Q. Please provide copies of outage history reports and statistics from recent events and storms, including any analysis and comparison of ETR performance (estimated vs actual restoration times) and restoration times.

A. Hydro maintains a record of estimated and actual restoration times in separate databases. At this time, Hydro does not collect and report on ETR performance. However, outage reports (providing actual outage durations and customer impacts) are filed within days of a significant outage occurrence. Also, as part of Hydro's quarterly reports with the Board, Hydro provides outage statistics and summaries of major events affecting customer service. The last four quarterly reports filed by Hydro are attached as PUB-NLH-197 Attachments 1 to 4.

newfoundland labrador
hydro
a nalcor energy company

Hydro Place. 500 Columbus Drive.
P.O. Box 12400. St. John's. NL
Canada A1B 4K7
t. 709.737.1400 f. 709.737.1800
www.nlh.nl.ca

August 14, 2013

Board of Commissioners of Public Utilities
Prince Charles Building
120 Torbay Road
St. John's, Newfoundland
A1A 5B2

ATTENTION: Ms. Cheryl Blundon
Director of Corporate Services & Board Secretary

Dear Ms. Blundon:

Enclosed please find nine (9) copies of Newfoundland and Labrador Hydro's Quarterly Regulatory Report for the period ending June 30, 2013.

If you have any questions on the enclosed, please contact the undersigned.

Yours truly,

Newfoundland and Labrador Hydro

Geoffrey P. Young
Senior Legal Counsel

GPY/jc

c.c. Gerard M. Hayes - Newfoundland Power

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	≤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)	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.

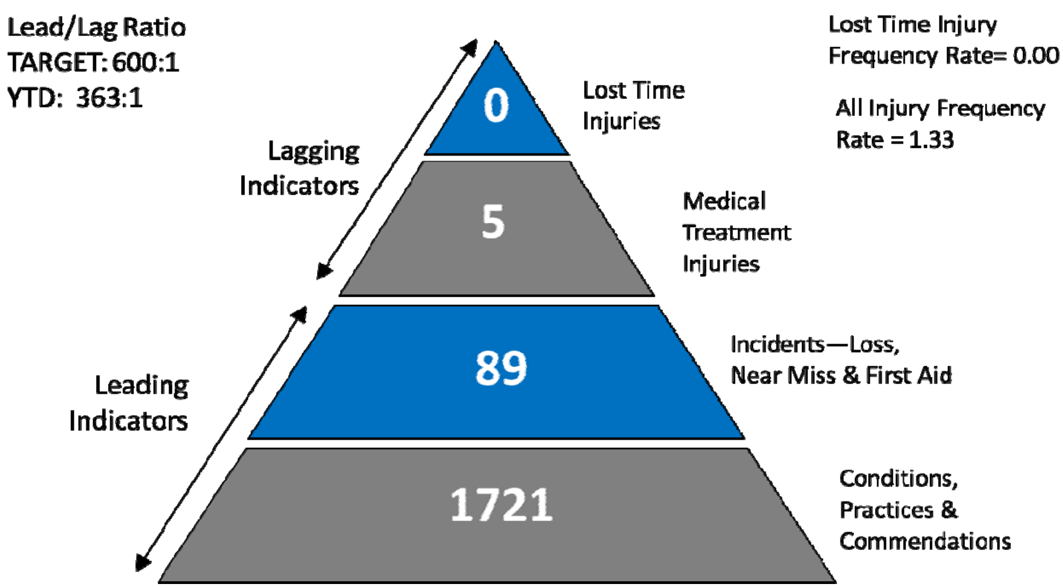
Hydro's leadership is engaging in safety tours and visiting employees to discuss workplace safety on a regular basis. Field visibility by the Leadership Team, Regional Managers and Safety Professionals has been increased in all areas.

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):

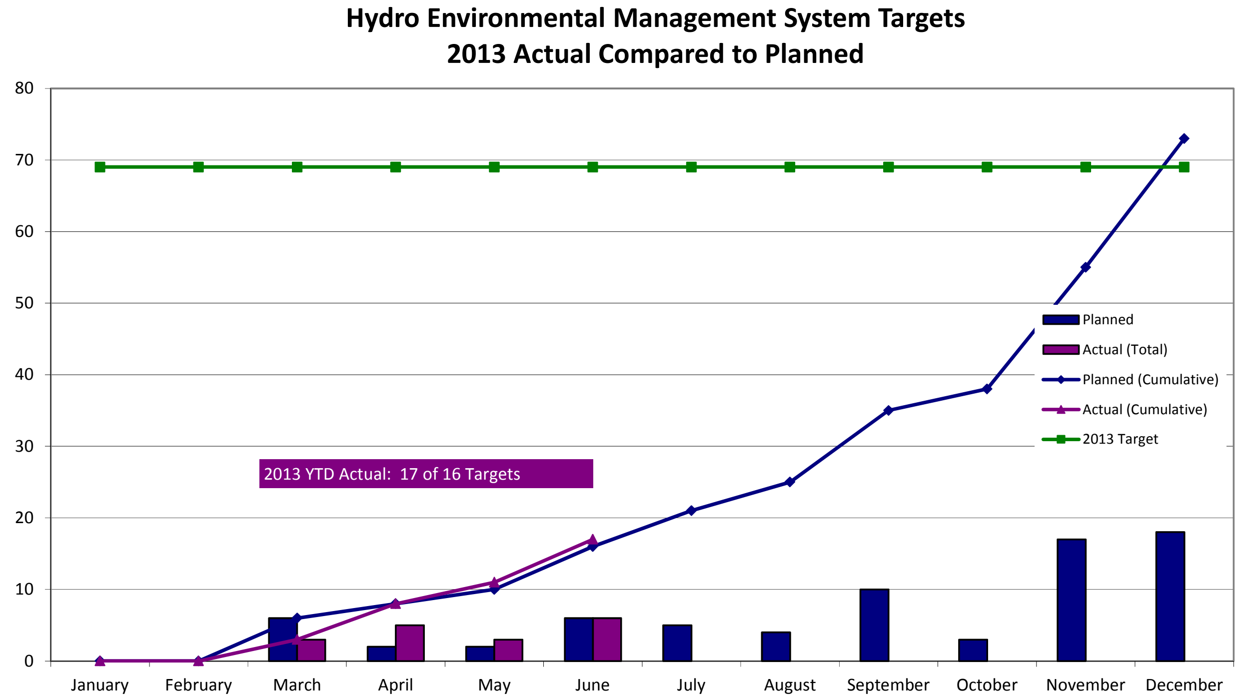
Minimum Hours

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

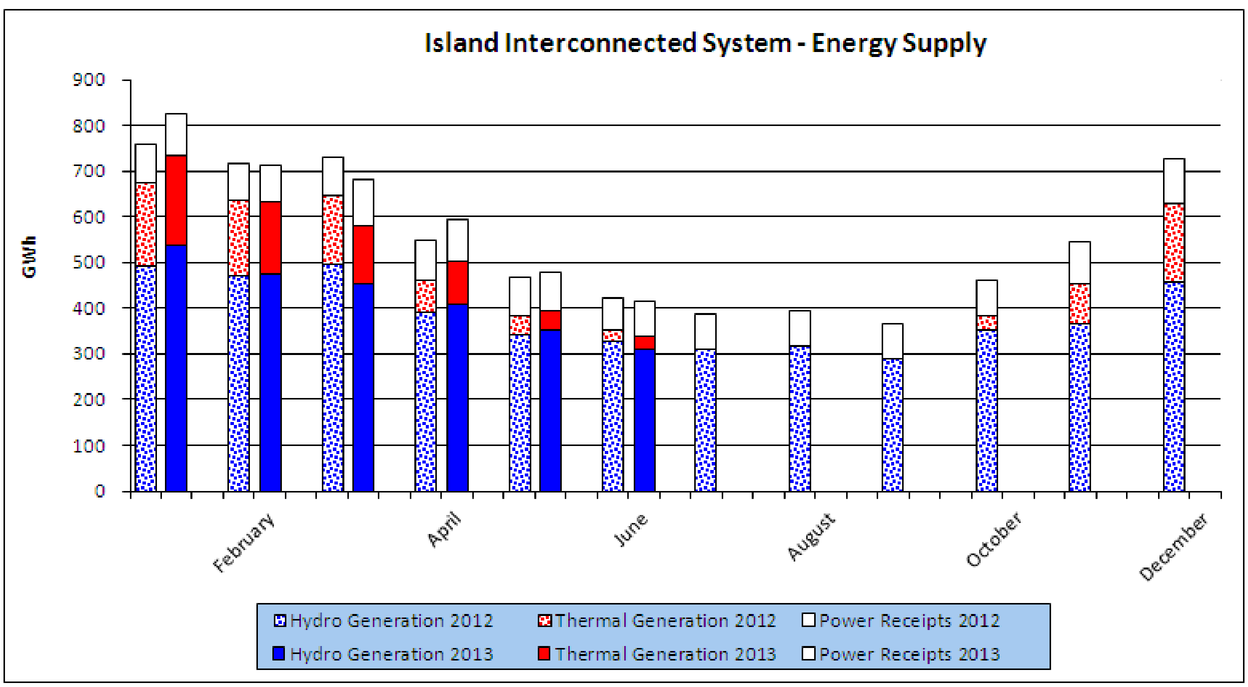
4.1.1 Energy Supply - Island Interconnected System

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.



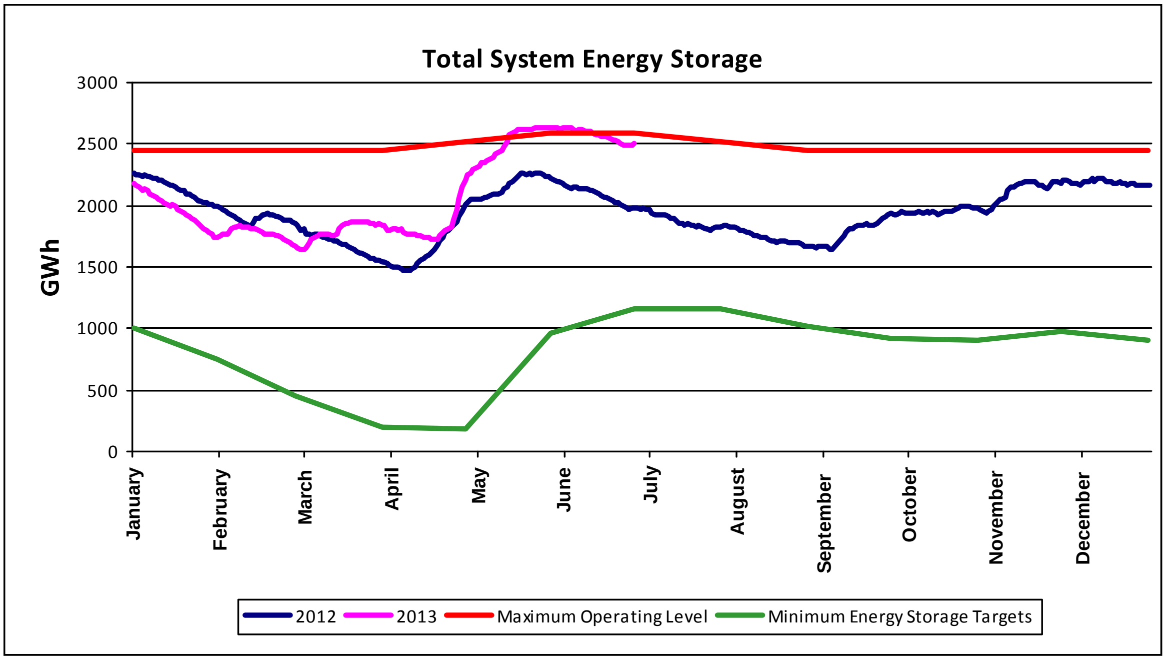
Island Interconnected System Production For the Quarter ended June 30, 2013					
	Year-to-date			2013 Annual Forecast (GWh)	2013 ($ 000)
	2013 (GWh)	2012 (GWh)	2013 Forecast (GWh)		
Production (net)					
Hydro	2,529.5	2,510.4	2,546.4	4,694.4	
Thermal	602.7	591.3	601.4	981.5	
Gas Turbines	0.7	(2.4)	1.6	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

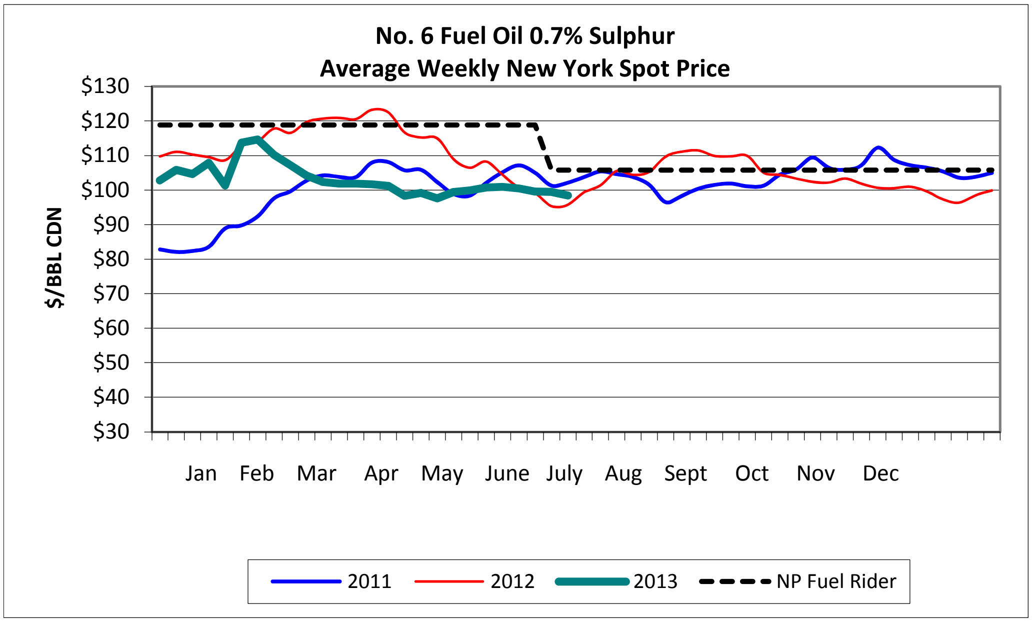
The fuel market prices for No. 6 fuel decreased from approximately $102/bbl at the start of the quarter to $98/bbl at the end of the quarter. The quarter ending inventory cost was $104.90/bbl, slightly lower than the current Newfoundland Power fuel price rider of $105.80/bbl. There is no Industrial Customer 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.

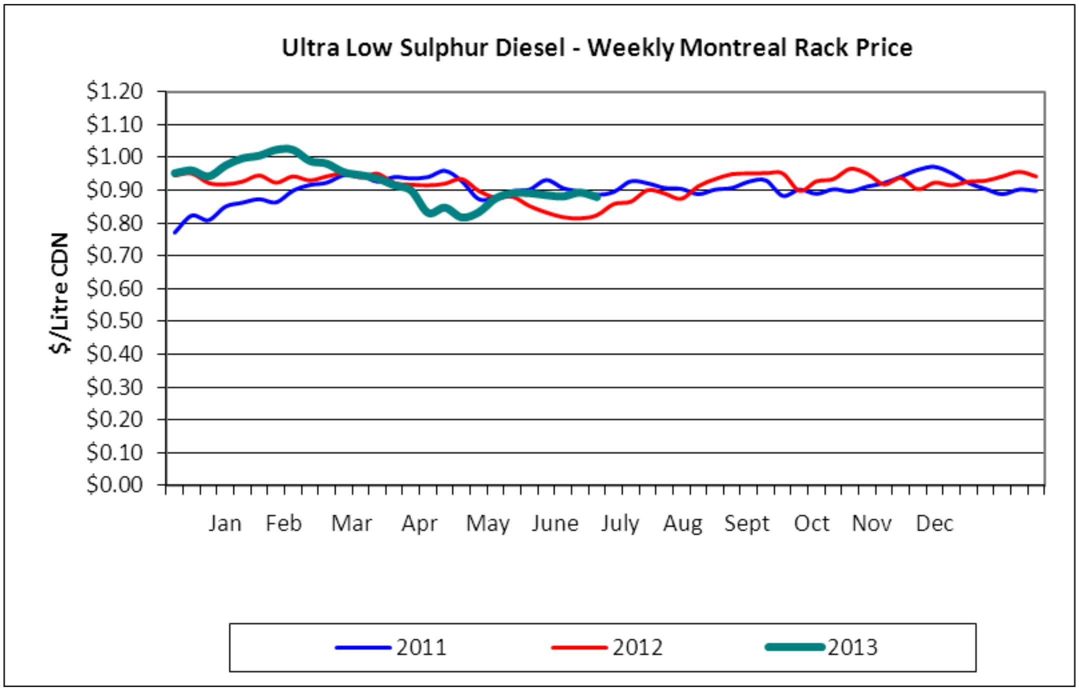


The following table provides the monthly forecast price of No. 6 fuel (0.7% sulphur) up to June 2014, landed on the Avalon Peninsula.

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

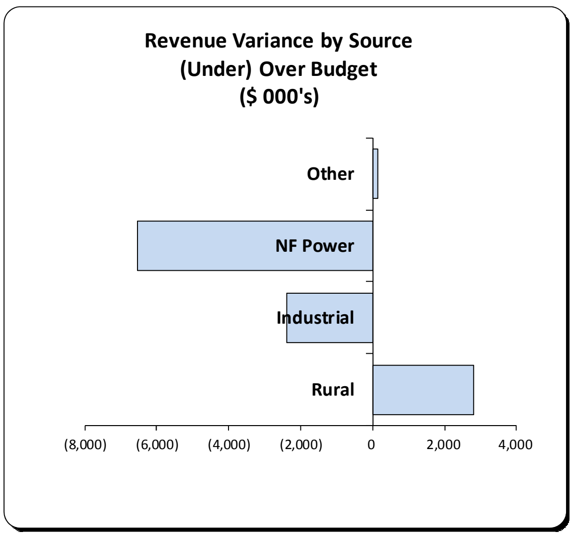
	Year-to-date						2013 Annual Forecast	
	2013		2012		2013 Forecast		(GWh)	$(000)[1]
	(GWh)	$(000)[1]	(GWh)	$(000)[1]	(GWh)	$(000)[1]		
Production (net)								
Diesels	24.1		24.0		25.9		50.6	
Purchases								
Non Utility Generators (NUGS)[2]	0.5	148.8	0.5	97.9	0.5	140.4	0.8	244.7
Hydro Québec	12.7	1,743.7	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**

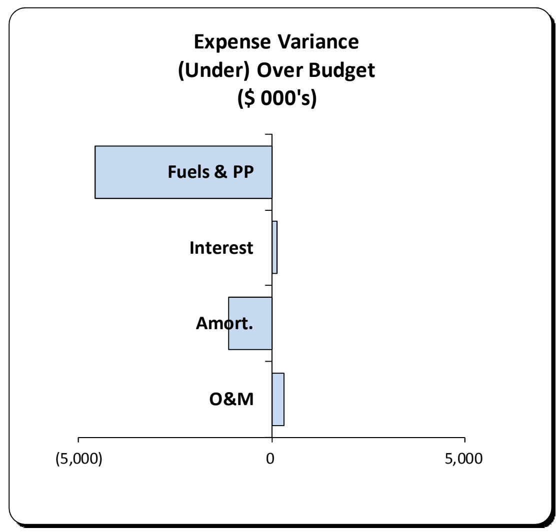
1 Purchases before taxes.
2 NUGS includes Frontier Power and Nalcor's wind/hydrogen facility in Ramea. Cost for 2012 is energy purchased from Frontier Power only.

