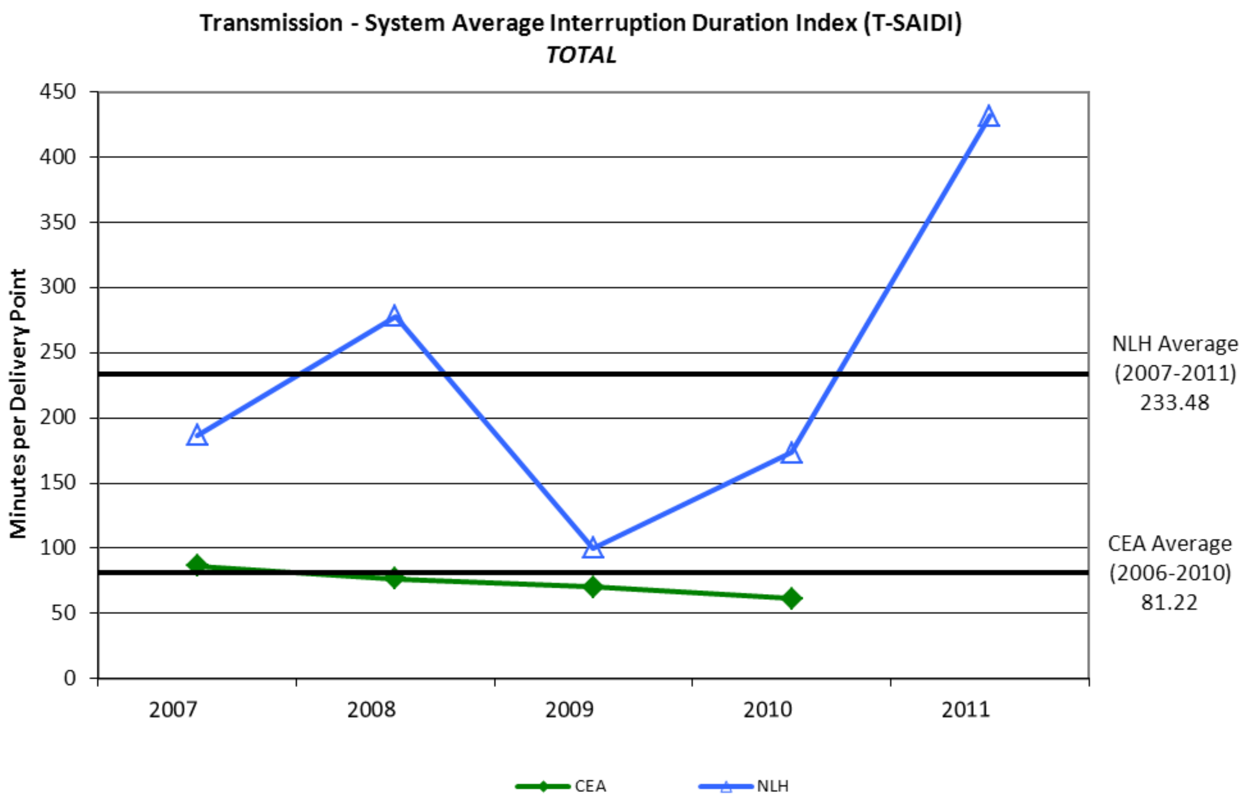
3.1.2 Reliability KPI: Transmission

3.1.2 a) Transmission System Average Interruption Duration Index (T-SAIDI) - *reliability KPI for bulk transmission assets which measures the average duration of outages in minutes per delivery point.*

The fourth quarter T-SAIDI was 267.6 minutes per delivery point (forced and planned combined). The total 2011 T-SAIDI was 432 minutes per delivery point, 67% above the 2011 target[4] of 258.5 minutes per delivery point. In comparison, the 2010 total was 173.5 minutes per delivery point. The forced outage duration in 2011 increased to 220.6 minutes from 41.3 minutes in 2010. The planned outage duration increased to 211.4 minutes from 132.2 minutes in 2010. Of note is that, for the fourth quarter, the contribution of the force outage duration was 78% of the 2011 total.



[4] "Target" means less than or equal to the value set as a performance outcome.



There were 12 planned outages and a number of forced outages in the fourth quarter. A summary of the forced and the notable planned outages follows:

Forced

There were four outages affecting customers supplied by TL-260 on the Baie Verte Peninsula, summarized as follows:

- On October 27, all customers experienced an unplanned outage of two minutes in duration. The trip was caused by an ice buildup on the transmission line.
- On October 28, all customers supplied experienced three unplanned outages of 26, six and 24 minutes in duration. The trips were caused by an ice buildup on the transmission line.
- On October 29, all customers experienced an unplanned power outage of 434 minutes in duration. Customers in the towns of Burlington, Middle Arm, Smith's Harbour, Ming's Bight, Pacquet, Nipper's Harbour and Woodstock were already experiencing an unplanned power outage due to issues on the distribution system. A helicopter patrol of TL-260 determined that ice falling from the conductor had caused two phase conductors to come to rest on top of a crossarm. There was other line damage also observed that required repairs before the line could be restored.

An early winter snowstorm passing through the area resulted in the outages during the period of October 27 – 29.

- On December 8, all customers experienced an unplanned power outage of 868 minutes in duration. The outage was caused by a tree contact on Newfoundland Power's transmission line, 363L. This occurred during a severe winter storm that impacted the area.

On December 8, customers on Change Islands and Fogo Island, served by the Farewell Head Terminal Station, experienced an unplanned power outage of four minutes in duration. The outage resulted when Newfoundland Power conducted emergency switching on transmission line 142L. Newfoundland Power isolated the Cobb's Pond Substation due to a broken pole on 108L. Cobb's Pond supplies the Farewell Head Terminal Station.

The following table lists the unplanned outages which occurred from December 8 to December 11 at various delivery points on the GNP. A winter storm passed through the area with extremely high winds (over 130 kmh), resulting in widespread salt contamination. In addition, a current transformer associated with the backup protection for TL-241 at Peter's Barren failed.

Start Time	End Time	Delivery Point Affected	Number of Interruptions	Duration of Interruptions (mins)	Cause
Dec 10, 2011 05:29	Dec 11, 2011 12:33	Bear Cove	26	823	Winter Storm/TL241 Protection Trips
Dec 10, 2011 06:25	Dec 10, 2011 14:40	Cow Head	24	154	Winter Storm
Dec 09, 2011 12:04	Dec 10, 2011 09:17	Daniels Harbour	11	200	Winter Storm
Dec 08, 2011 17:46	Dec 10, 2011 14:40	Glenburnie	26	799	Tree on TL226/Winter Storm
Dec 10, 2011 05:29	Dec 11, 2011 09:00	Hawkes Bay	4	509	Winter Storm/TL241 Protection Trips
Dec 10, 2011 05:29	Dec 10, 2011 16:46	Main Brook	5	1759	Winter Storm/TL241 Protection Trips
Dec 09, 2011 00:47	Dec 10, 2011 14:40	Parsons Pond	20	1194	Winter Storm/TL241 Protection Trips
Dec 10, 2011 05:29	Dec 11, 2011 12:33	Plum Point	33	348	Winter Storm/TL241 Protection Trips
Dec 08, 2011 17:46	Dec 10, 2011 14:40	Rocky Harbour	26	207	Tree on TL226/Winter Storm
Dec 10, 2011 05:29	Dec 10, 2011 16:46	Roddickton	5	1759	Winter Storm/TL241 Protection Trips
Dec 10, 2011 05:29	Dec 11, 2011 12:14	St. Anthony	8	516	Winter Storm/TL241 Protection Trips
Dec 08, 2011 17:46	Dec 10, 2011 14:40	Wiltondale	25	436	Tree on TL226/Winter Storm

Planned

On October 16, all customers supplied from transmission line TL-261 in the St. Anthony distribution system experienced a planned outage a 280 minutes in duration. The outage was required to perform maintenance on the 69 kV and 25 kV switchgear at the St. Anthony

Diesel Plant Terminal Station, for an emergency replacement of disconnect switch SA1-D1, and for replacement of an insulator on structure #232 TL-261.

On October 23, all customers supplied from transmission line TL-257 in the Main Brook and Roddickton areas experienced a planned outage of 230 minutes in duration. The outage was required to perform emergency repairs on disconnect switches B1C1-2 and B1C3-1 at the St. Anthony Airport Terminal Station.

On November 3, customers served by transmission line TL-220 in the towns of Pool's Cove, Belleoram, English Harbour West, St. Jacques, Recontre East, Gaultois, Harbour Breton, Hermitage and Seal Cove (Fortune Bay) experienced a planned power outage of 386 minutes in duration. The outage was required to safely connect a mobile substation at the English Harbour West Terminal. The terminal station was bypassed to allow workers to safely perform upgrades and maintenance to terminal station equipment.

On November 3, customers in Conne River experienced a planned outage of 580 minutes in duration. A mobile substation was connected at the Conne River Terminal Station but it was incorrectly energized at 25 kV. These customers are normally supplied at 12.5 kV. The mobile substation had been configured for an incorrect low side voltage. There were customer damages arising from this incident. An outage report was filed with the Board, which was followed up by the submission to the Board of Hydro's investigation report.

On November 5, customers supplied from the Rocky Harbour Terminal Station experienced a planned outage of 12 minutes in duration. Customers supplied from by the Glenburnie and Wiltondale Terminal Stations experienced planned outages of 83 minutes in duration. The outages were scheduled to complete maintenance on TL-226 and terminal station equipment. However, after the stations were isolated, the outage was cancelled due to time constraints following delays in switching at the Deer Lake end. No work was actually completed.

On November 10, customers served by transmission line TL-220 in the towns of Conne River, Pool's Cove, Belleoram, English Harbour West, St. Jacques, Recontre East, Gaultois, Harbour Breton, Hermitage and Seal Cove (Fortune Bay) experienced a planned power outage of 337 minutes in duration. The outage was required to safely disconnect mobile substations from the Conne River and English Harbour West Terminal Stations.

On November 14, Newfoundland Power customers supplied from transmission line TL-210 in the town of Glenwood experienced a planned outage of seven minutes in duration. The outage was required to complete outstanding maintenance work on TL-210.

On November 20, customers supplied from the Glenburnie Terminal Station experienced a planned outage of 236 minutes. The outage was required to replace the metering tank and perform maintenance at the terminal station.

On November 20, customers supplied from the Plum Point and Bear Cove Terminal Stations experienced a planned power outage of 51 minutes in duration. The outage was required to remove transmission line TL-241 from service in order to make preparations to safely connect a mobile substation at the Hawke's Bay Terminal Station.

On November 20, customers supplied from the Hawke's Bay Terminal Station experienced another planned power outage of 118 minutes in duration. This outage was required to safety complete the connection of a mobile substation at the terminal station. The terminal station was bypassed to allow workers to safely perform upgrades and maintenance to terminal equipment.

On November 30, customers served by the Jackson's Arm Terminal Station experienced a planned power outage of 19 minutes in duration, while customers served by the Hampden Terminal Station experienced a planned power outage of 251 minutes in duration. The outages were required to safely repair crossarms on structures #467 and #469 on TL-251 between the Hampden Tap and Hampden Terminal Station.

On December 13, customers served by the Plum Point, Hawke's Bay, Bear Cove, Main Brook, Roddickton, and St. Anthony Diesel Plant Terminal Stations on the Great Northern Peninsula experienced planned power outages ranging from 90 to 205 minutes. The outages were required to investigate and remove from service a faulty current transformer from circuit breaker B1L41 at the Peter's Barren Terminal Station. The diesel plants at Hawke's Bay and St. Anthony were used to lessen the customer impact of the planned outage.

As previously reported, Hydro's planned outage durations tend to be longer than the national average. This is due to the relatively high number of delivery points on the Hydro system that do not have alternative supply options such as multiple station transformers or greater distribution system integration. This was a contributing factor to the planned outages on the GNP where station maintenance required customer outages for which there is no alternate supply point or local generation.

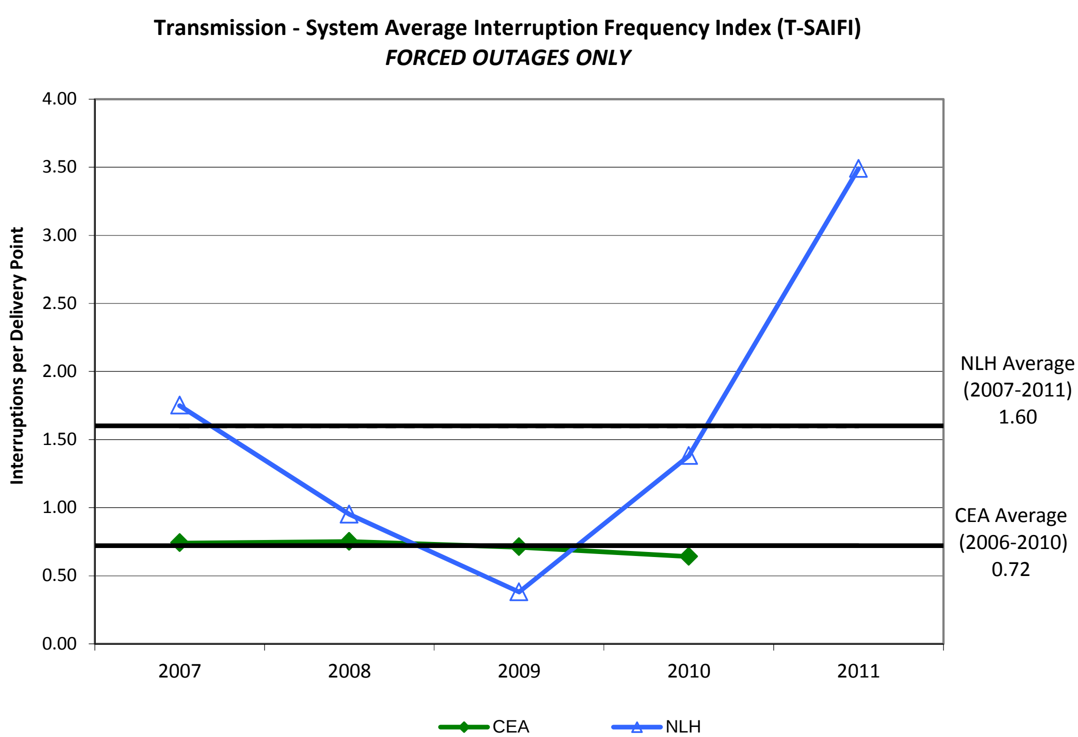
Appendix C1 lists all of the significant transmission events in 2011. Significant events are indentified as those resulting in forced outages with an unsupplied energy of greater than 1,000 megawatt (MW) mins. Unsupplied energy is a calculation of the outage duration times the load, in MW, at the delivery point before it was interrupted. This measures the energy that could have been supplied if the delivery had not been interrupted.

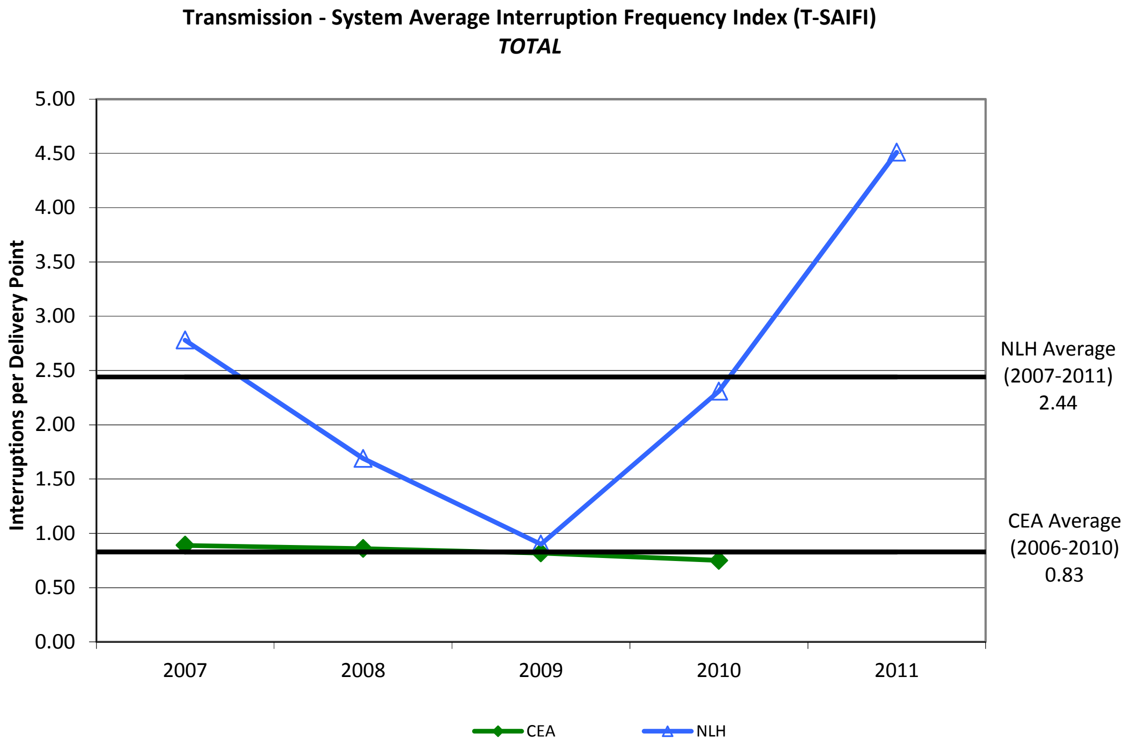
3.1.2 b) Transmission System Average Interruption Frequency Index (T-SAIFI) - *a reliability KPI for bulk transmission assets that measures the average number of sustained outages per delivery point*.

The fourth quarter T-SAIFI was 2.71 outages per bulk delivery point, with contributions of forced and planned outage frequency of 2.25 and 0.46, respectively. In comparison, the 2010 fourth quarter T-SAIFI was 0.59 outages per bulk delivery point. The increase was driven primarily by a deterioration of forced outage frequency (2.25 in 2011 compared to 0.16 in 2010). The planned outage frequency increased slightly (by 7%) from the fourth quarter of 2010. Overall, the increase in outage frequency was the result of the forced outages described in the previous section.

The overall 2011 T-SAIFI was 4.52 outages per bulk delivery point which is significantly higher than last year's average of 2.30 outages per delivery point, an increase of 97%. This increase can be attributed to a significant increase in the outage frequency in the Northern Region and outages to TL-260 supplying the Baie Verte Peninsula area. The 2011 target was 2.01 outages per bulk delivery point. The 2011 outcome was 125% above target. The number of forced outages per delivery point in 2011 (3.49) increased significantly from 2010 (1.38). The frequency of planned outages per delivery point increased by 10%, to 1.02 in 2011.

The frequency of Hydro's forced delivery point outages has been generally higher than the national average. This result is expected and can generally be attributed to the number of delivery points that are supplied by a single transmission line. The most severe example is on the Great Northern Peninsula, where one line, TL-239, supplies up to nine delivery points. There are a number of other locations where a single line supplies three delivery points.



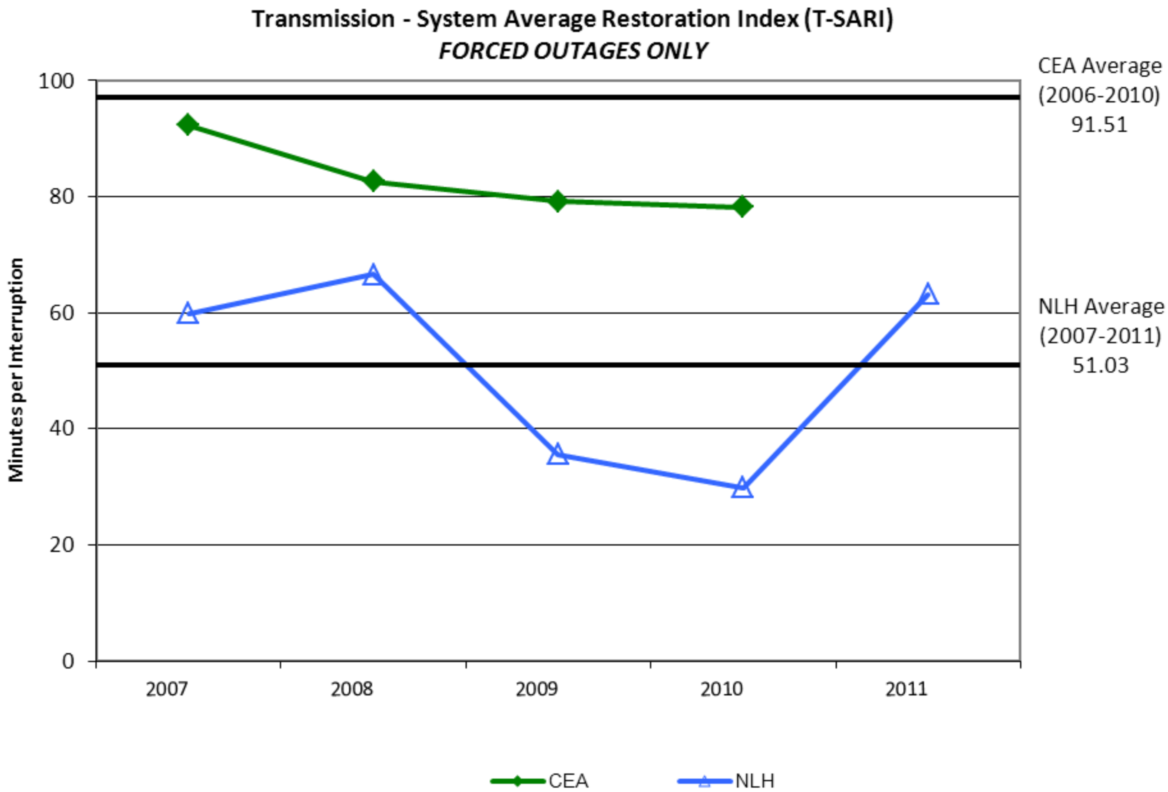


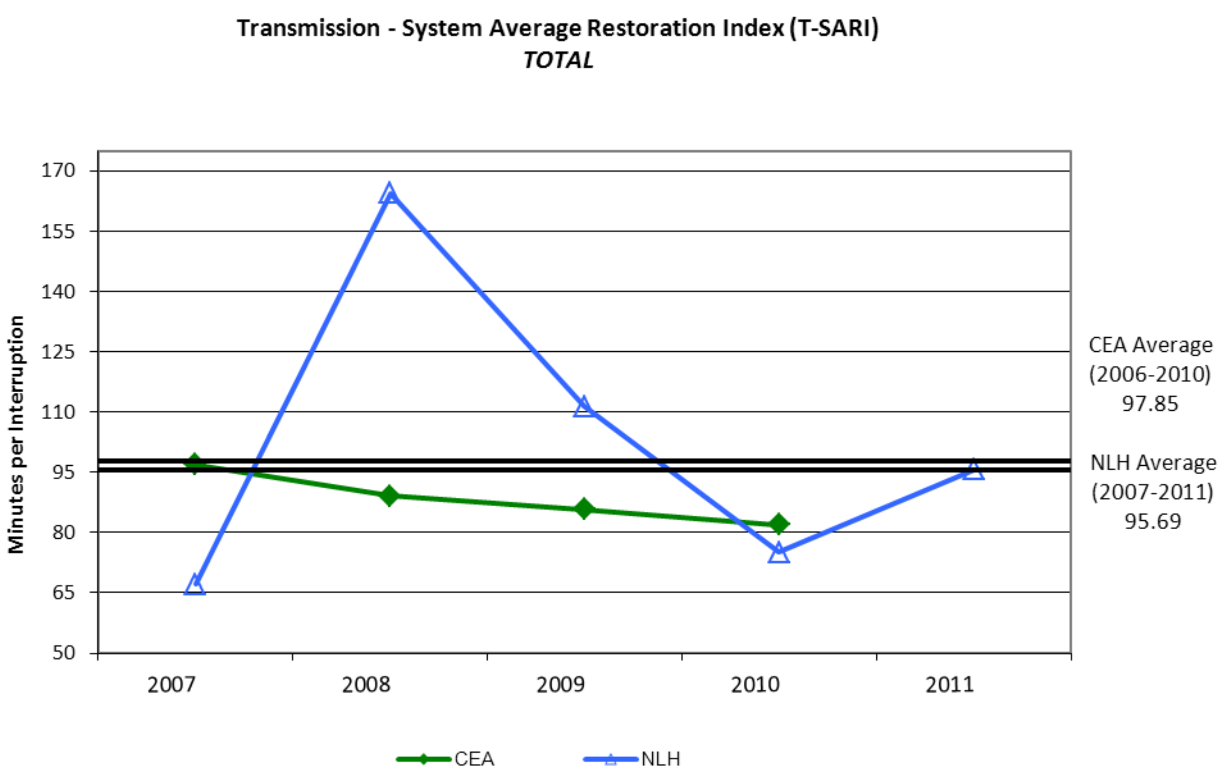
3.1.2 c) Transmission System Average Restoration Index (T-SARI) - *reliability KPI for bulk transmission assets which measures the average duration per transmission interruption. T-SARI is calculated by dividing T-SAIDI by T-SAIFI.*

Hydro's total transmission T-SARI was 98.4 minutes per interruption for the fourth quarter of 2011 compared to 123.6 minutes per interruption during the same quarter in 2010, a 20% decrease. The forced outage component of T-SARI was 79.8 minutes per interruption is and significantly higher than in 2010 (1.2 minutes per interruption). The planned outage component of T-SARI was 188.4 minutes per interruption which is 10% higher than during the fourth quarter of 2010.

Hydro's 2011 total transmission T-SARI was 95.8 minutes per interruption, compared to 75.0 minutes in 2010 and a 2011 target of 129 minutes. The forced outage component of T-SARI was 63.2 minutes per interruption, an increase of 110% over 2010. The planned outage component of T-SARI was 207.3 minutes per interruption, which is an increase of 46% over 2010. Since T-SARI is the ratio of T-SAIDI to T-SAIFI, this increase is driven by greater increase in T-SAIDI relative to T-SAIFI.

Hydro's total T-SARI performance in 2011 was better than the latest five-year national average. This can be seen in the chart below.


Transmission - System Average Restoration Index (T-SARI)
FORCED OUTAGES ONLY
Minutes per Interruption
100
80
60
40
20
0
2007
2008
2009
2010
2011
CEA Average
(2006-2010)
91.51
NLH Average
(2007-2011)
51.03
CEA
NLH

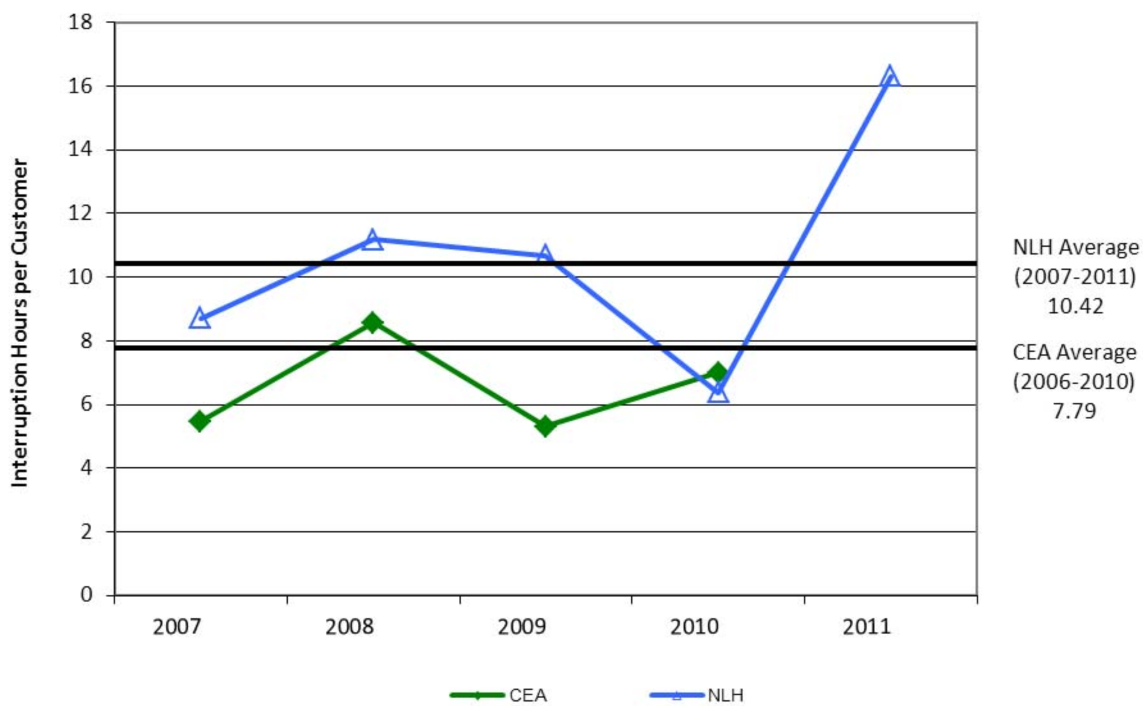

Transmission - System Average Restoration Index (T-SARI)
TOTAL
Minutes per Interruption
170
155
140
125
110
95
80
65
50
2007
2008
2009
2010
2011
CEA Average
(2006-2010)
97.85
NLH Average
(2007-2011)
95.69
CEA
NLH

3.1.3 Reliability KPI: Distribution

3.1.3 a) System Average Interruption Duration Index (SAIDI) - *a reliability KPI for distribution service and it measures service continuity in terms of the average cumulative duration of outages per customer served during the year.*

In the fourth quarter of 2011, the SAIDI was 9.56 hours per customer, compared to 1.32 hours per customer during the same quarter of 2010. The total 2011 SAIDI was 16.30 hours per customer, compared to 6.43 hours per customer in 2010. The performance in 2011 failed to meet the annual target of 6.21 hours per customer.

Service Continuity - System Average Interruption Duration Index (SAIDI)



A summary of the major interruptions during the fourth quarter is as follows:

On October 2, all customers in the towns of Labrador City and Wabush experienced a planned power outage of nearly seven hours. The outage was required for the Iron Ore Company of Canada (IOCC) to safely connect a new 46 kV feeder into the 46 kV Bus at the Wabush Terminal Station.

On October 11, a tree was cut in the vicinity of Bottom Waters Feeder No. 1 and it subsequently contacted the energized distribution line. This resulted in an unplanned outage to 372 customers in the towns of Woodstock, Pacquet, Ming's Bight, Rambler Mines, and Anaconda Mines. There were no injuries to any persons in the area. There was no damage to the line and all customers were restored following a four-hour and seven minute outage. The person who cut the tree was not identified.

On October 22, all customers in Labrador City and Wabush experienced an unplanned power outage of 41 minutes in duration. The outage resulted after IOCC lost approximately 100 MW of load, causing the overvoltage protection to trip at the 46 kV bus at the Wabush Terminal Station.

An early snowstorm impacted the Central and Northern regions on October 26, causing extensive damage to the distribution systems supplied by the Bottom Waters Terminal station and in the Roddickton/Englee areas. Some customers (Ming's Bight) were without power for up to four days while crews worked to repair the damages.

From December 8 to December 11, customers on the GNP distribution systems experienced forced outages of more than 48 hours. A winter storm passed through the area with extremely high winds (over 130 kmh), resulting in widespread salt contamination. The transmission section of this report provides more detail for the outages resulting from a loss of supply.

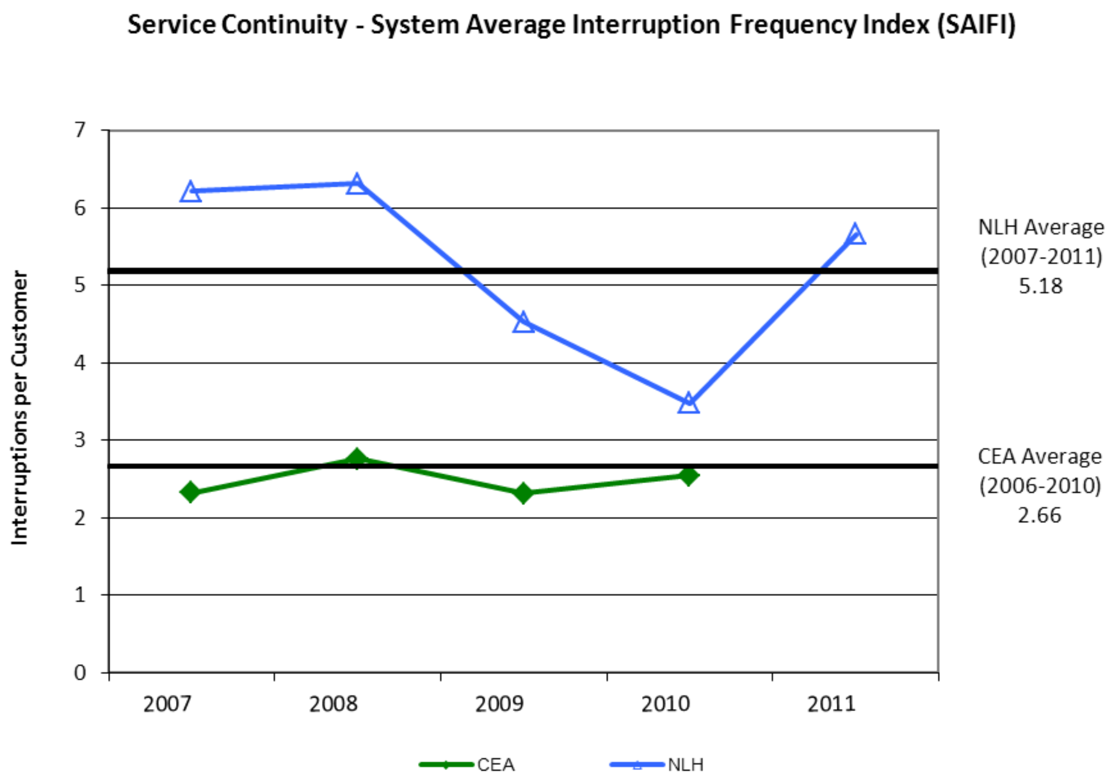
On December 23, there was an unplanned outage affecting 423 customers in Happy Valley supplied from feeder L6. The feeder tripped due to a phase unbalance. Hydro crews re-balanced the line and all customers were restored. Total outage time was three hours and 33 minutes.

The remainder of the significant events in 2011 which affected the distribution systems (outages generally to a complete system with duration of greater than five hours) are contained in Appendix C2.

3.1.3 b) System Average Interruption Frequency Index (SAIFI) - *reliability KPI for distribution service which measures the average cumulative number of sustained interruptions per customer per year.*

In the fourth quarter the SAIFI was 1.82 interruptions per customer, compared to 0.74 interruptions per customer during the same quarter of 2010, a 146% increase. The 2011 SAIFI was 5.66 interruptions per customer compared to 3.51 interruptions per customer in 2010, a 61% increase. The 2011 target of 3.8 interruptions per customer was not met. The performance in 2011 reverses the previous trend of improvement in the five-year average for Hydro, which had been approaching the latest national average for utilities without a predominant urban customer base[5].

[5] The CEA data is not yet available for 2011.



3.1.3.1 Additional Information

This section provides more detailed information in three tables with performance broken down by Area, Origin, and Type.

Rural Systems Service Continuity Performance by Area

SAIFI (Number per Period)

Area	Fourth Quarter 2011	Fourth Quarter 2010	12 Mths to Date 2011	12 Mths to Date 2010	5 Year Average (2006–2010)
Central					
Interconnected	0.87	0.69	2.91	2.46	3.33
Isolated	1.19	0.20	6.22	2.25	3.41
Northern					
Interconnected	2.84	0.36	6.28	2.39	4.23
Isolated	1.11	2.48	5.26	7.94	6.71
Labrador					
Interconnected	2.07	0.43	8.17	3.85	7.35
Isolated	2.73	3.59	8.13	11.90	11.43
Total	1.82	0.74	5.66	3.51	5.16

Note: System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers in an area

SAIDI (Hours per Period)

Area	Fourth Quarter 2011	Fourth Quarter 2010	12 Mths to Date 2011	12 Mths to Date 2010	5 Year Average (2006–2010)
Central					
Interconnected	10.71	1.84	16.86	7.95	9.00
Isolated	0.99	0.07	3.83	0.91	3.26
Northern					
Interconnected	16.74	0.34	25.17	3.53	7.40
Isolated	0.61	4.36	3.84	9.44	6.47
Labrador					
Interconnected	5.01	0.68	11.34	6.32	11.28
Isolated	1.17	4.14	10.91	12.26	16.27
Total	9.56	1.32	16.30	6.43	9.21

Note: System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.

Rural Systems Service Continuity Performance by Origin

SAIFI (Number per Period)					
Area	**Fourth Quarter**		**12 Mths to Date**		**5 Year Average**
	2011	**2010**	**2011**	**2010**	**(2006–2010)**
Loss of Supply – Transmission	0.68	0.06	2.59	0.56	2.15
Loss of Supply – NF Power	0.01	0.01	0.01	0.02	0.01
Loss of Supply – Isolated	0.12	0.15	0.50	0.54	0.60
Loss of Supply – L'Anse au Loup	0.03	0.05	0.05	0.11	0.05
Distribution	0.98	0.47	2.51	2.28	2.36
Total	1.82	0.74	5.66	3.51	5.16

Note: System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers.

SAIDI (Hours per Period)					
Area	**Fourth Quarter**		**12 Mths to Date**		**5 Year Average**
	2011	**2010**	**2011**	**2010**	**(2006–2010)**
Loss of Supply – Transmission	3.44	0.12	6.12	1.36	3.20
Loss of Supply – NF Power	0.49	0.08	0.49	0.18	0.04
Loss of Supply – Isolated	0.02	0.08	0.13	0.24	0.26
Loss of Supply – L'Anse au Loup	0.01	0.02	0.03	0.04	0.03
Distribution	5.60	1.02	9.54	4.61	5.68
Total	9.56	1.32	16.30	6.43	9.21

Note: System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.

Rural Systems Service Continuity Performance by Type

Area	Scheduled		Unscheduled		Total	
	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI
Central						
Interconnected	0.16	0.31	0.71	10.40	0.87	10.71
Isolated	0.46	0.38	0.73	0.61	1.19	0.99
Northern						
Interconnected	0.65	2.23	2.19	14.51	2.84	16.74
Isolated	0.01	0.03	1.11	0.58	1.12	0.61
Labrador						
Interconnected	0.68	0.41	1.40	4.60	2.07	5.01
Isolated	0.49	0.30	2.25	0.87	2.73	1.17
Total	0.44	0.83	1.38	8.73	1.82	9.56

Note:

1. System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers in an area.
2. System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.

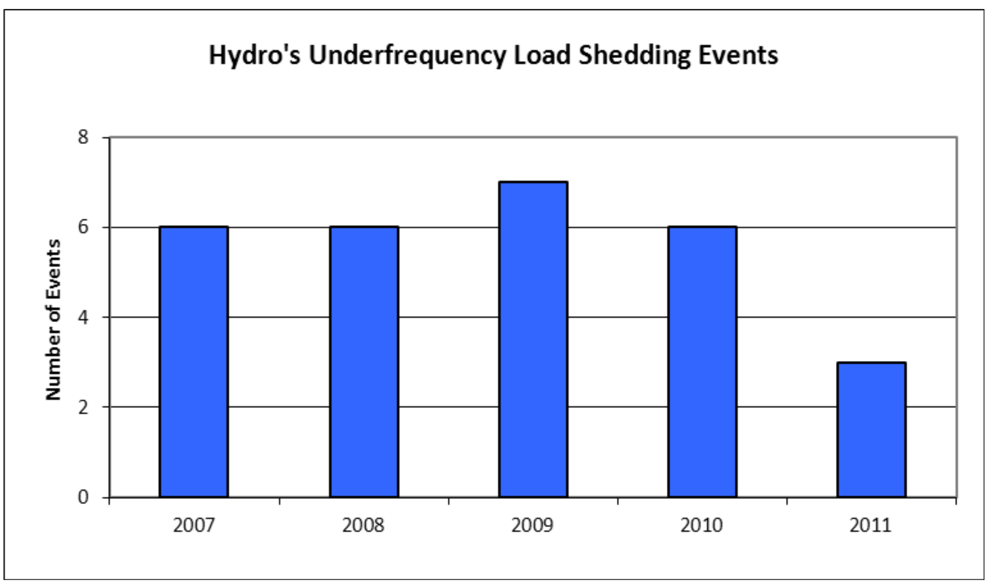
3.1.4 Reliability KPI: Other

3.1.4 a) Under Frequency Load Shedding (UFLS) - *reliability KPI that measures the number of events in which shedding of a customer load is required to counteract a generator trip. Customer loads are shed automatically depending upon the generation lost.*

There was one underfrequency event during the fourth quarter of 2011, summarized as follows:

On October 27, 2011 at 00:04 hours, the Upper Salmon Generating Unit tripped due to a power transformer lockout. The problem originated as an oil temperature trip on the transformer. It is believed that water entered the gauge and resulted in a flashover of the auxiliary contacts which operated the transformer lockout which, in turn, tripped the generating unit. With the removal of generation (approximately 66 MW) the system frequency dropped to 58.7 Hz resulting in the activation of the underfrequency protection at Newfoundland Power. Total system load at the time of the incident was 586 MW. An underfrequency event occurred in which 5,346 Newfoundland Power customers were impacted. Approximately, 24 MW-mins of energy went unserviced. Service was restored to all Newfoundland Power customers within two minutes.

In total, there were three UFLS events in 2011. This is three fewer events than what was experienced in 2010 and the best performance since underfrequency events were first recorded in 1998. Refer to the graph below which compares the UFLS events over the past five years to this year's performance.



The following table compares the UFLS events in the fourth quarter of 2011 to the same quarter in 2010.

Underfrequency Load Shedding Number of Events

Customers	Fourth Quarter		Year-to-date		5 Year Average
	2011	2010	2011	2010	(2007–2011)
NF Power	1	3	3	6	5.6
Industrials	0	2	0	2	5.0
Hydro Rural*	0	0	0	0	4.4
Total Events	1	3	3	9	5.6

Underfrequency Load Shedding Unsupplied Energy (MW-min)

Customers	Fourth Quarter		Year-to-date		5 Year Average
	2011	2010	2011	2010	(2007–2011)
NF Power	24	230	327	332	1,305
Industrials	0	120	0	120	279
Hydro Rural*	0	0	0	0	40
Total Events	24	350	327	452	1,625

* Underfrequency activity affecting Hydro Rural Customers may also result in a number of delivery point outages. Outage frequency and duration are also included in totals shown in the delivery point statistics section of the report for these areas, namely the Connaigre Peninsula and Bonne Bay.

The details of the previous two UFLS events in 2011 are summarized in Appendix C3.

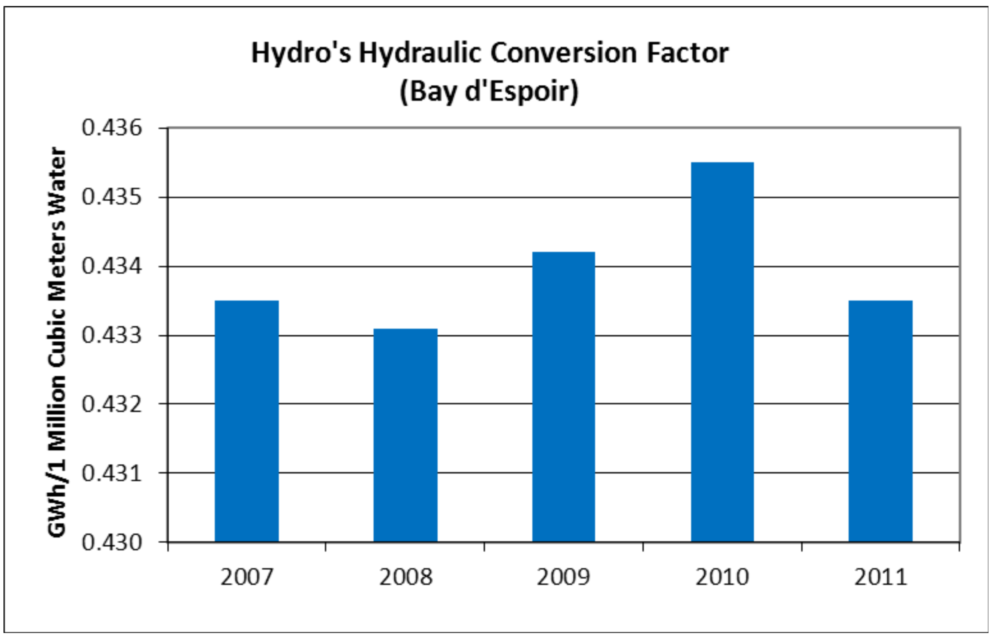
3.2 Operating Performance Indicators

This section presents information on two indicators of operating performance, both of which are associated with generation.

3.2.1 Operating KPI: Generation

3.2.1 a) Hydraulic Conversion Factor (Bay d'Espoir) - *a representative performance KPI for the principal hydroelectric generation assets located at Bay d'Espoir. This KPI tracks the efficiency in converting water to energy and it is calculated as the ratio of Net GWh generated for every one million cubic metres (MCM) of water consumed.*

In 2011, Hydro's hydraulic conversion factor for Bay d'Espoir was 0.4334 GWh/MCM. Performance had been improving since 2008, but declined in 2011.



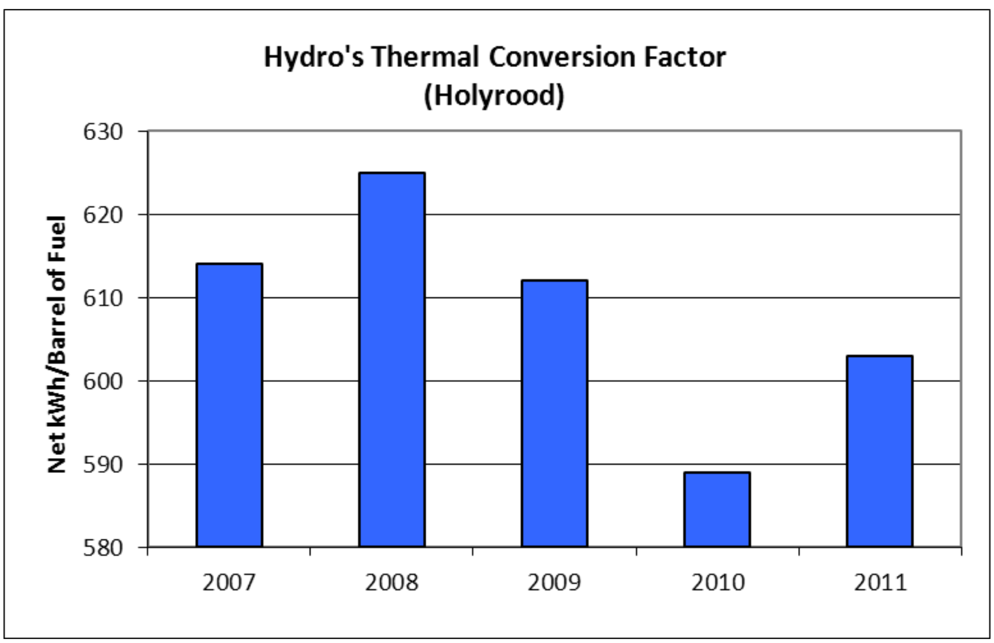
The decline in 2011 compared with that experienced in 2010 is primarily a result of very high water levels in all reservoirs. Due to water spillage in these reservoirs, the generators at Bay d'Espoir could not always be operated at their most efficient points.

3.2.1 b) Thermal Conversion Factor - *a representative performance KPI for the oil-fired thermal generation assets located at Holyrood. This KPI tracks the efficiency in converting heavy fuel oil into electrical energy and is measured as the ratio of the net kWhs generated to the number of barrels of No. 6 fuel oil consumed.*

The thermal conversion factor for Holyrood is directly proportional to the output level of the three units, with higher averages and sustained loadings resulting in higher conversion factors. The output level of the Holyrood Thermal Generating Station will vary depending on hydraulic production, quantity of power purchases, customer energy requirements and system security requirements.

In 2011, Hydro's net thermal conversion factor was 603 kWh per barrel, which is significantly below the 2011 target of 630 kWh per barrel. This reduction is primarily related to operating the plant at lower generating levels due to the high volume of water resources and energy receipts relative to the system load requirements. The experience in 2011 did show improvement over the 2010 performance of 589 kWh per barrel.

Production at Holyrood was kept to a minimum in 2011 with units dispatched only as required for Avalon Peninsula transmission support and system peak load considerations. The average net unit load while operating was 75 MW, up from 72 MW in 2010. Overall, net production from Holyrood for 2011 was 885 GWh, a 10% increase from 2010 production levels.



3.3 Financial Performance Indicators

The financial KPIs reported annually to the Board are:

1. Corporate operating, maintenance and administrative expense (OM&A) per MWh delivered;
2. Generation OM&A per MW installed capacity;
3. Generation OM&A per GWh generated;
4. Transmission OM&A per transmission circuit km; and
5. Distribution OM&A per distribution circuit km.[6]

In Order No. P.U. 8 (2007), the Board ordered that Hydro file a report no later than October 31, 2007 outlining an appropriate peer group with which Hydro's financial performance at the generation and transmission levels could be compared. In compliance with Board Order No. P.U. 8 (2007), Hydro filed a report titled "Peer Group Benchmarking" dated October 31, 2007 which summarized Hydro's findings regarding development of a peer group for financial KPIs related to generation and transmission. In that report, Hydro identified separate peer groups for generation KPIs and transmission KPIs and proposed that, subject to data availability, the selected peers remain constant to allow for meaningful trend comparisons over time. This is the fourth year of reporting generation and transmission financial KPI peer data. The list of peers used for KPI benchmarking for Financial Performance Indicators is included as Appendix C. This peer group benchmarking data is sourced from the U.S. Federal Energy Regulatory Commission (FERC) database, to which Hydro has a subscription. All financial data for the U.S.-based peer group is in $US and all financial data for Hydro is in $Cdn.

With respect to the Corporate and Distribution KPIs (items 1 and 5 above), in its 2007 Annual Report on KPIs Hydro had incorporated peer benchmarking data from the Canadian Electricity Association's (CEA) Committee on Performance Excellence (COPE) as published in the "Peer Group Performance Measures for Newfoundland Power" report. However, the CEA has informed Newfoundland Power that the composite information for these measures is no longer available, nor are any other cost-related CEA composite indicators available for benchmarking purposes.[7] As a result, Newfoundland Power is now using a peer group of U.S. companies. This group of US companies is not an appropriate group for Hydro due to Hydro's relatively small distribution component. In order to maintain consistency for year over year comparisons, Hydro is using the same peer group of U.S. companies for the Corporate Controllable Unit Cost KPI that Hydro uses for its generation financial benchmarking.

[6] This KPI is not available for benchmarking from 2007 onwards. It will continue to be reported for Hydro for annual comparison purposes. Please see section 3.3.4 a) Distribution Controllable Cost for a discussion of the alternate KPI to be used for peer benchmarking.

[7] "Peer Group Performance Measures for Newfoundland Power", December 23, 2008, p.2.

3.3.1 Financial KPI: Corporate

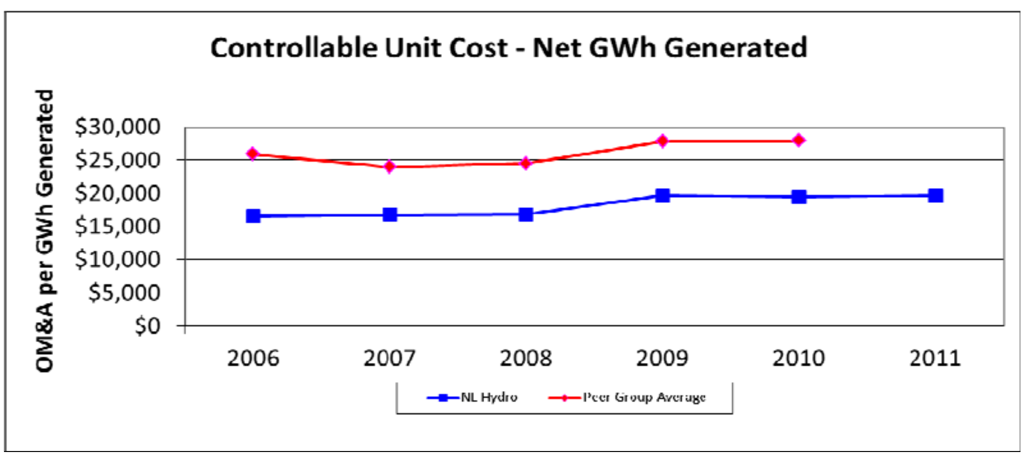
3.3.1 a) Controllable Unit Cost - *a high level corporate KPI that tracks Hydro's OM&A expenses in relation to its total energy delivered, expressed as dollars per MW hour. Total Corporate OM&A includes all operating labour and materials for Hydro's generation, transmission, distribution, customer-related and administrative costs, loss on disposal of capital assets. Energy deliveries have been normalized for weather, customer hydrology, and industrial strikes.*

Hydro's OM&A costs increased from $99.6 million in 2010 to $106.9 million[8] in 2011, resulting in a Controllable Unit Cost of $14.96 per MWh delivered for 2011.

Up to 2006, Hydro's Controllable Unit Cost was compared to the average Controllable Unit Cost for participants in the CEA COPE program as reported by Newfoundland Power. As of 2008, however, Newfoundland Power no longer uses CEA COPE benchmarking data for cost-related measures, because the composite information for these measures is no longer available for publication. Peer group results for the period 2006-2010 have therefore been herein restated using the same U.S. Peer Group that Hydro uses for generation financial KPIs.

For computation of Hydro's Corporate Controllable Unit Cost, normalized energy delivered is used. However, the available peer group data from the FERC database is based on net energy generated. Thus, for better comparison against the peer group, Hydro's data will also be calculated and charted on this basis. Hydro's Corporate OM&A per unit of net generation was $20.04 per MWh during 2011, higher than the computed Controllable Unit Cost, because normalized deliveries are higher than net generation due to the effect of Hydro's energy purchases.

Hydro's Corporate Controllable Unit Cost is following a very similar slow and steady upward trend as compared to the peer group. However, it is difficult to determine specifically what factors might be impacting the expenses of the peer group participants without detailed information regarding their operations and finances.



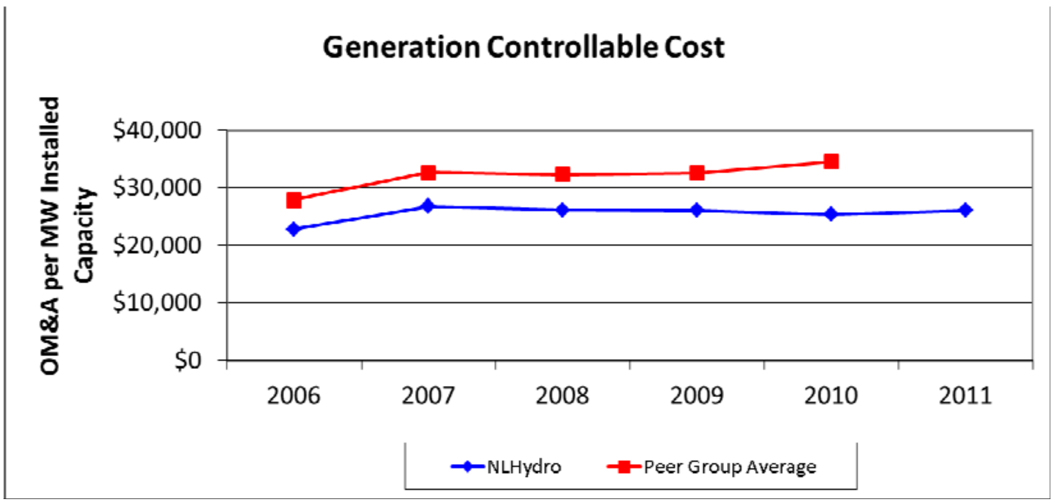
[8] This $106.9 million was calculated in the 2011 Cost of Service study and includes a $2.3 million cost to Hydro that was incurred to service an unregulated Industrial Customer. The $2.3 million was excluded when the $104.6 million regulated amount was reported on the Statement of Income – Regulated Operations for 2011, filed as part of the December 31, 2011 Quarterly Regulatory Report.

3.3.2 Financial KPI: Generation

3.3.2 a) Generation Controllable Cost - *a functional corporate KPI that tracks Hydro's generation costs in relation to its installed generation. It is computed by dividing generation OM&A by installed capacity as measured in MW.*

Generation Controllable Cost was $26,169 per MW for 2011 compared with $25,465 in 2010, a slight increase. As mentioned in prior annual KPI reports, an asbestos abatement program was undertaken at Holyrood in 2005 through 2007. Amortization of costs associated with this program will continue through to 2012.

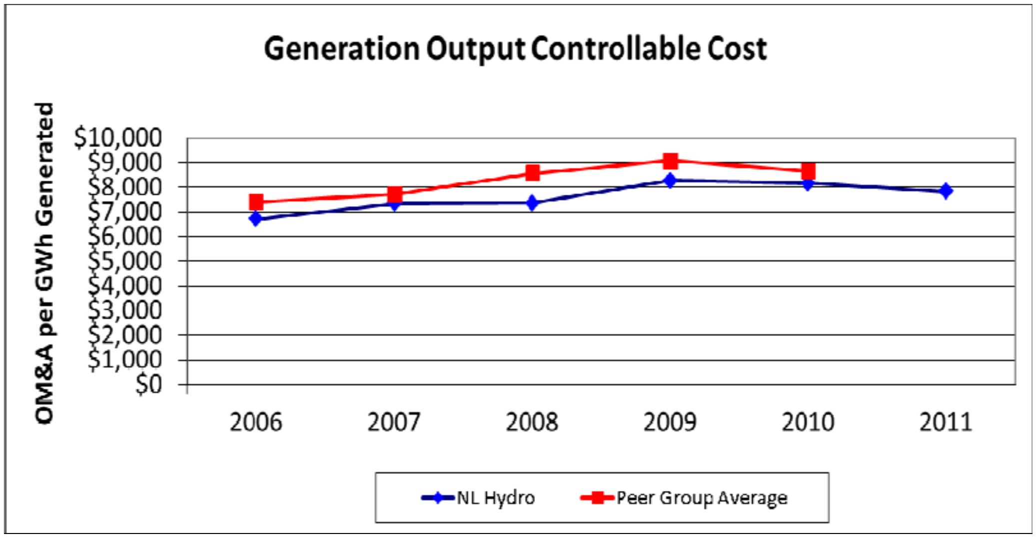
The peer group used to benchmark Generation Controllable Costs appears to be experiencing a similar cost trend as Hydro.



3.3.2 b) Generation Output Controllable Cost - *a functional corporate KPI that tracks Hydro's generation OM&A expenses in relation to its net generation measured in GWh.*

In 2011, Hydro's Generation Output Controllable Cost of $7,833 per GWh, was lower than the $8,159 in 2010. There was an increase in the Generation Costs component of approximately $0.9 million from 2010 to 2011 and an increase in the Net Energy Generated by 323 GWh.

From 2006 through 2010, Hydro's Generation Output Controllable Costs were in line with and trending in a similar direction as those of the peer group.

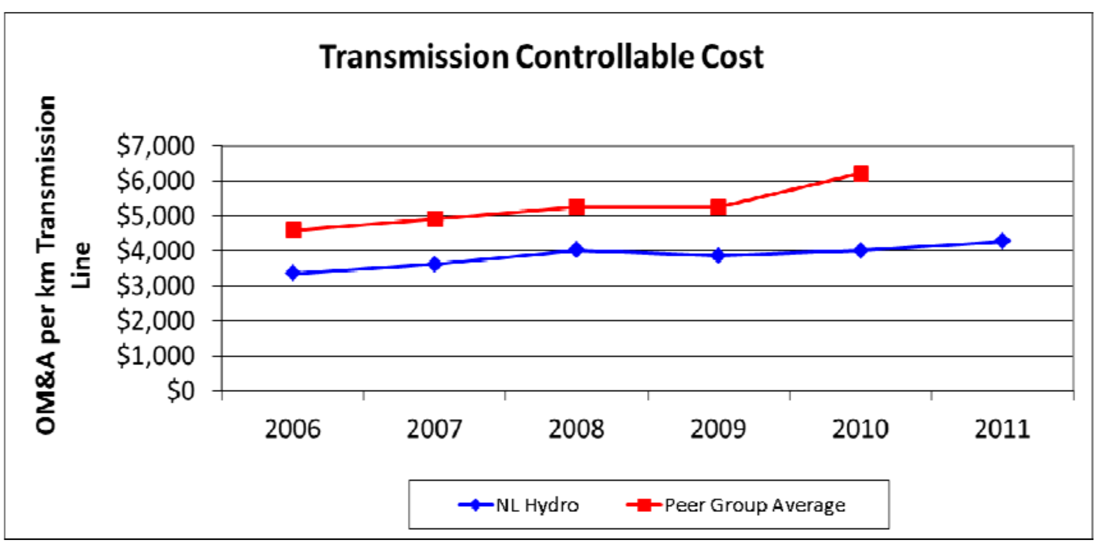


3.3.3 Financial KPI: Transmission

3.3.3 a) Transmission Controllable Cost - *a KPI that tracks Hydro's transmission OM&A expenses in relation to the 230 kV equivalent length of its transmission circuits (69 kV lines and above).*

In 2011, Hydro's Transmission Controllable Cost was $4,275 per km of transmission, an increase of 6% over 2010.

Hydro's costs per km of transmission circuit are trending in a similar pattern as the peer group, although per unit cost increases appear to be increasing at a slower rate within Hydro. A direct cost per unit km within the peer group is not meaningful due to differences in accounting and corporate cost allocations; however comparisons over time can highlight relevant trends.



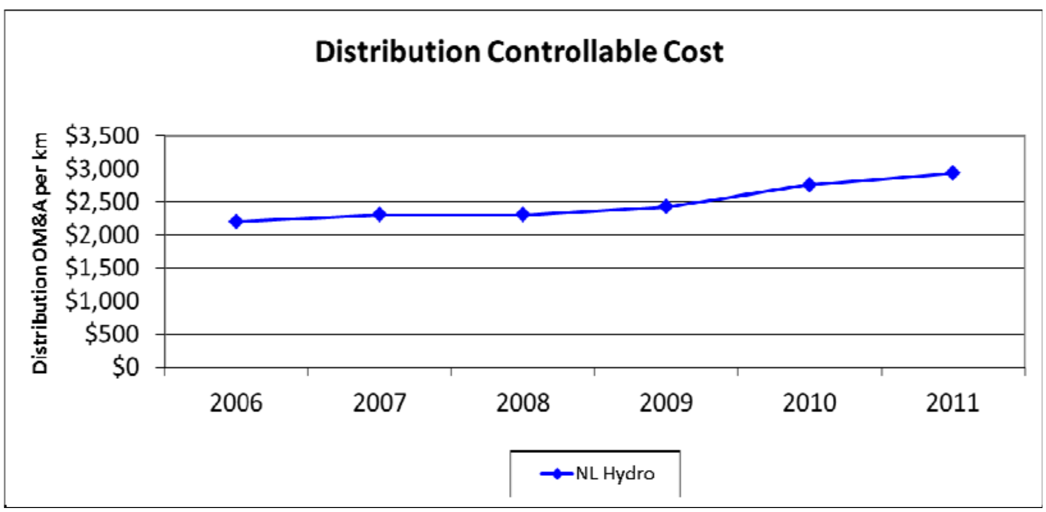
3.3.4 Financial KPI: Distribution

3.3.4 a) Distribution Controllable Cost - *a functional corporate KPI that tracks Hydro's distribution OM&A expenses in relation to the length of its equivalent 230 kV distribution circuits in kilometres*[9].

The Distribution Controllable Cost KPI had previously been reported as dollars per km of distribution using the CEA COPE data. As discussed, the CEA COPE data is no longer available for benchmarking of financial KPIs. Additionally, although distribution cost data is available for the U.S.-based peer group used by Hydro for Transmission Controllable Cost, the associated km of distribution data is unavailable. In the absence of the CEA COPE data, Newfoundland Power has chosen to use a KPI that divides total Distribution OM&A by MWh of retail sales. Hydro will therefore use this same data set. However, given Hydro's relatively small quantity of retail sales, combined with the rural and remote locations of these sales, it is expected that Hydro's Distribution cost per MWh will be significantly higher than Newfoundland Power's and the peer group average.

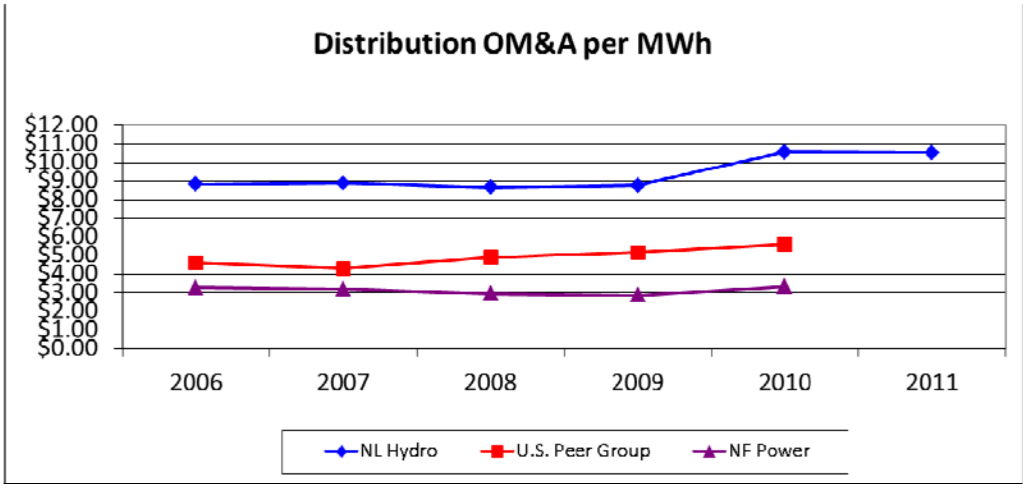
The distribution cost per km of circuit length will continue to be reported for year over year trend analysis.

At $2,934 per circuit km Hydro's Distribution Controllable Cost of 2011 increased from the $2,755 that was recorded in 2010. This is in line with the slight upward trend in this cost that was seen between 2006 and 2010.



[9] CEA COPE peer data used up to 2007 excluded circuits less than 1 kV. Hydro's data has also been adjusted to exclude circuits less than 1 kV from 2003 onward.

As expected, Hydro's distribution costs trend higher than those of its peers. The distribution systems are a relatively small component of Hydro's total plant compared to generation and transmission plant and also compared to Newfoundland Power's distribution assets. Thus, Hydro's higher costs are likely due to the rural and geographically dispersed nature of its distribution systems and the resultant inability to achieve cost economies.

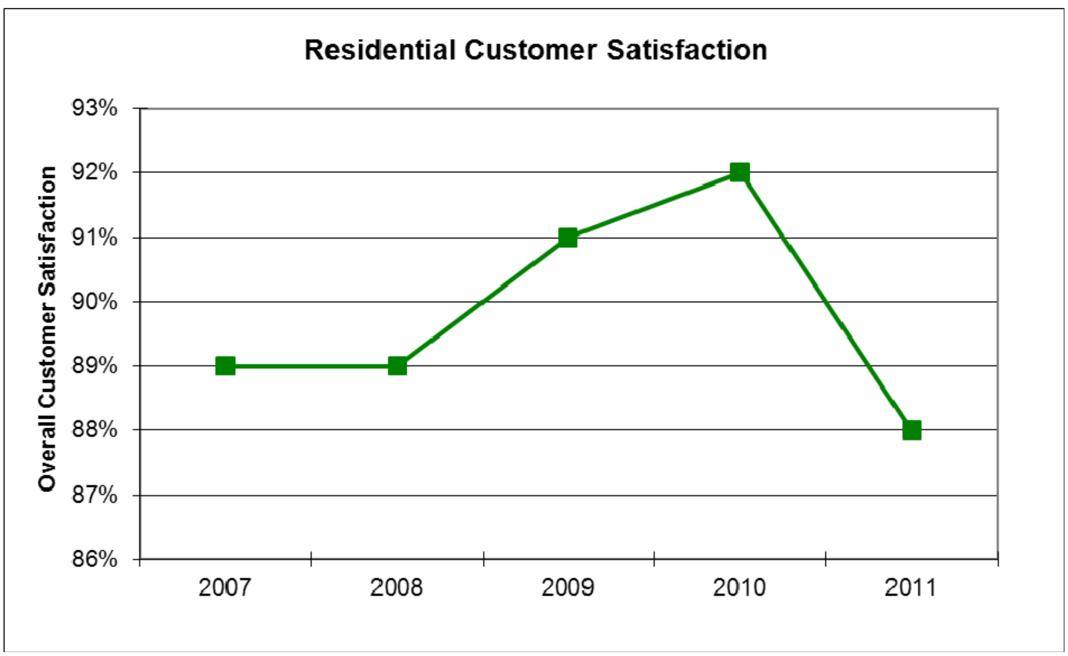


3.4 Customer-Related Performance Indicators

3.2.4 a) Residential Customer Satisfaction - *an indicator of Hydro's residential customers overall satisfaction level with service, which is tracked by the Percent Satisfied Customers KPI*[10].

The Percent Satisfied Customers measure is also a corporate performance KPI that tracks the satisfaction of rural residential customers with Hydro's performance. The Percent Satisfied Customers measure is produced via an annual survey of Hydro's residential customers.

In 2011, 88% of Hydro's residential customers were satisfied with Hydro's service. The satisfaction rating has decreased from the strong showing in the previous two years with no particular attribute indicating why the rating has decreased. In comparison, a Canadian Electricity Association 2011 Public Attitudes research project of Canadian Attitudes towards Electric Utilities indicates a national customer satisfaction index of 59%, which is a decrease of 6% from the 2010 national rating. The national survey points to price paid for electricity as the top driver of satisfaction.



[10] As of 2009, the Customer Satisfaction index (CSI) is no longer being calculated as a Customer-Related Performance Indicator.

4 Data Table of Key Performance Indicators

Key Performance Indicators' targets for 2011 were established in the same manner as in previous years. Any future changes in methodology will be included as such a change occurs.

Revised May 31-12

Newfoundland and Labrador Hydro
Key Performance Indicators (KPI)
Results for 2011 plus Targets/Budgets for 2012[1]

KPI	Measure Definition	Units	2007	2008	2009	2010	2011	2012T
Reliability								Target
Generation								
Weighted Capability Factor[2]	Availibility of Units for Supply	%	80.5	82.3	82.0	83.4	83.3	84.9
Weighted DAFOR[2]	Unavailibility of Units due to Forced Outage	%	7.9	5.0	4.5	1.8	2.7	2.7
Transmission[6]								
T-SAIDI	Outage Duration per Delivery Point	Minutes / Point	187	278	100	173	432	265
T-SAIFI	Number of Outages per Delivery Point	Number / Point	2.7	1.7	0.9	2.3	4.5	2.0
T-SARI	Outage Duration per Interuption	Minutes / Outage	69	164	111	75	96	133
Distribution								
SAIDI	Average Outage Duration for Customers	Hours / Customer	8.7	11.2	9.4	6.6	16.3	5.9
SAIFI	Number of Outages for Customers	Number / Customer	6.2	6.3	4.3	3.5	5.7	3.7
Under Frequency Load Shedding								
UFLS	Customer Load Interruptions Due to Generator Trip	Number of Events	6	6	7	6	3	6
Operating								
Hydraulic Conversion Factor[3]	Net Generation / 1 Million m^3 Water	GWh / MCM	0.433	0.433	0.434	0.436	0.434	0.433
Thermal Conversion Factor[4]	Net kWh / Barrel No. 6 HFO	kWh / BBL	614	625	612	589	603	630
Financial (Regulated)								
Controllable Unit Cost[5]	Controllable OM&A$ / Energy Deliveries	$/MWh	$14.15	$14.05	$14.91	$14.25	$14.96	N/A
Generation Controllable Costs	Generation OM&A$ / Installed MW	$ / MW	$26,836	$26,217	$26,138	$25,465	$26,169	N/A
	Generation OM&A$ / Net Generation	$ / GWh	$7,342	$7,362	$8,267	$8,159	$7,833	N/A
Transmission Controllable Costs	Transmission OM&A$ / 230 kV Eqv Circuit Km	$ / Km	$3,625	$4,023	$3,870	$4,021	$4,275	N/A
Distribution Controllable Costs	Distribution OM&A$ / Circuit Km	$ / Km	$2,307	$2,305	$2,429	$2,755	$2,934	N/A
Other								
Percent Satisfied Customers (Residential)	Satisfaction Rating	Max = 100%	88%	89%	91%	92%	88%	≥90%

Notes:
1. Historical data has been updated and/or corrected where applicable.
2. The 2012 targets for weighted capability factor and DAFOR are based on the annual generation outage schedule.
3. For the Bay d'Espoir hydroelectric plant.
4. For the Holyrood thermal plant.
5. Energy deliveries have been normalized for weather, customer hydrology, and industrial strikes. No adjustments have been made for AC Stephenville mill closure.
6. The 2012 targets for T-SAIFI and T-SAIDI are based on the combination of forced and planned outage performance.

Appendices

Appendix A: Rationale for Hydro's 2011 KPI Targets

KPI	Comment on KPI 2011 Target
Reliability	Hydro has adopted a target setting approach wherein known factors that affect reliability performance are incorporated into the target setting process wherever practical. This approach also uses percentage improvements and past performance levels to set target levels for continuous improvements.
Weighted Capability Factor	The 2011 target is set using the expected annual generation unit outage schedule combined with performance improvements relative to recent history.
Weighted DAFOR	The 2011 target is set using the expected annual generation unit outage schedule combined with performance improvements relative to recent history.
Transmission SAIDI, SAIFI, and SARI	The 2011 targets for forced outage performance are set based upon recent performance improvements. The planned outage contribution to total performance is set using the annual transmission terminals maintenance outage plan.
Distribution SAIDI & SAIFI	Improvements relative to the most recent five-year average.
Underfrequency Load Shedding	The 2011 target is based upon improvement over the most recent five-year average.
Operating	
Hydraulic Conversion Factor	Hold at the previous target value.
Thermal Conversion Factor	Per Board Order No. P.U. 14 (2004)
Financial	
Controllable Unit Cost	Unavailable
Generation, Transmission & Distribution Controllable Cost	Unavailable
Other	
Customer Satisfaction	Targeting continuous improvement.

Appendix B: Computation of Weighted Capability Factor and Factors Impacting Performance

Weighted Capability Factor is calculated using the following formula:

$$1-\frac{\sum_{all\ units}\left(\frac{unit\ total\ equivalent\ outage\ time \times unit\ MCR}{unit\ hours}\right)}{\sum_{all\ units} unit\ MCR}$$

Where,

MCR = Maximum Continuous Rating, the gross maximum electrical output, measured in megawatts, for which a generating unit has been designed and/or has been shown capable of producing continuously. MCR would only change if the generating capability of a unit is permanently altered by virtue of equipment age, regulation, or capital modifications. Such changes to MCR are infrequent and have not actually taken place within Hydro since the 1980's when two units at Holyrood were uprated due to modifications made to these units.

Unit hours = the sum of hours that a unit is in commercial service. This measure includes time that a unit is operating, shut down, on maintenance, or operating under some form of derating. Unit hours will only be altered in the infrequent event that a unit is removed from commercial service for an extended period of time.

Unit total equivalent outage time = the period of time a unit is wholly or partially unavailable to generate at its MCR. For the purposes of calculating outage time, the degree to which a unit is derated is converted to an outage equivalency. Thus, a unit that is able to generate at 75% load for four days would have an equivalent outage time of one full day out of four. Factors that can affect unit total equivalent outage time are classified by CEA under nine categories, which are outlined in Appendix A to this Report. Hydro tracks the time that each unit spends in each of these nine states and calculates the weighted capability accordingly.

Unit total equivalent outage time is the measure that is most likely to impact Weighted Capability Factor on a year-to-year basis, since MCR and unit hours are unlikely to change.

Appendix B: Computation of Weighted Capability Factor and Factors Impacting Performance (Cont'd)

Factors that Affect Unit Total Equivalent Outage Time

1. **Sudden Forced Outage.** An occurrence wherein a unit trips or becomes immediately unavailable.
2. **Immediately Deferrable Forced Outage**. An occurrence wherein a unit must be made unavailable within a very short time (10 minutes).
3. **Deferrable Forced Outage**. An occurrence or condition wherein a unit must be made unavailable within the next week.
4. **Starting Failure**. A condition wherein a unit is unable to start.
5. **Planned Outage**. A condition where a unit is unavailable because it is on its annual inspection and maintenance.
6. **Maintenance Outage**. A condition where a unit is unavailable due to repair work. Maintenance outage time covers outages that can be deferred longer than a week, but cannot wait until the next annual planned maintenance period.
7. **Forced Derating**. A condition that limits the usable capacity of a unit to something less than MCR. The derating is forced in nature, typically because of the breakdown of a subsystem on the unit.
8. **Scheduled Derating**. A condition that limits the usable capacity of a unit to something less than MCR, but is done by virtue of the decision of the unit operator. Scheduled deratings are less common than forced deratings, but can arise, for example, when a unit at Holyrood is derated to remove a pump from service.
9. **Common Mode Outages**. Common mode outages are rare, and arise when an event causes multiple units to become unavailable. An example might be the operation of multiple circuit breakers in a switchyard at Holyrood due to a lightning strike, rendering up to three units unavailable.

Note: There are hundreds of CEA equipment codes for generator subsystems that track the cause for the time spent in each of the above categories.

Appendix C1: Significant Transmission Events - 2011

- On January 4 at 19:15 hours, a tree fell onto transmission line TL-239 resulting in an unplanned outage to all customers on the Great Northern Peninsula, north of the town of Rocky Harbour. Customers were restored in stages using transmission line TL-226 and the diesel plants at Hawke's Bay and St. Anthony. Customer outages ranged from 10 minutes to 3 hours and 19 minutes. **Unsupplied Energy - 3,218 MW-Mins.**

- On August 20 at 19:59 hours, all customers in the Happy Valley-Goose Bay area experienced an unplanned outage of 253 minutes in duration. At the time, transmission line L1301 was out of service for a planned outage and customers were being supplied with the Happy Valley gas turbine. The gas turbine tripped due to a problem with the generator control system. Service was returned to customers by restoring L1301. **Unsupplied Energy - 2,968 MW-Mins.**

- On October 29 at 10:59 hours, all customers in supplied from transmission line TL-260 experienced an unplanned power outage of 434 minutes in duration. Customers in the towns of Burlington, Middle Arm, Smith's Harbour, Ming's Bight, Pacquet, Nipper's Harbour and Woodstock were already experiencing an unplanned power outage due to issues on the distribution system. A helicopter patrol of TL-260 determined that ice falling from the conductor had caused two phase conductors to come to rest on top of a crossarm. There was other line damage also observed that required repairs before the line could be restored. **Unsupplied Energy - 1,606 MW-Mins.**

- On December 8 at 19:59 hours, customers served by transmission line TL-260 on the Baie Verte Peninsula experienced an unplanned power outage of 868 minutes in duration. The outage was caused by a tree contact on Newfoundland Power's transmission line, 363L. This occurred during a severe winter storm that impacted the area. **Unsupplied Energy - 5,309 MW-Mins.**

- On December 10 at 05:37 hours, customers on the Great Northern Peninsula north of the town of Plum Point experienced an unplanned power outage ranging from 47 to 365 minutes in duration. The outage was caused by a trip of transmission line TL-241 at the Peter's Barren Terminal Station. The backup line protection misoperated due to a failed current transformer on circuit breaker B1L41. The protection was moved to another current transformer, with intentions to replace the failed current transformer during the summer of 2012. **Unsupplied Energy - 1,977 MW-Mins**

- On December 10 at 08:09 hours, customers served by the Plum Point and Bear Cove Terminal Stations experienced an unplanned power outage ranging from 122 to 401 minutes in duration. The outage was caused by a bus lockout at the Plum Point Terminal Station and the tripping of TL-241 and TL-244. Customers in St. Anthony were being supplied via the diesel plant. Customers in Main Brook and Roddickton were already experiencing a power outage which had started at 05:37 hours on that day. The Plum Point bus lockout was caused by multiple recloses and trips on the distribution system causing the transformer back up protection to operate to clear the fault. At the time of the trip there extremely high winds (over 130 kmh). **Unsupplied Energy - 2,586 MW-Mins**

Appendix C1: Significant Transmission Events – 2011 (Cont'd)

- On December 10at 16:46 hours, customers on the Great Northern Peninsula north of the town of Daniel's Harbour experienced an unplanned power outage ranging from four to 1,387 minutes in duration. The outage was caused by another trip of transmission line TL-241 at the Peter's Barren Terminal Station. The backup line protection misoperated due to a failed current transformer on circuit breaker B1L41. The protection was moved to another current transformer, with intentions to replace the failed current transformer during the summer of 2012. **Unsupplied Energy - 6,933 MW-Mins**

Appendix C2: Significant Distribution Events – 2011 (Excluding Fourth Quarter)

- On January 20, customers in the towns of Nipper's Harbour, Burlington, Smith's Harbour and Middle Arm on the Baie Verte Peninsula experienced a five-hour and 50 minute unplanned outage due to a line contact during a high wind storm.