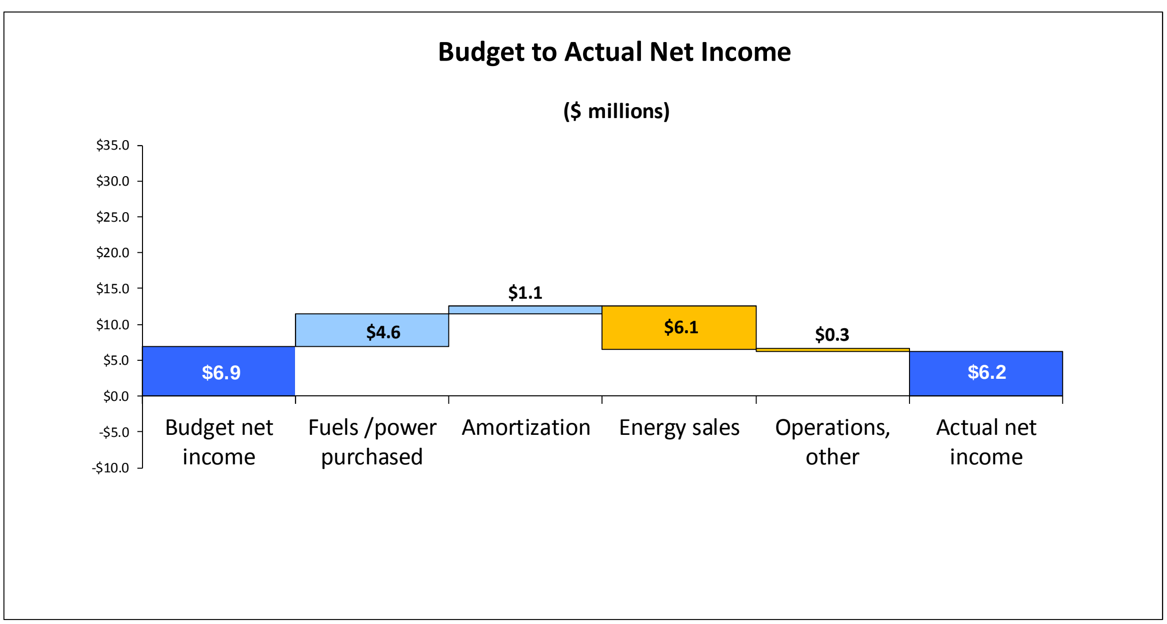
4.2 Financial

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.

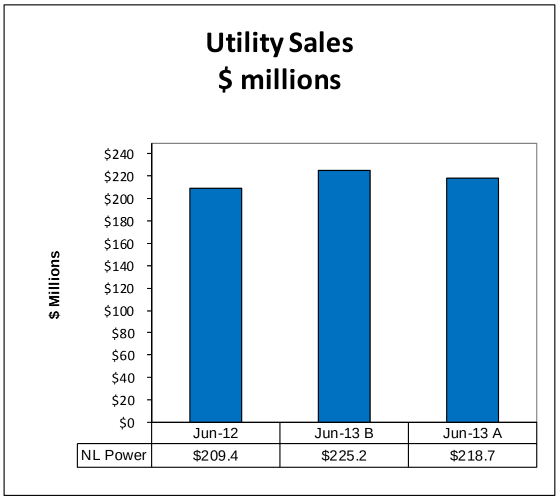
Statement of Retained Earnings - Regulated Operations
For the six months ended June 30, 2013
($ 000's)

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

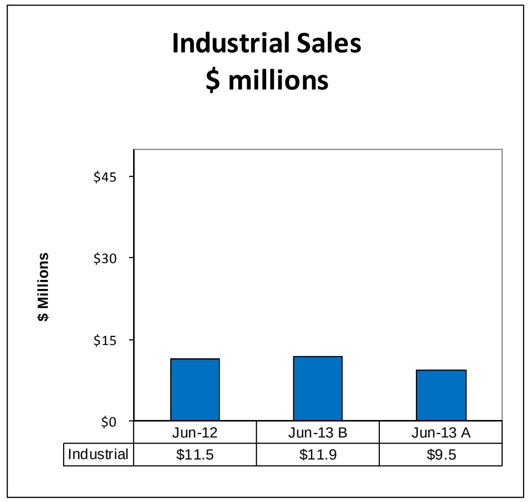
Statement of Comprehensive Income - Regulated Operations
For the six months ended June 30, 2013
($ 000's)

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

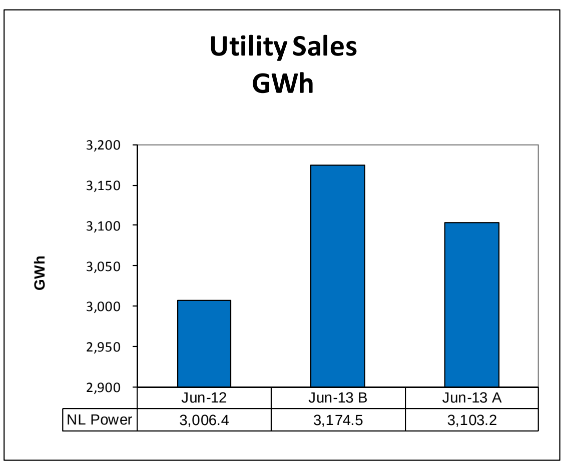
Sales - Regulated Operations
For the six months ended June 30, 2013



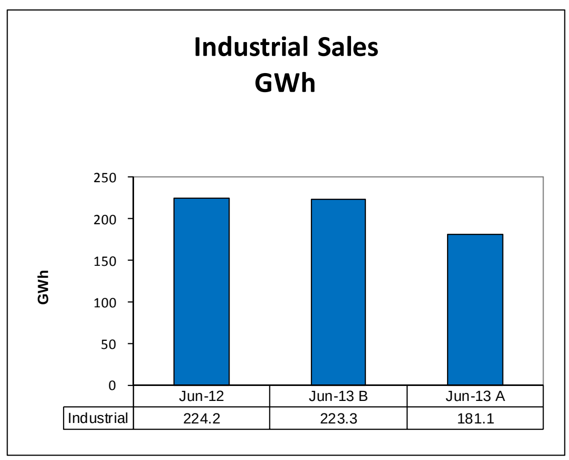
	Jun-12	Jun-13 B	Jun-13 A
NL Power	$209.4	$225.2	$218.7



	Jun-12	Jun-13 B	Jun-13 A
Industrial	$11.5	$11.9	$9.5



	Jun-12	Jun-13 B	Jun-13 A
NL Power	3,006.4	3,174.5	3,103.2



	Jun-12	Jun-13 B	Jun-13 A
Industrial	224.2	223.3	181.1

Revenue Summary - 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**
			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

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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 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
-	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	

			Reference
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/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						
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							0
(from page 4)							
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

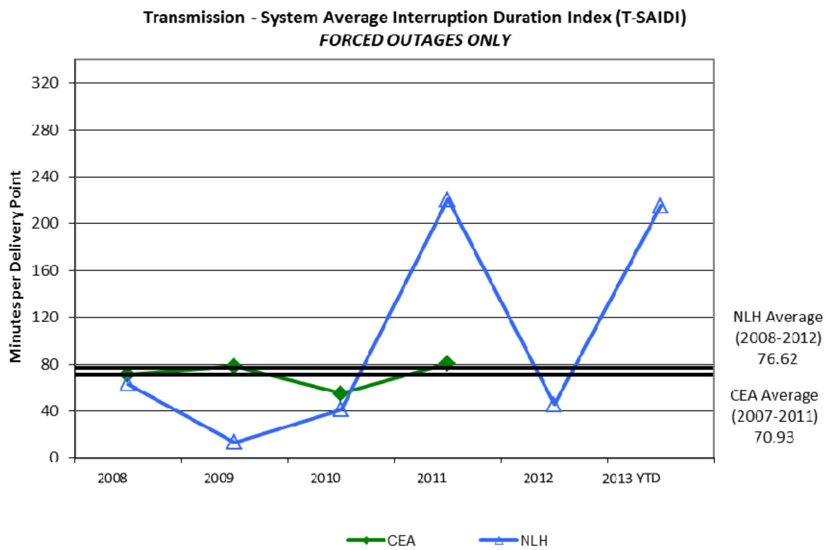
	A	B	C	D
	Hydraulic Balance	Utility Balance [1]	Industrial Balance [1]	Total To Date
	($)	($)	($)	($)
				(A + B + C)
	(from page 4)	**(from page 10)**	**(from page 11)**	
Opening Balance	(32,675,763)	(64,905,401)	(104,079,983)	(201,661,147)
January	(42,363,686)	(63,096,475)	(105,684,701)	(211,144,862)
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				

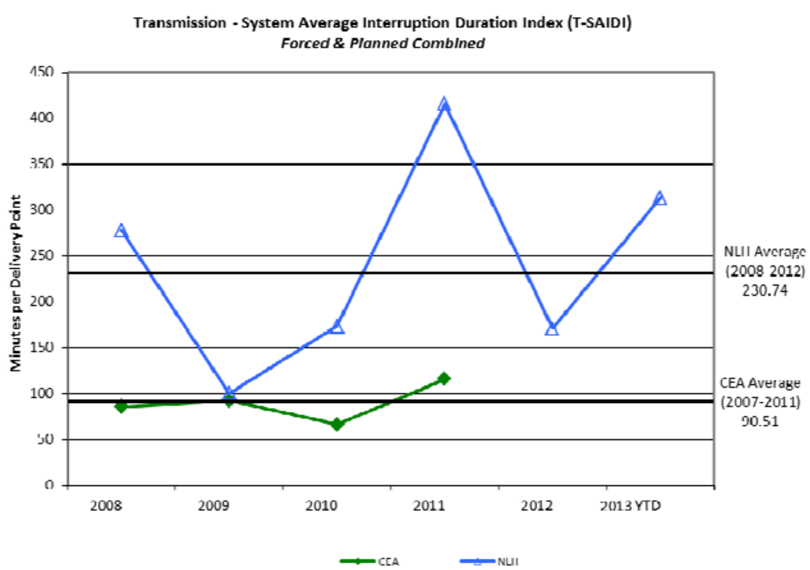
Performance Indices

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.

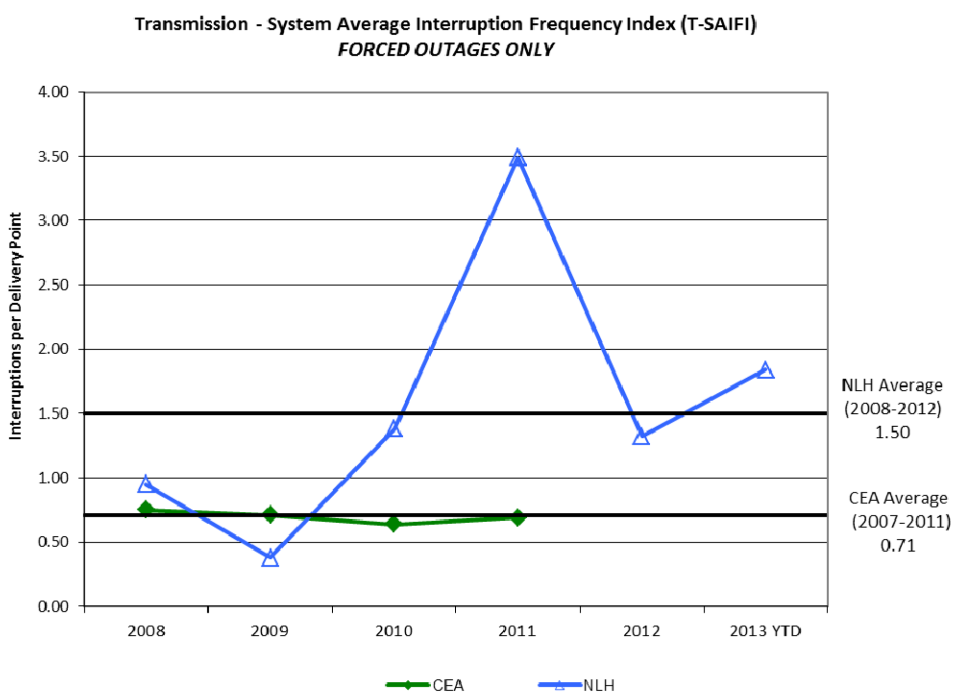
On June 7, customers supplied by the Glenburnie and Wiltondale Terminal Stations experienced a planned power outage of three hours and 51 minutes. The outage was required to repair disconnect switch L26-1 at Wiltondale station. In addition, personnel performed preventive and corrective maintenance on equipment in the Wiltondale and Glenburnie stations.

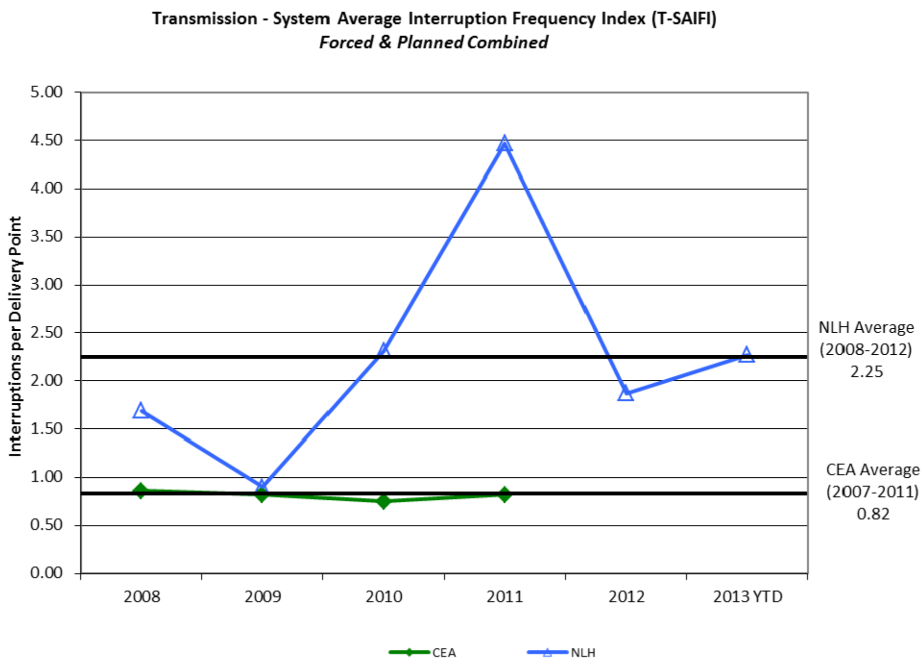
On June 15, customers supplied by the Bear Cove and Plum Point Terminal Stations experienced a planned power outage of six hours and 40 minutes. Customers supplied by feeder 1 at the St. Anthony Diesel Plant Terminal Station experienced a planned power outage of three hours and 22 minutes. The outage 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*.

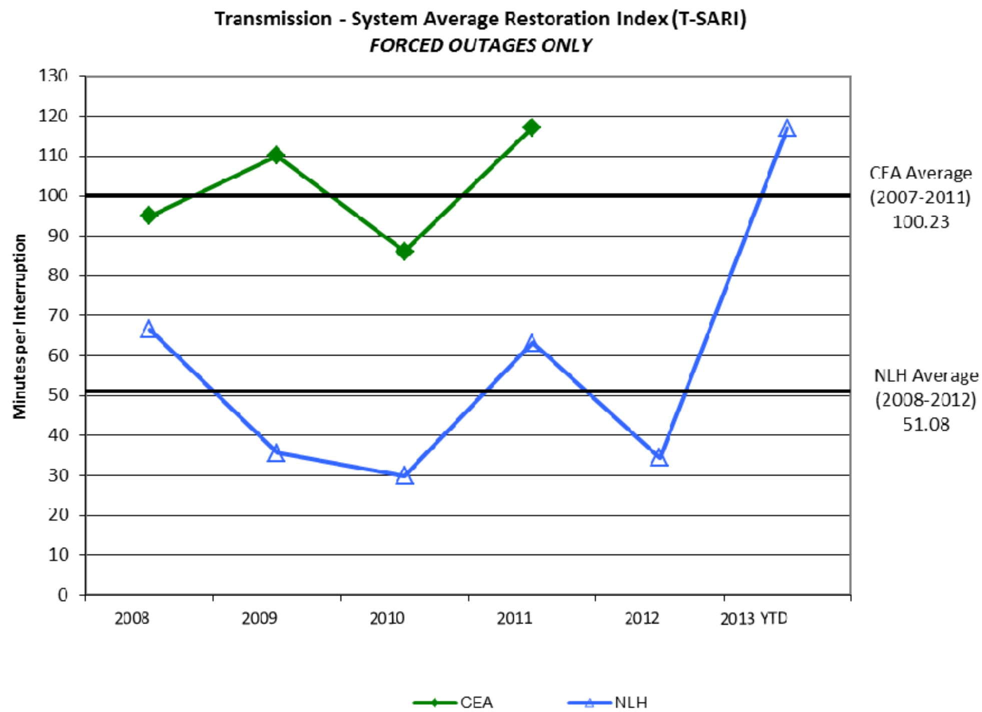
The second quarter T-SAIFI was 0.55 outages per bulk delivery point compared to 0.54 outages per bulk delivery point last year. The breakdown between forced and planned outages is as follows: 0.22 (forced) and 0.33 (planned). This is compared to 0.38 (forced) and 0.16 (planned) for the second quarter of 2012.

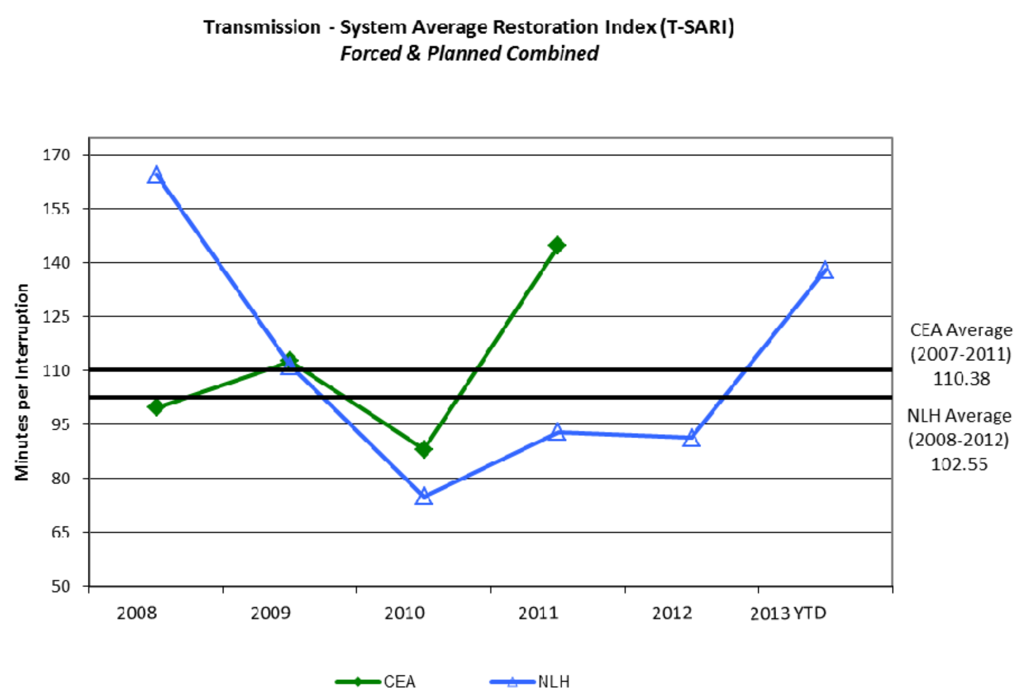




c) Transmission System Average Restoration Index (T-SARI) - *a reliability KPI for bulk transmission assets which measures the average duration per transmission interruption. T-SARI is calculated by dividing T-SAIDI by T-SAIFI.*

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
130
120
110
100
90
80
70
60
50
40
30
20
10
0
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
170
155
140
125
110
95
80
65
50
2008
2009
2010
2011
2012
2013 YTD
CEA Average
(2007-2011)
110.38
NLH Average
(2008-2012)
102.55
CEA
NLH

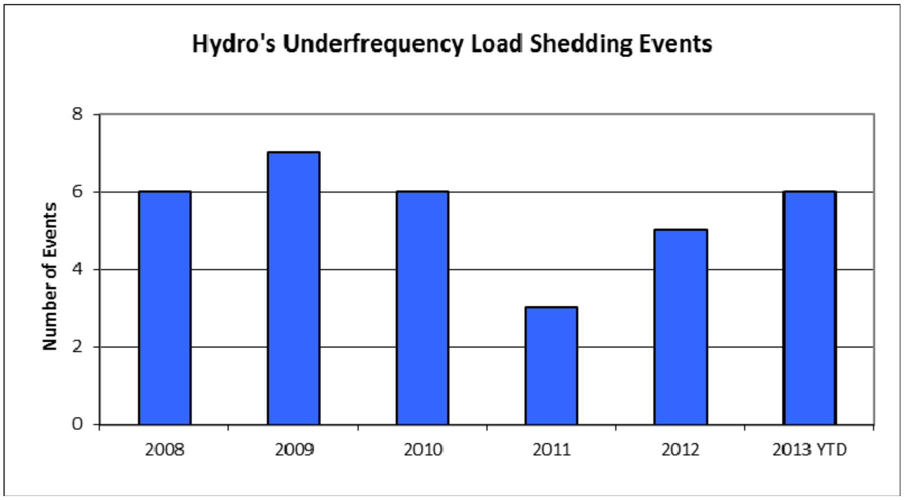
d) Underfrequency Load Shedding (UFLS) - *reliability KPI that measures the number of events in which shedding of a customer load is required to counteract a generator trip. Customer loads are shed automatically depending upon the generation lost.*

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)

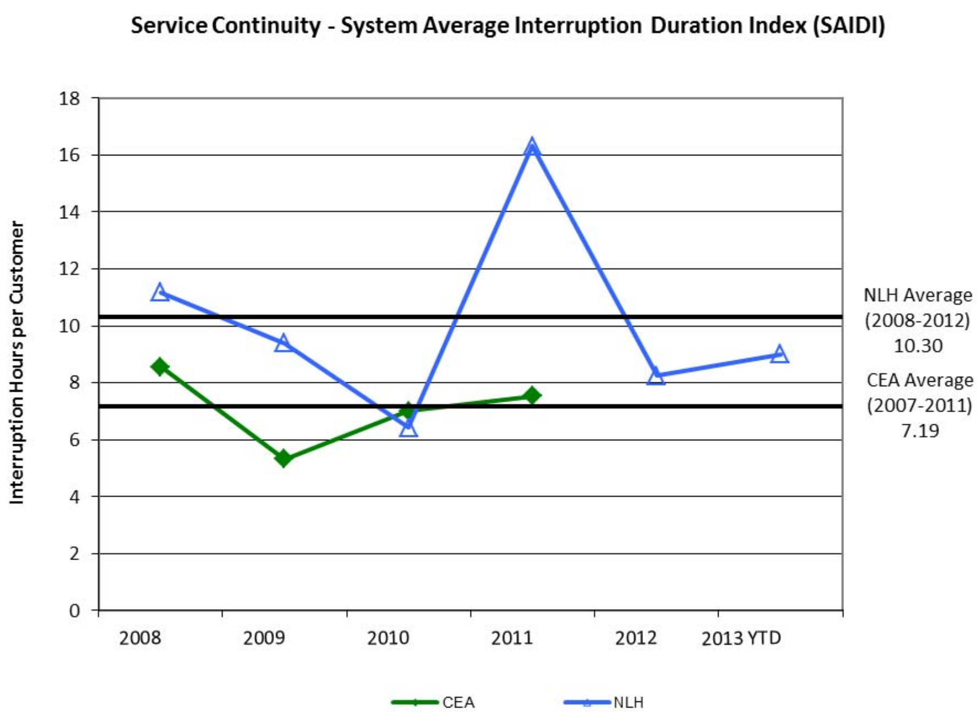
Customers	Second Quarter 2013	Second Quarter 2012	Year to Date 2013	Year to Date 2012	5 Year Average (2008–2012)
NF Power	12,177	48	13,742	2,274	1,643
Industrials	0	0	0	140	217
Hydro Rural*	303	0	324	21	48
Total Events	12,480	48	14,066	2,435	1,890

* 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

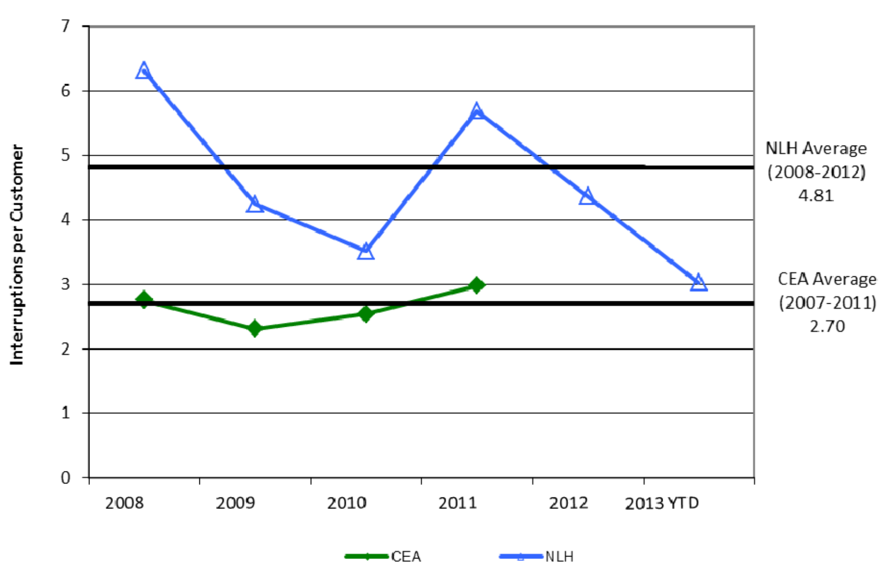
On April 25, at 18:00 hours (Labrador time), 40 customers serviced by Line 5 in Labrador City experienced an unplanned power outage. The outage was caused by a broken porcelain cut-out. In order to safely repair the cut-out, an emergency planned power outage was required for Line 5, affecting an additional 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.

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	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.

newfoundland labrador
hydro
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November 14, 2013

Board of Commissioners of Public Utilities
Prince Charles Building
120 Torbay Road
St. John's, Newfoundland
A1A 5B2

ATTENTION: Ms. Cheryl Blundon
Director of Corporate Services & Board Secretary

Dear Ms. Blundon:

Enclosed please find nine (9) copies of Newfoundland and Labrador Hydro's Quarterly Regulatory Report for the period ending September 30, 2013.

If you have any questions on the enclosed, please contact the undersigned.

Yours truly,

Newfoundland and Labrador Hydro

Geoffrey P. Young
Senior Legal Counsel

GPY/jc

c.c. Gerard M. Hayes - Newfoundland Power

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

QUARTERLY REGULATORY REPORT FOR THE QUARTER ENDED SEPTEMBER 30, 2013

Newfoundland and Labrador Hydro

newfoundland labrador hydro
a nalcor energy company

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	$\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)	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.

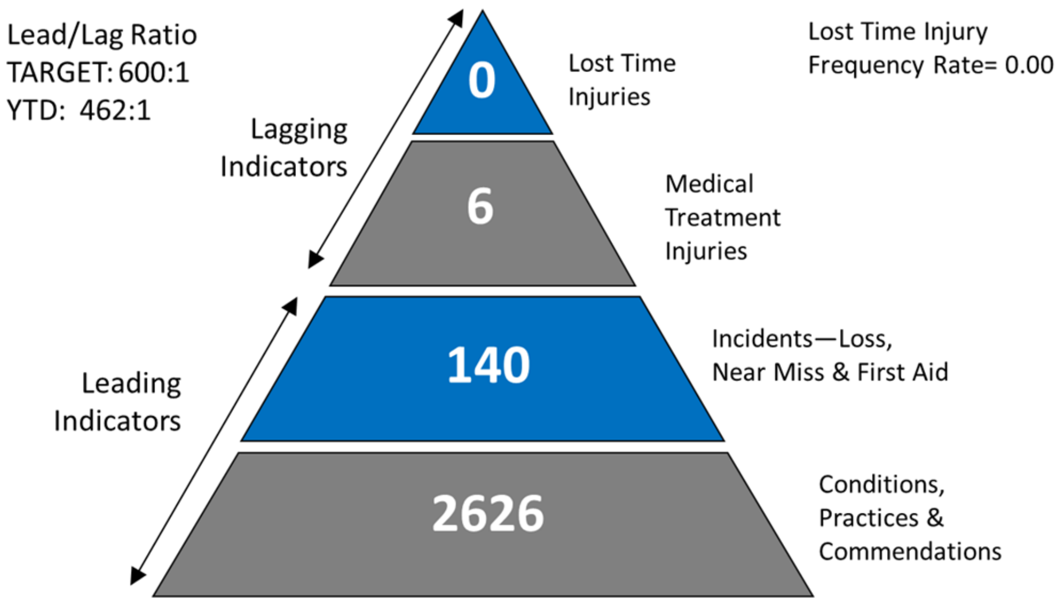
Hydro continues to focus in the area of Grounding and Bonding (G&B), Work Methods, Work Protection Code (WPC) and Corporate Standard Development. The Corporate Grounding and Bonding Committee continues to focus on training for line operations staff. The development of Work Methods for identified critical 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):

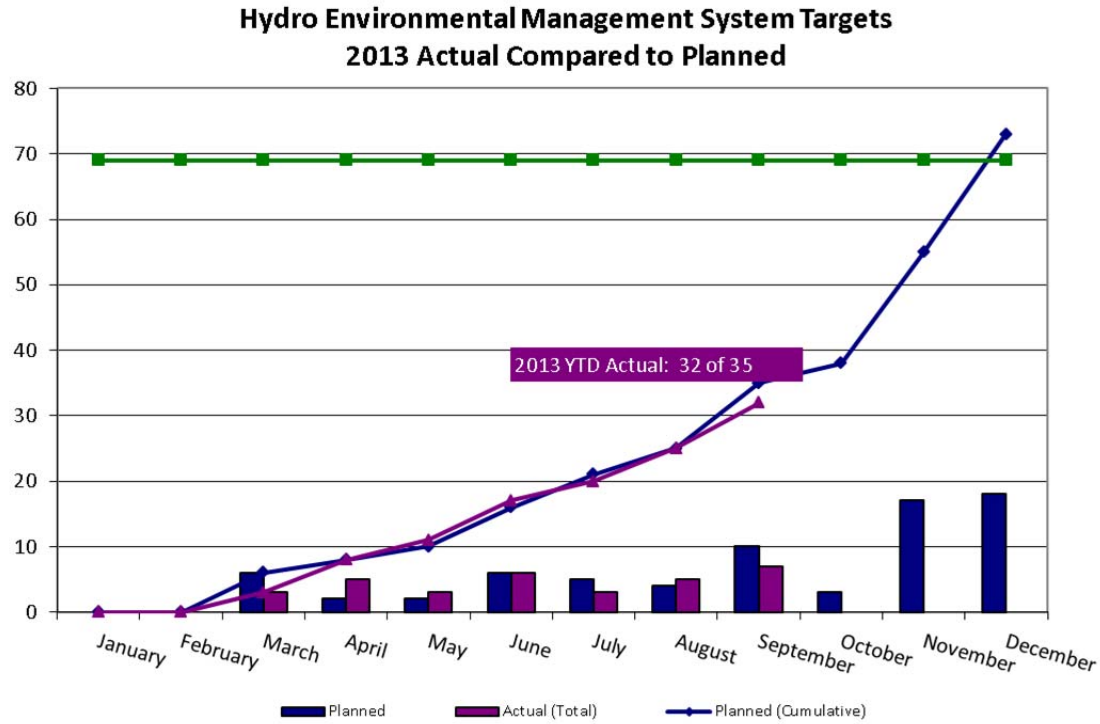
Minimum Hours

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

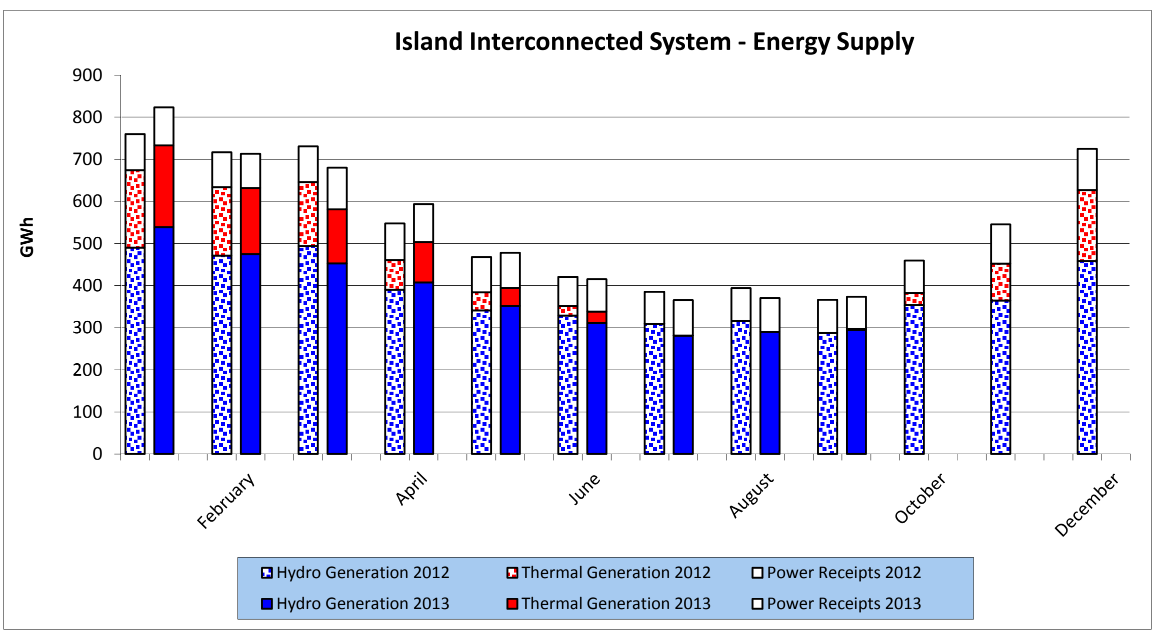
4.1.1 Energy Supply - Island Interconnected System

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.