- On January 24, all customers in the community of Makkovik experienced multiple recloser operations and momentary outages which were eventually followed by a total outage. Weather delayed crews from Happy Valley-Goose Bay from travelling to the area. Crews arrived on January 25 and determined that there was a problem with the main recloser. A phase wire of the main feeder had sagged and came into contact with the neutral wire. Repairs were made and customers were restored. The complete power outage lasted approximately 23 hours.

- A tree fell across the main feeder to the towns of Ming's Bight, Woodstock and Pacquet on February 16. This resulted in a 13 hour and 43 minute outage to these customers while the tree was removed and the damaged conductor was repaired. Customers in La Scie experienced an 11 hour and 40 minute outage due to a broken conductor in the main feeder on the same day.

- Customers in Robert's Arm, Triton, and Brighton experienced a five-hour and 14 minute unplanned outage on February 16. The outage was caused by two broken insulators in the main feeder which supplies these towns.

- All customers on Change Islands and Fogo Island experienced a five-hour and 15 minute unplanned outage on March 10. The outage was required in order for Newfoundland Power to make repairs to their transmission line which supplies the area. Customers in Shoal Bay, Joe Batt's Arm and Tilting on Fogo Island experienced an additional nine-hour and 30 minute unplanned outage on March 10. This was caused by a broken conductor in the main feeder to these towns.

- In April, customers in the Cow Head, Daniel's Harbour and Parson's Pond distribution systems all experienced planned interruptions to allow for maintenance of the terminal station equipment. Each of these outages is described in the transmission section of this Appendix.

- On April 9, customers in the Bear Cove and Plum Point distribution systems experienced an emergency planned outage. Refer to the transmission section of this Appendix for further details.

- On September 6, all customers in William's Harbour experienced a 12-hour unplanned outage due to a problem with the diesel plant's electrical system.

Appendix C3: Underfrequency Load Shedding Events (Excluding Fourth Quarter)

- On January 14, Holyrood generating Unit 3 tripped during testing of a replacement west fuel oil pump. During this testing the unit's DCS system detected a second fuel oil pump starting, though there was no start of the second pump, and dropped the fuel oil pressure resulting in the unit tripping. With the removal of generation (approximately 70 MW) the system frequency dropped to 58.7 Hz resulting in the activation of the underfrequency protection at Newfoundland Power. Total system load at the time of the incident was 966 MW. An underfrequency event occurred in which 5,487 Newfoundland Power customers were impacted. Approximately, 160 MW-mins of energy went unserviced. Service was restored to all NP customers within eight minutes.

- On May 12 at 1713 hours, Holyrood generating unit 1 tripped due to low drum level. The problem originated at a defective auxiliary contact associated with No. 4 and 5 heaters which impeded a bypass valve from opening. With the removal of generation (approximately 73 MW) the system frequency dropped to 58.8 Hz resulting in the activation of the underfrequency protection at Newfoundland Power. Total system load at the time of the incident was 786 MW. An underfrequency event occurred in which 6,485 Newfoundland Power customers were impacted. Approximately, 143 MW-mins of energy went unserviced. Service was restored to all NP customers within seven minutes.

Appendix D: List of U.S.-Based Peers for Financial KPI Benchmarking

Generation and Corporate Peer Group:

Alcoa Power Generating Inc.
Allete, Inc.
Aquila, Inc.
Avista Corporation
Buckeye Power, Inc.
Cleco Power LLC
Electric Energy, Inc.
Entergy Mississippi, Inc.
Hawaiian Electric Company, Inc.
Indiana-Kentucky Electric Corporation
Kentucky Power Company
Ohio Valley Electric Corporation
Portland General Electric Company
Public Service Company of New Hampshire
Puget Sound Energy, Inc.
Savannah Electric and Power Company
Sierra Pacific Power Company
Southern Electric Generating Company
Southern Indiana Gas and Electric Company
The Empire District Electric Company

Transmission Peer Group:

AEP Texas North Company
Allete, Inc.
Aquila, Inc.
Avista Corporation
Central Illinois Public Service Company
Delmarva Power & Light Company
Entergy Mississippi, Inc.
Kentucky Utilities Company
MDU Resources Group, Inc.
Mississippi Power Company
New York State Electric & Gas Corporation
Northern Indiana Public Service Company
Northern States Power Company (Wisconsin)
Oklahoma Gas and Electric Company
Public Service Company of Colorado
Public Service Company of Oklahoma
Sierra Pacific Power Company
Southwestern Electric Power Company
Tucson Electric Power Company
Westar Energy, Inc.

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

QUARTERLY REGULATORY REPORT FOR THE QUARTER ENDED DECEMBER 31, 2012

Newfoundland and Labrador Hydro

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APPENDICES:

1 HIGHLIGHTS

UPDATED June 6, 2013

HIGHLIGHTS
For the twelve months ended December 31, 2012

REGULATED	2012 Actual YTD	2012 Target/ Budget	2011 Actual YTD
Safety			
Lead:Lag Ratio[1]	230:1	600:1	578:1
All Injury Frequency Rate[1]	2.25	<u><</u>0.8	0.91
Production			
Quarter End Reservoir Storage (GWh)	2,173	1,010	2,260
Hydraulic Production (GWh)	4,595	4,682	4,512
Holyrood Fuel cost per barrel, current month ($)[2]	113	59	107
Holyrood Efficiency[2]	599	630	603
Electricity Delivery			
Sales including Wheeling (GWh)	6,782.2	7,068.9	6,628.7
Financial			
Revenue ($millions)	455.3	507.3	446.1
Expenses ($millions)	438.4	492.0	425.5
Net Operating Income ($millions)[3]	16.9	15.3	20.6
Current Rate Stabilization Plan (RSP) Balance ($millions)	(201.7)	(197.7)	(170.3)
Hydraulic	(32.7)	(40.2)	(32.7)
Utility	(64.9)	(54.5)	(55.9)
Industrial	(104.1)	(103.0)	(81.7)
Full Time Equivalent (FTE) Employees[4, 5, 6]			
Regulated	800.8	850.8	819.6
Non-Regulated	32.0	29.1	23.7

[1] Annual Target, and 2011 Actual
[2] Target based on approved 2007 Test Year forecast
[3] Does not include any earnings from CF(L)Co
[4] One FTE is the equivalent of actual paid regular hours - 2,080 hours per year in the operating environment and 1,950 hours per year in Hydro's head office environment.
[5] Annual Budget and 2011 Actual values
[6] 2012 Budget FTEs Regulated does not include vacancy adjustment of 27 FTEs

- Canadian Electricity Association presents Vice President's Award of Safety Excellence to Hydro (page 4)
- Hydro's Transmission Structure Corrosion Workshop Presentation (page 19)

2 SAFETY

Goal - To be a Safety Leader

Safety is Hydro's number one priority. Hydro remains committed to being a world class leader in safety performance.

Measurement	Year-to-date 2012 Actual	Annual 2012 Plan	Annual 2011 Actual
All Injury Frequency (AIF)	2.25	<0.8	0.91
Lost Time Injury Frequency (LTIF)	0.79	<0.2	0.13
Ratio of condition and incident reports to lost time and medical treatment injuries (lead/lag ratio)	230:1	600:1	578:1
Audit Work Protection Code Compliance	Completed		
Complete Work Method Development for Critical Tasks	87.33%	85%[1]	N/A

[1] Incorrectly reported as 100%; the Annual 2012 Plan was 85%.

Based on solid safety performance in 2011 and a downward trend in injuries over the past several years, the safety performance metrics for 2012 were set at an all injury frequency rate of 0.8 or less, a lost time injury frequency rate of 0.2 or less, and a lead/lag ration of 600:1 for Hydro. Although there was an increase in the number of injuries in 2012, preventing the metric targets from being met, the injuries were preventable, mainly low risk in nature and Hydro is still seeing overall continual improvement in injury performance.

Going forward, there is a targeted approach on injury prevention, communication and awareness, and visible leadership and support at all levels. There will also be a focus on supporting and recognizing the areas with exceptional safety performance to enable continued motivation and sustain a positive and strong safety culture.

Hydro continued its focus on planned safety objectives during the final quarter of 2012.

The public campaign for Power Line Hazards is ongoing. A new work group has been established in conjunction with Newfoundland Power, the Newfoundland Labrador Construction Safety Association (NLCSA), and Workplace Health, Safety and Compensation Commission (WHSCC), among others, to develop and deliver strategic initiatives around power line safety. Hydro also remains an active member of the WHSCC Technical Advisory Committee for Power Line Hazards (PLH), a technical resource for the WHSCC PLH Trainers Course. Hydro's three-year Safety Communication Plan efforts continue.

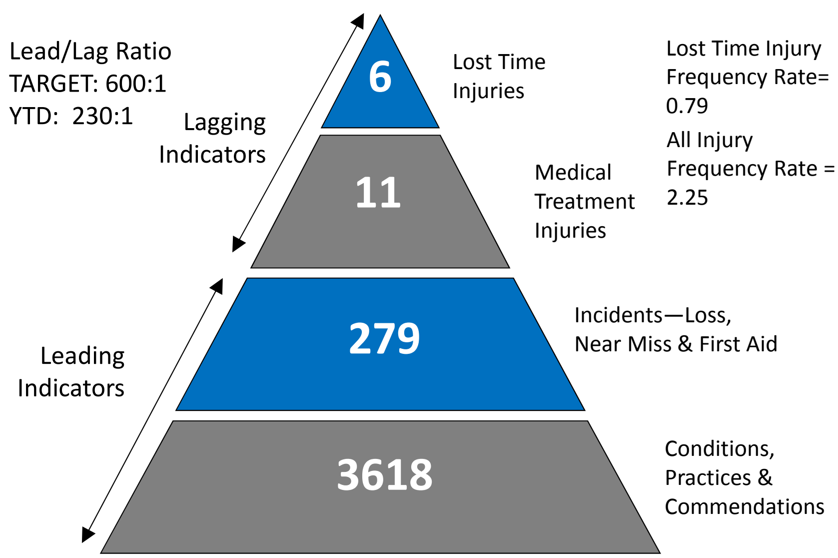
The development and enhancement of safety culture progresses with the (BeSafe) safety coaching workshops continued throughout the regions. Further sessions will be held into 2013.

From a key program perspective, Hydro remains focused on the areas of Grounding and Bonding, Work Methods and Work Protection Code (WPC). The Corporate Grounding and Bonding Committee has developed a training standard and course content, identified and trained trainers and commenced delivery to line operations staff. Further, work continues around the development of Work Methods for identified critical tasks. As the WPC Program reaches maturity, the focus will shift to evaluation with development of new software for the issuing of permits and a program audit application to assist the ongoing audit process.

In the fourth quarter, work also continued with respect to vulnerable workers, aimed at reducing exposures to new and younger workers. A new Local Orientation Standard has been developed and the "Green Hard Hat Program" that is used to enhance the visibility of new workers in the field has continued.

To further enhance the reporting of safety observations, Safe Workplace Observation Program (SWOP) training was delivered in the fourth quarter in partnership with the new Incident Investigation Training Program. Positive feedback has been received and training will continue into 2013.

The following safety triangle summarizes Hydro's year-to-date performance.



2.1 Canadian Electricity Association presents Vice President's Award of Safety Excellence to Hydro

On October 2 at the Occupational Health and Safety Awards Reception in Ottawa, Hydro accepted the 2011 Canadian Electricity Association (CEA) Vice President's Award of Safety Excellence at the bronze award level in the Transmission/ Distribution category.

This award is given to a CEA corporate utility who reported both an All Injury Frequency Rate and a Lost Time Injury Severity Rate which ranked at or above the top quartile of the utilities within their reporting group within the 2011 reporting year.

John Hollohan, Jim Haynes and Paul Smith accept the CEA's Vice President's Award of Safety Excellence

2.2 ATV Training at Hydro Generation

Employees at Hydro Generation received hands on training in the safe operation of All Terrain Vehicles (ATVs) on October 29 and 30, 2012. The training provided workers with the knowledge and hands on experience necessary to operate these ATVs safely in all types of terrain. Training has proven to be of high value as one of the many controls required to operate ATVs without incident and injury.

Hydro Generation's employees receive ATV training

2.3 Be Alert, Be Seen, Be Safe

Drake O'Brien, son of Mike O'Brien, Senior Business Development engineer, in high visibility clothing.

In October 2012, a safety observation was made regarding the absence of adequate lighting in a parking lot. The underlying message was simple, for both drivers and pedestrians: Be Alert, Be Seen, Be Safe!

In recent years, reflective garments, flashing lights, and other aids have been used to try to improve user visibility. Studies have shown that fluorescent materials in yellow, red and orange improve driver detection of pedestrians during the day; while lamps, flashing lights and retro reflective materials in red and yellow, particularly those that take advantage of the motion from a pedestrian's limbs, improved pedestrian recognition at night.

3 ENVIRONMENT AND CONSERVATION

Goal - To be an Environmental Leader

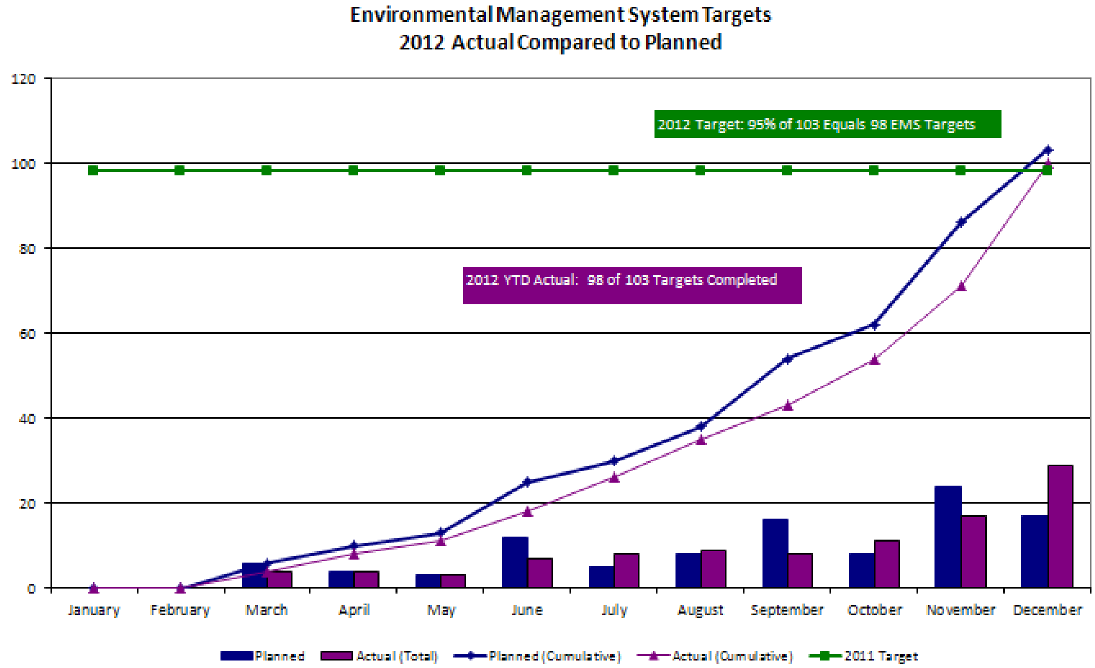
Hydro recognizes its commitment and responsibility to protect the environment.

Measurement	Year-to-date 2012 Actual	Annual 2012 Target	Annual 2011 Actual
Achievement of EMS targets[1]	96%	95%	93%
Variance from ideal production schedule at Holyrood Thermal Generating Station	6.9%	≤ 11.0%	9.8%
Annual energy savings from Residential and Commercial Conservation and Demand Management Programs	2.6 GWh	3.4 GWh	1.1 GWh
Annual energy savings from Industrial Conservation and Demand Management Programs	3.2 GWh	6.6 GWh	0.2 GWh
Annual energy savings from Internal Energy Efficiency Programs	0.26 GWh	0.15 GWh	0.17 GWh

[1] An EMS target is an initiative undertaken to improve environmental performance.

3.1 Achievement of EMS Targets

See graph below displaying planned target completion schedules and actual to date. The annual target for 2012 was achieved.



3.2 Variance from Ideal Production Schedule at Holyrood Thermal Generating Station

Summary of 2012 Performance:

Minimum Hours						
2012	**Variance[1]**		**Ideal**		**Variance**	
Month	**Unit-Hours**	**Cumulative**	**Unit-Hours**	**Cumulative**	**Percent**	**Cumulative**
January	120.0	120.0	2,088	2,088	5.7%	5.7%
February	98.5	218.5	1,872	3,960	5.3%	5.5%
March	80.0	298.5	1,656	5,616	4.8%	5.3%
April	10.0	308.5	840	6,456	1.2%	4.8%
May	66.0	374.5	600	7,056	11.0%	5.3%
June	0.0	374.5	288	7,344	0.0%	5.1%
July	0.0	374.5	0	7,344	0.0%	5.1%
August	0.0	374.5	0	7,344	0.0%	5.1%
September	0.0	374.5	0	7,344	0.0%	5.1%
October	186.0	560.5	624	7,968	29.8%	7.0%
November	50.0	610.5	1,032	9,000	4.8%	6.8%
December	144.0	754.5	1,896	10,896	7.6%	6.9%

[1] Variance is the number of hours greater than or less than the ideal. Hours greater than the ideal represent hours of operation that ideally could have been avoided. Hours less than the ideal represent hours of operation where a single contingency could have resulted in a load interruption.

3.2.1 Annual Energy Savings from Residential and Commercial Conservation and Demand Management (CDM) Programs

The energy savings for the residential and commercial portfolio continues to grow year over year. The largest component of the savings is due to the work on the direct installation program targeting the isolated communities in Labrador. The savings are lower than expected due to a number of factors, including a lower uptake in the components outside the direct installation initiative, as well as lower than expected savings in the first months of operation of the Isolated Systems Business Efficiency Program. Savings for the initial activities through the Block Heater Timer program are also not included as quality assurance is required to verify them.

3.2.2 Annual Energy Savings from Industrial Conservation and Demand Management Programs

Three projects have been completed through the Industrial program. The projects ranged in size and savings and addressed equipment replacement, lighting retrofits and process updates. There are other projects in various stages of feasibility research and review with economically viable projects moving to the implementation stage.

3.2.3 Annual Energy Savings from Internal Energy Efficiency Programs

Internal energy efficiency was very positive in 2012 with results exceeding the target. Some savings are realized from optimizing heating equipment and lighting in facilities through operational efforts. Retrofits of lighting and heating controls have resulted in the bulk of the savings.

4 Operational Excellence

Goal - Through operational excellence provide exceptional value to all consumers of energy.

Hydro strives to deliver operational excellence by maintaining safe, reliable delivery of power and energy to customers in a cost-effective manner while maintaining high customer satisfaction. The key focus areas are:

- Energy Supply;
- Asset Management; and
- Financial Performance.

UPDATED June 6, 2013

Measurement	Annual 2012 Actual	Annual 2012 Target	Annual 2011 Actual
Asset Management and Reliability			
Winter Availability[1]	99.97%	>98.0%	98.3%
Asset Management Strategy Execution plan implemented	Completed Targets	N/A	N/A
Financial Targets			
Annual Controllable Costs[2]	-1.7%	Budget	-3.2%
Net Income	$16.9 million	$15.3 million	$20.6 million
Return on Capital Employed	7.2%	7.3%	7.9%
Project Execution			
Completion rate of capital projects by year end	82%	>94%	83%
All-project variance from original budget	18%	8%	5%
Customer Service			
Rural Residential Customer Satisfaction rate	80%	>90%	88%

[1] Winter Availability is applicable for the months of January, February, March and December. For 2012, Hydro has implemented a modified winter availability metric which tracks the number of unit unavailability hours for which there would not have been ample system generation available to supply the system load under the loss of the largest generating unit (N-1). These unavailability hours are compared against the total hours in the month to provide for a simple percentage.
[2] Actual 2012 annual controllable costs are favorable from budget by -1.7% (2011 – 3.2% favorable)

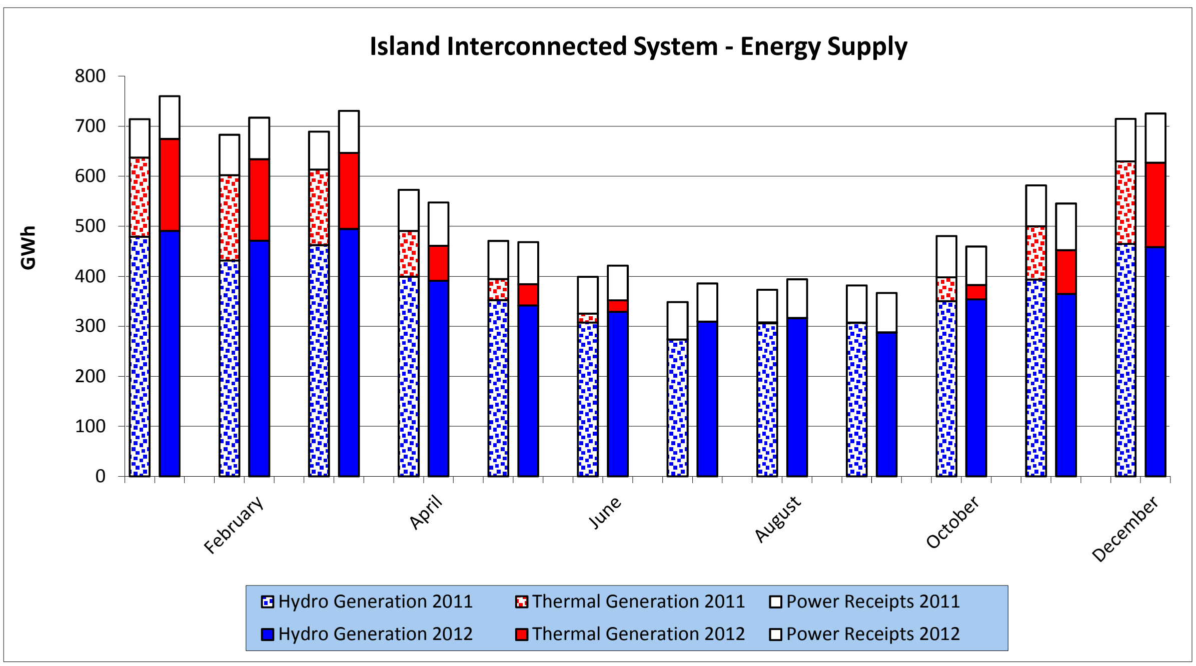
4.1 Energy Supply

4.1.1 Energy Supply - Island Interconnected System

Energy requirements from the Holyrood Generating station were slightly lower at the end of the fourth quarter of 2012 when compared to 2011. This was primarily due to reduced Avalon Peninsula requirements. Individual units are brought into service as required to meet customers' demand and for transmission support to the Avalon Peninsula. For the year, total thermal production was 29.5 GWh (3.3%) lower in 2012 than in 2011.

Annual hydroelectric production was 82.6 GWh or 1.8% above the levels in 2011, primarily due to increased system load requirements and a decrease in Holyrood requirements. The increase in hydroelectric production was partially offset by an increase in energy purchases. Total energy receipts were up by 98.4 GWh or 15.5% in 2012 when compared to 2011. This increase was primarily due to increased generation from Star Lake and from the Exploits generation at Grand Falls, Bishop's Falls and Buchans.

The energy supply for the Island Interconnected System is shown in the following chart and tables.



Island Interconnected System Production
For the Year ended December 31, 2012

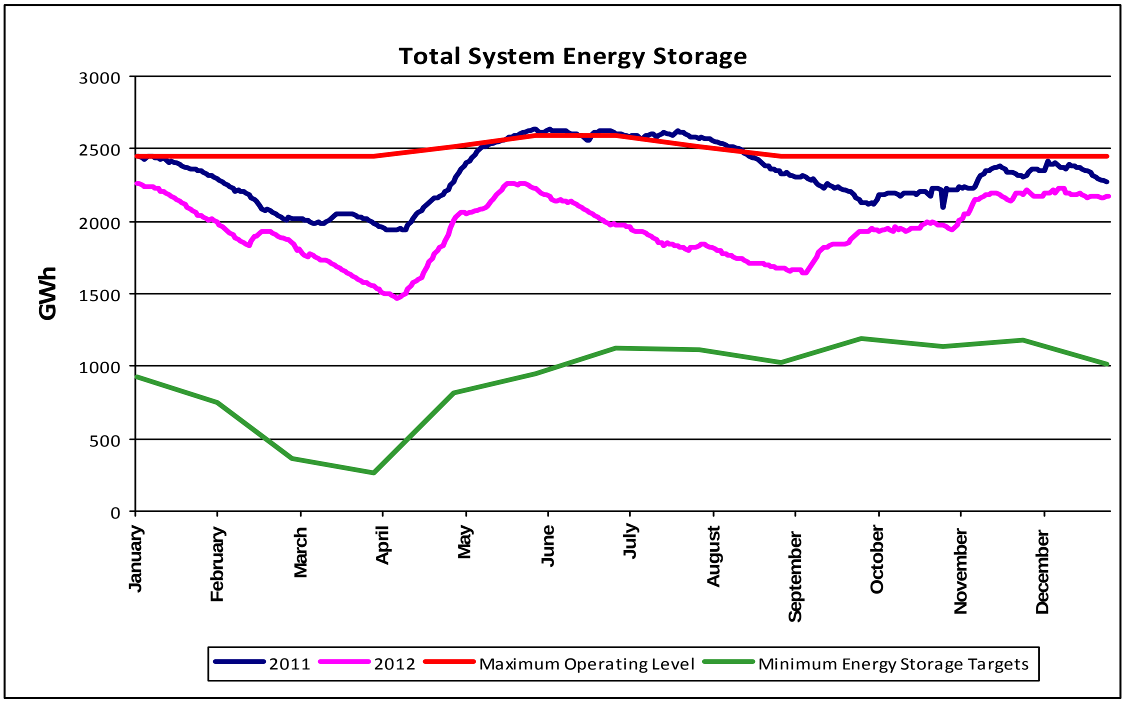
	Year-to-date			Annual Forecast (GWh)	2012 ($ 000)
	2012 (GWh)	2011 (GWh)	Forecast (GWh)		
Production (net)					
Hydro	4,595.0	4,512.4	4,681.7	4,681.7	
Thermal	855.8	885.3	925.8	925.8	
Gas Turbines	(3.9)	(10.2)	(2.2)	(2.2)	
Diesels	(0.5)	1.7	(0.3)	(0.3)	
Total Production	**5,446.4**	**5,389.2**	**5,605.0**	**5,605.0**	
Energy Receipts					
Non Utility Generators					
Rattle Brook	14.6	18.7	13.5	13.5	1,181.4
Corner Brook Pulp and Paper Co-generation	47.8	50.5	46.8	46.8	6,906.2
St. Lawrence Wind	103.8	110.0	105.0	105.0	7,383.3
Fermeuse Wind	91.2	88.0	88.5	88.5	6,885.5
Total Non Utility Generators	**257.4**	**267.2**	**253.8**	**253.8**	**22,356.4**
Secondary and Others					
Deer Lake Power	6.2	3.9	3.6	3.6	320.7
Hydro Request to NP	0.1	0.1	0.0	0.0	133.9
Nalcor Energy(1)	730.3	634.2	713.5	713.5	
Total Secondary and Other	**736.6**	**638.2**	**717.1**	**717.1**	**454.6**
Total Purchases	**994.0**	**905.4**	**970.9**	**970.9**	
Island Interconnected Total Produced and Purchased	**6,440.4**	**6,294.6**	**6,575.9**	**6,575.9**	

Note: Nalcor Energy includes Star Lake and the Grand Falls, Bishop's Falls and Buchans generation.

4.1.2 System Hydrology

Reservoir levels continue to be favourable. Inflows into the aggregate reservoir system were 115% of average during the fourth quarter of 2012. Annual inflows were near normal, at 99% of average. The aggregate storage position was 89% of the maximum operating level (MOL) and 215% of the minimum storage target at year end.

There was no energy spilled from Hydro's reservoirs in 2012.



System Hydrology Storage Levels			
	2012 (GWh)	2012 Minimum Target	2011 (GWh)
Quarter End Storage Levels	2,173	1,010	2,260

4.1.3 Energy Supply – Labrador Interconnected System

The purchased and produced energy on the Labrador Interconnected System was higher in 2012 (38.1 GWh or 5.0%) when compared to 2011. This is primarily due to higher industrial sales at the Iron Ore Company of Canada (IOCC) and increased Hydro Rural requirements in Labrador East and West. The increase was partially offset by reduced secondary sales to CFB Goose Bay.

Labrador Interconnected System Production For the Year ended December 31, 2012				
	Year-to-date			**Annual Forecast (GWh)**
	2012 (GWh)	**2011 (GWh)**	**Forecast (GWh)**	
Production (net)				
Gas Turbines	(0.7)	(2.2)	(0.4)	(0.4)
Diesels	0.0	(0.7)	0.0	0.0
Total Production	**(0.7)**	**(2.9)**	**(0.4)**	**(0.4)**
Purchases				
CF(L)Co for Labrador (at border)	**801.3**	**765.4**	**832.8**	**832.8**
Labrador Interconnected Total Produced and Purchased	**800.6**	**762.5**	**832.4**	**832.4**

4.1.4 Fuel Prices

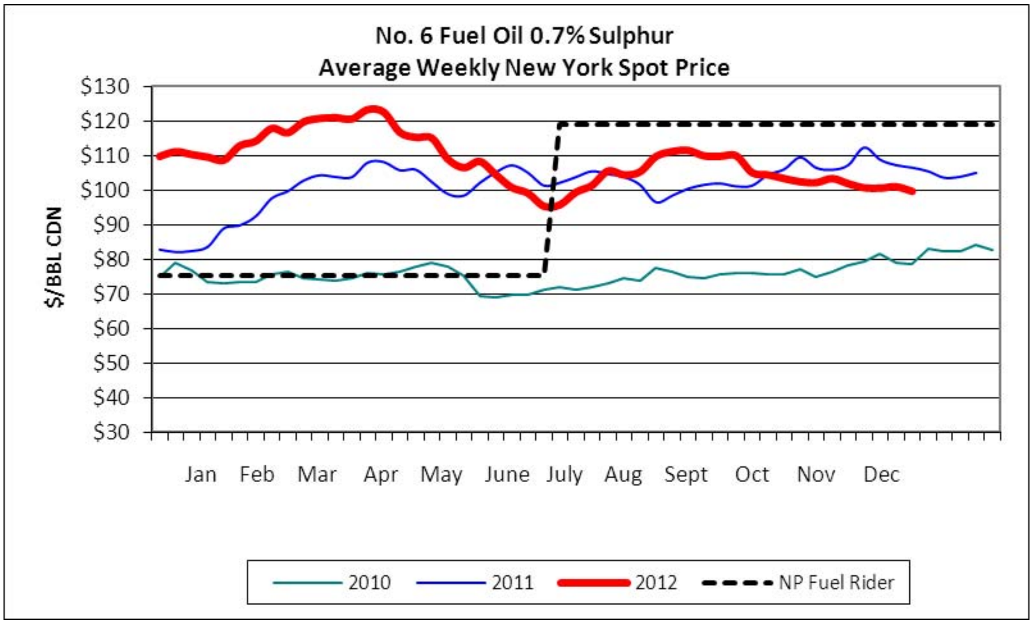
The fuel market prices for No. 6 fuel decreased slightly from approximately $104/bbl at the start of the quarter to $101/bbl at the end of the quarter. The quarter ending inventory cost was $113.60/bbl, lower than the current Newfoundland Power fuel price rider of $118.80/bbl. There is no Industrial Customer fuel price rider for 2012.

There was one shipment received during the fourth quarter of 2012:

November 8	225,149 bbls	$103.46

The inventory on December 31 was 180,936 barrels.

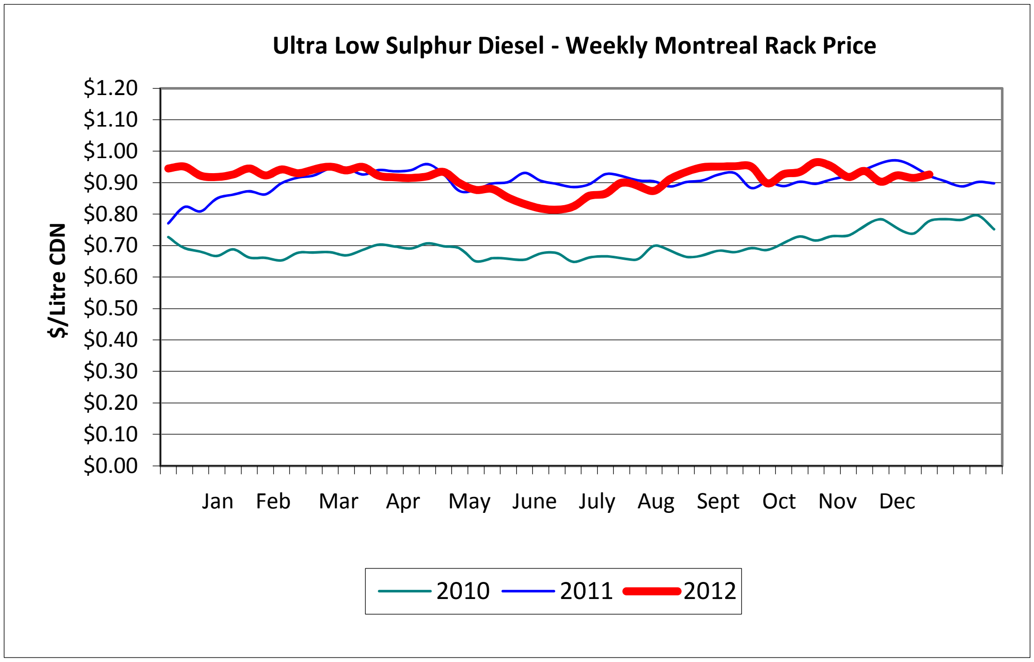
The following chart shows the No. 6 fuel prices year-to-date compared to 2010 and 2011, and the Newfoundland Power fuel rider price of $118.80/bbl.



The following table provides the monthly forecast price of No. 6 fuel (0.7% sulphur) up to September 2013, landed on the Avalon Peninsula.

No. 6 Fuel Oil Sulphur Forecast Price January 2013 – December 2013			
Month	**Price ($Cdn/bbl) 0.7%**	**Month**	**Price ($Cdn/bbl) 0.7%**
January 2013	101.10	July 2013	104.90
February 2013	103.10	August 2013	104.80
March 2013	99.70	September 2013	103.90
April 2013	102.00	October 2013	104.90
May 2013	100.80	November 2013	106.30
June 2013	102.60	December 2013	103.80
Note: The forecast is based on the PIRA Energy Group price forecast available January 3, 2013 and an exchange rate forecast by Canadian financial institutions and the Conference Board of Canada.			

The following chart shows Low Sulphur Diesel No. 1 fuel prices year-to-date compared to 2010 and 2011.



4.1.5 Energy Supply - Isolated Systems

Total isolated energy supply has decreased by almost 3% in 2012 compared to 2011.

Purchases from Hydro Québec for the L'Anse au Loup system have decreased by 3.6%. Decreased supply requirements (purchases and generation) on the L'Anse au Loup system account for 61% of the overall decrease in isolated supply. The decline in requirements on the L'Anse au Loup system is attributed to warmer weather in 2012 when compared to 2011. Environment Canada records show annual heating degree days for 2012 were 7% lower than in 2011.

Fish processing plants in St. Lewis, Black Tickle, and Little Bay Islands have not reopened this year and the closures are permanent. The decline in energy requirements in these communities accounts for almost 26% of overall decline in isolated supply.

The average cost of power purchased from Hydro Québec, based on Montreal rack fuel prices, has increased from $131 per megawatt hour in 2011 to $138 per megawatt hour in 2012. The average cost of power from NUGS, based on current diesel fuel prices, has increased from $275 per megawatt hour in 2011 to $289 per megawatt hour in 2012.

Isolated Systems Production
For the Year ended December 31, 2012

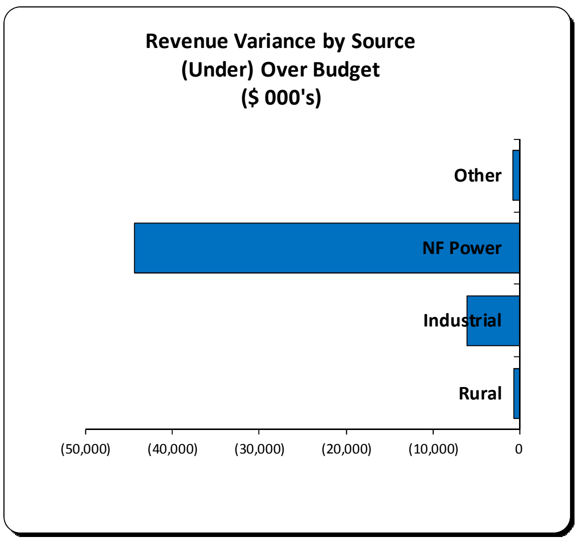
	Year-to-date						Annual Forecast (GWh)	$(000)[1]
	2012 (GWh)	$(000)[1]	2011 (GWh)	$(000)[1]	Forecast (GWh)	$(000)[1]		
Production (net)								
Diesels	45.6		47.3		49.0		49.0	
Purchases								
Non Utility Generators (NUGS)[2]	0.8	162.2	0.4	108.1	0.8	133.5	0.8	133.5
Hydro Québec	21.5	2,967.5	22.3	2,926.0	22.8	3,197.3	22.8	3,197.3
Total Purchases	**22.3**	**3,129.7**	**22.7**	**3,034.5**	**23.6**	**3,330.8**	**23.6**	**3,330.8**
Isolated Systems Total Produced and Purchased	**67.9**	**3,129.7**	**70.0**	**3,034.5**	**72.6**	**3,330.8**	**72.6**	**3,330.8**

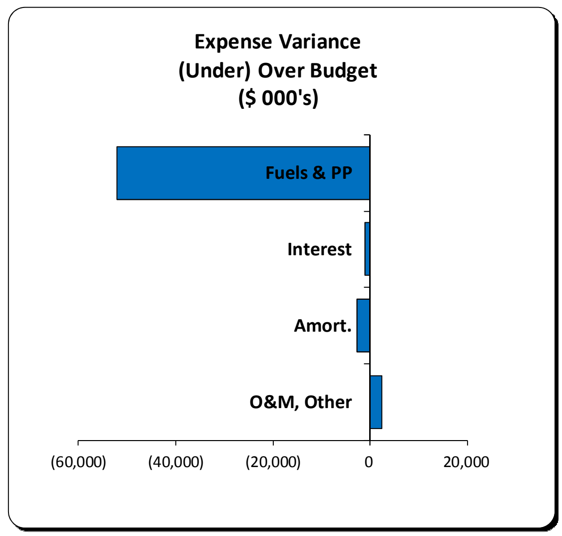
[1] Purchases before taxes.
[2] NUGS includes purchases from Frontier Power and production at Nalcor's wind/hydrogen facility in Ramea. Cost is energy purchased from Frontier Power only.

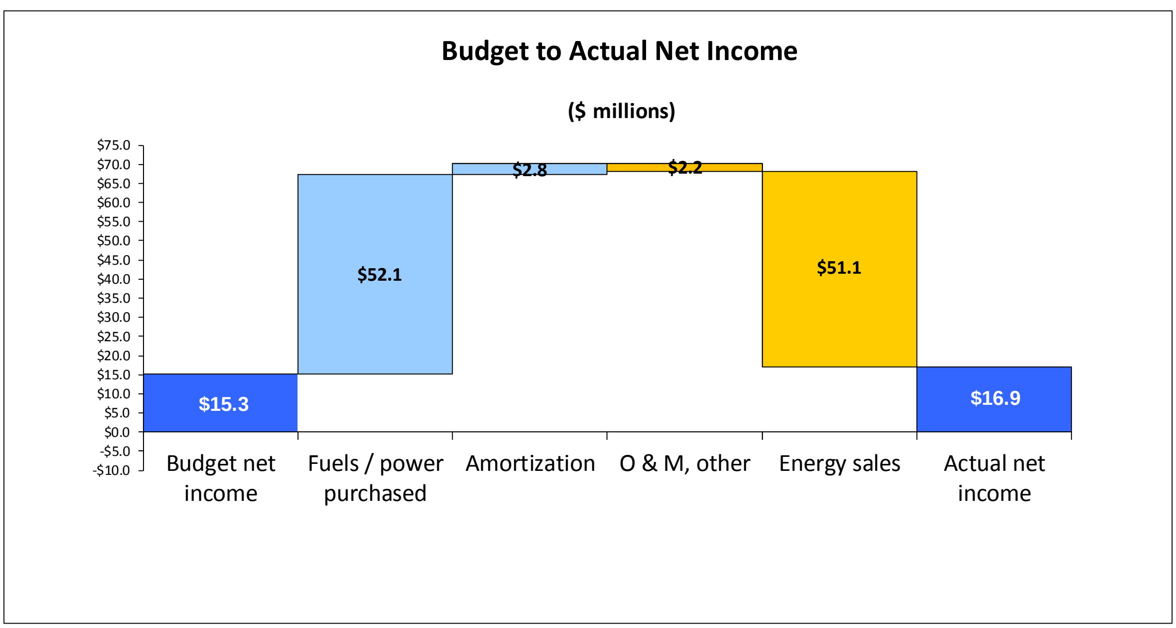
4.2 Financial

Below are charts of Hydro's (Regulated) Statement of Income year to date. Please see Appendix C for the remainder of the financial statements.

Regulated Operations
For the twelve months ended December 31, 2012







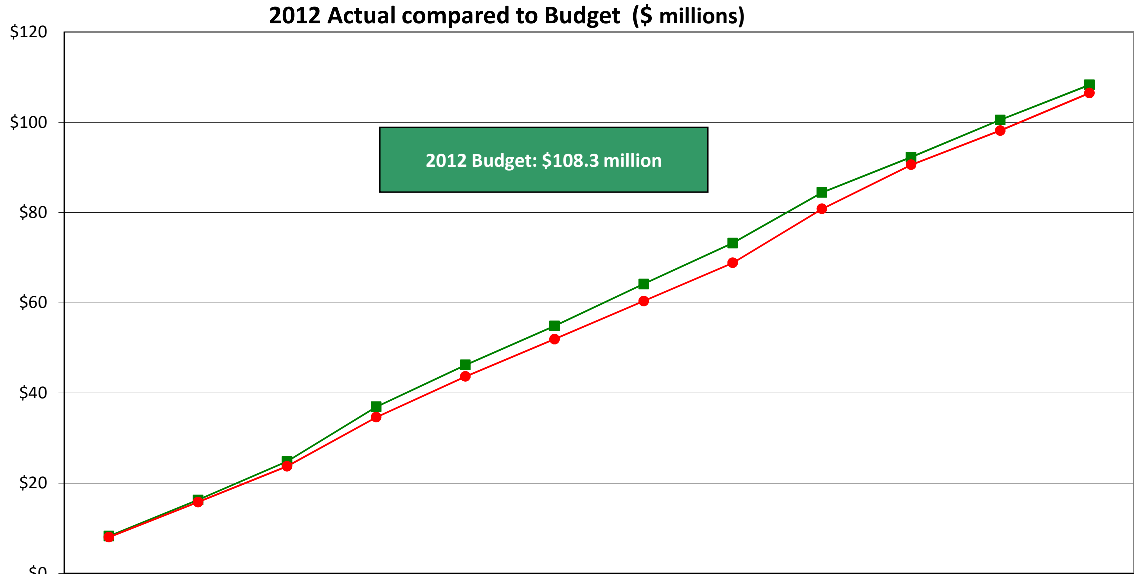
Statement of Income - Regulated Operations
For the twelve months ended December 31, 2012
($ 000's)

Fourth Quarter 2012 Actual	Fourth Quarter 2012 Budget	Fourth Quarter 2011 Actual		Year-to-date 2012 Actual	Year-to-date 2012 Budget	Year-to-date 2011 Actual
			Revenue			
122,409	149,312	125,842	Energy sales	453,178	504,308	443,796
72	747	677	Other revenue	2,116	2,948	2,317
122,481	150,059	126,519		455,294	507,256	446,113
			Expenses			
25,668	23,849	27,458	Operations	106,468	108,288	104,564
5,344	281	583	Loss on disposal of property, plant and equipment	5,396	1,125	925
42,662	71,681	35,759	Fuels	132,003	181,003	131,275
15,798	15,998	19,957	Power purchased	56,986	60,089	52,222
11,919	12,028	12,105	Amortization	47,580	50,338	45,684
21,825	23,664	22,750	Interest	89,961	91,136	90,844
123,216	147,501	118,612		438,394	491,979	425,514
(735)	2,558	7,907	**Net income (loss)**	16,900	15,277	20,599

The chart below illustrates the operations cost results for the year-to-date budget and actual.

Hydro Regulated Operating Costs

2012 Actual compared to Budget ($ millions)



	January	February	March	April	May	June	July	August	September	October	November	December
Cumulative Budget	$8.259	$16.288	$24.833	$36.929	$46.187	$54.847	$64.131	$73.229	$84.439	$92.251	$100.507	$108.288
Cumulative Actual	$8.024	$15.799	$23.738	$34.621	$43.649	$51.922	$60.362	$68.816	$80.800	$90.579	$98.142	$106.468

Cumulative Budget **Cumulative Actual**

4.3 Capital Expenditures

Capital Expenditures for the year ended December 31, 2012 will be reported as a separate document.

4.4 Other

4.4.1 Hydro's Transmission Structure Corrosion Workshop Presentation

The Transmission Structure Corrosion Workshop held on October 3, was jointly presented by the Centre for Energy Advancement through Technological Innovation, Overhead Line Design Issues and Wind and Ice Storm Mitigation and Transmission Line Asset Management Interest Group Programs.

The keynote speaker opened the workshop with a review of the fundamentals of corrosion process, its economic impact, the problems it causes on transmission structures, and the difficulties utilities have encountered in detecting it, specifically limitations of the non-destructive evaluations available to date.

Asim Halder's presentation covered the economic impact of corrosion damage on utility structures, as well as the corrosion process, detection and mitigation. The results of two case studies conducted for Hydro's own system about corrosion damage of anchor rods and grillage foundations.

4.4.2 Hydro Employees receive 2012 President's Awards

The President's Awards are Nalcor's most prestigious form of recognition. In 2012, 26 employees were nominated, and 11 employees received awards at the ceremony, held in St. John's on November 29. The recipients were recognized by their peers and the Leadership Team, as champions of the Nalcor Energy corporate goals.

Among the recipients of the 2012 President's Awards were:

Safety: **Paul Smith** - TRO Central

Environment: **Hughie Ireland** - TRO Central

Business Excellence: **Leveson Kearley** - Hydro Generation, **Alberta Marche** - Project Execution and Technical Services; **Bob Moulton** - Project Execution and Technical Services

People: **Renee Hodder** - Project Execution and Technical Services; **Fred Reid** - TRO Central

Community: **Annette Higdon** - Holyrood; **Clarence Kelly** - Hydro Generation

5 OTHER ITEMS

5.1 *Significant Issues*

5.1.1 Ramea Wind-Hydrogen-Diesel Project Update

Overall Project Site Showing (l-r) the Diesel Plant/Storage Tanks, Meteorological Tower, Hydrogen Electrolyser, 3 Hydrogen Storage Tanks, Distribution Box Structure, 3 Wind Turbines, and Quonset Hut Housing the Hydrogen Genset.

In accordance with Order No. P.U. 31 (2007), the following update is provided on the Wind-Hydrogen-Diesel Project for Ramea.

Implementation and Operation
Some project deficiencies remained in this quarter as a project staff member was re-assigned to other project work. Project close-out is deferred to Q2 2013 to resolve reliability problems with the Hydrogen Genset and complete remaining project deficiencies. The Operations schedule was revised to commence in Q3 2013, pending completion of project close-out documentation.

Capital Costs

($000)

Actual Cost to December 2012	Actual Cost Recoveries to December 2012	Net Cost to December 2012	Budget to December 2008	Budget Reforecast to September 2010[1]
11,864	**11,864**	**0**	**8,794**	**2,486**

[1] Project Change Order #3 is under draft to reflect various cost increases and schedule delays associated with incomplete commissioning activities, H_2 Genset fire and project deficiencies.

Operating Costs
There is nothing to report for this period as operation is planned to start in Q3 2013.

Reliability and Safety Issues
There is nothing to report for this period.

5.2 Community

5.2.1 Hydro Employees walk for Ronald McDonald House

Teams across the province participated in the Red Shoe Crew Walk in support of the Ronald McDonald House. Hydro employees participated in walks in St. John's, Bishop's Falls, St. Anthony New Harbour and Bay d'Espoir.

The New Harbour Hydro Red Show Crew

The St. Anthony Red Shoe Crew

5.2.2 Silver Lights give back to the Community

Santa's sleigh made its way downtown as an estimated 60,000 people lined the streets to see the Santa Clause parade in St. John's on November 25.

The Silver Lights (a volunteer group of employees and retirees with over 25 years of service) constructed a "Christmas Eve on Sesame Street" float that was over 20 feet high. In a close race for best float over 20 feet, Silver Lights tied for third place along with Tim Horton's.

A number of Nalcor and Hydro employees/retirees.

5.3 Statement of Energy Sold

Statement of Energy Sold (GWh)

For the Year ended December 31, 2012

	YEAR TO DATE 2012 ACTUAL	YEAR TO DATE 2011 ACTUAL	YEAR TO DATE 2012* FORECAST	2012* ANNUAL FORECAST	ANNUAL % CHANGE
Island Interconnected					
Newfoundland Power	5,359	5,317	5,359	5,359	0.8%
Island Industrials	410	311	410	410	31.8%
Rural					
Domestic	240	239	240	240	0.4%
General Service	163	151	163	163	7.9%
Streetlighting	3	3	3	3	0.0%
Sub-total Rural	406	393	406	406	3.3%
Sub-Total Island Interconnected	6,175	6,021	6,175	6,175	2.6%
Island Isolated					
Domestic	6	6	6	6	0.0%
General Service	1	1	1	1	0.0%
Streetlighting	0	0	0	0	0.0%
Sub-Total Island Isolated	7	7	7	7	0.0%
Labrador Interconnected					
Labrador Industrials	180	129	180	180	39.5%
CFB Goose Bay	18	51	18	18	-64.7%
Hydro Quebec (includes Menihek)	42	42	42	42	0.0%
Export	1,597	1,530	1,597	1,597	4.4%
Rural					
Domestic	285	272	285	285	4.8%
General Service	240	218	240	240	10.1%
Streetlighting	2	1	2	2	0.0%
Sub-total Rural	527	491	527	527	7.3%
Sub-Total Lab. Interconnected	2,364	2,243	2,364	2,364	5.4%
Labrador Isolated					
Domestic	21	21	21	21	0.0%
General Service	15	15	15	15	0.0%
Streetlighting	0	0	0	0	0.0%
Sub-Total Labrador Isolated	36	36	36	36	0.0%
L'Anse au Loup					
Domestic	13	13	13	13	0.0%
General Service	8	8	8	8	0.0%
Streetlighting	0	0	0	0	0.0%
Sub-Total L'Anse au Loup	21	21	21	21	0.0%
Total Energy Sold (Before Rural Accrual)	8,603	8,328	8,603	8,603	3.3%
Rural Accrual	10	11	-	-	
Total Energy Sold	8,613	8,339	8,603	8,603	3.3%
Sales to Non-Regulated Customers**	1819	1700	1819	1,819	7.0%

* Rural GWh - Based on 2012 Budget, Spring 2011 Rural Load Forecast
Non-rural GWh - Based on 2012 Wholesale Industrial Revenue Budget
** Included in Total Energy Sold

5.4 Customer Statistics

Customer Statistics
For the Quarter ended December 31, 2012

	FOURTH QUARTER		ANNUAL	
	2012 ACTUAL	2011 ACTUAL	2012 FORECAST	2011 ACTUAL
Customers				
Rural	37,576	37,116	38,694	37,116
Industrial	6	5	6	5
CFB Goose Bay	1	1	1	1
Utility	1	1	1	1
Non-Regulated	3	3	3	3
Reading Days	30.2	30.6	N/A	30.2

APPENDICES

Appendix A - Contributions in Aid of Construction (CIAC)
Appendix B - Damage Claims
Appendix C - Financial (to follow)
Appendix D - Rate Stabilization Plan Report
Appendix E - 2012 Key Performance Indicators Annual Report

CIAC QUARTERLY ACTIVITY REPORT
For the Quarter ended December 31, 2012

TYPE OF SERVICE	CIAC'S QUOTED	CIAC'S OUTSTANDING PREVIOUS QTR.	TOTAL CIAC'S QUOTED	CIAC'S ACCEPTED	CIAC'S EXPIRED	TOTAL CIAC'S OUTSTANDING
Domestic						
Within Plan. Boundary	5	7	12	5	3	4
Outside Plan. Boundary	2	5	7	3	4	0
Sub-total	7	12	19	8	7	4
General Service	8	6	14	7	2	5
Total	15	18	33	15	9	9

The table above summarizes Contribution in Aid of Construction (CIAC) activity for this quarter. The table is divided into three sections, as follows:

- The first section outlines the type of service for which a CIAC has been calculated, either Domestic or General Service.

- The second section indicates the number of CIACs quoted during the quarter as well as the number of CIAC quotes that remained outstanding at the end of the previous quarter. This format facilitates a reconciliation of the total number of CIACs that were active during the quarter.

- The third section provides information as to the disposition of the total CIACs quoted. A CIAC is considered accepted when a customer indicates they wish to proceed with construction of the extension and has agreed to pay any charge that may be applicable. A CIAC is considered outdated after six months has elapsed and the customers have not indicated their intention to proceed with the extension. A quoted CIAC is outstanding if it is neither accepted nor outdated.

CIAC QUARTERLY ACTIVITY REPORT
For the Quarter ended December 31, 2012

DATE QUOTED	SERVICE LOCATION	CIAC NO.	CIAC AMOUNT ($)	ESTIMATED CONST. COST ($)	ACCEPTED
DOMESTIC - WITHIN RESIDENTIAL PLANNING BOUNDARIES					
October 9, 2012	L'Anse au Loup	929827	$ 1,595.00	$ 2,320.00	Yes
October 10, 2012	Three Mile Rock	931545	$ 18,560.00	$ 21,025.00	
October 11, 2012	South Brook; Green Bay	935649	$ 3,357.50	$ 4,082.50	Yes
October 22, 2012	Change Islands	941246	$ 1,885.00	$ 2,900.00	
October 30, 2012	Westport	943391	$ 3,086.15	$ 725.00	Yes
DOMESTIC - OUTSIDE RESIDENTIAL PLANNING BOUNDARIES					
October 31, 2012	South Brook; Green Bay	756296	$ 96,377.00	$ 110,877.00	Yes
December 12, 2012	South Brook; Green Bay	942638	$ 1,872.50	$ 725.00	Yes
GENERAL SERVICE					
October 3, 2012	Happy Valley-Goose Bay	931563	$ -	$ 15,197.50	Yes
October 29, 2012	Cow Head	939794	$ -	$ 2,241.00	Yes
October 30, 2012	Happy Valley-Goose Bay	939374	$ -	$ 2,175.00	Yes
November 5, 2012	Happy Valley-Goose Bay	943312	$ -	$ 9,685.00	Yes
November 5, 2012	Happy Valley-Goose Bay	928379	$ 20,420.00	$ 77,625.00	Yes
November 27, 2012	Happy Valley-Goose Bay	945885	$ 1,831.18	$ 16,586.18	
December 3, 2012	Happy Valley-Goose Bay	945879	$ 4,350.00	$ 12,655.00	
December 5, 2012	Wabush	937925	$ 2,800.00	$ 10,540.00	Yes

CUSTOMER PROPERTY DAMAGE CLAIMS REPORT
For the Quarter ended December 31, 2012

Introduction

The Customer Property Damage Claims Report contains an overview of all damage claims activity summarized on a quarterly basis. The information contained in the report is broken down by cause as well as by the operating region where the claims originated.

The report is divided into four sections as follows:

1. The first section indicates the number of claims received during the quarter coupled with claims outstanding from the previous quarter.

2. The second section shows the number of claims for which the Company has accepted responsibility and the amount paid to claimants versus the amount originally claimed.

3. The third section shows the number of claims rejected and the dollar value associated with those claims.

4. The fourth section indicates those claims that remain outstanding at the end of the current quarter and the dollar value associated with such claims.

Definitions of Causes of Damage Claims

1. System Operations: Claims arising from system operations. Examples include normal reclosing or switching.

2. Power Interruptions: Claims arising from interruption of power supply. Examples include all scheduled or unscheduled interruptions.

3. Improper Workmanship: Claims arising from failure of electrical equipment caused by improper workmanship or methods. Examples include improper crimping of connections, insufficient sealing and taping of connections, improper maintenance, inadequate clearance or improper operation of equipment.

4. Weather Related: Claims arising from weather conditions. Examples include wind, rain, ice, lighting or corrosion caused by weather.

5. Equipment Failure: Claims arising from failure of electrical equipment not caused by improper workmanship. Examples include broken neutrals, broken tie wires, transformer failure, insulator failure or broken service wire.

6. Third Party: Claims arising from equipment failure caused by acts of third parties. Examples include motor vehicle accidents and vandalism.

7. Miscellaneous: All claims not related to electrical service.

8. Waiting Investigation: Cause to be determined.

CUSTOMER PROPERTY DAMAGE CLAIMS REPORT - BY CAUSE

For the Quarter ended December 31, 2012

CAUSE	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	AMT. CLAIMED	AMT. PAID	#	AMOUNT	#	AMOUNT
System Operations	0	2	2	0	$ -	$ -	0	$ -	2	$ 1,262.00
Power Interruptions	0	1	1	0	$ -	$ -	0	$ -	1	$ -
Improper Workmanship	1	5	6	0	$ -	$ -	1	$ 845.00	6	$ 5,477.02
Weather Related	12	6	18	1	$ 1,250.00	$ 947.39	9	$ 6,188.84	9	$ 6,904.50
Equipment Failure	3	6	9	0	$ -	$ -	2	$ 969.79	7	$ 28,117.09
Third Party	0	0	0	0	$ -	$ -	0	$ -	0	$ -
Miscellaneous	2	2	4	1	$ 2,512.60	$ 2,512.60	1	$ 28,750.00	2	$ 2,000.00
Waiting Investigation	2	8	10	0	$ -	$ -	0	$ -	8	$ 3,188.00
Total	20	30	50	2	$ 3,762.60	$ 3,459.99	13	$ 36,753.63	35	$ 46,948.61

For the Quarter ended December 31, 2011

CAUSE	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	AMT. CLAIMED	AMT. PAID	#	AMOUNT	#	AMOUNT
System Operations	4	0	4	0	$ -	$ -	5	$ -	0	$ -
Power Interruptions	4	2	6	0	$ -	$ -	6	$ 4,081.62	0	$ -
Improper Workmanship	7	4	11	2	$ 9,527.63	$ 8,622.13	0	$ -	8	$ 7,642.95
Weather Related	12	9	21	0	$ -	$ -	14	$ 10,326.42	6	$ 4,024.47
Equipment Failure	3	2	5	3	$ 21,680.50	$ 152,582.00	2	$ 372.89	3	$ 8,174.68
Third Party	0	0	0	0	$ -	$ -	0	$ -	0	$ -
Miscellaneous	3	1	4	0	$ -	$ -	5	$ 4,397.89	0	$ -
Waiting Investigation	2	8	10	0	$ -	$ -	0	$ -	5	$ 13,221.77
Total	35	26	61	5	$ 31,208.13	$ 161,204.13	32	$ 19,178.82	22	$ 33,063.87

CUSTOMER PROPERTY DAMAGE CLAIMS REPORT - BY REGION

For the Quarter ended December 31, 2012

REGION	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	AMT. CLAIMED	AMT. PAID	#	AMOUNT	#	AMOUNT
Central Region	4	10	14	1	$ 2,512.60	$ 2,512.60	5	$ 32,340.00	8	$ 4,173.44
Northern Region	12	12	24	0	$ -	$ -	7	$ 4,209.79	17	$ 33,325.17
Labrador Region	4	8	12	1	$ 1,250.00	$ 947.39	1	$ 203.84	10	$ 9,450.00
Total	20	30	50	2	$ 3,762.60	$ 3,459.99	13	$ 36,753.63	35	$ 46,948.61

For the Quarter ended December 31, 2011

REGION	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	AMT. CLAIMED	AMT. PAID	#	AMOUNT	#	AMOUNT
Central Region	11	9	20	2	$ 10,155.00	$ 8,389.50	10	$ 2,304.51	7	$ 9,174.88
Northern Region	18	9	27	2	$ 20,580.50	$ 152,342.00	16	$ 11,217.31	9	$ 5,204.15
Labrador Region	6	8	14	1	$ 472.63	$ 472.63	6	$ 5,657.00	6	$ 18,684.84
Total	35	26	61	5	$ 31,208.13	$ 161,204.13	32	$ 19,178.82	22	$ 33,063.87

FINANCIAL – REGULATED

Balance Sheet - Regulated Operations
As at December 31
($ 000's)

	Dec-12	Dec-11
ASSETS		
Current assets		
Cash and cash equivalents	2,480	6,685
Accounts receivable	80,185	79,359
Current portion of regulatory assets	2,157	2,762
Inventory	51,673	54,258
Prepaid expenses	2,949	2,284
	139,444	145,348
Property, plant, and equipment	1,440,619	1,410,432
Sinking funds	263,330	246,966
Regulatory assets	62,824	63,597
Long-term receivable	188	210
Total assets	1,906,405	1,866,553
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	39,299	49,341
Accrued interest	28,667	28,667
Current portion of long-term debt	8,150	8,150
Current portion of regulatory liabilities	168,985	137,593
Deferred credits	1,938	3,497
Due to related parties	1,873	49,258
Promissory notes	44,783	(5,118)
	293,695	271,388
Long-term debt	1,125,901	1,131,542
Regulatory liabilities	33,174	33,271
Asset retirement obligations	24,031	19,593
Employee future benefits	56,890	53,556
Contributed capital	100,000	100,000
Shareholder's equity / retained earnings	231,174	212,096
Accumulated other comprehensive income	41,540	45,107
Total liabilities and shareholder's equity	1,906,405	1,866,553

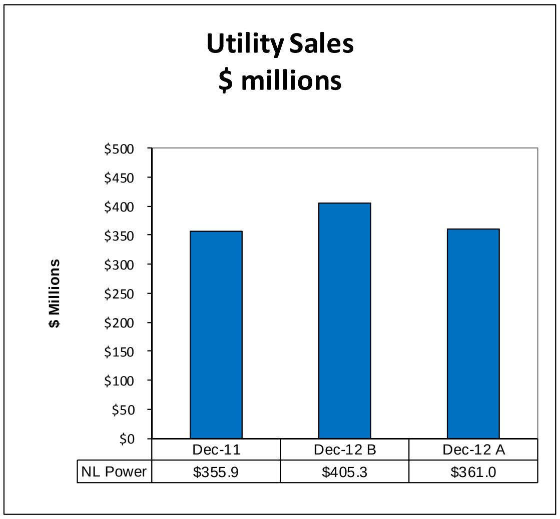
Statement of Retained Earnings - Regulated Operations
For the twelve months ended December 31, 2012
($ 000's)

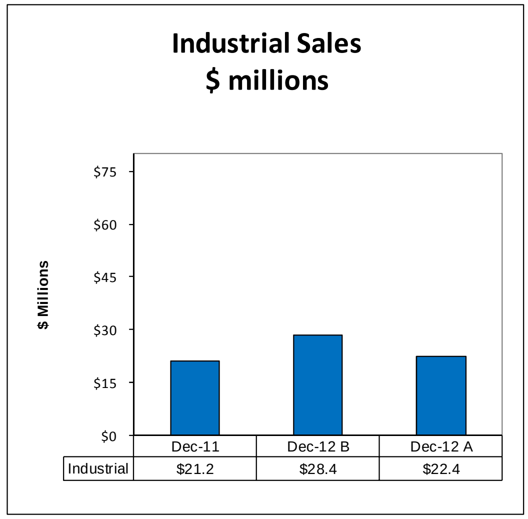
Fourth Quarter 2012 Actual	Fourth Quarter 2011 Actual		Year-to-date 2012 Actual	Year-to-date 2011 Actual
230,559	204,189	Balance, beginning of year	212,096	212,647
1,350	-	Adjustment	2,178	-
(735)	7,907	Net income (loss)	16,900	20,599
-	-	Dividends	-	(21,150)
231,174	212,096	Balance, end of year	231,174	212,096

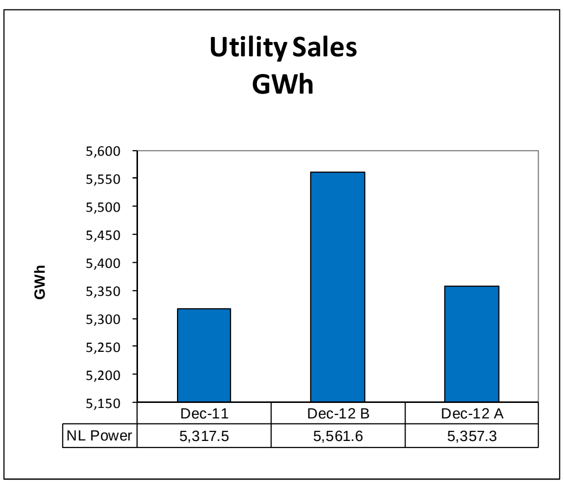
Statement of Comprehensive Income - Regulated Operations
For the twelve months ended December 31, 2012
($ 000's)

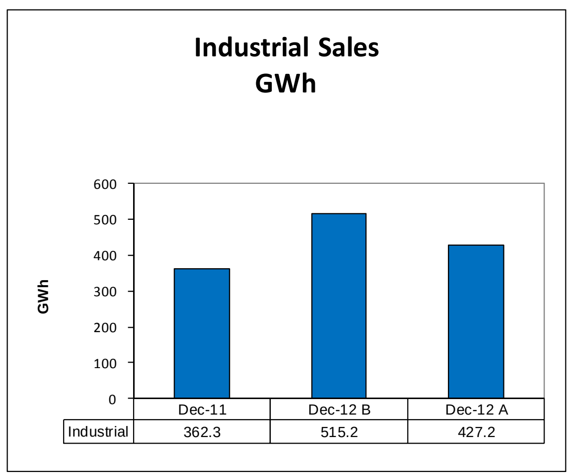
Fourth Quarter 2012 Actual	Fourth Quarter 2012 Budget	Fourth Quarter 2011 Actual		Year-to-date 2012 Actual	Year-to-date 2012 Budget	Year-to-date 2011 Actual
(735)	-	7,907	Net income (loss)	16,900	15,277	20,599
			Other comprehensive income			
5,534	-	5,736	Change in fair value of sinking fund investments	3,567	-	19,592
4,799	-	13,643	Total comprehensive income	20,467	15,277	40,191

Sales - Regulated Operations
For the twelve months ended December 31, 2012









Revenue Summary - Regulated Operations
For the twelve months ended December 31, 2012
($ 000's)

Fourth Quarter 2012 Actual	Fourth Quarter 2012 Budget	Fourth Quarter 2011 Actual		Year-to-date 2012 Actual	Year-to-date 2012 Budget	Year-to-date 2011 Actual
			REVENUE			
			Industrial			
1,009	2,326	1,109	Corner Brook Pulp and Paper Ltd.	5,767	8,222	4,197
5	646	-	Vale Inco	5	2,030	-
2,947	3,670	2,848	North Atlantic Refinery	11,432	13,307	9,381
412	-	1,393	C.F.B. Goose Bay	1,554	636	4,038
911	1,153	921	Teck Cominco Limited	3,593	4,130	3,585
-	52	-	Muskrat Falls	-	102	-
5,284	7,847	6,271	**Total Industrial**	22,351	28,427	21,201
			Utility			
99,572	121,837	102,581	Newfoundland Power Inc.	360,961	405,330	355,895
			Rural			
17,553	19,628	16,990	Interconnected and diesel	69,866	70,551	66,700
72	747	677	**Other**	2,116	2,948	2,317
122,481	150,059	126,519	**Total**	455,294	507,256	446,113
			ENERGY SALES (GWh)			
			Industrial			
12.6	34.2	15.3	Corner Brook Pulp and Paper Ltd.	97.3	135.7	54.6
-	8.3	-	Vale Inco	-	31.2	-
62.6	64.1	59.9	North Atlantic Refinery	240.4	254.9	184.6
4.8	-	15.8	C.F.B. Goose Bay	17.6	7.4	51.4
18.3	19.3	18.6	Teck Cominco Limited	71.9	75.6	71.7
-	6.1	-	Muskrat Falls	-	10.4	-
98.3	132.0	109.6	**Total Industrial**	427.2	515.2	362.3
			Utility			
1,441.0	1,518.6	1,481.2	Newfoundland Power Inc.	5,357.3	5,561.6	5,317.5
			Rural			
234.3	269.7	228.5	Interconnected and diesel	997.7	992.1	948.9
1,773.6	1,920.3	1,819.3	**Total**	6,782.2	7,068.9	6,628.7

Statement of Cash Flows - Regulated Operations
For the twelve months ended December 31, 2012
($ 000's)

	Year-to-date 2012	Year-to-date 2011
Operating activities		
Net income	16,900	20,599
Adjusted for items not involving cash flow		
Amortization	47,580	45,684
Accretion of long-term debt	498	460
Employee future benefits	4,521	5,208
Loss on disposal of property, plant and equipment	3,844	925
Other	92	-
	73,435	72,876
Changes in non-cash balances		
Accounts receivable	(826)	(17,930)
Inventory	2,585	(868)
Prepaid expenses	(665)	38
Regulatory assets	1,378	3,377
Regulatory liabilities	31,295	11,084
Accounts payable and accrued liabilities	(10,042)	(15,896)
Due to related parties	(47,385)	12,034
	49,775	64,715
Financing activities		
Decrease in long-term receivable	22	39
(Decrease) increase in deferred credits	(1,559)	3,374
Dividends	-	(21,150)
Increase in promissory notes	49,901	403
	48,364	(17,334)
Investing activities		
Additions to property, plant and equipment	(77,474)	(63,083)
Decrease in short term investments	-	8,992
Proceeds on disposal of property, plant and equipment	1,200	301
Increase in sinking funds	(26,070)	(24,666)
	(102,344)	(78,456)
Net decrease in cash	(4,205)	(31,075)
Cash position, beginning of year	6,685	37,760
Cash position, end of year	2,480	6,685

FINANCIAL – NON-REGULATED

Balance Sheet - Non-Regulated Activities
As at December 31
($ 000's)

	Dec-12	Dec-11
ASSETS		
Current assets		
Accounts receivable	3,488	3,691
Derivative assets	28	217
	3,516	3,908
Long-term receivable	-	1,398
Investment in CF(L)Co.	417,495	399,155
Total assets	421,011	404,461
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	2,224	3,458
Promissory notes	7,217	5,118
Derivative liabilities	-	30
	9,441	8,606
Long-term note payable	-	1,306
Share capital	22,504	22,504
Lower Churchill Development Corp	15,400	15,400
Retained earnings	373,578	356,645
Accumulated other comprehensive income	88	-
Total liabilities and shareholder's equity	421,011	404,461

Statement of Income - Non-Regulated Activities
For the twelve months ended December 31, 2012
($ 000's)

Fourth Quarter 2012 Actual	Fourth Quarter 2012 Budget	Fourth Quarter 2011 Actual		Year-to-date 2012 Actual	Year-to-date 2012 Budget	Year-to-date 2011 Actual
			Revenue			
14,033	15,987	15,278	Energy sales	52,275	70,846	74,260
14,033	15,987	15,278		52,275	70,846	74,260
			Expenses			
6,361	6,691	5,829	Operations	25,645	26,904	24,288
8	-	13	Fuels	36	-	36
1,954	3,300	1,087	Power purchased	7,696	11,912	4,569
229	-	(864)	Other income and expense	(59)	-	1,838
(117)	-	327	Interest	106	-	(655)
8,435	9,991	6,392		33,424	38,816	30,076
5,598	5,996	8,886	Net operating income	18,851	32,030	44,184
6,933	9,694	3,706	Equity in CF(L)Co	18,252	17,023	14,890
1,268	2,316	2,725	Preferred dividends	10,114	9,765	9,588
8,201	12,010	6,431		28,366	26,788	24,478
13,799	18,006	15,317	**Net income**	47,217	58,818	68,662

Statement of Retained Earnings - Non-Regulated Activties
For the twelve months ended December 31, 2012
($ 000's)

Fourth Quarter 2012 Actual	Fourth Quarter 2011 Actual		Year-to-date 2012 Actual	Year-to-date 2011 Actual
369,170	354,466	Balance, beginning of year	356,645	344,828
(2,147)	-	Adjustment	-	-
13,799	15,317	Net income	47,217	68,662
(7,244)	(13,138)	Dividends	(30,284)	(56,845)
373,578	356,645	Balance, end of year	373,578	356,645

Statement of Comprehensive Income - Non-Regulated Activities
For the twelve months ended December 31, 2012
($ 000's)

Fourth Quarter 2012 Actual	Fourth Quarter 2012 Budget	Fourth Quarter 2011 Actual		Year-to-date 2012 Actual	Year-to-date 2012 Budget	Year-to-date 2011 Actual
13,799	18,006	15,317	Net income	47,217	58,818	68,662
			Other comprehensive income (loss)			
-	-	-	Change in fair value of derivative instruments	-	-	(1,268)
51	-	-	Share of CF(L)Co other comprehensive income	88	-	-
13,850	18,006	15,317	Total comprehensive income	47,305	58,818	67,394

Statement of Cash Flows - Non-Regulated Activities
For the twelve months ended December 31, 2012
($ 000's)

	Year-to-date 2012	Year-to-date 2011
Operating activities		
Net income	47,217	68,662
Adjusted for items not involving cash flow		
Unrealized loss on derivatives	159	232
Equity in CF(L)Co	(18,252)	(14,890)
	29,124	54,004
Changes in non-cash balances		
Accounts receivable	203	1,712
Accounts payable and accrued liabilities	(1,234)	1,532
	28,093	57,248
Financing activities		
Increase (decrease) in promissory notes	2,099	(403)
Decrease in long-term receivable	1,398	24,009
Decrease in long-term note payable	(1,306)	(24,009)
Dividends	(30,284)	(56,845)
	(28,093)	(57,248)
Net change in cash	-	-
Cash position, beginning of year	-	-
Cash position, end of year	-	-

FINANCIAL – SUPPLEMENTARY

Supplementary Schedule - Regulated Operations
For the twelve months ended December 31, 2012
($ 000's)

Fourth Quarter 2012 Actual	Fourth Quarter 2012 Budget	Fourth Quarter 2011 Actual		Year-to-date 2012 Actual	Year-to-date 2012 Budget	Year-to-date 2011 Actual
			Other revenue			
209	168	225	Sundry	814	673	581
9	397	438	Pole attachments	1,213	1,588	1,634
10	25	14	Supplier's discount	89	99	102
(156)	157	-	Contributions in aid of construction	-	588	-
72	747	677	**Total other revenue**	2,116	2,948	2,317
			Interest			
27,291	28,552	27,060	Gross interest	108,308	108,519	107,338
128	128	117	Accretion of long-term debt	499	499	460
(473)	171	-	Accretion of decommissioning liabilities	-	686	-
539	539	539	Amortization of foreign exchange losses	2,157	2,157	2,157
(911)	(1,010)	(501)	Allowance for funds used during construction	(2,706)	(2,244)	(1,546)
(4,749)	(4,716)	(4,465)	Interest earned	(18,297)	(18,481)	(17,565)
21,825	23,664	22,750	**Total interest**	89,961	91,136	90,844

Cost Recoveries - Regulated Operations
For the twelve months ended December 31, 2012
($ 000's)

Fourth Quarter 2012 Actual	Fourth Quarter 2012 Budget	Fourth Quarter 2011 Actual		Year-to-date 2012 Actual	Year-to-date 2012 Budget	Year-to-date 2011 Actual
5	3	6	Executive Leadership	13	13	9
369	273	261	Human Resources and Organizational Effectiveness	1,054	1,096	940
1,167	1,271	672	Finance / CFO	4,827	5,120	2,994
7	2	56	Engineeering Services	43	8	209
44	23	36	Regulated Operations	126	93	95
1,592	1,572	1,031		6,063	6,330	4,247

Newfoundland and Labrador Hydro
Rate Stabilization Plan
December 31, 2012

Rate Stabilization Plan Report
December 31, 2012

Summary of Key Facts

The Rate Stabilization Plan of Newfoundland and Labrador Hydro (Hydro), as amended by Board Order No. P.U. 40 (2003) and Order No. P.U. 8 (2007), is established for Hydro's utility customer, Newfoundland Power, and Island Industrial customers to smooth rate impacts for variations between actual results and Test Year Cost of Service estimates for:

- Hydraulic production;
- No. 6 fuel cost used at Hydro's Holyrood generating station;
- Customer load (Utility and Island Industrial); and
- Rural rates.

The Test Year Cost of Service Study was approved by Board Order No. P.U. 8 (2007) and is based on projections of events and costs that are forecast to happen during a test year. Finance charges are calculated on the balances using the test year Weighted Average Cost of Capital which is currently 7.529% per annum. Holyrood's operating efficiency is set, for RSP purposes, at 630 kWh/barrel regardless of the actual conversion rate experienced.

	2007 Test Year Cost of Service			
	Net Hydraulic Production (kWh)	No. 6 Fuel Cost ($Can/bbl.)	Utility Load (kWh)	Industrial Load (kWh)
January	427,100,000	54.17	574,800,000	78,300,000
February	388,680,000	54.73	518,600,000	70,900,000
March	415,080,000	55.46	524,700,000	76,600,000
April	355,520,000	55.46	429,200,000	75,600,000
May	324,240,000	55.46	358,700,000	69,500,000
June	328,500,000	54.49	298,400,000	73,800,000
July	386,790,000	54.49	293,400,000	77,500,000
August	379,140,000	54.49	287,000,000	77,900,000
September	363,560,000	54.49	297,700,000	73,000,000
October	340,510,000	54.56	360,200,000	74,400,000
November	364,390,000	54.56	439,300,000	74,100,000
December	398,560,000	58.98	543,800,000	72,700,000
Total	4,472,070,000		4,925,800,000	894,300,000

Rate Stabilization Plan
Plan Highlights
December 31, 2012

	Actual	Cost of Service	Variance	Year-to-Date Due (To) From customers	Reference
Hydraulic production year-to-date	4,590.2 GWh	4,472.1 GWh	118.1 GWh	$ (10,830,537)	Page 4
No 6 fuel cost - Current month	$ 113.29	$ 58.98	$ 54.31	$ 84,592,255	Page 5
Year-to-date customer load - Utility	5,359.3 GWh	4,925.8 GWh	433.5 GWh	$ (97,564)	Page 8
Year-to-date customer load - Industrial	409.6 GWh	894.3 GWh	-484.7 GWh	$ (24,548,090)	Page 9
				$ 49,116,064	

Rural rates		
Rural Rate Alteration (RRA) [1]	$ (7,037,680)	
Less : RRA to utility customer	$ (6,270,574)	Page 10
RRA to Labrador interconnected	(767,106)	
Fuel variance to Labrador interconnected	$ 661,174	Page 6
Net Labrador interconnected	$ (105,932)	

Current plan summary [2]		
One year recovery		
Due (to) from utility customer [2]	$ (64,905,401)	Page 10
Due (to) from Industrial customers [2]	$ (104,079,983)	Page 11
Sub total	(168,985,384)	
Four year recovery		
Hydraulic balance	$ (32,675,763)	Page 4
Total plan balance	$ (201,661,147)	

[1] Beginning January 2011, the RRA includes a monthly credit of $98,295. This amount relates to the phase in of the application of the credit from secondary energy sales to CFB Goose Bay to the Rural deficit as stated in Section B, Clause 1.3(b) of the approved Rate Stabilization Plan Regulations which received final approval in Order No. P.U. 33 (2010) issued December 15, 2010.

[2] Disposition of the load variation is one of the issues to be considered by the Public Utilities Board in a pending hearing. This may impact the balances owing to customers in the current plan.

Rate Stabilization Plan
Net Hydraulic Production Variation
December 31, 2012

	A	B	C	D	E	F	G
	Cost of Service Net Hydraulic Production	Actual Net Hydraulic Production	Monthly Net Hydraulic Production Variance	Cost of Service No. 6 Fuel Cost	Net Hydraulic Production Variation	Financing Charges	Cumulative Variation and Financing Charges
	(kWh)	(kWh)	(kWh)	($Can/bbl.)	($)	($)	($)
			(A - B)		**(C / O[1] X D)**		**(E + F)**
							(to page 12)
Opening balance							(32,737,147)
January	427,100,000	489,800,074	(62,700,074)	54.17	(5,391,211)	(198,633)	(38,326,991)
February	388,680,000	470,451,513	(81,771,513)	54.73	(7,103,738)	(232,549)	(45,663,278)
March	415,080,000	493,310,549	(78,230,549)	55.46	(6,886,772)	(277,062)	(52,827,112)
April	355,520,000	389,781,961	(34,261,961)	55.46	(3,016,140)	(320,529)	(56,163,781)
May	324,240,000	341,379,893	(17,139,893)	55.46	(1,508,855)	(340,774)	(58,013,410)
June	328,500,000	321,226,024	7,273,976	54.49	629,141	(351,996)	(57,736,265)
July	386,790,000	308,929,190	77,860,810	54.49	6,734,342	(350,315)	(51,352,238)
August	379,140,000	315,733,699	63,406,301	54.49	5,484,142	(311,580)	(46,179,676)
September	363,560,000	286,134,767	77,425,233	54.49	6,696,668	(280,195)	(39,763,203)
October	340,510,000	352,757,654	(12,247,654)	54.56	(1,060,686)	(241,263)	(41,065,152)
November	364,390,000	363,638,371	751,629	54.56	65,093	(249,163)	(41,249,222)
December	398,560,000	457,015,214	(58,455,214)	58.98	(5,472,521)	(250,280)	(46,972,023)
	4,472,070,000	4,590,158,909	(118,088,909)		(10,830,537)	(3,404,339)	(46,972,023)
Hydraulic Allocation [2]					10,891,921	3,404,339	14,296,260
Hydraulic variation at year end					61,384	-	(32,675,763)

(1) O is the Holyrood Operating Efficiency of 630 kWh/barrel.

(2) At year end 25% of the hydraulic variation balance and 100% of the annual financing charges are allocated to customers.

	(from page 6)				**(to pages 11 & 12)**
	12 month kWh	% of kWh to total	Allocation	Reallocate Rural	Net
Utility	5,359,316,868	86.2%	12,328,828	913,395	13,242,223
Industrial	409,614,546	6.6%	942,297		942,297
Rural	445,624,295	7.2%	1,025,135	(1,025,135)	-
Total	6,214,555,709	100.0%	14,296,260	(111,740)	14,184,520
Labrador Inteconnected (write-off to income)				111,740	111,740
				-	14,296,260

Rate Stabilization Plan
No. 6 Fuel Variation
December 31, 2012

	A	B	C	D	E	F	G
	Actual Quantity No. 6 Fuel (bbl.)	Actual Quantity No. 6 Fuel for Non-Firm Sales (bbl.)	Net Quantity No. 6 Fuel (bbl.) **(A - B)**	Cost of Service No. 6 Fuel Cost ($Can/bbl.)	Actual Average No. 6 Fuel Cost ($Can/bbl.)	Cost Variance ($Can/bbl.) **(E - D)**	No.6 Fuel Variation ($) **(C X F)** **(to page 6)**
January	285,302	0	285,302	54.17	110.08	55.91	15,951,212
February	249,113	1	249,112	54.73	113.08	58.35	14,535,675
March	234,293	4	234,289	55.46	117.73	62.27	14,589,150
April	109,531	2	109,529	55.46	120.09	64.63	7,078,882
May	67,914	1	67,913	55.46	120.64	65.18	4,426,599
June	35,341	0	35,341	54.49	120.64	66.15	2,337,797
July	0	0	0	54.49	120.64	66.15	0
August	0	0	0	54.49	120.64	66.15	0
September	0	0	0	54.49	120.64	66.15	0
October	47,416	0	47,416	54.56	120.64	66.08	3,133,268
November	134,835	0	134,835	54.56	115.07	60.51	8,158,842
December	264,792	0	264,792	58.98	113.29	54.31	14,380,830
	1,428,536	8	1,428,528	55.47	114.80	59.33	84,592,255

Rate Stabilization Plan
Allocation of Fuel Variance - Year-to-Date
December 31, 2012

	A	B	C	D	E	F	G	H	I	J
	Twelve Months-to-Date				Year-to-Date Fuel Variance				Reallocate Rural Island Customers [1]	
	Utility	Industrial Customers	Rural Island Customers	Total	Utility	Industrial Customers	Rural Island Interconnected	Total	Utility	Labrador Interconnected
	(kWh)	(kWh)	(kWh)	(kWh)	($)	($)	($)	($)	($)	($)
				(A+B+C)	**(A/D X H)**	**(B/D X H)**	**(C/D X H)**		**(G X 89.10%)**	**(G X 10.90%)**
					(to page 7)			**(from page 5)**	**(to page 7)**	
January	5,387,374,077	310,709,943	443,384,150	6,141,468,170	13,992,606	807,006	1,151,600	15,951,212	1,026,076	125,524
February	5,411,960,615	318,486,236	446,787,595	6,177,234,446	26,709,984	1,571,845	2,205,058	30,486,887	1,964,707	240,351
March	5,444,552,052	323,780,517	450,230,292	6,218,562,861	39,465,522	2,346,964	3,263,551	45,076,037	2,907,824	355,727
April	5,416,033,886	334,510,476	449,217,858	6,199,762,220	45,561,878	2,814,038	3,779,003	52,154,919	3,367,092	411,911
May	5,397,954,002	347,942,112	447,071,118	6,192,967,232	49,317,947	3,178,943	4,084,628	56,581,518	3,639,404	445,224
June	5,397,155,554	371,316,326	445,616,103	6,214,087,983	51,173,512	3,520,662	4,225,141	58,919,315	3,764,601	460,540
July	5,411,227,178	393,584,930	444,143,442	6,248,955,550	51,020,654	3,710,981	4,187,680	58,919,315	3,731,223	456,457
August	5,417,227,542	409,252,423	444,944,673	6,271,424,638	50,894,231	3,844,880	4,180,204	58,919,315	3,724,562	455,642
September	5,397,489,558	409,873,231	445,251,708	6,252,614,497	50,861,346	3,862,296	4,195,673	58,919,315	3,738,345	457,328
October	5,380,451,580	410,641,120	445,226,094	6,236,318,794	53,536,538	4,085,959	4,430,086	62,052,583	3,947,207	482,879
November	5,347,160,714	409,003,027	445,081,465	6,201,245,206	60,541,353	4,630,793	5,039,279	70,211,425	4,489,998	549,281
December	5,359,316,868	409,614,546	445,624,295	6,214,555,709	72,950,782	5,575,655	6,065,818	84,592,255	5,404,644	661,174

(1) The Fuel Variance initially allocated to Rural Island Interconnected is re-allocated between Utility and Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the approved Cost of Service Study, which is 89.10% and 10.90% respectively. The Labrador Interconnected amount is then removed from the plan and written off to net income (loss).

Rate Stabilization Plan
Allocation of Fuel Variance - Monthly
December 31, 2012

	A	B	C	D	E	F	G
	Utility					**Industrial**	
	Fuel Variance		Rural Allocation		Total Fuel Variance	Fuel Variance	
	Year-to-Date Activity	Current Month Activity (1)	Year-to-Date Activity	Current Month Activity (1)	Activity for the month	Year-to-Date Activity	Current Month Activity (1)
	($)	($)	($)	($)	($)	($)	($)
					(B + D)		
	(from page 6)		**(from page 6)**		**(to page 10)**	**(from page 6)**	**(to page 11)**
January	13,992,606	13,992,606	1,026,076	1,026,076	15,018,682	807,006	807,006
February	26,709,984	12,717,378	1,964,707	938,631	13,656,009	1,571,845	764,839
March	39,465,522	12,755,538	2,907,824	943,117	13,698,655	2,346,964	775,119
April	45,561,878	6,096,356	3,367,092	459,268	6,555,624	2,814,038	467,074
May	49,317,947	3,756,069	3,639,404	272,312	4,028,381	3,178,943	364,905
June	51,173,512	1,855,565	3,764,601	125,197	1,980,762	3,520,662	341,719
July	51,020,654	(152,858)	3,731,223	(33,378)	(186,236)	3,710,981	190,319
August	50,894,231	(126,423)	3,724,562	(6,661)	(133,084)	3,844,880	133,899
September	50,861,346	(32,885)	3,738,345	13,783	(19,102)	3,862,296	17,416
October	53,536,538	2,675,192	3,947,207	208,862	2,884,054	4,085,959	223,663
November	60,541,353	7,004,815	4,489,998	542,791	7,547,606	4,630,793	544,834
December	72,950,782	12,409,429	5,404,644	914,646	13,324,075	5,575,655	944,862
		72,950,782		5,404,644	78,355,426		5,575,655

(1) The current month activity is calculated by subtracting year-to-date activity for the prior month from year-to-date activity for the current month.

Rate Stabilization Plan
Load Variation - Utility
December 31, 2012

	A	B	C	D	E	F	G	H	I	J	K
	Firm Energy						Secondary Energy				
	Cost of Service Sales (kWh)	Actual Sales (kWh)	Sales Variance (kWh) **(B - A)**	Cost of Service No. 6 Fuel Cost ($Can/bbl.)	Firm Energy Rate ($/kWh)	Load Variation ($) **C x {(D/O[1]) - E}**	Cost of Service Sales (kWh)	Actual Sales (kWh)	Firming Up Charge ($/kWh)	Load Variation ($) **(G - H) x I**	Total Load Variation ($) **(F + J)** **(to page 10)**
January	574,800,000	645,272,533	70,472,533	54.17	0.08805	(145,587)	0	0	0.00841	0	(145,587)
February	518,600,000	605,772,822	87,172,822	54.73	0.08805	(102,601)	0	0	0.00841	0	(102,601)
March	524,700,000	612,210,811	87,510,811	55.46	0.08805	(1,597)	0	0	0.00841	0	(1,597)
April	429,200,000	441,536,421	12,336,421	55.46	0.08805	(225)	0	0	0.00841	0	(225)
May	358,700,000	373,354,613	14,654,613	55.46	0.08805	(268)	0	0	0.00841	0	(268)
June	298,400,000	328,298,760	29,898,760	54.49	0.08805	(46,580)	0	7,776,883	0.00841	(65,404)	(111,984)
July	293,400,000	304,522,712	11,122,712	54.49	0.08805	(17,328)	0	431,009	0.00841	(3,625)	(20,953)
August	287,000,000	308,501,923	21,501,923	54.49	0.08805	(33,499)	0	201,364	0.00841	(1,693)	(35,192)
September	297,700,000	287,756,026	(9,943,974)	54.49	0.08805	15,492	0	668,007	0.00841	(5,618)	9,874
October	360,200,000	377,830,840	17,630,840	54.56	0.08805	(25,509)	0	639,640	0.00841	(5,379)	(30,888)
November	439,300,000	452,476,305	13,176,305	54.56	0.08805	(19,064)	0	814,175	0.00841	(6,847)	(25,911)
December	543,800,000	610,688,673	66,888,673	58.98	0.08805	372,506	0	563,351	0.00841	(4,738)	367,768
	4,925,800,000	5,348,222,439	422,422,439			(4,260)	0	11,094,429		(93,304)	(97,564)

(1) O is the Holyrood Operating Efficiency of 630 kWh/barrel.

Rate Stabilization Plan
Load Variation - Industrial
December 31, 2012

	A	B	C	D	E	F
	Cost of Service Sales (kWh)	Actual Sales (kWh)	Sales Variance (kWh) **(B - A)**	Cost of Service No. 6 Fuel Cost ($)	Firm Energy Rate ($/kWh)	Load Variation ($) **C x {(D/O[1]) - E}** **(to page 11)**
January	78,300,000	32,959,121	(45,340,879)	54.17	0.03676	(2,231,865)
February	70,900,000	32,673,789	(38,226,211)	54.73	0.03676	(1,915,631)
March	76,600,000	38,353,336	(38,246,664)	55.46	0.03676	(1,960,973)
April	75,600,000	42,843,871	(32,756,129)	55.46	0.03676	(1,679,464)
May	69,500,000	36,611,217	(32,888,783)	55.46	0.03676	(1,686,265)
June	73,800,000	33,665,857	(40,134,143)	54.49	0.03676	(1,995,954)
July	77,500,000	31,814,448	(45,685,552)	54.49	0.03676	(2,272,037)
August	77,900,000	38,042,334	(39,857,666)	54.49	0.03676	(1,982,204)
September	73,000,000	29,220,566	(43,779,434)	54.49	0.03676	(2,177,242)
October	74,400,000	31,036,954	(43,363,046)	54.56	0.03676	(2,161,352)
November	74,100,000	29,316,482	(44,783,518)	54.56	0.03676	(2,232,153)
December	72,700,000	33,076,571	(39,623,429)	58.98	0.03676	(2,252,950)
	894,300,000	409,614,546	(484,685,454)			(24,548,090)

(1) O is the Holyrood Operating Efficiency of 630 kWh/barrel.

Rate Stabilization Plan
Summary of Utility Customer
December 31, 2012

	A	B	C	D	E	F	G
	Load Variation	Allocation Fuel Variance	Allocation Rural Rate Alteration (1)	Subtotal Monthly Variances	Financing Charges	Adjustment (2)	Cumulative Net Balance
	($)	($)	($)	($)	($)	($)	($)
				(A + B + C)			
	(from page 8)	**(from page 7)**					**(to page 12)**
Opening Balance							(55,939,780)
January	(145,587)	15,018,682	(681,410)	14,191,685	(339,415)	(6,007,487)	(48,094,997)
February	(102,601)	13,656,009	(681,360)	12,872,048	(291,816)	(5,639,745)	(41,154,510)
March	(1,597)	13,698,655	(622,573)	13,074,485	(249,705)	(5,699,683)	(34,029,413)
April	(225)	6,555,624	(594,473)	5,960,926	(206,473)	(4,110,704)	(32,385,664)
May	(268)	4,028,381	(482,226)	3,545,887	(196,500)	(3,475,931)	(32,512,208)
June	(111,984)	1,980,762	(469,092)	1,399,686	(197,268)	(3,128,864)	(34,438,654)
July	(20,953)	(186,236)	(477,990)	(685,179)	(208,957)	(4,742,030)	(40,074,820)
August	(35,192)	(133,084)	(422,902)	(591,178)	(243,154)	(4,800,336)	(45,709,488)
September	9,874	(19,102)	(293,596)	(302,824)	(277,342)	(4,484,994)	(50,774,648)
October	(30,888)	2,884,054	(419,661)	2,433,505	(308,075)	(5,885,216)	(54,534,434)
November	(25,911)	7,547,606	(402,367)	7,119,328	(330,888)	(7,048,667)	(54,794,661)
December	367,768	13,324,075	(722,924)	12,968,919	(332,467)	(9,504,969)	(51,663,178)
Year to date	(97,564)	78,355,426	(6,270,574)	71,987,288	(3,182,060)	(64,528,626)	4,276,602
Hydraulic allocation **(from page 4)**							(13,242,223)
Total	(97,564)	78,355,426	(6,270,574)	71,987,288	(3,182,060)	(64,528,626)	(64,905,401)

(1) The Rural Rate Alteration is allocated between Utility and Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the approved Cost of Service Study, which is 89.10% and 10.90% respectively. The Labrador Interconnected amount is then removed from the plan and written off to net income (loss).

(2) The RSP adjustment rate for Utility is 1.555 cents per kwh effective July 1, 2012 to June 30, 2013.

Rate Stabilization Plan
Summary of Industrial Customers
December 31, 2012

	A	B	C	D	E	F
	Load Variation	Allocation Fuel Variance	Subtotal Monthly Variances	Financing Charges	Adjustment [1]	Cumulative Net Balance
	($)	($)	($)	($)	($)	($)
			(A + B)			
	(from page 9)	**(from page 7)**				**(to page 12)**
Opening Balance						(81,653,349) [2]
January	(2,231,865)	807,006	(1,424,859)	(495,432)	335,764	(83,237,876)
February	(1,915,631)	764,839	(1,150,792)	(505,046)	329,688	(84,564,026)
March	(1,960,973)	775,119	(1,185,854)	(513,092)	377,270	(85,885,702)
April	(1,679,464)	467,074	(1,212,390)	(521,111)	408,808	(87,210,395)
May	(1,686,265)	364,905	(1,321,360)	(529,149)	364,160	(88,696,744)
June	(1,995,954)	341,719	(1,654,235)	(538,167)	336,127	(90,553,019)
July	(2,272,037)	190,319	(2,081,718)	(549,430)	316,147	(92,868,020)
August	(1,982,204)	133,899	(1,848,305)	(563,477)	368,472	(94,911,330)
September	(2,177,242)	17,416	(2,159,826)	(575,874)	296,782	(97,350,248)
October	(2,161,352)	223,663	(1,937,689)	(590,673)	315,338	(99,563,272)
November	(2,232,153)	544,834	(1,687,319)	(604,100)	302,752	(101,551,939)
December	(2,252,950)	944,862	(1,308,088)	(616,167)	338,508	(103,137,686)
Year to date	(24,548,090)	5,575,655	(18,972,435)	(6,601,718)	4,089,816	(21,484,337)
Hydraulic allocation **(from page 4)**						(942,297)
Total	(24,548,090)	5,575,655	(18,972,435)	(6,601,718)	4,089,816	(104,079,983)

(1) The RSP adjustment rate for Industrial Customers excluding Teck Resources is 0.785 cents per kWh effective January 1, 2008. The rate for Teck Resources is 2.000 cents per kWh.

Rate Stabilization Plan
Overall Summary
December 31, 2012

	A	B	C	D
	Hydraulic Balance	Utility Balance	Industrial Balance	Total To Date
	($)	($)	($)	($)
				(A + B + C)
	(from page 4)	**(from page 10)**	**(from page 11)**	
Opening Balance	(32,737,147)	(55,939,780)	(81,653,349)	(170,330,276)
January	(38,326,991)	(48,094,997)	(83,237,876)	(169,659,864)
February	(45,663,278)	(41,154,510)	(84,564,026)	(171,381,814)
March	(52,827,112)	(34,029,413)	(85,885,702)	(172,742,227)
April	(56,163,781)	(32,385,664)	(87,210,395)	(175,759,840)
May	(58,013,410)	(32,512,208)	(88,696,744)	(179,222,362)
June	(57,736,265)	(34,438,654)	(90,553,019)	(182,727,938)
July	(51,352,238)	(40,074,820)	(92,868,020)	(184,295,078)
August	(46,179,676)	(45,709,488)	(94,911,330)	(186,800,494)
September	(39,763,203)	(50,774,648)	(97,350,248)	(187,888,099)
October	(41,065,152)	(54,534,434)	(99,563,272)	(195,162,858)
November	(41,249,222)	(54,794,661)	(101,551,939)	(197,595,822)
December	(32,675,763)	(64,905,401)	(104,079,983)	(201,661,147)

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

2012 ANNUAL REPORT
ON
KEY PERFORMANCE INDICATORS
Pursuant to Order No. P.U. 14 (2004)

NEWFOUNDLAND AND LABRADOR HYDRO

(Updated/Revised June 2013)

newfoundland labrador hydro
a nalcor energy company

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1 Introduction

In Order No. P.U. 14 (2004), the Board required Newfoundland and Labrador Hydro (Hydro) to file appropriate historic, current and forecast comparisons of reliability, operating, financial and other Key Performance Indicators (KPIs). These were ordered to be filed with Hydro's annual financial report, commencing in 2004.

In compliance with the above Order, Hydro has 16 individual KPIs within the following four general categories: Reliability; Operating; Financial; and Customer-Related.

Within each of these categories, KPI data is reported on a historic basis for Hydro. Where appropriate, KPIs are subcategorized based on whether they relate to generation, transmission, distribution or overall corporate activity. For most of the Reliability KPIs, data from the Canadian Electricity Association (CEA) is provided in this report, as has been the case in prior years. CEA data has been published only to 2011. CEA data is unavailable for underfrequency load shedding, a reliability KPI, as this measure is unique to Hydro's Island Interconnected System. In the Operating category, the KPIs used to measure performance relate to two specific facilities within Hydro's system: Bay d'Espoir and Holyrood. For these two generation plants, performance is measured and compared on a year-over-year basis.

Section 2 of this report provides an overview of Hydro's KPI performance in 2012 compared with the prior year as well as a comparison of actual KPI results compared with targets. This is followed by a detailed analysis of each individual KPI within the four categories named above in Section 3.

Section 3.3 Financial Performance Indicators are not yet available but will follow after the audited financial statements are available.

The 2012 financial data and 2013 targets in Section 4 Data Table of Key Performance Indicators are not available at this time. This section will be re-filed after the financial data is available and the 2013 target levels have been established.

2 Overview of Key Performance Indicator Results

2.1 Performance in 2012 versus 2011

Generation performance continued to improve in some areas in 2012, particularly with the thermal units. The Capability Factor for the Holyrood Generating Station improved significantly from 2011 and is now better than the latest CEA five-year average. The hydro plants experienced a decreased performance in this area due to an extended planned maintenance outage on Bay d'Espoir Unit 4. The performance of gas turbines was impacted by the failure of the Stephenville Gas Turbine which occurred in December 2011. The unit was not available in 2012 due to this forced outage.

The underfrequency load shedding performance met the target in 2012 with a total of five events and remains under the previous five-year average of 5.4 events per year. Performance in this area deteriorated from the three events experienced in 2011, which was the best performance since these events started being recorded in 1998.

Transmission and Distribution reliability improved significantly in 2012 from 2011. Improvements were seen in all areas and measures are comparable to the values seen before 2011. In 2011, there were a number of severe weather related events which caused numerous and lengthy outages, primarily in the Northern and Central regions.

The operating KPIs for energy conversion showed a slight reduction in performance for the Holyrood fuel conversion rate. Unit operating time continued to be minimized in 2012, with units placed on line only as required to support Avalon transmission and system peak loads.

The hydraulic conversion factor at Bay d'Espoir improved slightly in 2012 from 2011. In 2011, high water levels required the operation of the plant to reduce and control the spill of water, particularly during the summer months. This was not required in 2012 as the water levels were more in-line with normal levels.

Hydro's 2012 operating and maintenance costs are not available at this time. Financial KPI data will be provided at a later date.

The final category of KPIs called "Customer-Related" deals with Hydro's residential customer satisfaction. Customer satisfaction in 2012 of 80%, was the lowest of the previous five-years.

2.2 Performance in 2012 versus 2012 Target

The table below summarizes Hydro's KPI performance in 2012 compared to targets set for each measure. Targets were met with respect to the generation forced outage rate, transmission SAIDI, SAIFI and SARI the number of underfrequency load shedding events and the hydraulic conversion rate. Other targets were not met due to a number of challenges further described in this report.

The 2012 rationale for Hydro's 2012 KPI Targets is included in this report as Appendix A.

Updated June 6, 2013

Hydro's KPI Targets and Operating Results for 2012

Category	KPI	Units	2012 Target	2012 Results	Target Achieved
Reliability	Weighted Capability Factor (WCF)	%	84.9	82.9	No
	DAFOR	%	2.7	2.3	Yes
	T-SAIDI	Minutes/Point	265[1]	171[2]	Yes
	T-SAIFI	Number/Point	2.0[1]	1.9[2]	Yes
	T-SARI	Minutes/Outage	133[1]	90[2]	Yes
	SAIDI	Hours/Customer	5.9	8.3	No
	SAIFI	Number/Customer	3.7	4.4	No
	Underfrequency Load Shedding	# of events	6	5	Yes
Operating	Hydraulic CF	GWh/MCM	0.433	0.434	Yes
	Thermal CF	kWh/BBL	630	599	No
Financial	Controllable Unit Cost	$/MWh	N/A	14.93	
Other	Customer Satisfaction (Residential)	Max=100%	>90%	80%	No

[1] Transmission reliability targets were set on combined planned and unplanned outages.
[2] The transmission reliability indicator shown is for planned and unplanned outages.

3 Performance Indices

The following defines and describes detailed Key Performance Indicator (KPI) data within four general categories: Reliability, Operating, Financial, and Customer-Related.

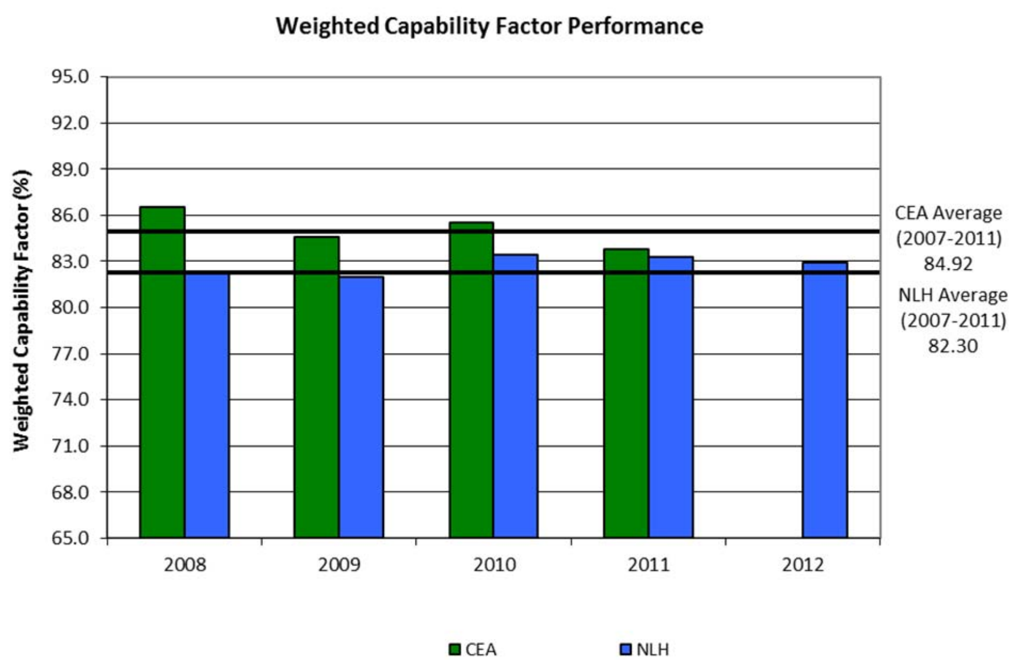
3.1 Reliability Performance Indicators

Hydro monitors reliability performance with eight separate metrics. These metrics have been divided into the following subcategories: Generation, Transmission, Distribution, and Other.

3.1.1 Reliability KPI: Generation

3.1.1 a) Weighted Capability Factor (WCF) – *a reliability KPI for generation assets that includes Hydro's thermal, gas turbine and hydroelectric generation assets on the Island and Labrador Interconnected Systems. The WCF measures the percentage of the time that a unit or a group of units is available to supply power at maximum continuous generating capacity. The factor is weighted to reflect the difference in generating unit sizes, meaning larger units have a greater impact on this measure.*

In 2012, Hydro's WCF was 82.9%. This is lower than the target of 84.9%; however, it does reflect an improvement over the 2007 to 2011 five-year average of 82.3%.



Thermal unit performance improved in 2012 to 76% from 67% in 2011. Holyrood Unit 1 had the lowest capability factor of 70% and Unit 2 had the highest capability factor of 83%. Unit 3 had a capability factor of 75%. There were no major equipment failures in 2012.

Overall, the hydraulic unit performance declined slightly in 2012, to 91% compared to 93% in 2011. There were no major issues with the hydraulic generation and all units, except Bay d'Espoir Unit 4, experienced a capability factor above 90%. The capability factor of this unit was reduced to 68% in 2012 due to an extended planned outage required for a stator rewind.

Gas turbine performance decreased to 53% in 2012 from 71% in 2011. The capability factor for the Stephenville unit was 0%. The Stephenville unit failed in December 2011 due to a stator ground fault. This unit is not anticipated to be available again until repairs are completed in the spring of 2013. Calculation details for weighted capability as well as a list of factors that may impact KPI performance are in Appendix B of this report.

The table below provides a comparison by unit type along with the weightings applied to the CEA values to provide for the comparison to Hydro for the period 2007-2011. Hydro's hydro generation capability was slightly better than the comparable weighted national average. The weighted average is lower for Hydro's thermal-oil fired units and gas turbines.

Capability Factor Performance

	CEA (2007-2011)	**NLH (2007-2011)**	**Weighting Factor**
Hydro	91.31	92.79	50%
Thermal - Oil Fired	74.13	62.41	33%
Gas Turbine	87.21	70.05	17%

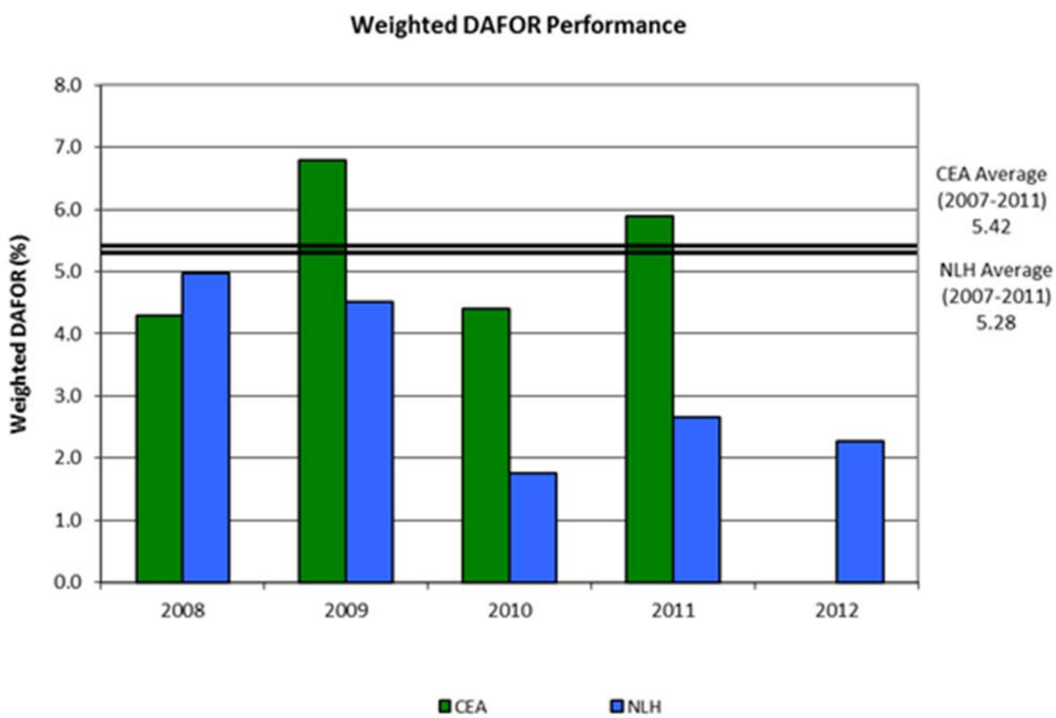
The weighted national average is developed by using national average capabilities values for the unit types in Hydro's system (hydro, oil-fired thermal and gas turbine) and applying weightings to these based upon the maximum continuous ratings of Hydro's generation. The quoted CEA value is therefore not a CEA published value but a re-stated value to facilitate a comparison to Hydro.

3.1.1 b) Weighted Derating-Adjusted Forced Outage Rate (DAFOR) - *a reliability KPI for generation assets that includes Hydro's thermal and hydroelectric generation assets on the interconnected systems[3]. DAFOR measures the percentage of the time that a unit or group of units is unable to generate at its Maximum Continuous Rating (MCR) due to forced outages. The KPI is weighted to reflect differences in generating unit sizes.*

In 2012, Hydro's weighted DAFOR was 2.3% versus a target of 2.7%. The DAFOR was impacted by a hydrogen leak, high vibration on No. 1 bearing, and a problem with the turning gear, all associated with Holyrood Unit 1. There was also a problem with the condenser on Holyrood Unit 3 which affected the DAFOR. Hydro's overall weighted DAFOR from 2007 to 2011 of 5.3%, is slightly better than the equivalently weighted national average for the same period of 5.4%. The following table provides a 2007-2011 comparison by unit type:

DAFOR Performance

	CEA (2007-2011)	NLH (2007-2011)	Weighting Factor
Thermal - Oil Fired	9.84	13.81	34%
Hydro	3.19	0.97	66%



[3] DAFOR is not applicable to the gas turbines because of the gas turbines' low operating hours.

3.1.1.1 Generation Equipment Performance

The table below highlights the various performance indices for Hydro's generation facilities. Indices for 2011 and for the latest Canadian Electricity Association (CEA) national average for the period 2007-2011 are included for comparison.

Generation Performance Indices				
Index		**Hydro**	**Thermal**	**Gas Turbine**
Failure Rate	NLH 2012	2.33	9.87	231.67
(Forced Outages per 8,760	NLH 2011	2.12	2.95	137.66
operating hours)	CEA '07-'11	2.01	7.52	21.58
Incapability	NLH 2012	9.35	24.04	32.88
Factor	NLH 2011	6.56	33.32	24.90
(Percent of Time)	CEA '07-'11	8.69	25.87	12.79
Derating Adjusted Forced	NLH 2012	1.05	6.24	
Outage Rate	NLH 2011	0.82	7.88	
(Percent of Time)	CEA '07-'11	3.19	9.84	
Utilization	NLH 2012			55.05
Forced Outage	NLH 2011			10.45
Probability (Percent of Time)	CEA '07-'11			10.04

3.1.1.1 (a) Hydro Unit Performance

As indicated in the above Generation Performance Indices table, all hydro unit measures deteriorated in 2012 when compared to 2011. However, the hydraulic unit derating adjusted forced outage rate continues to be significantly better than the latest five-year national average.

3.1.1.1 (b) Thermal Unit Performance

Thermal unit performance improved in 2012 in the measures of derating adjusted forced outage rate and incapability factor. Performance in both of these measures is better than the national five-year averages. There was a significant decline in 2012 in the failure rate measure and performance is now worse than the national five-year average.

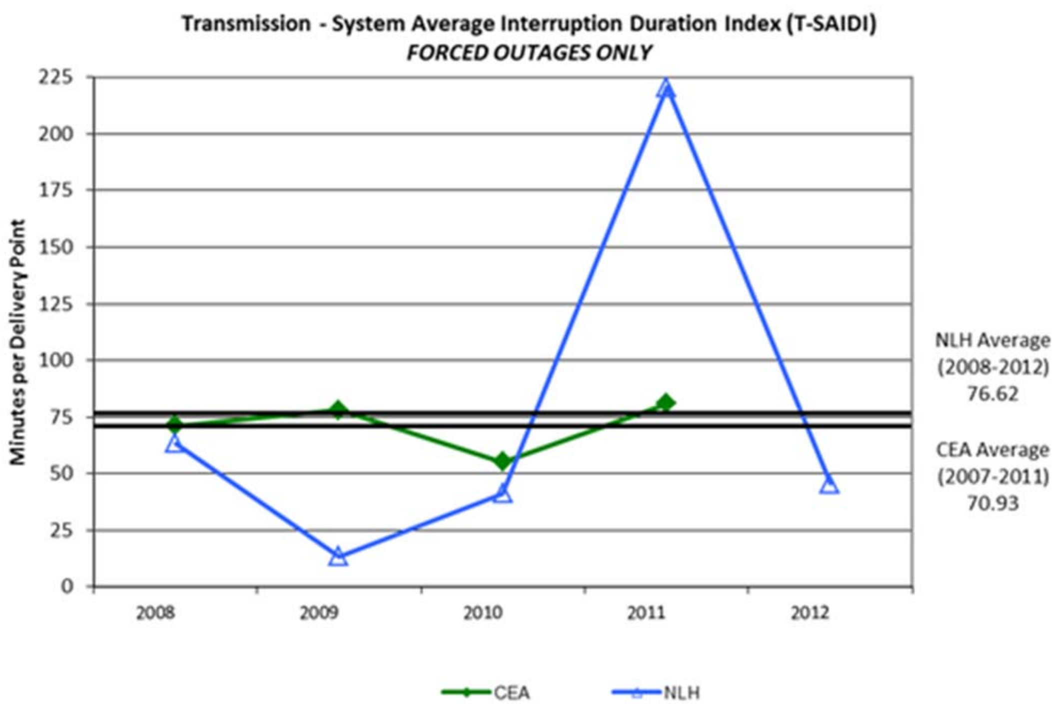
3.1.1.1 (c) Gas Turbine Unit Performance

The Generation Performance Indices table also indicates that Hydro's gas turbines performance declined significantly in 2012 from 2011 for all measures, and continues to be below the national average. This was primarily due a failure at the Stephenville gas turbine in December 2011 which rendered the unit inoperable for all of 2012. The failure rate calculation is very volatile due to the normally low operating hours of Hydro's gas turbines. Of particular importance to Hydro's use of gas turbines is the utilization forced outage probability (UFOP). The measure describes the degree to which a standby unit can be called upon to supply load when requested. The Stephenville failure had a significant effect on these measures.

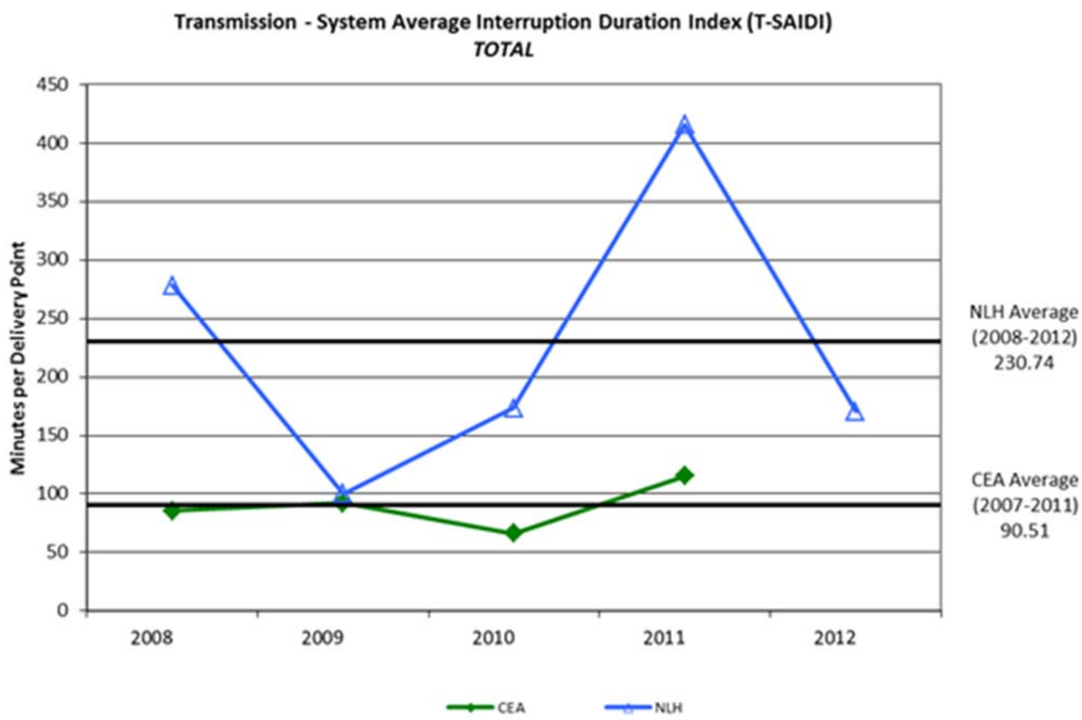
3.1.2 Reliability KPI: Transmission

3.1.2 a) Transmission System Average Interruption Duration Index (T-SAIDI) - *reliability KPI for bulk transmission assets which measures the average duration of outages in minutes per delivery point.*

The fourth quarter T-SAIDI was 32.4 minutes per delivery point (forced and planned combined). The total 2012 T-SAIDI was 171 minutes per delivery point, 35% below the 2012 target[4] of 265 minutes per delivery point. In comparison, the 2011 total was 432 minutes per delivery point. The forced outage duration in 2012 decreased to 46 minutes from 221 minutes in 2011. The planned outage duration decreased to 125 minutes from 211 minutes in 2011. Of note is that, for the fourth quarter, the contribution of the force outage duration was 56% of the 2012 total.



[4] "Target" means less than or equal to the value set as a performance outcome.



There were a number of forced outages and three planned outages in the fourth quarter. A summary of these outages follows:

Forced

On October 12, customers served by the Hawke's Bay and Parsons Pond Terminal Stations experienced a series of unplanned outages due to salt contamination. Refer to the following table for details:

Date	Delivery Point	Time of Incident	Time of Restoration	Outage Duration	Cause of Outage
October 12	Hawke's Bay	1727	1730	3 minutes	Salt Contamination
October 12	Hawke's Bay	1828	1829	1 minute	Salt Contamination
October 12	Hawke's Bay	1831	1837	6 minutes	Salt Contamination
October 12	Parson's Pond	1459	1506	7 minutes	Salt Contamination
October 12	Parson's Pond	1620	1642	22 minutes	Salt Contamination

On October 14, all customers supplied by the South Brook Terminal Station experienced an unplanned outage of 35 minutes in duration. Crews found a jumper burnt off voltage regulator T1B1-VR1 at the station. Disconnect switch L22T1 was opened by Hydro's Energy Control Centre immediately, resulting in the unplanned outage. The jumper was repaired and the station was restored to service. The jumper burnt off due a severely corroded connector. Some customers continued to experience an outage due to faults on the distribution system during this time.

On October 16, customers north of Plum Point on the Great Northern Peninsula (GNP) experienced unplanned outages. The table below outlines the outage details (all were a result of salt contaminated equipment):

Date	Delivery Point	Time of Incident	Time of Restoration	Outage Duration	Cause of Outage
October 16	Bear Cove	445	907	4 hrs & 22 mins	138 kV Bus Lockout at Bear Cove TS and trip of TL241 and TL 244.
October 16	Plum Point	657	859	2 hrs & 2 mins	TL241 trip and Plum Point Reactor R1 locked.
October 16	St. Anthony	445	500	15 minutes*	138 kV Bus Lockout at Bear Cove TS and trip of TL241 and TL244.
October 16	Main Brook	445	500	15 minutes*	138 kV Bus Lockout at Bear Cove TS and trip of TL241 and TL244.
October 16	Roddickton	445	500	15 minutes*	138 kV Bus Lockout at Bear Cove TS and trip of TL241 and TL244.
*Note: Customers in St. Anthony, Main Brook, and Roddickton were restored via St. Anthony Diesel Plant.					

On October 24, customers served by the Happy Valley Terminal Station experienced an unplanned power outage of 32 minutes in duration. This outage occurred after transmission line L1301 tripped due to the operation of the lockout relay on transformer T31 at Churchill Falls. Personnel were working on the transformer, which was out of service, but the gas pressure relay was not blocked. This relay should have been blocked prior to starting work on the transformer.

On November 17, all customers supplied by the Farewell Head Terminal Station experienced an unplanned outage of ten minutes in duration. Newfoundland Power's Cobb's Pond Substation tripped due to a lockout of transformer T2. This lockout also tripped transmission line 142L which supplies Farewell Head via the Boyd Cove Substation and transmission line TL254.

On December 22, Newfoundland Power customers supplied by transmission line TL215 in the Port Aux Basque area experienced an unplanned outage of three minutes in duration. The outage occurred after high winds tripped TL215. Since the circuit breaker B1L15 was bypassed at the Doyles Terminal Station, TL214 tripped to isolate the fault. Newfoundland Power customers in the Doyles area were also affected by this event.

On December 24, all customers supplied by transmission line TL227 in Parson's Pond Area experienced an unplanned outage of one hour and two minutes in duration. The outage was caused by salt contamination on the line. The section of TL227 between the Parson's Pond and Daniel's Harbour Terminal Stations was isolated and customers were restored by closing in the Cow Head end of TL227.

On December 26, all customers supplied by the Rocky Harbour Terminal Station experienced an unplanned outage of 53 minutes in duration. All customers supplied by the Glenburnie and Wiltondale Terminal Stations experienced unplanned outages of one hour and 39 minutes in duration. The outage was caused by a tree coming into contact with transmission line TL226. The tree broke a conductor between Rocky Harbour and Wiltondale Stations. Rocky Harbour customers were restored from Berry Hill whilst Wiltondale and Glenburnie customers were restored from Deer Lake. The conductor was repaired on December 27.

On December 30, all customers supplied by the Rocky Harbour, Glenburnie, and Wiltondale Terminal Stations experienced an unplanned outage of two minutes in duration. The outage was caused by heavy snow build-up on transmission line TL226.

On December 30, all customers supplied by the Rocky Harbour, Glenburnie, and Wiltondale Terminal Stations experienced another unplanned outage of 49 minutes in duration. Similar to the events on December 26, the outage was caused by a tree contacting transmission line TL226. The tree broke a conductor between Rocky Harbour and Wiltondale Stations. Rocky Harbour customers were restored from Berry Hill while Wiltondale and Glenburnie customers were restored from Deer Lake. The conductor was repaired on December 31.

Planned

On November 4, all customers supplied by the Main Brook and Roddickton Terminal Stations experienced a planned outage of five hours and 14 minutes in duration. The outage was required to perform maintenance on Bus B1 PTs and install disconnect switch SST-1 at the St. Anthony Airport Terminal Station. Customers in the St. Anthony area were supplied by the St. Anthony Diesel plant.

On November 22, Newfoundland Power customers supplied by the Doyles Terminal Station experienced a planned outage of two hours and 50 minutes in duration. The outage was required to remove jumpers from circuit breaker B1L15 and to install a bypass around this breaker, to facilitate its replacement. Newfoundland Power customers in the Port Aux Basque area were supplied by local Newfoundland Power generation.

On December 31, all customers supplied by the Rocky Harbour Terminal Station experienced a planned outage of three minutes in duration. The short outage was required to restore TL226 following the completion of repairs to the conductor, broken during the previous day.

As previously reported, Hydro's planned outage durations tend to be longer than the national average. This is due to the relatively high number of delivery points on the Hydro system that do not have alternative supply options such as multiple station transformers or greater distribution system integration. This was a contributing factor to the planned outages on the GNP where station maintenance required customer outages for which there is no alternate supply point or local generation.

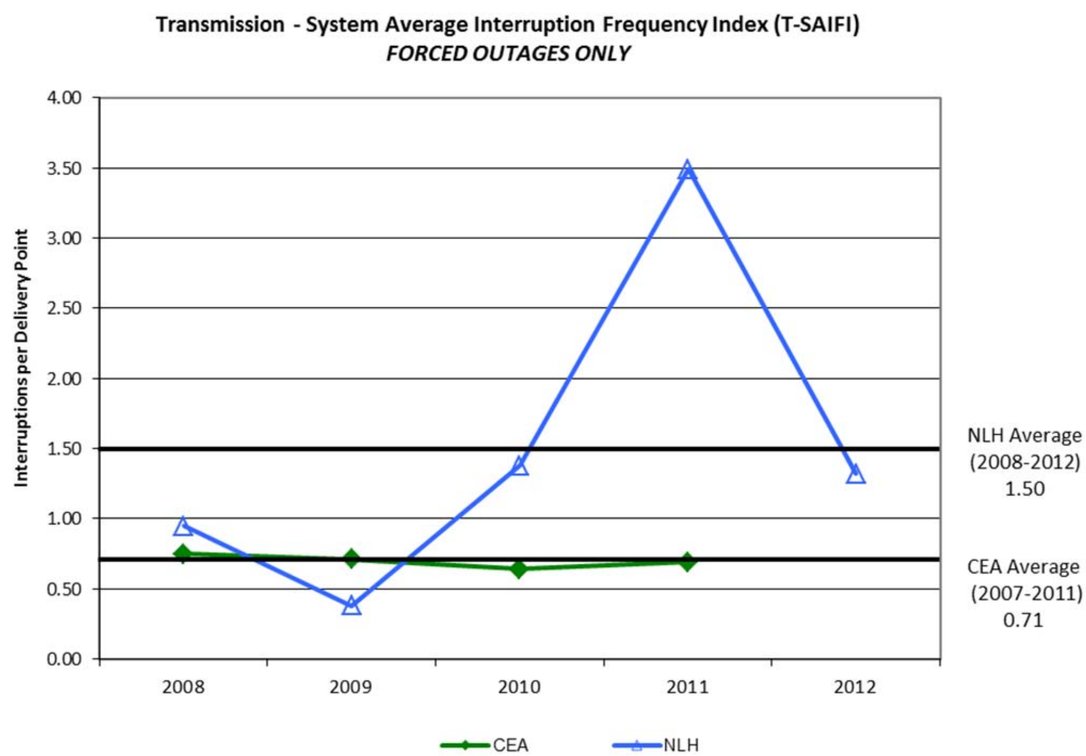
Appendix C1 lists all of the significant transmission events in 2012. Significant events are identified as those resulting in forced outages with an unsupplied energy of greater than 1,000 MW-mins. Unsupplied energy is a calculation of the outage duration multiplied by the load, in MW, at the delivery point before it was interrupted. This measures the energy that could have been supplied if the delivery had not been interrupted.

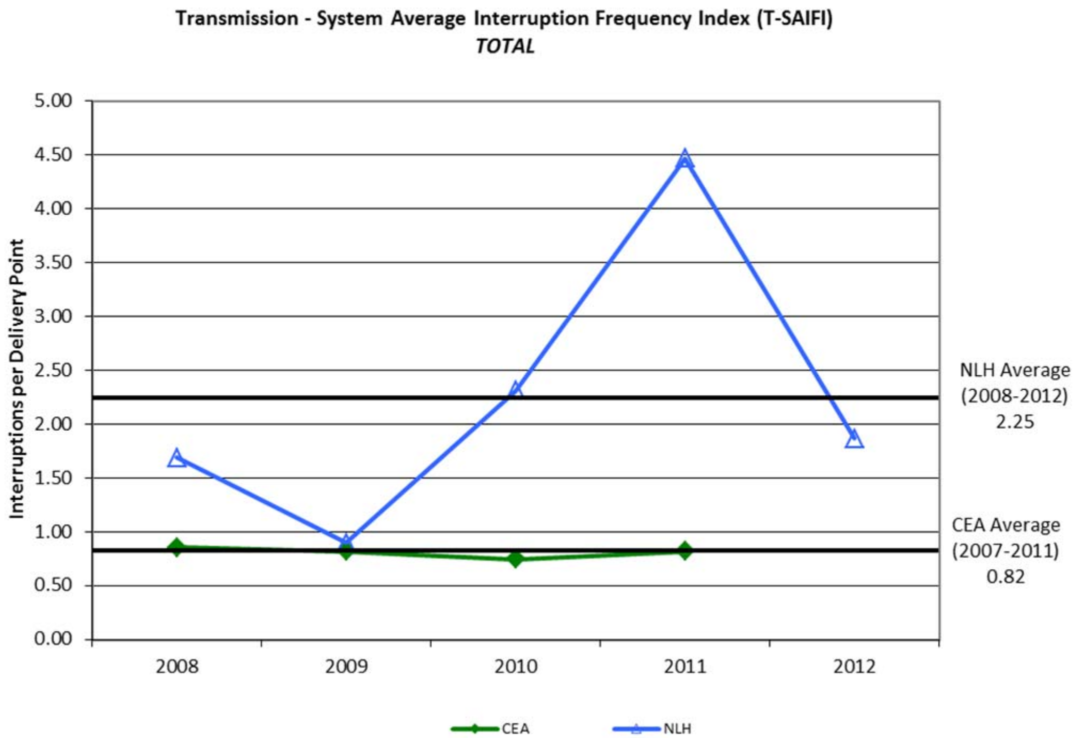
3.1.2 b) Transmission System Average Interruption Frequency Index (T-SAIFI) - *a reliability KPI for bulk transmission assets that measures the average number of sustained outages per delivery point*.

The fourth quarter T-SAIFI was 0.52 outages per bulk delivery point, with contributions of forced and planned outage frequency of 0.45 and 0.07, respectively. In comparison, the 2011 fourth quarter T-SAIFI was 2.71 outages per bulk delivery point. The decrease in outage frequency was the result of a lower number of forced outages this quarter.

The overall 2012 T-SAIFI was 1.88 outages per bulk delivery point which is significantly lower than last year's average of 4.52 outages per delivery point, a decrease of 58%. The 2012 target was 2.00 outages per bulk delivery point and this target was met. The number of forced outages per delivery point in 2012 (1.32) decreased 62% from 2011 (3.49). The frequency of planned outages per delivery point decreased by 46%; to 0.55 in 2012.

The frequency of Hydro's forced delivery point outages has been generally higher than the national average. This result is expected and can generally be attributed to the number of delivery points that are supplied by a single transmission line. The most severe example is on the Great Northern Peninsula, where one line, TL-239, supplies up to nine delivery points. There are a number of other locations where a single line supplies three delivery points.





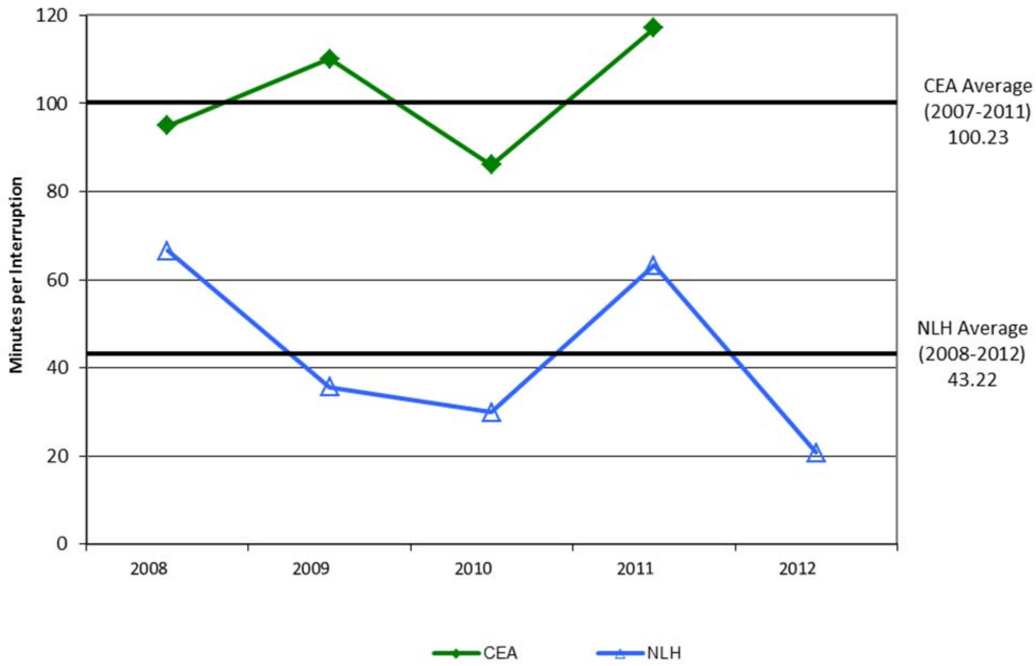
3.1.2 c) Transmission System Average Restoration Index (T-SARI) - *reliability KPI for bulk transmission assets which measures the average duration per transmission interruption. T-SARI is calculated by dividing T-SAIDI by T-SAIFI.*

Hydro's total transmission T-SARI was 62.4 minutes per interruption for the fourth quarter of 2012 compared to 98.4 minutes per interruption during the same quarter in 2011, a 37% decrease. The forced outage component of T-SARI was 40.8 minutes per interruption compared to 79.8 minutes per interruption in 2011. The planned outage component of T-SARI was 200.4 minutes per interruption which is 6% higher than during the fourth quarter of 2011.

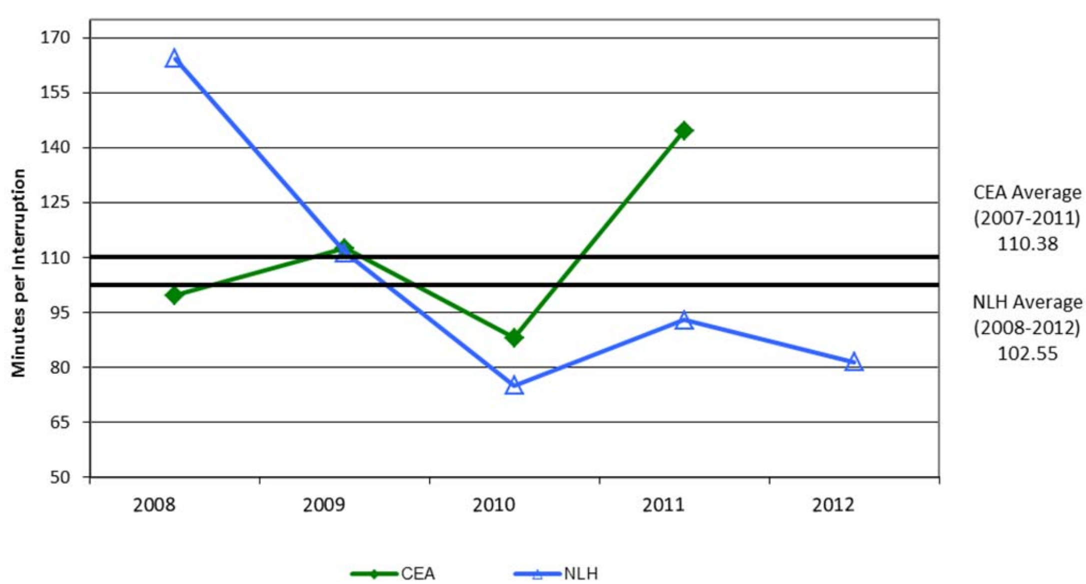
Hydro's 2012 total transmission T-SARI was 90 minutes per interruption, compared to 94 minutes in 2011 and a 2012 target of 133 minutes. The forced outage component of T-SARI was 34.8 minutes per interruption, a decrease of 44% over 2011. The planned outage component of T-SARI was 226 minutes per interruption, which is an increase of 9% over 2011. Since T-SARI is the ratio of T-SAIDI to T-SAIFI, this increase is driven by greater increase in T-SAIDI relative to T-SAIFI.

Hydro's total T-SARI performance continues to be better than the latest five-year national average. This can be seen in the chart below.

Transmission - System Average Restoration Index (T-SARI)
FORCED OUTAGES ONLY



Transmission - System Average Restoration Index (T-SARI)
TOTAL

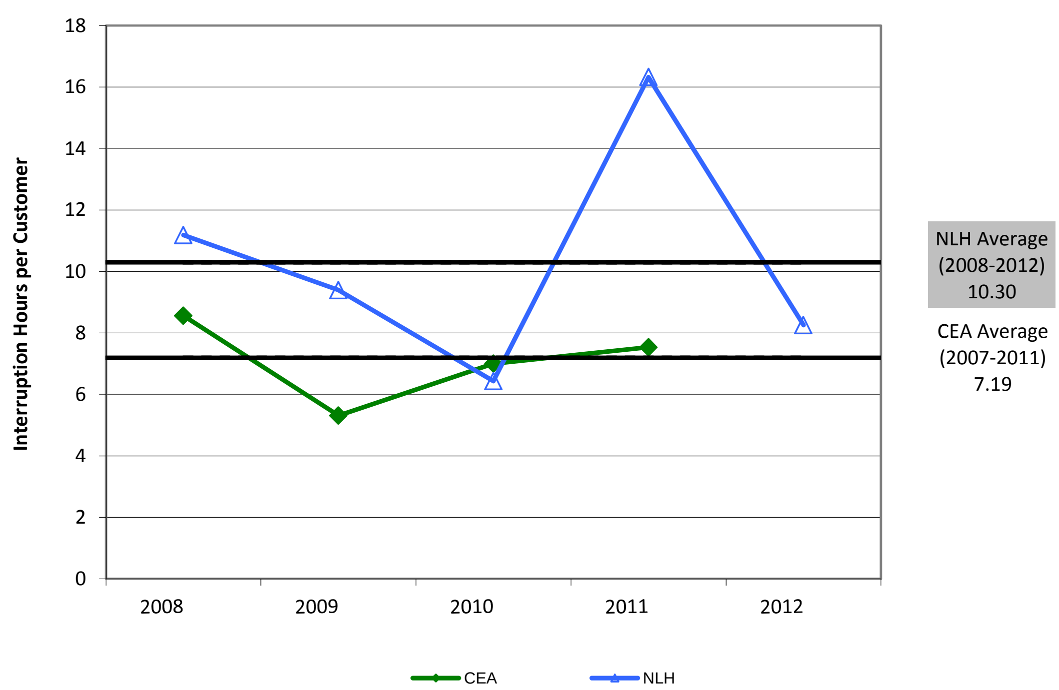


3.1.3 Reliability KPI: Distribution

3.1.3 a) System Average Interruption Duration Index (SAIDI) - *a reliability KPI for distribution service and it measures service continuity in terms of the average cumulative duration of outages per customer served during the year.*

In the fourth quarter of 2012, the SAIDI was 3.41 hours per customer, compared to 9.57 hours per customer during the same quarter of 2011. The total 2012 SAIDI was 8.25 hours per customer, compared to 16.32 hours per customer in 2011. The performance in 2012 was worse than the annual target of 5.90 hours per customer but showed a considerable improvement over the previous year.

Service Continuity - System Average Interruption Duration Index (SAIDI)



A summary of the major interruptions during the fourth quarter is as follows:

- On October 6, all customers (166) in Rigolet, Labrador experienced an unplanned power outage. The outage occurred when Diesel Units 2065 and 2051 experienced mechanical problems with their actuators. All customers were restored at 1340 hours. Outage duration was five hours and 40 minutes.

- On November 4, 146 customers serviced by Line 18 in Labrador City experienced two emergency planned power outages. The outages were requested by the local emergency response team due to a fire in an unfinished apartment building. Total customer outage time was nearly six hours.

- On November 25, all customers (105) in Black Tickle, Labrador experienced an unplanned power outage. The outage occurred after mobile generator 2 tripped off-line. All customers were restored at 1838 hours. The cause of the mobile tripping could not be determined. The total customer outage duration was five hours and 48 minutes.

- On December 6, 95 customers in Nain, Labrador experienced an unplanned power outage. The outage occurred when a vehicle hit and broke a utility pole. A community wide outage was required to isolate the affected area to perform maintenance. During this outage all Nain customers (452) experienced an unplanned power outage from 0300 hours to 0310 hours. The damaged pole was repaired and all the 95 customers initially impacted were restored. The total customer outage duration was 15 hours and 30 minutes.

- On December 16, at 0000 hours (Labrador time), 50 customers in Nain, Labrador experienced an emergency planned power outage. The outage was required to repair an after cooler on Unit 2085. All customers were restored at 0640 hours with Unit 2085. The total customer outage duration was six hours and 40 minutes.

The remainder of the significant events in 2012, which affected the distribution systems (i.e., outages generally to a complete system with duration of greater than five hours), are contained in Appendix C2.

3.1.3 b) System Average Interruption Frequency Index (SAIFI) - *reliability KPI for distribution service which measures the average cumulative number of sustained interruptions per customer per year.*

In the fourth quarter the SAIFI was 1.64 interruptions per customer, compared to 1.85 interruptions per customer during the same quarter of 2011, an 11% decrease. The total 2012 SAIFI was 4.37 interruptions per customer compared to 5.70 interruptions per customer in 2011, a 23% decrease. The 2012 target of 3.7 interruptions per customer was not met; however, the performance in 2012 shows an improvement from 2011.

Service Continuity - System Average Interruption Frequency Index (SAIFI)

3.1.3.1 Additional Information

This section provides more detailed information in three tables with performance broken down by Area, Origin, and Type.

Rural Systems Service Continuity Performance by Area

SAIFI (Number per Period)					
Area	**Fourth Quarter 2012**	**Fourth Quarter 2011**	**12 Mths to Date 2012**	**12 Mths to Date 2011**	**5 Year Average**
Central					
Interconnected	0.89	7.80	2.08	2.91	3.00
Isolated	0.32	1.19	0.88	6.22	3.19
Northern					
Interconnected	2.31	2.94	4.81	6.38	4.54
Isolated	5.03	1.11	8.65	5.26	6.34
Labrador					
Interconnected	1.10	2.07	5.44	8.17	6.34
Isolated	3.51	2.73	9.59	8.28	11.35
Total	1.64	1.85	4.37	5.70	4.86

Note: System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers in an area

SAIDI (Hours per Period)					
Area	**Fourth Quarter 2012**	**Fourth Quarter 2011**	**12 Mths to Date 2012**	**12 Mths to Date 2011**	**5 Year Average**
Central					
Interconnected	2.31	10.71	4.98	16.86	9.99
Isolated	0.87	0.99	2.02	3.83	2.38
Northern					
Interconnected	5.73	16.78	11.05	25.21	11.11
Isolated	5.36	0.61	6.89	3.84	5.97
Labrador					
Interconnected	2.17	5.01	9.28	11.34	11.23
Isolated	4.92	1.17	15.11	10.92	15.51
Total	3.41	9.57	8.25	16.32	10.47

Note: System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.

Rural Systems Service Continuity Performance by Origin

SAIFI (Number per Period)					
Area	**Fourth Quarter**		**12 Mths to Date**		**5 Year**
	2012	**2011**	**2012**	**2011**	**Average**
Loss of Supply – Transmission	0.23	0.68	1.40	2.59	1.85
Loss of Supply – NF Power	0.00	0.01	0.01	0.01	0.01
Loss of Supply – Isolated	0.20	0.12	0.49	0.50	0.57
Loss of Supply – L'Anse au Loup	0.00	0.03	0.03	0.05	0.05
Distribution	1.20	1.01	2.45	2.53	2.38
Total	1.64	1.85	4.37	5.70	4.86

Note: System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers.

SAIDI (Hours per Period)					
Area	**Fourth Quarter**		**12 Mths to Date**		**5 Year**
	2012	**2011**	**2012**	**2011**	**Average**
Loss of Supply – Transmission	0.23	3.44	1.70	6.12	3.48
Loss of Supply – NF Power	0.00	0.49	0.00	0.49	0.14
Loss of Supply – Isolated	0.08	0.02	0.27	0.13	0.24
Loss of Supply – L'Anse au Loup	0.00	0.01	0.00	0.03	0.03
Distribution	3.10	5.61	6.26	9.55	6.58
Total	3.41	9.57	8.25	16.31	10.47

Note: System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an

Rural Systems Service Continuity Performance by Type

Area	Scheduled		Unscheduled		Total	
	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI
Central						
Interconnected	0.32	1.16	0.57	1.15	0.89	2.31
Isolated	0.16	0.05	0.16	0.82	0.32	0.88
Northern						
Interconnected	0.73	1.84	1.58	3.90	2.31	5.73
Isolated	0.32	0.57	4.71	4.79	5.03	5.36
Labrador						
Interconnected	0.47	1.66	0.63	0.52	1.10	2.17
Isolated	0.88	2.87	2.64	2.05	3.51	4.92
Total	0.49	1.50	1.14	1.91	1.64	3.41

Note:

1. System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers in an area.

2. System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.

3.1.4 Reliability KPI: Other

3.1.4 a) Under Frequency Load Shedding (UFLS) - *reliability KPI that measures the number of events in which shedding of a customer load is required to counteract a generator trip. Customer loads are shed automatically depending upon the generation lost.*

There were three underfrequency events during the fourth quarter of 2012, summarized as follows:

On October 17, Holyrood Generating Unit #1 tripped due to a faulty vibration probe on the unit's Turbine Instrumentation System. With the removal of generation (approximately 71 MW) the system frequency dropped to 58.58 Hz resulting in the activation of the under frequency protection at Hydro and Newfoundland Power. Total system load at the time of the incident was 706 MW. A total of 1,278 Hydro customers were restored nine minutes after the event occurred, and 16,545 Newfoundland Power customers were reported to be restored within eleven minutes after the event occurred. Customers were restored in stages after capacitor banks on the Avalon were placed in service.

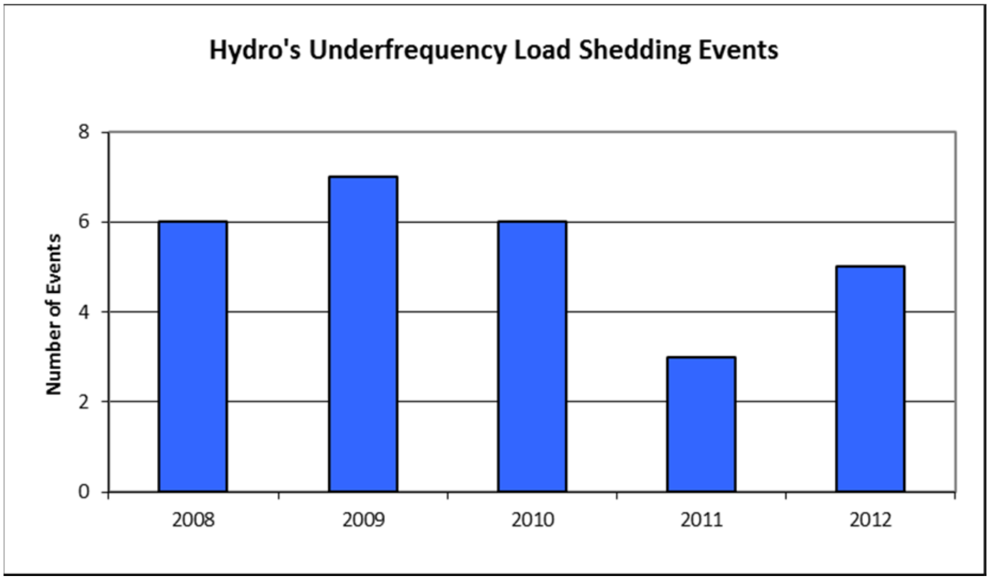
Load Shed:	Hydro: 4 MW
	Newfoundland Power: 39 MW
	Total Load Shed: 43 MW

On November 21, at 1438 hours, Holyrood Generating Unit #2 tripped. With the removal of generation (approximately 98 MW) the system frequency dropped to 58.55 Hz resulting in the activation of the under frequency protection at Hydro and Newfoundland Power. Total system load at the time of the incident was 903 MW. Hydro customers (1,282) were restored ten minutes after the event occurred, (50 MW-mins). Newfoundland Power customers (12,071) were reported to be restored within two to fourteen minutes after the event occurred, (399 MW-mins).

Load Shed:	Hydro: 5 MW
	Newfoundland Power: 54 MW
	Total Load Shed: 59 MW

On November 25, at 1124 hours Holyrood Generating Unit #2 tripped again. With the removal of generation (approximately 60 MW) the system frequency dropped to 58.79 Hz resulting in the activation of the under frequency protection at Newfoundland Power. Total system load at the time of the incident was 722 MW. Newfoundland Power customers (6,660) were reported to be restored within sixteen minutes after the event occurred. The load was 16 MW for 91.5 MW-mins.

In total, there were five UFLS events in 2012. This represents two more events than what were experienced in 2011, but below the five-year average of 5.4 events. Refer to the graph below which compares the UFLS events over the past five years to this year's performance.



The following table compares the UFLS events in the fourth quarter of 2012 to the same quarter in 2011.

Underfrequency Load Shedding Number of Events					
Customers	**Fourth Quarter 2012**	**Fourth Quarter 2011**	**Year to Date 2012**	**Year to Date 2011**	**5 Year Average (2008–2012)**
NF Power	3	1	5	3	5.4
Industrials	0	0	1	0	2.8
Hydro Rural*	2	0	3	0	2.8
Total Events	3	1	5	3	5.4

Underfrequency Load Shedding Unsupplied Energy (MW-min)					
Customers	**Fourth Quarter 2012**	**Fourth Quarter 2011**	**Year to Date 2012**	**Year to Date 2011**	**5 Year Average (2008–2012)**
NF Power	920	24	3,194	324	1,643
Industrials	0	0	140	0	217
Hydro Rural*	86	0	107	0	44
Total Events	1,006	24	3,440	324	1,904

* Underfrequency activity affecting Hydro Rural Customers may also result in a number of delivery point outages. Outage frequency and duration are also included in totals shown in the delivery point statistics section of the report for these areas, namely the Connaigre Peninsula and Bonne Bay.

The details of the previous two UFLS events in 2012 are summarized in Appendix C3.

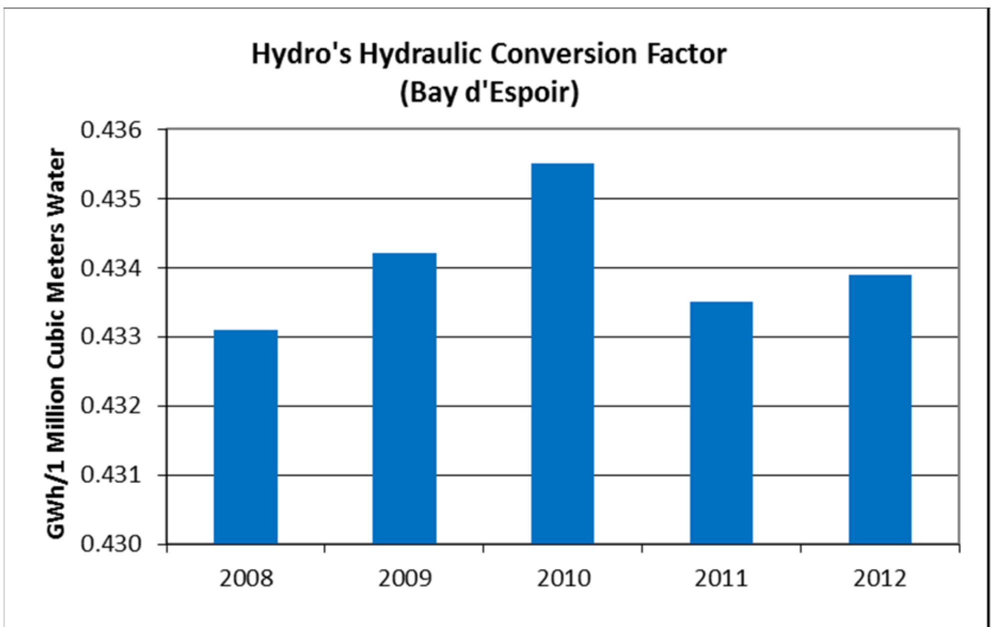
3.2 Operating Performance Indicators

This section presents information on two indicators of operating performance, both of which are associated with generation.

3.2.1 Operating KPI: Generation

3.2.1 a) Hydraulic Conversion Factor (Bay d'Espoir) - *a representative performance KPI for the principal hydroelectric generation assets located at Bay d'Espoir. This KPI tracks the efficiency in converting water to energy and it is calculated as the ratio of Net GWh generated for every one million cubic metres (MCM) of water consumed.*

In 2012, Hydro's hydraulic conversion factor for Bay d'Espoir was 0.4339 GWh/MCM. The performance in 2012 improved slightly from that in 2011, primarily due to reservoir storages which had returned to normal levels and allowed for more efficient operation of the hydro-electric generation. In 2011, reservoirs were very high and there was a significant amount of spill which required that generation be operated at high levels in order to minimize the same.

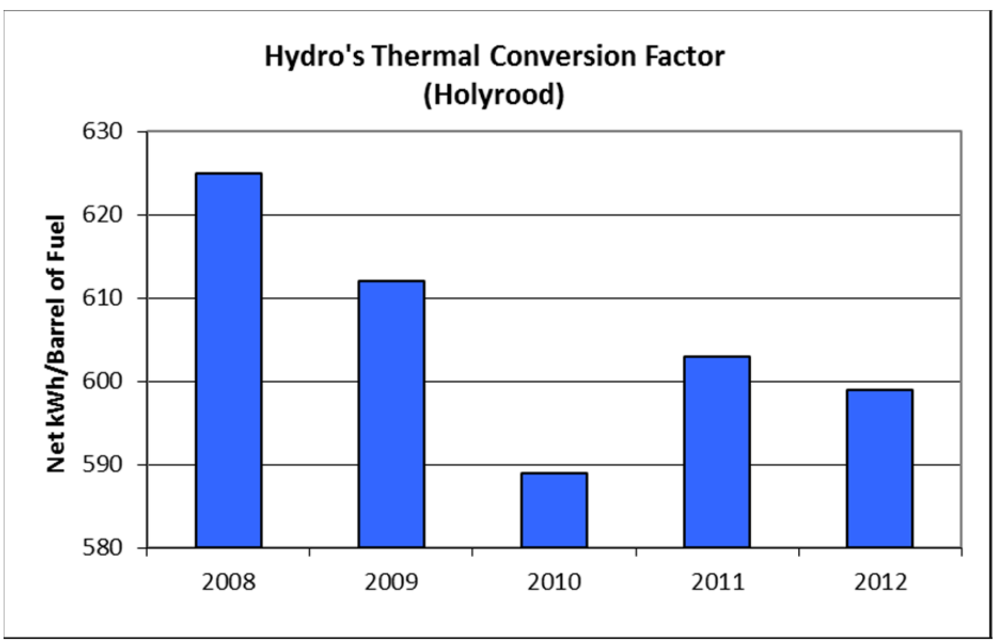


3.2.1 b) Thermal Conversion Factor - *a representative performance KPI for the oil-fired thermal generation assets located at Holyrood. This KPI tracks the efficiency in converting heavy fuel oil into electrical energy and is measured as the ratio of the net kWhs generated to the number of barrels of No. 6 fuel oil consumed.*

The thermal conversion factor for Holyrood is directly proportional to the output level of the three units, with higher averages and sustained loadings resulting in higher conversion factors. In turn, the output level of the Holyrood Thermal Generating Station will vary depending on hydraulic production, quantity of power purchases, customer energy requirements and system security requirements.

In 2012, Hydro's net thermal conversion factor was 599 kWh per barrel, which is significantly below the 2012 target of 630 kWh per barrel. This reduction is primarily related to operating the plant at lower generating levels due to the high volume of water resources and energy receipts relative to the system load requirements. The experience in 2012 declined slightly from an improvement in 2011.

Production at Holyrood was kept to a minimum in 2012 with units dispatched only as required for Avalon transmission support and system peak load considerations. The average net unit load while operating was 80 MW, up from 75 MW in 2011. Overall, net production from Holyrood for 2012 was 856 GWh, a 3.3% decrease from 2011 production levels.



3.3 Financial Performance Indicators [complete section updated]

The financial KPIs reported annually to the Board are:

1. Corporate operating, maintenance and administrative expense (OM&A) per MWh delivered;
2. Generation OM&A per MW installed capacity;
3. Generation OM&A per GWh generated;
4. Transmission OM&A per transmission circuit km; and
5. Distribution OM&A per distribution circuit km.[5]

In Order No. P.U. 8 (2007), the Board ordered that Hydro file a report no later than October 31, 2007 outlining an appropriate peer group with which Hydro's financial performance at the generation and transmission levels could be compared. In compliance with Board Order No. P.U. 8 (2007), Hydro filed a report titled "Peer Group Benchmarking" dated October 31, 2007 which summarized Hydro's findings regarding development of a peer group for financial KPIs related to generation and transmission. In that report, Hydro identified separate peer groups for generation KPIs and transmission KPIs and proposed that, subject to data availability, the selected peers remain constant to allow for meaningful trend comparisons over time. This is the fifth year of reporting generation and transmission financial KPI peer data. The list of peers used for KPI benchmarking for Financial Performance Indicators is included as Appendix C. This peer group benchmarking data is sourced from the U.S. Federal Energy Regulatory Commission (FERC) database, to which Hydro has a subscription. All financial data for the U.S.-based peer group is in $US and all financial data for Hydro is in $Cdn.

With respect to the Corporate and Distribution KPIs (items 1 and 5 above), in its 2007 Annual Report on KPIs Hydro had incorporated peer benchmarking data from the Canadian Electricity Association's (CEA) Committee on Performance Excellence (COPE) as published in the "Peer Group Performance Measures for Newfoundland Power" report. However, the CEA has informed Newfoundland Power that the composite information for these measures is no longer available, nor are any other cost-related CEA composite indicators available for benchmarking purposes.[6] As a result, Newfoundland Power is now using a peer group of U.S. companies. This group of US companies is not an appropriate group for Hydro due to Hydro's relatively small distribution component. In order to maintain consistency for year-over-year comparisons, Hydro is using the same peer group of U.S. companies for the Corporate Controllable Unit Cost KPI that Hydro uses for its generation financial benchmarking.

[5] This KPI is not available for benchmarking from 2007 onwards. It will continue to be reported for Hydro for annual comparison purposes. Please see section 3.3.4 a) Distribution Controllable Cost for a discussion of the alternate KPI to be used for peer benchmarking.
[6] "Peer Group Performance Measures for Newfoundland Power", December 23, 2008, p.2.