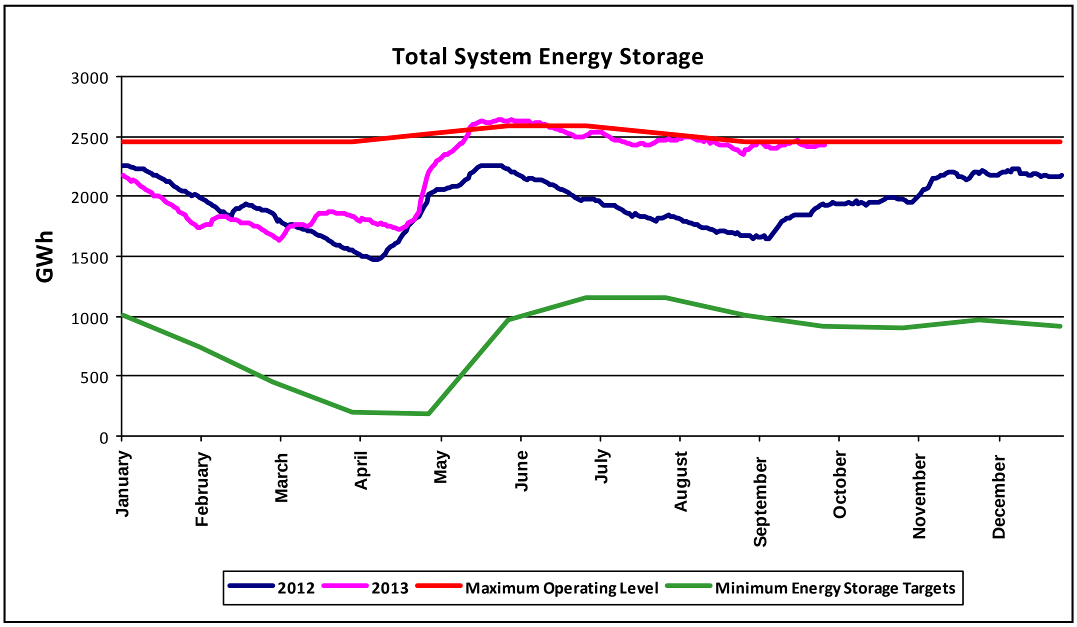
Island Interconnected System Production For the Quarter ended September 30, 2013					
	Year-to-date			2013 Annual Forecast (GWh)	2013 ($ 000)
	2013 (GWh)	2012 (GWh)	2013 Forecast (GWh)		
Production (net)					
Hydro	3,394.5	3,421.6	3,478.5	4,694.4	
Thermal	602.9	589.8	613.4	981.5	
Gas Turbines	(1.2)	(3.6)	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**

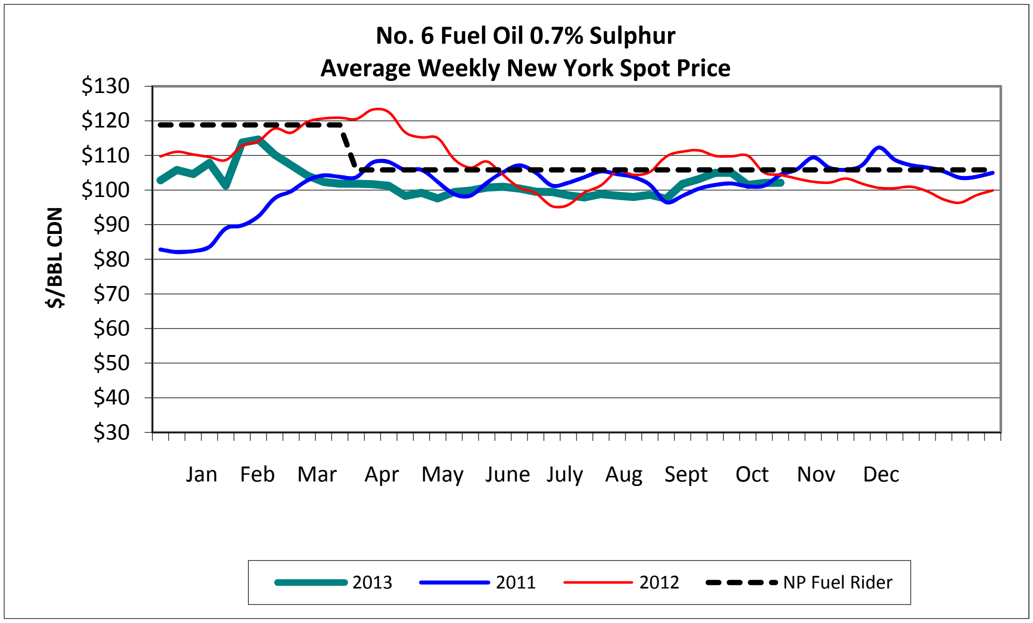
4.1.4 Fuel Prices

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.



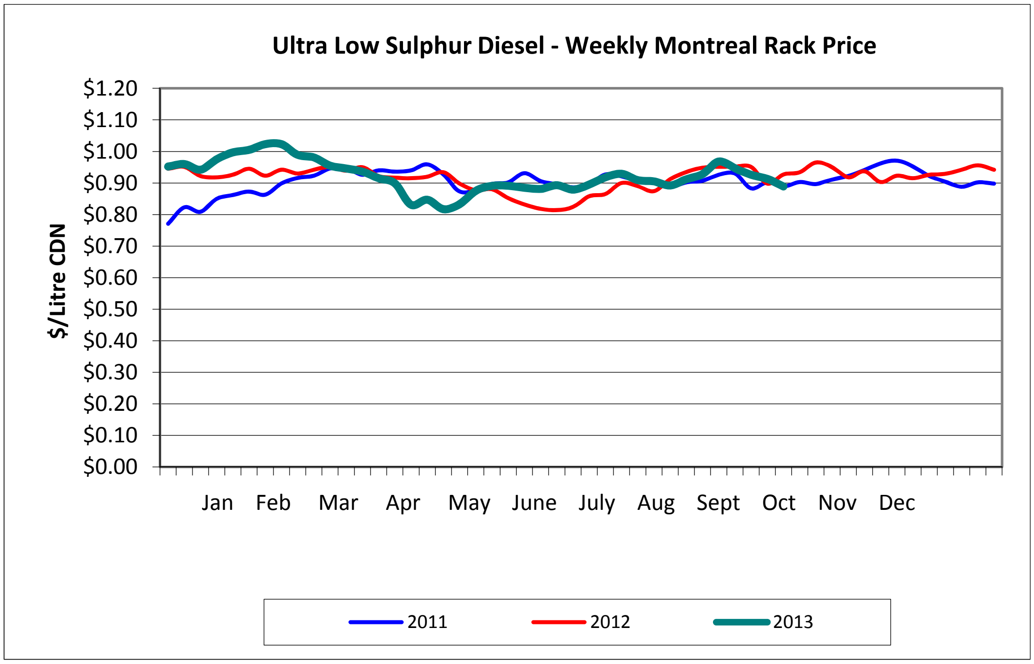
The following table provides the monthly forecast price of No. 6 fuel (0.7% sulphur) up to September 2014, landed on the Avalon Peninsula.

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

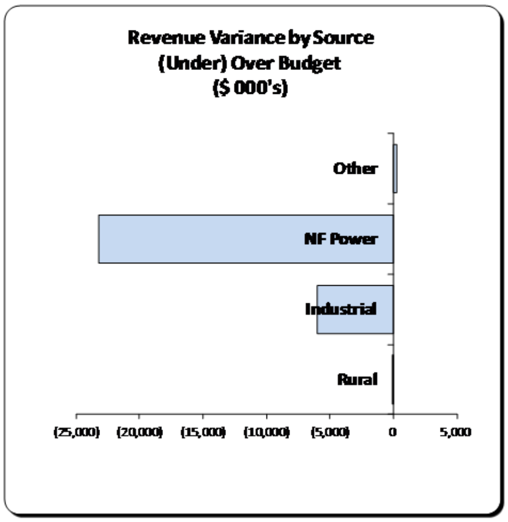
	Year-to-date						2013 Annual Forecast	
	2013		2012		2013 Forecast			
	(GWh)	$(000)[1]	(GWh)	$(000)[1]	(GWh)	$(000)[1]	(GWh)	$(000)[1]
Production (net)								
Diesels	35.2		34.0		38.2		50.6	
Purchases								
Non Utility Generators (NUGS)[2]	0.5	153.2	0.5	104.7	0.5	152.4	0.8	244.7
Hydro Québec	16.5	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**

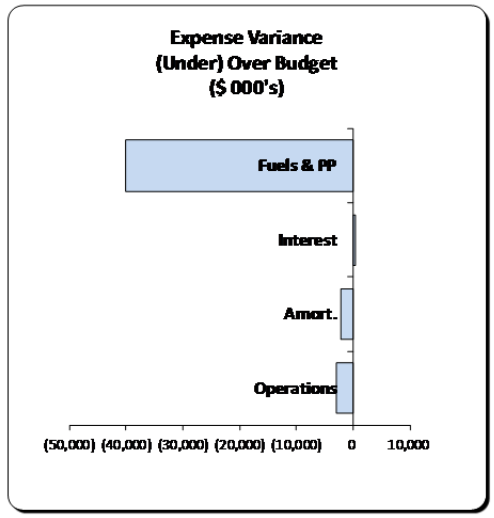
[1] Purchases before taxes.
[2] NUGS includes Frontier Power and Nalcor's wind/hydrogen facility in Ramea. Year to date cost for 2012 energy purchases include Frontier Power only.

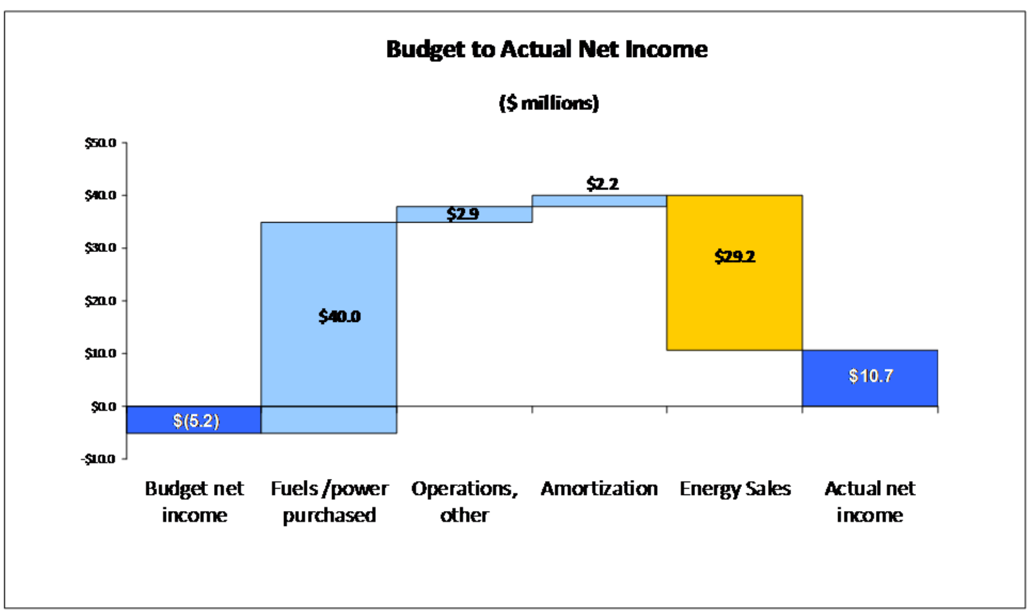
4.2 Financial

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[1]	
	2013 ACTUAL	2012 ACTUAL	2013 YTD BUDGET	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

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.

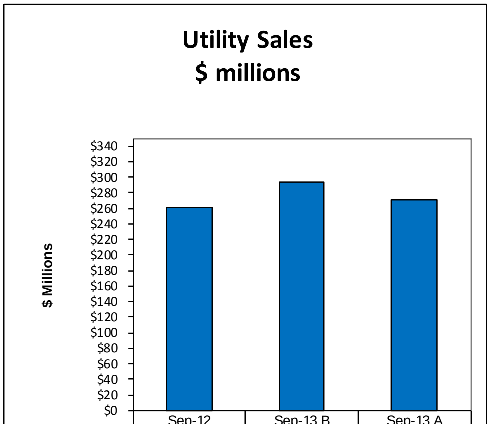
Statement of Retained Earnings - Regulated Operations
For the nine months ended September 30, 2013
($ 000's)

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

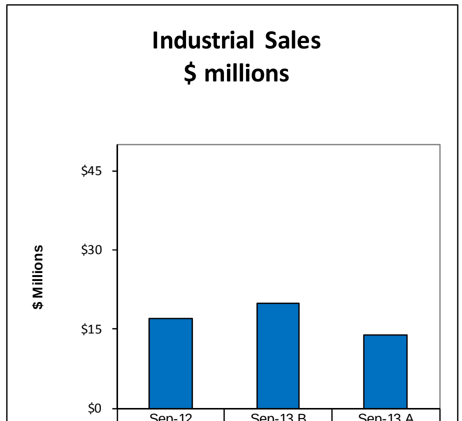
Statement of Comprehensive Income - Regulated Operations
For the nine months ended September 30, 2013
($ 000's)

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

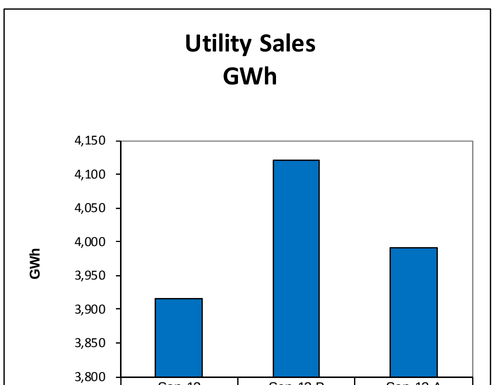
Sales - Regulated Operations
For the nine months ended September 30, 2013



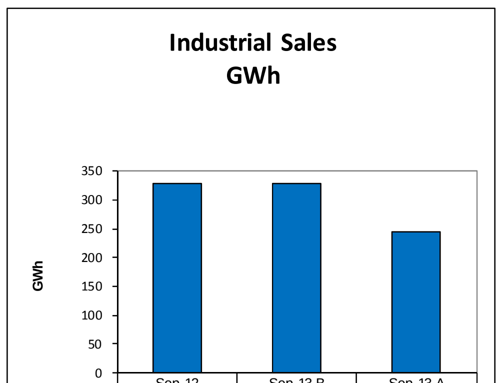
	Sep-12	Sep-13 B	Sep-13 A
NL Power	$261.4	$293.4	$270.2



	Sep-12	Sep-13 B	Sep-13 A
Industrial	$17.1	$20.0	$14.0



	Sep-12	Sep-13 B	Sep-13 A
NL Power	3,916.3	4,121.7	3,990.2



	Sep-12	Sep-13 B	Sep-13 A
Industrial	328.9	327.9	245.4

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 (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	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 Activity for the month	Fuel Variance	
	Year-to-Date Activity	Current Month Activity (1)	Year-to-Date Activity	Current Month Activity (1)		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 (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	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

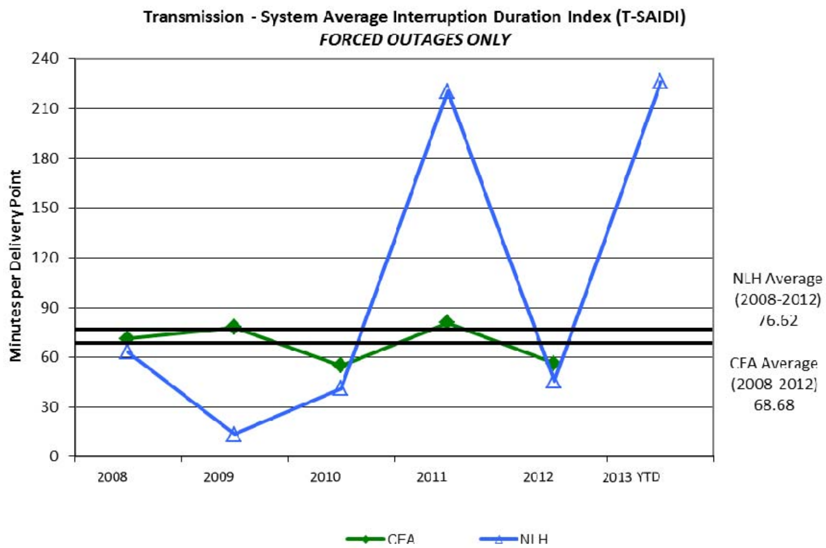
	A	B	C	D	E	F	G
	Hydraulic Balance	Utility Balance	Industrial Balance	Segregated Load Balance	Utility RSP Surplus	Industrial RSP Surplus	Total To Date
	($)	($)	($)	($)	($)		($)
							(A + B + C + D + E + F)
	(from page 4)	**(from page 10)**	**(from page 11)**	**(from page 12)**	**(from page 13)**	**(from 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							

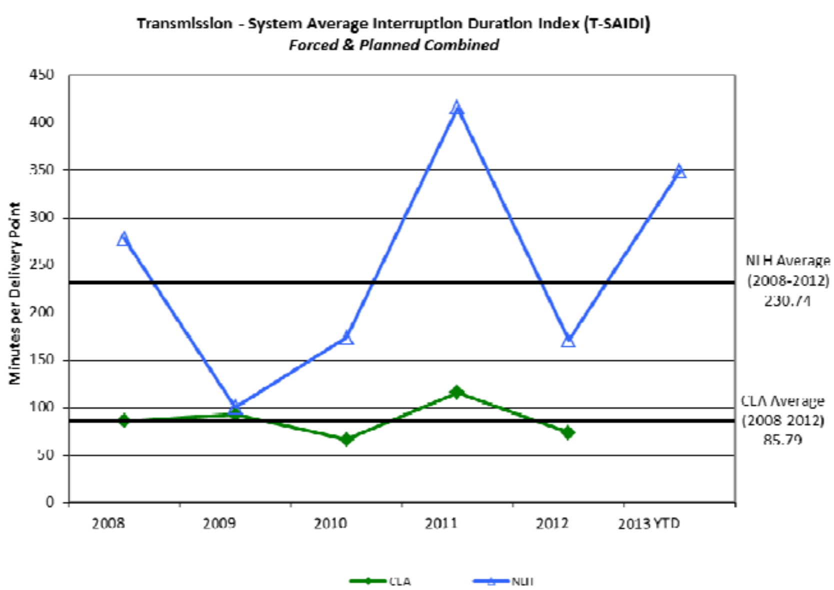
Performance Indices

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

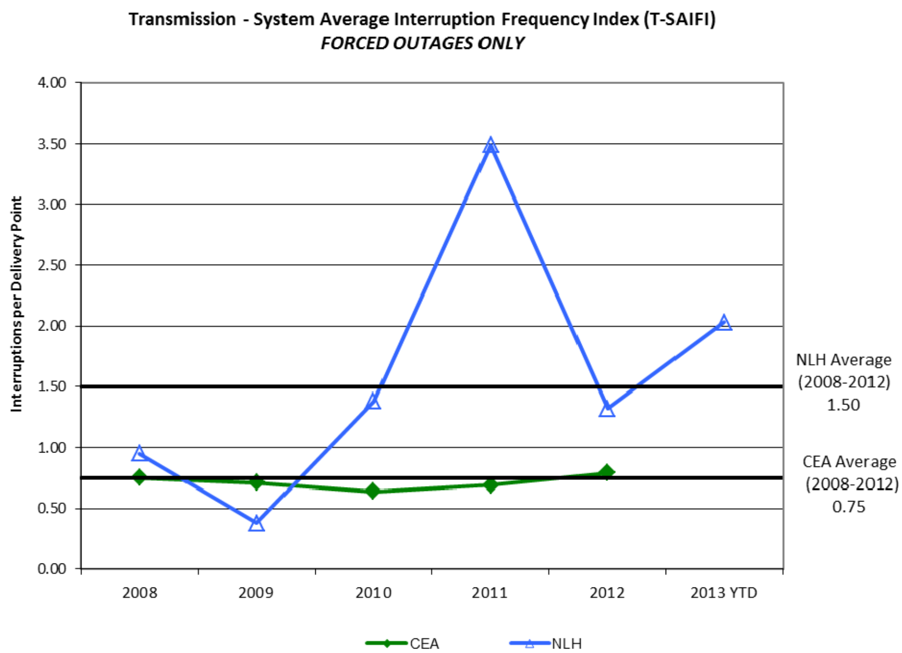
On August 6, customers supplied by the Daniels Harbour Terminal Station experienced a planned power outage of four hours and three minutes. The outage was required to perform maintenance on the high and low voltage switchgear in the terminal station.