3.3.1 Financial KPI: Corporate

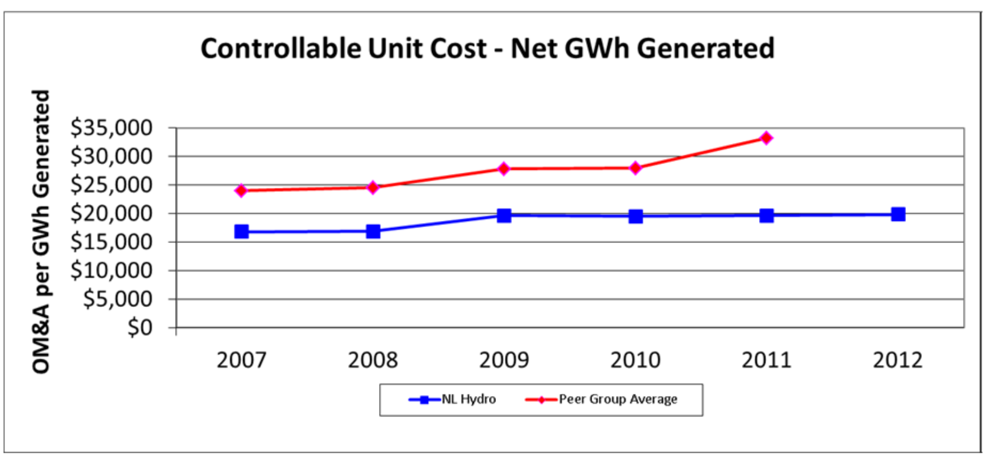
3.3.1 a) Controllable Unit Cost - *a high level corporate KPI that tracks Hydro's OM&A expenses in relation to its total energy delivered, expressed as dollars per MW hour. Total Corporate OM&A includes all operating labour and materials for Hydro's generation, transmission, distribution, customer-related and administrative costs, loss on disposal of capital assets. Energy deliveries have been normalized for weather, customer hydrology, and industrial strikes.*

Hydro's OM&A costs increased from $106.9 million in 2011 to $108.7 million[7] in 2012, resulting in a Controllable Unit Cost of $14.93 per MWh delivered for 2012.

Up to 2006, Hydro's Controllable Unit Cost was compared to the average Controllable Unit Cost for participants in the CEA COPE program as reported by Newfoundland Power. As of 2008, however, Newfoundland Power no longer uses CEA COPE benchmarking data for cost-related measures, because the composite information for these measures is no longer available for publication. Peer group results for the period 2007-2011 have therefore been herein restated using the same U.S. Peer Group that Hydro uses for generation financial KPIs.

For computation of Hydro's Corporate Controllable Unit Cost, normalized energy delivered is used. However, the available peer group data from the FERC database is based on net energy generated. Thus, for better comparison against the peer group, Hydro's data will also be calculated and charted on this basis. Hydro's Corporate OM&A per unit of net generation was $19.79 per MWh during 2012, higher than the computed Controllable Unit Cost, because normalized deliveries are higher than net generation due to the effect of Hydro's energy purchases.

Hydro's Corporate Controllable Unit Cost is following a very steady trend as compared to an upward trend for the peer group. However, it is difficult to determine specifically what factors might be impacting the expenses of the peer group participants without detailed information regarding their operations and finances.



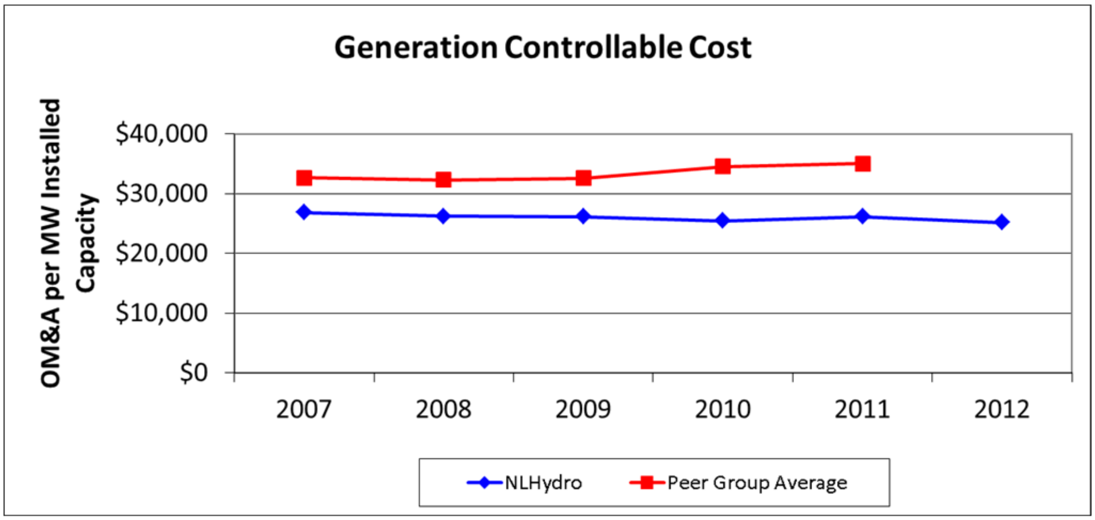
[7] This $108.7 million was calculated in the 2012 Cost of Service study and includes a $2.2 million cost to Hydro that was incurred to service an unregulated Industrial Customer. The $2.2 million was excluded when the $106.5 million regulated amount was reported on the Statement of Income – Regulated Operations for 2012, filed as part of the December 31, 2012 Quarterly Regulatory Report.

3.3.2 Financial KPI: Generation

3.3.2 a) Generation Controllable Cost - *a functional corporate KPI that tracks Hydro's generation costs in relation to its installed generation. It is computed by dividing generation OM&A by installed capacity as measured in MW.*

Generation Controllable Cost was $25,131 per MW for 2012 compared with $26,169 in 2011 a decrease of $1,038 per MW. As mentioned in prior annual KPI reports, an asbestos abatement program was undertaken at Holyrood in 2005 through 2007. Amortization of costs associated with this program concluded during 2012.

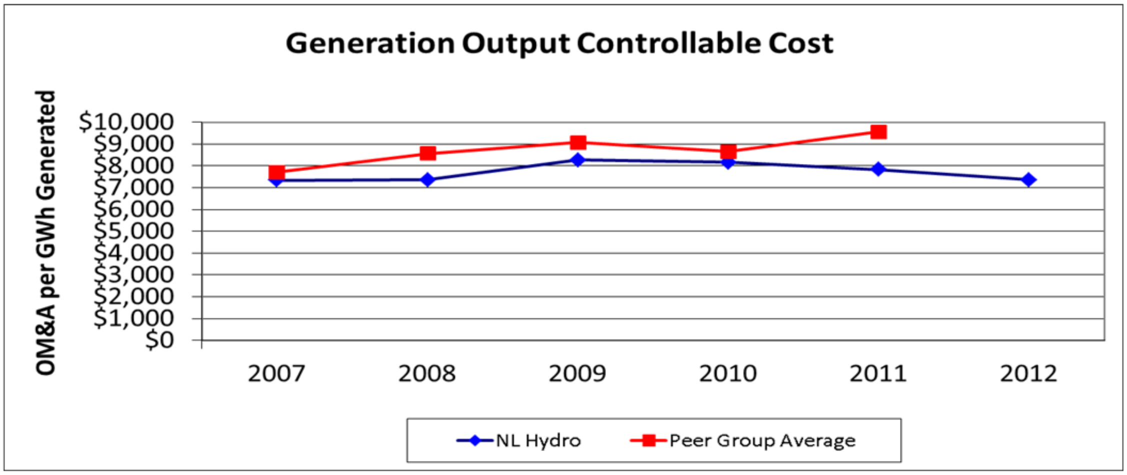
The peer group used to benchmark Generation Controllable Costs appears to be experiencing an increase in OM&A per MW installed capacity while Hydro is relatively stable.



3.3.2 b) Generation Output Controllable Cost - *a functional corporate KPI that tracks Hydro's generation OM&A expenses in relation to its net generation measured in GWh.*

In 2012, Hydro's Generation Output Controllable Cost of $7,358 per GWh, was lower than the $7,833 in 2011. There was a decrease in the Generation Costs component of approximately $2.2 million from 2011 to 2012 offset by an increase of 60 GWh in the Net Energy Generated.

From 2007 through 2010, Hydro's Generation Output Controllable Costs were primarily in line with and trending in a similar direction as those of the peer group with a moderate decline for Hydro in 2011.

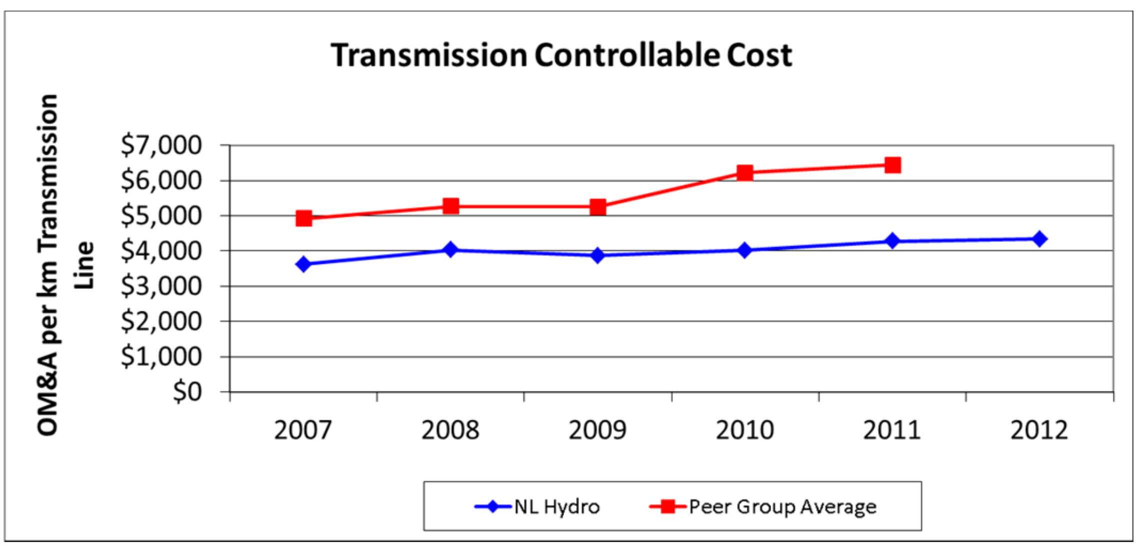


3.3.3 Financial KPI: Transmission

3.3.3 a) Transmission Controllable Cost - *a KPI that tracks Hydro's transmission OM&A expenses in relation to the 230 kV equivalent length of its transmission circuits (69 kV lines and above).*

In 2012, Hydro's Transmission Controllable Cost was $4,335 per km of transmission, an increase of 1.4% over 2011.

Hydro's costs per km of transmission circuit are trending in a similar pattern as the peer group, although per unit cost increases appear to be increasing at a slower rate within Hydro. A direct cost per unit km within the peer group is not meaningful due to differences in accounting and corporate cost allocations; however comparisons over time can highlight relevant trends.



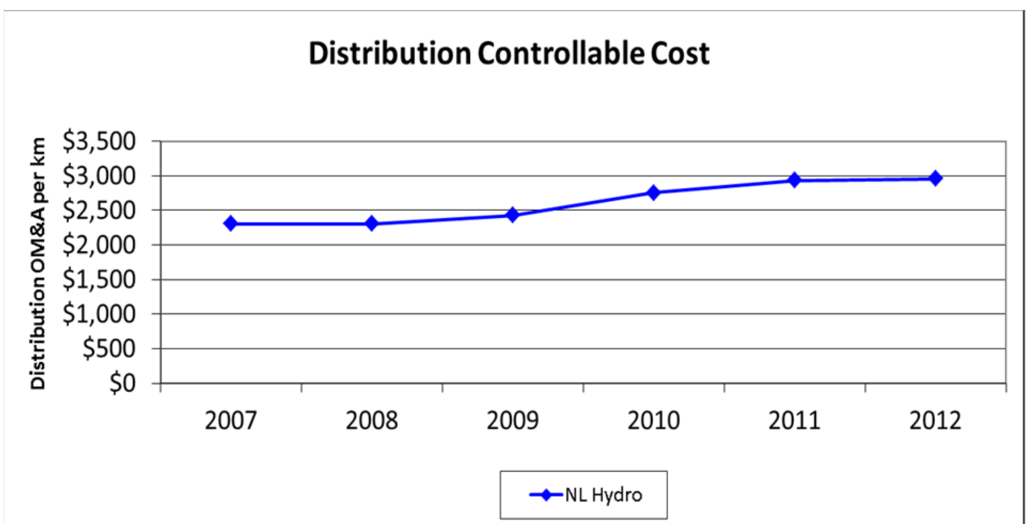
3.3.4 Financial KPI: Distribution

3.3.4 a) Distribution Controllable Cost - *a functional corporate KPI that tracks Hydro's distribution OM&A expenses in relation to the length of its equivalent 230 kV distribution circuits in kilometres[8].*

The Distribution Controllable Cost KPI had previously been reported as dollars per km of distribution using the CEA COPE data. As discussed, the CEA COPE data is no longer available for benchmarking of financial KPIs. Additionally, although distribution cost data is available for the U.S.-based peer group used by Hydro for Transmission Controllable Cost, the associated km of distribution data is unavailable. In the absence of the CEA COPE data, Newfoundland Power has chosen to use a KPI that divides total Distribution OM&A by MWh of retail sales. Hydro will therefore use this same data set. However, given Hydro's relatively small quantity of retail sales, combined with the rural and remote locations of these sales, it is expected that Hydro's Distribution cost per MWh will be significantly higher than Newfoundland Power's and the peer group average.

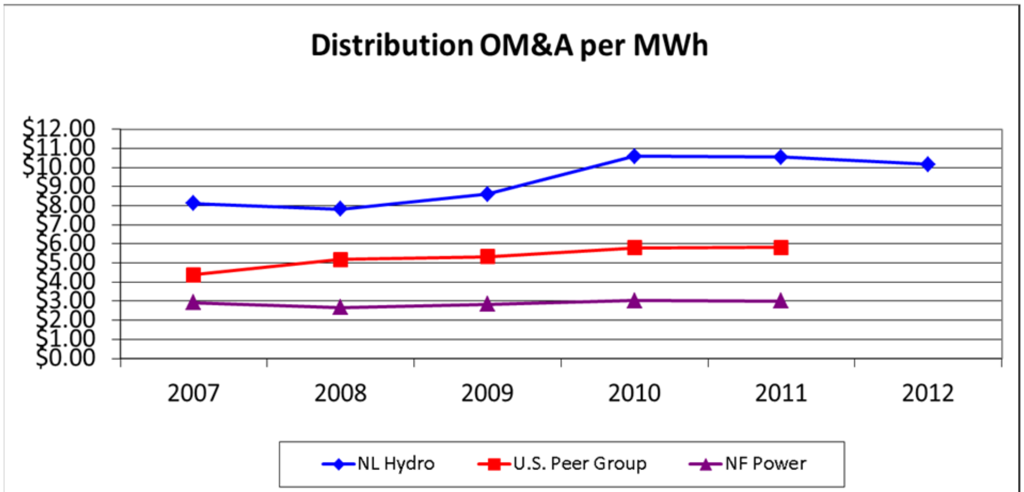
The distribution cost per km of circuit length will continue to be reported for year-over-year trend analysis.

At $2,960 per circuit km Hydro's Distribution Controllable Cost of 2012 increased from the $2,934 that was recorded in 2011. This is in line with the upward trend in this cost that was seen between 2007 and 2011.



[8] CEA COPE peer data used up to 2007 excluded circuits less than 1 kV. Hydro's data has also been adjusted to exclude circuits less than 1 kV from 2003 onward.

As expected, Hydro's distribution costs of $10.16 in 2012 trend higher than those of its peers in the table below. The distribution systems are a relatively small component of Hydro's total plant compared to generation and transmission plant and also compared to Newfoundland Power's distribution assets. Thus, Hydro's higher costs per MWh are likely due to the rural and geographically dispersed nature of its distribution systems and the resultant inability to achieve cost economies.



3.4 Customer-Related Performance Indicators

3.4.1 a) Residential Customer Satisfaction - *an indicator of Hydro's residential customers overall satisfaction level with service, which is tracked by the Percent Satisfied Customers KPI*[9].

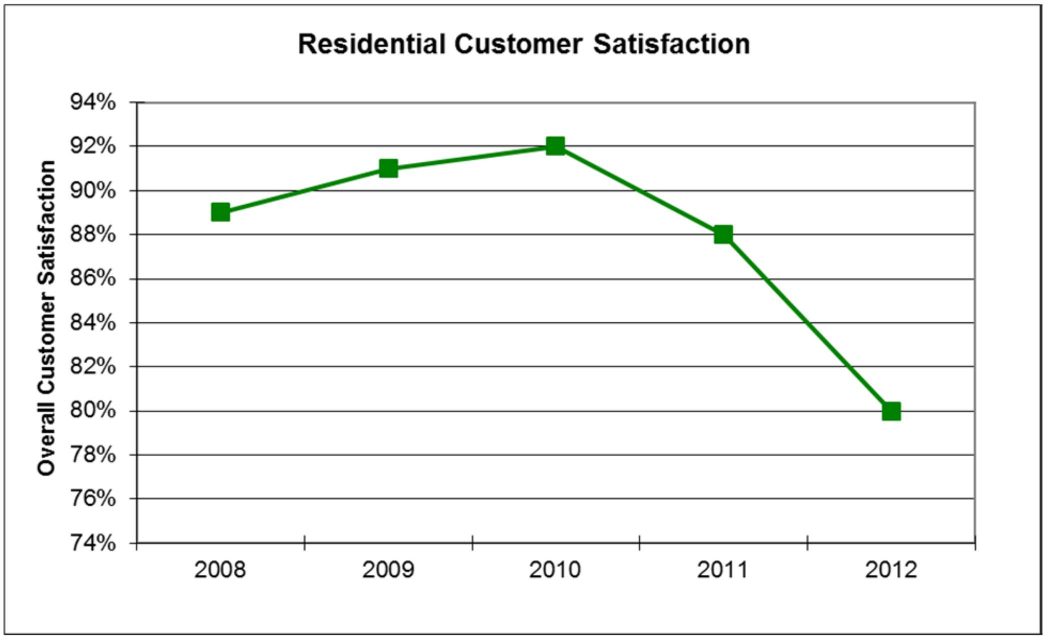
The Percent Satisfied Customers measure is also a corporate performance KPI that tracks the satisfaction of rural residential customers with Hydro's performance. The Percent Satisfied Customers measure is produced via an annual survey of Hydro's residential customers.

Hydro targeted a 2012 residential satisfaction rate of ≥90%, up two points from the 2011 actual results of 88%. The 2012 residential customer satisfaction survey shows that the majority of customers (80%) are either *very satisfied* (46% provided a rating of 9 or 10, on a scale of 1 to 10) or *somewhat satisfied* (34% provided a rating of 7 or 8, on a scale of 1 to 10) with Hydro. Compared with 2011, the proportion of customers who provided a rating of 9 or 10 held steady at 46%, while the proportion that provided a rating of 7 or 8 decreased from 42% in 2011 to 34% in 2012.

Overall in 2012, there was a slippage in the proportion of customers who provided a rating of 7 or 8 and an increase in the proportion of customers who provided a rating of 5 or 6. Customer

[9] As of 2009, the Customer Satisfaction index (CSI) is no longer being calculated as a Customer-Related Performance Indicator.

satisfaction with the reliability of service appears to be the indicator for the slippage.



4 Data Table of Key Performance Indicators

Key Performance Indicators' targets for 2013 were established in the same manner as in previous years. Any future changes in methodology will be included as such a change occurs.

Updated June 6-13

Newfoundland and Labrador Hydro
Key Performance Indicators (KPI)
Results for 2012 plus Targets/Budgets for 2013[1]

KPI	Measure Definition	Units	2008	2009	2010	2011	2012	2013T
Reliability								Target
Generation								
Weighted Capability Factor[2]	Availibility of Units for Supply	%	82.3	82.0	83.4	83.3	82.9	84.0
Weighted DAFOR[2]	Unavailibility of Units due to Forced Outage	%	5.0	4.5	1.8	2.7	2.3	2.8
Transmission[6,]								
T-SAIDI	Outage Duration per Delivery Point	Minutes / Point	278	100	173	432	171	203
T-SAIFI	Number of Outages per Delivery Point	Number / Point	1.7	0.9	2.3	4.5	1.9	1.7
T-SARI	Outage Duration per Interuption	Minutes / Outage	164	111	75	96	90	122
Distribution								
SAIDI	Average Outage Duration for Customers	Hours / Customer	11.2	9.4	6.6	16.3	8.3	5.9
SAIFI	Number of Outages for Customers	Number / Customer	6.3	4.3	3.5	5.7	4.4	3.6
Under Frequency Load Shedding								
UFLS	Customer Load Interruptions Due to Generator Trip	Number of Events	6	7	6	3	5	6
Operating								
Hydraulic Conversion Factor[3]	Net Generation / 1 Million m^3 Water	GWh / MCM	0.433	0.434	0.436	0.434	0.434	0.433
Thermal Conversion Factor[4]	Net kWh / Barrel No. 6 HFO	kWh / BBL	625	612	589	603	599	607
Financial (Regulated)								
Controllable Unit Cost[5]	Controllable OM&A$ / Energy Deliveries	$/MWh	$14.05	$14.91	$14.25	$14.96	$14.93	N/A
Generation Controllable Costs	Generation OM&A$ / Installed MW	$ / MW	$26,217	$26,138	$25,465	$26,169	$25,131	N/A
	Generation OM&A$ / Net Generation	$ / GWh	$7,362	$8,267	$8,159	$7,833	$7,358	N/A
Transmission Controllable Costs	Transmission OM&A$ / 230 kV Eqv Circuit Km	$ / Km	$4,023	$3,870	$4,021	$4,275	$4,335	N/A
Distribution Controllable Costs	Distribution OM&A$ / Circuit Km	$ / Km	$2,305	$2,429	$2,755	$2,934	$2,960	N/A
Other								
Percent Satisfied Customers (Residential)	Satisfaction Rating	Max = 100%	89%	91%	92%	88%	80%	≥90%

Notes:
1. Historical data has been updated and/or corrected where applicable.
2. The 2012 targets for weighted capability factor and DAFOR are based on the annual generation outage schedule.
3. For the Bay d'Espoir hydroelectric plant.
4. For the Holyrood thermal plant.
5. Energy deliveries have been normalized for weather, customer hydrology, and industrial strikes. No adjustments have been made for AC Stephenville mill closure.
6. The 2012 targets for T-SAIFI and T-SAIDI are based on the combination of forced and planned outage performance.

Appendices

Appendix A: Rationale for Hydro's 2012 KPI Targets

KPI	Comment on KPI 2012 Target
Reliability	Hydro has adopted a target setting approach wherein known factors that affect reliability performance are incorporated into the target setting process wherever practical. This approach also uses percentage improvements and past performance levels to set target levels for continuous improvements.
Weighted Capability Factor	The 2012 target is set using the expected annual generation unit outage schedule combined with performance improvements relative to recent history.
Weighted DAFOR	The 2012 target is set using the expected annual generation unit outage schedule combined with performance improvements relative to recent history.
Transmission SAIDI, SAIFI, and SARI	The 2012 targets for forced outage performance are set based upon recent performance improvements. The planned outage contribution to total performance is set using the annual transmission terminals maintenance outage plan.
Distribution SAIDI & SAIFI	Improvements relative to the most recent five-year average.
Underfrequency Load Shedding	The 2012 target is based upon improvement over the most recent five-year average.
Operating	
Hydraulic Conversion Factor	Hold at the previous target value.
Thermal Conversion Factor	Per Board Order No. P.U. 14 (2004)
Financial	
[ ]	N/A
[ ]	N/A
Other	
Customer Satisfaction	Targeting continuous improvement.

Appendix B: Computation of Weighted Capability Factor and Factors Impacting Performance

Weighted Capability Factor is calculated using the following formula:

$$1 - \frac{\sum_{all\ units} \left(\frac{unit\ total\ equivalent\ outage\ time \times unit\ MCR}{unit\ hours} \right)}{\sum_{all\ units} unit\ MCR}$$

Where,

MCR = Maximum Continuous Rating, the gross maximum electrical output, measured in megawatts, for which a generating unit has been designed and/or has been shown capable of producing continuously. MCR would only change if the generating capability of a unit is permanently altered by virtue of equipment age, regulation, or capital modifications. Such changes to MCR are infrequent and have not actually taken place within Hydro since the 1980's when two units at Holyrood were uprated due to modifications made to these units.

Unit hours = the sum of hours that a unit is in commercial service. This measure includes time that a unit is operating, shut down, on maintenance, or operating under some form of derating. Unit hours will only be altered in the infrequent event that a unit is removed from commercial service for an extended period of time.

Unit total equivalent outage time = the period of time a unit is wholly or partially unavailable to generate at its MCR. For the purposes of calculating outage time, the degree to which a unit is derated is converted to an outage equivalency. Thus, a unit that is able to generate at 75% load for four days would have an equivalent outage time of one full day out of four. Factors that can affect unit total equivalent outage time are classified by CEA under nine categories, which are outlined in Appendix A to this Report. Hydro tracks the time that each unit spends in each of these nine states and calculates the weighted capability accordingly.

Unit total equivalent outage time is the measure that is most likely to impact Weighted Capability Factor on a year-to-year basis, since MCR and unit hours are unlikely to change.

Appendix B: Computation of Weighted Capability Factor and Factors Impacting Performance (Cont'd)

Factors that Affect Unit Total Equivalent Outage Time

1. **Sudden Forced Outage.** An occurrence wherein a unit trips or becomes immediately unavailable.
2. **Immediately Deferrable Forced Outage**. An occurrence wherein a unit must be made unavailable within a very short time (10 minutes).
3. **Deferrable Forced Outage**. An occurrence or condition wherein a unit must be made unavailable within the next week.
4. **Starting Failure**. A condition wherein a unit is unable to start.
5. **Planned Outage**. A condition where a unit is unavailable because it is on its annual inspection and maintenance.
6. **Maintenance Outage**. A condition where a unit is unavailable due to repair work. Maintenance outage time covers outages that can be deferred longer than a week, but cannot wait until the next annual planned maintenance period.
7. **Forced Derating**. A condition that limits the usable capacity of a unit to something less than MCR. The derating is forced in nature, typically because of the breakdown of a subsystem on the unit.
8. **Scheduled Derating**. A condition that limits the usable capacity of a unit to something less than MCR, but is done by virtue of the decision of the unit operator. Scheduled deratings are less common than forced deratings, but can arise, for example, when a unit at Holyrood is derated to remove a pump from service.
9. **Common Mode Outages**. Common mode outages are rare, and arise when an event causes multiple units to become unavailable. An example might be the operation of multiple circuit breakers in a switchyard at Holyrood due to a lightning strike, rendering up to three units unavailable.

Note: There are hundreds of CEA equipment codes for generator subsystems that track the cause for the time spent in each of the above categories.

Appendix C1: Significant Transmission Events - 2012

- On May 26, all customers served by the Happy Valley Terminal Station experienced an unplanned power outage of one hour and 31 minutes in duration. At the time there was a planned outage underway to transmission line L1301 and the Happy Valley Gas Turbine was in service supplying customers. A gas alarm occurred on the gas turbine unit transformer - T3. The planned work was cancelled on L1301, but before the line could be restored, the gas turbine tripped. Customers were restored after L1301 was returned to service. **Unsupplied Energy: 1,456 MW-mins.**

- On September 11, all Newfoundland Power customers east of the Western Avalon Terminal Station experienced an unplanned outage due to the high winds of Hurricane Leslie which tracked over the Avalon Peninsula. The following table provides additional detail:

Delivery Point Interruptions on Sept 11, 2012

Delivery Point Affected	Start Time	Finish Time	Duration of Interruptions (mins)	MW Load	MW-Mins
Hardwoods (Outage 1)	Sep 11, 2012 08:09	Sep 11, 2012 08:38	29.00	73.35	2,127.15
Hardwoods (Outage 2)	Sep 11, 2012 08:52	Sep 11, 2012 09:06	14.00	42.00	588.00
Oxen Pond	Sep 11, 2012 08:09	Sep 11, 2012 09:19	70.00	94.28	6,599.60
Holyrood - 38L (1)	Sep 11, 2012 08:09	Sep 11, 2012 08:48	39.00	9.82	382.98
Holyrood - 38L (2)	Sep 11, 2012 08:52	Sep 11, 2012 10:20	88.00	5.84	81.76
Holyrood - 39L (1)	Sep 11, 2012 08:09	Sep 11, 2012 08:35	26.00	0.00	0.00
Holyrood - 39L (2)	Sep 11, 2012 08:52	Sep 11, 2012 09:16	24.00	0.00	0.00
Western Avalon 64L (1)	Sep 11, 2012 08:01	Sep 11, 2012 08:05	4.00	0.00	0.00
Western Avalon 64L (2)	Sep 11, 2012 08:09	Sep 11, 2012 08:29	20.00	32.06	641.20
Western Avalon 64L (3)	Sep 11, 2012 08:31	Sep 11, 2012 08:34	3.00	3.43	10.29
Western Avalon 64L (4)	Sep 11, 2012 08:52	Sep 11, 2012 08:59	7.00	27.65	193.55
Western Avalon 64L (5)	Sep 11, 2012 09:14	Sep 11, 2012 09:29	15.00	33.22	66.44
Western Avalon Bus 2	Sep 11, 2012 08:09	Sep 11, 2012 09:58	109.00	2.10	228.90
		Total	448.00	211.61	10,919.87

The initial outage was caused by multiple faults that occurred on NP's 138 kV loop between the Western Avalon and Holyrood Terminal Stations. Combined with other system conditions and the nature and duration of these faults, the protection equipment on Hydro's 230 KV transmission lines responded and tripped. Investigation has determined that there was no fault on the 230 kV transmission system during this time and system stability was not lost. The slow clearing 138 kV faults created a severe 230 kV voltage dip and caused the protection operations which led to the outage.

A second outage occurred after transmission line TL237 faulted between the Come by Chance and Western Avalon Terminal Stations. This fault was also caused by the hurricane force winds resulting in the line conductors slapping together. **Total Unsupplied Energy: 10,541 MW-mins.**

Appendix C1: Significant Transmission Events – 2012 (Cont'd)

- On October 24, customers served by the Happy Valley Terminal Station experienced an unplanned power outage of 32 minutes in duration. This outage occurred after transmission line L1301 tripped due to the operation of the lockout relay on transformer T31 at Churchill Falls. Personnel were working on the transformer, which was out of service, but the gas pressure relay was not blocked. This relay should have been blocked prior to starting work on the transformer. **Unsupplied Energy: 1,186 MW-mins.**

Appendix C2: Significant Distribution Events – 2012 (Excluding Fourth Quarter)

- On February 12, there was an unplanned outage affecting approximately 20 customers in La Poile. The outage occurred during a high wind and heavy rain storm. Due to the poor visibility caused by the weather conditions (high winds which later caused snow squalls), attempts to bring in a crew by helicopter were delayed until February 14. The cause of the outage was a blown fuse at a pole-mounted disconnect switch, associated with the customer feeder. Total outage time to the customers was more than 51 hours.

- On March 14, all customers (105) in Black Tickle experienced a lengthy power outage caused by a fire in the diesel plant. The fire damaged most of the overhead electrical conductors in the power plant engine hall. Power was restored to the community on March 15 after the maintenance personnel successfully and safely completed the temporary repairs to one of the three generator units damaged in the fire. A mobile unit was transported to the site and used to supply customers.

Appendix C3: Underfrequency Load Shedding Events (Excluding Fourth Quarter)

- On January 14, Holyrood Generating Unit # 1 and Unit # 2 tripped due a fault on the 66 kV line supplying station service to the generating plant. With the removal of generation (approximately 142 MW) the system frequency dropped below 58.3 Hz resulting in the activation of the underfrequency protection at Newfoundland Power (18,940 customers), Hydro (2,200 Customers) and Corner Brook Pulp and Paper. Total system load at the time of the incident was 1,055 MW. Hydro indicated to Newfoundland Power and Corner Brook Pulp and Paper that power could be restored ten minutes after the event occurred and power was restored to all customers affected by the underfrequency in 40 minutes.

- On May 22, Cat Arm Generating Unit # 1 tripped after the fire protection deluge system operated on the unit transformer, T1. Personnel investigated, however, there was no fire or indication of a fire found at the transformer. With the removal of generation (approximately 60 MW) the system frequency dropped to 58.7 Hz resulting in the activation of the underfrequency protection at Newfoundland Power. This underfrequency event affected 6,046 Newfoundland Power customers for up to four minutes for a total load loss of 48 MW-mins. Total system load at the time of the incident was 570 MW.

Appendix D: List of U.S.-Based Peers for Financial KPI Benchmarking

Generation and Corporate Peer Group:

Alcoa Power Generating Inc.
Allete, Inc.
Aquila, Inc.
Avista Corporation
Buckeye Power, Inc.
Cleco Power LLC
Electric Energy, Inc.
Entergy Mississippi, Inc.
Hawaiian Electric Company, Inc.
Indiana-Kentucky Electric Corporation
Kentucky Power Company
Ohio Valley Electric Corporation
Portland General Electric Company
Public Service Company of New Hampshire
Puget Sound Energy, Inc.
Savannah Electric and Power Company
Sierra Pacific Power Company
Southern Electric Generating Company
Southern Indiana Gas and Electric Company
The Empire District Electric Company

Transmission Peer Group:

AEP Texas North Company
Allete, Inc.
Aquila, Inc.
Avista Corporation
Central Illinois Public Service Company
Delmarva Power & Light Company
Entergy Mississippi, Inc.
Kentucky Utilities Company
MDU Resources Group, Inc.
Mississippi Power Company
New York State Electric & Gas Corporation
Northern Indiana Public Service Company
Northern States Power Company (Wisconsin)
Oklahoma Gas and Electric Company
Public Service Company of Colorado
Public Service Company of Oklahoma
Sierra Pacific Power Company
Southwestern Electric Power Company
Tucson Electric Power Company
Westar Energy, Inc.

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

QUARTERLY REGULATORY REPORT FOR THE QUARTER ENDED MARCH 31, 2013

Newfoundland and Labrador Hydro

Table of Contents

APPENDICES:

1 HIGHLIGHTS

HIGHLIGHTS
For the three months ended March 31, 2013

REGULATED	2013 Actual YTD	2013 Target/ Budget	2012 Actual YTD
Safety			
Lead:Lag Ratio[1]	458:1	600:1	323:1
All Injury Frequency Rate[1]	1.04	<0.8	1.81
Production			
Quarter End Reservoir Storage (GWh)	1,831	196	1,527
Hydraulic Production (GWh)	1,462	1,492	1,452
Holyrood Fuel cost per barrel, current month ($) [2]	111	55	118
Holyrood Efficiency [2]	606	630	607
Electricity Delivery			
Sales including Wheeling (GWh)	2,327.7	2,403.7	2,329.8
Financial			
Revenue ($millions)	166.1	172.0	164.2
Expenses ($millions)	157.6	156.2	146.5
Net Operating Income ($millions)[3]	8.5	15.8	17.7
Current Rate Stabilization Plan (RSP) Balance ($millions)	(224.4)	(235.1)	(172.7)
Hydraulic	(53.4)	(64.8)	(52.8)
Utility	(61.5)	(63.0)	(34.0)
Industrial	(109.5)	(107.3)	(85.9)
Full Time Equivalent (FTE) Employees[4, 5]			
Regulated	778.4	863.5	776.0
Non-Regulated	31.5	15.0	22.7

[1] Annual Target, and 2012 Actual
[2] Target based on approved 2007 Test Year forecast
[3] Does not include any earnings from CF(L)Co
[4] One FTE is the equivalent of actual paid regular hours - 2,080 hours per year in the operating environment and 1,950 hours per year in Hydro's head office environment.
[5] Annual Budget and 2012 Actual values

- No Lost Time Injuries (page 2);
- Power Your Knowledge Elementary School Safety Program launched (page 4);
- Quarter end Hydrology Storage Level at 79% of maximum operating level (page 13).

2 SAFETY

Goal - To be a Safety Leader

Safety is Hydro's number one priority. Hydro remains committed to being a world class leader in safety performance.

Measurement	Year-to-date 2013 Actual	Annual 2013 Plan	Annual 2012 Actual
All Injury Frequency (AIF)	1.04	$\leq$0.8	2.25
Lost Time Injury Frequency (LTIF)	0.00	$\leq$0.2	0.79
Ratio of condition and incident reports to lost time and medical treatment injuries (lead/lag ratio)	458:1	600:1	230:1
Planned Grounding and Bonding Activities	In progress	100%	N/A
Complete Work Method Activities for Critical Tasks	89.89	100%	87.33%

Hydro continued its focus on planned safety objectives into the first quarter of 2013.

One of the key initiatives identified as an area requiring attention was injury prevention. As a part of a corporate prevention awareness initiative, a strategy was developed focusing on three of the Company's top injury trends: Slips; Trips and Falls; Sprains and Strains; and Hand Injuries. Several fact sheets have been circulated to employees highlighting the injury experience for the past five years with more communication planned throughout the year.

With a focus on being more visible in the field, leaders have been conducting safety tours and visiting employees to discuss workplace safety. Field visits by the Leadership Team, Regional Managers and safety professionals have been occurring in all areas of the Company and feedback to date has been positive.

The public campaign for Power Line Hazards (PLH) is ongoing. The PLH Working Group has met to discuss communication strategies and initiatives around power line safety.

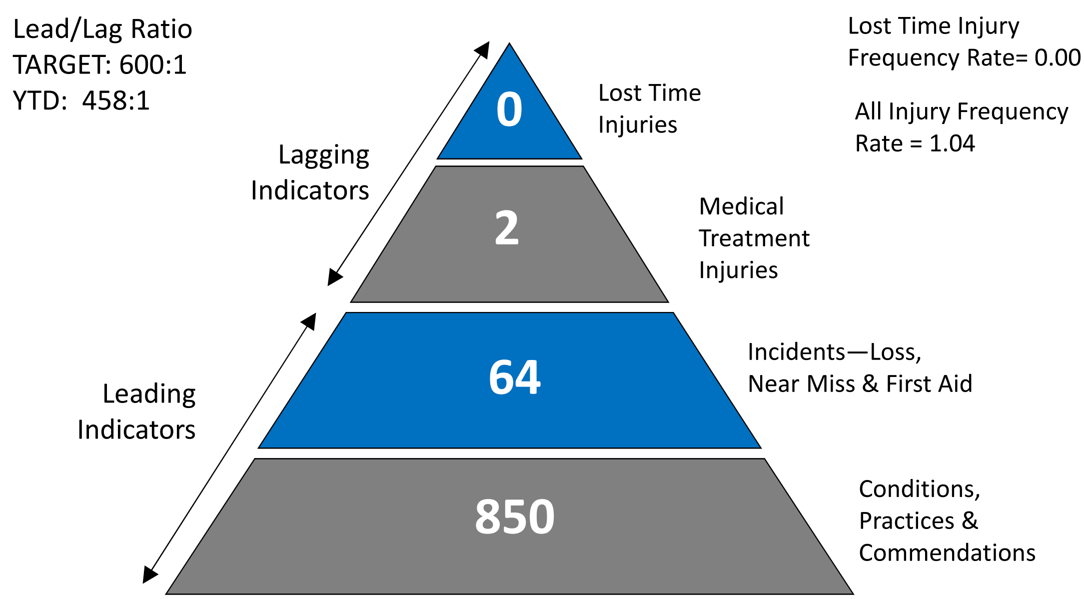
Continuing with the development and enhancement of safety culture, BeSafe safety coaching workshops will continue throughout Hydro in 2013 with the remainder to be completed in 2014.

A corporate grounding and bonding committee has been established. A corporate standard has been developed for overhead lines, and the training package has been finalized. Corporate training is in progress.

From a program perspective, Hydro continues its focus in the areas of Work Protection Code (WPC) and Hearing Conservation. Work continues around the development of Work Methods for identified critical tasks with current targets on track. The WPC Program has been focusing on the development of new software for the issuing of permits and auditing compliance to the code. A new Hearing Conservation standard has been developed and communicated to all employees identifying key focus areas that have to be addressed in their regions.

To enhance the reporting of safety observations, Safe Workplace Observation Program (SWOP) training has continued in 2013 in partnership with Incident Investigation Training Program.

The following safety triangle summarizes Hydro's year-to-date performance for 2013.



2.1 Hydro launches Newest Electrical Safety Program

Hydro has paired up with teachers and the Department of Education to develop an educational resource to teach children about electricity. Hydro recognizes the importance of educating students on electrical safety, how it is generated, and how it is used on a daily basis. These topics have been included in the new Power Your Knowledge program - a web-based resource at www.poweryourknowledge.com. The initiative was developed to help educate elementary students on the science and potential dangers of electricity and how it influences their everyday life.

On January 29, Hydro launched the Power Your Knowledge program at Hazelwood Elementary school in St. John’s. The launch included an overview of the website, an electrical safety presentation, and a demonstration using Hydro’s power science kit. Through the program, a safety presentation and power science kits were developed and sent to every Grade 6 classroom in the province.

2.2 Promoting Power Line Safety

Hydro continues to work with Newfoundland Power to urge contractors to work safe near power lines. Throughout the first quarter of 2013, the utilities are running an advertising and marketing campaign to help raise awareness about power line safety.

Brian Lannon, Corporate Safety Specialist, Safety and Health, hosts the power line safety booth at the NLCSA Annual Conference.

As part of this initiative, Hydro sponsored Newfoundland and Labrador Construction Safety Association’s (NLCSA) Annual Health and Safety Conference. The annual conference is dedicated to increasing knowledge and awareness of health and safety issues throughout the province. On February 14, three members of the Corporate Safety and Health Department hosted a booth at the conference to provide awareness around power line safety.

2.3 Hydro Generation focuses on Safety Training

Safety is Hydro's number one priority. To ensure the safety of employees, Hydro Generation staff provided safety training and hosted safety sessions in a variety of areas throughout January and February. Employees in Hydro Generation completed the following training sessions: confined space entry, fall protection, Work Protection, BeSafe coaching, first aid, snowmobile safety, ladder rescue training and exciter training.

Employees in Bay d'Espoir take part in ladder rescue training

3 ENVIRONMENT AND CONSERVATION

Goal - To be an Environmental Leader

Hydro recognizes its commitment and responsibility to protect the environment.

Measurement	Year-to-date 2013 Actual	Annual 2013 Target	Annual 2012 Actual
Variance from ideal production schedule at Holyrood Thermal Generating Station	14%	≤ 10.0%	6.9%
Achievement of EMS targets[1]	4%	95%	96%
Annual energy savings from Residential and Commercial Conservation and Demand Management Programs	0.5 GWh	2.9 GWh	2.3 GWh[2]
Conduct evaluation of Industrial Energy Efficiency Program (IEEP) and develop multi-year plan	Work to begin in second quarter	Complete evaluation	N/A
Annual energy savings from Internal Energy Efficiency Programs	0	0.40 GWh	0.26 GWh

[1] An EMS target is an initiative undertaken to improve environmental performance.
[2] Revised

3.1 Variance from Ideal Production Schedule at Holyrood Thermal Generating Station

Summary of 2013 Performance (year-to-date):

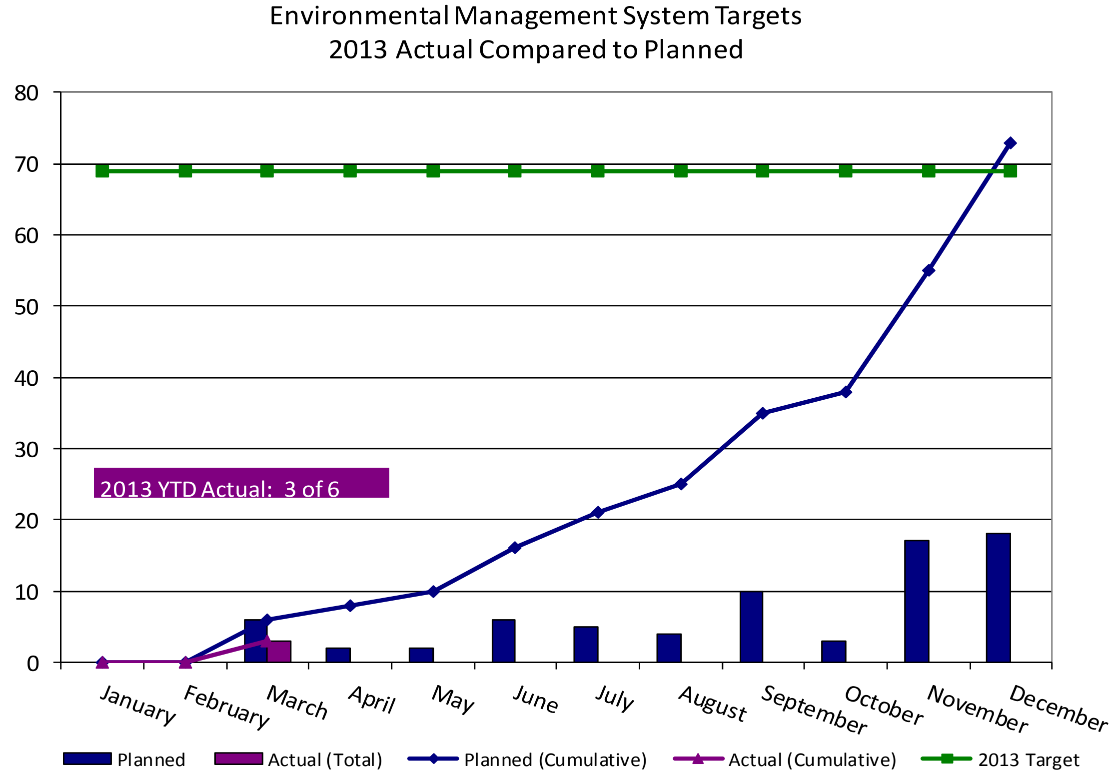
Minimum Hours

2013	Variance[1]		Ideal		Variance	
Month	Unit-Hours	Cumulative	Unit-Hours	Cumulative	Percent	Cumulative
January	360	360	2,088	2,088	17.2%	17.2%
February	337	697	1,728	3,816	19.5%	18.3%
March	48	745	1,512	5,328	3.2%	14.0%

[1] Variance is the number of hours greater than or less than the ideal. Hours greater than the ideal represent hours of operation that ideally could have been avoided. Hours less than the ideal represent hours of operation where a single contingency could have resulted in a load interruption.

3.2 Achievement of EMS Targets

See graph below displaying planned target completion schedules and actual to-date.



3.2.1 Annual Energy Savings from Residential and Commercial Conservation and Demand Management Programs

The advertising and promotions contract for the takeCHARGE portfolio was awarded to a new agency at the start of 2013 and extensive work is being done in the development of new promotional strategies for the residential and commercial portfolios. Rebate activity has been especially strong in the first quarter due to Hydro's interaction with builders, resulting in a high number of rebates related to construction.

Planning is underway for the launch of the second year of the Isolated Community Energy Efficiency Program, a direct installation program for residential and commercial customers in Hydro's isolated systems. Program activities will be starting in the second quarter. The Isolated System Business Efficiency Program (ISBEP) continues, with a direct mail promotional campaign initiated and additional building audits conducted to engage the business community in energy efficiency.

Hydro is working with the Provincial Government's Climate Change, Energy Efficiency and Emissions Trading Secretariat on communications strategies and issues surrounding updated energy efficiency codes for residential new construction as a key component of education and awareness efforts for the market.

3.2.2 Annual Energy Savings from Internal Energy Efficiency Programs

Efforts were focused around establishing energy efficiency related EMS targets for 2013 in the regions. These targets outline projects and processes to further internal energy efficiency efforts. Processes have been put in place to ensure internal efficiency is considered in engineering project development. Work has begun on an assessment of the controls system for the heating, ventilation and air conditioning systems for Hydro Place and other sites will also be examined for energy efficiency opportunities.

3.3 Hydro Undertakes Investigation on Holyrood Unit 1

As noted above, Unit 1 at the Holyrood plant shut down due to an electrical disturbance that originated in the high-voltage switchyard at the Holyrood Terminal Station during a severe winter storm on January 11, 2013. This disturbance was caused by an electrical fault resulting from the extremely high winds, heavy snow and salt contamination of equipment in the switchyard adjacent, and connected to, the generating station.

Following this event, Hydro began a comprehensive analysis with independent experts to investigate the cause of the unit shutdown and determine the repairs required to restore the unit to service. The investigation identified that a lubricating oil pump did not provide the required lubricating oil to the bearings during the unit shutdown. The reason the pump set did not deliver the required pressure is still under investigation. Hydro filed a capital plan with the Public Utilities Board on April 3 for the repair and restoration of the unit.

Timely restoration of Unit 1 is necessary for stand-by operations during regular maintenance work and scheduled capital upgrades on Units 2 and 3 this summer and early fall, and to ensure safe and reliable operation of the plant entering into the 2013 peak winter period.

4 OPERATIONAL EXCELLENCE

Goal - Through operational excellence provide exceptional value to all consumers of energy.

Hydro strives to deliver operational excellence by maintaining safe, reliable delivery of power and energy to customers in a cost-effective manner while maintaining high customer satisfaction. The key focus areas are:

- Energy Supply;
- Asset Management; and
- Financial Performance.

Measurement	Year-to-date 2013 Actual	Annual 2013 Target	Annual 2012 Actual
Asset Management and Reliability			
Contingency Reserve[1]	93.6	≥99.5%	99.97%
Asset Management Strategy Execution	Tracking in compliance to plan	Plan Implementation	Completed as planned for 2012
Financial Targets			
Annual Controllable Costs	$32.3 million	$111.9 million (Budget)	$106.5 million
Net Income	$8.5 million	$6.2 million	$16.9 million
Project Execution			
Completion rate of capital projects by year end[3]	-	≥90%	82%
All-project variance from original budget[3]	-	8%	18%
Customer Service			
Customer Service Improvement Plan[2]	In Progress	Execute Plan	N/A

[1] The contingency reserve metric tracks the number of unit unavailability hours for which there would not have been ample system generation available to supply the system load under the loss of the largest generating unit (N-1). These unavailability hours are compared against the total hours in the month.
[2] A draft "New Service Connections and New Construction" information brochure has been produced to provide customers and electrical contractors with the process to follow when requesting electrical service, with a guideline of the timelines required throughout the process of initial request to final connection.
[3] Measured at year end.

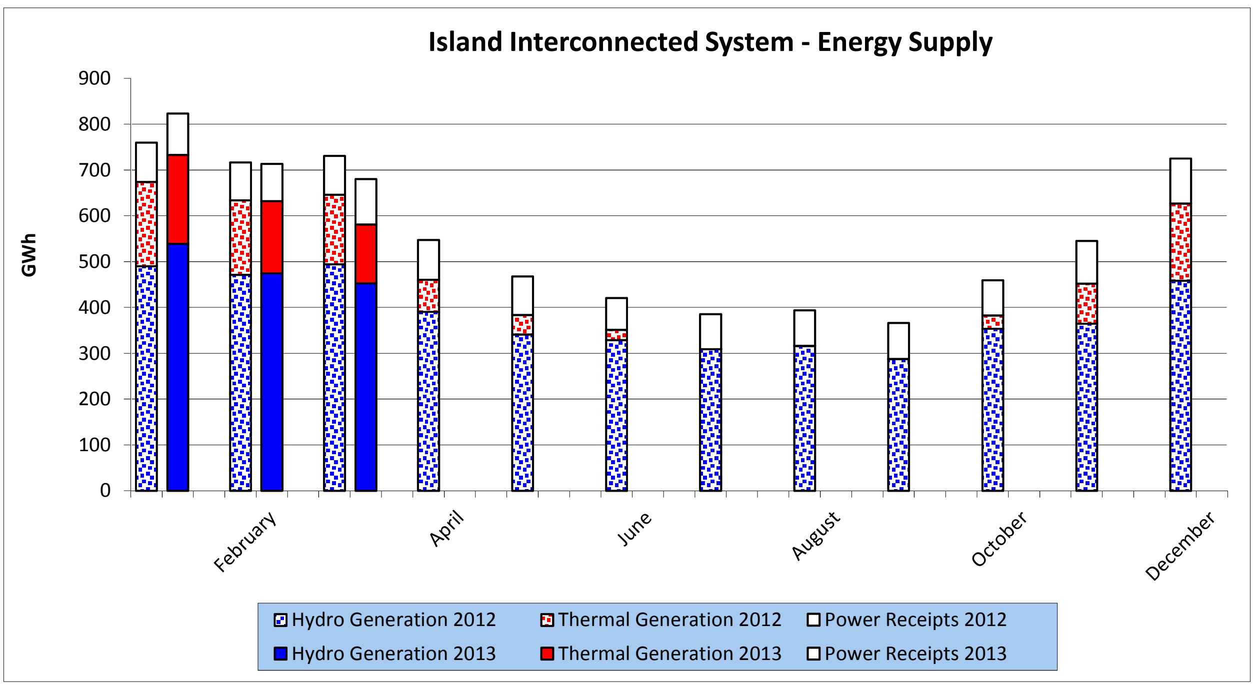
4.1 Energy Supply

4.1.1 Energy Supply - Island Interconnected System

Energy requirements from the Holyrood Generating Station (Holyrood) were lower during the first quarter of 2013 when compared to the same period in 2012 (17.5 GWh or 3.7%). This was primarily due to the failure of Unit 1 on January 11 and the resultant decrease in minimum energy production. Individual units are brought into service as required to meet customer's demand and for transmission support to the Avalon Peninsula.

Hydroelectric production for the first quarter of 2013 was 10.1 GWh, less than 1% above the levels in 2012, primarily due to increased system load requirements. The increase in hydroelectric production was partially offset by an overall increase in energy purchases. Total energy purchases were up by 18.4 GWh or 7.3% in the first quarter of 2013 when compared to 2012. This increase was primarily due to increased generation from the Nalcor facilities at Exploits and from the Corner Brook Pulp and Paper Ltd. co-generation unit. The increase in energy purchases was partially offset by a decrease in production at the St. Lawrence wind farm. That facility experienced operational issues during the first quarter.

The energy supply for the Island Interconnected System is shown in the following chart and tables.



Island Interconnected System Production
For the Quarter ended March 31, 2013

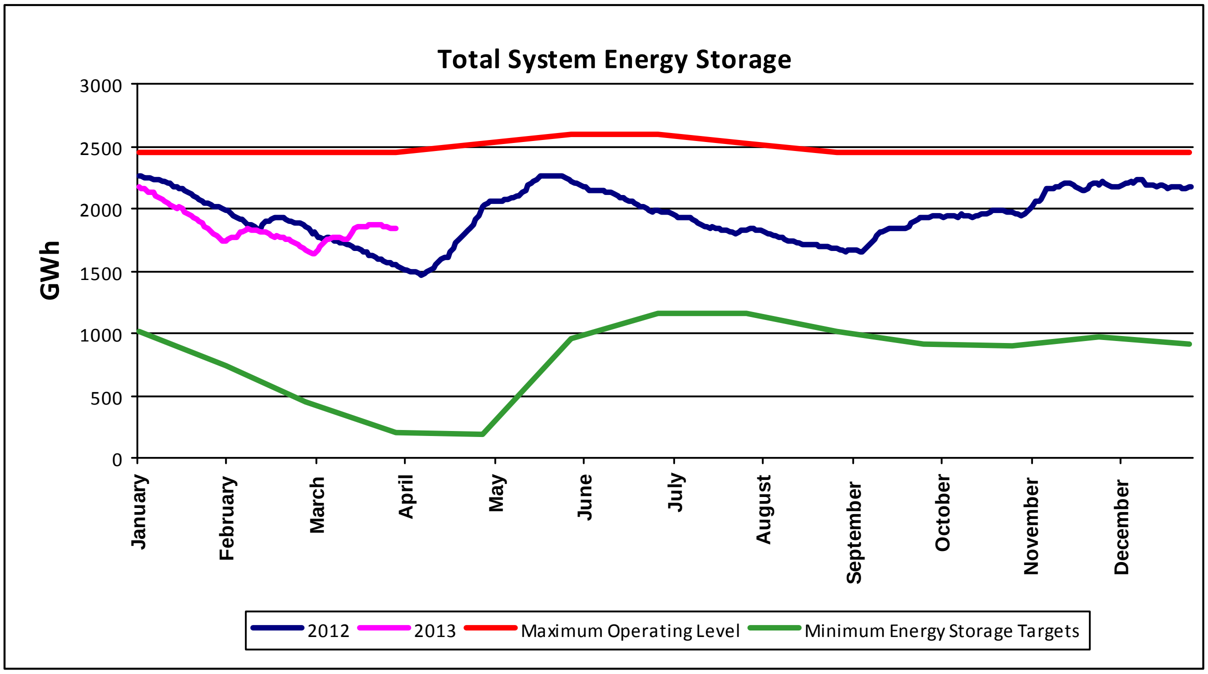
	Year-to-date			2013 Annual Forecast (GWh)	2013 ($ 000)
	2013 (GWh)	2012 (GWh)	2013 Forecast (GWh)		
Production (net)					
Hydro	1,462.1	1,452.0	1,491.5	4,637.0	
Thermal	449.3	466.8	488.6	1,158.3	
Gas Turbines	0.6	(0.9)	1.0	2.8	
Diesels	0.8	(0.2)	0.1	0.4	
Total Production	**1,912.8**	**1,917.7**	**1,981.2**	**5,798.5**	
Energy Receipts					
Non Utility Generators					
Rattle Brook	2.8	1.5	1.9	15.1	**280.8**
Corner Brook Pulp and Paper Co-generation	16.4	13.1	16.0	51.6	**2,494.9**
St. Lawrence Wind	22.4	31.5	33.0	104.8	**1,598.8**
Fermeuse Wind	27.6	25.7	26.6	84.4	**2,089.5**
Total Non Utility Generators	**69.2**	**71.8**	**77.5**	**255.9**	**6,464.0**
Secondary and Others					
Deer Lake Power	1.9	1.6	0.0	0.0	**55.1**
Hydro Request to NP	0.8	0.0	0.0	0.0	**239.3**
Nalcor Energy[1]	199.5	179.6	199.7	765.6	
Total Secondary and Other	**202.2**	**181.2**	**199.7**	**765.6**	**294.3**
Total Purchases	**271.4**	**253.0**	**277.2**	**1,021.5**	
Island Interconnected Total Produced and Purchased	**2,184.2**	**2,170.7**	**2,258.4**	**6,820.0**	

[1] Nalcor Energy includes Star Lake and the Grand Falls, Bishop's Falls and Buchans generation.

4.1.2 System Hydrology

Reservoir storage levels continued to be favourable in the first quarter of 2013. Inflows into the aggregate reservoir system during the first three months were above average at 135%. There were two mild and wet periods experienced during the first two weeks of March which resulted in melting snow and increased inflows. Hydro conducted its first winter snow survey in February. The results indicate that the snow pack water equivalent, over the aggregate reservoir system, is 104% of the 29 year average. With average precipitation from the date of the survey to the end of the run-off period (June 30), it is estimated that the reservoirs will fill to 87% of the maximum operating level (MOL).

Reservoir levels at the end of the quarter were at 79% of the MOL and in excess of 900% of the minimum storage target. This compares with 64% of the MOL at the end of the first quarter in 2012.



System Hydrology Storage Levels			
	2013 (GWh)	2013 Minimum Target (GWh)	2012 (GWh)
Quarter End Storage Levels	1,831	196	1,527

4.1.3 Energy Supply – Labrador Interconnected System

The purchased and produced energy on the Labrador Interconnected System was down during the first quarter of 2013 (13.8 GWh or 4.5%) when compared to 2012. This is due to lower industrial sales at the Iron Ore Company of Canada (IOCC), reduced secondary sales to CFB Goose Bay, and a reduction in Hydro Rural requirements in Labrador East and West.

Labrador Interconnected System Production For the Quarter ended March 31, 2013				
	Year-to-date			**2013 Annual Forecast (GWh)**
	2013 (GWh)	**2012 (GWh)**	**2013 Forecast (GWh)**	
Production (net)				
Gas Turbines	(0.6)	(1.0)	0.2	0.6
Diesels	0.0	0.0	0.1	0.2
Total Production	**(0.6)**	**(1.0)**	**0.3**	**0.8**
Purchases				
CF(L)Co for Labrador (at border)	**295.0**	**309.2**	**356.5**	**1,050.3**
Labrador Interconnected Total Produced and Purchased	**294.4**	**308.2**	**356.8**	**1,051.1**

4.1.4 Fuel Prices

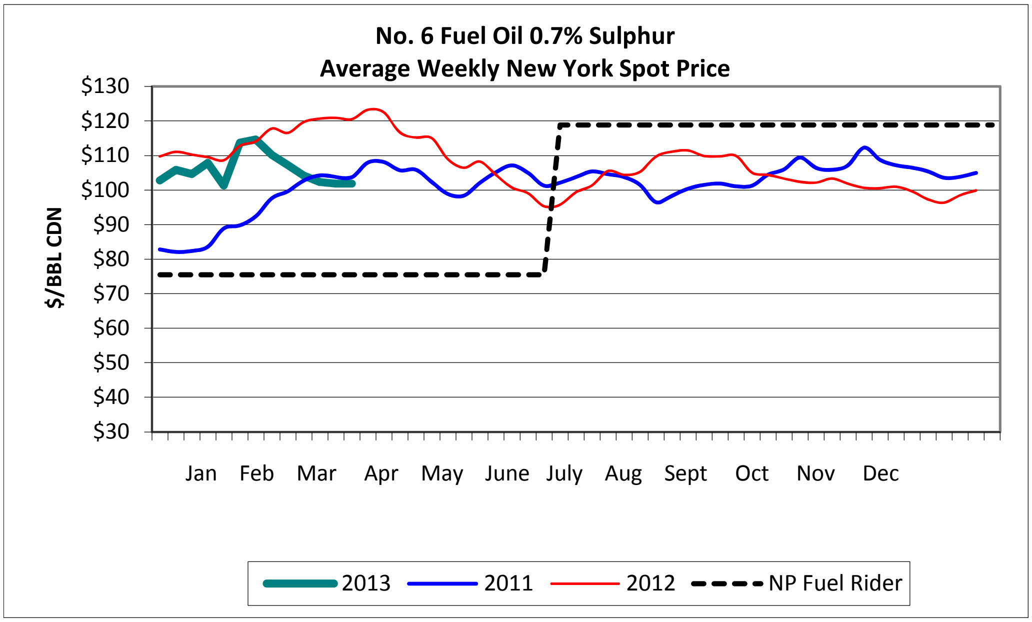
The fuel market prices for No. 6 fuel increased slightly from approximately $101/bbl at the start of the quarter to $102/bbl. at the end of the quarter. The quarter ending inventory cost was $111.07/bbl, lower than the current Newfoundland Power fuel price rider of $118.80/bbl. There is no Industrial Customer fuel price rider for 2013.

There were four shipments received during the first quarter of 2013:

January 4	221,080 bbls	$ 98.65
January 26	225,786 bbls	$108.04
February 16	217,348 bbls	$111.10
February 27	221,701 bbls	$114.15

The inventory on March 31 was 323,916 barrels.

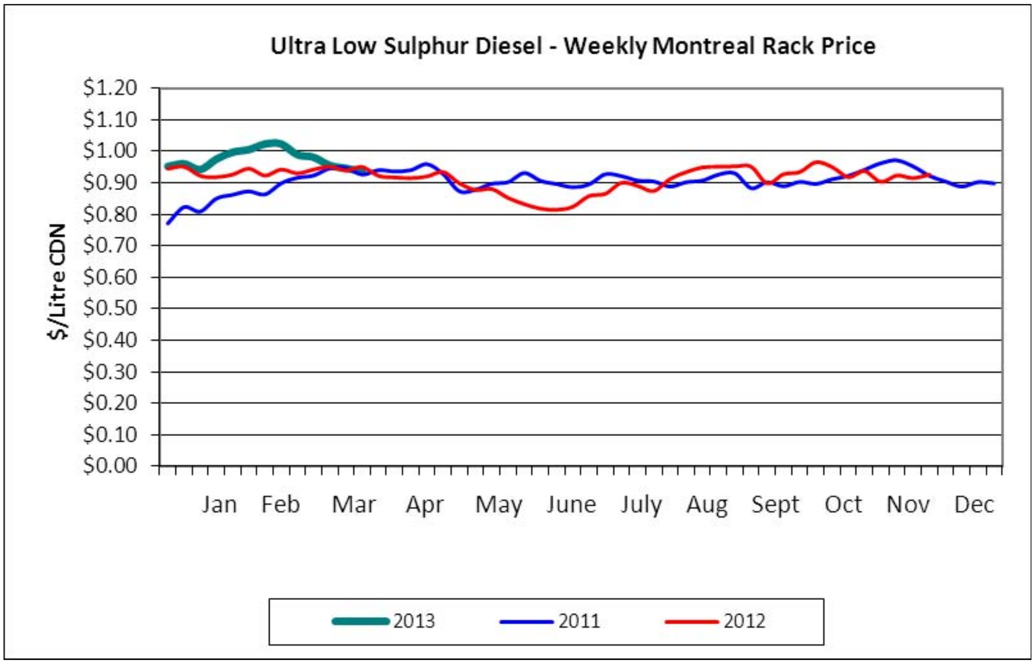
The following chart shows the No. 6 fuel prices year-to-date compared to 2011 and 2012, and the Newfoundland Power fuel rider price of $118.80/bbl.



The following table provides the monthly forecast price of No. 6 fuel (0.7% sulphur) up to March 2014, landed on the Avalon Peninsula.

No. 6 Fuel Oil Sulphur Forecast Price April 2013 – March 2014			
Month	**Price ($Cdn/bbl) 0.7%**	**Month**	**Price ($Cdn/bbl) 0.7%**
April 2013	104.30	October 2013	110.40
May 2013	106.00	November 2013	111.30
June 2013	109.10	December 2013	107.90
July 2013	111.70	January 2014	99.60
August 2013	112.50	February 2014	99.60
September 2013	110.70	March 2014	99.60
Note: The forecast is based on the PIRA Energy Group price forecast available March 26, 2013 and an exchange rate forecast by Canadian financial institutions and the Conference Board of Canada.			

The following chart shows Low Sulphur Diesel No. 1 fuel prices year-to-date compared to 2011 and 2012.



4.1.5 Energy Supply - Isolated Systems

Total isolated energy supply decreased by 1% in the first quarter of 2013 over the first quarter of 2012 with the decline attributed to milder weather in February and March of 2013 when compared to 2012. Net diesel production was 4% lower while energy purchases were six percent higher when comparing 2013 to 2012.

The average cost of power purchased from Hydro Québec, based on Montreal rack fuel prices, has increased from $142 per megawatt hour in the first quarter of 2012 to $143 per megawatt hour in 2013. Average cost of power from NUGS, based on current diesel fuel prices, has increased from $291 per megawatt hour in the first quarter of 2012 to $300 per megawatt hour in 2013.

Isolated Systems Production
For the Quarter ended March 31, 2013

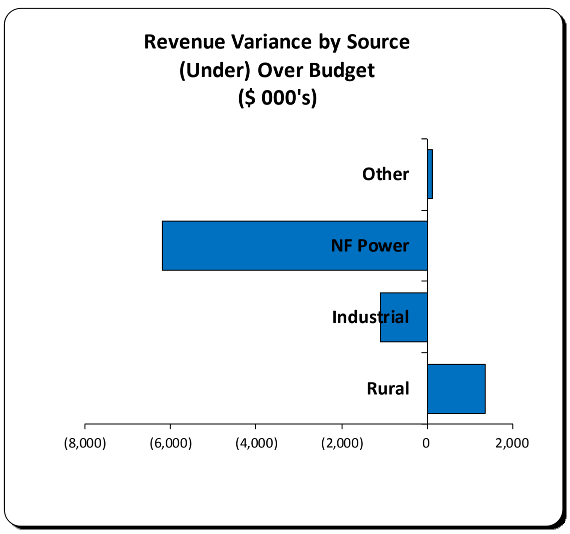
	Year-to-date						2013 Annual Forecast	
	2013		2012		2013 Forecast		(GWh)	$(000)[1]
	(GWh)	$(000)[1]	(GWh)	$(000)[1]	(GWh)	$(000)[1]		
Production (net)								
Diesels	12.8		13.4		13.8		50.6	
Purchases								
Non Utility Generators (NUGS)[2]	0.4	109.1	0.4	73.3	0.3	106.0	0.8	244.7
Hydro Québec	7.2	1,038.4	6.8	956.4	7.1	873.3	23.2	3,353.2
Total Purchases	**7.6**	**1,147.5**	**7.2**	**1,029.7**	**7.4**	**979.3**	**24.0**	**3,597.9**
Isolated Systems Total Produced and Purchased	**20.4**	**1,147.5**	**20.6**	**1,029.7**	**21.2**	**979.3**	**74.6**	**3,597.9**

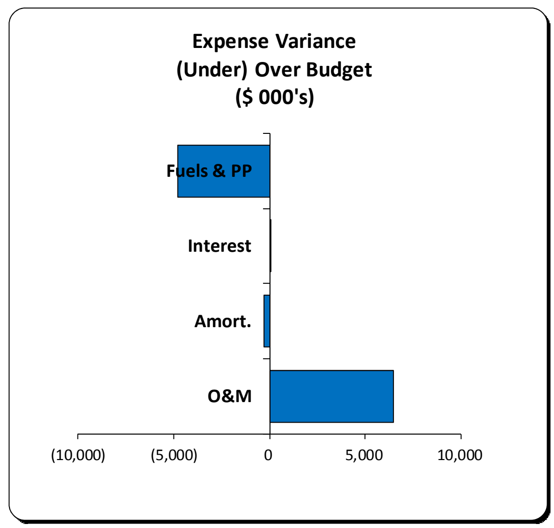
[1] Purchases before taxes.
[2] NUGS includes Frontier Power and Nalcor's wind/hydrogen facility in Ramea. Cost for 2012 is energy purchased from Frontier Power only.

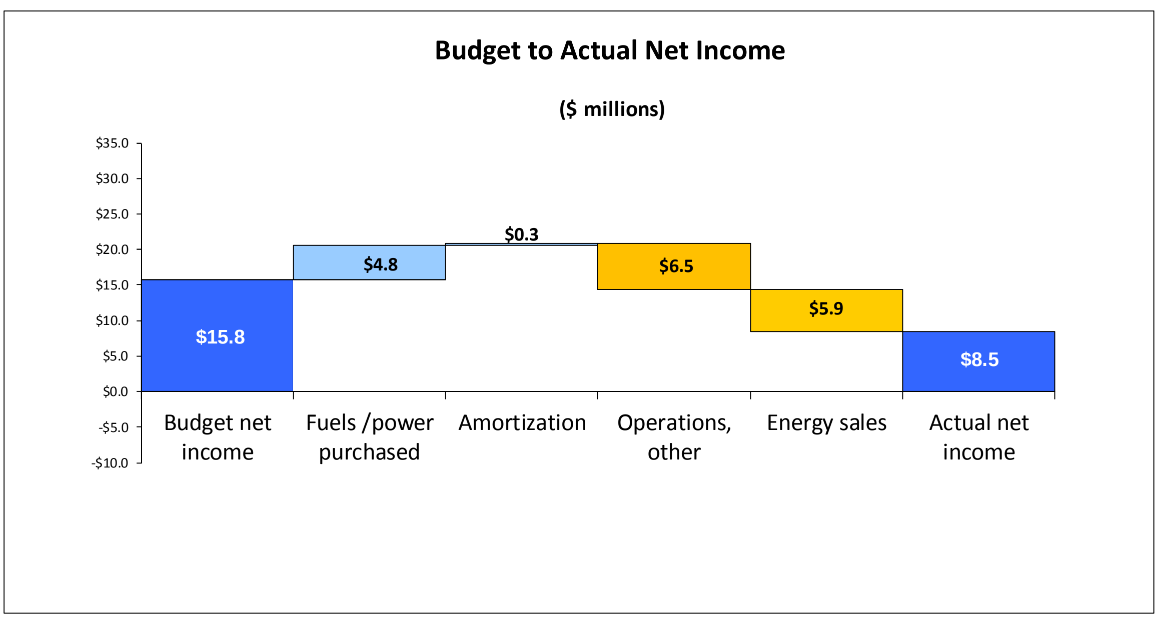
4.2 Financial

Below are charts of Hydro's (regulated) Statement of Income year to date. Please see Appendix C for the remainder of the financial statements.

Regulated Operations
For the three months ended March 31, 2013







Statement of Income - Regulated Operations
For the three months ended March 31, 2013
($ 000's)

First Quarter 2013 Actual	First Quarter 2013 Budget	First Quarter 2012 Actual		Year-to-date 2013 Actual	Year-to-date 2013 Budget	Year-to-date 2012 Actual	2013 Annual Budget
			Revenue				
165,503	171,449	163,482	Energy sales	165,503	171,449	163,482	535,619
634	518	649	Other revenue	634	518	649	2,072
166,137	171,967	164,131		166,137	171,967	164,131	537,691
			Expenses				
32,295	25,919	23,739	Operations	32,295	25,919	23,739	111,922
69	(9)	3	Loss (gain) on disposal of property, plant and equipment	69	(9)	3	1,601
73,551	77,815	72,872	Fuels	73,551	77,815	72,872	212,462
16,194	16,741	15,117	Power purchased	16,194	16,741	15,117	59,377
12,672	12,939	11,920	Amortization	12,672	12,939	11,920	55,118
22,815	22,808	22,811	Interest	22,815	22,808	22,811	91,039
157,596	156,213	146,462		157,596	156,213	146,462	531,519
8,541	15,754	17,669	**Net income**	8,541	15,754	17,669	6,172

Note : Certain of the 2012 comparative figures were restated to conform with the 2013 presentation.

4.3 Capital Expenditures

Capital Expenditures - Overview
For the Quarter ended March 31, 2013
($000)

	PU Board Approved Budget	First Quarter Actuals	Year To Date Actuals	Expected Remaining Expenditures
Generation	34,142	3,433	3,433	30,560
Transmission and Rural Operations	37,195	4,330	4,330	32,783
General Properties	7,768	145	145	7,609
Allowance for Unforeseen Events	1,000	-	-	1,000
Projects Approved by PU Board Order	5,689	2,687	2,687	3,594
New Projects Under $50,000 Approved by Hydro	61	61	61	-
Total 2013 Capital Budget	85,855	10,656	10,656	75,546
2013 FEED costs for 2014 projects[1]	-	110	110	-
Total 2013 Capital plus 2014 FEED	85,855	10,766	10,766	75,546

[1] These costs represent Front End Engineering and Design (FEED) costs incurred in 2013 related to 2014 capital projects.

2013 Capital Budget Approved by Board Order No. P.U. 4 (2013)	$62,272
Carryover Projects 2012 to 2013	19,501
New Project Approved by Board Order No. P.U. 25 (2012)	2,252
New Project Approved by Board Order No. P.U. 26 (2012)	1,295
New Project Approved by Board Order No. P.U. 35 (2012)	190
New Project Approved by Board Order No. P.U. 1 (2013)	284
2013 New Projects Under $50,000 approved by Hydro	61
Total Approved Capital Budget	$85,855

5 OTHER ITEMS

5.1 Significant Issues

5.1.1 Ramea Wind-Hydrogen-Diesel Project Update

Overall Project Site Showing (l-r) the Diesel Plant/Storage Tanks, Meteorological Tower, Hydrogen Electrolyser, 3 Hydrogen Storage Tanks, Distribution Box Structure, 3 Wind Turbines, and Quonset Hut Housing the Hydrogen Genset.

In accordance with Order No. P.U. 31 (2007), the following update is provided on the Wind-Hydrogen-Diesel Project for Ramea.

Implementation and Operation
Some project deficiencies remained in this quarter and project close-out is deferred to resolve reliability problems with the Hydrogen Genset and to address those project deficiencies.

Capital Costs

($000)

Actual Cost to March 2013	Actual Cost Recoveries to March 2013	Net Cost to March 2013	Budget to December 2008	Budget Reforecast to September 2010[1]
11,869	**11,869**	**0**	**8,794**	**2,486**

Operating Costs
There is nothing to report for this period as operation is planned to start in the third quarter 2013.

Reliability and Safety Issues
There is nothing to report for this period.

[1] Project Change Order #3 is under draft to reflect various cost increases and schedule delays associated with incomplete commissioning activities, H_2 Genset issues and project deficiencies.

5.1.2 Severe Weather causes a Loss of Generation at Holyrood

On January 10 and 11, a severe snow storm hit the province, bringing more than 50 cm of snow to some areas with winds up to 120 kilometers per hour; this caused a number of protection trips on the provincial electricity system and in particular a major interruption to production at the Holyrood Thermal Generating Station due to trouble within the station's switchyard. Tens of thousands of residents were left without power due to the loss of generation. Hydro's crews responded quickly and safely to restore generation at Holyrood. The severe weather made it difficult for terminal station crews to reach the site and perform the necessary work to restore power generation and this impacted the time to restore the plant. Hydro experienced no significant damage to the transmission system and once crews were onsite, the process of restoring power was quickly underway. The total loss of power to the station resulted in additional time to safely bring the generation back to service. Sufficient generation was brought into service in the early morning of January 12.

During the storm, Unit 1 at Holyrood sustained damage and was removed from service.

5.1.3 Voltage Conversion Project in Labrador City

This project includes energizing the new Quartzite substation and establishing a 25 kilovolt (KV) line to Labrador City's new hospital which is due to be completed by May 2013.

The new Quartzite substation, paired with the Vanier substation, will replace the existing five stations that currently supply the town. The new voltage and system upgrade will provide a more reliable and stable power supply to the community.

Employees from across Hydro worked together to start work on the Labrador City voltage conversion project in mid-December 2012.

5.2 Community

5.2.1 A Wave of Pink for a Good Cause

For a second consecutive year, Hydro employees participated in the Bust a Move fundraising event, which took place in March 23. Employees committed to raising $5,000 for the cause, which go towards tools for cancer care, diagnostic imaging and research for breast health in Newfoundland and Labrador. The company matched the donations raised by employees with a $1,500 donation.

5.2.2 Bishop's Falls Supports a Good Cause with a Dessert Fundraiser

On March 15, Hydro's Bishop's Falls' employees came together for a dessert-day fundraiser. The team dressed in green and encouraged donations in exchange for St. Patrick's Day treats. The group raised $600, which was donated to Ronald McDonald House Newfoundland and Labrador.

Employees in Bishop's Falls dressed in green for their first dessert day.

5.2.3 Hydro Donates Used Office Supplies to Habitat for Humanity

In March, Hydro's Supply Chain donated used office materials, cubicles, desks and chairs from Hydro Place to Habitat for Humanity. Habitat for Humanity collected the donations at Hydro Place and brought them to their Restore for sale. The money that Habitat for Humanity receives from the sale of the used furniture will help complete their ongoing housing projects in the province.

Rob Joyce, employee of Habitat for Humanity, and Nicholas Gale, Supervisor of Hydro Place Operations and Transportation, load Habitat for Humanity truck with old office supplies from Hydro Place.

5.3 Statement of Energy Sold

Statement of Energy Sold (GWh)
For the Quarter ended March 31

	YEAR TO DATE 2013 ACTUAL	YEAR TO DATE 2012 ACTUAL	YEAR TO DATE 2013 YTD BUDGET	2013[1] ANNUAL BUDGET	YTD % CHANGE
Island Interconnected					
Newfoundland Power	1,884	1,863	1,946	5,691	1.1%
Island Industrials	88	104	108	446	-15.4%
Rural					
Domestic	84	84	80	248	0.0%
General Service	48	45	42	159	6.7%
Streetlighting	1	1	1	3	0.0%
Sub-total Rural	133	130	123	410	2.3%
Sub-Total Island Interconnected	2,105	2,097	2,177	6,547	0.4%
Island Isolated					
Domestic	2	2	2	6	0.0%
General Service	0	0	0	1	0.0%
Streetlighting	0	0	0	0	0.0%
Sub-Total Island Isolated	2	2	2	7	0.0%
Labrador Interconnected					
Labrador Industrials	64	71	110	374	-9.9%
CFB Goose Bay	0	1	0	0	-100.0%
Hydro Quebec (includes Menihek)	15	16	15	41	-6.3%
Export	288	310	222	1,283	-7.1%
Rural					
Domestic	116	122	119	300	-4.9%
General Service	86	89	89	263	-3.4%
Streetlighting	0	0	0	2	0.0%
Sub-total Rural	202	211	208	565	-4.3%
Sub-Total Lab. Interconnected	569	609	555	2,263	-6.6%
Labrador Isolated					
Domestic	7	7	6	23	0.0%
General Service	3	4	4	17	-25.0%
Streetlighting	0	0	0	0	0.0%
Sub-Total Labrador Isolated	10	11	10	40	-9.1%
L'Anse au Loup					
Domestic	5	5	5	15	0.0%
General Service	2	2	2	8	0.0%
Streetlighting	0	0	0	0	0.0%
Sub-Total L'Anse au Loup	7	7	7	23	0.0%
Total Energy Sold	2,693	2,726	2,751	8,880	-1.2%
Sales to Non-Regulated Customers[2]	367	396	347	1,698	-7.3%

[1] Rural GWh - Based on 2013 Budget, Fall 2012 Rural Load Forecast
Non-rural GWh - Based on 2013TY Wholesale Industrial Revenue Budget
[2] Included in Total Energy Sold

5.4 Customer Statistics

Customer Statistics
For the Quarter ended March 31

	FIRST QUARTER		ANNUAL	
	2013 ACTUAL	2012 ACTUAL	2013 Budget	2012 ACTUAL
Customers				
Rural	37,676	37,275	37,604	37,576
Industrial	6	5	7	6
CFB Goose Bay	1	1	0	1
Utility	1	1	1	1
Non-Regulated	3	3	3	3
Reading Days	29.4	29.9	N/A	30.0

APPENDICES

CIAC QUARTERLY ACTIVITY REPORT
For the Quarter ended March 31, 2013

TYPE OF SERVICE	CIAC'S QUOTED	CIAC'S OUTSTANDING PREVIOUS QTR.	TOTAL CIAC'S QUOTED	CIAC'S ACCEPTED	CIAC'S EXPIRED	TOTAL CIAC'S OUTSTANDING
Domestic						
Within Plan. Boundary	2	4	6	0	2	4
Outside Plan. Boundary	0	0	0	0	0	0
Sub-total	2	4	6	0	2	4
General Service	5	5	10	4	3	3
Total	7	9	16	4	5	7

The table above summarizes Contribution in Aid of Construction (CIAC) activity for this quarter. The table is divided into three sections, as follows:

- The first section outlines the type of service for which a CIAC has been calculated, either Domestic or General Service.

- The second section indicates the number of CIACs quoted during the quarter as well as the number of CIAC quotes that remained outstanding at the end of the previous quarter. This format facilitates a reconciliation of the total number of CIACs that were active during the quarter.

- The third section provides information as to the disposition of the total CIACs quoted. A CIAC is considered accepted when a customer indicates they wish to proceed with construction of the extension and has agreed to pay any charge that may be applicable. A CIAC is considered outdated after six months has elapsed and the customers have not indicated their intention to proceed with the extension. A quoted CIAC is outstanding if it is neither accepted nor outdated.

CIAC QUARTERLY ACTIVITY REPORT
For the Quarter ended March 31, 2013

DATE QUOTED	SERVICE LOCATION	CIAC NO.	CIAC AMOUNT ($)	ESTIMATED CONST. COST ($)	ACCEPTED
DOMESTIC - WITHIN RESIDENTIAL PLANNING BOUNDARIES					
March 22, 2013	St. Veronica's	971695	$ 300.00	$ 1,050.00	
March 27, 2013	St. Alban's	934314	$ 2,320.00	$ 3,045.00	
DOMESTIC - OUTSIDE RESIDENTIAL PLANNING BOUNDARIES					
Nil					
GENERAL SERVICE					
January 28, 2013	Rigolet	935678	$ 3,760.00	$ 18,865.00	
January 30, 2013	Hopedale	663793	$ 469.75	$ 31,599.75	Yes
February 7, 2013	Wabush	953818	$ 537.00	$ 14,185.00	
February 11, 2013	Postville	942122	$ 4,227.00	$ 20,030.00	
March 8, 2013	Wabush	969123	$ -	$ 9,564.00	Yes

CUSTOMER PROPERTY DAMAGE CLAIMS REPORT
For the Quarter ended March 31, 2013

Introduction

The Customer Property Damage Claims Report contains an overview of all damage claims activity summarized on a quarterly basis. The information contained in the report is broken down by cause as well as by the operating region where the claims originated.

The report is divided into four sections as follows:

1. The first section indicates the number of claims received during the quarter coupled with claims outstanding from the previous quarter.

2. The second section shows the number of claims for which the Company has accepted responsibility and the amount paid to claimants versus the amount originally claimed.

3. The third section shows the number of claims rejected and the dollar value associated with those claims.

4. The fourth section indicates those claims that remain outstanding at the end of the current quarter and the dollar value associated with such claims.

Definitions of Causes of Damage Claims

1. System Operations: Claims arising from system operations. Examples include normal reclosing or switching.

2. Power Interruptions: Claims arising from interruption of power supply. Examples include all scheduled or unscheduled interruptions.

3. Improper Workmanship: Claims arising from failure of electrical equipment caused by improper workmanship or methods. Examples include improper crimping of connections, insufficient sealing and taping of connections, improper maintenance, inadequate clearance or improper operation of equipment.

4. Weather Related: Claims arising from weather conditions. Examples include wind, rain, ice, lighting or corrosion caused by weather.

5. Equipment Failure: Claims arising from failure of electrical equipment not caused by improper workmanship. Examples include broken neutrals, broken tie wires, transformer failure, insulator failure or broken service wire.

6. Third Party: Claims arising from equipment failure caused by acts of third parties. Examples include motor vehicle accidents and vandalism.

7. Miscellaneous: All claims not related to electrical service.

8. Waiting Investigation: Cause to be determined.

CUSTOMER PROPERTY DAMAGE CLAIMS REPORT - BY CAUSE

For the Quarter ended March 31, 2013

CAUSE	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	AMT. CLAIMED	AMT. PAID	#	AMOUNT	#	AMOUNT
System Operations	1	2	3	0	$ -	$ -	2	$ 500.00	1	$ 762.00
Power Interruptions	0	1	1	0	$ -	$ -	0	$ -	1	$ -
Improper Workmanship	1	6	7	3	$ 13,180.19	$ 12,094.37	1	$ 2,158.94	5	$ 3,540.72
Weather Related	17	9	26	4	$ 6,195.50	$ 2,579.37	16	$ 8,342.38	6	$ 7,264.67
Equipment Failure	1	7	8	0	$ -	$ -	2	$ 1,594.33	5	$ 17,564.00
Third Party	0	0	0	1	$ 48,000.00	$ 48,000.00	0	$ -	0	$ -
Miscellaneous	1	2	3	0	$ -	$ -	2	$ 3,106.00	1	$ -
Waiting Investigation	4	8	12	0	$ -	$ -	1	$ -	6	$ 16,265.00
Total	25	35	60	8	$ 67,375.69	$ 62,673.74	24	$ 15,701.65	25	$ 45,396.39

For the Quarter ended March 31, 2012

CAUSE	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	AMT. CLAIMED	AMT. PAID	#	AMOUNT	#	AMOUNT
System Operations	2	0	2	0	$ -	$ -	2	$ 750.00	0	$ -
Power Interruptions	1	0	1	0	$ -	$ -	1	$ 500.00	0	$ -
Improper Workmanship	2	8	10	3	$ 4,251.06	$ 4,251.06	0	$ -	7	$ 16,419.62
Weather Related	14	7	21	0	$ -	$ -	17	$ 6,765.90	4	$ 5,008.32
Equipment Failure	3	3	6	1	$ 1,325.68	$ 1,325.68	0	$ -	5	$ 19,161.06
Third Party	0	0	0	0	$ -	$ -	0	$ -	0	$ -
Miscellaneous	2	0	2	1	$ 560.42	$ 560.42	1	$ 161.53	0	$ -
Waiting Investigation	0	4	4	0	$ -	$ -	0	$ -	4	$ 13,221.77
Total	24	22	46	5	$ 6,137.16	$ 6,137.16	21	$ 8,177.43	20	$ 53,810.77

CUSTOMER PROPERTY DAMAGE CLAIMS REPORT - BY REGION

For the Quarter ended March 31, 2013

REGION	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	AMT. CLAIMED	AMT. PAID	#	AMOUNT	#	AMOUNT
Central Region	3	8	11	3	$ 49,545.50	$ 49,245.50	5	$ 4,435.56	2	$ 469.00
Northern Region	20	17	37	3	$ 5,444.37	$ 2,213.24	17	$ 10,766.09	15	$ 35,632.74
Labrador Region	2	10	12	2	$ 12,385.82	$ 11,215.00	2	$ 500.00	8	$ 9,294.65
Total	25	35	60	8	$ 67,375.69	$ 62,673.74	24	$ 15,701.65	25	$ 45,396.39

For the Quarter ended March 31, 2012

REGION	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	AMT. CLAIMED	AMT. PAID	#	AMOUNT	#	AMOUNT
Central Region	7	7	14	2	$ 3,787.99	$ 2,973.50	5	$ 1,300.00	7	$ 7,936.89
Northern Region	15	9	24	2	$ 1,886.10	$ 1,886.10	15	$ 6,627.43	7	$ 17,073.46
Labrador Region	2	6	8	1	$ 463.07	$ 463.07	1	$ 250.00	6	$ 28,800.42
Total	24	22	46	5	$ 6,137.16	$ 5,322.67	21	$ 8,177.43	20	$ 53,810.77

FINANCIAL – REGULATED

Balance Sheet - Regulated Operations
As at March 31
($ 000's)

	Mar-13	Mar-12
ASSETS		
Current assets		
Cash and cash equivalents	375	-
Trade and other receivables	76,679	81,978
Current portion of regulatory assets	2,157	2,581
Inventory	66,539	81,313
Prepayments	3,637	5,873
	149,387	171,745
Property, plant, and equipment	1,438,958	1,408,416
Sinking funds	267,100	246,793
Regulatory assets	62,520	63,143
Total assets	1,917,965	1,890,097
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Bank indebtedness	-	3,771
Trade and other payables	42,111	58,348
Accrued interest	17,454	17,454
Current portion of long-term debt	8,150	8,150
Current portion of regulatory liabilities	170,973	119,915
Deferred credit	1,914	4,941
Due to related parties	3,779	6,962
Promissory notes	32,410	41,184
	276,791	260,725
Long-term debt	1,124,448	1,130,182
Regulatory liabilities	53,959	53,352
Decommissioning liabilities	24,307	21,765
Employee benefit liability	58,908	53,860
Contributed capital	100,000	100,000
Shareholder's equity / retained earnings	239,715	230,593
Accumulated other comprehensive income	39,837	39,620
Total liabilities and shareholder's equity	1,917,965	1,890,097

Note: Certain of the 2012 comparative figures were restated to conform with the 2013 presentation.

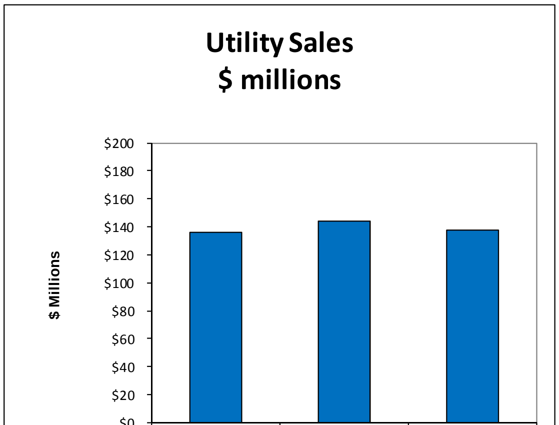
Statement of Retained Earnings - Regulated Operations
For the three months ended March 31, 2013
($ 000's)

First Quarter 2013 Actual	First Quarter 2012 Actual		Year-to-date 2013 Actual	Year-to-date 2012 Actual
231,174	212,096	Balance, beginning of period	231,174	212,096
-	828	Adjustment	-	828
8,541	17,669	Net income	8,541	17,669
239,715	230,593	Balance, end of period	239,715	230,593

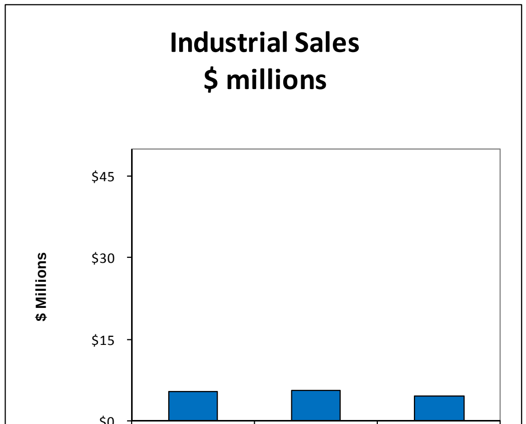
Statement of Comprehensive Income - Regulated Operations
For the three months ended March 31, 2013
($ 000's)

First Quarter 2013 Actual	First Quarter 2013 Budget	First Quarter 2012 Actual		Year-to-date 2013 Actual	Year-to-date 2013 Budget	Year-to-date 2012 Actual	2013 Annual Budget
8,541	15,754	17,669	Net income	8,541	15,754	17,669	6,172
			Other comprehensive loss				
(1,703)	-	(5,487)	Change in fair value of sinking fund investments	(1,703)	-	(5,487)	-
6,838	15,754	12,182	Total comprehensive income	6,838	15,754	12,182	6,172

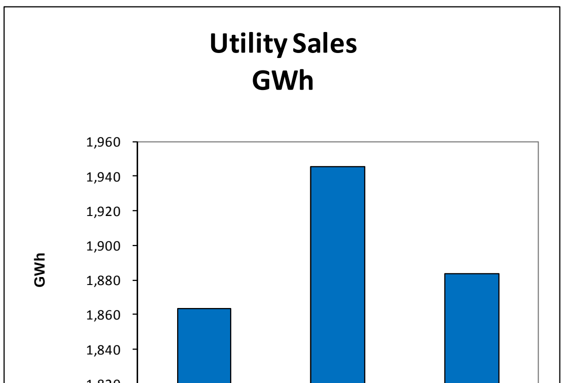
Sales - Regulated Operations
For the three months ended March 31, 2013



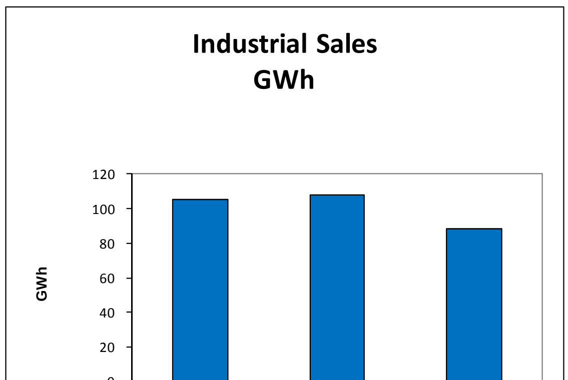
	Mar-12	Mar-13 B	Mar-13 A
NL Power	$135.8	$144.2	$138.0



	Mar-12	Mar-13 B	Mar-13 A
Industrial	$5.4	$5.7	$4.6



	Mar-12	Mar-13 B	Mar-13 A
NL Power	1,863.3	1,945.6	1,883.8



	Mar-12	Mar-13 B	Mar-13 A
Industrial	105.3	108.2	88.4

Revenue Summary - Regulated Operations
For the three months ended March 31, 2013
($ 000's)

First Quarter 2013 Actual	First Quarter 2013 Budget	First Quarter 2012 Actual		Year-to-date 2013 Actual	Year-to-date 2013 Budget	Year-to-date 2012 Actual	2013 Annual Budget
			REVENUE				
			Industrial				
1,117	1,368	1,433	Corner Brook Pulp and Paper Ltd.	1,117	1,368	1,433	6,644
12	437	-	Vale Inco	12	437	-	3,817
2,583	2,987	2,901	North Atlantic Refinery	2,583	2,987	2,901	13,390
3	-	111	C.F.B. Goose Bay	3	-	111	-
918	935	923	Teck Cominco Limited	918	935	923	4,337
-	-	-	Praxair	-	-	-	760
4,633	5,727	5,368	**Total Industrial**	4,633	5,727	5,368	28,948
			Utility				
137,980	144,172	135,843	Newfoundland Power Inc.	137,980	144,172	135,843	430,447
			Rural				
22,890	21,550	22,271	Interconnected and diesel	22,890	21,550	22,271	76,224
634	518	649	**Other**	634	518	649	2,072
166,137	171,967	164,131	**Total**	166,137	171,967	164,131	537,691
			ENERGY SALES (GWh)				
			Industrial				
17.1	22.3	24.1	Corner Brook Pulp and Paper Ltd.	17.1	22.3	24.1	87.9
0.2	4.4	-	Vale Inco	0.2	4.4	-	39.6
52.6	62.5	61.3	North Atlantic Refinery	52.6	62.5	61.3	238.4
-	-	1.3	C.F.B. Goose Bay	-	-	1.3	-
18.5	19.0	18.6	Teck Cominco Limited	18.5	19.0	18.6	74.0
-	-	-	Praxair	-	-	-	6.5
88.4	108.2	105.3	**Total Industrial**	88.4	108.2	105.3	446.4
			Utility				
1,883.8	1,945.6	1,863.3	Newfoundland Power Inc.	1,883.8	1,945.6	1,863.3	5,691.0
			Rural				
355.5	349.9	361.2	Interconnected and diesel	355.5	349.9	361.2	1,044.7
2,327.7	2,403.7	2,329.8	**Total**	2,327.7	2,403.7	2,329.8	7,182.1

Note: Certain of the 2012 comparative figures were restated to conform with the 2013 presentation.

Statement of Cash Flows - Regulated Operations
For the three months ended March 31, 2013
($ 000's)

	Year-to-date 2013	Year-to-date 2012
Operating activities		
Net income	8,541	17,669
Adjusted for items not involving cash flow		
Amortization	12,765	11,971
Amortization of deferred contributions	-	(52)
Accretion of long-term debt	130	120
Employee benefits	2,018	1,289
Loss on disposal of property, plant and equipment	100	-
	23,554	30,997
Changes in non-cash balances		
Trade and other receivables	3,506	(2,619)
Inventory	(14,866)	(27,055)
Prepayments	(688)	(3,589)
Regulatory assets	304	635
Regulatory liabilities	22,773	2,403
Trade and other payables	2,812	9,007
Accrued interest	(11,213)	(11,213)
Due to related parties	1,906	(42,296)
	28,088	(43,730)
Financing activities		
Decrease in long-term receivable	188	210
Decrease (increase) in deferred credit	(24)	140
(Decrease) increase in promissory notes	(12,373)	46,295
	(12,209)	46,645
Investing activities		
Additions to property, plant and equipment	(10,928)	(6,577)
Increase in sinking funds	(7,056)	(6,794)
	(17,984)	(13,371)
Net decrease in cash	(2,105)	(10,456)
Cash position, beginning of period	2,480	6,685
Cash position, end of period	375	(3,771)

Note: Certain of the 2012 comparative figures were restated to conform with the 2013 presentation.

FINANCIAL - NON-REGULATED

Balance Sheet - Non-Regulated Activities
As at March 31
($ 000's)

	Mar-13	Mar-12
ASSETS		
Current assets		
Trade and other receivables	3,335	2,502
	3,335	2,502
Long-term receivable	-	1,312
Investment in CF(L)Co.	433,347	417,489
Total assets	436,682	421,303
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Trade and other payables	1,830	1,892
Promissory notes	7,590	6,816
Derivative liabilities	202	78
	9,622	8,786
Long-term note payable	-	1,312
Share capital	22,504	22,504
Lower Churchill Development Corp	15,400	15,400
Retained earnings	389,853	374,709
Accumulated other comprehensive income (loss)	(697)	(1,408)
Total liabilities and shareholder's equity	436,682	421,303

Note: Certain of the 2012 comparative figures were restated to conform with the 2013 presentation.

Statement of Income - Non-Regulated Activities
For the three months ended March 31, 2013
($ 000's)

First Quarter 2013 Actual	First Quarter 2013 Budget	First Quarter 2012 Actual		Year-to-date 2013 Actual	Year-to-date 2013 Budget	Year-to-date 2012 Actual	2013 Annual Budget
			Revenue				
16,244	13,063	11,370	Energy sales	16,244	13,063	11,370	65,822
16,244	13,063	11,370		16,244	13,063	11,370	65,822
			Expenses				
7,917	6,418	6,237	Operations	7,917	6,418	6,237	26,550
1,798	892	1,892	Power purchased	1,798	892	1,892	5,032
230	-	47	Other income and expense	230	-	47	-
(163)	-	100	Interest	(163)	-	100	-
9,782	7,310	8,276		9,782	7,310	8,276	31,582
6,462	5,753	3,094	Net operating income	6,462	5,753	3,094	34,240
15,850	13,894	18,482	Equity in CF(L)Co	15,850	13,894	18,482	15,460
3,017	2,212	2,814	Preferred dividends	3,017	2,212	2,814	8,847
18,867	16,106	21,296		18,867	16,106	21,296	24,307
25,329	21,859	24,390	**Net income**	25,329	21,859	24,390	58,547

Note : Certain of the 2012 comparative figures were restated to conform with the 2013 presentation.

Statement of Retained Earnings - Non-Regulated Activities
For the three months ended March 31, 2013
($ 000's)

First Quarter 2013 Actual	First Quarter 2012 Actual		Year-to-date 2013 Actual	Year-to-date 2012 Actual
373,578	356,645	Balance, beginning of period	373,578	356,645
0	1,267	Adjustments	-	1,267
25,329	24,390	Net income	25,329	24,390
(9,054)	(7,593)	Dividends	(9,054)	(7,593)
389,853	374,709	Balance, end of period	389,853	374,709

Statement of Comprehensive Income - Non-Regulated Activities
For the three months ended March 31, 2013
($ 000's)

First Quarter 2013 Actual	First Quarter 2013 Budget	First Quarter 2012 Actual		Year-to-date 2013 Actual	Year-to-date 2013 Budget	Year-to-date 2012 Actual	2013 Annual Budget
25,329	21,859	24,390	Net income	25,329	21,859	24,390	58,547
			Other comprehensive loss				
-	-	-	Change in fair value of derivative instruments	-	-	-	-
(785)	-	(98)	Share of CF(L)Co other comprehensive income (loss)	(785)	-	(98)	-
24,544	21,859	24,292	Total comprehensive income	24,544	21,859	24,292	58,547

Statement of Cash Flows - Non-Regulated Activities
For the three months ended March 31, 2013
($ 000's)

	Year-to-date 2013	Year-to-date 2012
Operating activities		
Net income	25,329	24,390
Adjusted for items not involving cash flow		
Unrealized loss on derivatives	230	264
Equity in CF(L)Co	(16,637)	(18,482)
	8,922	6,172
Changes in non-cash balances		
Trade and other receivables	153	1,189
Trade and other payables	(394)	(1,566)
	8,681	5,795
Financing activities		
Increase in promissory notes	373	1,705
Decrease in long-term receivable	-	87
Increase in long-term note payable	-	6
Dividends	(9,054)	(7,593)
	(8,681)	(5,795)
Net change in cash	-	-
Cash position, beginning of period	-	-
Cash position, end of period	-	-

Note: Certain of the 2012 comparative figures were restated to conform with the 2013 presentation.

Supplementary Schedule - Regulated Operations
For the three months ended March 31, 2013
($ 000's)

First Quarter 2013 Actual	First Quarter 2013 Budget	First Quarter 2012 Actual		Year-to-date 2013 Actual	Year-to-date 2013 Budget	Year-to-date 2012 Actual	2013 Annual Budget
			Other revenue				
174	149	237	Sundry	174	149	237	595
402	344	399	Pole attachments	402	344	399	1,375
58	25	13	Supplier's discount	58	25	13	102
634	518	649	**Total other revenue**	634	518	649	2,072
			Interest				
27,571	27,818	27,023	Gross interest	27,571	27,818	27,023	112,806
130	130	120	Accretion of long-term debt	130	130	120	540
539	551	539	Amortization of foreign exchange losses	539	551	539	2,157
(656)	(431)	(432)	Allowance for funds used during construction	(656)	(431)	(432)	(2,747)
(4,769)	(5,260)	(4,439)	Interest earned	(4,769)	(5,260)	(4,439)	(21,717)
22,815	22,808	22,811	**Total interest**	22,815	22,808	22,811	91,039

Note: Certain of the 2012 comparative figures were restated to conform with the 2013 presentation.

Cost Recoveries - Regulated Operations
For the three months ended March 31, 2013
($ 000's)

First Quarter 2013 Actual	First Quarter 2013 Budget	First Quarter 2012 Actual		Year-to-date 2013 Actual	Year-to-date 2013 Budget	Year-to-date 2012 Actual	2013 Annual Budget
2	3	4	Executive Leadership	2	3	4	14
240	288	200	Human Resources and Organizational Effectiveness	240	288	200	1,157
1,270	1,312	1,204	Finance / CFO	1,270	1,312	1,204	5,286
5	2	30	Engineering Services	5	2	30	8
30	29	25	Regulated Operations	30	29	25	115
1,547	1,634	1,463		1,547	1,634	1,463	6,580

Newfoundland and Labrador Hydro
Rate Stabilization Plan
March 31, 2013

Rate Stabilization Plan Report
March 31, 2013

Summary of Key Facts

The Rate Stabilization Plan of Newfoundland and Labrador Hydro (Hydro), as amended by Board Order No. P.U. 40 (2003) and Order No. P.U. 8 (2007), is established for Hydro's utility customer, Newfoundland Power, and Island Industrial customers to smooth rate impacts for variations between actual results and Test Year Cost of Service estimates for:

- Hydraulic production;
- No. 6 fuel cost used at Hydro's Holyrood generating station;
- Customer load (Utility and Island Industrial); and
- Rural rates.

The Test Year Cost of Service Study was approved by Board Order No. P.U. 8 (2007) and is based on projections of events and costs that are forecast to happen during a test year. Finance charges are calculated on the balances using the test year Weighted Average Cost of Capital which is currently 7.529% per annum. Holyrood's operating efficiency is set, for RSP purposes, at 630 kWh/barrel regardless of the actual conversion rate experienced.

	2007 Test Year Cost of Service			
	Net Hydraulic Production	No. 6 Fuel Cost	Utility Load	Industrial Load
	(kWh)	($Can/bbl.)	(kWh)	(kWh)
January	427,100,000	54.17	574,800,000	78,300,000
February	388,680,000	54.73	518,600,000	70,900,000
March	415,080,000	55.46	524,700,000	76,600,000
April	355,520,000	55.46	429,200,000	75,600,000
May	324,240,000	55.46	358,700,000	69,500,000
June	328,500,000	54.49	298,400,000	73,800,000
July	386,790,000	54.49	293,400,000	77,500,000
August	379,140,000	54.49	287,000,000	77,900,000
September	363,560,000	54.49	297,700,000	73,000,000
October	340,510,000	54.56	360,200,000	74,400,000
November	364,390,000	54.56	439,300,000	74,100,000
December	398,560,000	58.98	543,800,000	72,700,000
Total	4,472,070,000		4,925,800,000	894,300,000

Rate Stabilization Plan
Plan Highlights
March 31, 2013

	Actual	Cost of Service	Variance	Year-to-Date Due (To) From customers	Reference
Hydraulic production year-to-date	1,462.1 GWh	1,230.9 GWh	231.2 GWh	$ (20,035,423)	Page 4
No 6 fuel cost - Current month	$ 111.07	$ 55.46	$ 55.61	$ 39,520,844	Page 5
Year-to-date customer load - Utility	1,883.8 GWh	1,618.1 GWh	265.7 GWh	$ (385,057)	Page 8
Year-to-date customer load - Industrial	88.4 GWh	225.8 GWh	-137.4 GWh	$ (6,895,260)	Page 9
				$ 12,205,104	

Rural rates		
Rural Rate Alteration (RRA) [1]	$ (2,773,253)	
Less : RRA to utility customer	$ (2,470,968)	Page 10
RRA to Labrador interconnected	(302,285)	
Fuel variance to Labrador interconnected	$ 308,945	Page 6
Net Labrador interconnected	$ 6,660	

Current plan summary [2]		
One year recovery		
Due (to) from utility customer [2]	$ (61,498,387)	Page 10
Due (to) from Industrial customers [2]	$ (109,475,008)	Page 11
Sub total	(170,973,395)	
Four year recovery		
Hydraulic balance	$ (53,469,728)	Page 4
Total plan balance	$ (224,443,123)	

(1) Beginning January 2011, the RRA includes a monthly credit of $98,295. This amount relates to the phase in of the application of the credit from secondary energy sales to CFB Goose Bay to the Rural deficit as stated in Section B, Clause 1.3(b) of the approved Rate Stabilization Plan Regulations which received final approval in Order No. P.U. 33 (2010) issued December 15, 2010.

(2) Disposition of the load variation is one of the issues to be considered by the Public Utilities Board in a pending hearing. This may impact the balances owing to customers in the current plan.

Rate Stabilization Plan
Net Hydraulic Production Variation
March 31, 2013

	A	B	C	D	E	F	G
	Cost of Service Net Hydraulic Production (kWh)	Actual Net Hydraulic Production (kWh)	Monthly Net Hydraulic Production Variance (kWh) **(A - B)**	Cost of Service No. 6 Fuel Cost ($Can/bbl.)	Net Hydraulic Production Variation ($) **(C / O[1] X D)**	Financing Charges ($)	Cumulative Variation and Financing Charges ($) **(E + F)** **(to page 12)**
Opening balance							(32,675,763)
January	427,100,000	537,465,293	(110,365,293)	54.17	(9,489,663)	(198,260)	(42,363,686)
February	388,680,000	473,366,259	(84,686,259)	54.73	(7,356,951)	(257,042)	(49,977,679)
March	415,080,000	451,303,396	(36,223,396)	55.46	(3,188,809)	(303,240)	(53,469,728)
April							
May							
June							
July							
August							
September							
October							
November							
December							
	1,230,860,000	1,462,134,948	(231,274,948)		(20,035,423)	(758,542)	(53,469,728)
Hydraulic Allocation [2]							
Hydraulic variation at year end					(20,035,423)	(758,542.00)	(53,469,728)

(1) O is the Holyrood Operating Efficiency of 630 kWh/barrel.

(2) At year end 25% of the hydraulic variation balance and 100% of the annual financing charges are allocated to customers.

Rate Stabilization Plan
No. 6 Fuel Variation
March 31, 2013

	A	B	C	D	E	F	G
	Actual Quantity No. 6 Fuel	Actual Quantity No. 6 Fuel for Non-Firm Sales	Net Quantity No. 6 Fuel	Cost of Service No. 6 Fuel Cost	Actual Average No. 6 Fuel Cost	Cost Variance	No.6 Fuel Variation
	(bbl.)	(bbl.)	(bbl.) **(A - B)**	($Can/bbl.)	($Can/bbl.)	($Can/bbl.) **(E - D)**	($) **(C X F)** **(to page 6)**
January	297,603	0	297,603	54.17	105.89	51.72	15,392,012
February	242,076	6	242,070	54.73	108.00	53.27	12,895,076
March	202,010	0	202,010	55.46	111.07	55.61	11,233,756
April							
May							
June							
July							
August							
September							
October							
November							
December							
	741,688	6	741,682				39,520,844

Rate Stabilization Plan
Allocation of Fuel Variance - Year-to-Date
March 31, 2013

	A	B	C	D	E	F	G	H	I	J
	Twelve Months-to-Date				Year-to-Date Fuel Variance				Reallocate Rural Island Customers (1)	
	Utility	Industrial Customers	Rural Island Customers	Total	Utility	Industrial Customers	Rural Island Interconnected	Total	Utility	Labrador Interconnected
	(kWh)	(kWh)	(kWh)	(kWh)	($)	($)	($)	($)	($)	($)
				(A+B+C)	**(A/D X H)**	**(B/D X H)**	**(C/D X H)**		**(G X 89.10%)**	**(G X 10.90%)**
					(to page 7)			**(from page 5)**	**(to page 7)**	
January	5,417,867,263	408,268,165	449,267,696	6,275,403,124	13,288,689	1,001,381	1,101,942	15,392,012	981,830	120,112
February	5,419,401,011	401,459,126	448,779,138	6,269,639,275	24,451,020	1,811,286	2,024,782	28,287,088	1,804,081	220,701
March	5,379,834,205	394,061,387	446,084,468	6,219,980,060	34,182,680	2,503,808	2,834,356	39,520,844	2,525,411	308,945
April										
May										
June										
July										
August										
September										
October										
November										
December										

(1) The Fuel Variance initially allocated to Rural Island Interconnected is re-allocated between Utility and Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the approved Cost of Service Study, which is 89.10% and 10.90% respectively. The Labrador Interconnected amount is then removed from the plan and written off to net income (loss).

Rate Stabilization Plan
Allocation of Fuel Variance - Monthly
March 31, 2013

	A	B	C	D	E	F	G
	Utility					**Industrial**	
	Fuel Variance		Rural Allocation		Total Fuel Variance	Fuel Variance	
	Year-to-Date Activity	Current Month Activity (1)	Year-to-Date Activity	Current Month Activity (1)	Activity for the month	Year-to-Date Activity	Current Month Activity (1)
	($)	($)	($)	($)	($)	($)	($)
					(B + D)		
	(from page 6)		**(from page 6)**		**(to page 10)**	**(from page 6)**	**(to page 11)**
January	13,288,689	13,288,689	981,830	981,830	14,270,519	1,001,381	1,001,381
February	24,451,020	11,162,331	1,804,081	822,251	11,984,582	1,811,286	809,905
March	34,182,680	9,731,660	2,525,411	721,330	10,452,990	2,503,808	692,522
April							
May							
June							
July							
August							
September							
October							
November							
December							
		34,182,680		2,525,411	36,708,091		2,503,808

(1) The current month activity is calculated by subtracting year-to-date activity for the prior month from year-to-date activity for the current month.

Rate Stabilization Plan
Load Variation - Utility
March 31, 2013

	A	B	C	D	E	F	G	H	I	J	K
	Firm Energy						Secondary Energy				
	Cost of Service Sales	Actual Sales	Sales Variance	Cost of Service No. 6 Fuel Cost	Firm Energy Rate	Load Variation	Cost of Service Sales	Actual Sales	Firming Up Charge	Load Variation	Total Load Variation
	(kWh)	(kWh)	(kWh)	($Can/bbl.)	($/kWh)	($)	(kWh)	(kWh)	($/kWh)	($)	($)
			(B - A)			**C x {(D/O[1]) - E}**				**(G - H) x I**	**(F + J)**
											(to page 10)
January	574,800,000	702,723,435	127,923,435	54.17	0.08805	(264,274)	0	1,099,493	0.00841	(9,247)	(273,521)
February	518,600,000	606,876,717	88,276,717	54.73	0.08805	(103,900)	0	429,853	0.00841	(3,615)	(107,515)
March	524,700,000	572,269,039	47,569,039	55.46	0.08805	(868)	0	374,966	0.00841	(3,153)	(4,021)
April											
May											
June											
July											
August											
September											
October											
November											
December											
	1,618,100,000	1,881,869,191	263,769,191			(369,042)	0	1,904,312		(16,015)	(385,057)

(1) O is the Holyrood Operating Efficiency of 630 kWh/barrel.

Rate Stabilization Plan
Load Variation - Industrial
March 31, 2013

	A	B	C	D	E	F
	Cost of Service Sales	Actual Sales	Sales Variance	Cost of Service No. 6 Fuel Cost	Firm Energy Rate	Load Variation
	(kWh)	(kWh)	(kWh)	($)	($/kWh)	($)
			(B - A)			**C x {(D/O[1]) - E}**
						(to page 11)
January	78,300,000	31,612,740	(46,687,260)	54.17	0.03676	(2,298,140)
February	70,900,000	25,864,750	(45,035,250)	54.73	0.03676	(2,256,852)
March	76,600,000	30,955,597	(45,644,403)	55.46	0.03676	(2,340,268)
April						
May						
June						
July						
August						
September						
October						
November						
December						
	225,800,000	88,433,087	(137,366,913)			(6,895,260)

(1) O is the Holyrood Operating Efficiency of 630 kWh/barrel.

Rate Stabilization Plan
Summary of Utility Customer
March 31, 2013

	A	B	C	D	E	F	G
	Load Variation	Allocation Fuel Variance	Allocation Rural Rate Alteration [1]	Subtotal Monthly Variances	Financing Charges	Adjustment [2]	Cumulative Net Balance
	($)	($)	($)	($)	($)	($)	($)
				(A + B + C)			
	(from page 8)	**(from page 7)**					**(to page 12)**
Opening Balance							(64,905,401)
January	(273,521)	14,270,519	(849,811)	13,147,187	(393,814)	(10,944,447)	(63,096,475)
February	(107,515)	11,984,582	(877,767)	10,999,300	(382,838)	(9,443,617)	(61,923,630)
March	(4,021)	10,452,990	(743,390)	9,705,579	(375,722)	(8,904,614)	(61,498,387)
April							
May							
June							
July							
August							
September							
October							
November							
December							
Year to date	(385,057)	36,708,091	(2,470,968)	33,852,066	(1,152,374)	(29,292,678)	3,407,014
Hydraulic allocation **(from page 4)**							0
Total	(385,057)	36,708,091	(2,470,968)	33,852,066	(1,152,374)	(29,292,678)	(61,498,387)

(1) The Rural Rate Alteration is allocated between Utility and Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the approved Cost of Service Study, which is 89.10% and 10.90% respectively. The Labrador Interconnected amount is then removed from the plan and written off to net income (loss).

(2) The RSP adjustment rate for Utility is 1.555 cents per kwh effective July 1, 2012 to June 30, 2013.

Rate Stabilization Plan
Summary of Industrial Customers
March 31, 2013

	A	B	C	D	E	F
	Load Variation	Allocation Fuel Variance	Subtotal Monthly Variances	Financing Charges	Adjustment [1]	Cumulative Net Balance
	($)	($)	($)	($)	($)	($)
			(A + B)			
	(from page 9)	**(from page 7)**				**(to page 12)**
Opening Balance						(104,079,983) [2]
January	(2,298,140)	1,001,381	(1,296,759)	(631,505)	323,546	(105,684,701)
February	(2,256,852)	809,905	(1,446,947)	(641,242)	275,249	(107,497,641)
March	(2,340,268)	692,522	(1,647,746)	(652,242)	322,621	(109,475,008)
April						
May						
June						
July						
August						
September						
October						
November						
December						
Year to date	(6,895,260)	2,503,808	(4,391,452)	(1,924,989)	921,416	(5,395,025)
Hydraulic allocation **(from page 4)**						0
Total	(6,895,260)	2,503,808	(4,391,452)	(1,924,989)	921,416	(109,475,008)

(1) The RSP adjustment rate for Industrial Customers excluding Teck Resources and Vale is 0.785 cents per kWh effective January 1, 2008. The rate for Teck Resources and Vale is 2.000 cents per kWh.

Rate Stabilization Plan
Overall Summary
March 31, 2013

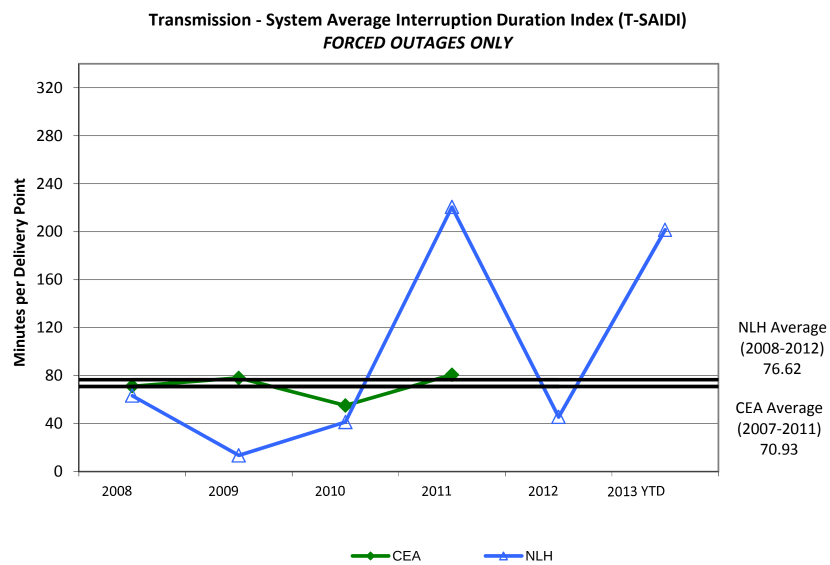
	A	B	C	D
	Hydraulic Balance	Utility Balance	Industrial Balance	Total To Date
	($)	($)	($)	($)
				(A + B + C)
	(from page 4)	**(from page 10)**	**(from page 11)**	
Opening Balance	(32,675,763)	(64,905,401)	(104,079,983)	(201,661,147)
January	(42,363,686)	(63,096,475)	(105,684,701)	(211,144,862)
February	(49,977,679)	(61,923,630)	(107,497,641)	(219,398,950)
March	(53,469,728)	(61,498,387)	(109,475,008)	(224,443,123)
April				
May				
June				
July				
August				
September				
October				
November				
December				

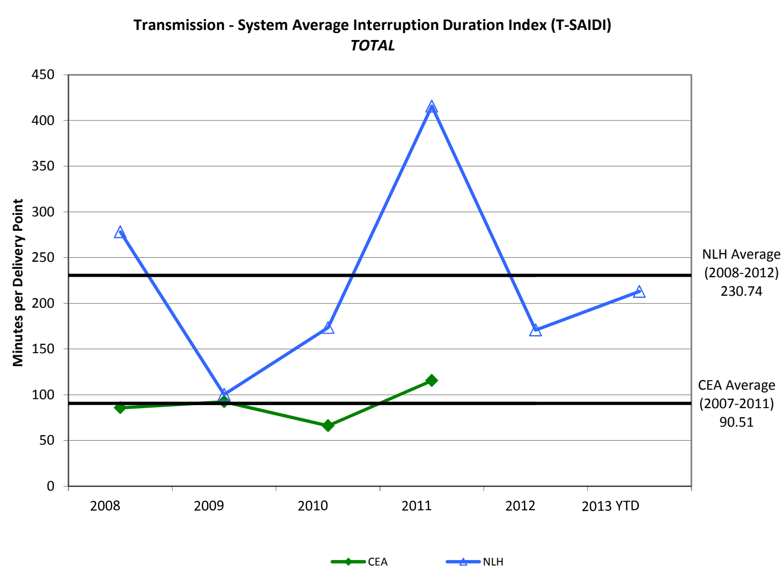
Performance Indices

Bulk Power System Delivery Point Interruption Performance

a) Transmission System Average Interruption Duration Index (T-SAIDI) - *a reliability KPI for bulk transmission assets which measures the average duration of outages in minutes per delivery point.*

The first quarter T-SAIDI was 213.0 minutes per delivery point (forced and planned combined) compared to 9.0 minutes per delivery point for the same quarter last year, a very significant increase. The forced component was 201.6 minutes per delivery point, compared to 3.6 minutes per delivery point in 2012. The planned component was 11.4 minutes per delivery point compared to 5.4 minutes per delivery point in 2012, an increase of 111%.





There were a multiple number of significant forced outages and two planned outages in this quarter. A summary of the forced and notable planned outages follows:

Forced

On January 11, there was a major system event affecting Delivery Points (DP's) in all regions of the Island Interconnected System. It is summarized as follows:

A severe winter blizzard resulted in Island wide power outages and significant customer impact. The events started early in the morning at the Holyrood Terminal Station, where the high winds and heavy, salt contaminated, snow created electrical faults and significant disturbances. By 06:48 hours, there was a loss of all three generating units at the Holyrood Thermal Generating Station and trips and lockouts of the 138 KV and 230 KV busses. This effectively isolated the Holyrood generating and terminal stations from the remainder of the grid. There was a significant customer impact, primarily to customers on the Avalon Peninsula. The station service supply into the plant was interrupted and could not be re-established until personnel arrived at site to reset lockout relays. This occurred at approximately 15:00 hours. To date, Unit 1 remains out of service and requires a major refurbishment.

Approximately one hour following the loss of the Holyrood generating and terminal stations (at 07:42 hours), there was a trip of the only remaining 230 kV transmission line from Western Avalon to the major load centers in St. John’s and surrounding area. With the separation of the east/west power systems and loss of supply to the eastern Avalon, there was severe instability in the Central and Western areas, resulting in the loss of multiple generating stations and transmission lines. The customer impact had then spread to be island wide with only a few smaller regions still with power.

The line from Western Avalon tripped again approximately one hour and ten minutes later (at 08:51 hours), resulting in additional customer outages and reversing much of the restoration effort that had taken place up to that time.

The following table outlines the delivery point customer interruptions.

Events on January 11, 2013

Delivery Point Affected	Start Time	Finish Time	Duration of Interruptions (mins)	MW Load	MW-Mins
Deer Lake Power - TL225	1/11/2013 7:43	1/11/2013 11:52	249	0.0	0.0
Deer Lake - NP	1/11/2013 7:43	1/11/2013 11:43	240	12.7	3,040.8
Port Aux Basques	1/11/2013 7:43	1/11/2013 11:20	217	15.7	3,415.6
Doyles	1/11/2013 7:43	1/11/2013 11:20	217	3.9	855.0
Grandy Brook	1/11/2013 7:43	1/11/2013 12:07	264	3.7	976.8
Bottom Brook - 400L	1/11/2013 7:43	1/11/2013 12:07	171	0.0	0.0
Stephenville	1/11/2013 7:43	1/11/2013 10:34	171	34.4	5,877.3
Massey Drive Bus B3 (1)	1/11/2013 7:43	1/11/2013 8:01	18	65.3	1,174.7
Massey Drive Bus B3 (2)	1/11/2013 8:10	1/11/2013 9:45	95	34.6	3,288.9
Massey Drive Bus B3 (3)	1/11/2013 7:43	1/11/2013 9:45	122	30.6	3,738.1
Massey Drive Bus B4	1/11/2013 7:43	1/11/2013 11:58	255	35.5	9,042.3
Wiltondale (1)	1/11/2013 7:43	1/11/2013 9:19	96	0.1	10.2
Glenburine (1)	1/11/2013 7:43	1/11/2013 9:19	96	2.1	204.7
Rocky Harbour (1)	1/11/2013 7:43	1/11/2013 9:19	96	3.1	296.8
Wiltondale (2)	1/11/2013 9:40	1/11/2013 9:47	7	0.1	0.4
Glenburine (2)	1/11/2013 9:40	1/11/2013 9:47	7	1.0	7.2
Rocky Harbour (2)	1/11/2013 9:40	1/11/2013 9:47	7	1.5	10.4
South Brook	1/11/2013 7:43	1/11/2013 7:48	5	3.8	19.0
Duck Pond Mine	1/11/2013 7:43	1/11/2013 23:59	976	8.6	8,364.3
St. Anthony	1/11/2013 8:01	1/11/2013 8:32	31	7.3	226.6
Roddickton	1/11/2013 8:01	1/11/2013 8:30	29	1.7	48.1
Cobb's Pond	1/11/2013 7:43	1/11/2013 9:12	89	60.0	5,340.0
Farewell Head	1/11/2013 7:43	1/11/2013 9:12	89	3.0	267.0
Glenwood	1/11/2013 7:43	1/11/2013 9:12	89	3.0	267.0
Grand Falls	1/11/2013 7:43	1/11/2013 10:03	140	60.0	8,400.0
Sunnyside - 100L	1/11/2013 7:43	1/11/2013 9:03	80	10.3	820.0
Sunnyside - 109L	1/11/2013 7:43	1/11/2013 9:03	80	11.8	944.8
Holyrood - 39L	1/11/2013 6:42	1/11/2013 6:43	1	0.0	0.0
Hardwoods (1)	1/11/2013 7:43	1/11/2013 8:00	17	159.7	2,715.2
Hardwoods (2)	1/11/2013 8:51	1/11/2013 9:14	23	108.1	2,486.1
Oxen Pond (1)	1/11/2013 6:48	1/11/2013 7:11	23	171.0	3,933.0
Oxen Pond (2)	1/11/2013 7:43	1/11/2013 8:03	20	115.5	2,309.8
Oxen Pond (3)	1/11/2013 8:51	1/11/2013 9:31	40	110.9	4,435.2
		Totals	4,020	968.0	72,515.2

On February 4, North Atlantic Refining Limited (NARL) at Come by Chance, experienced an unplanned power outage of four hours and 26 minutes. The outage occurred when protection relays operated and locked out Bus 1 and Bus 2 at the Come By Chance Terminal Station, isolating NARL from the system grid. The bus protection relays tripped transmission lines TL-207 at the Sunnyside Terminal Station and TL-237 at the Western Avalon Terminal Station. The cause of the outage was plastic debris coming in contact with high voltage equipment during high winds on that day, and the failure of a component (blocking diode) in the protection circuit that caused a misoperation of the 230 kV bus lockout, tripping the bus tie breaker B1B2.

Following the incident, a revised circuit design was implemented to eliminate the use of blocking diodes in the Come By Chance breaker failure circuits. The breaker failure protection was upgraded with the revised design on February 28.

On February 6, 7 and 8, customers supplied by the Hawke's Bay Terminal Station, experienced seven unplanned power outages. The outages were caused by severe salt contamination on TL-221. The following table outlines the customer impact.

Delivery Point Affected	Date of Incident	Time of Incident	Time of Restoration	Outage Duration (mins)	Load Loss (MW)	MW-Mins
Hawke's Bay	2/6/2013	20:54	21:02	8	4.2	33.6
Hawke's Bay	2/7/2013	2:56	3:07	11	3.3	33.8
Hawke's Bay	2/7/2013	6:24	7:11	47	4.4	223.4
Hawke's Bay	2/7/2013	18:04	18:07	3	5.1	15.3
Hawke's Bay	2/7/2013	18:27	19:43	76	4.7	305.9
Hawke's Bay	2/8/2013	0:49	0:52	3	3.4	10.1
Hawke's Bay	2/8/2013	4:35	4:39	4	3.6	14.2

On February 10, Newfoundland Power customers in the Sunnyside, Clarenville, Bonavista Peninsula, and the Burin Peninsula areas experienced an unplanned power outage of up to four hours. The outage occurred when the 230 kV Bus 1, at the Sunnyside Terminal Station, experienced a bus protection lockout. It was determined that ice falling from overhead lines fell on substation equipment causing the protection relays to operate. Customers were restored after the bus lockout was reset and the station was restored at 13:09 hours. Attempts by Newfoundland Power, to restore customers using generation on the Burin Peninsula prior to this had failed.

Starting on February 17 and continuing until February 18, customers on the Great Northern Peninsula experienced three unplanned power outages; refer to the tables below for the customer impact. The outages were caused by high winds causing a structure failure on TL-259 and a transformer lockout on T1 at Berry Hill.

Delivery Point Affected	Date of Incident	Time of Incident	Time of Restoration	Outage Duration (mins)	Load Loss (MW)	MW-Mins
Cow Head	2/17/2013	16:07	16:22	14	1.2	16.8
Parson's Pond	2/17/2013	16:07	16:13	5	0.6	3.2
Daniel's Harbour	2/17/2013	16:07	16:13	5	0.8	3.8
Hawke's Bay	2/17/2013	16:07	16:50	42	4.5	189.0
Plum Point	2/17/2013	16:07	16:13	5	2.3	11.5
Bear Cove	2/17/2013	16:07	16:13	5	3.5	17.5
Main Brook	2/17/2013	16:07	16:17	9	0.5	4.7
Roddickton	2/17/2013	16:07	16:17	9	1.3	11.7
St. Anthony	2/17/2013	16:07	16:17	9	7.5	67.5
Wiltondale	2/17/2013	16:24	16:32	7	0.3	2.1
Glenburine	2/17/2013	16:24	16:32	7	5.9	41.3
Rocky Harbour	2/17/2013	16:24	16:32	7	8.4	58.8
Cow Head	2/17/2013	16:24	17:04	39	1.8	70.2
Wiltondale	2/17/2013	17:53	17:54	1	0.1	0.1
Glenburine	2/17/2013	17:53	17:54	1	2.3	2.3
Rocky Harbour	2/17/2013	17:53	17:54	1	3.3	3.3
Cow Head	2/17/2013 - 2/18/2013	17:53	2:15	501	2.0	1,002.0
St. Anthony	2/17/2013	18:19	18:20	1	6.5	6.5
Parson's Pond	2/17/2013	18:20	18:25	4	0.6	2.4
Main Brook	2/17/2013	18:21	18:22	1	0.4	0.4
Roddickton	2/17/2013	18:21	18:22	1	2.0	2.0
St. Anthony	2/17/2013	18:21	18:22	1	6.5	6.5
Parson's Pond	2/17/2013 - 2/18/2013	18:26	6:28	720	0.7	504.0
Daniel's Harbour	2/17/2013 - 2/18/2013	18:26	6:28	720	0.6	432.0
Plum Point	2/17/2013	18:32	18:33	1	2.5	2.5
Main Brook	2/17/2013	18:32	18:33	1	0.4	0.4
Roddickton	2/17/2013	18:32	18:33	1	2.0	2.0
Plum Point	2/17/2013	18:44	18:45	1	2.4	2.4
St. Anthony	2/17/2013	18:44	18:45	1	6.3	6.3
St. Anthony	2/17/2013	18:53	18:54	1	2.0	2.0
St. Anthony	2/17/2013	18:56	19:03	7	6.1	62.5
Plum Point	2/17/2013 - 2/18/2013	18:57	6:42	703	2.4	1,687.2
Bear Cove	2/17/2013 - 2/18/2013	18:57	6:52	713	3.7	2,638.1
Main Brook	2/17/2013 - 2/18/2013	18:57	0:01	301	0.4	120.4
Roddickton	2/17/2013 - 2/18/2013	18:57	0:01	301	1.8	541.8
St. Anthony L1	2/17/2013 - 2/18/2013	18:56	19:16	19	1.5	28.5
St. Anthony L2	2/18/2013	0:07	0:24	17	1.1	18.7
Hawkes Bay	2/18/2013	0:51	1:05	14	4.0	56.0

On February 20, customers in Daniel's Harbour experienced an unplanned outage of three hours and 36 minutes and customers in Parson's Pond experienced an unplanned outage of 42 minutes. The outage was caused by arcing on the 66 kV bus PTs at the Daniel's Harbour Terminal Station. This arcing, caused by salt contamination, resulted in a low voltage condition on the GNP for approximately one minute until transmission line TL-262 was opened by the Energy Control Centre.

Planned

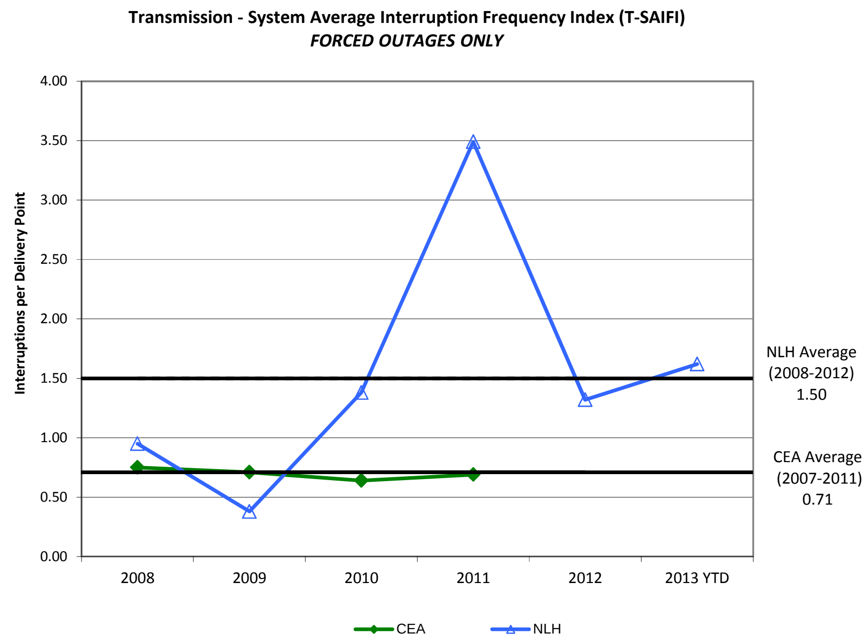
On February 10, customers north of Plum Point on the Great Northern Peninsula, experienced a planned power outage of 18 minutes. The outage was required to connect the mobile substation to the 25 kV bus at Hawke's Bay. This facilitated the removal of TL-221 from service due to the severe salt contamination. The following table outlines the overall customer impact of this outage.

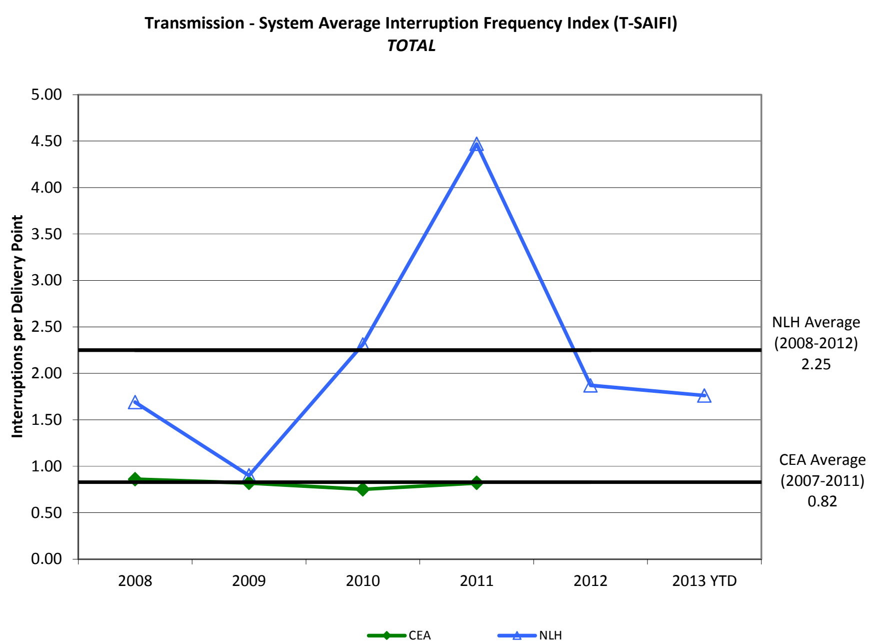
Location	Time of Incident	Time of Restoration	Outage Duration (mins)	Load Loss (MW)	MW-Mins
Plum Point	10:48	11:07	18	3.5	63.0
Bear Cove	10:48	11:07	18	5.2	93.6
Roddickton	10:48	11:07	18	2.4	43.2
Main Brook	10:48	11:07	18	0.6	10.8
St. Anthony Line 2	10:41	11:17	36	2.0	72.0
Hawke's Bay	13:19	13:42	23	5.4	124.2

On February 20, Newfoundland Power customers in the Glenwood area experienced a planned outage of two minutes. This outage was required to safely switch transmission line TL-210 in order to replace a cross arm on Structure 222.

b) Transmission System Average Interruption Frequency Index (T-SAIFI) - *a reliability KPI for bulk transmission assets that measures the average number of sustained outages per delivery point*.

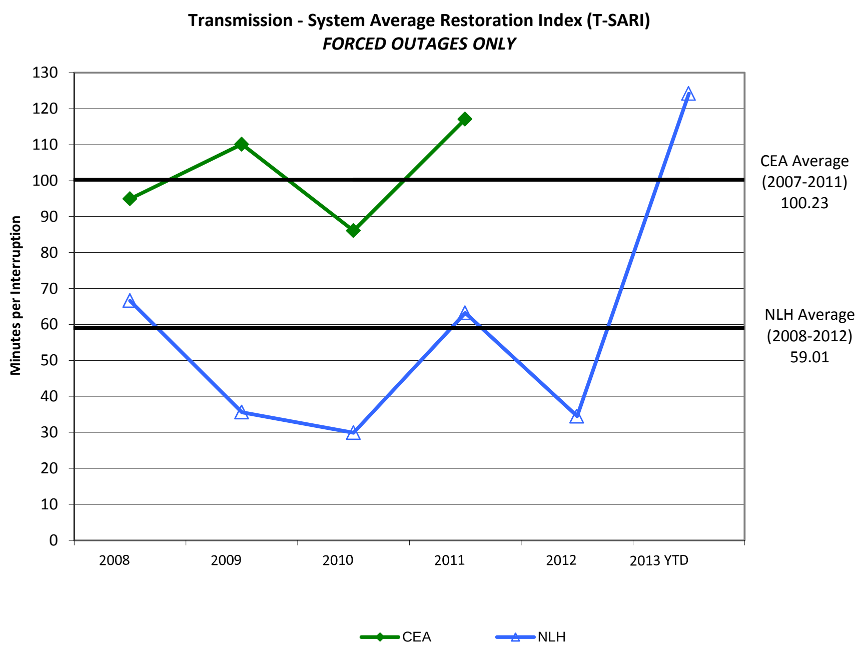
The first quarter T-SAIFI was 1.76 outages per bulk delivery point compared to 0.16 outages per bulk delivery point last year. The breakdown between forced and planned outages is as follows: 1.62 (forced) and 0.14 (planned). This is compared to 0.07 (forced) and 0.09 (planned) for the first quarter of 2012.

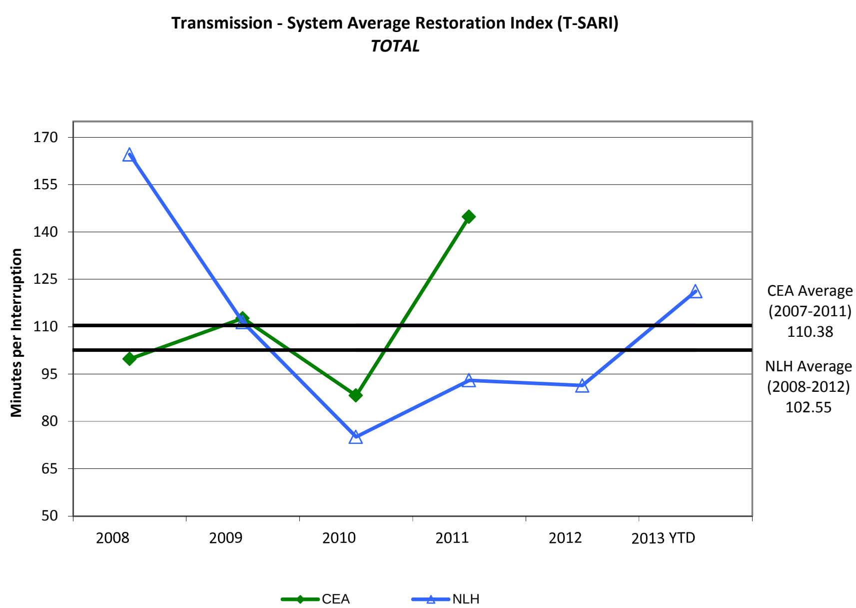




c) Transmission System Average Restoration Index (T-SARI) - *a reliability KPI for bulk transmission assets which measures the average duration per transmission interruption. T-SARI is calculated by dividing T-SAIDI by T-SAIFI.*

Hydro's total transmission T-SARI was 121.2 minutes per interruption for the first quarter versus 57.0 minutes per interruption for 2012, an increase of 112%. The forced outage component of T-SARI was 124.2 minutes per interruption. This compares with 54.0 minutes per interruption for the same quarter in 2012. The planned outage component of T-SARI was 84.0 minutes per interruption, compared to 59.4 minutes per interruption for the same quarter last year.





d) Underfrequency Load Shedding (UFLS) - *reliability KPI that measures the number of events in which shedding of a customer load is required to counteract a generator trip. Customer loads are shed automatically depending upon the generation lost.*

There were four underfrequency events during this quarter. These events are summarized as follows:

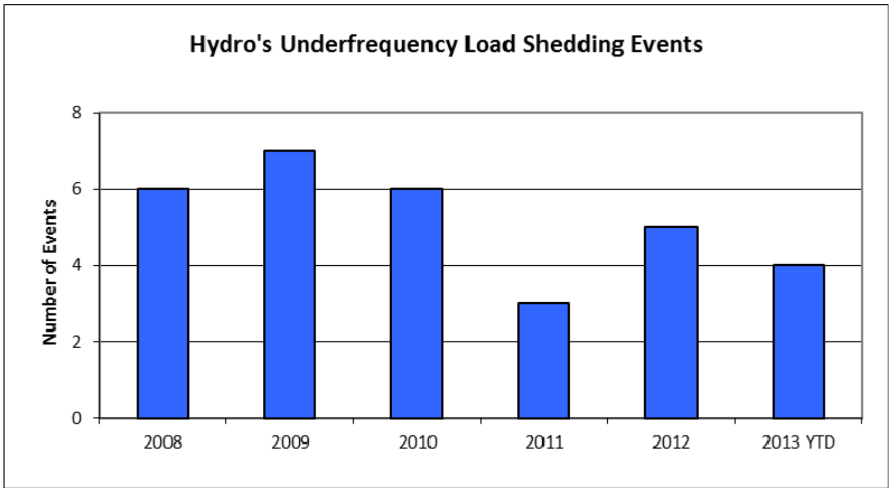
On January 16, Holyrood Generating Unit 3 tripped. The cause of the unit trip has not been determined. With the removal of generation (approximately 121 MW) the system frequency dropped to 58.4 Hz resulting in the activation of the underfrequency protection at Hydro and Newfoundland Power. Total system load at the time of the incident was 1,024 MW. There were 2,199 Hydro customers restored three minutes after the event occurred (23 MW-Mins). There were 15,299 Newfoundland Power customers reported to be restored within thirteen minutes after the event occurred (960 MW-Mins).

On January 18, Bay d'Espoir Generating Unit 4 tripped. Personnel investigated and determined that the cause of the trip of Unit 4 was a shorted and grounded current transformer (CT) associated with the generator. The CT was replaced and the unit was released for service on January 20 at 03:00 hours. With the removal of generation (approximately 68 MW) the system frequency dropped below 58.8 Hz resulting in the activation of the underfrequency protection at Newfoundland Power. Total system load at the time of the incident was 1,312 MW. There were 4,309 Newfoundland Power customers reported to be restored within fifteen minutes after the event occurred (270 MW-Mins).

On March 1, Bay d'Espoir Generating Unit 1 tripped. Hydro's investigation determined that the exciter processor had malfunctioned. The exciter processor was replaced and Unit 1 was available and synched online at 13:54 hours on March 2. With the removal of generation (approximately 52 MW) the system frequency dropped below 58.8 Hz resulting in the activation of the underfrequency protection at Newfoundland Power. Total system load at the time of the incident was 836 MW. There were 6,256 Newfoundland Power customers reported to be restored within five minutes after the event occurred (23 MW, 115 MW-Mins).

On March 10, Holyrood Generating Unit 3 tripped. The cause of the unit trip was attributed to a problem with the fuel oil pump. Personnel corrected the issue and the unit was restored to service on March 11 at 00:05 hours. With the removal of generation (approximately 69 MW) the system frequency dropped to 58.78 Hz resulting in the activation of the underfrequency protection at Newfoundland Power. Total system load at the time of the incident was 968 MW. There were 6,041 Newfoundland Power customers reported to be restored within eleven minutes after the event occurred (20 MW, 220 MW-Mins).

Refer to the graph below which compares the UFLS events over the past five years to the year-to-date 2013 performance.



Underfrequency Load Shedding Number of Events					
Customers	First Quarter		Year to Date		5 Year Average
	2013	2012	2013	2012	(2008–2012)
NF Power	4	1	4	1	5.4
Industrials	0	1	1	1	2.8
Hydro Rural*	1	1	1	1	2.8
Total Events	4	1	4	1	5.4

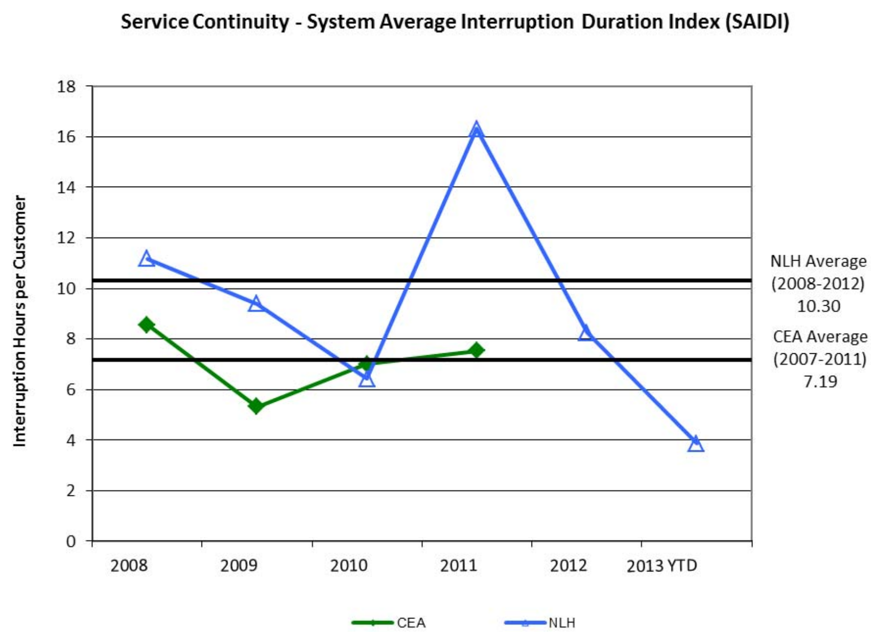
Underfrequency Load Shedding Unsupplied Energy (MW-min)					
Customers	First Quarter		Year to Date		5 Year Average
	2013	2012	2013	2012	(2008–2012)
NF Power	1,565	2,226	2,274	2,226	1,643
Industrials	0	140	0	140	217
Hydro Rural*	21	20.7	0	20.7	48
Total Events	1,586	2,387	1,586	2,387	1,890

* Underfrequency activity affecting Hydro Rural Customers may also result in a number of delivery point outages. Outage frequency and duration are also included in totals shown in the delivery point statistics section of the report for these areas, namely the Connaigre Peninsula and Bonne Bay.

Rural Systems Service Continuity Performance

a) System Average Interruption Duration Index (SAIDI) - *a reliability KPI for distribution service and it measures service continuity in terms of the average cumulative duration of outages per customer served during the year.*

For the first quarter, the SAIDI was 3.87 hours per customer compared to 0.92 hours per customer in 2012, a 321% increase.



A summary of the major interruptions follows:

On January 18, customers serviced by Lines 3, 7, 8, 9, 11, and 12 in Wabush experienced an unplanned power outage. The outage occurred due to an overload on the 46 kV line supplying the Wabush distribution system. The outage duration was up to three hours for some customers.

On January 19, all customers on Fogo and Change Islands experienced an unplanned power outage. The outage occurred when the breaker supplying Change Islands and Fogo Island tripped. An issue with the main submarine cable between the two Islands was deemed to be the cause of the trip. Hydro crews transferred distribution to the spare submarine cable and this was energized on January 20. Power was rotated to customers on Fogo Island due to high power demand caused by cold load pickup using distribution feeders L4, L5, and L6. All customers on Fogo Island were fully restored in the evening on January 20. Customers experienced outage durations of up to 30 hours and 16 minutes.

On February 27, 373 customers serviced by Line 11 in Labrador City experienced an unplanned power outage of three hours in duration. Hydro crews investigated the outage and found a dead crow in the Quartzite substation.

On March 4 at 18:58 hours, 1,010 customers supplied by Line 16 in Happy Valley-Goose Bay experienced an unplanned power outage. The outage occurred when the line recloser tripped due to a broken utility pole. Hydro crews completed repairs and the first attempt to restore these customers occurred at 22:27. The recloser tripped again at 22:29, with the cause suspected to be an overload on the line due to cold load pickup. Following this trip there were numerous, unsuccessful, attempts to restore customers on Line 16. On three occasions, at 22:41, 23:10 and at 00:45 hours, the attempts resulted in trips of the station transformers (T1 and T2) and an outage to all customers (4,919) supplied by the Happy Valley-Goose Bay (HVGB) station, of durations three, 15 and 8 minutes, respectively.

By 03:50 on March 5, Line 16 had been sectionalized and some of the customers supplied by this line were restored. At 04:37 however, the station transformers (T1 and T2) tripped again resulting in another outage to all customers supplied by the HVGB station, of three minutes in duration. All customers on Line 16 (excluding those on Feeder 9) were restored again by 05:13. Customers on Feeder 9 were restored at 05:45 hours.

After further investigation, it was determined that the issues in restoring Line 16 were due to a severe feeder unbalance and operation of a back-up overcurrent relay which is wired to trip the transformer breakers. There were several action items arising from these events.

On March 22, at 21:00 hours (Labrador time), 825 customers served by feeder L7 in the town of Happy Valley-Goose Bay experienced an unplanned power outage. The outage was caused by a tree contacting the feeder and breaking the primary conductor. The tree was removed, the conductor was repaired and all customers were restored at 00:00 hours (midnight on March 23).

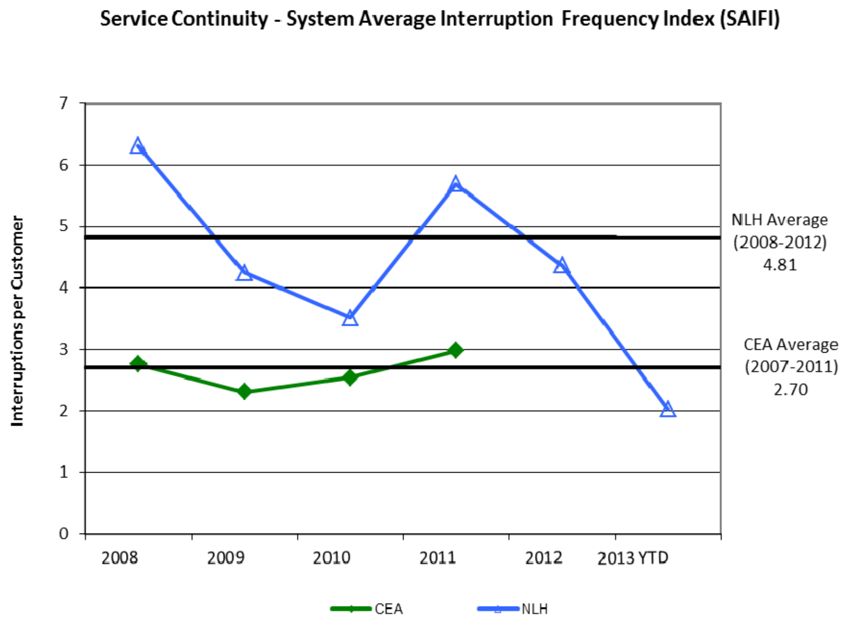
On March 24, starting at 06:10 hours (Labrador time), 804 customers in the towns of Happy Valley-Goose Bay and Mud Lake experienced a planned power outage. The outage was required to reduce the local load to match the generation capability of the Happy Valley gas turbine during a planned outage on transmission line L1301. Line L1301 was removed from service to safely interconnect a new terminal station for construction power for Muskrat Falls. The following table outlines the customer outage durations:

Date	Asset	Time of Incident	Time of Restoration	Outage Duration	Number of Customers
March 24	Line 5	06:30	15:08	8 hours and 38 mins.	363
March 24	Line 6	06:10	15:15	9 hours and 5 mins.	428
March 24	Line 17	06:10	15:15	9 hours and 5 mins.	13

Thirty customers in Mud Lake experienced an additional unplanned outage at 15:15 hours following attempts to restore feeder L6. A tree had contacted the feeder during the planned outage earlier in the day. The tree was removed and these customers were restored at 16:30 hours.

b) System Average Interruption Frequency Index (SAIFI) - *reliability KPI for distribution service and measures the average cumulative number of sustained interruptions per customer per year.*

In the first quarter, the SAIFI was 2.02 interruptions per customer compared to 0.68 interruptions per customer in 2012, a 197% increase. This increase is related to the significant events in January and February which affected all interconnected regions.



c) Additional Information - *The following section provides more detailed information in three tables with performance broken down by Area, Origin, and Type.*

Rural Systems Service Continuity Performance by Area

SAIFI (Number per Period)					
Area	First Quarter 2013	First Quarter 2012	12 Mths to Date 2013	12 Mths to Date 2012	5 Year Average
Central					
Interconnected	1.25	0.46	2.87	2.08	3.05
Isolated	0.67	0.18	1.37	4.36	3.21
Northern					
Interconnected	2.13	0.71	6.24	5.27	4.75
Isolated	1.89	2.10	8.44	5.80	6.43
Labrador					
Interconnected	2.80	0.53	7.72	8.44	6.58
Isolated	3.16	1.79	10.96	6.62	11.30
Total	2.02	0.68	5.71	5.10	5.00

Note: System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers in an area

SAIDI (Hours per Period)					
Area	First Quarter 2013	First Quarter 2012	12 Mths to Date 2013	12 Mths to Date 2012	5 Year Average
Central					
Interconnected	5.18	1.17	8.99	13.34	10.49
Isolated	0.83	0.08	2.80	3.06	2.43
Northern					
Interconnected	3.55	0.62	13.97	22.44	11.54
Isolated	1.87	0.78	7.98	3.30	5.80
Labrador					
Interconnected	3.11	0.55	11.82	11.56	11.62
Isolated	4.18	3.48	15.82	6.32	16.01
Total	3.87	0.92	11.20	14.18	10.88

Note: System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.

Rural Systems Service Continuity Performance by Origin

SAIFI (Number per Period)					
Area	**First Quarter**		**12 Mths to Date**		**5 Year**
	2013	**2012**	**2013**	**2012**	**Average**
Loss of Supply – Transmission	0.42	0.17	1.65	2.21	1.88
Loss of Supply – NF Power	0.00	0.00	0.01	0.01	0.01
Loss of Supply – Isolated	0.14	0.14	0.50	0.48	0.56
Loss of Supply – L'Anse au Loup	0.05	0.03	0.05	0.05	0.06
Distribution	1.41	0.35	3.51	2.35	2.49
Total	2.02	0.68	5.71	5.10	5.00

Note: System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers.

SAIDI (Hours per Period)					
Area	**First Quarter**		**12 Mths to Date**		**5 Year**
	2013	**2012**	**2013**	**2012**	**Average**
Loss of Supply – Transmission	0.64	0.06	2.28	5.09	3.60
Loss of Supply – NF Power	0.00	0.00	0.00	0.49	0.14
Loss of Supply – Isolated	0.03	0.16	0.14	0.24	0.24
Loss of Supply – L'Anse au Loup	0.05	0.00	0.05	0.02	0.04
Distribution	3.14	0.69	8.72	8.34	6.87.
Total	3.87	0.92	11.20	14.17	10.88

Note: System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.

Rural Systems Service Continuity Performance by Type (First Quarter 2013)

Area	Scheduled		Unscheduled		Total	
	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI
Central						
Interconnected	0.02	0.02	1.23	5.16	1.28	5.18
Isolated	0.40	0.70	0.27	0.13	0.67	0.83
Northern						
Interconnected	0.01	0.00	2.13	3.54	2.13	3.55
Isolated	0.00	0.00	1.89	1.87	1.89	1.87
Labrador						
Interconnected	0.54	0.87	2.26	2.24	2.80	3.11
Isolated	0.64	0.95	2.53	3.23	3.16	4.18
Total	0.20	0.31	1.83	3.56	2.02	3.87

Note:

1. System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers in an area.
2. System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

QUARTERLY REGULATORY REPORT FOR THE QUARTER ENDED JUNE 30, 2013

Newfoundland and Labrador Hydro

Table of Contents

1 HIGHLIGHTS

HIGHLIGHTS
For the six months ended June 30, 2013

REGULATED	2013 Actual YTD	2013 Target/ Budget	2012 Actual YTD
Safety			
Lead:Lag Ratio[1]	363:1	600:1	404:1
All Injury Frequency Rate[1]	1.33	≤0.8	1.34
Production			
Quarter End Reservoir Storage (GWh)	2,523	1,155	1,974
Hydraulic Production (GWh)	2,529	2,546	2,510
Holyrood Fuel cost per barrel, current month ($) [2]	105	55	121
Holyrood Efficiency [2]	598	630	602
Electricity Delivery			
Sales including Wheeling (GWh)	3,887.4	3,977.1	3,840.4
Financial			
Revenue ($millions)	270.0	275.9	261.6
Expenses ($millions)	263.8	269.0	247.9
Net Operating Income ($millions)[3]	6.2	6.9	13.8
Current Rate Stabilization Plan (RSP) Balance ($millions)	(246.7)	(251.2)	(182.7)
Hydraulic	(59.8)	(69.1)	(57.7)
Utility	(70.5)	(69.8)	(34.4)
Industrial	(116.4)	(112.3)	(90.6)
Full Time Equivalent (FTE) Employees[4, 5]			
Regulated	795.5	863.5	785.6
Non-Regulated	34.3	15.0	29.9

[1] Annual Target, and 2012 Actual
[2] Target based on approved 2007 Test Year forecast
[3] Does not include any earnings from CF(L)Co
[4] One FTE is the equivalent of actual paid regular hours - 2,080 hours per year in the operating environment and 1,950 hours per year in Hydro's head office environment.
[5] Annual Budget and 2012 Actual values

- Hydro has lost-time injury frequency rate of zero for the first half of the year (page 2);
- Hydro staff celebrate Environment Week (page 9);
- Reservoir storage levels remain high (page 12);
- Rate Stabilization Plan results in a rate decrease (page 22).

2 SAFETY

Goal - To be a Safety Leader

Safety is Hydro's number one priority. Hydro remains committed to being a world class leader in safety performance.

Measurement	Year-to-date 2013 Actual	Annual 2013 Plan	Annual 2012 Actual
All Injury Frequency (AIF)	1.33	$\leq$0.8	2.25
Lost Time Injury Frequency (LTIF)	0.00	$\leq$0.2	0.79
Ratio of condition and incident reports to lost time and medical treatment injuries (lead/lag ratio)	363:1	600:1	230:1
Planned Grounding and Bonding Activities	In progress	100%	N/A
Complete Work Method Activities for Critical Tasks	92%	100%	87.33%

A corporate Injury Prevention Campaign was released, focusing on three of the company's top injury trends: Slips, Trips and Falls; Sprains and Strains; and Hand Injuries. The Injury Prevention Campaign will serve as a means of educating employees about possible safety hazards both within and outside the workplace through the use of creative visuals. The campaign's tagline, *"if only all hazards were this obvious",* encourages employees to be aware of their surroundings and obvious hazards, while reminding them to be mindful of the subtle dangers that may exist.