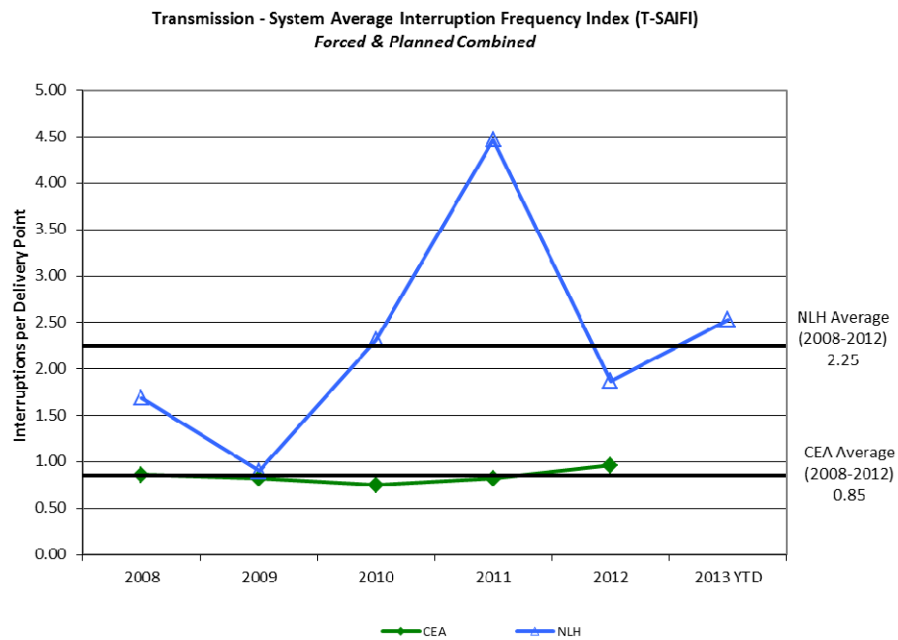
On August 15, customers in the Burgeo area supplied by the Grandy Brook Terminal Station experienced a planned power outage of three hours and 40 minutes. The outage was required to complete emergency replacement and repairs to insulators on transmission line TL250.

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*.

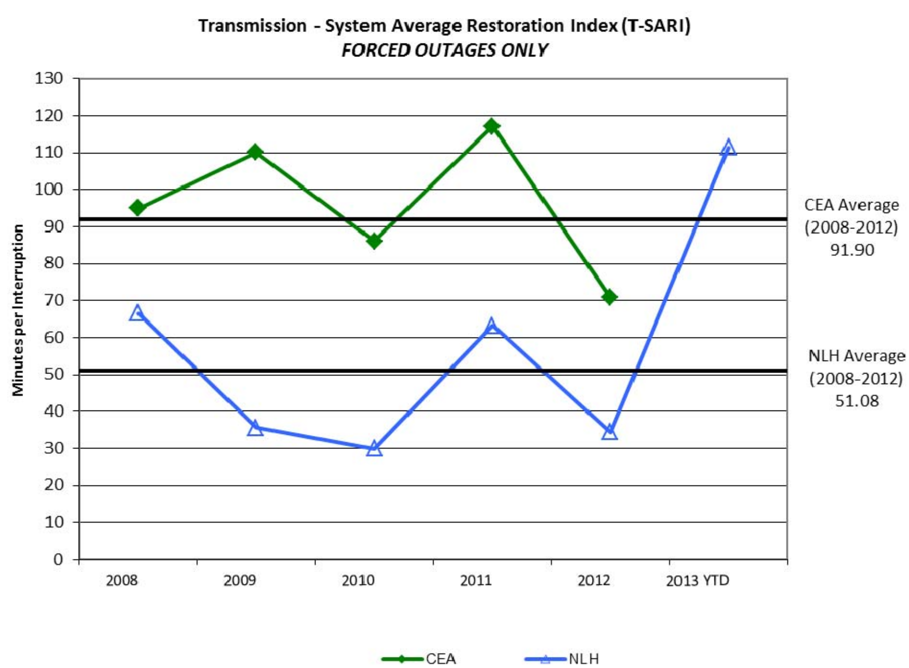
The third quarter T-SAIFI was 0.39 outages per bulk delivery point compared to 0.70 outages per bulk delivery point last year, a 44% decrease. The breakdown between forced and planned outages is as follows: 0.28 (forced) and 0.10 (planned). This is compared to 0.46 (forced) and 0.23 (planned) for the third quarter of 2012.

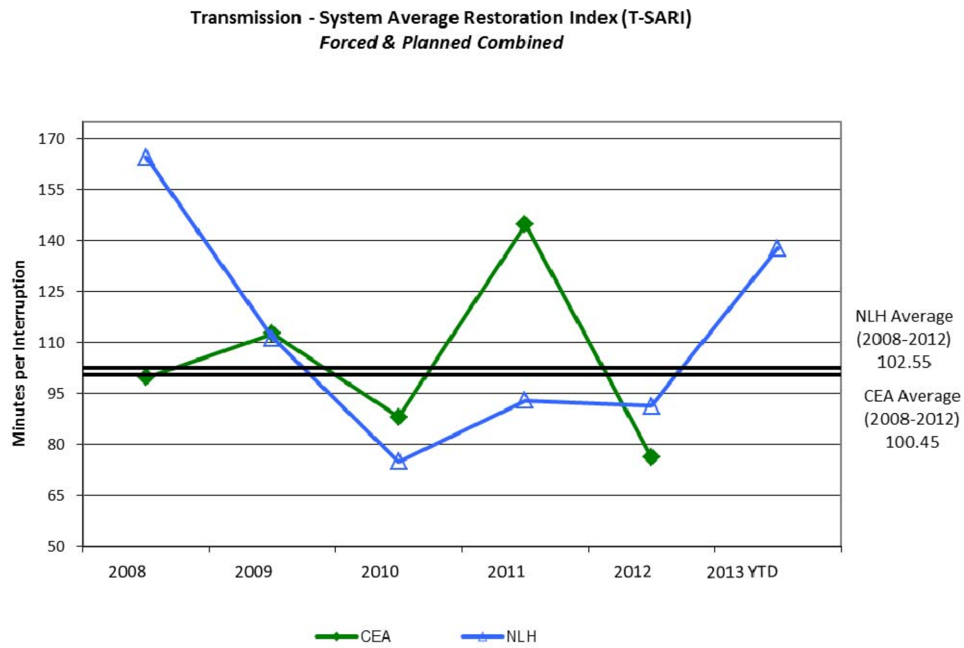




c) Transmission System Average Restoration Index (T-SARI) - *a reliability KPI for bulk transmission assets which measures the average duration per transmission interruption. T-SARI is calculated by dividing T-SAIDI by T-SAIFI.*

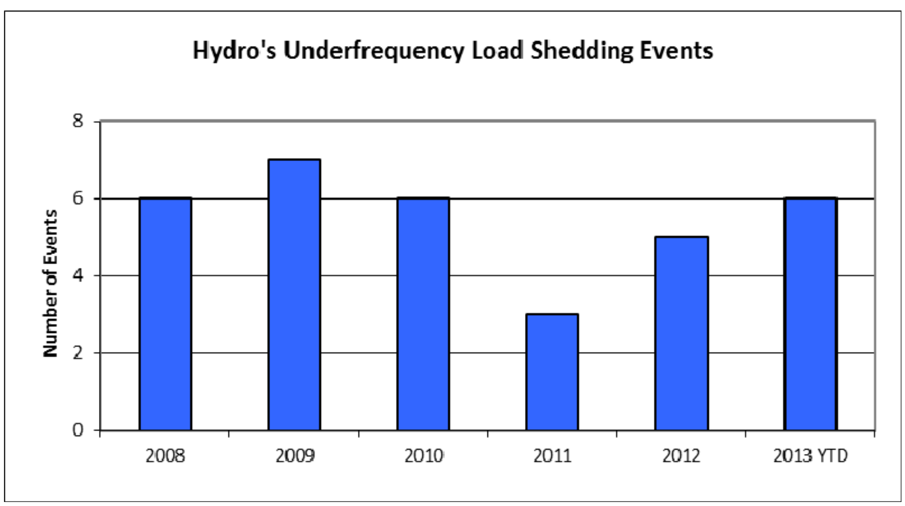
Hydro's total transmission T-SARI was 136.2 minutes per interruption for the third quarter versus 135.6 minutes per interruption for 2012. The forced outage component of T-SARI was 57.6 minutes per interruption. This compares with 28.8 minutes per interruption for the same quarter in 2012, an increase 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)

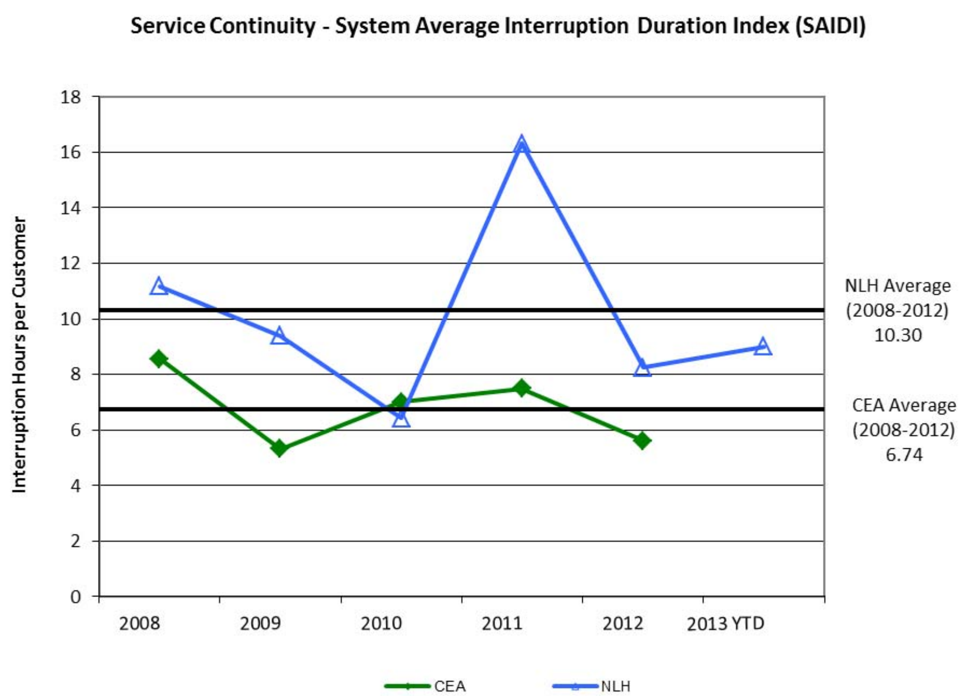
Customers	Third Quarter 2013	Third Quarter 2012	Year to Date 2013	Year to Date 2012	5 Year Average (2008–2012)
NF Power	0	0	13,742	2,274	1,643
Industrials	0	0	0	140	217
Hydro Rural*	0	0	324	21	48
Total Events	0	0	14,066	2,435	1,890

* 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.

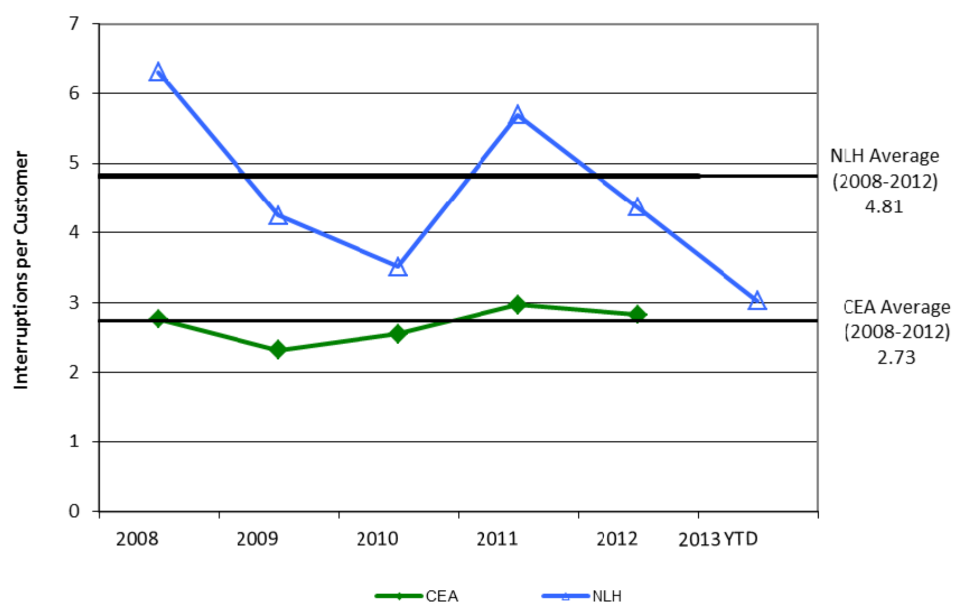
On August 10, all 265 customers serviced by the diesel plant in Hopedale, Labrador experienced an unplanned power outage of 7 hours and 35 minutes. The outage occurred after diesel Unit 2053 shutdown due to an issue with its rotor. Hydro's onsite Diesel Representative tried unsuccessfully to restore 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.

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

QUARTERLY REGULATORY REPORT
FOR THE QUARTER ENDED
DECEMBER 31, 2013

Newfoundland and Labrador Hydro

Table of Contents

APPENDICES:

1 HIGHLIGHTS

TO BE UPDATED

HIGHLIGHTS
For the twelve months ended December 31, 2013

REGULATED	2013 Actual YTD	2013 Target/ Budget	2012 Actual YTD
Safety			
Lead:Lag Ratio[1]	404:1	600:1	230:1
All Injury Frequency Rate[1]	1.16	$\leq$0.8	2.25
Production			
Quarter End Reservoir Storage (GWh)	2,155	912	2,173
Hydraulic Production (GWh)	4,688	4,694	4,595
Holyrood Fuel cost per barrel, current month ($) [2]	105	59	113
Holyrood Efficiency [2]	594	630	599
Electricity Delivery			
Sales including Wheeling (GWh)		7,182.1	6,782.2
Financial			
Revenue ($millions)		537.7	455.3
Expenses ($millions)		531.5	438.4
Net Operating Income ($millions)[3]		6.2	16.9
Current Rate Stabilization Plan (RSP) Balance ($millions)	(240.9)	(237.9)	(201.7)
Hydraulic	(38.1)	(57.1)	(32.7)
Utility	(189.8)	(67.8)	(64.9)
Industrial	(13.0)	(113.0)	(104.1)
Full Time Equivalent (FTE) Employees[4, 5]			
Regulated		863.5	800.8
Non-Regulated		15.0	32.0

[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

- Annual Energy Savings from Internal Energy Efficiency Programs (page 7)
- Red Shoe Crew Finale a Success (page 18)

2 SAFETY

Goal - To be a Safety Leader

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

Measurement	Year-to-date 2013 Actual	Annual 2013 Plan	Annual 2012 Actual
All Injury Frequency (AIF)	1.16	$\leq$0.8	2.25
Lost Time Injury Frequency (LTIF)	0.26	$\leq$0.2	0.79
Ratio of condition and incident reports to lost time and medical treatment injuries (lead/lag ratio)	404:1	600:1	230:1
Planned Grounding and Bonding Activities	100%	100%	N/A
Complete Work Method Activities for Critical Tasks	96%	100%	87.33%

Hydro's safety results showed a marked improvement over its 2012 results, particularly in the critical measure of AIF and LTIF.

During the fourth quarter, Hydro continued its focus on injury prevention initiatives and planned safety objectives.

The "Take a Moment for Safety" multi-faceted internal communication campaign with focus on injury prevention awareness around three of the company's top injury trends; Slips, Trips and Falls; Sprains and Strains and Hand Injuries is ongoing.

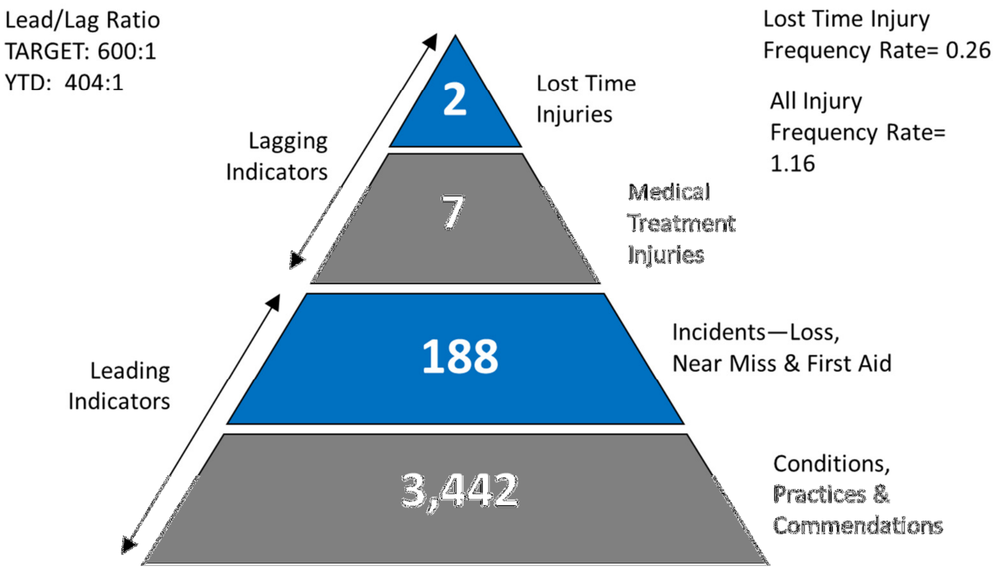
From a core program perspective, Hydro completed all planned objectives and met established targets in the area of Grounding and Bonding, Work Methods and the Work Protection Code (WPC). The Corporate Grounding and Bonding Committee completed the required training for line operations staff and will continue efforts in 2014 with a focus around plants and stations. The development of Work Methods for identified critical tasks is ongoing and has moved into an evaluation phase that will also continue into 2014 to ensure that quality and user-friendly work procedures are available. The WPC Program Committees continue with a focus on program auditing and implementing improvements.