The Injury Prevention Campaign is part of an overall internal safety program, *"Take a Moment for Safety"* currently being developed that will enhance Hydro's current safety programs and move the company another step closer to achieving safety excellence.

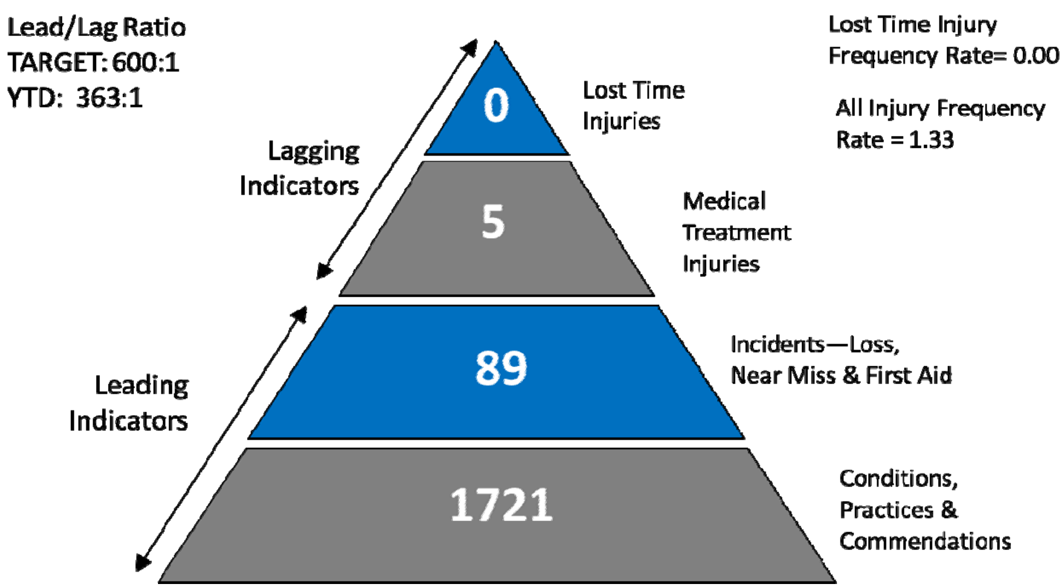
Hydro's leadership is engaging in safety tours and visiting employees to discuss workplace safety on a regular basis. Field visibility by the Leadership Team, Regional Managers and Safety Professionals has been increased in all areas.

Safety Week 2013 ran from May 5 to May 10. The national theme was "Safety and Health: A Commitment for Life! *Are you as Safe as you Think?*" and as with previous years, various locations around Hydro organized and participated in Safety Week activities.

The public safety campaign related Power Line Hazards is ongoing both internally and externally. Hydro continues to partner with other utilities, government agencies and other stakeholders to discuss communication strategies and initiatives around power line safety.

From a key program perspective, Hydro continues to focus in the area of Grounding and Bonding (G&B), Work Methods, Work Protection Code (WPC) and Corporate Standard Development. The Corporate Grounding and Bonding team has developed a new G&B standard and training package for line operations staff. Work continues around the development of Work Methods for identified critical tasks and is moving into an evaluation phase. The WPC Program has been focusing on the development of new software for the issuing of permits and auditing compliance to the code. A corporate wide WPC Forum was held in June. New standards for Hearing Conservation and Early and Safe Return to Work have been developed and communicated to all employees.

The following safety triangle summarizes Hydro's year-to-date performance for 2013.



2.1 Canadian Electrical Association (CEA) Injury Incident Statistics

CEA Comparison statistics for 2008 through 2012 are as follows:

Newfoundland and Labrador Hydro CEA Injury Incident Statistics						
						5 Year Average
	2008	**2009**	**2010**	**2011**	**2012**	**2008-2012**
All Injury Frequency						
Hydro	1.44	1.44	1.39	0.91	2.25	1.49
CEA Group II Average	2.06	1.76	1.67	1.34	1.56	1.68
Lost Time Frequency						
Hydro	0.78	0.92	0.38	0.13	0.79	0.60
CEA Group II Average	0.52	0.47	0.36	0.37	0.46	0.44
Lost Time Severity						
Hydro	26.10	41.38	23.29	0.13	44.53	27.09
CEA Group II Average	15.23	9.87	7.79	7.98	14.81	11.14

2.2 2013 National Safety Week

National Safety Week is recognized and supported by Hydro and is used to reinforce key safety policies and to promote prevention awareness.

The theme of this year's national campaign was "Safety and Health: A Commitment for Life! *Are you as Safe as you Think?*" Prevention awareness is a key component of safety week. Recognizing a dangerous situation or a potential hazard is an important aspect of being safe. The most common injuries occur from low risk activities that consist of slips/trips/falls, hand-related injuries, and strains and sprains. In addition, the 'Take a Moment for Safety' message was introduced and will be launched along with a full injury prevention campaign in July.

Employees are encouraged to keep safety a top priority while at work to help prevent injuries by following policies such as the back-in policy. Encouraging others to keep safety in mind also helps the Company move towards its goal of establishing a zero harm work environment.

2.3 Look Up. Keep Back. Call Ahead.

Hydro's commitment to education on the importance of power line safety continued this spring with a radio and online advertising campaign focusing on the *"Look Up. Keep Back. Call Ahead."* theme running for three weeks in May. The results of this campaign are being analyzed and will impact how and when Hydro promotes power line safety in the fall of 2013.

2.4 Hydro's Safety Website gets New Look

In June, Hydro's safety website www.hydrosafety.ca was updated and now includes some new safety information on children's electrical safety and public safety around dams. It also includes recreational safety information; everything from hiking safety to fireworks safety; along with information on how to stay safe around power lines and tips for power outage safety.

2.5 Hydro Generation and TRO deliver Electrical Safety Presentation

Schools on the South Coast received a visit from Dave Collier, Plant Security and Safety Supervisor, Hydro Generations, and Murray Anderson, Line Worker A, Transmission and Rural Operations (TRO). The pair went to Fitzgerald Academy in English Harbour West and John Watkin's Academy in Hermitage to deliver electrical safety presentations to students.

2.6 Community Safety Event in Bay d'Espoir

On May 8, Hydro launched its first Community Safety Event. The event took place at the Milltown Lions Club in Bay d'Espoir. The event educated grade four, five and six students about electrical safety and how to be safe at home and around hydroelectric structures, such as dams. Rob Bartlett, Safety, Health and Environment Coordinator, Bob Woodman, Manager of Long-Term Asset Planning and Leveson Kearley, Manager of Work Execution, gave an informative presentation to the children.

Rob Bartlett, Jessica Lowe, Appr Power System Operator, Murray Anderson, Line Worker A and Randy Dollimont, Line Worker A, get ready for a fun and informative electrical safety presentation.

2.7 Line Worker Focus Group

As part of the corporate mandate to reduce workplace incidents and improve safety performance, a Line Worker Focus Group has been formed. The first meeting was held in Bishop's Falls on June 6. Rob Henderson, VP Newfoundland and Labrador Hydro, kicked off the meeting and stressed the critical importance of protecting line workers from injury. The committee's work will help line workers who work in a dangerous environment every day to learn from each other and share experiences of best practice to prevent injuries.

The Line Worker Focus Group at their first meeting in Bishop's Falls.

3 ENVIRONMENT AND CONSERVATION

Goal - To be an Environmental Leader

Hydro recognizes its commitment and responsibility to protect the environment.

Measurement	Year-to-date 2013 Actual	Annual 2013 Target	Annual 2012 Actual
Variance from ideal production schedule at Holyrood Thermal Generating Station	12.1%	≤ 10.0%	6.9%
Achievement of EMS targets[1]	23%	95%	96%
Annual energy savings from Residential and Commercial Conservation and Demand Management Programs	0.9 GWh	2.9 GWh	2.3 GWh
Conduct evaluation of Industrial Energy Efficiency Program (IEEP) and develop multi-year plan	Work scope is being defined	Complete evaluation	N/A
Annual energy savings from Internal Energy Efficiency Programs	0.06 GWh	0.40 GWh	0.26 GWh

[1] An EMS target is an initiative undertaken to improve environmental performance.

3.1 Variance from Ideal Production Schedule at Holyrood Thermal Generating Station

Summary of 2013 Performance (year-to-date):

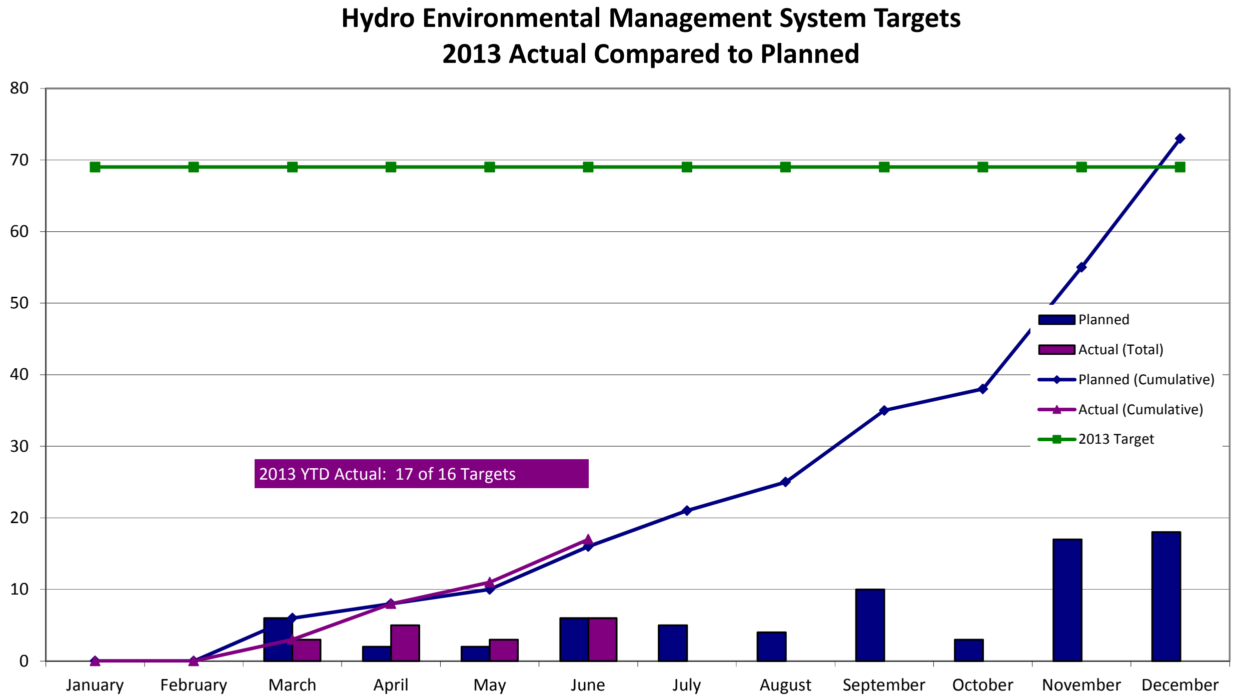
Minimum Hours

2013	Variance[1]		Ideal		Variance	
Month	Unit-Hours	Cumulative	Unit-Hours	Cumulative	Percent	Cumulative
January	360	360	2,088	2,088	17.2%	17.2%
February	337	697	1,728	3,816	19.5%	18.3%
March	48	745	1,512	5,328	3.2%	14.0%
April	72	817	1,224	6,552	5.9%	12.5%
May	76	893	624	7,176	12.2%	12.4%
June	24	917	432	7,608	5.6%	12.1%

[1] Variance is the number of hours greater than or less than the ideal. Hours greater than the ideal represent hours of operation that ideally could have been avoided. Hours less than the ideal represent hours of operation where a single contingency could have resulted in a load interruption.

3.2 Achievement of EMS Targets

See graph below displaying planned target completion schedules and actual to-date.



3.2.1 Annual Energy Savings from Residential and Commercial Conservation and Demand Management (CDM) Programs

Participation in the existing commercial and residential programs continues to be steady. A major portion of the energy savings in the second quarter are from the Block Heater Timer program. These savings were a result of activity in 2012 but not accounted for until additional work was undertaken to verify the savings, which was completed this quarter.

The Isolated Systems Community Energy Efficiency program has launched activity for 2013 and will contribute to the savings target. This program provides direct installation of energy efficiency items for residential and commercial customers in isolated diesel systems. For 2013, as an expansion of the 2012 efforts, a pilot program is being added to examine the applicability of domestic hot water waste heat recovery with residential customers.

Work is continuing with Newfoundland Power on the development of the additional programs to be launched later in 2013, based on the 2012-2016 CDM Plan. These programs will also contribute to the savings target.

3.2.2 Conduct Evaluation of Industrial Energy Efficiency Program and Develop Multi-Year Plan

Efforts have been made to identify the scope of work for the evaluation to take place in 2013. There has been continued contact with Industrial Customers and there are projects that are being completed through the program.

3.2.3 Annual Energy Savings from Internal Energy Efficiency Programs

Projects have been completed in TRO Northern and TRO Central to improve lighting, control systems and heating controls. Work continues on assessing building control systems for optimization opportunities through recommissioning and work has been done on the Hydro Place building to implement optimization recommendations.

An end use profile document has been prepared that outlines the energy uses for Hydro facilities and will be a living document used to assess opportunities for savings and identifying targets. The collection of data for this document was a significant effort in 2012 and early 2013 and highlights of the findings will be shared internally.

3.3 2012 Environmental Performance Report Released

On June 7, the 2012 Environmental Performance Report, which details the company's environmental activities, was released. The report is a key component of being accountable to the citizens of Newfoundland and Labrador. Hydro, and all Nalcor operations, maintain a high standard of environmental responsibility and performance through the implementation of a comprehensive Environmental Management System (EMS).

3.4 Environment Week

From June 2-8, employees across the province participated in several Environment Week activities. At Hydro Place, several activities throughout the week encouraged employees to think green. Environment Week is a call to action for all employees to adopt a greener lifestyle, to celebrate actions that promote a cleaner environment and inspire others to do the same.

Rod Healey, Environmental Specialist, Stan Cook Jr. from Stan Cook Sea Kayaking, and Gerard McDonald, V.P. Human Resources and Organizational Effectiveness, prepare for Environment Week opening ceremonies at Hydro Place.

4 OPERATIONAL EXCELLENCE

Goal - Through operational excellence provide exceptional value to all consumers of energy.

Hydro strives to deliver operational excellence by maintaining safe, reliable delivery of power and energy to customers in a cost-effective manner while maintaining high customer satisfaction. The key focus areas are:

- Energy Supply;
- Asset Management; and
- Financial Performance.

Measurement	Year-to-date 2013 Actual	Annual 2013 Target	Annual 2012 Actual
Asset Management and Reliability			
Contingency Reserve[1]	96.7	>99.5%	99.97%
Asset Management Strategy Execution	Tracking in compliance to plan	Plan Implementation	Completed as planned for 2012
Financial Targets			
Annual Controllable Costs	$57.0 million	$111.9 million (Budget)	$106.5 million
Net Income	$6.2 million	$6.2 million	$16.9 million
Project Execution			
Completion rate of capital projects by year end[2]	-	>90%	82%
All-project variance from original budget[2]	-	8%	18%
Customer Service			
Customer Service Improvement Plan	In Progress	Complete 3-5 Year Strategy	N/A

[1] The contingency reserve metric tracks the number of unit unavailability hours for which there would not have been ample system generation available to supply the system load under the loss of the largest generating unit (N-1). These unavailability hours are compared against the total hours in the month.
[2] Measured at year end.

4.1 Energy Supply

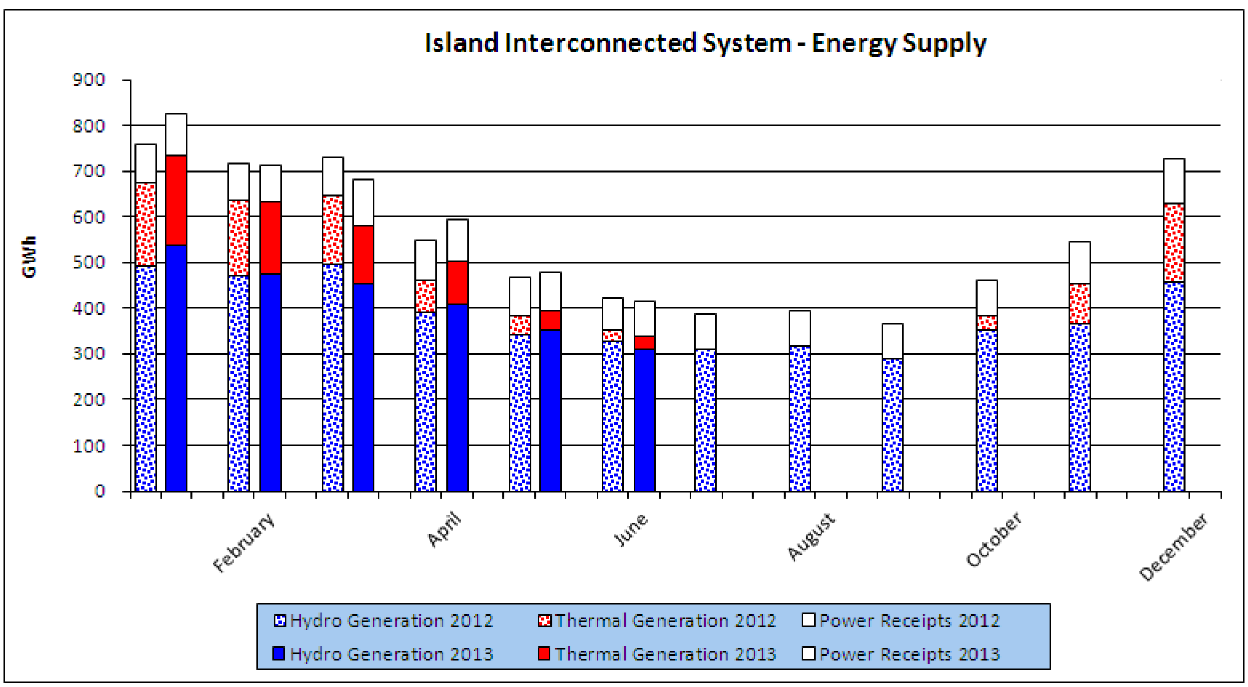
4.1.1 Energy Supply - Island Interconnected System

The energy produced and purchased on the Island Interconnected system is up by 63.6 GWh or 1.8% through the second quarter of 2013 compared to 2012. This is due to higher utility requirements which have been partially offset by lower energy requirements for the Industrial Customers.

Energy requirements from the Holyrood Thermal Generating Station were higher through the second quarter of 2013 when compared to the same period in 2012 (11.4 GWh or 1.9%). This was primarily due to cooler temperatures, particularly during the late spring period, which resulted in increased requirements for Avalon Peninsula transmission support. Individual units are brought into service as required to meet customers' needs and for transmission support to the Avalon Peninsula.

Hydroelectric production through the second quarter of 2013 was 19.1 GWh or 0.8% above the levels in 2012, primarily due to increased system load requirements. The increase in hydroelectric production was partially offset by increased Holyrood production and an overall increase in energy purchases. Total energy purchases were up by 28.8 GWh or 5.8% through the second quarter of 2013 when compared to 2012. This increase was primarily due to increased generation from the Nalcor facilities at Exploits and the Corner Brook Pulp and Paper (CBPP) co-generation unit. This increase in energy purchases was partially offset by a decrease in production at the St. Lawrence wind farm. That facility experienced operational issues during the first quarter.

The energy supply for the Island Interconnected System is shown in the following chart and tables.



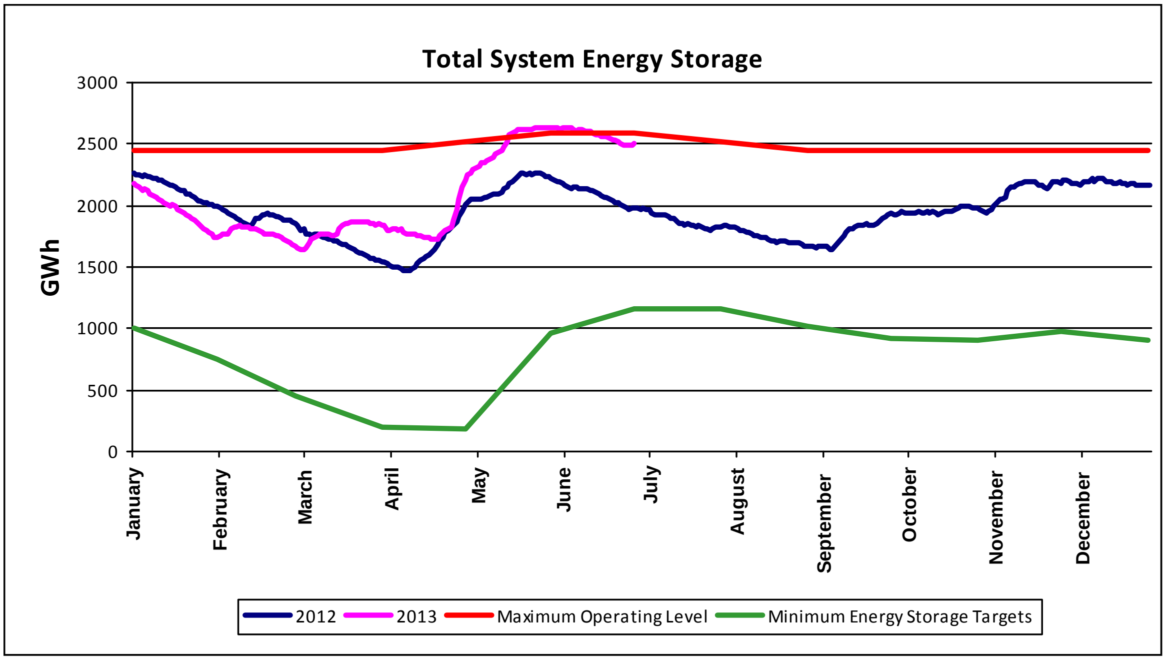
Island Interconnected System Production For the Quarter ended June 30, 2013					
	Year-to-date			2013 Annual Forecast (GWh)	2013 ($ 000)
	2013 (GWh)	2012 (GWh)	2013 Forecast (GWh)		
Production (net)					
Hydro	2,529.5	2,510.4	2,546.4	4,694.4	
Thermal	602.7	591.3	601.4	981.5	
Gas Turbines	0.7	(2.4)	1.6	3.0	
Diesels	0.8	(0.4)	0.9	1.0	
Total Production	**3,133.7**	**3,098.9**	**3,150.3**	**5,679.9**	
Energy Purchases					
Non Utility Generators					
Rattle Brook	7.7	6.3	8.3	15.6	**641.5**
Corner Brook Pulp and Paper Co-generation	29.6	23.3	29.5	52.7	**4,620.3**
St. Lawrence Wind	44.9	56.3	43.4	91.9	**3,201.1**
Fermeuse Wind	48.3	46.3	46.9	86.0	**3,708.4**
Total Non Utility Generators	**130.5**	**132.2**	**128.1**	**246.2**	**12,171.3**
Secondary and Others					
Deer Lake Power	3.8	2.9	3.2	3.2	**80.1**
Hydro Request to NP	0.8	0.0	0.0	0.0	**349.6**
Nalcor Energy[1]	386.7	357.9	390.6	760.2	
Total Secondary and Other	**391.3**	**360.8**	**393.8**	**763.4**	**429.7**
Total Purchases	**521.8**	**493.0**	**521.9**	**1,009.6**	
Island Interconnected Total Produced and Purchased	**3,655.5**	**3,591.9**	**3,672.2**	**6,689.5**	

[1] Nalcor Energy includes Star Lake and the Grand Falls, Bishop's Falls and Buchans generation.

4.1.2 System Hydrology

Reservoir storage levels continue to be high. Inflows into the aggregate reservoir system were 110% of average during the second quarter of 2013 and are now 118% of average for the year to date. Reservoir levels at the end of the quarter were at 96% of the maximum operating level (MOL) and 218% of the minimum storage target. This compares with 76% of the MOL at the end of the second quarter in 2012.

There was a significant amount spillage experienced at multiple reservoirs during the second quarter. The spills were primarily triggered by a period of heavy rainfall and snow melt experienced during the last week of April. In total there has been a lost energy equivalent of 255 GWh to the end of June.



System Hydrology Storage Levels			
	2013 (GWh)	**2013 Minimum Target (GWh)**	**2012 (GWh)**
Quarter End Storage Levels	2,523	1,155	1,974

4.1.3 Energy Supply – Labrador Interconnected System

The purchased and produced energy on the Labrador Interconnected system was up through the second quarter of 2013 (7.5 GWh or 1.6%) when compared to 2012. This is primarily owing to higher industrial sales at the Iron Ore Company of Canada (IOCC) which have been partially offset by reduced secondary sales to CFB Goose Bay and a reduction in Hydro Rural requirements in Labrador East and West.

Labrador Interconnected System Production For the Quarter ended June 30, 2013				
	Year-to-date			**2013 Annual Forecast (GWh)**
	2013 (GWh)	**2012 (GWh)**	**2013 Forecast (GWh)**	
Production (net)				
Gas Turbines	(0.6)	(1.1)	(0.6)	(0.3)
Diesels	0.0	0.0	0.1	0.2
Total Production	**(0.6)**	**(1.1)**	**(0.5)**	**(0.1)**
Purchases				
CF(L)Co for Labrador (at border)	**479.1**	**472.1**	**454.3**	**935.3**
Labrador Interconnected Total Produced and Purchased	**478.5**	**471.0**	**453.8**	**935.2**

4.1.4 Fuel Prices

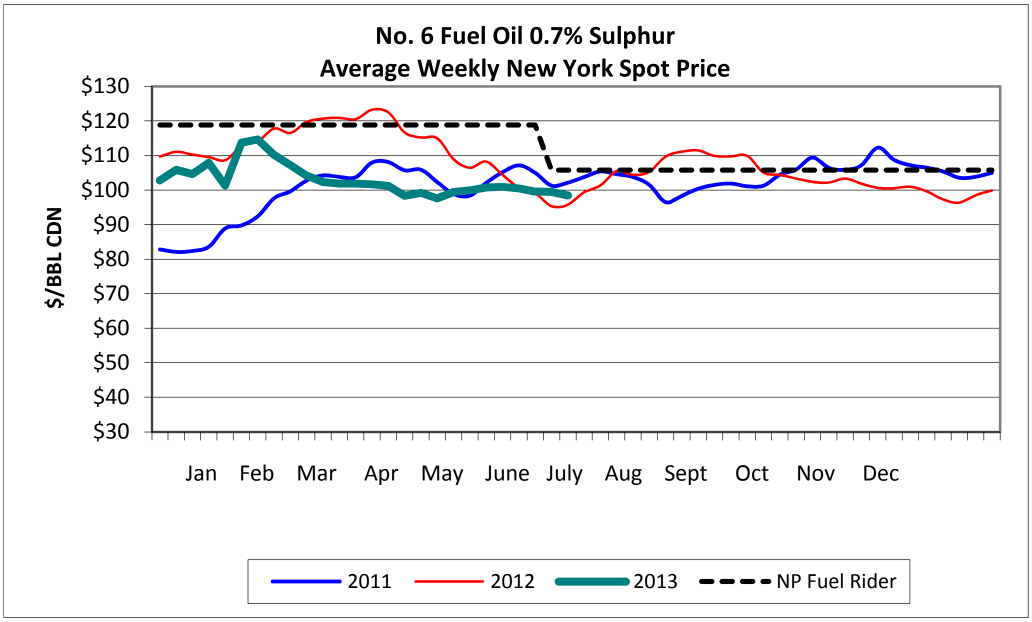
The fuel market prices for No. 6 fuel decreased from approximately $102/bbl at the start of the quarter to $98/bbl at the end of the quarter. The quarter ending inventory cost was $104.90/bbl, slightly lower than the current Newfoundland Power fuel price rider of $105.80/bbl. There is no Industrial Customer fuel price rider for 2013.

There were two shipments received during the second quarter of 2013:

April 2	197,691 bbls	$103.03
April 27	200,824 bbls	$ 98.94

The inventory on June 30 was 454,635 barrels.

The following chart shows the No. 6 fuel prices year-to-date compared to 2011 and 2012, and the Newfoundland Power fuel rider price of $105.80/bbl.



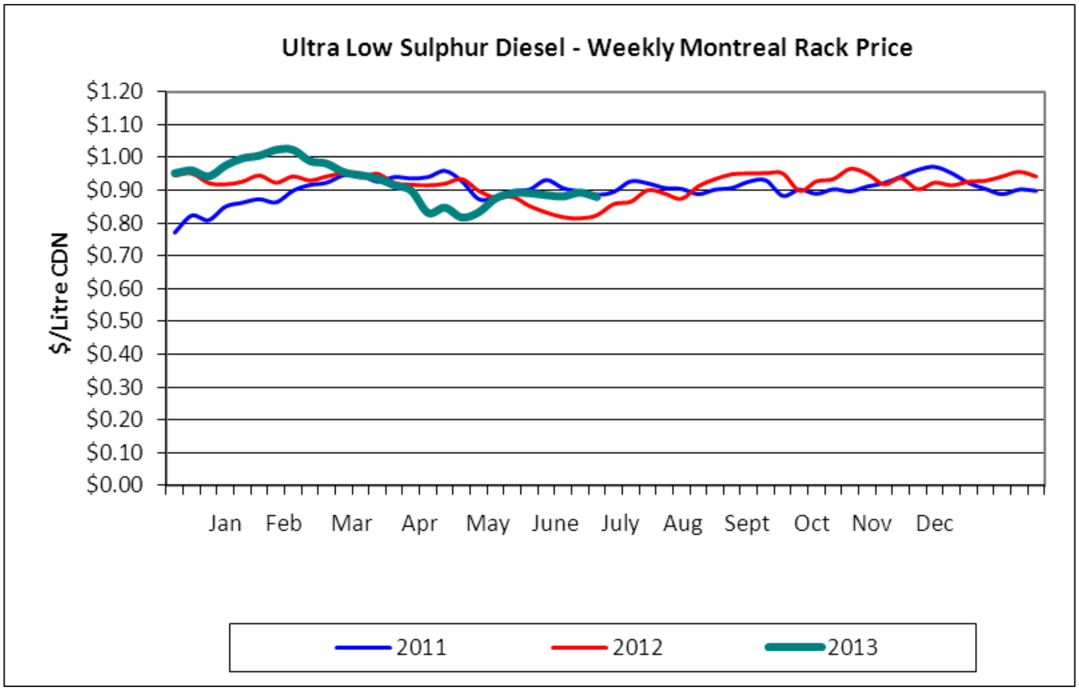
The following table provides the monthly forecast price of No. 6 fuel (0.7% sulphur) up to June 2014, landed on the Avalon Peninsula.

No. 6 Fuel Oil Sulphur
Forecast Price July 2013 – June 2014

Month	Price ($Cdn/bbl) 0.7%	Month	Price ($Cdn/bbl) 0.7%
July 2013	101.10	January 2014	101.70
August 2013	101.20	February 2014	101.50
September 2013	105.00	March 2014	100.10
October 2013	104.80	April 2014	97.90
November 2013	104.70	May 2014	96.00
December 2013	101.80	June 2014	97.30

Note: The forecast is based on the PIRA Energy Group price forecast available June 25, 2013 and an exchange rate forecast by Canadian financial institutions and the Conference Board of Canada.

The following chart shows Low Sulphur Diesel No. 1 fuel prices year-to-date compared to 2011 and 2012.



4.1.5 Energy Supply - Isolated Systems

Total isolated energy supply increased by 2% for the first half of 2013 over the first half of 2012 with the increase primarily attributed to sales growth on the L'Anse au Loup and Mary's Harbour systems. Net diesel production was marginally higher while energy purchases were approximately 6% higher when comparing 2013 to 2012. Compared with the forecast for produced and purchased energy for the isolated systems, the first half of 2013 is lower than expected.

Energy purchases are based on fuel prices with the average cost for the first half of 2013 being $143 per megawatt hour. The average cost for energy purchases is unchanged from the same period in 2012.

Isolated Systems Production
For the Quarter ended June 30, 2013

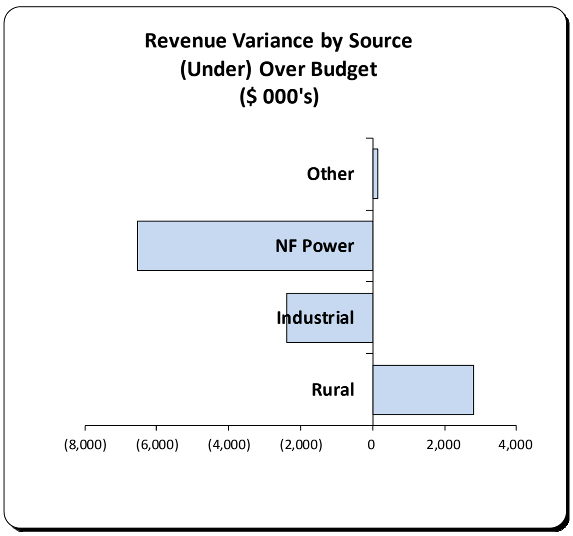
	Year-to-date						2013 Annual Forecast	
	2013		2012		2013 Forecast			
	(GWh)	$(000)[1]	(GWh)	$(000)[1]	(GWh)	$(000)[1]	(GWh)	$(000)[1]
Production (net)								
Diesels	24.1		24.0		25.9		50.6	
Purchases								
Non Utility Generators (NUGS)[2]	0.5	148.8	0.5	97.9	0.5	140.4	0.8	244.7
Hydro Québec	12.7	1,743.7	12.0	1686.3	12.8	1828.0	23.2	3,353.2
Total Purchases	**13.2**	**1,892.5**	**12.5**	**1,784.2**	**13.3**	**1968.4**	**24.0**	**3,597.9**
Isolated Systems Total Produced and Purchased	**37.3**	**1,892.5**	**36.5**	**1,784.2**	**39.2**	**1968.4**	**74.6**	**3,597.9**

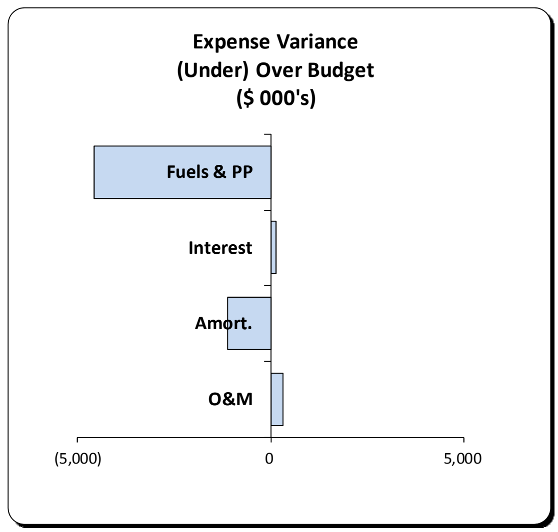
[1] Purchases before taxes.
[2] NUGS includes Frontier Power and Nalcor's wind/hydrogen facility in Ramea. Cost for 2012 is energy purchased from Frontier Power only.

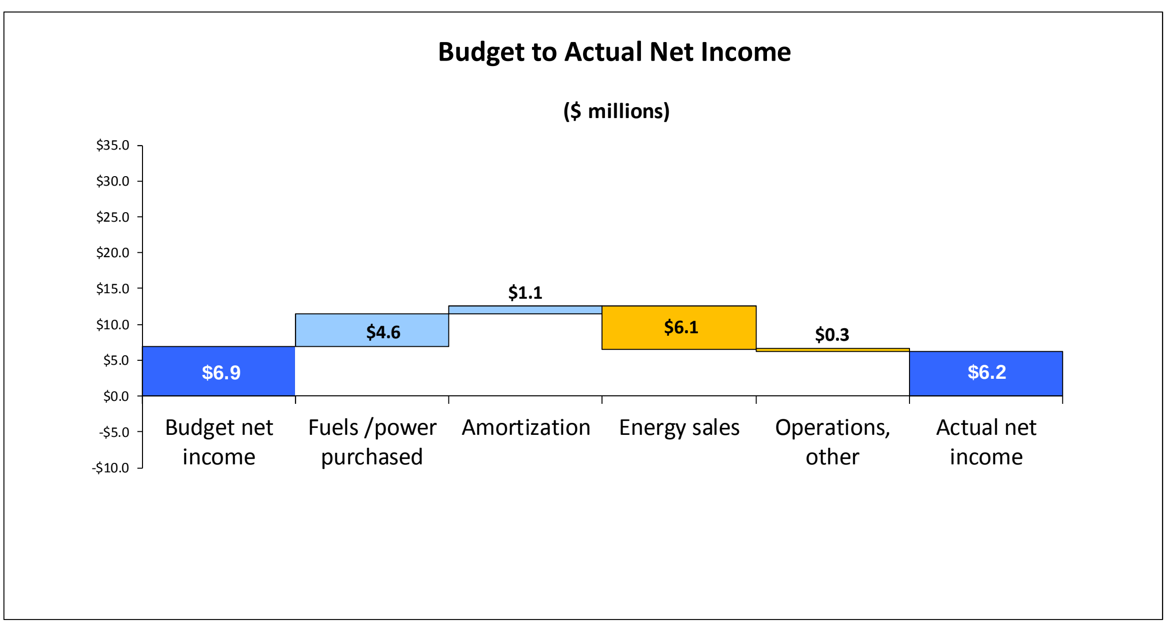
4.2 Financial

Below are charts of Hydro's (regulated) Statement of Income year to date. Please see Appendix C for the remainder of the financial statements.

Regulated Operations
For the six months ended June 30, 2013







Statement of Income - Regulated Operations
For the six months ended June 30, 2013
($ 000's)

Second Quarter 2013 Actual	Second Quarter 2013 Budget	Second Quarter 2012 Actual		Year-to-date 2013 Actual	Year-to-date 2013 Budget	Year-to-date 2012 Actual	2013 Annual Budget
			Revenue				
103,297	103,458	96,830	Energy sales	268,800	274,907	260,312	535,619
542	518	688	Other revenue	1,176	1,036	1,337	2,072
103,839	103,976	97,518		269,976	275,943	261,649	537,691
			Expenses				
24,729	30,751	28,183	Operations	57,024	56,670	51,922	111,922
(103)	2	(61)	(Gain) loss on disposal of property, plant and equipment	(34)	(7)	(58)	1,601
31,547	31,194	25,276	Fuels	105,098	109,009	98,148	212,462
14,373	14,489	13,504	Power purchased	30,567	31,230	28,621	59,377
12,644	13,485	11,979	Amortization	25,316	26,424	23,899	55,118
23,005	22,887	22,532	Interest	45,820	45,695	45,343	91,039
106,195	112,808	101,413		263,791	269,021	247,875	531,519
(2,356)	(8,832)	(3,895)	**Net income (loss)**	6,185	6,922	13,774	6,172

Note : Certain of the 2012 comparative figures were restated to conform with the 2013 presentation.

4.3 Capital Expenditures

Capital Expenditures - Overview
For the Quarter ended June 30, 2013
($000)

	PU Board Approved Budget	Second Quarter Actuals	Year To Date Actuals	Expected Remaining Expenditures
Generation	34,142	5,574	9,007	23,355
Transmission and Rural Operations	37,195	7,240	11,570	26,390
General Properties	7,768	2,217	2,362	5,406
Allowance for Unforeseen Events	1,000	117	401	599
Projects Approved by PU Board Order	35,536	7,251	9,937	26,191
New Projects Under $50,000 Approved by Hydro	61	7	69	-8
Total 2013 Capital Budget	115,702	22,406	33,346	81,933
2013 FEED costs for 2014 projects[1]	-	144	254	-
Total 2013 Capital plus 2014 FEED	115,702	22,550	33,600	81,933

[1] These costs represent Front End Engineering and Design (FEED) costs incurred in 2013 related to 2014 capital projects.

	($000)
2013 Capital Budget Approved by Board Order No. P.U. 4(2013)	$62,272
Carryover Projects 2012 to 2013	19,501
New Project Approved by Board Order No. P.U. 25(2012)	2,252
New Project Approved by Board Order No. P.U. 26(2012)	1,295
New Project Approved by Board Order No. P.U. 35(2012)	190
New Project Approved by Board Order No. P.U. 1(2013)	284
New Project Approved by Board Order No. P.U. 12(2013)	5,198
New Project Approved by Board Order No. P.U. 14(2013)	12,810
New Project Approved by Board Order No. P.U. 15(2013)	3,823
New Project Approved by Board Order No. P.U. 20(2013)	8,016
2013 New Projects Under $50,000 approved by Hydro	61
Total Approved Capital Budget	$115,702

5 OTHER ITEMS

5.1 Significant Issues

5.1.1 Ramea Wind-Hydrogen-Diesel Project Update

Overall Project Site Showing (l-r) the Diesel Plant/Storage Tanks, Meteorological Tower, Hydrogen Electrolyser, 3 Hydrogen Storage Tanks, Distribution Box Structure, 3 Wind Turbines, and Quonset Hut Housing the Hydrogen Genset.

In accordance with Order No. P.U. 31 (2007), the following update is provided on the Wind-Hydrogen-Diesel Project for Ramea.

Implementation and Operation

Some project deficiencies remained in this quarter and project close-out is deferred to the third quarter of 2013 to resolve reliability problems with the Hydrogen Genset and complete remaining project deficiencies. The operations schedule was revised to commence in the fourth quarter of 2013, pending completion of project close-out documentation.

Capital Costs

($000)

Actual Cost to June 2013	Actual Cost Recoveries to June 2013	Net Cost to June 2013	Budget to December 2008	Budget Reforecast to September 2010[1]
11,869	11,869	0	8,794	2,486

Operating Costs

There is nothing to report for this period as operation is planned to start in the third quarter of 2013.

Reliability and Safety Issues

There is nothing to report for this period.

[1] Project Change Order #3 is under draft to reflect various cost increases and schedule delays associated with incomplete commissioning activities, H_2 Genset issues and project deficiencies.

5.1.2 Rate Stabilization Plan resulted in Rate Decrease

Hydro filed an updated fuel price projection for the Rate Stabilization Plan (RSP) with the Newfoundland and Labrador Board of Commissioners of Public Utilities on April 12, 2013. This resulted in Hydro's Island Interconnected, L'Anse au Loup and Isolated Rural residential and general service customers receiving an overall average rate decrease of 3.0% effective July 1, 2013.

The decrease is an overall average resulting from the 7.9% decrease associated with the RSP and the 4.8% increase associated with Newfoundland Power's General Rate Application. Information outlining the specific rate changes was distributed to customers in late June.

5.1.3 St. Anthony Occupational Health and Safety Committee win Award

Hydro's St. Anthony Occupational Health and Safety Committee (OHSC) received the committee of the year award recently from the Newfoundland and Labrador Occupational Health and Safety Association. Executing work in a safe and healthy manner, and ensuring all employees go home safely each day is Hydro's number one priority. The members of the St. Anthony Occupational Health and Safety Committee demonstrate a commitment to improving workplace safety and exemplify the importance and value of safety. Joe Lake, President of the Newfoundland and Labrador Occupational Health and Safety Association presented the award and encouraged the group to continue to be safety leaders.

5.2 Community

5.2.1 Hydro participated in Community Investment Program

The Community Investment Program (CIP) is a donation/sponsorship program that aligns with Nalcor's corporate goals and priorities. The program looks to enhance and invest in local communities, be a catalyst for good corporate citizenship and assist in empowering employees to improve the quality of life for our community. Hydro sponsored more than 25 initiatives over the past three months. Sponsorships included employee volunteerism for groups such as MADD Labrador West and several school breakfast programs; employee donation matching to charities such as the Canadian Cancer Society, Autism Society of Newfoundland and Labrador and the East Coast Trail Association; and Funding for a new playground in Dildo, a Children's Safety Booklet for Child Find Newfoundland and Labrador and the Senior Resource Centre dinner and auction.

5.2.2 Acts of Kindness Week 2013

The third annual Acts of Kindness Week kicked off on April 22, 2013 with an array of volunteer activities for employees to participate in. Activities included; providing breakfast to children in schools, spending time with seniors, building benches and stacking shelves. Employees generously volunteered time away from work to help out not-for-profit and charity organizations in their communities.

Small gestures often make lasting impressions, as was evident with the response from residents at the Greenwood Manor Senior's Home in Bay d'Espoir. Jessica Lowe, Appr. Power System Operator, played her guitar and sang a few songs with the residents while the other volunteers prepared a lunch of sandwiches, fruit, dessert and tea.

5.3 Statement of Energy Sold

Statement of Energy Sold (GWh)
For the Quarter ended June 30

	YEAR TO DATE			2013[1]	
	2013 ACTUAL	**2012 ACTUAL**	**2013 YTD BUDGET**	**ANNUAL BUDGET**	**YTD % CHANGE**
Island Interconnected					
Newfoundland Power	3,103	3,014	3,175	5,691	3.0%
Island Industrials	180	217	223	446	-17.1%
Rural					
Domestic	146	146	138	248	0.0%
General Service	90	87	80	159	3.4%
Streetlighting	1	1	1	3	0.0%
Sub-total Rural	237	234	219	410	1.3%
Sub-Total Island Interconnected	3,520	3,465	3,617	6,547	1.6%
Island Isolated					
Domestic	4	4	3	6	0.0%
General Service	1	1	1	1	0.0%
Streetlighting	0	0	0	0	0.0%
Sub-Total Island Isolated	5	5	4	7	0.0%
Labrador Interconnected					
Labrador Industrials	124	110	189	374	12.7%
CFB Goose Bay	1	8	0	0	-87.5%
Hydro Quebec (includes Menihek)	24	25	23	41	-4.0%
Export	701	723	590	1,283	-3.0%
Rural					
Domestic	183	188	178	300	-2.7%
General Service	147	151	144	263	-2.6%
Streetlighting	1	0	1	2	0.0%
Sub-total Rural	331	339	323	565	-2.4%
Sub-Total Lab. Interconnected	1,181	1,205	1,125	2,263	-2.0%
Labrador Isolated					
Domestic	12	12	12	23	0.0%
General Service	7	7	8	17	0.0%
Streetlighting	0	0	0	0	0.0%
Sub-Total Labrador Isolated	19	19	20	40	0.0%
L'Anse au Loup					
Domestic	8	8	8	15	0.0%
General Service	4	4	4	8	0.0%
Streetlighting	0	0	0	0	0.0%
Sub-Total L'Anse au Loup	12	12	12	23	0.0%
Total Energy Sold	4,737	4,706	4,778	8,880	0.7%
Sales to Non-Regulated Customers[2]	849	858	802	1,698	-1.0%

[1] Rural GWh - Based on 2013 Budget, Fall 2012 Rural Load Forecast
Non-rural GWh - Based on 2013TY Wholesale Industrial Revenue Budget
[2] Included in Total Energy Sold

5.4 Customer Statistics

Customer Statistics For the Quarter ended June 30	SECOND QUARTER		ANNUAL	
	2013 ACTUAL	2012 ACTUAL	2013 Budget	2012 ACTUAL
Customers				
Rural	37,687	37,273	37,604	37,576
Industrial	4	4	5	4
CFB Goose Bay	1	1	0	1
Utility	1	1	1	1
Non-Regulated	3	3	3	3
Reading Days	29.9	30.1	N/A	30.0

APPENDICES

CIAC QUARTERLY ACTIVITY REPORT
For the Quarter ended June 30, 2013

TYPE OF SERVICE	CIAC'S QUOTED	CIAC'S OUTSTANDING PREVIOUS QTR.	TOTAL CIAC'S QUOTED	CIAC'S ACCEPTED	CIAC'S EXPIRED	TOTAL CIAC'S OUTSTANDING
Domestic						
Within Plan. Boundary	14	4	18	6	2	10
Outside Plan. Boundary	1	0	1	1	0	0
Sub-total	15	4	19	7	2	10
General Service	3	3	6	1	0	5
Total	18	7	25	8	2	15

The table above summarizes Contribution in Aid of Construction (CIAC) activity for this quarter. The table is divided into three sections, as follows:

- The first section outlines the type of service for which a CIAC has been calculated, either Domestic or General Service.
- The second section indicates the number of CIACs quoted during the quarter as well as the number of CIAC quotes that remained outstanding at the end of the previous quarter. This format facilitates a reconciliation of the total number of CIACs that were active during the quarter.
- The third section provides information as to the disposition of the total CIACs quoted. A CIAC is considered accepted when a customer indicates they wish to proceed with construction of the extension and has agreed to pay any charge that may be applicable. A CIAC is considered outdated after six months has elapsed and the customers have not indicated their intention to proceed with the extension. A quoted CIAC is outstanding if it is neither accepted nor outdated.

CIAC QUARTERLY ACTIVITY REPORT
For the Quarter ended June 30, 2013

DATE QUOTED	SERVICE LOCATION	CIAC NO.	CIAC AMOUNT ($)	ESTIMATED CONST. COST ($)	ACCEPTED
DOMESTIC - WITHIN RESIDENTIAL PLANNING BOUNDARIES					
April 2, 2013	King's Point	972591	$ 41,850.00	$ 42,600.00	
April 5, 2013	South Brook; Green Bay	974939	$ 3,022.50	$ 3,772.50	
April 16, 2013	South Brook; Green Bay	972590	$ 2,271.20	$ 3,021.20	
April 17, 2013	South Brook; Green Bay	977719	$ 6,345.00	$ 7,095.00	
April 19, 2013	Happy Valley-Goose Bay	974852	$ 4,950.00	$ 5,700.00	
April 19, 2013	Happy Valley-Goose Bay	974848	$ 4,950.00	$ 6,450.00	
April 23, 2013	St. Veronica's	976957	$ 2,850.00	$ 3,600.00	Yes
May 16, 2013	Conne River	981948	$ -	$ 2,512.50	Yes
May 21, 2013	South Brook; Green Bay	981807	$ 2,865.00	$ 3,515.00	Yes
May 21, 2013	South Brook; Green Bay	980960	$ 6,180.00	$ 6,930.00	Yes
June 3, 2013	Fleur de Lys	982404	$ 393.75	$ 2,343.75	Yes
June 7, 2013	South Brook; Green Bay	982271	$ 586.20	$ 1,126.20	
June 11, 2013	LaScie	984576	$ 3,650.00	$ 5,600.00	
June 17, 2013	Change Islands	941246	$ 180.00	$ 1,830.00	
DOMESTIC - OUTSIDE RESIDENTIAL PLANNING BOUNDARIES					
May 23, 2013	St. Anthony	982280	$ 2,235.00	$ 2,525.55	Yes
GENERAL SERVICE					
April 19, 2013	Westport	972270	$ 6,920.00	$ 9,470.00	Yes
May 29, 2013	L'Anse au Loup	921237	$ 774,269.00	$ 801,279.00	
May 29, 2013	Bear Cove	921568	$ -	$ 22,500.00	

CUSTOMER PROPERTY DAMAGE CLAIMS REPORT
For the Quarter ended June 30, 2013

Introduction

The Customer Property Damage Claims Report contains an overview of all damage claims activity summarized on a quarterly basis. The information contained in the report is broken down by cause as well as by the operating region where the claims originated.

The report is divided into four sections as follows:

1. The first section indicates the number of claims received during the quarter coupled with claims outstanding from the previous quarter.

2. The second section shows the number of claims for which the Company has accepted responsibility and the amount paid to claimants versus the amount originally claimed.

3. The third section shows the number of claims rejected and the dollar value associated with those claims.

4. The fourth section indicates those claims that remain outstanding at the end of the current quarter and the dollar value associated with such claims.

Definitions of Causes of Damage Claims

1. System Operations: Claims arising from system operations. Examples include normal reclosing or switching.

2. Power Interruptions: Claims arising from interruption of power supply. Examples include all scheduled or unscheduled interruptions.

3. Improper Workmanship: Claims arising from failure of electrical equipment caused by improper workmanship or methods. Examples include improper crimping of connections, insufficient sealing and taping of connections, improper maintenance, inadequate clearance or improper operation of equipment.

4. Weather Related: Claims arising from weather conditions. Examples include wind, rain, ice, lighting or corrosion caused by weather.

5. Equipment Failure: Claims arising from failure of electrical equipment not caused by improper workmanship. Examples include broken neutrals, broken tie wires, transformer failure, insulator failure or broken service wire.

6. Third Party: Claims arising from equipment failure caused by acts of third parties. Examples include motor vehicle accidents and vandalism.

7. Miscellaneous: All claims not related to electrical service.

8. Waiting Investigation: Cause to be determined.

CUSTOMER PROPERTY DAMAGE CLAIMS REPORT - BY CAUSE

For the Quarter ended June 30, 2013

CAUSE	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	AMT. CLAIMED	AMT. PAID	#	AMOUNT	#	AMOUNT
System Operations	0	1	1	0	$ -	$ -	0	$ -	1	$ 762.00
Power Interruptions	1	1	2	0	$ -	$ -	2	$ -	0	$ -
Improper Workmanship	2	5	7	2	$ 3,060.21	$ 2,314.74	1	$ 677.99	3	$ 3,123.70
Weather Related	7	6	13	1	$ 1,705.12	$ 1,705.12	6	$ 1,500.03	5	$ 8,434.67
Equipment Failure	1	5	6	1	$ 7,460.58	$ 5,738.95	0	$ -	5	$ 17,564.00
Third Party	0	0	0	0	$ -	$ -	0	$ -	0	$ -
Miscellaneous	1	1	2	0	$ -	$ -	0	$ -	2	$ 3,549.00
Waiting Investigation	1	6	7	0	$ -	$ -	3	$ 3,188.00	4	$ 13,336.61
Total	13	25	38	4	$ 12,225.91	$ 9,758.81	12	$ 5,366.02	20	$ 46,769.98

For the Quarter ended June 30, 2012

CAUSE	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	AMT. CLAIMED	AMT. PAID	#	AMOUNT	#	AMOUNT
System Operations	0	0	0	0	$ -	$ -	0	$ -	0	$ -
Power Interruptions	4	0	4	0	$ -	$ -	3	$ 915.00	1	$ 169.98
Improper Workmanship	1	7	8	1	$ 10,578.65	$ 10,458.65	1	$ 110.00	6	$ 5,730.97
Weather Related	4	4	8	1	$ 2,150.00	$ 682.50	2	$ 500.00	5	$ 4,057.32
Equipment Failure	2	5	7	1	$ 3,597.06	$ 2,756.45	2	$ 100.00	4	$ 15,564.00
Third Party	0	0	0	0	$ -	$ -	0	$ -	0	$ -
Miscellaneous	2	0	2	0	$ -	$ -	0	$ -	2	
Waiting Investigation	1	4	5	0	$ -	$ -	0	$ -	4	$ 3,188.00
Total	14	20	34	3	$ 16,325.71	$ 13,897.60	8	$ 1,625.00	22	$ 28,710.27

CUSTOMER PROPERTY DAMAGE CLAIMS REPORT - BY REGION

For the Quarter ended June 30, 2013

REGION	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	AMT. CLAIMED	AMT. PAID	#	AMOUNT	#	AMOUNT
Central Region	4	2	6	1	$ 7,460.58	$ 5,738.95	3	$ 158.14	2	$ 1,074.62
Northern Region	5	15	20	2	$ 3,274.86	$ 3,274.86	6	$ 922.19	11	$ 36,384.36
Labrador Region	4	8	12	1	$ 1,490.47	$ 745.00	3	$ 4,285.69	7	$ 9,311.00
Total	13	25	38	4	$ 12,225.91	$ 9,758.81	12	$ 5,366.02	20	$ 46,769.98

For the Quarter ended June 30, 2012

REGION	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	AMT. CLAIMED	AMT. PAID	#	AMOUNT	#	AMOUNT
Central Region	6	7	13	1	$ 2,150.00	$ 682.50	4	$ 735.00	8	$ 5,976.89
Northern Region	4	7	11	1	$ 3,597.06	$ 2,756.45	2	$ -	8	$ 14,545.38
Labrador Region	4	6	10	1	$ 10,578.65	$ 10,458.65	2	$ 890.00	6	$ 8,188.00
Total	14	20	34	3	$ 16,325.71	$ 13,897.60	8	$ 1,625.00	22	$ 28,710.27

FINANCIAL – REGULATED

Balance Sheet - Regulated Operations
As at June 30
($ 000's)

	Jun-13	Jun-12
ASSETS		
Current assets		
Cash and cash equivalents	3,728	4,747
Accounts receivable	52,712	45,306
Current portion of regulatory assets	2,157	2,399
Inventory	80,274	79,875
Prepaid expenses	4,456	4,187
	143,327	136,514
Property, plant, and equipment	1,445,660	1,411,079
Sinking funds	260,236	252,900
Regulatory assets	62,351	62,955
Total assets	1,911,574	1,863,448
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	40,385	34,822
Accrued interest	28,667	28,667
Current portion of long-term debt	8,150	8,150
Current portion of regulatory liabilities	186,901	124,939
Deferred credits	1,533	3,372
Due to related parties	5,003	13,366
Promissory notes	6,149	18,949
	276,788	232,265
Long-term debt	1,123,512	1,128,794
Regulatory liabilities	60,326	58,252
Asset retirement obligations	24,312	19,908
Employee future benefits	59,624	54,719
Contributed capital	100,000	100,000
Shareholder's equity / retained earnings	237,359	226,698
Accumulated other comprehensive income	29,653	42,812
Total liabilities and shareholder's equity	1,911,574	1,863,448

Note: Certain of the 2012 comparative figures were restated to conform with the 2013 presentation.

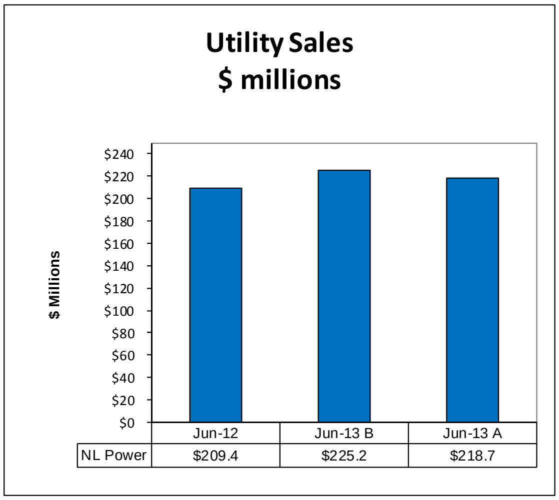
Statement of Retained Earnings - Regulated Operations
For the six months ended June 30, 2013
($ 000's)

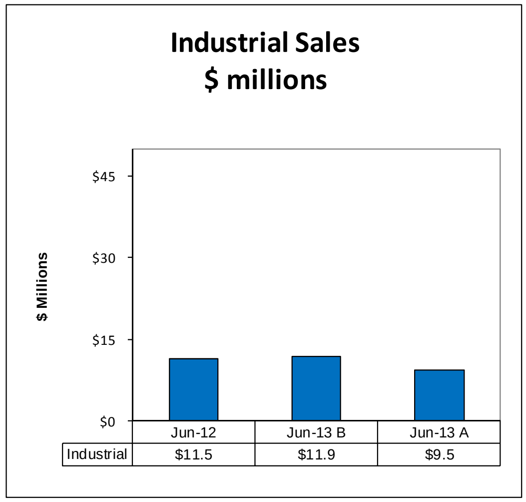
Second Quarter 2013 Actual	Second Quarter 2012 Actual		Year-to-date 2013 Actual	Year-to-date 2012 Actual
239,715	230,593	Balance, beginning of period	231,174	212,096
-	-	Adjustment	-	828
(2,356)	(3,895)	Net income (loss)	6,185	13,774
237,359	226,698	Balance, end of period	237,359	226,698

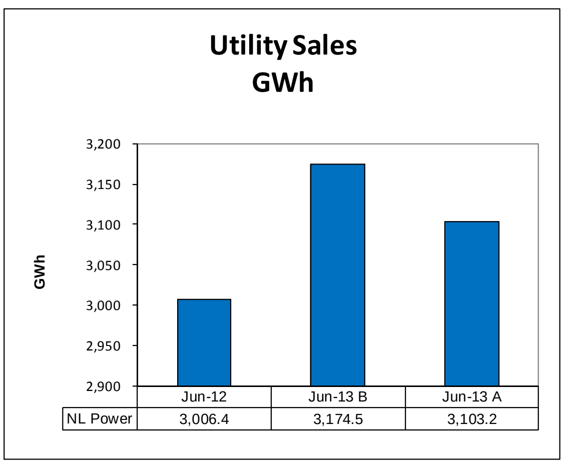
Statement of Comprehensive Income - Regulated Operations
For the six months ended June 30, 2013
($ 000's)

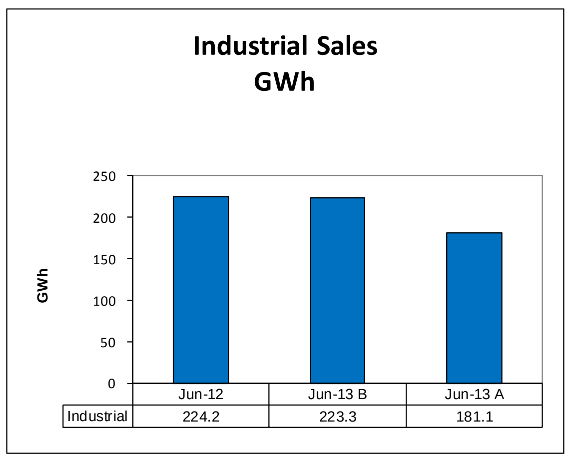
Second Quarter 2013 Actual	Second Quarter 2013 Budget	Second Quarter 2012 Actual		Year-to-date 2013 Actual	Year-to-date 2013 Budget	Year-to-date 2012 Actual	2013 Annual Budget
(2,356)	(8,832)	(3,895)	Net income (loss)	6,185	6,922	13,774	6,172
			Other comprehensive (loss) income				
(10,184)	-	3,192	Change in fair value of sinking fund investments	(11,887)	-	(2,295)	-
(12,540)	(8,832)	(703)	Total comprehensive (loss) income	(5,702)	6,922	11,479	6,172

Sales - Regulated Operations
For the six months ended June 30, 2013









Revenue Summary - Regulated Operations
For the six months ended June 30, 2013
($ 000's)

Second Quarter 2013 Actual	Second Quarter 2013 Budget	Second Quarter 2012 Actual		Year-to-date 2013 Actual	Year-to-date 2013 Budget	Year-to-date 2012 Actual	2013 Annual Budget
			REVENUE				
			Industrial				
1,048	1,441	1,693	Corner Brook Pulp and Paper Ltd.	2,165	2,809	3,126	6,644
17	663	-	Vale Inco	29	1,100	-	3,817
2,780	2,979	2,993	North Atlantic Refinery	5,363	5,966	5,894	13,390
114	-	569	C.F.B. Goose Bay	117	-	680	-
892	914	906	Teck Cominco Limited	1,810	1,849	1,829	4,337
-	136	-	Praxair	-	136	-	760
4,851	6,133	6,161	**Total Industrial**	9,484	11,860	11,529	28,948
			Utility				
80,722	81,067	73,566	Newfoundland Power Inc.	218,702	225,239	209,409	430,447
			Rural				
17,724	16,258	17,103	Interconnected and diesel	40,614	37,808	39,374	76,224
542	518	688	**Other**	1,176	1,036	1,337	2,072
103,839	103,976	97,518	**Total**	269,976	275,943	261,649	537,691
			ENERGY SALES (GWh)				
			Industrial				
15.3	24.3	30.6	Corner Brook Pulp and Paper Ltd.	32.4	46.6	54.7	87.9
0.3	8.2	-	Vale Inco	0.5	12.6	-	39.6
58.0	63.6	63.7	North Atlantic Refinery	110.6	126.1	125.0	238.4
1.3	-	6.4	C.F.B. Goose Bay	1.3	-	7.7	-
17.8	18.4	18.2	Teck Cominco Limited	36.3	37.4	36.8	74.0
-	0.6	-	Praxair	-	0.6	-	6.5
92.7	115.1	118.9	**Total Industrial**	181.1	223.3	224.2	446.4
			Utility				
1,219.4	1,228.9	1,143.1	Newfoundland Power Inc.	3,103.2	3,174.5	3,006.4	5,691.0
			Rural				
247.6	229.4	248.6	Interconnected and diesel	603.1	579.3	609.8	1,044.7
1,559.7	1,573.4	1,510.6	**Total**	3,887.4	3,977.1	3,840.4	7,182.1

Note: Certain of the 2012 comparative figures were restated to conform with the 2013 presentation.

Statement of Cash Flows - Regulated Operations
For the six months ended June 30, 2013
($ 000's)

	Year-to-date 2013	Year-to-date 2012
Operating activities		
Net income	6,185	13,774
Adjusted for items not involving cash flow		
Amortization	25,231	23,583
Accretion of long-term debt	264	243
Employee future benefits	2,734	2,306
Gain on disposal of property, plant and equipment	(34)	(65)
Other	(115)	-
	34,265	39,841
Changes in non-cash balances		
Accounts receivable	27,473	34,053
Inventory	(28,601)	(25,617)
Prepaid expenses	(1,507)	(1,903)
Regulatory assets	473	1,005
Regulatory liabilities	45,068	12,327
Accounts payable and accrued liabilities	1,086	(14,519)
Due to related parties	3,130	(35,892)
	81,387	9,295
Financing activities		
Decrease in long-term receivable	188	210
Decrease in deferred credits	(405)	(21)
(Decrease) increase in promissory notes	(38,634)	24,067
	(38,851)	24,256
Investing activities		
Additions to property, plant and equipment	(33,700)	(24,508)
Proceeds on disposal of property, plant and equipment	3,743	239
Increase in sinking funds	(11,331)	(11,220)
	(41,288)	(35,489)
Net increase (decrease) in cash	1,248	(1,938)
Cash position, beginning of period	2,480	6,685
Cash position, end of period	3,728	4,747

Note: Certain of the 2012 comparative figures were restated to conform with the 2013 presentation.

FINANCIAL - NON-REGULATED

Balance Sheet - Non-Regulated Activities
As at June 30
($ 000's)

	Jun-13	Jun-12
ASSETS		
Current assets		
Accounts receivable	5,092	3,012
Prepaid expenses	769	-
	5,861	3,012
Investment in CF(L)Co.	430,156	415,927
Total assets	436,017	418,939
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	1,984	3,579
Promissory notes	7,851	5,051
Derivative liabilities	932	585
	10,767	9,215
Share capital	22,504	22,504
Lower Churchill Development Corp	15,400	15,400
Retained earnings	387,653	371,822
Accumulated other comprehensive loss	(307)	(2)
Total liabilities and shareholder's equity	436,017	418,939

Note: Certain of the 2012 comparative figures were restated to conform with the 2013 presentation.

Statement of Income - Non-Regulated Activities
For the six months ended June 30, 2013
($ 000's)

Second Quarter 2013 Actual	Second Quarter 2013 Budget	Second Quarter 2012 Actual		Year-to-date 2013 Actual	Year-to-date 2013 Budget	Year-to-date 2012 Actual	2013 Annual Budget
			Revenue				
16,156	16,757	9,879	Energy sales	32,400	29,820	21,249	65,822
16,156	16,757	9,879		32,400	29,820	21,249	65,822
			Expenses				
6,593	6,823	6,429	Operations	14,510	13,241	12,666	26,550
1,608	1,391	1,470	Power purchased	3,406	2,283	3,362	5,032
730	-	507	Other income and expense	960	-	554	-
(79)	-	134	Interest	(242)	-	234	-
8,852	8,214	8,540		18,634	15,524	16,816	31,582
7,304	8,543	1,339	Net operating income	13,766	14,296	4,433	34,240
(3,013)	(3,177)	(1,709)	Equity in CF(L)Co	12,837	10,717	16,773	15,460
2,215	2,211	2,828	Preferred dividends	5,232	4,423	5,642	8,847
(798)	(966)	1,119		18,069	15,140	22,415	24,307
6,506	7,577	2,458	**Net income**	31,835	29,436	26,848	58,547

Note : Certain of the 2012 comparative figures were restated to conform with the 2013 presentation.

Statement of Retained Earnings - Non-Regulated Activties
For the six months ended June 30, 2013
($ 000's)

Second Quarter 2013 Actual	Second Quarter 2012 Actual		Year-to-date 2013 Actual	Year-to-date 2012 Actual
389,853	374,709	Balance, beginning of period	373,578	356,645
0	(1,260)	Adjustments	-	7
6,506	2,458	Net income	31,835	26,848
(8,706)	(4,085)	Dividends	(17,760)	(11,678)
387,653	371,822	Balance, end of period	387,653	371,822

Statement of Comprehensive Income - Non-Regulated Activities
For the six months ended June 30, 2013
($ 000's)

Second Quarter 2013 Actual	Second Quarter 2013 Budget	Second Quarter 2012 Actual		Year-to-date 2013 Actual	Year-to-date 2013 Budget	Year-to-date 2012 Actual	2013 Annual Budget
6,506	7,577	2,458	Net income	31,835	29,436	26,848	58,547
			Other comprehensive loss				
390	-	96	Share of CF(L)Co other comprehensive income (loss)	(395)	-	(2)	-
6,896	7,577	2,554	Total comprehensive income	31,440	29,436	26,846	58,547

Statement of Cash Flows - Non-Regulated Activities
For the six months ended June 30, 2013
($ 000's)

	Year-to-date 2013	Year-to-date 2012
Operating activities		
Net income	31,835	26,848
Adjusted for items not involving cash flow		
Unrealized loss on derivatives	960	771
Equity in CF(L)Co	(13,056)	(16,773)
	19,739	10,846
Changes in non-cash balances		
Accounts receivable	(1,604)	679
Accounts payable and accrued liabilities	(240)	121
Increase in prepaid expenses	(769)	-
	17,126	11,646
Financing activities		
Increase (decrease) in promissory notes	634	(60)
Decrease in long-term receivable	-	1,398
Decrease in long-term note payable	-	(1,306)
Dividends	(17,760)	(11,678)
	(17,126)	(11,646)
Net change in cash	-	-
Cash position, beginning of period	-	-
Cash position, end of period	-	-

Note: Certain of the 2012 comparative figures were restated to conform with the 2013 presentation.

Supplementary Schedule - Regulated Operations
For the six months ended June 30, 2013
($ 000's)

Second Quarter 2013 Actual	Second Quarter 2013 Budget	Second Quarter 2012 Actual		Year-to-date 2013 Actual	Year-to-date 2013 Budget	Year-to-date 2012 Actual	2013 Annual Budget
			Other revenue				
116	149	223	Sundry	290	298	460	595
404	343	406	Pole attachments	806	687	805	1,375
22	26	59	Supplier's discount	80	51	72	102
542	518	688	**Total other revenue**	1,176	1,036	1,337	2,072
			Interest				
27,934	28,155	26,910	Gross interest	55,505	55,973	53,933	112,806
134	134	123	Accretion of long-term debt	264	264	243	540
539	527	539	Amortization of foreign exchange losses	1,078	1,078	1,078	2,157
(684)	(532)	(545)	Allowance for funds used during construction	(1,340)	(963)	(977)	(2,747)
(4,918)	(5,397)	(4,495)	Interest earned	(9,687)	(10,657)	(8,934)	(21,717)
23,005	22,887	22,532	**Total interest**	45,820	45,695	45,343	91,039

Note: Certain of the 2012 comparative figures were restated to conform with the 2013 presentation.

Cost Recoveries - Regulated Operations
For the six months ended June 30, 2013
($ 000's)

Second Quarter				Year-to-date			
2013 Actual	2013 Budget	2012 Actual		2013 Actual	2013 Budget	2012 Actual	2013 Annual Budget
-	4	2	Executive Leadership	2	7	6	14
306	291	245	Human Resources and Organizational Effectiveness	546	579	445	1,157
1,339	1,331	1,455	Finance / CFO	2,609	2,643	2,659	5,286
21	2	15	Engineering Services	26	4	45	8
42	28	31	Regulated Operations	72	57	56	115
1,708	1,656	1,748		3,255	3,290	3,211	6,580

Newfoundland and Labrador Hydro
Rate Stabilization Plan
June 30, 2013

Rate Stabilization Plan Report
June 30, 2013

Summary of Key Facts

The Rate Stabilization Plan of Newfoundland and Labrador Hydro (Hydro), as amended by Board Order No. P.U. 40 (2003) and Order No. P.U. 8 (2007), is established for Hydro's utility customer, Newfoundland Power, and Island Industrial customers to smooth rate impacts for variations between actual results and Test Year Cost of Service estimates for:

- Hydraulic production;
- No. 6 fuel cost used at Hydro's Holyrood generating station;
- Customer load (Utility and Island Industrial); and
- Rural rates.

The Test Year Cost of Service Study was approved by Board Order No. P.U. 8 (2007) and is based on projections of events and costs that are forecast to happen during a test year. Finance charges are calculated on the balances using the test year Weighted Average Cost of Capital which is currently 7.529% per annum. Holyrood's operating efficiency is set, for RSP purposes, at 630 kWh/barrel regardless of the actual conversion rate experienced.

	2007 Test Year Cost of Service			
	Net Hydraulic Production	No. 6 Fuel Cost	Utility Load	Industrial Load
	(kWh)	($Can/bbl.)	(kWh)	(kWh)
January	427,100,000	54.17	574,800,000	78,300,000
February	388,680,000	54.73	518,600,000	70,900,000
March	415,080,000	55.46	524,700,000	76,600,000
April	355,520,000	55.46	429,200,000	75,600,000
May	324,240,000	55.46	358,700,000	69,500,000
June	328,500,000	54.49	298,400,000	73,800,000
July	386,790,000	54.49	293,400,000	77,500,000
August	379,140,000	54.49	287,000,000	77,900,000
September	363,560,000	54.49	297,700,000	73,000,000
October	340,510,000	54.56	360,200,000	74,400,000
November	364,390,000	54.56	439,300,000	74,100,000
December	398,560,000	58.98	543,800,000	72,700,000
Total	4,472,070,000		4,925,800,000	894,300,000

Rate Stabilization Plan
Plan Highlights
June 30, 2013

	Actual	Cost of Service	Variance	Year-to-Date Due (To) From customers	Reference
Hydraulic production year-to-date	2,530.6 GWh	2,239.1 GWh	291.4 GWh	$ (25,359,154)	Page 4
No 6 fuel cost - Current month	$ 104.90	$ 54.49	$ 50.41	$ 53,203,791	Page 5
Year-to-date customer load - Utility	3,103.2 GWh	2,704.4 GWh	398.8 GWh	$ (455,314)	Page 8
Year-to-date customer load - Industrial	179.9 GWh	444.7 GWh	-264.8 GWh	$ (13,357,765)	Page 9
				$ 14,031,558	

Rural rates		
Rural Rate Alteration (RRA) (1)	$ (4,749,113)	
Less : RRA to utility customer	$ (4,231,460)	Page 10
RRA to Labrador interconnected	(517,653)	
Fuel variance to Labrador interconnected	$ 415,993	Page 6
Net Labrador interconnected	$ (101,660)	

Current plan summary		
One year recovery		
Due (to) from utility customer	$ (70,527,942)	Page 10
Due (to) from Industrial customers	$ (116,373,601)	Page 11
Sub total	(186,901,543)	
Four year recovery		
Hydraulic balance	$ (59,841,516)	Page 4
Total plan balance	$ (246,743,059)	

(1) Beginning January 2011, the RRA includes a monthly credit of $98,295. This amount relates to the phase in of the application of the credit from secondary energy sales to CFB Goose Bay to the Rural deficit as stated in Section B, Clause 1.3(b) of the approved Rate Stabilization Plan Regulations which received final approval in Order No. P.U. 33 (2010) issued December 15, 2010.

Rate Stabilization Plan
Net Hydraulic Production Variation
June 30, 2013

	A	B	C	D	E	F	G
	Cost of Service Net Hydraulic Production	Actual Net Hydraulic Production	Monthly Net Hydraulic Production Variance	Cost of Service No. 6 Fuel Cost	Net Hydraulic Production Variation	Financing Charges	Cumulative Variation and Financing Charges
	(kWh)	(kWh)	(kWh)	($Can/bbl.)	($)	($)	($)
			(A - B)		**(C / O[1] X D)**		**(E + F)** **(to page 12)**
Opening balance							(32,675,763)
January	427,100,000	537,465,293	(110,365,293)	54.17	(9,489,663)	(198,260)	(42,363,686)
February	388,680,000	473,366,259	(84,686,259)	54.73	(7,356,951)	(257,042)	(49,977,679)
March	415,080,000	451,303,396	(36,223,396)	55.46	(3,188,809)	(303,240)	(53,469,728)
April	355,520,000	406,276,108	(50,756,108)	55.46	(4,468,149)	(324,428)	(58,262,305)
May	324,240,000	351,332,533	(27,092,533)	55.46	(2,385,003)	(353,507)	(61,000,815)
June	328,500,000	310,817,215	17,682,785	54.49	1,529,421	(370,122)	(59,841,516)
July							
August							
September							
October							
November							
December							
	2,239,120,000	2,530,560,804	(291,440,804)		(25,359,154)	(1,806,599)	(59,841,516)
Hydraulic Allocation [2]							
Hydraulic variation at year end					(25,359,154)	(1,806,599.00)	(59,841,516)

(1) O is the Holyrood Operating Efficiency of 630 kWh/barrel.

(2) At year end 25% of the hydraulic variation balance and 100% of the annual financing charges are allocated to customers.

Rate Stabilization Plan
No. 6 Fuel Variation
June 30, 2013

	A	B	C	D	E	F	G
	Actual Quantity No. 6 Fuel (bbl.)	Actual Quantity No. 6 Fuel for Non-Firm Sales (bbl.)	Net Quantity No. 6 Fuel (bbl.) **(A - B)**	Cost of Service No. 6 Fuel Cost ($Can/bbl.)	Actual Average No. 6 Fuel Cost ($Can/bbl.)	Cost Variance ($Can/bbl.) **(E - D)**	No.6 Fuel Variation ($) **(C X F)** **(to page 6)**
January	297,603	0	297,603	54.17	105.89	51.72	15,392,012
February	242,076	6	242,070	54.73	108.00	53.27	12,895,076
March	202,010	0	202,010	55.46	111.07	55.61	11,233,756
April	153,817	0	153,817	55.46	107.83	52.37	8,055,421
May	67,271	0	67,271	55.46	104.90	49.44	3,325,862
June	45,659	0	45,659	54.49	104.90	50.41	2,301,664
July							
August							
September							
October							
November							
December							
	1,008,436	6	1,008,430				53,203,791

Rate Stabilization Plan

Allocation of Fuel Variance - Year-to-Date

June 30, 2013

	A	B	C	D	E	F	G	H	I	J
	Twelve Months-to-Date				Year-to-Date Fuel Variance				Reallocate Rural Island Customers (1)	
	Utility	Industrial Customers	Rural Island Customers	Total	Utility	Industrial Customers	Rural Island Interconnected	Total	Utility	Labrador Interconnected
	(kWh)	(kWh)	(kWh)	(kWh)	($)	($)	($)	($)	($)	($)
				(A+B+C)	**(A/D X H)**	**(B/D X H)**	**(C/D X H)**		**(G X 89.10%)**	**(G X 10.90%)**
					(to page 7)			**(from page 5)**	**(to page 7)**	
January	5,417,867,263	408,268,165	449,267,696	6,275,403,124	13,288,689	1,001,381	1,101,942	15,392,012	981,830	120,112
February	5,419,401,011	401,459,126	448,779,138	6,269,639,275	24,451,020	1,811,286	2,024,782	28,287,088	1,804,081	220,701
March	5,379,834,205	394,061,387	446,084,468	6,219,980,060	34,182,680	2,503,808	2,834,356	39,520,844	2,525,411	308,945
April	5,432,108,667	383,415,551	447,485,136	6,263,009,354	41,264,419	2,912,574	3,399,272	47,576,265	3,028,751	370,521
May	5,446,666,862	378,526,004	449,016,540	6,274,209,406	44,188,345	3,070,949	3,642,833	50,902,127	3,245,764	397,069
June	5,448,313,745	372,407,301	449,800,851	6,270,521,897	46,227,563	3,159,782	3,816,446	53,203,791	3,400,453	415,993
July										
August										
September										
October										
November										
December										

(1) The Fuel Variance initially allocated to Rural Island Interconnected is re-allocated between Utility and Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the approved Cost of Service Study, which is 89.10% and 10.90% respectively. The Labrador Interconnected amount is then removed from the plan and written off to net income (loss).

Rate Stabilization Plan

Allocation of Fuel Variance - Monthly

June 30, 2013

	A	B	C	D	E	F	G
	Utility					**Industrial**	
	Fuel Variance		Rural Allocation		Total Fuel Variance	Fuel Variance	
	Year-to-Date Activity	Current Month Activity (1)	Year-to-Date Activity	Current Month Activity (1)	Activity for the month	Year-to-Date Activity	Current Month Activity (1)
	($)	($)	($)	($)	($)	($)	($)
					(B + D)		
	(from page 6)		**(from page 6)**		**(to page 10)**	**(from page 6)**	**(to page 11)**
January	13,288,689	13,288,689	981,830	981,830	14,270,519	1,001,381	1,001,381
February	24,451,020	11,162,331	1,804,081	822,251	11,984,582	1,811,286	809,905
March	34,182,680	9,731,660	2,525,411	721,330	10,452,990	2,503,808	692,522
April	41,264,419	7,081,739	3,028,751	503,340	7,585,079	2,912,574	408,766
May	44,188,345	2,923,926	3,245,764	217,013	3,140,939	3,070,949	158,375
June	46,227,563	2,039,218	3,400,453	154,689	2,193,907	3,159,782	88,833
July							
August							
September							
October							
November							
December							
		46,227,563		3,400,453	49,628,016		3,159,782

(1) The current month activity is calculated by subtracting year-to-date activity for the prior month from year-to-date activity for the current month.

Rate Stabilization Plan
Load Variation - Utility
June 30, 2013

	A	B	C	D	E	F	G	H	I	J	K
	Firm Energy						Secondary Energy				
	Cost of Service Sales	Actual Sales	Sales Variance	Cost of Service No. 6 Fuel Cost	Firm Energy Rate	Load Variation	Cost of Service Sales	Actual Sales	Firming Up Charge	Load Variation	Total Load Variation
	(kWh)	(kWh)	(kWh)	($Can/bbl.)	($/kWh)	($)	(kWh)	(kWh)	($/kWh)	($)	($)
			(B - A)			**C x {(D/O[1]) - E}**				**(G - H) x I**	**(F + J)**
											(to page 10)
January	574,800,000	702,723,435	127,923,435	54.17	0.08805	(264,274)	0	1,099,493	0.00841	(9,247)	(273,521)
February	518,600,000	606,876,717	88,276,717	54.73	0.08805	(103,900)	0	429,853	0.00841	(3,615)	(107,515)
March	524,700,000	572,269,039	47,569,039	55.46	0.08805	(868)	0	374,966	0.00841	(3,153)	(4,021)
April	429,200,000	493,252,447	64,052,447	55.46	0.08805	(1,169)	0	558,436	0.00841	(4,696)	(5,865)
May	358,700,000	387,603,409	28,903,409	55.46	0.08805	(528)	0	309,399	0.00841	(2,602)	(3,130)
June	298,400,000	337,722,526	39,322,526	54.49	0.08805	(61,262)	0	0	0.00841	0	(61,262)
July											
August											
September											
October											
November											
December											
	2,704,400,000	3,100,447,573	396,047,573			(432,001)	0	2,772,147		(23,313)	(455,314)

(1) O is the Holyrood Operating Efficiency of 630 kWh/barrel.

Rate Stabilization Plan
Load Variation - Industrial
June 30, 2013

	A	B	C	D	E	F
	Cost of Service Sales	Actual Sales	Sales Variance	Cost of Service No. 6 Fuel Cost	Firm Energy Rate	Load Variation
	(kWh)	(kWh)	(kWh)	($)	($/kWh)	($)
			(B - A)			**C x {(D/O¹) - E}**
						(to page 11)
January	78,300,000	31,612,740	(46,687,260)	54.17	0.03676	(2,298,140)
February	70,900,000	25,864,750	(45,035,250)	54.73	0.03676	(2,256,852)
March	76,600,000	30,955,597	(45,644,403)	55.46	0.03676	(2,340,268)
April	75,600,000	32,198,035	(43,401,965)	55.46	0.03676	(2,225,295)
May	69,500,000	31,721,670	(37,778,330)	55.46	0.03676	(1,936,961)
June	73,800,000	27,547,154	(46,252,846)	54.49	0.03676	(2,300,249)
July						
August						
September						
October						
November						
December						
	444,700,000	179,899,946	(264,800,054)			(13,357,765)

(1) O is the Holyrood Operating Efficiency of 630 kWh/barrel.

Rate Stabilization Plan
Summary of Utility Customer
June 30, 2013

	A	B	C	D	E	F	G
	Load Variation	Allocation Fuel Variance	Allocation Rural Rate Alteration (1)	Subtotal Monthly Variances	Financing Charges	Adjustment (2)	Cumulative Net Balance
	($)	($)	($)	($)	($)	($)	($)
				(A + B + C)			
	(from page 8)	**(from page 7)**					**(to page 12)**
Opening Balance							(64,905,401)
January	(273,521)	14,270,519	(849,811)	13,147,187	(393,814)	(10,944,447)	(63,096,475)
February	(107,515)	11,984,582	(877,767)	10,999,300	(382,838)	(9,443,617)	(61,923,630)
March	(4,021)	10,452,990	(743,390)	9,705,579	(375,722)	(8,904,614)	(61,498,387)
April	(5,865)	7,585,079	(652,666)	6,926,548	(373,141)	(7,678,759)	(62,623,739)
May	(3,130)	3,140,939	(559,777)	2,578,032	(379,970)	(6,032,044)	(66,457,721)
June	(61,262)	2,193,907	(548,049)	1,584,596	(403,232)	(5,251,585)	(70,527,942)
July							
August							
September							
October							
November							
December							
Year to date	(455,314)	49,628,016	(4,231,460)	44,941,242	(2,308,717)	(48,255,066)	(5,622,541)
Hydraulic allocation **(from page 4)**							0
Total	(455,314)	49,628,016	(4,231,460)	44,941,242	(2,308,717)	(48,255,066)	(70,527,942)

(1) The Rural Rate Alteration is allocated between Utility and Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the approved Cost of Service Study, which is 89.10% and 10.90% respectively. The Labrador Interconnected amount is then removed from the plan and written off to net income (loss).

(2) The RSP adjustment rate for Utility is 1.555 cents per kwh effective July 1, 2012 to June 30, 2013.

Rate Stabilization Plan
Summary of Industrial Customers
June 30, 2013

	A	B	C	D	E	F
	Load Variation	Allocation Fuel Variance	Subtotal Monthly Variances	Financing Charges	Adjustment (1)	Cumulative Net Balance (2)
	($)	($)	($)	($)	($)	($)
			(A + B)			
	(from page 9)	**(from page 7)**				**(to page 12)**
Opening Balance						(104,079,983)
January	(2,298,140)	1,001,381	(1,296,759)	(631,505)	323,546	(105,684,701)
February	(2,256,852)	809,905	(1,446,947)	(641,242)	275,249	(107,497,641)
March	(2,340,268)	692,522	(1,647,746)	(652,242)	322,621	(109,475,008)
April	(2,225,295)	408,766	(1,816,529)	(664,240)	327,497	(111,628,280)
May	(1,936,961)	158,375	(1,778,586)	(677,305)	324,664	(113,759,507)
June	(2,300,249)	88,833	(2,211,416)	(690,236)	287,558	(116,373,601)
July						
August						
September						
October						
November						
December						
Year to date	(13,357,765)	3,159,782	(10,197,983)	(3,956,770)	1,861,135	(12,293,618)
Hydraulic allocation **(from page 4)**						0
Total	(13,357,765)	3,159,782	(10,197,983)	(3,956,770)	1,861,135	(116,373,601)

(1) The RSP adjustment rate for Industrial Customers excluding Teck Resources and Vale is 0.785 cents per kWh effective January 1, 2008. The rate for Teck Resources and Vale is 2.000 cents per kWh.

Rate Stabilization Plan
Overall Summary
June 30, 2013

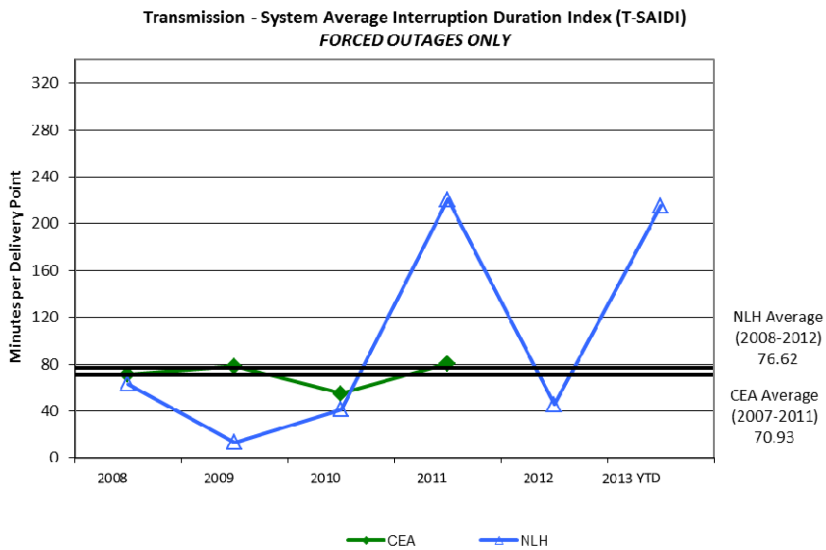
	A	B	C	D
	Hydraulic Balance	Utility Balance (1)	Industrial Balance (1)	Total To Date
	($)	($)	($)	($)
				(A + B + C)
	(from page 4)	**(from page 10)**	**(from page 11)**	
Opening Balance	(32,675,763)	(64,905,401)	(104,079,983)	(201,661,147)
January	(42,363,686)	(63,096,475)	(105,684,701)	(211,144,862)
February	(49,977,679)	(61,923,630)	(107,497,641)	(219,398,950)
March	(53,469,728)	(61,498,387)	(109,475,008)	(224,443,123)
April	(58,262,305)	(62,623,739)	(111,628,280)	(232,514,324)
May	(61,000,815)	(66,457,721)	(113,759,507)	(241,218,043)
June	(59,841,516)	(70,527,942)	(116,373,601)	(246,743,059)
July				
August				
September				
October				
November				
December				

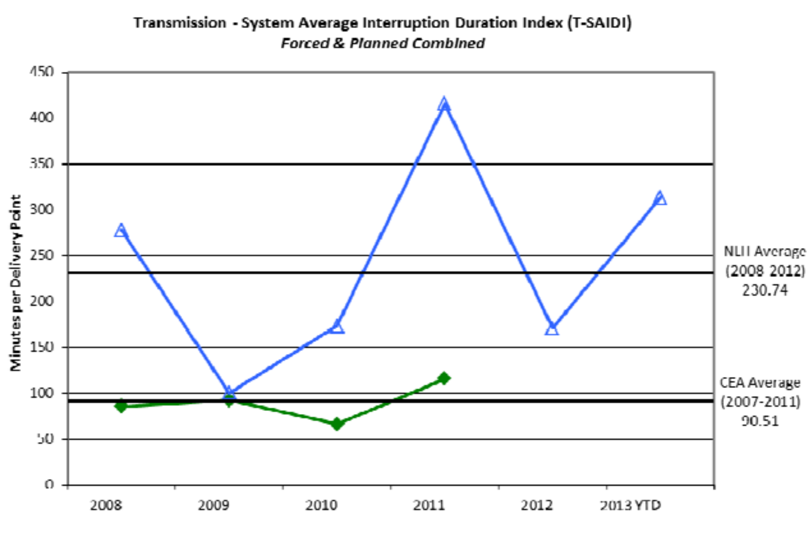
Performance Indices

Bulk Power System Delivery Point Interruption Performance

a) Transmission System Average Interruption Duration Index (T-SAIDI) - *a reliability KPI for bulk transmission assets which measures the average duration of outages in minutes per delivery point.*

The second quarter T-SAIDI was 112.8 minutes per delivery point (forced and planned combined) compared to 36.0 minutes per delivery point for the same quarter last year, an increase of 213%. The forced component was 13.8 minutes per delivery point, compared to 11.4 minutes per delivery point in 2012. The planned component was 99.0 minutes per delivery point compared to 24.6 minutes per delivery point in 2012, an increase of more than 300%.





There were seven significant forced outages and 11 planned outages in this quarter. A summary of these forced and planned outages follows:

Forced

On April 28, customers supplied by transmission lines TL214 and TL215 in the Doyles and Port Aux Basque areas experienced an unplanned power outage of seven minutes. The outage occurred after transmission line TL215 faulted due to salt contamination. TL214 was required to trip to isolate the fault on TL215 due to breaker B1L15 being out of service and bypassed at the Doyles Terminal Station. This breaker was returned to service on June 26.

On May 5, customers supplied by the South Brook Terminal Station experienced an unplanned power outage of one hour and four minutes. The outage was caused by a broken crossarm on transmission line TL222. TL222 was isolated between Stony Brook and South Brook and customers were restored via TL223 from Springdale. Transmission line TL222 was restored on May 7 following repairs to the crossarm.

On June 9, customers supplied by the Plum Point Terminal Station experienced two unplanned power outages of one hour and 14 minutes and one hour and 57 minutes. Both outages were caused by problems with the oil circulation pumps on the mobile substation at Plum Point. The issue was discovered and corrected after the second trip.

On June 14, customers supplied by the Happy Valley Terminal Station and the Muskrat Falls Tap Terminal Station experienced an unplanned power outage of two hours and 40 minutes. The outage occurred after lightning hit transmission line L1301/L1302. There was a delay in the restoration of customers due to an issue with the overvoltage protection setting at the Muskrat Falls Tap Terminal Station. There were protection settings changes implemented following this event.

On June 15, customers supplied by the Main Brook and Roddickton Terminal Stations experienced an unplanned power outage of 20 minutes. The outage occurred during switching for a planned outage of TL241. The diesel plant at St. Anthony was in-service and when TL256 was opened at St. Anthony Airport, TL261 tripped resulting in the outage to Main Brook and Roddickton.

On June 22, customers supplied by the Happy Valley Terminal Station and Nalcor Energy at Muskrat Falls Tap Terminal Station experienced an unplanned power outage of one hour and eight minutes. The outage occurred after lightning hit transmission line L1301/L1302. There was delay in the restoration of customers due to an issue with low air pressure at the circuit breaker at the Churchill Falls end of L1301.

On June 22, another unplanned outage was experienced by the customers supplied by the Happy Valley Terminal Station and the Muskrat Falls Tap Terminal Station, this time with a duration of 16 minutes. The outage occurred after lightning hit transmission line L1301/L1302.

Planned

On April 1, customers supplied via feeders L4 and L7 in Happy Valley-Goose Bay area experienced a planned power outage of three hours and 49 minutes, while all other customers in the region were supplied via the Happy Valley Gas Turbine and the North Side Diesel Plant. The outage was required to facilitate a line outage for Churchill Falls personnel to safely carry out work in the CF terminal station.

On April 14, customers supplied via feeder L10 in Happy Valley-Goose Bay area experienced a planned power outage of nine hours, while all other customers in the region were supplied via the Happy Valley Gas Turbine and the North Side Diesel Plant. This outage was also required to facilitate a line outage for Churchill Falls personnel to safely carry out work in the CF terminal station.

On May 29, customers supplied by the Bay L'Argent Terminal Station experienced a planned power outage of four hours and 36 minutes. The outage was required to perform corrective and planned maintenance on the 138 kV disconnect switches at the station.

On May 2, customers supplied by the Glenburnie and Wiltondale Terminal Stations experienced a planned power outage of 12 minutes. The outage was required to safely restore TL226 following line maintenance on the line section between the Rocky Harbour Tap and South East Hill.

On May 13, customers supplied by the Hawke's Bay Terminal Station experienced a planned power outage of 26 minutes. The outage was required to safety restore TL221 and to remove mobile substation P235 from the Hawke's Bay Terminal Station.

On May 25, customers supplied by the Bear Cove Terminal Station experienced a planned power outage of seven hours and 58 minutes. The outage was required to perform preventive maintenance on the 138 kV disconnect switches at the station.

On May 25, customers supplied by the Plum Point Terminal Station experienced a planned power outage of six hours and 37 minutes. The outage was required to perform preventive maintenance on the 138 kV disconnect switches at the station. In addition, the mobile substation P235 was installed in order to facilitate maintenance on transformer T1 at Plum Point.

On June 1, customers supplied by the Springdale Terminal Station experienced a planned power outage of six hours and one minute. This outage was required to install a bypass around the Springdale Terminal Station by interconnecting TL222 to TL223. The Springdale station is now tapped off the TL222/TL223 line. This was required to facilitate the replacement of circuit breaker B1L22 at Springdale while maintaining the 138 kV loop from Stony Brook to Deer Lake.

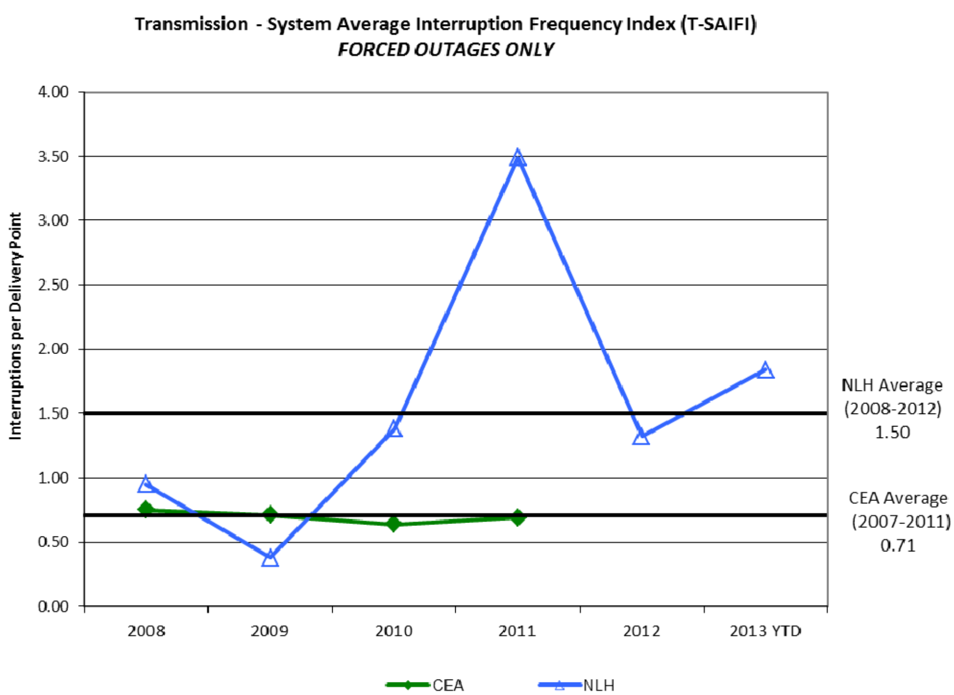
On June 7, customers supplied by the Glenburnie and Wiltondale Terminal Stations experienced a planned power outage of three hours and 51 minutes. The outage was required to repair disconnect switch L26-1 at Wiltondale station. In addition, personnel performed preventive and corrective maintenance on equipment in the Wiltondale and Glenburnie stations.

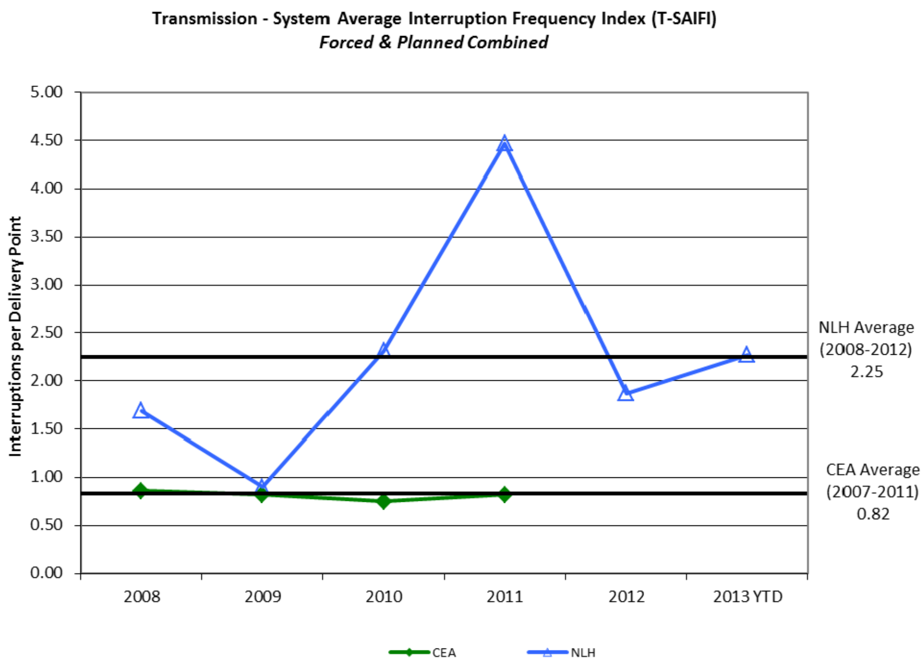
On June 15, customers supplied by the Bear Cove and Plum Point Terminal Stations experienced a planned power outage of six hours and 40 minutes. Customers supplied by feeder 1 at the St. Anthony Diesel Plant Terminal Station experienced a planned power outage of three hours and 22 minutes. The outage was required to perform preventive maintenance on the 138 kV disconnect switches at Bear Cove and Peter Barren stations in addition to the disconnection of the mobile substation P235 from the Plum Point station. Customers in Roddickton, Main Brook, and feeders 2 and 3 in St. Anthony were supplied by the St. Anthony Diesel Plant during this period.

On June 26, customers supplied by the Doyles Terminal Station experienced a planned power outage of three hours and 56 minutes. The outage was required to remove the bypass and energize the new circuit breaker B1L15 at Doyles. Newfoundland Power customers in the Port Aux Basques area were supplied via backup generation during this terminal station outage.

b) Transmission System Average Interruption Frequency Index (T-SAIFI) - *a reliability KPI for bulk transmission assets that measures the average number of sustained outages per delivery point*.

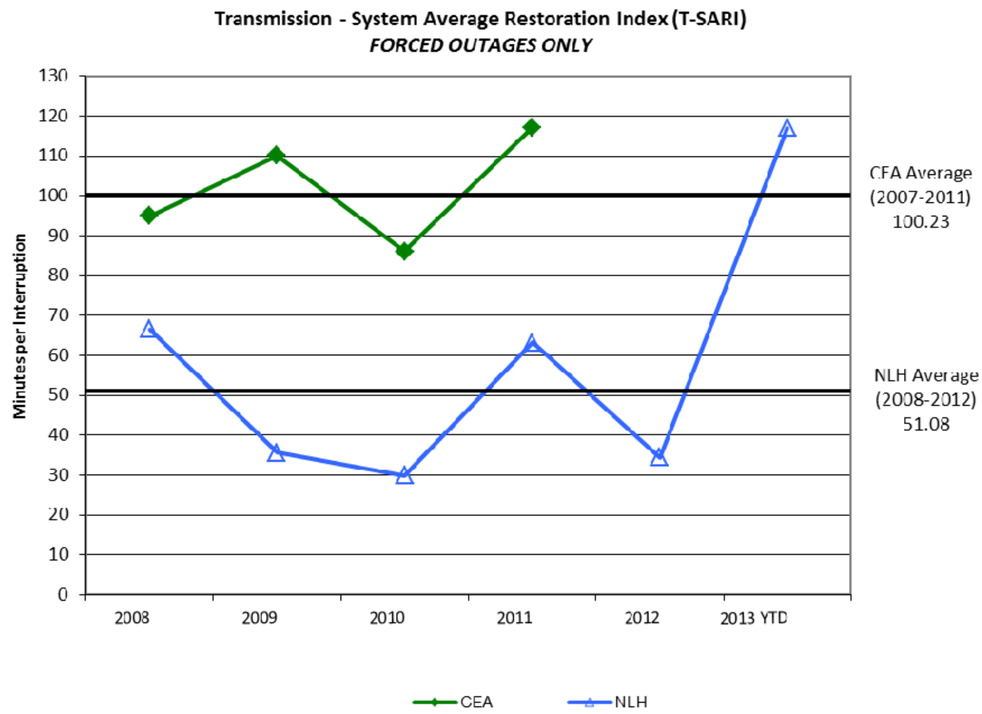
The second quarter T-SAIFI was 0.55 outages per bulk delivery point compared to 0.54 outages per bulk delivery point last year. The breakdown between forced and planned outages is as follows: 0.22 (forced) and 0.33 (planned). This is compared to 0.38 (forced) and 0.16 (planned) for the second quarter of 2012.

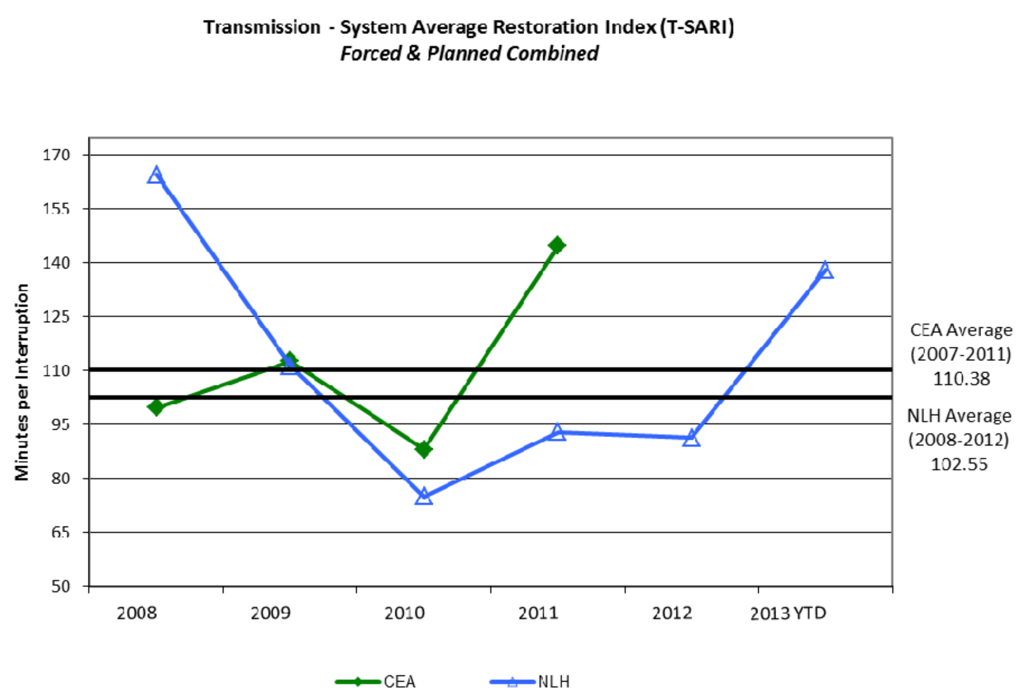




c) Transmission System Average Restoration Index (T-SARI) - *a reliability KPI for bulk transmission assets which measures the average duration per transmission interruption. T-SARI is calculated by dividing T-SAIDI by T-SAIFI.*

Hydro's total transmission T-SARI was 204.6 minutes per interruption for the second quarter versus 67.2 minutes per interruption for 2012, an increase of 204%. The forced outage component of T-SARI was 61.2 minutes per interruption. This compares with 30.6 minutes per interruption for the same quarter in 2012. The planned outage component of T-SARI was 302.4 minutes per interruption, compared to 153.0 minutes per interruption for the same quarter last year.


Transmission - System Average Restoration Index (T-SARI)
FORCED OUTAGES ONLY
Minutes per Interruption
0
10
20
30
40
50
60
70
80
90
100
110
120
130
2008
2009
2010
2011
2012
2013 YTD
CEA Average
(2007-2011)
100.23
NLH Average
(2008-2012)
51.08
CEA
NLH


Transmission - System Average Restoration Index (T-SARI)
Forced & Planned Combined
Minutes per Interruption
50
65
80
95
110
125
140
155
170
2008
2009
2010
2011
2012
2013 YTD
CEA Average
(2007-2011)
110.38
NLH Average
(2008-2012)
102.55
CEA
NLH

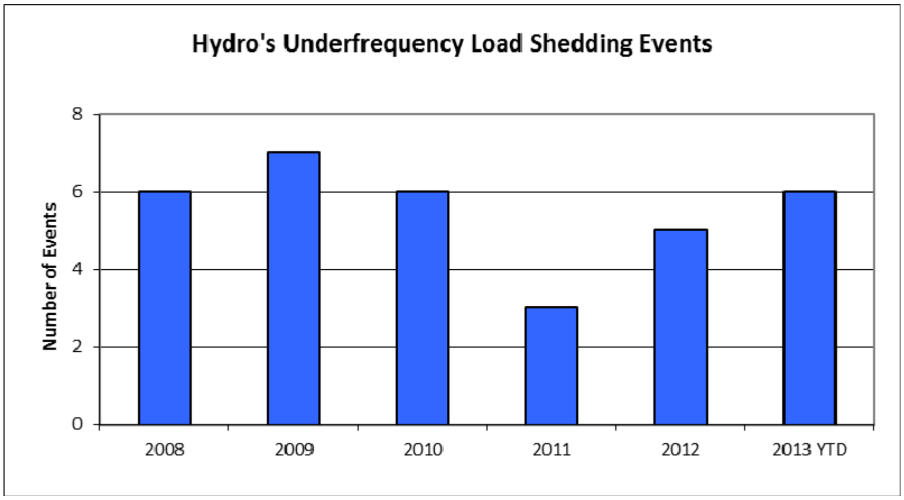
d) Underfrequency Load Shedding (UFLS) - *reliability KPI that measures the number of events in which shedding of a customer load is required to counteract a generator trip. Customer loads are shed automatically depending upon the generation lost.*

There were two underfrequency events during this quarter. These events are summarized as follows:

On April 16 at 11:35 hours, Holyrood Generating Unit 2 tripped. The cause of the unit trip was attributed to a malfunction of a pistol grip switch which it is used to place the lube oil pumps in and out of service. With the removal of generation (approximately 91 MW) the system frequency dropped to 58.57 Hz resulting in the activation of the underfrequency protection at Newfoundland and Labrador Hydro, and Newfoundland Power. Total system load at the time of the incident was 901 MW. There were 14,430 Newfoundland Power customers reported to be restored within 22 minutes after the event occurred (385 MW-Mins). There were 1,281 Hydro customers restored within three minutes after the event occurred (15 MW-Mins).

On April 17 at 07:00 hours, Bay d'Espoir Terminal Station experienced a 230 kV bus lockout, tripping Units 3 and 5 in addition to making Units 4 and 6 and transmission line TL202 unavailable to the system. The lockout operation was initiated when Unit 4 was being placed online and its unit breaker B2T4 was forced close due to loss of air (an air pipe failed on the air system resulting in the loss of air). The protection for Unit 4 operated as expected, however stuck contacts on two current monitor relays in the breaker failure circuits for the 230 kV ring bus breakers B2B3 and B3B4 resulted in Units 5 and 6 and TL202 becoming isolated from the system. With the removal of the online Units 3 and 5 (approximately 146 MW) the system frequency dropped to 58.07 Hz resulting in the activation of the underfrequency protection at Newfoundland and Labrador Hydro, and Newfoundland Power. Total system load at the time of the incident was 921 MW. Restoration of service to customers began shortly after the incident as generation output was increased on all available units. There were 42,502 Newfoundland Power customers reported to be restored within two hours and 29 minutes after the event occurred (11,792 MW-Mins). Customers were restored in blocks as generation became available to the system. There were 6,662 Hydro customers restored within 40 minutes after the event occurred (288 MW-Mins).

Refer to the graph below which compares the UFLS events over the past five years to the year-to-date 2013 performance.



Underfrequency Load Shedding Number of Events					
Customers	Second Quarter 2013	Second Quarter 2012	Year to Date 2013	Year to Date 2012	5 Year Average (2008–2012)
NF Power	2	1	6	2	5.4
Industrials	0	0	0	1	2.8
Hydro Rural*	2	0	3	1	2.8
Total Events	2	1	6	2	5.4

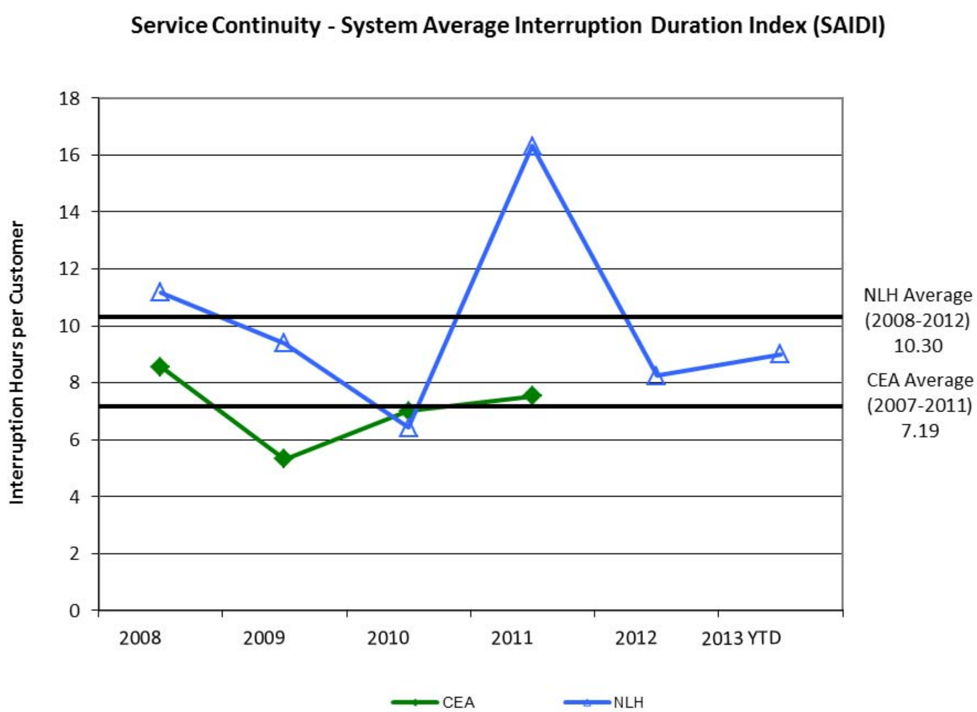
Underfrequency Load Shedding Unsupplied Energy (MW-min)					
Customers	Second Quarter 2013	Second Quarter 2012	Year to Date 2013	Year to Date 2012	5 Year Average (2008–2012)
NF Power	12,177	48	13,742	2,274	1,643
Industrials	0	0	0	140	217
Hydro Rural*	303	0	324	21	48
Total Events	12,480	48	14,066	2,435	1,890

* Underfrequency activity affecting Hydro Rural Customers may also result in a number of delivery point outages. Outage frequency and duration are also included in totals shown in the delivery point statistics section of the report for these areas, namely the Connaigre Peninsula and Bonne Bay.

Rural Systems Service Continuity Performance

a) System Average Interruption Duration Index (SAIDI) - *a reliability KPI for distribution service and it measures service continuity in terms of the average cumulative duration of outages per customer served during the year.*

For the second quarter, the SAIDI was 4.71 hours per customer compared to 1.58 hours per customer in 2012, an increase of nearly 200%.



A summary of the major interruptions follows:

On April 6, beginning at 08:45 hours, all customers (1,541) on Fogo Island experienced a series of lengthy unplanned power outages. All customers were restored by 11:00 hours on April 7. Hydro's investigation concluded the cause of the outages was a defective insulator on Line 1. Crews were dispatched to locate the cause and once discovered, the defective insulator was replaced. Weather at the time of the incident was poor and resulted in delays in restoration.

On April 8, all 1,048 customers serviced by South Brook Lines 3, 5, 7 experienced an unplanned power outage of up to eight hours and 30 minutes. The outage was caused the failure of a connector that resulted in a pole fire. The pole fire caused damage to the pole and the crossarm. Both the pole and the crossarm were replaced. Customers on Line 3 and Line 7 experienced an outage duration of four hours and 35 minutes.

On April 8, all 841 customers serviced by Bottom Waters Lines 3, 6, 7 experienced an unplanned power outage of up to six hours and 50 minutes. The outage was caused by a faulty voltage regulator (BW3-VR1). The regulator was removed from service to restore customers and was later replaced. The outage durations were as follows:

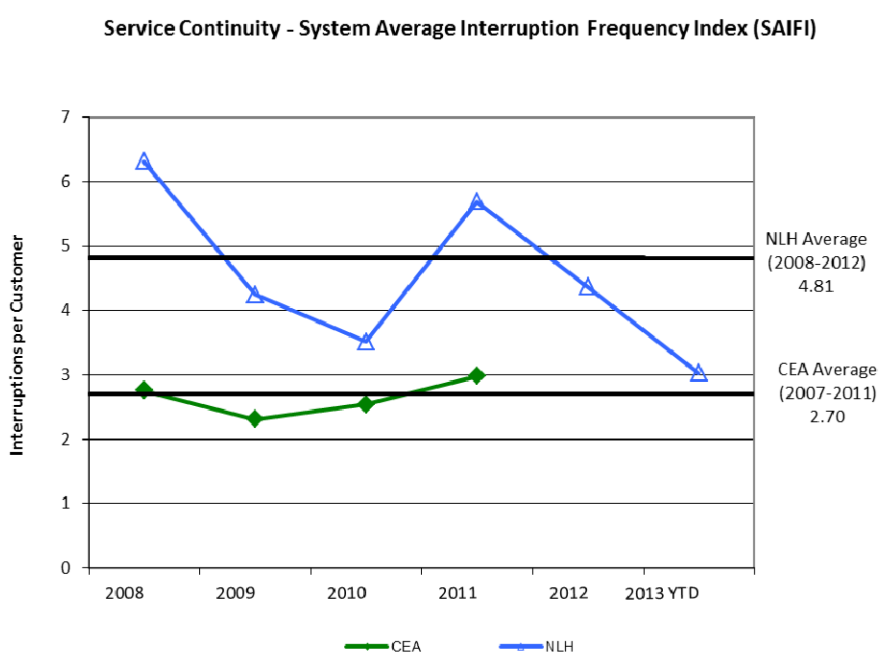
Line 3: five hours and 45 minutes
Line 6: six hours and 50 minutes
Line 7: six hours and 15 minutes

On April 25, at 18:00 hours (Labrador time), 40 customers serviced by Line 5 in Labrador City experienced an unplanned power outage. The outage was caused by a broken porcelain cut-out. In order to safely repair the cut-out, an emergency planned power outage was required for Line 5, affecting an additional 214 customers. Hydro crews repaired the cut-out and all customers were restored at 19:20 hours.

On May 14, all 1,606 customers on Fogo Island experienced an unplanned power outage. The outage occurred when a lightning arrester failed at the submarine cable termination station. Hydro crews repaired the problem and all customers were restored during the morning hours on May 15. Total outage time was eight hours and 46 minutes.

b) System Average Interruption Frequency Index (SAIFI) - *reliability KPI for distribution service and measures the average cumulative number of sustained interruptions per customer per year.*

In the second quarter, the SAIFI was 0.92 interruptions per customer compared to 0.98 interruptions per customer in 2012, a 6% decrease. This decrease is related to a reduction in events in the Northern and Labrador Regions.



c) Additional Information - *The following section provides more detailed information in three tables with performance broken down by Area, Origin, and Type.*

Rural Systems Service Continuity Performance by Area

SAIFI (Number per Period)

Area	Second Quarter 2013	Second Quarter 2012	12 Mths to Date 2013	12 Mths to Date 2012	5 Year Average
Central					
Interconnected	1.11	0.19	4.03	2.08	3.16
Isolated	0.24	0.04	2.13	4.79	3.43
Northern					
Interconnected	0.21	0.81	5.64	5.34	4.64
Isolated	0.50	0.78	8.17	5.44	6.36
Labrador					
Interconnected	1.44	2.17	7.00	9.59	6.70
Isolated	1.07	1.45	10.57	7.11	11.04
Total	0.92	0.98	5.74	5.45	5.04

Note: System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers in an area

SAIDI (Hours per Period)

Area	Second Quarter 2013	Second Quarter 2012	12 Mths to Date 2013	12 Mths to Date 2012	5 Year Average
Central					
Interconnected	5.93	0.42	15.70	13.45	11.50
Isolated	0.02	0.11	4.35	4.40	2.92
Northern					
Interconnected	0.20	2.13	12.04	22.45	11.43
Isolated	1.24	0.55	8.67	2.92	5.98
Labrador					
Interconnected	9.06	2.82	18.12	13.51	13.40
Isolated	0.52	1.52	14.79	6.37	15.55
Total	4.71	1.58	14.77	14.76	11.68

Note: System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.

Rural Systems Service Continuity Performance by Origin

SAIFI (Number per Period)					
Area	**Second Quarter 2013**	**Second Quarter 2012**	**12 Mths to Date 2013**	**12 Mths to Date 2012**	**5 Year Average**
Loss of Supply – Transmission	0.10	0.56	1.24	2.53	1.86
Loss of Supply – NF Power	0.00	0.00	0.01	0.01	0.01
Loss of Supply – Isolated	0.06	0.05	0.52	0.47	0.55
Loss of Supply – L'Anse au Loup	0.00	0.00	0.05	0.05	0.06
Distribution	0.75	0.37	3.92	2.38	2.55
Total	0.92	0.98	5.74	5.45	5.04

Note: System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers.

SAIDI (Hours per Period)					
Area	**Second Quarter 2013**	**Second Quarter 2012**	**12 Mths to Date 2013**	**12 Mths to Date 2012**	**5 Year Average**
Loss of Supply – Transmission	1.07	0.74	2.80	5.43	3.83
Loss of Supply – NF Power	0.01	0.00	0.01	0.48	0.14
Loss of Supply – Isolated	0.01	0.01	0.17	0.26	0.24
Loss of Supply – L'Anse au Loup	0.00	0.00	0.05	0.02	0.04
Distribution	3.62	0.83	11.73	8.57	7.44
Total	4.71	1.58	14.77	14.76	11.68

Note: System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an

Rural Systems Service Continuity Performance by Type (Second Quarter 2013)

Area	Scheduled		Unscheduled		Total	
	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI
Central						
Interconnected	0.00	0.00	1.11	5.93	1.11	5.93
Isolated	0.00	0.00	0.24	0.02	0.24	0.02
Northern						
Interconnected	0.00	0.00	0.21	0.20	0.21	0.20
Isolated	0.14	1.17	0.37	0.06	5.00	1.24
Labrador						
Interconnected	0.77	7.76	0.68	1.30	1.44	9.06
Isolated	0.00	0.00	1.07	0.52	1.07	0.52
Total	0.22	2.24	0.70	2.47	0.92	4.71

Note:
1. System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers in an area.
2. System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

QUARTERLY REGULATORY REPORT FOR THE QUARTER ENDED SEPTEMBER 30, 2013

Newfoundland and Labrador Hydro

Table of Contents

1 HIGHLIGHTS

HIGHLIGHTS
For the nine months ended September 30, 2013

REGULATED	2013 Actual YTD	2013 Target/ Budget	2012 Actual YTD
Safety			
Lead:Lag Ratio[1]	462.1	600:1	285:1
All Injury Frequency Rate[1]	1.04	<u><</u>0.8	1.76
Production			
Quarter End Reservoir Storage (GWh)	2,428	1,155	1,927
Hydraulic Production (GWh)	3,395	3,479	3,422
Holyrood Fuel cost per barrel, current month ($) [2]	105	55	121
Holyrood Efficiency [2]	593	630	601
Electricity Delivery			
Sales including Wheeling (GWh)	4,996.6	5,204.1	5,008.6
Financial			
Revenue ($millions)	339.9	368.8	332.7
Expenses ($millions)	329.2	374.0	315.1
Net Operating Income ($millions)[3]	10.7	(5.2)	17.6
Current Rate Stabilization Plan (RSP) Balance ($millions)	(240.9)	(244.9)	(182.7)
Hydraulic	(38.1)	(72.4)	(57.7)
Utility	(189.8)	(60.7)	(34.4)
Industrial	(13.0)	(111.8)	(90.6)
Full Time Equivalent (FTE) Employees[4, 5]			
Regulated	818.2	863.5	796.6
Non-Regulated	32.4	15.0	30.1

[1] Annual Target, and 2012 Actual
[2] Target based on approved 2007 Test Year forecast
[3] Does not include any earnings from CF(L)Co
[4] One FTE is the equivalent of actual paid regular hours - 2,080 hours per year in the operating environment and 1,950 hours per year in Hydro's head office environment.
[5] Annual Budget and 2012 Actual values

- Lost-time injury frequency rate remains zero (page 2);
- Osprey nest relocated from Wabush pump house (page 7);
- Reservoir levels at 100% of maximum (page 11).

2 SAFETY

Goal - To be a Safety Leader

Safety is Hydro's number one priority. Hydro remains committed to being a world class leader in safety performance.

Measurement	Year-to-date 2013 Actual	Annual 2013 Plan	Annual 2012 Actual
All Injury Frequency (AIF)	1.04	≤0.8	2.25
Lost Time Injury Frequency (LTIF)	0.00	≤0.2	0.79
Ratio of condition and incident reports to lost time and medical treatment injuries (lead/lag ratio)	462:1	600:1	230:1
Planned Grounding and Bonding Activities	In progress	100%	N/A
Complete Work Method Activities for Critical Tasks	91%	100%	87.33%

Hydro continued its focus on injury prevention initiatives and planned safety objectives during the third quarter of 2013.

The corporate Injury Prevention Campaign is ongoing, focusing on three of the company's top injury trends; Slips, Trips and Falls, Sprains and Strains and Hand Injuries. The campaign continues to encourage employees to be aware of their surroundings and obvious hazards, while reminding them to be mindful of the subtle dangers that may exist. Injury prevention materials continue to be developed with the recent addition of a workshop related to the Mechanics of Safe Lifting.

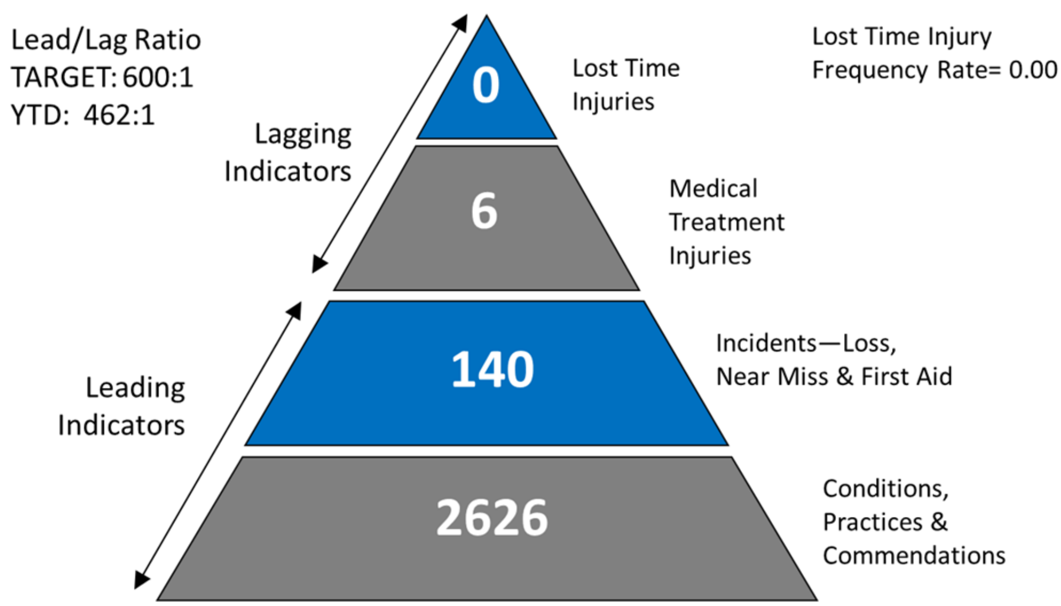
Hydro continues to focus in the area of Grounding and Bonding (G&B), Work Methods, Work Protection Code (WPC) and Corporate Standard Development. The Corporate Grounding and Bonding Committee continues to focus on training for line operations staff. The development of Work Methods for identified critical tasks is ongoing and an evaluation phase has commenced. The WPC Program Committee continues with a focus on program auditing and implementing opportunity for improvement. New standards development and revisions continues to strengthen the Hydro Safety Program, standards for Hot Work Permits, Working Alone and Local Safety and Health Orientations have been developed or revised and will be communicated to all employees.

Field visibility by the leadership team, regional managers and safety professionals continues to increase in all areas. Visits provide opportunity for meaningful discussions around safety and dialogue around core safety programs and how they are working in the field with both regular operations and contractor workforces.

The 7th Annual Company Safety Summit was held in St. John's with over 170 people from all regions participating. The theme anchored back to the internal safety theme "Take a Moment for Safety" and as with previous years, various locations around Hydro participated. Hydro's goal is a zero harm workplace where no one gets hurt and taking a moment for safety is a key factor to achieving this. During this year's event, many employees from across the system shared with the audience, their personal stories around safety in the workplace and lessons learned.

The public safety campaign around Power Line Hazards (PLH) is ongoing both internally and externally. Hydro continues to partner with other utilities, government agencies and other stakeholders to discuss communication strategies and initiatives around power line safety. Several media releases were provided in the last quarter as part of this group initiative.

The following safety triangle summarizes Hydro's year-to-date performance for 2013.



2.1 Hydro and Newfoundland Power Work Together to Educate on Power Line Safety

Hydro and Newfoundland Power partnered in September to urge the public, contractors and heavy equipment operators to take a moment to identify the location of overhead and/or underground power lines before beginning work. The utilities issued a joint press release and invited members of the media to a construction site to demonstrate some of the hazards. Several radio, TV and newspaper interviews were conducted and many social media posts were promoted with information on this critical issue.

2.2 Hydro's Safety Website Gets New Look

Hydro's safety website - **www.hydrosafety.ca** has been updated with some new safety information in an effort to keep our communities, families and friends safe. The site now features new information on children's electrical safety and public safety around dams. There's also recreational safety information, along with information on how to stay safe around power lines and tips for power outage safety.

3 ENVIRONMENT AND CONSERVATION

Goal - To be an Environmental Leader

Hydro recognizes its commitment and responsibility to protect the environment.

Measurement	Year-to-date 2013 Actual	Annual 2013 Target	Annual 2012 Actual
Variance from ideal production schedule at Holyrood Thermal Generating Station	12.3%	≤ 10.0%	6.9%
Achievement of EMS targets[1]	44%	95%	96%
Annual energy savings from Residential and Commercial Conservation and Demand Management Programs	1.79 GWh	2.9 GWh	2.3 GWh
Conduct evaluation of Industrial Energy Efficiency Program (IEEP) and develop multi-year plan	Scope completed, work to be done in Q4	Complete evaluation	N/A
Annual energy savings from Internal Energy Efficiency Programs	0.08 GWh	0.40 GWh	0.26 GWh

[1] An EMS target is an initiative undertaken to improve environmental performance.

3.1 Variance from Ideal Production Schedule at Holyrood Thermal Generating Station

Summary of 2013 Performance (year-to-date):

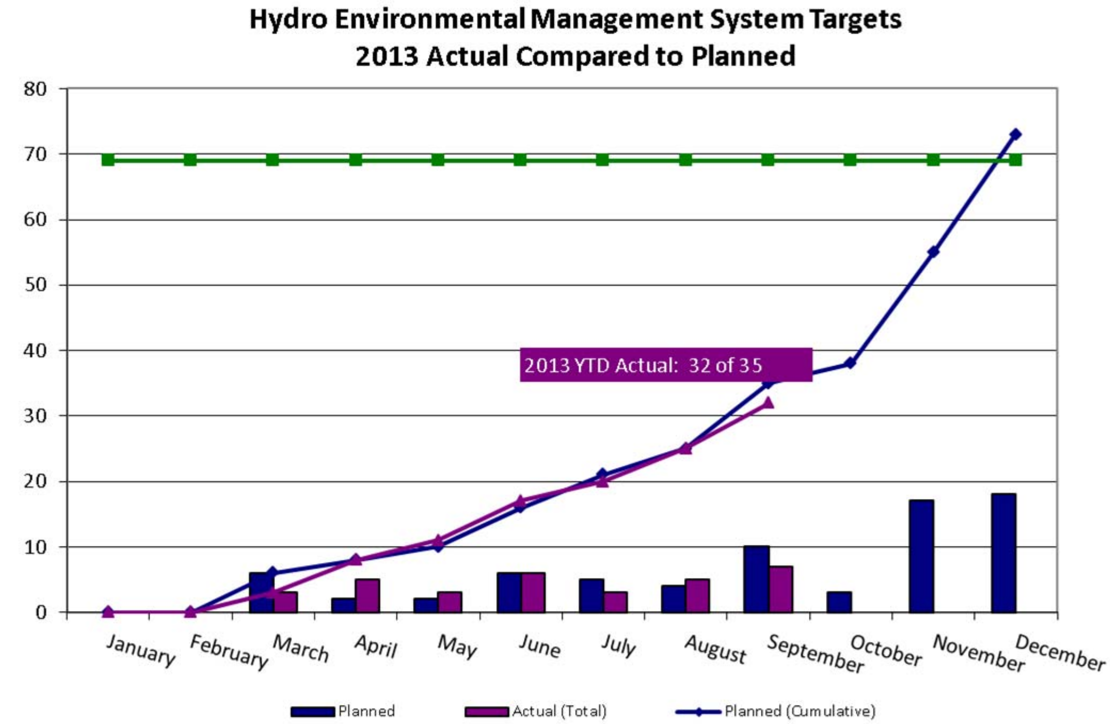
Minimum Hours

2013	Variance[1]		Ideal		Variance	
Month	Unit-Hours	Cumulative	Unit-Hours	Cumulative	Percent	Cumulative
January	360	360	2,088	2,088	17.2%	17.2%
February	337	697	1,728	3,816	19.5%	18.3%
March	48	745	1,512	5,328	3.2%	14.0%
April	72	817	1,224	6,552	5.9%	12.5%
May	76	893	624	7,176	12.2%	12.4%
June	24	917	432	7,608	5.6%	12.1%
July	0	917	0	7,608	0.0%	12.1%
August	0	917	0	7,608	0.0%	12.1%
September	24	941	72	7,680	33.3%	12.3%

[1] Variance is the number of hours greater than or less than the ideal. Hours greater than the ideal represent hours of operation that ideally could have been avoided. Hours less than the ideal represent hours of operation where a single contingency could have resulted in a load interruption.

3.2 Achievement of EMS Targets

See graph below displaying planned target completion schedules and actual to-date.



3.2.1 Annual Energy Savings from Residential and Commercial Conservation and Demand Management (CDM) Programs

Direct installations related to the Isolated Systems Community Energy Efficiency Program have been completed with approximately 90% participation across the isolated systems. This program provides direct installation of small energy efficiency items in homes and businesses and has resulted in the installations of more than 2,100 kits since the launch of the program in 2012. The Domestic Hot Water Heat Recovery Pilot component is progressing with installations and evaluation of usage. Efforts are being made to encourage increased participation in mail-in rebate and retailer coupon program components as they have seen low uptake to date.

Use of existing residential rebates through the takeCHARGE program focusing on heating savings slowed for the summer months, but it is hoped they will pick up-in the fall heating season. Uptake for the commercial lighting program is expected to increase with the addition of new technologies available for rebate. Additional lighting for high bay applications such as arenas and warehouses have been added to the list for incentives.

3.2.2 Conduct Evaluation of Industrial Energy Efficiency Program and Develop Multi-Year Plan

There continues to be dialogue with the Industrial Customers and an announcement of the closure of the current program for evaluation and assessment has been made. Customers had until October 11 to be considered under the existing program framework. The scope of work has been prepared and work will be completed on the evaluation in the last quarter.

3.2.3 Annual Energy Savings from Internal Energy Efficiency Programs

Internal efficiency projects are connected to EMS targets and are progressing well across the system. The Paradise River Engine Hall has been retrofitted with higher efficiency lighting providing both energy savings and increased light output, increasing safety for workers. Exterior lighting has also been changed to LED, which has energy savings as well as increased lighting levels for increased safety around the plant. There are a number of additional retrofits that are on schedule with the continued focus on lighting and HVAC controls.

3.3 Osprey Nest on the Regulator Structure at the Wabush Pump House

The regulator structure at the pump house for the Town of Wabush protected water supply has a history of attracting osprey nests. Last year, a nest caught fire and caused a trip in the power supply to the pump house. Wayne Lidster, Environmental Co-ordinator, visited the location on June 16, and discovered a new nest well under construction and two adult osprey in the area. Due to the possibility of fire and possibility of knocking out power to the pump house, it was decided to remove the nest from the structure. Since this involved a protected water supply, permission had to be received from council to perform the work. Permission was also required from Provincial Wildlife, as osprey and their nests are a protected species under the Wildlife Act. On June 17, the required confirmation was received and the line was taken out of service in preparation for the relocation. The team completed a Tailboard Safety Talk and a review of the procedure before they took on the task.

4 OPERATIONAL EXCELLENCE

Goal - Through operational excellence provide exceptional value to all consumers of energy.

Hydro strives to deliver operational excellence by maintaining safe, reliable delivery of power and energy to customers in a cost-effective manner while maintaining high customer satisfaction. The key focus areas are:

- Energy Supply;
- Asset Management; and
- Financial Performance.

Measurement	Year-to-date 2013 Actual	Annual 2013 Target	Annual 2012 Actual
Asset Management and Reliability			
Contingency Reserve[1]	97.8	≥99.5%	99.97%
Asset Management Strategy Execution	Tracking in compliance to plan	Plan Implementation	Completed as planned for 2012
Financial Targets			
Annual Controllable Costs	\$84.2 million	\$111.9 million (Budget)	\$106.5 million
Net Income	\$10.7 million	\$6.2 million	\$16.9 million
Project Execution			
Completion rate of capital projects by year end[2]	-	≥90%	82%
All-project variance from original budget[2]	-	8%	18%
Customer Service			
Customer Service Improvement Plan	In Progress	Complete 3-5 Year Strategy	N/A

[1] The contingency reserve metric tracks the number of unit unavailability hours for which there would not have been ample system generation available to supply the system load under the loss of the largest generating unit (N-1). These unavailability hours are compared against the total hours in the month.
[2] Measured at year end.

4.1 Energy Supply

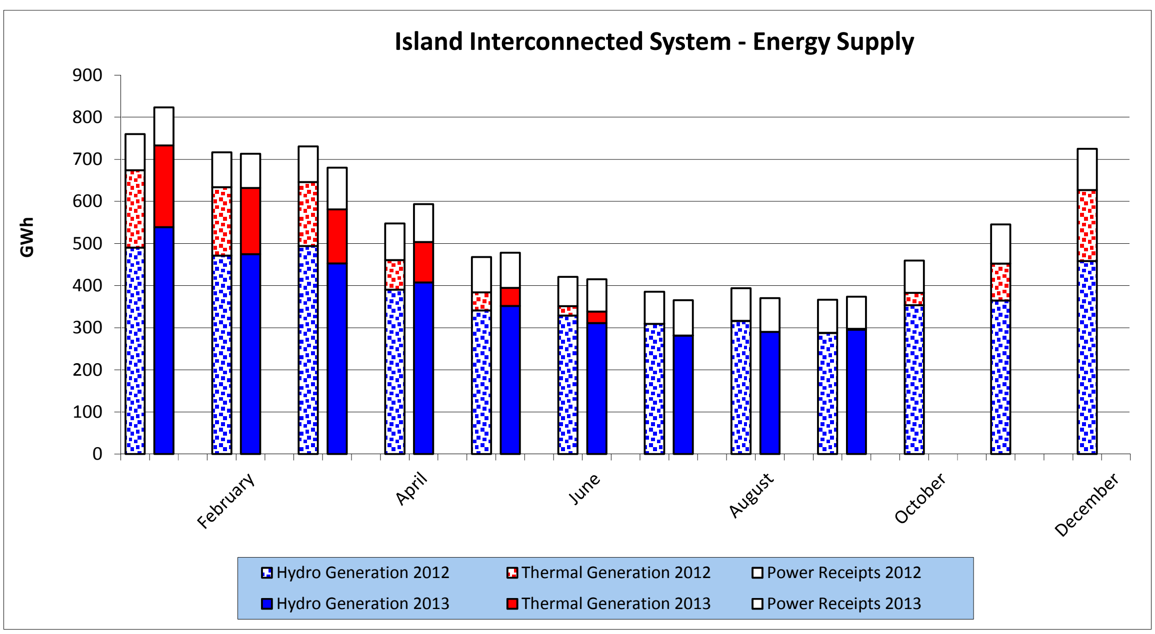
4.1.1 Energy Supply - Island Interconnected System

The energy produced and purchased on the Island Interconnected system is up by 26.7 GWh or 0.6% through the third quarter of 2013 compared to 2012. This is owing to higher utility requirements which have been partially offset by lower energy requirements for the Industrial Customers, particularly Corner Brook Pulp and Paper Limited.

Energy requirements from the Holyrood Generating station were higher through the third quarter of 2013 when compared to the same period in 2012 (13.1 GWh or 2.2%). This was primarily due to cooler temperatures, particularly during the late spring period, which resulted in increased requirements for Avalon transmission support. Individual units are brought into service as required to meet customer's demand and for transmission support to the Avalon Peninsula. The first unit was started in late September following the summer shutdown period.

Hydroelectric production through the third quarter of 2013 was 27.1 GWh or 0.8% below the levels in 2012, primarily due to increased Holyrood requirements and an increase in energy purchases. Total energy purchases were up by 37.2 GWh or 5.1% through the third quarter of 2013 when compared to 2012. This increase was primarily due to increased generation from the Nalcor facilities at Exploits, the CBPP co-generation unit and the Fermeuse wind farm. The increase in energy purchases was partially offset by a decrease in production at the St. Lawrence wind farm. This facility experienced operational issues during the first quarter.

The energy supply for the Island Interconnected System is shown in the following chart and tables.



Island Interconnected System Production
For the Quarter ended September 30, 2013

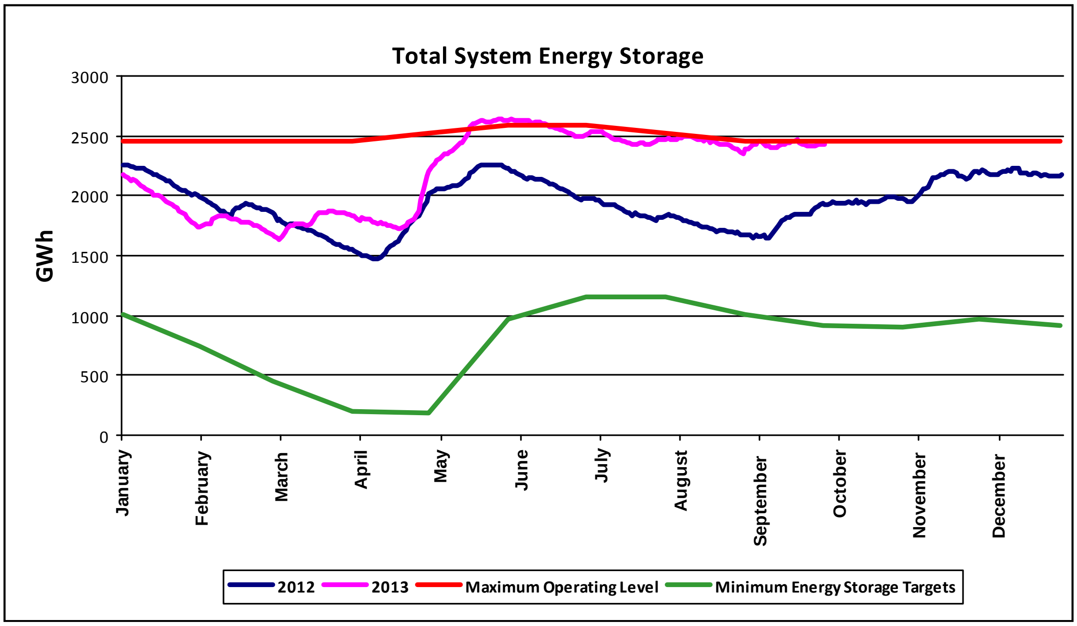
	Year-to-date			2013 Annual Forecast (GWh)	2013 ($ 000)
	2013 (GWh)	2012 (GWh)	2013 Forecast (GWh)		
Production (net)					
Hydro	3,394.5	3,421.6	3,478.5	4,694.4	
Thermal	602.9	589.8	613.4	981.5	
Gas Turbines	(1.2)	(3.6)	1.9	3.0	
Diesels	0.7	(0.4)	0.9	1.0	
Total Production	**3,996.9**	**4,007.4**	**4,094.7**	**5,679.9**	
Energy Purchases					
Non Utility Generators					
Rattle Brook	10.9	9.8	11.1	15.6	**884.6**
Corner Brook Pulp and Paper Co-generation	40.8	35.8	41.2	52.7	**6,542.1**
St. Lawrence Wind	67.7	74.3	62.9	91.9	**4,828.7**
Fermeuse Wind	71.9	64.2	62.6	86.0	**5,507.1**
Total Non Utility Generators	**191.3**	**184.1**	**177.8**	**246.2**	**17,762.5**
Secondary and Others					
Deer Lake Power	5.9	4.2	3.2	3.2	**80.1**
Hydro Request to NP	1.0	0.1	0.0	0.0	**366.8**
Nalcor Energy(1)	564.6	537.2	580.6	760.2	
Total Secondary and Other	**571.5**	**541.5**	**583.8**	**763.4**	**447.0**
Total Purchases	**762.8**	**725.6**	**761.6**	**1,009.6**	
Island Interconnected Total Produced and Purchased	**4,759.7**	**4,733.0**	**4,856.3**	**6,689.5**	

[1]Nalcor Energy includes Star Lake and the Grand Falls, Bishop's Falls and Buchans generation.

4.1.2 System Hydrology

Reservoir storage levels continue to be high. Inflows into the aggregate reservoir system were well above average at 170% of average during the third quarter of 2013 and are now 127% of average for the year to date. Reservoir levels at the end of the quarter were at 100% of the maximum operating level (MOL) and 266% of the minimum storage target. This compares with 79% of the MOL at the end of the third quarter in 2012.

Spill continued out of several reservoir systems during the third quarter of 2013 due to the significant amount of precipitation experienced.



System Hydrology Storage Levels			
	2013 (GWh)	**2013 Minimum Target (GWh)**	**2012 (GWh)**
Quarter End Storage Levels	2,428	913	1,927

4.1.3 Energy Supply – Labrador Interconnected System

The purchased and produced energy on the Labrador Interconnected System was up through the third quarter of 2013 (16.7 GWh or 3.0%) when compared to 2012. This is primarily owing to higher industrial sales at the Iron Ore Company of Canada (IOCC) and slightly higher Hydro Rural requirements. The increase in energy requirements has been partially offset by reduced secondary sales to CFB Goose Bay.

Labrador Interconnected System Production For the Quarter ended September 30, 2013				
	Year-to-date			**2013 Annual Forecast (GWh)**
	2013 (GWh)	**2012 (GWh)**	**2013 Forecast (GWh)**	
Production (net)				
Gas Turbines	0.3	(0.5)	(0.4)	(0.3)
Diesels	0.0	0.0	0.1	0.2
Total Production	**0.3**	**(0.5)**	**(0.3)**	**(0.1)**
Purchases				
CF(L)Co for Labrador (at border)	**577.0**	**561.1**	**633.4**	**935.3**
Labrador Interconnected Total Produced and Purchased	**577.3**	**560.6**	**633.1**	**935.2**

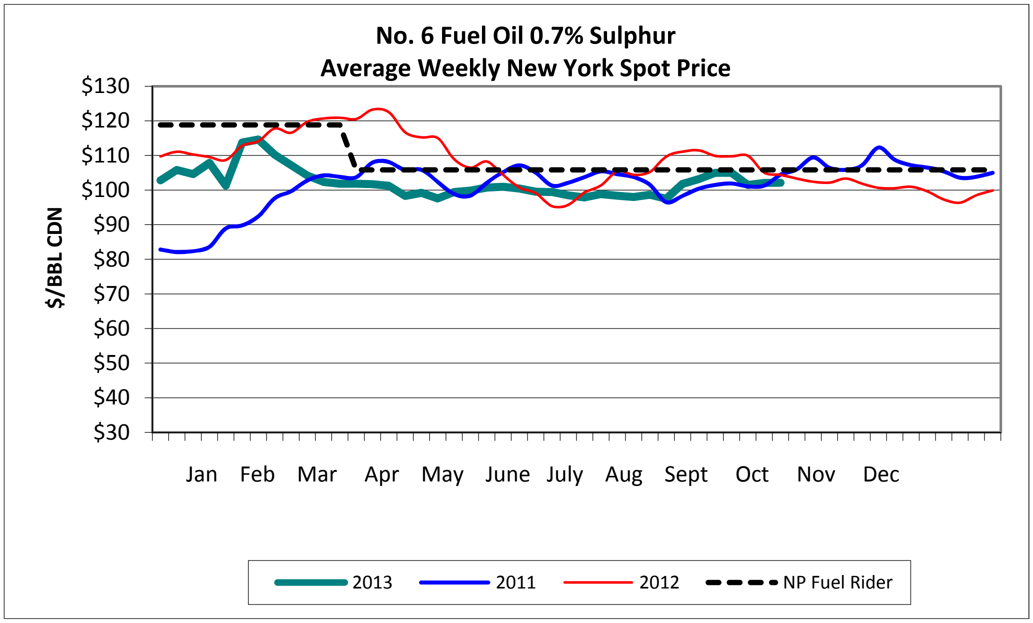
4.1.4 Fuel Prices

The fuel market prices for No. 6 fuel increased slightly from approximately $98/bbl. at the start of the quarter to $102/bbl. at the end of the quarter. The quarter ending inventory cost was $104.90/bbl., lower than the current Newfoundland Power fuel price rider of $105.80/bbl. There is no Industrial Customer fuel price rider for 2013.

There were no shipments received during the third quarter of 2013.

The inventory on September 30 was 446,823 barrels.

The following chart shows the No. 6 fuel prices year-to-date compared to 2011 and 2012, and the Newfoundland Power fuel rider price of $105.80/bbl.



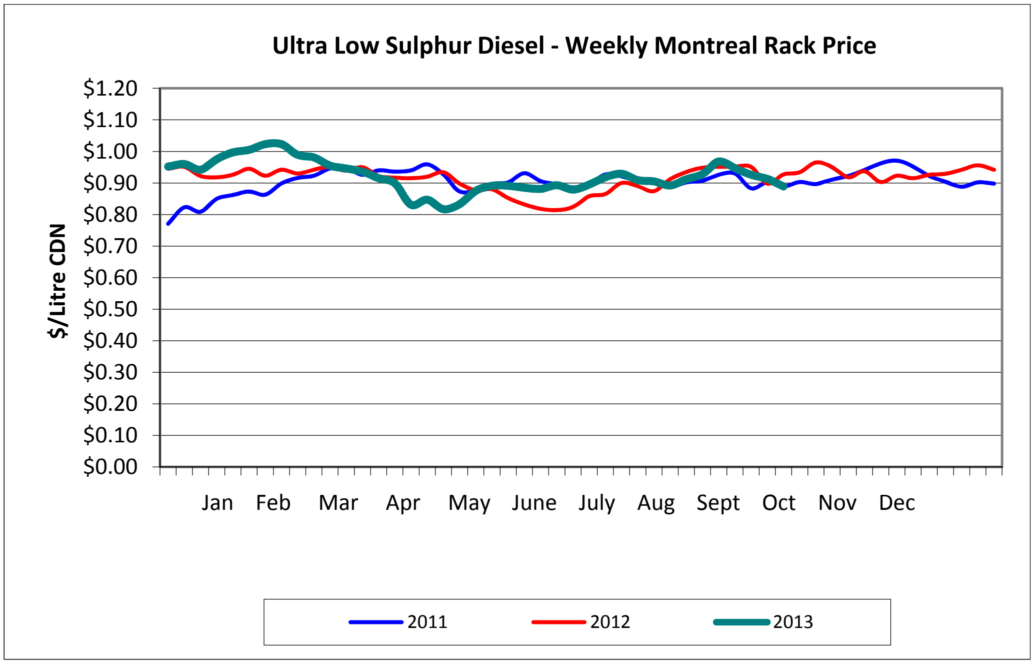
The following table provides the monthly forecast price of No. 6 fuel (0.7% sulphur) up to September 2014, landed on the Avalon Peninsula.

No. 6 Fuel Oil Sulphur
Forecast Price October 2013 –September 2014

Month	Price ($Cdn/bbl) 0.7%	Month	Price ($Cdn/bbl) 0.7%
October 2013	110.70	April 2014	104.60
November 2013	113.50	May 2014	102.70
December 2013	109.00	June 2014	104.50
January 2014	111.50	July 2014	105.00
February 2014	107.50	August 2014	106.30
March 2014	106.90	September 2014	106.90

Note: The forecast is based on the PIRA Energy Group price forecast available September 26, 2013 and an exchange rate forecast by Canadian financial institutions and the Conference Board of Canada.

The following chart shows Low Sulphur Diesel No. 1 fuel prices year-to-date compared to 2011 and 2012.



4.1.5 Energy Supply - Isolated Systems

Total isolated energy supply increased by 3.6% for the first nine months of 2013 compared with 2012 with the increase primarily attributed to sales growth on the L'Anse au Loup and Mary's Harbour systems. Net diesel production was 3.5% higher and energy purchases were 3.7% higher when comparing 2013 to 2012. Compared with the year-to-date forecast for total produced and purchased energy for the isolated systems, 2013 is lower than expected.

Energy purchases are based on fuel prices with the average cost for the first nine months of 2013 being $142 per megawatt hour. The average cost for energy purchases for the same period in 2012 was $139 per megawatt hour.

Isolated Systems Production
For the Quarter ended September 30, 2013

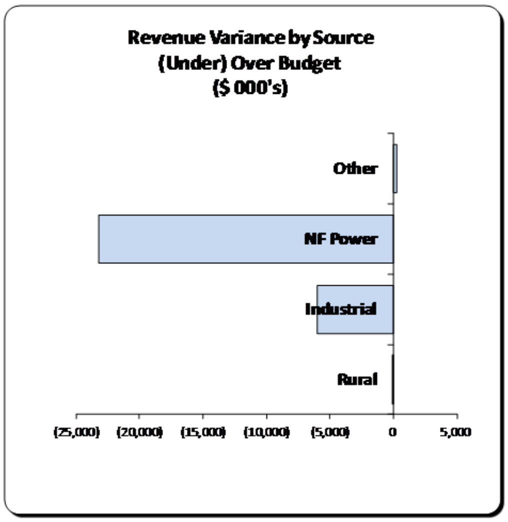
	Year-to-date						2013 Annual Forecast	
	2013		2012		2013 Forecast		(GWh)	$(000)[1]
	(GWh)	$(000)[1]	(GWh)	$(000)[1]	(GWh)	$(000)[1]		
Production (net)								
Diesels	35.2		34.0		38.2		50.6	
Purchases								
Non Utility Generators (NUGS)[2]	0.5	153.2	0.5	104.7	0.5	152.4	0.8	244.7
Hydro Québec	16.5	2,256.1	15.9	2,170.6	17.5	2,289.8	23.2	3,353.2
Total Purchases	**17.0**	**2,409.3**	**16.4**	**2,275.3**	**18.0**	**2442.2**	**24.0**	**3,597.9**
Isolated Systems Total Produced and Purchased	**52.2**	**2,409.3**	**50.4**	**2,275.3**	**56.2**	**2,442.2**	**74.6**	**3,597.9**

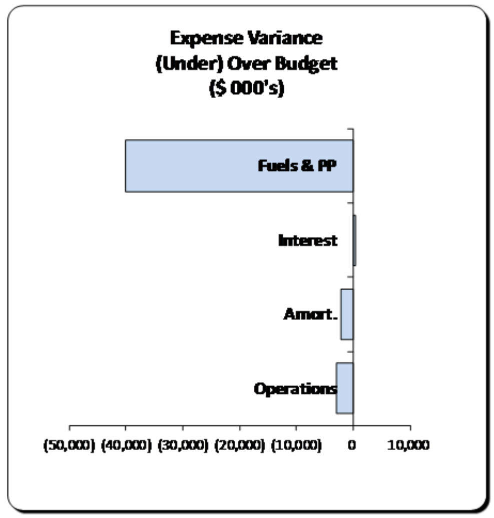
[1] Purchases before taxes.
[2] NUGS includes Frontier Power and Nalcor's wind/hydrogen facility in Ramea. Year to date cost for 2012 energy purchases include Frontier Power only.

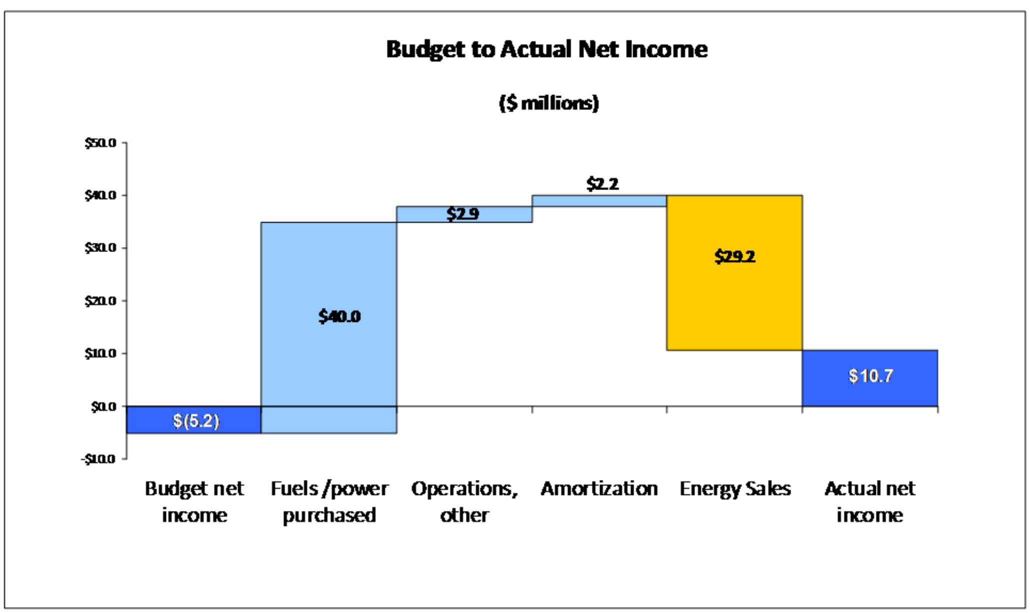
4.2 Financial

Below are charts of Hydro's (regulated) Statement of Income year to date. Please see Appendix C for the remainder of the financial statements.

Regulated Operations
For the nine months ended September 30, 2013







Statement of Income - Regulated Operations
For the nine months ended September 30, 2013
($ 000's)

Third Quarter 2013 Actual	Third Quarter 2013 Budget	Third Quarter 2012 Actual		Year-to-date 2013 Actual	Year-to-date 2013 Budget	Year-to-date 2012 Actual	2013 Annual Budget
			Revenue				
69,242	92,342	70,457	Energy sales	338,042	367,249	330,769	535,619
645	517	551	Other revenue	1,821	1,553	1,888	2,072
69,887	92,859	71,008		339,863	368,802	332,657	537,691
			Expenses				
27,187	30,528	28,878	Operations	84,211	87,198	80,800	111,922
96	-	110	Loss (gain) on disposal of property, plant and equipment	62	(7)	52	1,601
(11,144)	24,584	(8,807)	Fuels	93,954	133,593	89,341	212,462
13,300	13,017	12,567	Power purchased	43,867	44,247	41,188	59,377
12,924	14,024	12,079	Amortization	38,240	40,448	35,978	55,118
23,033	22,826	22,320	Interest	68,853	68,521	67,663	91,039
65,396	104,979	67,147		329,187	374,000	315,022	531,519
4,491	(12,120)	3,861	**Net income (loss)**	10,676	(5,198)	17,635	6,172

Note : Certain of the 2012 comparative figures were restated to conform with the 2013 presentation.

4.3 Capital Expenditures

Capital Expenditures - Overview
For the Quarter ended September 30, 2013
($000)

	PU Board Approved Budget	Third Quarter Actuals	Year To Date Actuals	Expected Remaining Expenditures
Generation	34,142	6,396	15,403	13,322
Transmission and Rural Operations	37,195	10,658	22,228	14,840
General Properties	7,768	1,431	3,793	3,455
Allowance for Unforeseen Events [1]	1,000	-193	209	792
Projects Approved by PU Board Order	35,536	2,002	11,940	12,420
New Projects Under $50,000 Approved by Hydro	185	12	80	104
Total 2013 Capital Budget	115,826	20,306	53,653	44,933
2013 FEED costs for 2014 projects [2]	-	-	253	-
Total 2013 Capital plus 2014 FEED	115,826	20,306	53,906	44,933

[1] Costs are presented net of insurance recoveries.
[2] These costs represent Front End Engineering and Design (FEED) costs incurred in 2013 related to 2014 capital projects.