Field visibility of the Leadership Team, Regional Managers and Safety Professionals continues to increase in all areas and will continue. Visits provided opportunity for meaningful discussions around safety and core safety programs and how they are working in the field with both regular operations and contractor work forces.

The public safety campaign around Power Line Hazards is ongoing both internal and externally. Hydro continues to partner with the Public Contact Work Group on the external front; internally Hydro has started a Line Worker Focus Group to review all lines related incidents, best practices and opportunities for improvement to continue toward safety excellence. This group is comprised of key members that represent all regions across the system thus providing knowledgeable input, expertise and sharing communications back to the regions.

Hydro's framework for safety excellence remains intact; with a balanced focus on culture/behaviors vs. processes, continued focus on injury prevention awareness such as slips, trips and falls; hand and tool-related Injuries; sprains and strains.

The following safety triangle summarizes Hydro's year-to-date performance for 2013.



2.1 *Employees Take a Moment for Safety at the 7th Annual Safety Summit*

Over 170 employees gathered at this year's summit to discuss and engage in this two day, safety focused event. Ed Martin, President and CEO, shared the organization's latest safety measures with 2013 looking to be one of the best years to date. Gerard MacDonald, Vice President, Human Resources and Organizational Effectiveness, stressed the importance of taking a moment for safety. Guest speakers shared heartfelt stories of safety risks and losses at work, raising awareness and stressed the importance of safety at work as well as at home. The Safety Summit brought forth valuable lessons learned as well as a progression forward for a work environment where everyone goes home safely each and every day.

Gerard MacDonald speaks to attendees at the 7th Annual Safety Summit

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	10.4%	≤ 10.0%	6.9%
Achievement of EMS targets[1]	95%	95%	96%
Annual energy savings from Residential and Commercial Conservation and Demand Management Programs	2.1 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 Quarter 1, 2014	Complete evaluation	N/A
Annual energy savings from Internal Energy Efficiency Programs	0.85 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*

On January 11, 2013 there was a major winter storm which caused widespread power outages to the Island Interconnected System. Unit 1 at Hydro's Holyrood Thermal Generating Station received significant damage on that day, and was out of service for some time. As a result, the variance from ideal production schedule at Holyrood exceeds the 2013 target.

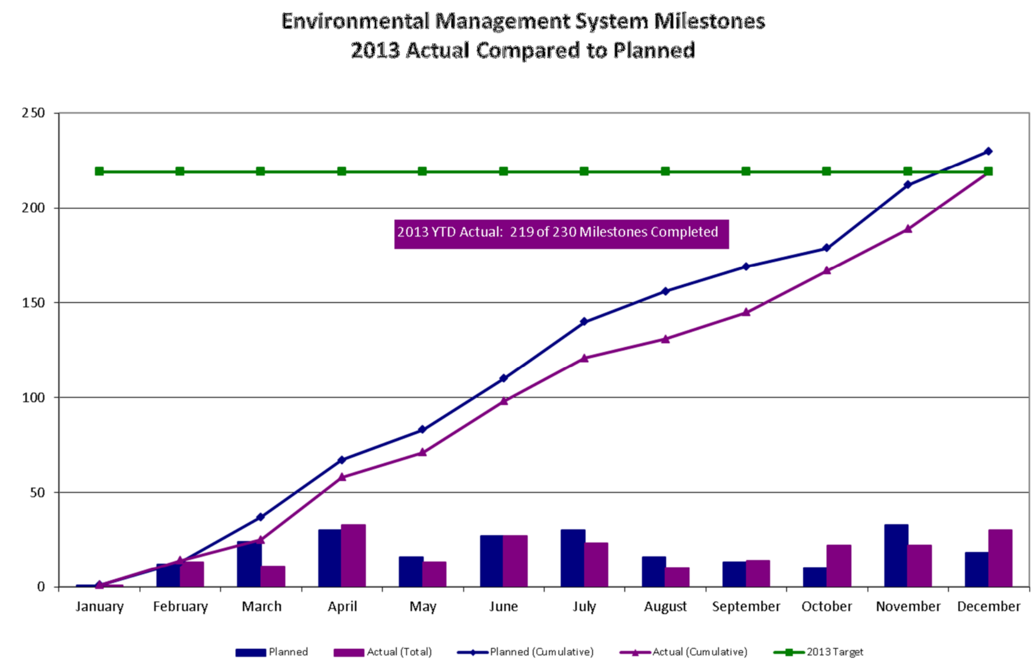
Minimum Hours

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%
October	125	1,065	720	8,400	17.4%	12.7%
November	101	1,166	1,248	9,648	8.1%	12.1%
December	54	1,220	2,112	11,760	2.6%	10.4%

[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

Hydro achieved its 2013 EMS target for 2013, as shown in the graph below, which displays planned target completion schedules and actual to-date.



3.2.1 Annual Energy Savings from Residential and Commercial Conservation and Demand Management (CDM) Programs

takeCHARGE rebates remained steady for the fourth quarter and increased emphasis was placed on promotions through working jointly with retailers to promote incentives together with store level sales on products offered by Hydro. The increase in activity that usually occurs as heating season began was not seen, but Hydro will be exploring what promotional measures and communications messages have worked with customers. Hydro is working on a residential program evaluation in partnership with Newfoundland Power and the results of that will determine possible changes and updates to the programs and the promotional strategies.

The Business Efficiency Program (BEP) was launched in November. The program provides technical support to customers to identify efficiency opportunities as well as financial assistance for retrofit projects. This custom program provides incentives to commercial customers based on project energy savings rather than a prescriptive list of technologies, allowing for the unique efficiency needs of individual sectors to be addressed.

The energy savings target was not met in 2013 primarily due to lower than targeted results from the Isolated Community Energy Efficiency Program through coupon redemptions and participation in home retrofit incentives. Direct installation of small items including showerheads and CFLs in homes received strong participation. In addition, the Commercial Lighting and Isolated Business Efficiency Programs saw less than targeted savings and the launch of the joint utility Business Efficiency Program happening late in the third quarter meant no savings were recorded for 2013. Further discussion of these issues and improvements will be provided in the forthcoming annual CDM report.

3.2.2 Conduct Evaluation of Industrial Energy Efficiency Program (IEEP) and Develop Multi-Year Plan

The evaluation of the IEEP started in the fourth quarter but there were challenges in getting adequate interview responses from customers. Additional time has been scheduled to obtain responses..

3.2.3 Annual Energy Savings from Internal Energy Efficiency Programs

Internal energy efficiency savings were significantly higher than estimated due to strong savings from the optimizing controls in the Hydro Place building. Savings of 0.42 GWh resulted from this work. These efforts will continue into 2014 reaching to optimizing other buildings in future.

3.3 Energy Efficiency Week

In November, Hydro Place employees participated in Energy Efficiency Week. Information was provided to employees on the focus on energy efficiency at Hydro Place, along with some of the successes and challenges to date; new lighting technologies that are being implemented at Hydro sites; unexpected benefits of LED lighting discovered at one site; and several other energy efficiency projects.

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]	97.5%	≥99.5%	99.97%
Asset Management Strategy Execution	Completed as planned for 2013	Plan Implementation	Completed as planned for 2012
Financial Targets			
Annual Controllable Costs	To be updated	$111.9 million (Budget)	-1.7%
Net Income	To be updated	$6.2 million	$16.9 million
Project Execution			
Completion rate of capital projects by year end[2]	82%	≥90%	82%
All-project variance from original budget[2]	27%	8%	18%
Customer Service			
Customer Service Improvement Plan	Draft Completed	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 total energy produced and purchased on the Island Interconnected System was up by 217.3 GWh or 3.4% in 2013 compared to 2012. This is owing to significantly higher Utility requirements which have been partially offset by lower energy requirements for the Industrial Customers, particularly at North Atlantic Refining Limited and Corner Brook Pulp and Paper Limited.

Energy requirements from the Holyrood Thermal Generating Station were higher in 2013 when compared to 2012 (101.6 GWh or 11.9%). This was primarily due to colder temperatures, particularly during the late spring and early winter periods, which resulted in increased requirements for system generation and Avalon Peninsula transmission support. Individual units were brought into service as required to meet customers' demand and for transmission support to the Avalon Peninsula.

Hydro-electric production in 2013 was 93.3 GWh or 2.0% above the levels in 2012, primarily due to increased system load requirements. Total energy purchases were up by 18.4 GWh or 1.9% through 2013 when compared to 2012. This increase was primarily due to increased generation from the Nalcor facilities on the Exploits River, 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 and at the Nalcor Buchans Generating Plant.

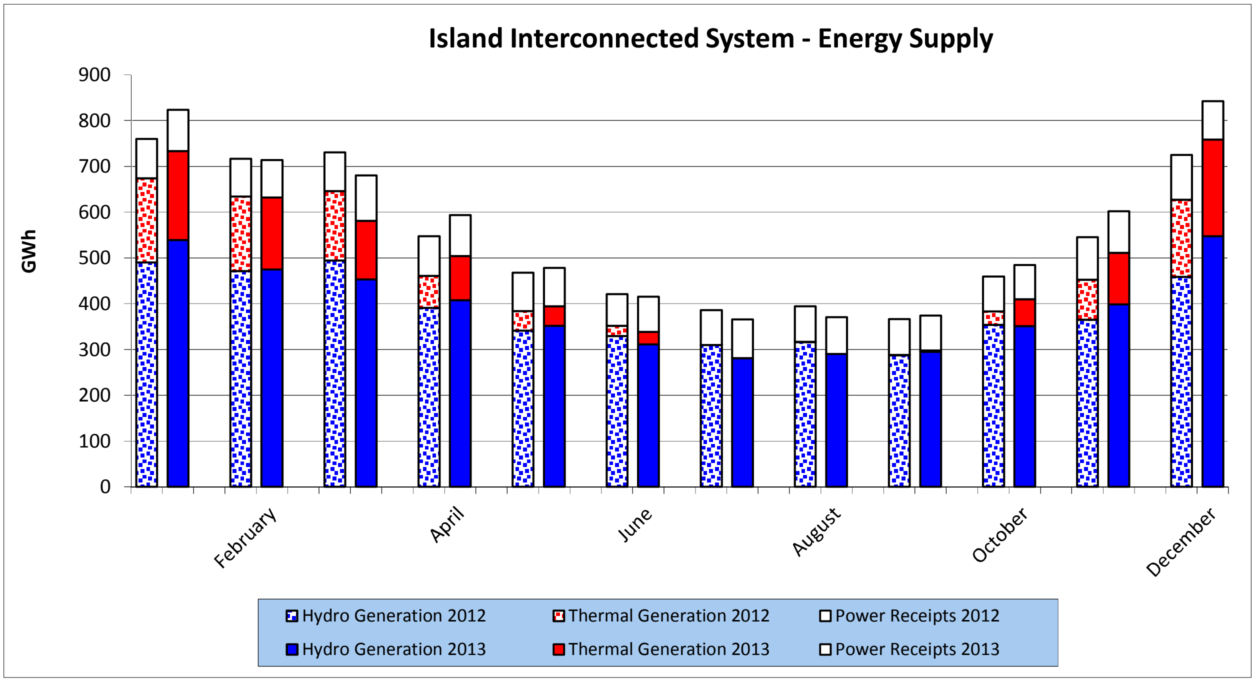
There were generation supply problems experienced in December due to a number of issues (summarized as follows):

December 15-16, 2013 – the Exploits generation was reduced to 38 MW from the typical 63 MW in winter due to issues with frazil ice;
December 21, 2013 - the Hardwoods Gas Turbine unit (50 MW) became unavailable when the final testing after a unit overhaul revealed fuel valve issues; and
December 26, 2013 – there was a Holyrood Unit 3 forced draft fan failure resulting in 100 MW becoming unavailable.

In addition to the above, one end of the Stephenville Gas Turbine was unavailable and there were ongoing minor deratings of Holyrood Unit 2 and the Granite Canal generating unit. On December 29, Hydro began to implement its Generation Shortage Protocol, carrying out the steps of requesting Newfoundland Power voltage reductions and interruption of curtailable customers.

On December 31, arrangements for a short-term capacity agreement to provide up to 60 MW were finalized with CBPP. Also on December 31, Hydro notified the Public Utilities Board of extended capacity issues with the Stephenville Gas Turbine, Hardwoods Gas Turbine and Holyrood Unit 3. To the end of the month, there were no customer interruptions experienced as a result of these supply issues.

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



Island Interconnected System Production
For the Quarter ended December 31, 2013

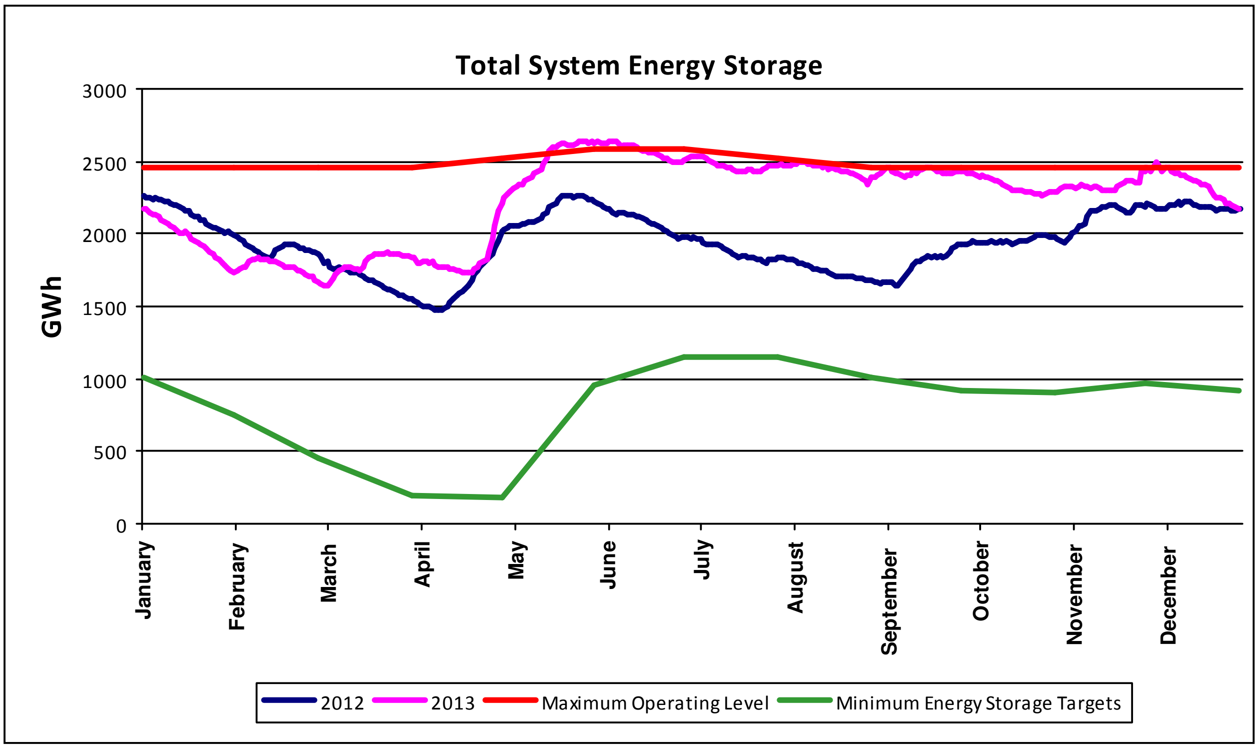
	Year-to-date			2013 Annual Forecast (GWh)	2013 ($ 000)
	2013 (GWh)	2012 (GWh)	2013 Forecast (GWh)		
Production (net)					
Hydro	4,688.3	4,595.0	4,694.4	4,694.4	
Thermal	957.4	855.8	981.5	981.5	
Gas Turbines	(1.5)	(3.9)	3.0	3.0	
Diesels	1.1	(0.5)	1.0	1.0	
Total Production	**5,645.3**	**5,446.4**	**5,679.9**	**5,679.9**	
Energy Purchases					
Non Utility Generators					
Rattle Brook	14.8	14.6	15.6	15.6	**1,228.8**
Corner Brook Pulp and Paper Co-generation	55.9	47.8	52.7	52.7	**9,259.7**
St. Lawrence Wind	96.4	103.8	91.9	91.9	**6,876.0**
Fermeuse Wind	95.5	91.2	86.0	86.0	**7,313.3**
Total Non Utility Generators	**262.6**	**257.4**	**246.2**	**246.2**	**24,677.8**
Secondary and Others					
Deer Lake Power	8.5	6.2	3.2	3.2	**160.1**
Hydro Request to NP	1.0	0.1	0.0	0.0	**533.5**
Nalcor Energy[(1)]	740.3	730.3	760.2	760.2	
Total Secondary and Other	**749.8**	**736.6**	**763.4**	**763.4**	**693.6**
Total Purchases	**1,012.4**	**994.0**	**1,009.6**	**1,009.6**	
Island Interconnected Total Produced and Purchased	**6,657.7**	**6,440.4**	**6,689.5**	**6,689.5**	

Note 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 favourable. Inflows into the aggregate reservoir system were above normal at 106% of average during the fourth quarter of 2013 and were 122% of average for the year. The annual inflows for 2013 were the third highest in the 63 years of hydrological record (only 1977 and 1993 were higher). Reservoir levels at the end of the year were at 88% of the maximum operating level (MOL) and 236% of the minimum storage target. This compares with an aggregate level that was 89% of the MOL at the end of 2012.

There was spill out of several reservoir systems in the fourth 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	2,155	912	2,173

4.1.3 Energy Supply – Labrador Interconnected System

The purchased and produced energy on the Labrador Interconnected system was higher in 2013 (38.7 GWh or 4.8%) when compared to 2012. This is primarily owing to higher industrial sales at the Iron Ore Company of Canada (IOCC) and higher Hydro Rural requirements in Labrador East and West. The increase in energy requirements was partially offset by reduced secondary sales to CFB Goose Bay.