2013 Capital Budget Approved by Board Order No. P.U. 4(2013)	$62,272
Carryover Projects 2012 to 2013	19,501
New Project Approved by Board Order No. P.U. 25(2012)	2,252
New Project Approved by Board Order No. P.U. 26(2012)	1,295
New Project Approved by Board Order No. P.U. 35(2012)	190
New Project Approved by Board Order No. P.U. 1(2013)	284
New Project Approved by Board Order No. P.U. 12(2013)	5,198
New Project Approved by Board Order No. P.U. 14(2013)	12,810
New Project Approved by Board Order No. P.U. 15(2013)	3,823
New Project Approved by Board Order No. P.U. 20(2013)	8,016
2013 New Projects Under $50,000 approved by Hydro	185
Total Approved Capital Budget	$115,826

5 OTHER ITEMS

5.1 Significant Issues

5.1.1 Ramea Wind-Hydrogen-Diesel Project Update

Overall Project Site Showing (l-r) the Diesel Plant/Storage Tanks, Meteorological Tower, Hydrogen Electrolyser, 3 Hydrogen Storage Tanks, Distribution Box Structure, 3 Wind Turbines, and Quonset Hut Housing the Hydrogen Genset.

In accordance with Order No. P.U. 31(2007), the following update is provided on the Wind-Hydrogen-Diesel Project for Ramea.

Implementation and Operation
Some project deficiencies remained in this quarter as project staff member was required on and re-assigned to other project work. Project close-out is deferred to Q4 2013 to resolve reliability problems with the Hydrogen Genset and complete remaining project deficiencies. Operations schedule was revised to commence in Q1 2014, pending completion of project close-out documentation.

Capital Costs

($000)

Actual Cost to September 2013	Actual Cost Recoveries to September 2013	Net Cost to September 2013	Budget to December 2008	Budget Reforecast to September 2010[1]
11,869	11,869	0	8,794	2,486

Operating Costs
There is nothing to report for this period.

[1] Project Change Order #3 is under draft to reflect various cost increases and schedule delays associated with incomplete commissioning activities, H_2 Genset issues and project deficiencies.

Reliability and Safety Issues
There is nothing to report for this period.

5.1.2 Line Worker Training and Orientation

Line Worker apprentices who recently received apprentice jobs completed a five-day orientation and training session in Bishop's Falls and Springdale during the week of July 8. The goal of the training was to ensure the apprentices are ready to get started in the workforce with a safety mindset. The focus of the training was job specific with health, safety and environment training at the forefront for the week.

The Line Worker apprentices during one of their safety training sessions in Bishop's Falls.

5.2 Community

5.2.1 Bike Ride for Cancer

Rob Bartlett, Safety, Health and Environmental Coordinator in Bay d'Espoir, and a team of friends participated in a three-day bike ride for cancer from July 19-21. This was the sixth year for the event and Rob's fifth time participating. The ride, which began at the Trans-Canada Highway Bay d'Espoir turn-off and ended at the St. Alban's Recreation Complex, required biking approximately 55 km a day. Rob and his team worked hard to raise $6,300 from donations collected during the ride throughout the communities, through Hydro employees and from tickets sales on a bike. Hydro's Community Investment Program also contributed to help the cause.

Rob Bartlett and friends participated in three-day bike race to raise money for cancer patients

5.2.2 Hydro - A Presenting Sponsor for Red Shoe Crew Walk for Families

Newfoundland and Labrador Hydro was the presenting sponsor of Ronald McDonald House's second annual provincial Red Shoe Crew Walk for Families, which took place in 34 communities throughout the province on September 21 and 22. Hydro employees supported the operations of the Ronald McDonald House by organizing their own fundraisers, as well as making donations through Hydro's Employee Giving Program. Hydro teams surpassed their original goal of $11,000 and raised a total of $25,000 this year.

5.3 Statement of Energy Sold

Statement of Energy Sold (GWh)

For the Quarter ended September 30

	YEAR TO DATE 2013 ACTUAL	YEAR TO DATE 2012 ACTUAL	YEAR TO DATE 2013 YTD BUDGET	2013[1] ANNUAL BUDGET	YTD % CHANGE
Island Interconnected					
Newfoundland Power	3,990	3,916	4,122	5,691	1.9%
Island Industrials	259	316	328	446	-18.0%
Rural					
Domestic	187	185	182	248	1.1%
General Service	128	128	119	159	0.0%
Streetlighting	2	2	2	3	0.0%
Sub-total Rural	317	315	303	410	0.6%
Sub-Total Island Interconnected	4,566	4,547	4,753	6,547	0.4%
Island Isolated					
Domestic	5	5	4	6	0.0%
General Service	1	1	1	1	0.0%
Streetlighting	0	0	0	0	0.0%
Sub-Total Island Isolated	6	6	5	7	0.0%
Labrador Interconnected					
Labrador Industrials	143	123	248	374	16.3%
CFB Goose Bay	3	13	0	0	-76.9%
Hydro Quebec (includes Menihek)	30	30	29	41	0.0%
Export	1,204	1,223	1,025	1,283	-1.6%
Rural					
Domestic	214	215	212	300	-0.5%
General Service	180	183	186	263	-1.6%
Streetlighting	1	1	1	2	0.0%
Sub-total Rural	395	399	399	565	-1.0%
Sub-Total Lab. Interconnected	1,775	1,788	1,701	2,263	-0.7%
Labrador Isolated					
Domestic	16	16	16	23	0.0%
General Service	11	11	13	17	0.0%
Streetlighting	0	0	0	0	0.0%
Sub-Total Labrador Isolated	27	27	29	40	0.0%
L'Anse au Loup					
Domestic	10	10	10	15	0.0%
General Service	6	6	6	8	0.0%
Streetlighting	0	0	0	0	0.0%
Sub-Total L'Anse au Loup	16	16	16	23	0.0%
Total Energy Sold	6,390	6,384	6,504	8,880	0.1%
Sales to Non-Regulated Customers[2]	1,377	1,376	1,302	1,698	0.1%

[1] Rural GWh - Based on 2013 Budget, Fall 2012 Rural Load Forecast
Non-rural GWh - Based on 2013TY Wholesale Industrial Revenue Budget
[2] Included in Total Energy Sold

5.4 Customer Statistics

Customer Statistics
For the Quarter ended September 30

	THIRD QUARTER		ANNUAL	
	2013 ACTUAL	2012 ACTUAL	2013 Budget	2012 ACTUAL
Customers				
Rural	37,740	37,380	37,604	37,576
Industrial	4	4	5	4
CFB Goose Bay	1	1	0	1
Utility	1	1	1	1
Non-Regulated	3	3	3	3
Reading Days	30.0	30.1	N/A	30.0

APPENDICES

Appendix A - Contributions in Aid of Construction (CIAC)
Appendix B - Damage Claims
Appendix C - Financial
Appendix D - Rate Stabilization Plan Report
Appendix E - Performance Indices

CIAC QUARTERLY ACTIVITY REPORT
For the Quarter ended September 30, 2013

TYPE OF SERVICE	CIAC'S QUOTED	CIAC'S OUTSTANDING PREVIOUS QTR.	TOTAL CIAC'S QUOTED	CIAC'S ACCEPTED	CIAC'S EXPIRED	TOTAL CIAC'S OUTSTANDING
Domestic						
Within Plan. Boundary	9	10	19	10	1	8
Outside Plan. Boundary	3	0	3	0	0	3
Sub-total	12	10	22	10	1	11
General Service	6	6	12	3	1	6
Total	18	16	34	13	2	17

The table above summarizes Contribution in Aid of Construction (CIAC) activity for this quarter. The table is divided into three sections, as follows:

- The first section outlines the type of service for which a CIAC has been calculated, either Domestic or General Service.
- The second section indicates the number of CIACs quoted during the quarter as well as the number of CIAC quotes that remained outstanding at the end of the previous quarter. This format facilitates a reconciliation of the total number of CIACs that were active during the quarter.
- The third section provides information as to the disposition of the total CIACs quoted. A CIAC is considered accepted when a customer indicates they wish to proceed with construction of the extension and has agreed to pay any charge that may be applicable. A CIAC is considered outdated after six months has elapsed and the customers have not indicated their intention to proceed with the extension. A quoted CIAC is outstanding if it is neither accepted nor outdated.

CIAC QUARTERLY ACTIVITY REPORT
For the Quarter ended September 30, 2013

DATE QUOTED	SERVICE LOCATION	CIAC NO.	CIAC AMOUNT ($)	ESTIMATED CONST. COST ($)	ACCEPTED
DOMESTIC - WITHIN RESIDENTIAL PLANNING BOUNDARIES					
July 10, 2013	Trout River	984363	$ 990.00	$ 3,540.00	Yes
July 16, 2013	St. Anthony	961378	$ 12,010.00	$ 13,895.00	Yes
July 18, 2013	South Brook; Green Bay	991469	$ 207.50	$ 957.50	Yes
August 1, 2013	South Brook; Green Bay	994459	$ 67,051.00	$ 94,351.00	
August 15, 2013	Trout River	993635	$ 4,200.00	$ 7,050.00	
August 21, 2013	Swanger's Cove	997071	$ 2,870.00	$ 5,420.00	Yes
August 28, 2013	Harbour Breton	947685	$ 582.00	$ 1,307.00	Yes
September 17, 2013	Happy Valley-Goose Bay	1000198	$ 2,400.00	$ 4,950.00	Yes
September 27, 2013	South Brook; Green Bay	1005031	$ 2,230.00	$ 2,980.00	
DOMESTIC - OUTSIDE RESIDENTIAL PLANNING BOUNDARIES					
August 22, 2013	St. Anthony	990945	$ 1,830.00	$ 2,580.00	
September 9, 2013	Labrador City	918434	$ 465,180.00	$ 501,180.00	
September 20, 2013	Westport	1001275	$ 1,959.00	$ 2,684.00	
GENERAL SERVICE					
July 12, 2013	Wabush	983365	$ 6,789.22	$ 9,339.22	
August 22, 2013	Daniel's Harbour	971178	$ -	$ 1,800.00	
September 9, 2013	L'Anse au Loup	993605	$ -	$ 8,690.00	
September 27, 2013	Churchill Falls	989303	$ 18,881.81	$ 26,082.00	
September 30, 2013	Happy Valley-Goose Bay	1001037	$ 2,715.00	$ 17,430.00	
September 30, 2013	Middle Arm	1000896	$ -	$ 2,990.00	

CUSTOMER PROPERTY DAMAGE CLAIMS REPORT
For the Quarter ended September 30, 2013

Introduction

The Customer Property Damage Claims Report contains an overview of all damage claims activity summarized on a quarterly basis. The information contained in the report is broken down by cause as well as by the operating region where the claims originated.

The report is divided into four sections as follows:

1. The first section indicates the number of claims received during the quarter coupled with claims outstanding from the previous quarter.

2. The second section shows the number of claims for which the Company has accepted responsibility and the amount paid to claimants versus the amount originally claimed.

3. The third section shows the number of claims rejected and the dollar value associated with those claims.

4. The fourth section indicates those claims that remain outstanding at the end of the current quarter and the dollar value associated with such claims.

Definitions of Causes of Damage Claims

1. System Operations: Claims arising from system operations. Examples include normal reclosing or switching.

2. Power Interruptions: Claims arising from interruption of power supply. Examples include all scheduled or unscheduled interruptions.

3. Improper Workmanship: Claims arising from failure of electrical equipment caused by improper workmanship or methods. Examples include improper crimping of connections, insufficient sealing and taping of connections, improper maintenance, inadequate clearance or improper operation of equipment.

4. Weather Related: Claims arising from weather conditions. Examples include wind, rain, ice, lighting or corrosion caused by weather.

5. Equipment Failure: Claims arising from failure of electrical equipment not caused by improper workmanship. Examples include broken neutrals, broken tie wires, transformer failure, insulator failure or broken service wire.

6. Third Party: Claims arising from equipment failure caused by acts of third parties. Examples include motor vehicle accidents and vandalism.

7. Miscellaneous: All claims not related to electrical service.

8. Waiting Investigation: Cause to be determined.

CUSTOMER PROPERTY DAMAGE CLAIMS REPORT - BY CAUSE

For the Quarter ended September 30, 2013

CAUSE	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	AMT. CLAIMED	AMT. PAID	#	AMOUNT	#	AMOUNT
System Operations	0	1	1	0	$ -	$ -	0	$ -	0	$ -
Power Interruptions	0	0	0	0	$ -	$ -	1	$ 762.00	0	$ -
Improper Workmanship	1	3	4	0	$ -	$ -	0	$ -	4	$ 4,211.59
Weather Related	5	5	10	2	$ 2,913.00	$ 941.34	3	$ 900.00	5	$ 11,504.67
Equipment Failure	0	5	5	0	$ -	$ -	0	$ -	6	$ 33,447.27
Third Party	0	0	0	0	$ -	$ -	0	$ -	0	$ -
Miscellaneous	3	2	5	1	$ 1,349.00	$ 904.30	1	$ -	3	$ 2,847.73
Waiting Investigation	6	4	10	0	$ -	$ -	1	$ -	8	$ 859.85
Total	15	20	35	3	$ 4,262.00	$ 1,845.64	6	$ 1,662.00	26	$ 52,871.11

For the Quarter ended September 30, 2012

CAUSE	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	AMT. CLAIMED	AMT. PAID	#	AMOUNT	#	AMOUNT
System Operations	2	0	2	0	$ -	$ -	0	$ -	2	$ 1,262.00
Power Interruptions	3	2	5	0	$ -	$ -	4	$ 2,369.98	1	$ -
Improper Workmanship	1	6	7	1	$ 677.95	$ 120.00	0	$ -	5	$ 5,522.02
Weather Related	3	5	8	1	$ -	$ 1,818.95	1	$ 863.32	6	$ 5,364.00
Equipment Failure	2	4	6	0	$ -	$ -	0	$ -	6	$ 38,964.00
Third Party	0	0	0	0	$ -	$ -	0	$ -	0	$ -
Miscellaneous	0	2	2	1	$ 3,838.61	$ 2,687.03	0	$ -	2	$ 600.60
Waiting Investigation	4	4	8	0	$ -	$ -	0	$ -	8	$ 3,988.00
Total	15	23	38	3	$ 4,516.56	$ 4,625.98	5	$ 3,233.30	30	$ 55,700.62

CUSTOMER PROPERTY DAMAGE CLAIMS REPORT - BY REGION

For the Quarter ended September 30, 2013

REGION	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	AMT. CLAIMED	AMT. PAID	#	AMOUNT	#	AMOUNT
Central Region	5	2	7	0	$ -	$ -	1	$ -	6	$ 2,925.47
Northern Region	9	11	20	2	$ -	$ 941.34	3	$ 900.00	15	$ 43,542.87
Labrador Region	1	7	8	1	$ 1,349.00	$ 904.30	2	$ 762.00	5	$ 6,402.77
Total	15	20	35	3	$ 4,262.00	$ 1,845.64	6	$ 1,662.00	26	$ 52,871.11

For the Quarter ended September 30, 2012

REGION	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	AMT. CLAIMED	AMT. PAID	#	AMOUNT	#	AMOUNT
Central Region	3	9	12	2	$ 4,516.56	$ 2,807.03	0	$ -	10	$ 7,168.54
Northern Region	10	8	18	1	$ -	$ 1,818.95	5	$ 3,233.30	12	$ 39,082.08
Labrador Region	2	6	8	0	$ -	$ -	0	$ -	8	$ 9,450.00
Total	15	23	38	3	$ 4,516.56	$ 4,625.98	5	$ 3,233.30	30	$ 55,700.62

FINANCIAL – REGULATED

Balance Sheet - Regulated Operations
As at September 30
($ 000's)

	Sep-13	Sep-12
ASSETS		
Current assets		
Cash and cash equivalents	2,114	2,856
Accounts receivable	44,313	40,524
Current portion of regulatory assets	2,157	2,218
Inventory	78,889	79,514
Prepaid expenses	4,620	4,264
	132,093	129,376
Property, plant, and equipment	1,453,332	1,422,529
Sinking funds	266,969	262,003
Regulatory assets	62,248	62,802
Total assets	1,914,642	1,876,710
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	31,976	33,868
Accrued interest	17,454	17,454
Current portion of long-term debt	8,150	8,150
Current portion of regulatory liabilities	202,834	148,125
Deferred credits	1,267	3,006
Due to related parties	3,359	20,697
Promissory notes	35,562	27,135
	300,602	258,435
Long-term debt	1,121,950	1,127,387
Regulatory liabilities	38,553	40,270
Asset retirement obligations	24,662	20,066
Employee future benefits	60,142	55,807
Contributed capital	100,000	100,000
Shareholder's equity / retained earnings	241,850	231,604
Accumulated other comprehensive income	26,883	43,141
Total liabilities and shareholder's equity	1,914,642	1,876,710

Note: Certain of the 2012 comparative figures were restated to conform with the 2013 presentation.

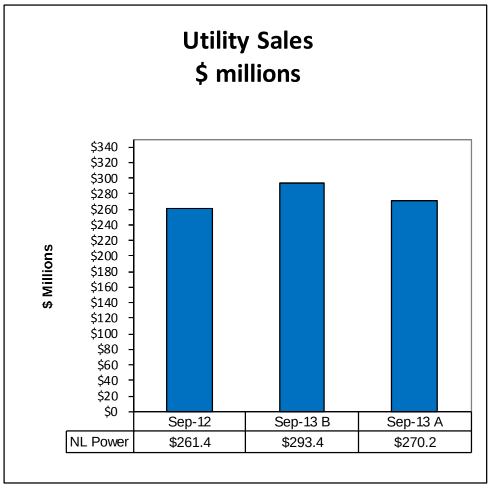
Statement of Retained Earnings - Regulated Operations
For the nine months ended September 30, 2013
($ 000's)

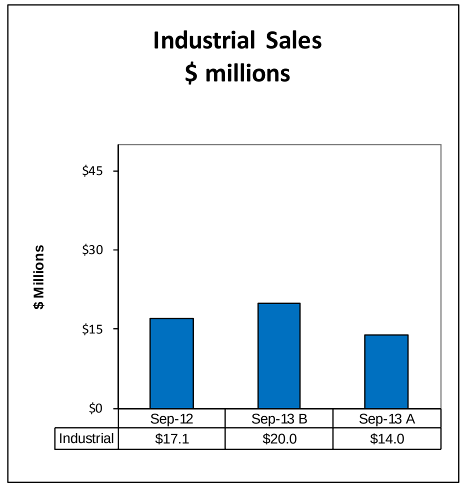
Third Quarter 2013 Actual	Third Quarter 2012 Actual		Year-to-date 2013 Actual	Year-to-date 2012 Actual
239,715	226,698	Balance, beginning of period	231,174	212,096
-	1,045	Adjustment	-	1,873
2,135	3,861	Net income	10,676	17,635
241,850	231,604	Balance, end of period	241,850	231,604

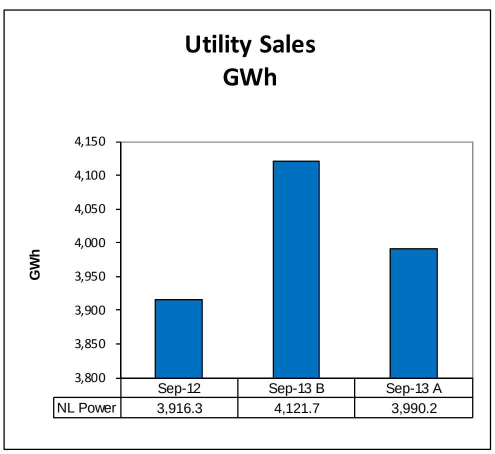
Statement of Comprehensive Income - Regulated Operations
For the nine months ended September 30, 2013
($ 000's)

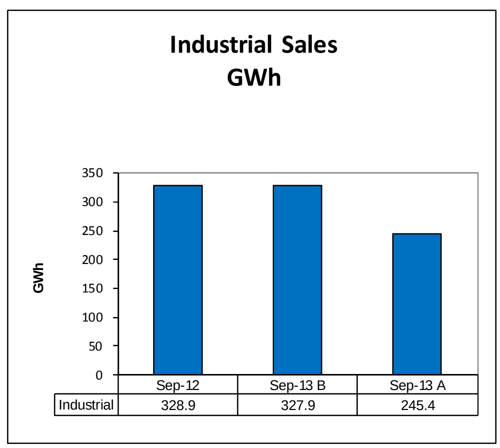
Third Quarter 2013 Actual	Third Quarter 2013 Budget	Third Quarter 2012 Actual		Year-to-date 2013 Actual	Year-to-date 2013 Budget	Year-to-date 2012 Actual	2013 Annual Budget
4,491	(12,120)	3,861	Net income (loss)	10,676	(5,198)	17,635	6,172
			Other comprehensive (loss) income				
(2,770)	-	329	Change in fair value of sinking fund investments	(14,657)	-	(1,966)	-
1,721	(12,120)	4,190	Total comprehensive (loss) income	(3,981)	(5,198)	15,669	6,172

Sales - Regulated Operations
For the nine months ended September 30, 2013









Revenue Summary - Regulated Operations
For the nine months ended September 30, 2013
($ 000's)

Third Quarter 2013 Actual	Third Quarter 2013 Budget	Third Quarter 2012 Actual		Year-to-date 2013 Actual	Year-to-date 2013 Budget	Year-to-date 2012 Actual	2013 Annual Budget
			REVENUE				
			Industrial				
840	2,058	1,632	Corner Brook Pulp and Paper Ltd.	3,005	4,867	4,758	6,644
51	1,243	-	Vale Inco	80	2,343	-	3,817
2,562	3,299	2,591	North Atlantic Refinery	7,925	9,265	8,485	13,390
213	-	462	C.F.B. Goose Bay	330	-	1,142	-
848	1,208	853	Teck Cominco Limited	2,658	3,057	2,682	4,337
-	302	-	Praxair	-	438	-	760
4,514	8,110	5,538	**Total Industrial**	13,998	19,970	17,067	28,948
			Utility				
51,495	68,186	51,980	Newfoundland Power Inc.	270,197	293,425	261,389	430,447
			Rural				
13,233	16,046	12,939	Interconnected and diesel	53,847	53,854	52,313	76,224
645	517	551	**Other**	1,821	1,553	1,888	2,072
69,887	92,859	71,008	**Total**	339,863	368,802	332,657	537,691
			ENERGY SALES (GWh)				
			Industrial				
9.5	23.4	30.0	Corner Brook Pulp and Paper Ltd.	41.9	70.0	84.7	87.9
1.0	13.0	-	Vale Inco	1.5	25.6	-	39.6
52.0	48.0	52.8	North Atlantic Refinery	162.6	174.1	177.8	238.4
1.8	-	5.1	C.F.B. Goose Bay	3.1	-	12.8	-
-	17.6	16.8	Teck Cominco Limited	36.3	55.0	53.6	74.0
-	2.6	-	Praxair	-	3.2	-	6.5
64.3	104.6	104.7	**Total Industrial**	245.4	327.9	328.9	446.4
			Utility				
887.0	947.2	909.9	Newfoundland Power Inc.	3,990.2	4,121.7	3,916.3	5,691.0
			Rural				
157.9	175.2	153.6	Interconnected and diesel	761.0	754.5	763.4	1,044.7
1,109.2	1,227.0	1,168.2	**Total**	4,996.6	5,204.1	5,008.6	7,182.1

Note: Certain of the 2012 comparative figures were restated to conform with the 2013 presentation.

Statement of Cash Flows - Regulated Operations
For the nine months ended September 30, 2013
($ 000's)

	Year-to-date 2013	Year-to-date 2012
Operating activities		
Net income	10,676	17,635
Adjusted for items not involving cash flow		
Amortization	38,240	35,978
Accretion of long-term debt	402	371
Employee future benefits	3,252	2,241
(Gain) loss on disposal of property, plant and equipment	(200)	52
Other	(115)	-
	52,255	56,277
Changes in non-cash balances		
Accounts receivable	35,872	38,835
Inventory	(27,216)	(25,256)
Prepaid expenses	(1,671)	(1,980)
Regulatory assets	576	1,339
Regulatory liabilities	39,228	17,531
Accounts payable and accrued liabilities	(7,323)	(15,473)
Accrued interest	(11,213)	(11,213)
Due to related parties	1,486	(28,561)
	81,994	31,499
Financing activities		
Decrease in long-term receivable	188	210
(Decrease) increase in deferred credits	(671)	491
(Decrease) increase in promissory notes	(9,221)	32,256
	(9,704)	32,957
Investing activities		
Additions to property, plant and equipment	(54,096)	(46,988)
Proceeds on disposal of property, plant and equipment	3,974	233
Increase in sinking funds	(22,534)	(21,530)
	(72,656)	(68,285)
Net decrease in cash	(366)	(3,829)
Cash position, beginning of period	2,480	6,685
Cash position, end of period	2,114	2,856

Note: Certain of the 2012 comparative figures were restated to conform with the 2013 presentation.

FINANCIAL - NON-REGULATED

Balance Sheet - Non-Regulated Activities
As at September 30
($ 000's)

	Sep-13	Sep-12
ASSETS		
Current assets		
Accounts receivable	5,278	3,683
Derivative assets	-	258
Prepaid expenses	639	-
	5,917	3,941
Investment in CF(L)Co.	424,445	409,589
Total assets	430,362	413,530
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	2,061	3,615
Promissory notes	8,438	5,865
Derivative liabilities	132	-
	10,631	9,480
Share capital	22,504	22,504
Lower Churchill Development Corp	15,400	15,400
Retained earnings	382,061	366,109
Accumulated other comprehensive (loss) income	(234)	37
Total liabilities and shareholder's equity	430,362	413,530

Note: Certain of the 2012 comparative figures were restated to conform with the 2013 presentation.

Statement of Income - Non-Regulated Activities
For the nine months ended September 30, 2013
($ 000's)

Third Quarter 2013 Actual	Third Quarter 2013 Budget	Third Quarter 2012 Actual		Year-to-date 2013 Actual	Year-to-date 2013 Budget	Year-to-date 2012 Actual	2013 Annual Budget
			Revenue				
19,536	21,098	16,993	Energy sales	51,936	50,918	38,242	65,822
19,536	21,098	16,993		51,936	50,918	38,242	65,822
			Expenses				
6,500	6,798	6,618	Operations	21,010	20,039	19,284	26,550
-	-	28	Fuels	-	-	28	-
2,480	1,743	2,380	Power purchased	5,886	4,026	5,742	5,032
(799)	-	(842)	Other income and expense	161	-	(288)	-
423	-	(11)	Interest	181	-	223	-
8,604	8,541	8,173		27,238	24,065	24,989	31,582
10,932	12,557	8,820	Net operating income	24,698	26,853	13,253	34,240
(5,450)	(4,130)	(6,375)	Equity in CF(L)Co	7,387	6,587	10,398	15,460
2,228	2,212	3,204	Preferred dividends	7,460	6,635	8,846	8,847
(3,222)	(1,918)	(3,171)		14,847	13,222	19,244	24,307
7,710	10,639	5,649	**Net income**	39,545	40,075	32,497	58,547

Note : Certain of the 2012 comparative figures were restated to conform with the 2013 presentation.

Statement of Retained Earnings - Non-Regulated Activties
For the nine months ended September 30, 2013
($ 000's)

Third Quarter 2013 Actual	Third Quarter 2012 Actual		Year-to-date 2013 Actual	Year-to-date 2012 Actual
387,653	371,822	Balance, beginning of period	373,578	356,645
-	-	Adjustments	-	7
7,710	5,649	Net income	39,545	32,497
(13,302)	(11,362)	Dividends	(31,062)	(23,040)
382,061	366,109	Balance, end of period	382,061	366,109

Statement of Comprehensive Income - Non-Regulated Activities
For the nine months ended September 30, 2013
($ 000's)

Third Quarter 2013 Actual	Third Quarter 2013 Budget	Third Quarter 2012 Actual		Year-to-date 2013 Actual	Year-to-date 2013 Budget	Year-to-date 2012 Actual	2013 Annual Budget
7,710	10,639	5,649	Net income	39,545	40,075	32,497	58,547
			Other comprehensive (loss) income				
73	-	39	Share of CF(L)Co other comprehensive (loss) income	(322)	-	37	-
7,783	10,639	5,688	Total comprehensive income	39,223	40,075	32,534	58,547

Statement of Cash Flows - Non-Regulated Activities
For the nine months ended September 30, 2013
($ 000's)

	Year-to-date 2013	Year-to-date 2012
Operating activities		
Net income	39,545	32,497
Adjusted for items not involving cash flow		
Unrealized loss (gain) on derivatives	160	(70)
Equity in CF(L)Co	(7,272)	(10,398)
	32,433	22,029
Changes in non-cash balances		
Accounts receivable	(1,790)	8
Accounts payable and accrued liabilities	(163)	157
Increase in prepaid expenses	(639)	-
	29,841	22,194
Financing activities		
Increase in promissory notes	1,221	754
Decrease in long-term receivable	-	1,398
Decrease in long-term note payable	-	(1,306)
Dividends	(31,062)	(23,040)
	(29,841)	(22,194)
Net change in cash	-	-
Cash position, beginning of period	-	-
Cash position, end of period	-	-

Note: Certain of the 2012 comparative figures were restated to conform with the 2013 presentation.

Supplementary Schedule - Regulated Operations
For the nine months ended September 30, 2013
($ 000's)

Third Quarter 2013 Actual	Third Quarter 2013 Budget	Third Quarter 2012 Actual		Year-to-date 2013 Actual	Year-to-date 2013 Budget	Year-to-date 2012 Actual	2013 Annual Budget
			Other revenue				
225	147	145	Sundry	515	445	605	595
403	344	399	Pole attachments	1,209	1,031	1,204	1,375
17	26	7	Supplier's discount	97	77	79	102
645	517	551	**Total other revenue**	1,821	1,553	1,888	2,072
			Interest				
28,133	28,451	27,084	Gross interest	83,638	84,424	81,017	112,806
138	138	128	Accretion of long-term debt	402	402	371	540
540	540	540	Amortization of foreign exchange losses	1,618	1,618	1,618	2,157
(734)	(798)	(818)	Allowance for funds used during construction	(2,074)	(1,761)	(1,795)	(2,747)
(5,044)	(5,505)	(4,614)	Interest earned	(14,731)	(16,162)	(13,548)	(21,717)
23,033	22,826	22,320	**Total interest**	68,853	68,521	67,663	91,039

Note: Certain of the 2012 comparative figures were restated to conform with the 2013 presentation.

Cost Recoveries - Regulated Operations
For the nine months ended September 30, 2013
($ 000's)

Third Quarter 2013 Actual	Third Quarter 2013 Budget	Third Quarter 2012 Actual		Year-to-date 2013 Actual	Year-to-date 2013 Budget	Year-to-date 2012 Actual	2013 Annual Budget
1	4	2	Executive Leadership	3	11	8	14
313	290	240	Human Resources and Organizational Effectiveness	859	869	685	1,157
1,373	1,330	1,001	Finance / CFO	3,982	3,973	3,660	5,286
29	2	- 9	Engineering Services	55	6	36	8
29	29	26	Regulated Operations	101	86	82	115
1,745	1,655	1,260		5,000	4,945	4,471	6,580

Newfoundland and Labrador Hydro
Rate Stabilization Plan
September 30, 2013

Rate Stabilization Plan Report
September 30, 2013

Summary of Key Facts

The Rate Stabilization Plan of Newfoundland and Labrador Hydro (Hydro), as amended by Board Order No. P.U. 40 (2003) and Order No. P.U. 8 (2007), is established for Hydro's utility customer, Newfoundland Power, and Island Industrial customers to smooth rate impacts for variations between actual results and Test Year Cost of Service estimates for:

- Hydraulic production;
- No. 6 fuel cost used at Hydro's Holyrood generating station;
- Customer load (Utility and Island Industrial); and
- Rural rates.

The Test Year Cost of Service Study was approved by Board Order No. P.U. 8 (2007) and is based on projections of events and costs that are forecast to happen during a test year. Finance charges are calculated on the balances using the test year Weighted Average Cost of Capital which is currently 7.529% per annum. Holyrood's operating efficiency is set, for RSP purposes, at 630 kWh/barrel regardless of the actual conversion rate experienced.

	2007 Test Year Cost of Service			
	Net Hydraulic Production	No. 6 Fuel Cost	Utility Load	Industrial Load
	(kWh)	($Can/bbl.)	(kWh)	(kWh)
January	427,100,000	54.17	574,800,000	78,300,000
February	388,680,000	54.73	518,600,000	70,900,000
March	415,080,000	55.46	524,700,000	76,600,000
April	355,520,000	55.46	429,200,000	75,600,000
May	324,240,000	55.46	358,700,000	69,500,000
June	328,500,000	54.49	298,400,000	73,800,000
July	386,790,000	54.49	293,400,000	77,500,000
August	379,140,000	54.49	287,000,000	77,900,000
September	363,560,000	54.49	297,700,000	73,000,000
October	340,510,000	54.56	360,200,000	74,400,000
November	364,390,000	54.56	439,300,000	74,100,000
December	398,560,000	58.98	543,800,000	72,700,000
Total	4,472,070,000		4,925,800,000	894,300,000

Rate Stabilization Plan
Plan Highlights
September 30, 2013

	Actual	Cost of Service	Variance	Year-to-Date Due (To) From customers	Reference
Hydraulic production year-to-date	3,397.6 GWh	3,368.6 GWh	29.0 GWh	$ (2,659,391)	Page 4
No 6 fuel cost - Current month	$ 104.90	$ 54.49	$ 50.41	$ 53,591,749	Page 5
Year-to-date customer load - Utility	3,990.2 GWh	3,582.5 GWh	407.7 GWh	$ (469,175)	Page 8
Year-to-date customer load - Industrial	259.1 GWh	673.1 GWh	-414.0 GWh	$ (20,777,047)	Page 9
				$ 29,686,136	

Rural rates		
Rural Rate Alteration (RRA) (1)	$ (6,151,104)	
Less : RRA to utility customer	$ (5,480,633)	Page 10
RRA to Labrador interconnected	(670,471)	
Fuel variance to Labrador interconnected	$ 423,521	Page 6
Net Labrador interconnected	$ (246,950)	

Current plan summary		
One year recovery		
Due (to) from utility customer	$ (76,510,156)	Page 10
Due (to) from Industrial customers	$ 7,553	Page 11
Sub total	(76,502,603)	
Four year recovery		
Hydraulic balance	$ (38,080,051)	Page 4
Segregated Load Variation		Page 12
Utility Customer	$ 6,006	
Industrial Customer	$ (2,208,331)	
Sub total	$ (2,202,325)	
Utility RSP Surplus	$ (113,256,364)	Page 13
Industrial RSP Surplus	$ (10,872,356)	Page 14
Total plan balance	$ (240,913,698)	

(1) Beginning January 2011, the RRA includes a monthly credit of $98,295. This amount relates to the phase in of the application of the credit from secondary energy sales to CFB Goose Bay to the Rural deficit as stated in Section B, Clause 1.3(b) of the approved Rate Stabilization Plan Regulations which received final approval in Order No. P.U. 33 (2010) issued December 15, 2010.

Rate Stabilization Plan
Net Hydraulic Production Variation
September 30, 2013

	A Cost of Service Net Hydraulic Production (kWh)	B Actual Net Hydraulic Production (kWh)	C Monthly Net Hydraulic Production Variance (kWh) **(A - B)**	D Cost of Service No. 6 Fuel Cost ($Can/bbl.)	E Net Hydraulic Production Variation ($) **(C / O(1) X D)**	F Financing Charges ($)	G Cumulative Variation and Financing Charges ($) **(E + F)** **(to page 15)**
Opening balance							(32,675,763)
January	427,100,000	537,465,293	(110,365,293)	54.17	(9,489,663)	(198,260)	(42,363,686)
February	388,680,000	473,366,259	(84,686,259)	54.73	(7,356,951)	(257,042)	(49,977,679)
March	415,080,000	451,303,396	(36,223,396)	55.46	(3,188,809)	(303,240)	(53,469,728)
April	355,520,000	406,276,108	(50,756,108)	55.46	(4,468,149)	(324,428)	(58,262,305)
May	324,240,000	351,332,533	(27,092,533)	55.46	(2,385,003)	(353,507)	(61,000,815)
June	328,500,000	310,817,215	17,682,785	54.49	1,529,421	(370,122)	(59,841,516)
July	386,790,000	281,274,794	105,515,206	54.49	9,126,228	(363,088)	(51,078,376)
August	379,140,000	290,520,764	88,619,236	54.49	7,664,861	(309,918)	(43,723,433)
September	363,560,000	295,245,361	68,314,639	54.49	5,908,674	(265,292)	(38,080,051)
October							
November							
December							
	3,368,610,000	3,397,601,723	(28,991,723)		(2,659,391)	(2,744,897)	(38,080,051)
Hydraulic Allocation (2)							
Hydraulic variation at year end					(2,659,391)	(2,744,897.00)	(38,080,051)

(1) O is the Holyrood Operating Efficiency of 630 kWh/barrel.

(2) At year end 25% of the hydraulic variation balance and 100% of the annual financing charges are allocated to customers.

Rate Stabilization Plan
No. 6 Fuel Variation
September 30, 2013

	A	B	C	D	E	F	G
	Actual Quantity No. 6 Fuel	Actual Quantity No. 6 Fuel for Non-Firm Sales	Net Quantity No. 6 Fuel	Cost of Service No. 6 Fuel Cost	Actual Average No. 6 Fuel Cost	Cost Variance	No.6 Fuel Variation
	(bbl.)	(bbl.)	(bbl.) **(A - B)**	($Can/bbl.)	($Can/bbl.)	($Can/bbl.) **(E - D)**	($) **(C X F)** **(to page 6)**
January	297,603	0	297,603	54.17	105.89	51.72	15,392,012
February	242,076	6	242,070	54.73	108.00	53.27	12,895,076
March	202,010	0	202,010	55.46	111.07	55.61	11,233,756
April	153,817	0	153,817	55.46	107.83	52.37	8,055,421
May	67,271	0	67,271	55.46	104.90	49.44	3,325,862
June	45,659	0	45,659	54.49	104.90	50.41	2,301,664
July	1,972	0	1,972	54.49	104.90	50.41	99,395
August	0	0	0	54.49	104.90	50.41	0
September	5,724	0	5,724	54.49	104.90	50.41	288,563
October							
November							
December							
	1,016,132	6	1,016,126				53,591,749

Rate Stabilization Plan
Allocation of Fuel Variance - Year-to-Date
September 30, 2013

	A	B	C	D	E	F	G	H	I	J
	Twelve Months-to-Date				Year-to-Date Fuel Variance				Reallocate Rural Island Customers [(1)]	
	Utility	Industrial Customers	Rural Island Customers	Total	Utility	Industrial Customers	Rural Island Interconnected	Total	Utility	Labrador Interconnected
	(kWh)	(kWh)	(kWh)	(kWh)	($)	($)	($)	($)	($)	($)
				(A+B+C)	**(A/D X H)**	**(B/D X H)**	**(C/D X H)**		**(G X 89.10%)**	**(G X 10.90%)**
					(to page 7)			**(from page 5)**	**(to page 7)**	
January	5,417,867,263	408,268,165	449,267,696	6,275,403,124	13,288,689	1,001,381	1,101,942	15,392,012	981,830	120,112
February	5,419,401,011	401,459,126	448,779,138	6,269,639,275	24,451,020	1,811,286	2,024,782	28,287,088	1,804,081	220,701
March	5,379,834,205	394,061,387	446,084,468	6,219,980,060	34,182,680	2,503,808	2,834,356	39,520,844	2,525,411	308,945
April	5,432,108,667	383,415,551	447,485,136	6,263,009,354	41,264,419	2,912,574	3,399,272	47,576,265	3,028,751	370,521
May	5,446,666,862	378,526,004	449,016,540	6,274,209,406	44,188,345	3,070,949	3,642,833	50,902,127	3,245,764	397,069
June	5,448,313,745	372,407,301	449,800,851	6,270,521,897	46,227,563	3,159,782	3,816,446	53,203,791	3,400,453	415,993
July	5,441,806,520	361,925,730	449,368,015	6,253,100,265	46,387,490	3,085,157	3,830,539	53,303,186	3,413,010	417,529
August	5,427,809,237	353,170,019	450,019,502	6,230,998,758	46,432,287	3,021,199	3,849,700	53,303,186	3,430,083	419,617
September	5,433,230,398	352,544,876	452,270,963	6,238,046,237	46,677,487	3,028,752	3,885,510	53,591,749	3,461,989	423,521
October										
November										
December										

(1) The Fuel Variance initially allocated to Rural Island Interconnected is re-allocated between Utility and Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the approved Cost of Service Study, which is 89.10% and 10.90% respectively. The Labrador Interconnected amount is then removed from the plan and written off to net income (loss).

Rate Stabilization Plan
Allocation of Fuel Variance - Monthly
September 30, 2013

	A	B	C	D	E	F	G
	Utility					Industrial	
	Fuel Variance		Rural Allocation		Total Fuel Variance	Fuel Variance	
	Year-to-Date Activity	Current Month Activity (1)	Year-to-Date Activity	Current Month Activity (1)	Activity for the month	Year-to-Date Activity	Current Month Activity (1)
	($)	($)	($)	($)	($)	($)	($)
					(B + D)		
	(from page 6)		**(from page 6)**		**(to page 10)**	**(from page 6)**	**(to page 11)**
January	13,288,689	13,288,689	981,830	981,830	14,270,519	1,001,381	1,001,381
February	24,451,020	11,162,331	1,804,081	822,251	11,984,582	1,811,286	809,905
March	34,182,680	9,731,660	2,525,411	721,330	10,452,990	2,503,808	692,522
April	41,264,419	7,081,739	3,028,751	503,340	7,585,079	2,912,574	408,766
May	44,188,345	2,923,926	3,245,764	217,013	3,140,939	3,070,949	158,375
June	46,227,563	2,039,218	3,400,453	154,689	2,193,907	3,159,782	88,833
July	46,387,490	159,927	3,413,010	12,557	172,484	3,085,157	(74,625)
August	46,432,287	44,797	3,430,083	17,073	61,870	3,021,199	(63,958)
September	46,677,487	245,200	3,461,989	31,906	277,106	3,028,752	7,553
October							
November							
December							
		46,677,487		3,461,989	50,139,476		3,028,752

(1) The current month activity is calculated by subtracting year-to-date activity for the prior month from year-to-date activity for the current month.

Rate Stabilization Plan
Load Variation - Utility
September 30, 2013

	A	B	C	D	E	F	G	H	I	J	K
	Firm Energy						Secondary Energy				
	Cost of Service Sales	Actual Sales	Sales Variance	Cost of Service No. 6 Fuel Cost	Firm Energy Rate	Load Variation	Cost of Service Sales	Actual Sales	Firming Up Charge	Load Variation	Total Load Variation
	(kWh)	(kWh)	(kWh)	($Can/bbl.)	($/kWh)	($)	(kWh)	(kWh)	($/kWh)	($)	($)
			(B - A)			**C x {(D/O[1]) - E}**				**(G - H) x I**	**(F + J)**
											(to page 10)
January	574,800,000	702,723,435	127,923,435	54.17	0.08805	(264,274)	0	1,099,493	0.00841	(9,247)	(273,521)
February	518,600,000	606,876,717	88,276,717	54.73	0.08805	(103,900)	0	429,853	0.00841	(3,615)	(107,515)
March	524,700,000	572,269,039	47,569,039	55.46	0.08805	(868)	0	374,966	0.00841	(3,153)	(4,021)
April	429,200,000	493,252,447	64,052,447	55.46	0.08805	(1,169)	0	558,436	0.00841	(4,696)	(5,865)
May	358,700,000	387,603,409	28,903,409	55.46	0.08805	(528)	0	309,399	0.00841	(2,602)	(3,130)
June	298,400,000	337,722,526	39,322,526	54.49	0.08805	(61,262)	0	0	0.00841	0	(61,262)
July	293,400,000	298,446,496	5,046,496	54.49	0.08805	(7,862)	0	0	0.00841	0	(7,862)
August	287,000,000	294,706,004	7,706,004	54.49	0.08805	(12,005)	0	0	0.00841	0	(12,005)
September	297,700,000	293,845,194	(3,854,806)	54.49	0.08805	6,006	0	0	0.00841	0	6,006
October											
November											
December											
	3,582,500,000	3,987,445,267	404,945,267			(445,862)	0	2,772,147		(23,313)	(469,175)

(1) O is the Holyrood Operating Efficiency of 630 kWh/barrel.

Rate Stabilization Plan
Load Variation - Industrial
September 30, 2013

	A	B	C	D	E	F
	Cost of Service Sales	Actual Sales	Sales Variance	Cost of Service No. 6 Fuel Cost	Firm Energy Rate	Load Variation
	(kWh)	(kWh)	(kWh)	($)	($/kWh)	($)
			(B - A)			**C x {(D/O[1]) - E}**
						(to page 11)
January	78,300,000	31,612,740	(46,687,260)	54.17	0.03676	(2,298,140)
February	70,900,000	25,864,750	(45,035,250)	54.73	0.03676	(2,256,852)
March	76,600,000	30,955,597	(45,644,403)	55.46	0.03676	(2,340,268)
April	75,600,000	32,198,035	(43,401,965)	55.46	0.03676	(2,225,295)
May	69,500,000	31,721,670	(37,778,330)	55.46	0.03676	(1,936,961)
June	73,800,000	27,547,154	(46,252,846)	54.49	0.03676	(2,300,249)
July	77,500,000	21,332,877	(56,167,123)	54.49	0.03676	(2,793,307)
August	77,900,000	29,286,623	(48,613,377)	54.49	0.03676	(2,417,644)
September	73,000,000	28,595,423	(44,404,577)	54.49	0.03676	(2,208,331)
October						
November						
December						
	673,100,000	259,114,869	(413,985,131)			(20,777,047)

(1) O is the Holyrood Operating Efficiency of 630 kWh/barrel.

Rate Stabilization Plan
Summary of Utility Customer
September 30, 2013

	A	B	C	D	E	F	G	H
	Load Variation	Allocation Fuel Variance	Allocation Rural Rate Alteration (1)	Subtotal Monthly Variances	Financing Charges	Adjustment (2)	August Adjustments (3)	Cumulative Net Balance
	($)	($)	($)	($)	($)	($)	($)	($)
				(A + B + C)				
	(from page 8)	**(from page 7)**						**(to page 15)**
Opening Balance								(64,905,401)
January	(273,521)	14,270,519	(849,811)	13,147,187	(393,814)	(10,944,447)		(63,096,475)
February	(107,515)	11,984,582	(877,767)	10,999,300	(382,838)	(9,443,617)		(61,923,630)
March	(4,021)	10,452,990	(743,390)	9,705,579	(375,722)	(8,904,614)		(61,498,387)
April	(5,865)	7,585,079	(652,666)	6,926,548	(373,141)	(7,678,759)		(62,623,739)
May	(3,130)	3,140,939	(559,777)	2,578,032	(379,970)	(6,032,044)		(66,457,721)
June	(61,262)	2,193,907	(548,049)	1,584,596	(403,232)	(5,251,585)		(70,527,942)
July	(7,862)	172,484	(395,725)	(231,103)	(427,928)	(1,590,720)		(72,777,693)
August	(12,005)	61,870	(446,842)	(396,977)	(441,579)	(1,570,783)		(75,187,032)
August Adjustments - remove load variation							823,770	(74,363,262)
August Adjustments - RSP Surplus Allocation							(112,573,325)	(186,936,587)
Transfer Utility RSP Surplus							112,573,325	(74,363,262)
September		277,106	(406,606)	(129,500)	(451,199)	(1,566,195)		(76,510,156)
October								
November								
December								
Year to date	(475,181)	50,139,476	(5,480,633)	44,183,662	(3,629,423)	(52,982,764)	823,770	(11,604,755)
Hydraulic allocation **(from page 4)**								0
Total	(475,181)	50,139,476	(5,480,633)	44,183,662	(3,629,423)	(52,982,764)	823,770	(76,510,156)

(1) The Rural Rate Alteration is allocated between Utility and Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the approved Cost of Service Study, which is 89.10% and 10.90% respectively. The Labrador Interconnected amount is then removed from the plan and written off to net income (loss).

(2) The RSP adjustment rate for the Utility is 0.533 cents per kwh effective July 1, 2013 to June 30, 2014.

(3) Per Board Order No. P.U. 26(2013), $49 million of the January 1, 2007 to August 31, 2013 accumulated Load Variation component of the RSP has been credited to the Industrial Customer balance as at August 31, 2013, and the remaining balance has been transferred to the Utility customer balance.

Rate Stabilization Plan
Summary of Industrial Customers
September 30, 2013

	A	B	C	D	E	F	G
	Load Variation	Allocation Fuel Variance	Subtotal Monthly Variances	Financing Charges	Adjustment [1]	August Adjustments [2]	Cumulative Net Balance
	($)	($)	($)	($)	($)	($)	($)
			(A + B)				
	(from page 9)	**(from page 7)**					**(to page 12)**
Opening Balance							(104,079,983)
January	(2,298,140)	1,001,381	(1,296,759)	(631,505)	323,546		(105,684,701)
February	(2,256,852)	809,905	(1,446,947)	(641,242)	275,249		(107,497,641)
March	(2,340,268)	692,522	(1,647,746)	(652,242)	322,621		(109,475,008)
April	(2,225,295)	408,766	(1,816,529)	(664,240)	327,497		(111,628,280)
May	(1,936,961)	158,375	(1,778,586)	(677,305)	324,664		(113,759,507)
June	(2,300,249)	88,833	(2,211,416)	(690,236)	287,558		(116,373,601)
July	(2,793,307)	(74,625)	(2,867,932)	(706,097)	232,954		(119,714,676)
August	(2,417,644)	(63,958)	(2,481,602)	(726,369)	302,465		(122,620,182)
August Adjustments - remove load variation						160,749,555	38,129,373
August Adjustments - RSP Surplus Allocation						(49,000,000)	(10,870,627)
Transfer Industrial RSP Surplus						10,870,627	0
September	-	7,553	7,553	0	-		7,553
October							
November							
December							
Year to date	(18,568,716)	3,028,752	(15,539,964)	(5,389,236)	2,396,554	122,620,182	104,087,536
Hydraulic allocation **(from page 4)**							0
Total	(18,568,716)	3,028,752	(15,539,964)	(5,389,236)	2,396,554	122,620,182	7,553

(1) The RSP adjustment rate for Industrial Customers excluding Teck Resources and Vale is 0.785 cents per kWh effective January 1, 2008. The rate for Teck Resources and Vale is 2.000 cents per kWh.

(2) Per Board Order No. P.U. 26(2013), $49 million of the January 1, 2007 to August 31, 2013 accumulated Load Variation component of the RSP has been credited to the Industrial Customer balance as at August 31, 2013, and the remaining balance has been transferred to the Utility customer balance.

Rate Stabilization Plan
Load Variation Sept - December 2013
September 30, 2013

	A	B	C	D	E	F	G
	Utility Customer			Island Industrial Customers			
	Load Variation	Financing Charges	Total To Date	Load Variation	Financing Charges	Total To Date	Total To Date
		($)	($)		($)	($)	($)
			(A + B)			(D+ E)	(C +F)
Opening Balance			-				
Payment							
January							
February							
March							
April							
May							
June							
July							
August							
September	6,006	-	6,006	(2,208,331)	-	(2,208,331)	(2,202,325)
October							
November							
December							
Total	6,006	-	6,006	(2,208,331)	-	(2,208,331)	(2,202,325)

Rate Stabilization Plan
Utility RSP Surplus
September 30, 2013

	A	B	C	D
	Industrial Customer Adjustment	Utility Payout	Financing Charges	Cumulative Balance
	($)	($)	($)	($)
Opening Balance				
January				
February				
March				
April				
May				
June				
July				
August	(112,573,325)		0	(112,573,325)
September			(683,039)	(113,256,364)
October				
November				
December				
Year to date	(112,573,325)	0	(683,039)	(113,256,364)
Total	(112,573,325)	0	(683,039)	(113,256,364)

Rate Stabilization Plan
Industrial RSP Surplus
September 30, 2013

	A	B	C	D	E
	Industrial Surplus	Teck Drawdown	Industrial Drawdown	Financing Charges	Cumulative Balance
	($)	($)	($)	($)	($)
Opening Balance					
January					
February					
March					
April					
May					
June					
July					
August	(49,000,000)	0	38,129,373	0	(10,870,627)
September	0	64,229	0	(65,958)	(10,872,356)
October					
November					
December					
Year to date	(49,000,000)	64,229	38,129,373	(65,958)	(10,872,356)
Total	(49,000,000)	64,229	38,129,373	(65,958)	(10,872,356)

Rate Stabilization Plan
Overall Summary
September 30, 2013

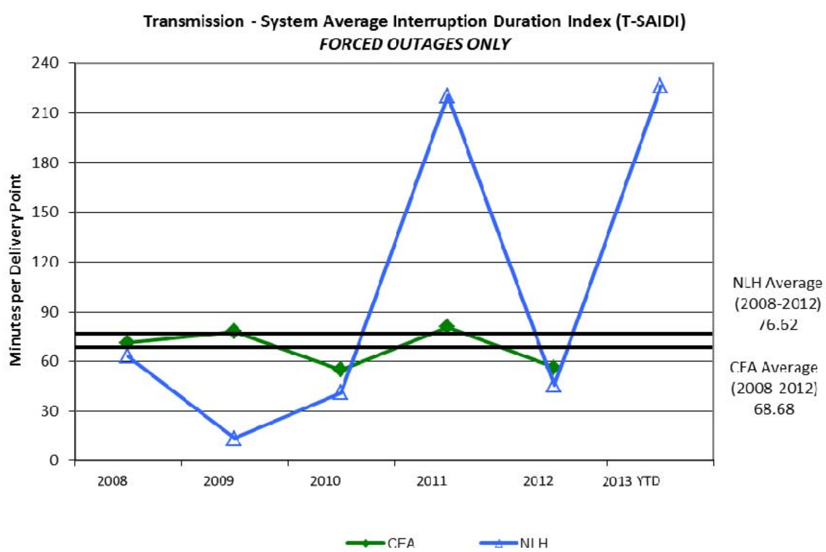
	A	B	C	D	E	F	G
	Hydraulic Balance	Utility Balance	Industrial Balance	Segregated Load Balance	Utility RSP Surplus	Industrial RSP Surplus	Total To Date
	($)	($)	($)	($)	($)		($) **(A + B + C + D + E + F)**
	(from page 4)	**(from page 10)**	**(from page 11)**	**(from page 12)**	**(from page 13)**	**(from page 14)**	
Opening Balance	(32,675,763)	(64,905,401)	(104,079,983)				(201,661,147)
January	(42,363,686)	(63,096,475)	(105,684,701)				(211,144,862)
February	(49,977,679)	(61,923,630)	(107,497,641)				(219,398,950)
March	(53,469,728)	(61,498,387)	(109,475,008)				(224,443,123)
April	(58,262,305)	(62,623,739)	(111,628,280)				(232,514,324)
May	(61,000,815)	(66,457,721)	(113,759,507)				(241,218,043)
June	(59,841,516)	(70,527,942)	(116,373,601)				(246,743,059)
July	(51,078,376)	(72,777,693)	(119,714,676)				(243,570,745)
August	(43,723,433)	(75,187,032)	(122,620,182)				(241,530,647)
September	(38,080,051)	(76,510,156)	7,553	(2,202,325)	(113,256,364)	(10,872,356)	(240,913,698)
October							
November							
December							

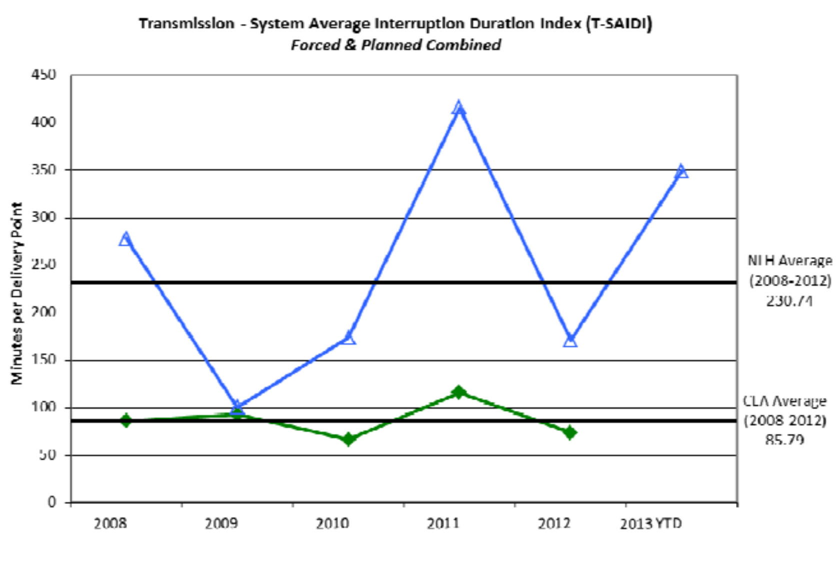
Performance Indices

Bulk Power System Delivery Point Interruption Performance

a) Transmission System Average Interruption Duration Index (T-SAIDI) - *a reliability KPI for bulk transmission assets which measures the average duration of outages in minutes per delivery point.*

The third quarter T-SAIDI was 52.8 minutes per delivery point (forced and planned combined) compared to 94.2 minutes per delivery point for the same quarter last year, a decrease of 44%. The forced component was 16.2 minutes per delivery point, compared to 13.2 minutes per delivery point in 2012, an increase of 23%. The planned component was 36.6 minutes per delivery point compared to 81.0 minutes per delivery point in 2012, a decrease of 55%.





There were six significant forced outages and three planned outages in this quarter. A summary of these forced and planned outages follows:

Forced

On July 27, customers supplied by the Hawke's Bay Terminal Station experienced an unplanned power outage of five minutes. The outage occurred after lightning hit transmission line TL221.

On July 31, customers supplied by the Happy Valley Terminal Station and at the Muskrat Falls Tap Terminal Station experienced an unplanned power outage of seven minutes. The outage occurred after lightning hit transmission line L1301/L1302.

On August 13, customers supplied by the Bottom Waters Terminal Station experienced an unplanned power outage of three minutes. The outage occurred after lightning hit transmission line TL260.

On August 6, Newfoundland Power customers in the Port aux Basques area and in the Doyles area, supplied by the Doyles Terminal Station, experienced unplanned power outages of two hours and 32 minutes and two hours and 50 minutes, respectively. The outages occurred after transformer T1 locked out at the Doyles Terminal Station following a lightning strike.

On August 6, customers in the Main Brook, Roddickton and St. Anthony areas supplied by the St. Anthony Airport Terminal Station experienced an unplanned power outage of five minutes. The outage occurred due to the mis-operation of the relay protection at the St. Anthony Airport Terminal Station for a fault on TL256. This operation prevented a line reclose at Bear Cove which would have limited the customer interruption to less than one minute. An attempt had been made previously to block this protection but only one of two output contacts was blocked. Both trip outputs are now blocked until a review of the protection requirements is completed.

On August 5, all customers supplied by the Happy Valley Terminal Station experienced an unplanned power outage of 24 minutes. The customer supplied by the Muskrat Falls Tap Terminal Station experienced an unplanned power outage of two hours and 50 minutes. The outage occurred after lightning hit the Hydro Québec 735 kV transmission network resulting in the load shed of the Churchill Falls Plant and the loss of the 138 kV lines L1301/L1302. Happy Valley customers were supplied via the gas turbine until L1301/L1302 was restored. The Muskrat Falls customer was supplied via local diesel generation until the line was restored.

Planned

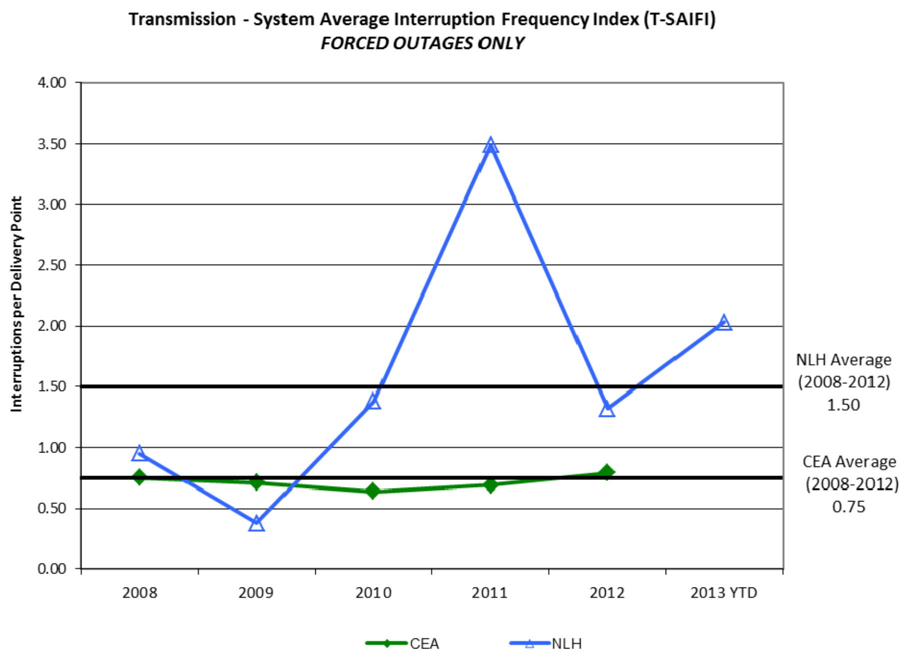
On August 6, customers supplied by the Daniels Harbour Terminal Station experienced a planned power outage of four hours and three minutes. The outage was required to perform maintenance on the high and low voltage switchgear in the terminal station.

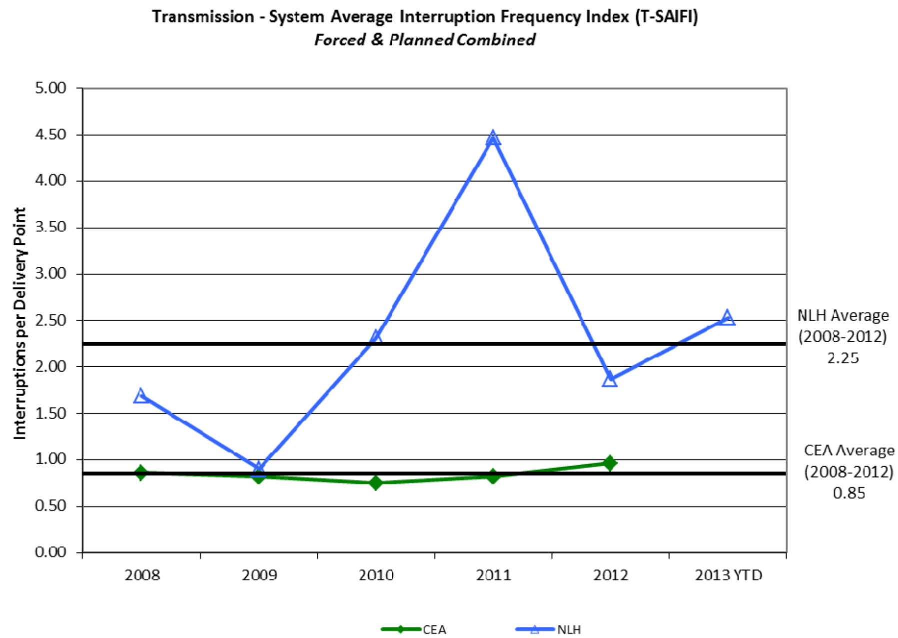
On August 15, customers in the Burgeo area supplied by the Grandy Brook Terminal Station experienced a planned power outage of three hours and 40 minutes. The outage was required to complete emergency replacement and repairs to insulators on transmission line TL250.

On September 3, customers supplied by the Jackson's Arm and Hampden Terminal Stations experienced a planned power outage of seven hours and 52 minutes. The outage was required to allow a contractor to tie in a new section of transmission line TL251 to allow for the removal and replacement of the Sandy Pond Bridge near Howley.

b) Transmission System Average Interruption Frequency Index (T-SAIFI) - *a reliability KPI for bulk transmission assets that measures the average number of sustained outages per delivery point*.

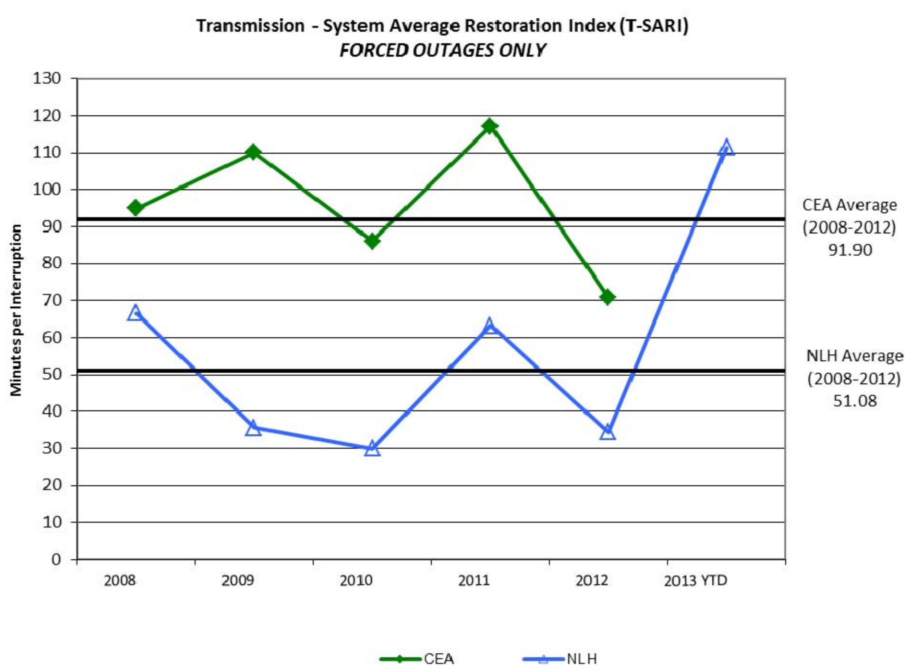
The third quarter T-SAIFI was 0.39 outages per bulk delivery point compared to 0.70 outages per bulk delivery point last year, a 44% decrease. The breakdown between forced and planned outages is as follows: 0.28 (forced) and 0.10 (planned). This is compared to 0.46 (forced) and 0.23 (planned) for the third quarter of 2012.

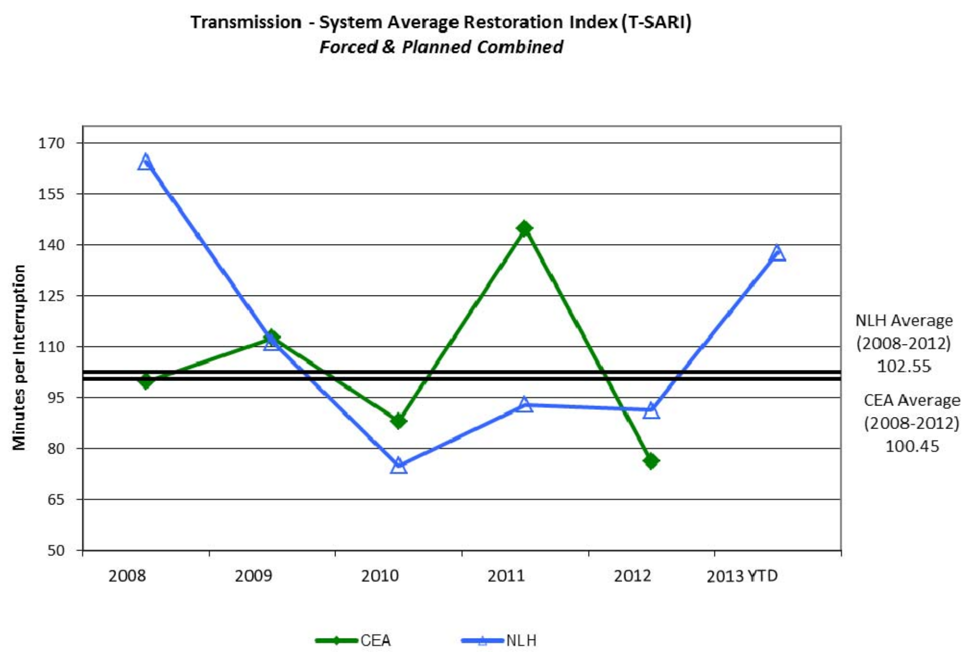




c) Transmission System Average Restoration Index (T-SARI) - *a reliability KPI for bulk transmission assets which measures the average duration per transmission interruption. T-SARI is calculated by dividing T-SAIDI by T-SAIFI.*

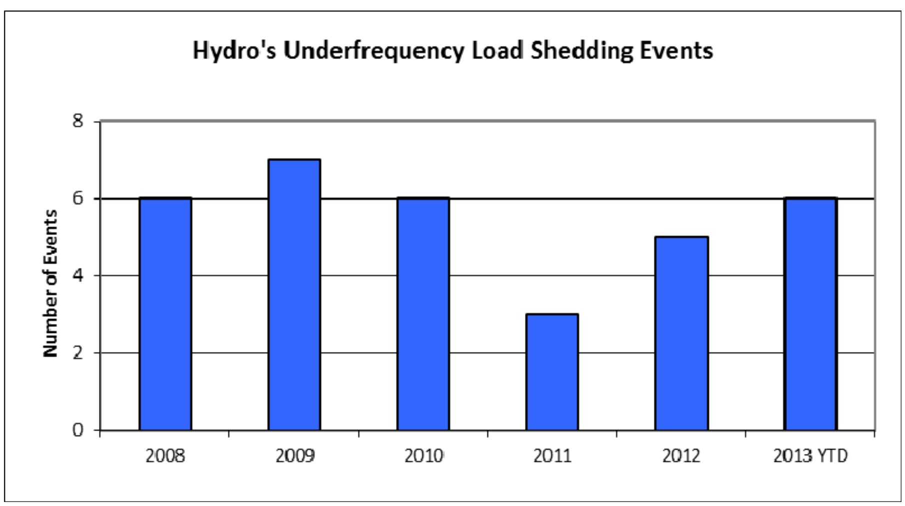
Hydro's total transmission T-SARI was 136.2 minutes per interruption for the third quarter versus 135.6 minutes per interruption for 2012. The forced outage component of T-SARI was 57.6 minutes per interruption. This compares with 28.8 minutes per interruption for the same quarter in 2012, an increase of 100%. The planned outage component of T-SARI was 351.6 minutes per interruption, compared to 349.2 minutes per interruption for the same quarter last year.





d) Underfrequency Load Shedding (UFLS) - *reliability KPI that measures the number of events in which shedding of a customer load is required to counteract a generator trip. Customer loads are shed automatically depending upon the generation lost.*

There were no underfrequency events during this quarter. Refer to the graph below which compares the UFLS events over the past five years to the year-to-date 2013 performance.



Underfrequency Load Shedding Number of Events

Customers	Third Quarter 2013	Third Quarter 2012	Year to Date 2013	Year to Date 2012	5 Year Average (2008–2012)
NF Power	0	0	6	2	5.4
Industrials	0	0	0	1	2.8
Hydro Rural*	0	0	3	1	2.8
Total Events	0	0	6	2	5.4

Underfrequency Load Shedding Unsupplied Energy (MW-min)

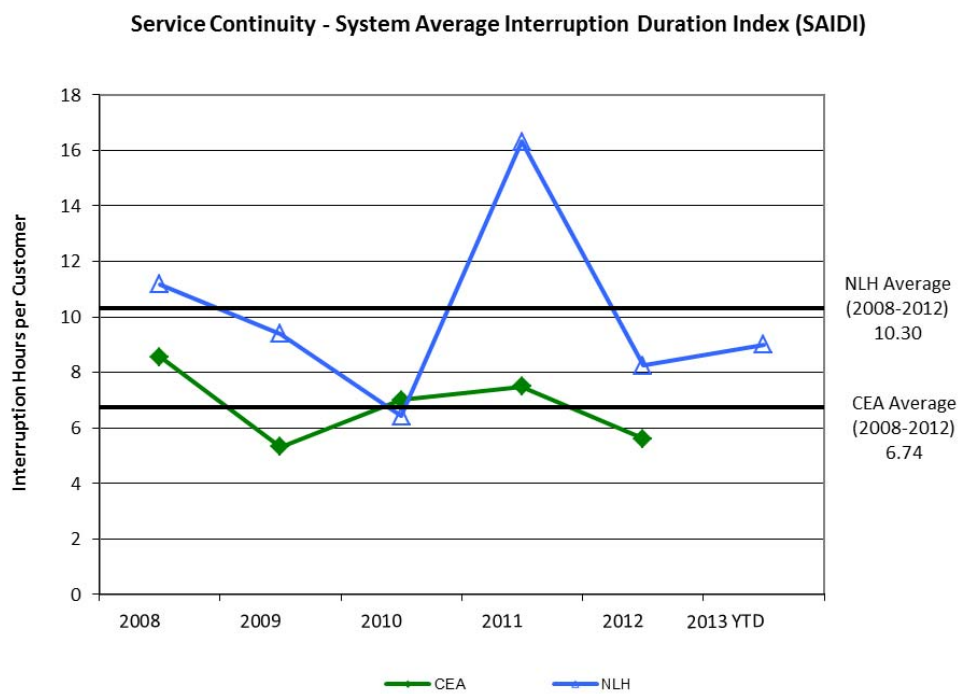
Customers	Third Quarter 2013	Third Quarter 2012	Year to Date 2013	Year to Date 2012	5 Year Average (2008–2012)
NF Power	0	0	13,742	2,274	1,643
Industrials	0	0	0	140	217
Hydro Rural*	0	0	324	21	48
Total Events	0	0	14,066	2,435	1,890

* Underfrequency activity affecting Hydro Rural Customers may also result in a number of delivery point outages. Outage frequency and duration are also included in totals shown in the delivery point statistics section of the report for these areas, namely the Connaigre Peninsula and Bonne Bay.

Rural Systems Service Continuity Performance

a) System Average Interruption Duration Index (SAIDI) - *a reliability KPI for distribution service and it measures service continuity in terms of the average cumulative duration of outages per customer served during the year.*

For the third quarter, the SAIDI was 4.21 hours per customer compared to 2.34 hours per customer in 2012, an increase of 80%.



A summary of the major interruptions follows:

On July 2, all 31 customers serviced by Charlottetown, Labrador Line 2 experienced an unplanned power outage of 12 hours and 45 minutes. The outage occurred after a lightning strike damaged a distribution pole.

On July 3, all 282 customers serviced by Plum Point Line 2 experienced a planned power outage of 4 hours and 56 minutes. The outage was required to complete upgrades on the distribution system.

On July 16, all 97 customers serviced by King's Point Line 2 experienced an unplanned power outage of 11 hours and 36 minutes. The outage occurred after a forest fire damaged two distribution poles and a pole-top transformer. The poles and transformer were replaced.

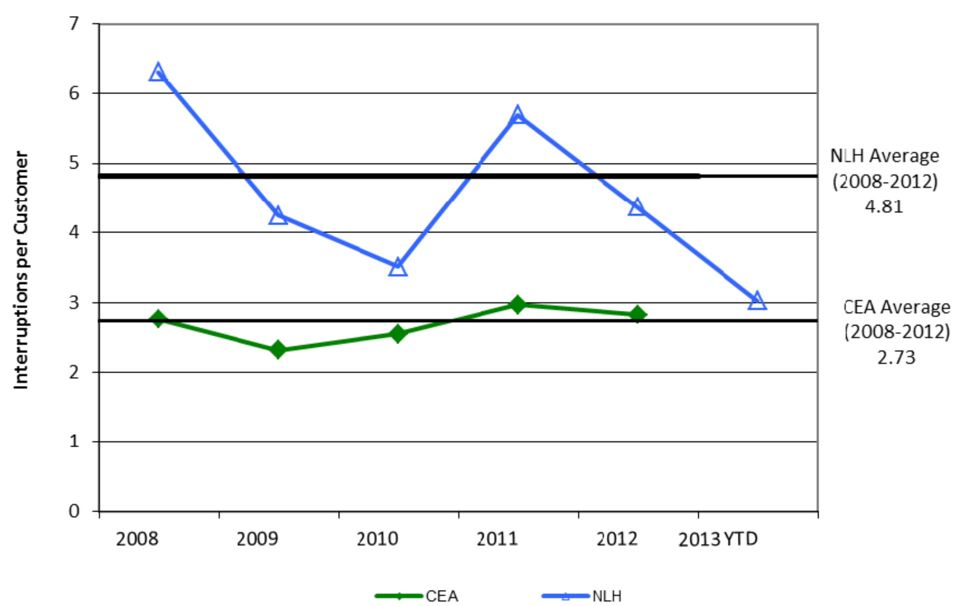
On August 10, all 265 customers serviced by the diesel plant in Hopedale, Labrador experienced an unplanned power outage of 7 hours and 35 minutes. The outage occurred after diesel Unit 2053 shutdown due to an issue with its rotor. Hydro's onsite Diesel Representative tried unsuccessfully to restore customers with Units 2054 and 2074. A maintenance crew was required to travel from Happy Valley-Goose Bay to the site to replace a starter on Unit 2074 and replace fuses for the station service feed. Customers were restored using Units 2054 and 2074.

On September 8, all 5,630 customers serviced by the Wabush Terminal Station in the towns of Labrador City and Wabush experienced a planned power outage of up to 11 hours and 45 minutes. This outage was required safely perform maintenance on equipment in the Wabush Terminal Station.

b) System Average Interruption Frequency Index (SAIFI) - *reliability KPI for distribution service and measures the average cumulative number of sustained interruptions per customer per year.*

In the third quarter, the SAIFI was 0.96 interruptions per customer compared to 1.07 interruptions per customer in 2012, a 10% decrease.

Service Continuity - System Average Interruption Frequency Index (SAIFI)



c) Additional Information - *The following section provides more detailed information in three tables with performance broken down by Area, Origin, and Type.*

Rural Systems Service Continuity Performance by Area

SAIFI (Number per Period)

Area	Third Quarter 2013	Third Quarter 2012	12 Mths to Date 2013	12 Mths to Date 2012	Five-Year Average
Central					
Interconnected	0.33	0.54	4.05	2.02	2.97
Isolated	1.72	0.34	3.68	3.06	3.64
Northern					
Interconnected	0.04	0.98	4.92	5.44	3.96
Isolated	0.54	0.75	8.38	4.74	6.19
Labrador					
Interconnected	2.49	1.64	8.10	6.41	6.55
Isolated	1.74	2.83	9.48	8.80	10.98
Total	0.96	1.07	5.87	4.59	4.74

Note: System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers in an area.

SAIDI (Hours per Period)

Area	Third Quarter 2013	Third Quarter 2012	12 Mths to Date 2013	12 Mths to Date 2012	Five-Year Average
Central					
Interconnected	0.72	1.08	15.98	13.32	11.12
Isolated	1.21	0.99	4.62	3.81	2.98
Northern					
Interconnected	0.15	2.56	10.87	22.08	10.40
Isolated	0.36	0.20	10.47	2.14	6.19
Labrador					
Interconnected	13.46	3.72	28.11	12.08	15.99
Isolated	1.95	5.20	11.57	11.36	15.51
Total	4.21	2.34	17.32	14.41	11.99

Note: System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.

Rural Systems Service Continuity Performance by Origin

SAIFI (Number per Period)					
Area	Third Quarter 2013	Third Quarter 2012	12 Mths to Date 2013	12 Mths to Date 2012	Five-Year Average
Loss of Supply – Transmission	0.43	0.44	1.25	1.83	1.56
Loss of Supply – NF Power	0.00	0.01	0.00	0.02	0.01
Loss of Supply – Isolated	0.13	0.10	0.56	0.43	0.55
Loss of Supply – L'Anse au Loup	0.00	0.00	0.05	0.05	0.06
Distribution	0.40	0.52	4.00	2.26	2.56
Total	0.96	1.07	5.87	4.59	4.74

Note: System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers.

SAIDI (Hours per Period)					
Area	Third Quarter 2013	Third Quarter 2012	12 Mths to Date 2013	12 Mths to Date 2012	Five-Year Average
Loss of Supply – Transmission	1.86	0.67	4.03	4.90	3.91
Loss of Supply – NF Power	0.00	0.00	0.01	0.49	0.14
Loss of Supply – Isolated	0.11	0.03	0.27	0.26	0.25
Loss of Supply – L'Anse au Loup	0.00	0.00	0.05	0.02	0.04
Distribution	2.24	1.63	12.97	8.74	7.66
Total	4.21	2.34	17.32	14.40	11.99

Note: System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.

Rural Systems Service Continuity Performance by Type (Third Quarter 2013)

Area	Scheduled		Unscheduled		Total	
	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI
Central						
Interconnected	0.00	0.00	0.33	0.72	0.33	0.72
Isolated	0.08	0.04	1.65	1.17	1.72	1.21
Northern						
Interconnected	0.03	0.15	0.00	0.00	0.04	0.15
Isolated	0.00	0.00	0.54	0.36	0.54	0.36
Labrador						
Interconnected	0.79	6.72	1.70	6.73	2.49	13.46
Isolated	0.01	0.02	1.73	1.93	1.74	1.96
Total	0.23	1.94	0.73	2.27	0.96	4.21

Note:
1. System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers in an area.
2. System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.