Labrador Interconnected System Production
For the Quarter ended December 31, 2013

	Year-to-date			2013 Annual Forecast (GWh)
	2013 (GWh)	2012 (GWh)	2013 Forecast (GWh)	
Production (net)				
Gas Turbines	0.1	(0.7)	(0.3)	(0.3)
Diesels	0.1	0.0	0.2	0.2
Total Production	**0.2**	**(0.7)**	**(0.1)**	**(0.1)**
Purchases				
CF(L)Co for Labrador (at border)	**839.1**	**801.3**	**935.3**	**935.3**
Labrador Interconnected Total Produced and Purchased	**839.3**	**800.6**	**935.2**	**935.2**

4.1.4 Fuel Prices

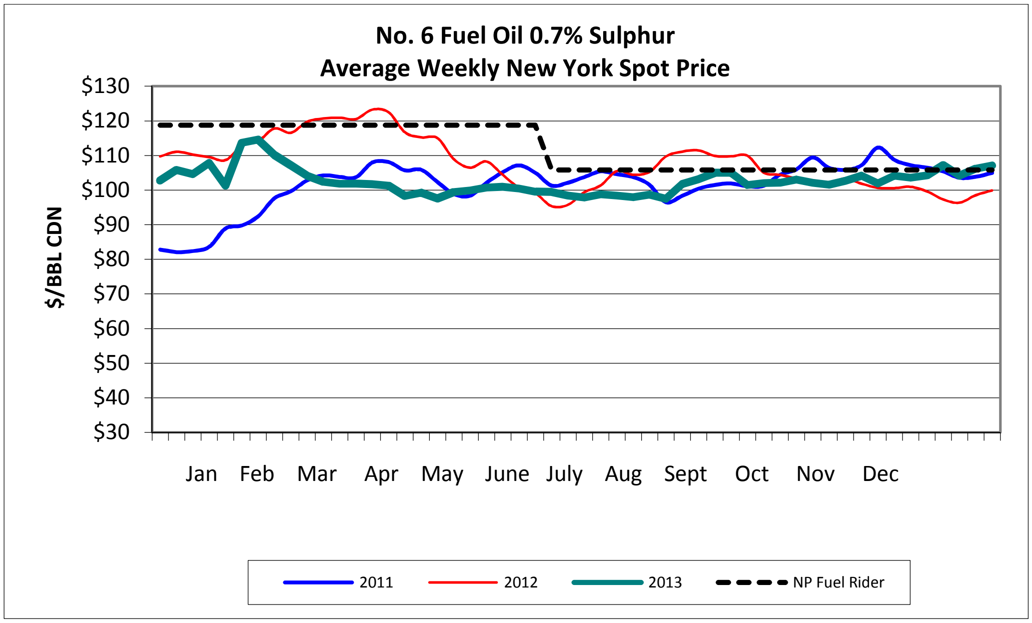
The fuel market prices for No. 6 fuel increased slightly from approximately $102 /bbl at the start of the quarter to $107/bbl at the end of the quarter. The quarter ending inventory cost was $104.73/bbl, lower than the current Newfoundland Power fuel price rider of $105.80/bbl. There is no Industrial Customer fuel price rider for 2013.

There were two shipments received during the fourth quarter of 2013.

November 7	217,755 bbls	$105.89
December 22	225,117 bbls	$103.89

The inventory on December 31 was 294,862 barrels.

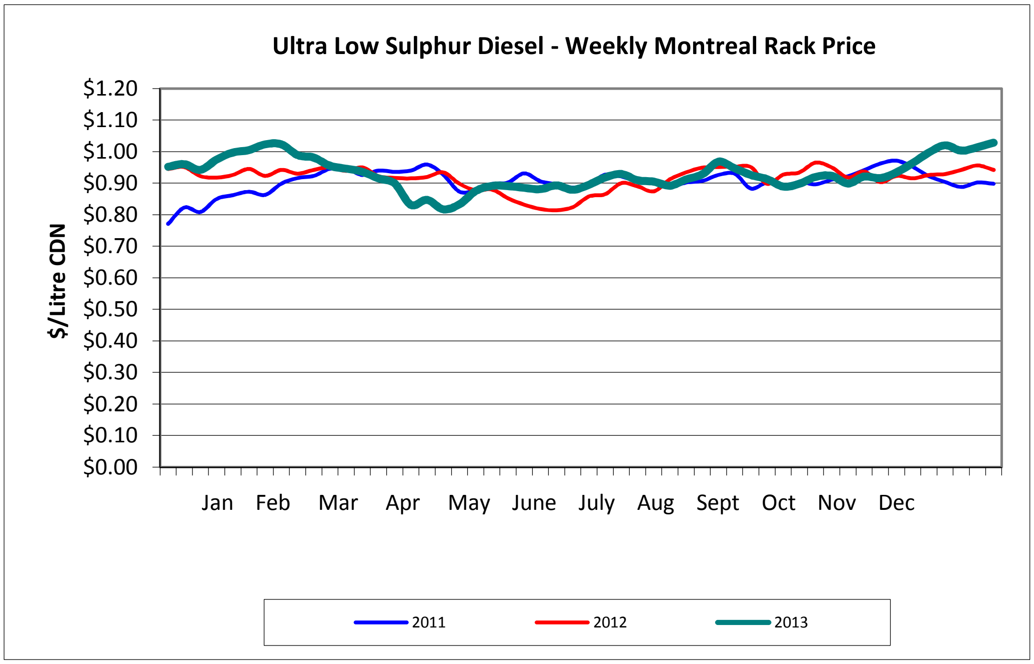
The following chart shows the No. 6 fuel prices year-to-date compared to 2011 and 2012, and the Newfoundland Power fuel rider price of $105.80/bbl.



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 January 2014 –December 2014			
Month	**Price ($Cdn/bbl) 0.7%**	**Month**	**Price ($Cdn/bbl) 0.7%**
January 2014	105.30	July 2014	108.30
February 2014	105.20	August 2014	109.40
March 2014	102.30	September 2014	107.80
April 2014	105.40	October 2014	101.60
May 2014	104.70	November 2014	98.70
June 2014	105.90	December 2014	101.10
Note: The forecast is based on the PIRA Energy Group price forecast available January 13, 2014 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 has increased by 5.1% in 2013.

Purchases from Hydro Québec for the L'Anse au Loup system have increased 4.4 %. Increased supply requirements (purchases and generation) on the L'Anse au Loup system account for 58% of the overall increase in isolated supply. Much of the increased requirement can be attributed to colder weather in 2013 than in 2012.

Average cost of power, purchased from Hydro Québec and based on Montreal rack fuel prices, was $138 per megawatt hour in 2013; unchanged from 2012. Average cost of power from NUGS, based on current diesel fuel prices, has increased from $289 per megawatt hour in 2012 to $296 per megawatt hour in 2013.

Isolated Systems Production
For the year ended December 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	48.2		45.6		50.6		50.6	
Purchases								
Non-Utility Generators (NUGS)[2]	0.8	220.8	0.8	296.2	0.8	244.7	0.8	244.7
Hydro Québec	22.4	3,056.0	21.5	2,931.2	23.2	3,353.2	23.2	3,353.2
Total Purchases	**23.2**	**3,276.8**	**22.3**	**3,093.4**	**24.0**	**3,597.9**	**24.0**	**3,597.9**
Isolated Systems Total Produced and Purchased	**71.4**	**3,276.8**	**67.9**	**3,093.4**	**74.6**	**3,597.9**	**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 also includes energy purchased from Nalcor's wind/hydrogen facility in 2010 and 2011.

4.2 Financial

Financial data for December 31, 2013 will follow when audited Financial Statements become available.

4.3 Capital Expenditures

Capital Expenditures for the year ended December 31, 2013 will be reported as 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) 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
The project was completed as of December 2013. Operations are scheduled to commence in the first quarter of 2014.

Capital Costs

($000)

Actual Cost to December 2013	Actual Cost Recoveries to December 2013	Net Cost to December 2013	Budget to December 2008	Budget Reforecast to September 2010
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 first quarter of 2014.

Reliability and Safety Issues
There is nothing to report for this period.

5.1.2 President's Awards recognized Outstanding Employees

For six years, employees within the organization who go above and beyond expectations are recognized through the annual President's Awards. This year 29 employees were nominated for awards by colleagues and 12 of those nominees received awards at the President's Award ceremony held in St. John's on November 28. The award winners have been recognized by their peers and the Leadership Team as leaders in Nalcor's corporate goals of Safety, Environment, Business Excellence, People and Community. All awards were proudly presented by Nalcor's President and CEO, Ed Martin.

5.2 Community

5.2.1 Red Shoe Crew Finale a Success

The 2013 Ronald McDonald House Red Shoe Crew Walk for Families came to a close on October 3 at Hydro Place. Ronald McDonald himself came by to offer a huge smile and congratulations to Newfoundland and Labrador Hydro along with Ronald McDonald House on raising a grand total of $193,000 at this year's Red Shoe Crew event. "This grand total surpassed all expectations," says Ronald McDonald House board chair, Gerry Beresford. "This donation will be enough to run the Newfoundland Ronald McDonald house for one third of the entire year."

L-R: Annette Godsell, Executive Director, RMHNL, Ronald McDonald, Rob Henderson VP, Hydro, Christine Morgan, Manager, Development & Communications, Valerie Geary, Development Associate, RMHNL, Kaydee and Shelley McIssac, current guests of Ronald McDonald House and Gerry Beresford, Board Chair, RMHNL.

5.3 Statement of Energy Sold

Statement of Energy Sold (GWh)

For the Quarter ended December 31

	YEAR TO DATE			
	2013 ACTUAL	**2012 ACTUAL**	**2013 BUDGET**	**ANNUAL % CHANGE**
Island Interconnected				
Newfoundland Power	5,606	5,359	5,691	4.6%
Island Industrials	351	410	446	-14.4%
Rural				
Domestic	246	240	248	2.5%
General Service	170	163	159	4.3%
Streetlighting	3	3	3	0.0%
Sub-total Rural	419	406	410	3.2%
Sub-Total Island Interconnected	6,376	6,175	6,547	3.3%
Island Isolated				
Domestic	6	6	6	0.0%
General Service	1	1	1	0.0%
Streetlighting	0	0	0	0.0%
Sub-Total Island Isolated	7	7	7	0.0%
Labrador Interconnected				
Labrador Industrials	201	180	374	11.7%
CFB Goose Bay	3	18	0	-83.3%
Hydro Quebec (includes Menihek)	47	42	41	11.9%
Export	1,547	1,597	1,283	-3.1%
Rural				
Domestic	289	285	300	1.4%
General Service	239	240	263	-0.4%
Streetlighting	2	2	2	0.0%
Sub-total Rural	530	527	565	0.6%
Sub-Total Lab. Interconnected	2,328	2,364	2,263	-1.5%
Labrador Isolated				
Domestic	21	21	23	0.0%
General Service	14	15	17	-6.7%
Streetlighting	0	0	0	0.0%
Sub-Total Labrador Isolated	35	36	40	-2.8%
L'Anse au Loup				
Domestic	14	13	15	7.7%
General Service	8	8	8	0.0%
Streetlighting	0	0	0	0.0%
Sub-Total L'Anse au Loup	22	21	23	4.8%
Total Energy Sold (Before Rural Accrual)	8,768	8,603	8,880	1.9%
Rural Accrual	3	10	-	-70.0%
Total Energy Sold	8,771	8,613	8,880	1.8%
Sales to Non-Regulated Customers**	1795	1819	1698	-1.3%

* Rural GWh - Based on 2013 Budget, Fall 2012 Rural Load Forecast
Non-rural GWh - Based on 2013TY Wholesale Industrial Revenue Budget
** Included in Total Energy Sold

5.4 Customer Statistics

Customer Statistics
For the Quarter ended December 31

	FOURTH QUARTER		ANNUAL	
	2013 ACTUAL	2012 ACTUAL	2013 Budget	2012 ACTUAL
Customers				
Rural	38,022	37,576	37,604	37,576
Industrial	5	4	5	4
CFB Goose Bay	1	1	0	1
Utility	1	1	1	1
Non-Regulated	4	3	3	3
Reading Days	29.7	30.2	N/A	30.0

APPENDICES

CIAC QUARTERLY ACTIVITY REPORT
For the Quarter ended December 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	8	8	16	4	5	7
Outside Plan. Boundary	4	3	7	3	0	4
Sub-total	12	11	23	7	5	11
General Service	5	6	11	7	1	5
Total	17	17	34	14	6	16

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, 2013

DATE QUOTED	SERVICE LOCATION	CIAC NO.	CIAC AMOUNT ($)	ESTIMATED CONST. COST ($)	ACCEPTED
DOMESTIC - WITHIN RESIDENTIAL PLANNING BOUNDARIES					
October 28, 2013	South Brook; Green Bay	973970	$ 5,180.00	$ 7,730.00	Yes
October 29, 2013	South Brook; Green Bay	999784	$ 7,680.00	$ 10,230.00	
October 30, 2013	English Harbour West	1002815	$ 1,650.00	$ 3,300.00	
November 13, 2013	South Brook; Green Bay	1009112	$ 81,228.50	$ 108,528.50	Yes
November 15, 2013	South Brook; Green Bay	1012567	$ 680.00	$ 1,430.00	
November 18, 2013	St. Alban's	1012643	$ 3,900.00	$ 7,050.00	
November 27, 2013	South Brook; Green Bay	1011832	$ 1,417.93	$ 2,167.93	Yes
December 4, 2013	South Brook; Green Bay	1016033	$ 66,196.00	$ 93,496.00	
DOMESTIC - OUTSIDE RESIDENTIAL PLANNING BOUNDARIES					
October 1, 2013	Westport	1000689	$ 3,086.15	$ 5,636.15	Yes
October 29, 2013	South Brook; Green Bay	1000851	$ 96,377.00	$ 110,877.00	
October 31, 2013	Springdale	1009930	$ 14,430.00	$ 15,180.00	
December 4, 2013	Westport	1016106	$ 2,346.10	$ 4,896.10	
GENERAL SERVICE					
October 3, 2013	South Brook; Green Bay	978070	$ 2,126.14	$ 6,603.64	Yes
October 21, 2013	Labrador City	984843	$ 2,400.00	$ 8,920.00	
October 22, 2013	Wabush	998928	$ -	$ 12,094.00	
October 29, 2013	Labrador City	997970	$ 27,636.00	$ 30,600.00	
November 1, 2013	Happy Valley-Goose Bay	1008594	$ 1,660.00	$ 14,440.00	Yes

CUSTOMER PROPERTY DAMAGE CLAIMS REPORT
For the Quarter ended December 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 December 31, 2013

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	$ -	$ -	3	$ -	1	$ 1,228.54
Power Interruptions	3	0	3	0	$ -	$ -	3	$ 6,912.00	0	$ -
Improper Workmanship	3	4	7	1	$ 1,087.89	$ 864.43	0	$ -	6	$ 5,993.70
Weather Related	9	5	14	0	$ -	$ -	5	$ 14,742.41	10	$ 19,748.02
Equipment Failure	0	6	6	1	$ 15,883.27	$ 15,883.27	0	$ -	5	$ 17,564.00
Third Party	0	0	0	0	$ -	$ -	0	$ -	0	$ -
Miscellaneous	4	3	7	3	$ 2,847.73	$ 1,776.83	5	$ 3,189.85	0	$ -
Waiting Investigation	3	8	11	0	$ -	$ -	1	$ -	8	$ 2,116.99
Total	25	26	51	5	$ 19,818.89	$ 18,524.53	17	$ 24,844.26	30	$ 46,651.25

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

CUSTOMER PROPERTY DAMAGE CLAIMS REPORT - BY REGION

For the Quarter ended Decemeber 31, 2013

REGION	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	AMT. CLAIMED	AMT. PAID	#	AMOUNT	#	AMOUNT
Central Region	12	6	18	1	$ 991.00	$ 338.14	7	$ 14,573.26	11	$ 11,450.51
Northern Region	9	15	24	3	$ 17,425.12	$ 17,201.66	7	$ 2,884.00	14	$ 30,200.74
Labrador Region	4	5	9	1	$ 1,402.77	$ 984.73	3	$ 7,387.00	5	$ 5,000.00
Total	25	26	51	5	$ 19,818.89	$ 18,524.53	17	$ 24,844.26	30	$ 46,651.25

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

FINANCIAL – REGULATED

Financial data will follow when audited financial statements are available.

Newfoundland and Labrador Hydro
Rate Stabilization Plan
December 31, 2013

Rate Stabilization Plan Report
December 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
December 31, 2013

	Actual	Cost of Service	Variance	Year-to-Date Due (To) From customers	Reference
Hydraulic production year-to-date	4,693.8 GWh	4,472.1 GWh	221.7 GWh	$ (20,392,250)	Page 4
No 6 fuel cost - Current month	$ 104.85	$ 58.98	$ 45.87	$ 82,131,930	Page 5
Year-to-date customer load - Utility	5,605.7 GWh	4,925.8 GWh	679.9 GWh	$ 316,808	Page 8
Year-to-date customer load - Industrial	351.4 GWh	894.3 GWh	-542.9 GWh	$ (27,477,202)	Page 9
				$ 34,579,286	

Rural rates		
Rural Rate Alteration (RRA) [1]	$ (11,418,449)	
Less : RRA to utility customer	$ (10,173,838)	Page 10
RRA to Labrador interconnected	(1,244,611)	
Fuel variance to Labrador interconnected	$ 639,139	Page 6
Net Labrador interconnected	$ (605,472)	

Current plan summary		
One year recovery		
Due (to) from utility customer	$ (80,173,930)	Page 10
Due (to) from Industrial customers	$ 566,125	Page 11
Sub total	(79,607,805)	
Four year recovery		
Hydraulic balance	$ (39,801,010)	Page 4
Segregated Load Variation		Page 12
Utility Customer	$ 790,787	
Industrial Customer	$ (8,991,282)	
Sub Total	$ (8,200,495)	
Utility RSP Surplus	$ (115,330,446)	Page 13
Industrial RSP Surplus	$ (10,858,146)	Page 14
Total plan balance	$ (253,797,902)	

[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
December 31, 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 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	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	340,510,000	350,824,648	(10,314,648)	54.56	(893,281)	(231,051)	(39,204,383)
November	364,390,000	398,097,750	(33,707,750)	54.56	(2,919,198)	(237,873)	(42,361,454)
December	398,560,000	547,251,746	(148,691,746)	58.98	(13,920,380)	(257,028)	(56,538,862)
	4,472,070,000	4,693,775,867	(221,705,867)		(20,392,250)	(3,470,849)	(56,538,862)
Hydraulic Allocation (2)					13,267,003	3,470,849	16,737,852
Hydraulic variation at year end					(7,125,247)	-	(39,801,010)

(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	5,605,729,562	87.4%	14,626,152	1,064,717	15,690,869
Industrial	351,353,424	5.5%	916,731		916,731
Rural	457,992,791	7.1%	1,194,969	(1,194,969)	-
Total	6,415,075,777	100.0%	16,737,852	(130,252)	16,607,600
Labrador Inteconnected (write-off to income)				130,252	130,252
				-	16,737,852

Rate Stabilization Plan
No. 6 Fuel Variation
December 31, 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	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	96,311	0	96,311	54.56	104.65	50.09	4,824,218
November	176,423	4	176,419	54.56	105.22	50.66	8,937,387
December	322,215	31	322,184	58.98	104.85	45.87	14,778,576
	1,611,080	41	1,611,039	55.47	106.63	51.16	82,131,930

Rate Stabilization Plan
Allocation of Fuel Variance - Year-to-Date
December 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	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	5,460,083,858	346,307,206	454,251,410	6,260,642,474	50,946,222	3,231,277	4,238,468	58,415,967	3,776,475	461,993
November	5,505,016,420	350,543,086	456,303,327	6,311,862,833	58,743,564	3,740,616	4,869,174	67,353,354	4,338,434	530,740
December	5,605,729,562	351,353,424	457,992,791	6,415,075,777	71,769,906	4,498,362	5,863,662	82,131,930	5,224,523	639,139

(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, 2013

	A	B	C	D	E	F	G
	Utility					**Industrial**	
	Fuel Variance		Rural Allocation		Total Fuel Variance Activity for the month	Fuel Variance	
	Year-to-Date Activity	Current Month Activity [1]	Year-to-Date Activity	Current Month Activity [1]		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	50,946,222	4,268,735	3,776,475	314,486	4,583,221	3,231,277	202,525
November	58,743,564	7,797,342	4,338,434	561,959	8,359,301	3,740,616	509,339
December	71,769,906	13,026,342	5,224,523	886,089	13,912,431	4,498,362	757,746
		71,769,906		5,224,523	76,994,429		4,498,362

(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, 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	360,200,000	405,323,940	45,123,940	54.56	0.08805	(65,286)	0	0	0.00841	0	(65,286)
November	439,300,000	498,223,042	58,923,042	54.56	0.08805	(85,251)	0	0	0.00841	0	(85,251)
December	543,800,000	711,965,166	168,165,166	58.98	0.08805	936,520	0	0	0.00841	0	936,520
	4,925,800,000	5,602,957,415	677,157,415			340,121	0	2,772,147		(23,313)	316,808

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

Rate Stabilization Plan
Load Variation - Industrial
December 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	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	74,400,000	24,799,284	(49,600,716)	54.56	0.03676	(2,472,257)
November	74,100,000	33,552,362	(40,547,638)	54.56	0.03676	(2,021,023)
December	72,700,000	33,886,909	(38,813,091)	58.98	0.03676	(2,206,875)
	894,300,000	351,353,424	(542,946,576)			(27,477,202)

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

Rate Stabilization Plan
Summary of Utility Customer
December 31, 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	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) (3)	(186,936,587)
Transfer Utility RSP Surplus							112,573,325 (4)	(74,363,262)
September		277,106	(406,606)	(129,500)	(451,199)	(1,566,195)		(76,510,156)
October		4,583,221	(477,308)	4,105,913	(464,225)	(2,160,377)		(75,028,845)
November		8,359,301	(539,413)	7,819,888	(455,238)	(2,655,529)		(70,319,724)
December		13,912,431	(3,676,484)	10,235,947	(604,510)	(3,794,774)		(64,483,061)
Year to date	(475,181)	76,994,429	(10,173,838)	66,345,410	(5,153,396)	(61,593,444)	823,770	422,340
Hydraulic allocation **(from page 4)**								(15,690,869)
Total	(475,181)	76,994,429	(10,173,838)	66,345,410	(5,153,396)	(61,593,444)	823,770	(80,173,930)

(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 of $112,573,325 has been transferred to the Utility Customer balance.

(4) The August Adjustment of $112,573,325 has been reallocated to the Utility RSP Surplus (Page 13).

Rate Stabilization Plan
Summary of Industrial Customers
December 31, 2013

	A	B	C	D	E	F		G
	Load Variation	Allocation Fuel Variance	Subtotal Monthly Variances	Financing Charges	Adjustment (1)	August Adjustments		Cumulative Net Balance
	($)	($)	($)	($)	($)	($)		($)
			(A + B)					
	(from page 9)	**(from page 7)**						**(to page 15)**
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	(2)	38,129,373
August Adjustments - RSP Surplus Allocation						(49,000,000)	(2)	(10,870,627)
Transfer Industrial RSP Surplus						10,870,627	(3)	-
September		7,553	7,553	-	-			7,553
October		202,525	202,525	46	-			210,124
November		509,339	509,339	1,275	-			720,738
December		757,746	757,746	4,372	-			1,482,856
Year to date	(18,568,716)	4,498,362	(14,070,354)	(5,383,543)	2,396,554	122,620,182		105,562,839
Hydraulic allocation **(from page 4)**								(916,731)
Total	(18,568,716)	4,498,362	(14,070,354)	(5,383,543)	2,396,554	122,620,182		566,125

(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 RSP Surplus (Page 14) as at September 1, 2013, and the remaining balance has been transferred to the Utility RSP Surplus (Page 13).

(3) The August Adjustment of $10,870,627 has been reallocated to the Industrial RSP Surplus (Page 14).

Rate Stabilization Plan
Load Variation September - December 2013
December 31, 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 [1]
		($)	($)		($)	($)	($)
			(A + B)			(D+ E)	(C +F)
	(from page 8)			**(from page 9)**			**(to page 15)**
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	(65,286)	36	(59,244)	(2,472,257)	(13,399)	(4,693,987)	(4,753,231)
November	(85,251)	(359)	(144,854)	(2,021,023)	(28,481)	(6,743,491)	(6,888,345)
December	936,520	(879)	790,787	(2,206,875)	(40,916)	(8,991,282)	(8,200,495)
Total	791,989	(1,202)	790,787	(8,908,486)	(82,796)	(8,991,282)	(8,200,495)

(1) Per Board Order No. P.U. 29(2013), the load variation from the Industrial and Utility Customers as of September 1, be held in a separate account until its disposition.

Rate Stabilization Plan
Utility RSP Surplus
December 31, 2013

	A	B	C	D
	Industrial Customer Adjustment	Utility Payout	Financing Charges	Cumulative Balance (1)
	($)	($)	($)	($)
	(from page 10)			**(to page 15)**
Opening Balance	-	-	-	-
January	-	-	-	-
February	-	-	-	-
March	-	-	-	-
April	-	-	-	-
May	-	-	-	-
June	-	-	-	-
July	-	-	-	-
August	(112,573,325)	-	-	(112,573,325)
September	0	-	(683,039)	(113,256,364)
October	0	-	(687,183)	(113,943,547)
November	0	-	(691,352)	(114,634,899)
December	0	-	(695,547)	(115,330,446)
Year to date	(112,573,325)	-	(2,757,121)	(115,330,446)
Total	(112,573,325)	-	(2,757,121)	(115,330,446)

(1) $112,573,325 has been reallocated from the Utility Customer current plan (Page 10).

Rate Stabilization Plan
Industrial RSP Surplus
December 31, 2013

	A	B	C	D	E
	Industrial Surplus	Teck Allocation [2]	Industrial Drawdown	Financing Charges	Cumulative Balance [1]
	($)	($)	($)	($)	($)
	(from page 11)		**(from page 11)**		**(to page 15)**
Opening Balance					
January	-	-	-	-	-
February	-	-	-	-	-
March	-	-	-	-	-
April	-	-	-	-	-
May	-	-	-	-	-
June	-	-	-	-	-
July	-	-	-	-	-
August	(49,000,000)	-	38,129,373	-	(10,870,627)
September	-	64,229	-	(65,958)	(10,872,356)
October	-	69,255	-	(65,968)	(10,869,069)
November	-	69,405	-	(65,948)	(10,865,611)
December	-	73,393	-	(65,927)	(10,858,146)
Year to date	(49,000,000)	276,282	38,129,373	(263,801)	(10,858,146)
Total	(49,000,000)	276,282	38,129,373	(263,801)	(10,858,146)

(1) $10,870,627 has been reallocated from the Industrial Customers current plan (Page 11).
(2) Per Board Order No. P.U. 29(2013), the RSP drawdown adjustment rate for Teck Resources is 1.111 cents per kwh effective September 1, 2013.

Rate Stabilization Plan
Overall Summary
December 31, 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	(39,204,383)	(75,028,845)	210,124	(4,753,231)	(113,943,547)	(10,869,069)	(243,588,950)
November	(42,361,454)	(70,319,724)	720,738	(6,888,345)	(114,634,899)	(10,865,611)	(244,349,295)
December	(39,801,010)	(80,173,930)	566,125	(8,200,495)	(115,330,446)	(10,858,146)	(253,797,902)

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

2013 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 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 2012. 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 2013 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 2013 financial data and 2014 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 2014 target levels have been established.

2 Overview of Key Performance Indicator Results

2.1 Performance in 2013 versus 2012

There was an improvement in hydro plant performance in all measures, although overall generation performance was affected by a major failure of Holyrood Unit 1 on January 11. The performance of gas turbines was impacted by the extended planned outages of the Hardwoods and Happy Valley Gas Turbines. In addition the Stephenville Gas Turbine was not returned to service until June after a failure in December 2011.

The underfrequency load shedding performance target was not met in 2013 with a total of seven events.

Transmission and Distribution reliability declined in 2013 from 2012. There was a major interruption on January 11 which affected the entire system. Additionally, there were a number of severe weather related events which caused outages, primarily in the Northern and Central regions late in 2013.

The operating KPI for energy conversion showed a reduction in performance for the Holyrood fuel conversion rate. Unit operating time continued to be minimized in 2013, with units placed on line only as required to support Avalon Peninsula transmission and system peak loads.

The hydraulic conversion factor at Bay d'Espoir declined slightly in 2013 from 2012. In 2013, high water levels required that the plant be operated to reduce and control the spill of water, in particular during the summer and fall months.

Hydro's 2013 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 was not measured in 2013.

2.2 Performance in 2013 versus 2013 Target

The table below summarizes Hydro's KPI performance in 2013 compared to targets set for each measure. Targets were not met for all reliability and operating measures due to a number of challenges further described in this report.

The rationale for the 2013 targets was summarized in the February 2013 report to the Board entitled *2012 Annual Report on Key Performance Indicators*. The 2013 rationale is included in this report as Appendix A.

Hydro's KPI Targets and Operating Results for 2013

Category	KPI	Units	2013 Target	2013 Results	Target Achieved
Reliability	Weighted Capability Factor (WCF)	%	84.0	75.5	No
	DAFOR	%	2.8	12.2	No
	T-SAIDI	Minutes/Point	203[1]	468.5[2]	No
	T-SAIFI	Number/Point	1.7[1]	3.5[2]	No
	T-SARI	Minutes/Outage	122[1]	133.9[2]	No
	SAIDI	Hours/Customer	5.9	18.6	No
	SAIFI	Number/Customer	3.6	5.7	No
	Underfrequency Load Shedding	# of events	6	7	No
Operating	Hydraulic CF	GWh/MCM	0.433	0.432	No
	Thermal CF	kWh/BBL	607	595	No
Financial	Controllable Unit Cost	$/MWh	Not Available	Not Available	
Other	Customer Satisfaction (Residential)	Max=100%	>90%	N/A	N/A

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

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

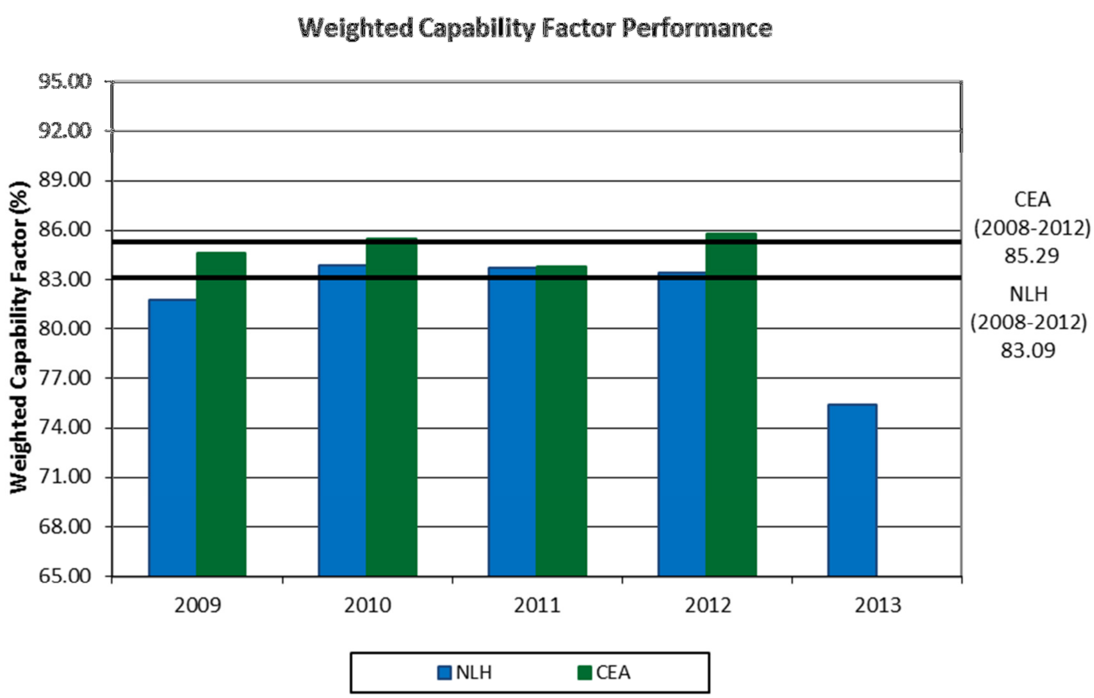
3.1 Reliability Performance Indicators

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 2013, Hydro's WCF was 75.5%. This is lower than the target of 84.0% and the 2008 to 2012 five-year average of 83.1%.



Thermal unit performance declined in 2013 to 46%, from 76% in 2012. Holyrood Unit 1 had the lowest capability factor of 22% while Holyrood Unit 2 had the highest capability factor of 72%. Unit 3 had a capability factor of 44%. On January 11, Unit 1 had a major bearing failure after the loss of lubricating oil during an unplanned shutdown. Investigation determined that the turbine and generator lubricating oil system failed to maintain sufficient oil to the bearings when the unit shut down as the result of a fault in the terminal station. Major repairs to the unit were required and the unit was release for service on October 9. Unit 3 was unavailable from May 22 to November 21 for two planned outages. These planned outages were to replace the unit's exciter and to replace the unit's protection and control panels.

Overall, the hydraulic unit performance improved slightly in 2013, to 92% compared to 91% in 2012. There were no major issues with the hydraulic generation and all units, except the Hinds Lake Unit which experienced a capability factor of 88% in 2013 due to a number of short duration planned outages.

Gas turbine performance improved to 65% in 2013 from 56% in 2012. The Stephenville unit failed in December 2011 due to a stator ground fault. This unit was release for service in June 2013. Performance of both Hardwoods and Happy Valley units was affected by planned outages of extended duration. 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 2008-2012. Hydro's hydro generation capability was better than the comparable weighted national average. The weighted average is lower for Hydro's thermal-oil fired units and gas turbines.

Capability Factory Performance			
	CEA (2008-2012)	**NLH (2008-2012)**	**Weighting Factor**
Hydro	86.19	92.22	60%
Thermal – Oil Fired	74.38	66.00	31%
Gas Turbine	90.67	70.05	9%

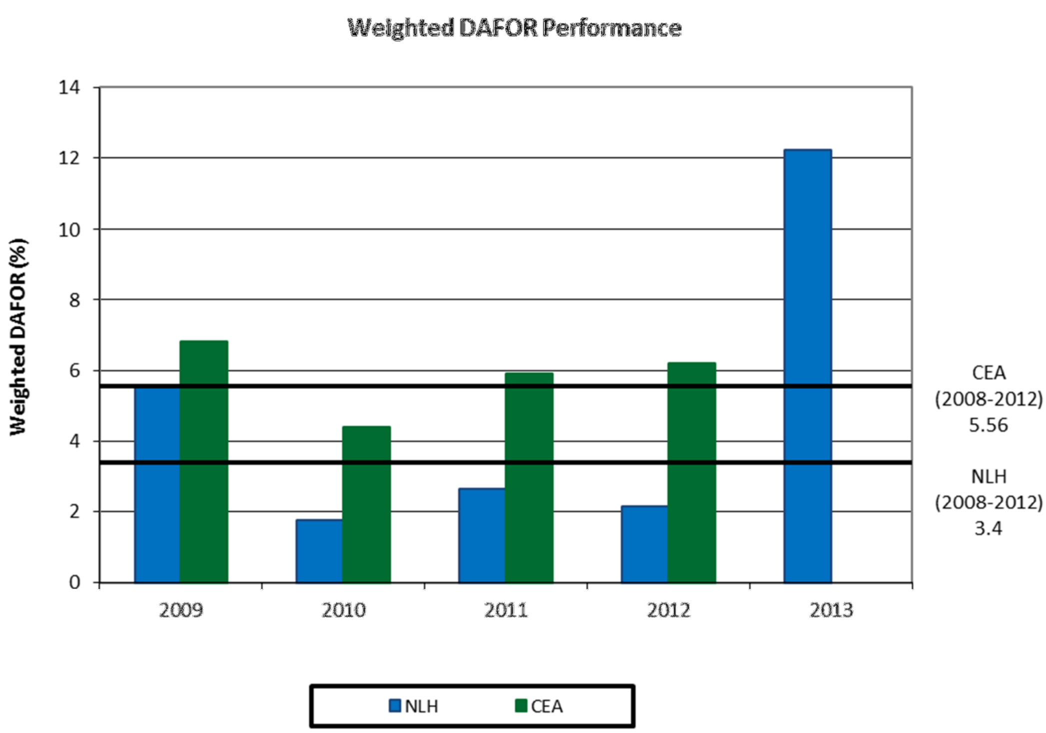
The weighted national average is developed by using national average capabilities values for the unit types in Hydro's system (hydro, oil-fired thermal and gas turbine) and applying weightings to these based upon the maximum continuous ratings of Hydro's generation. The quoted CEA value is therefore 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 2013, Hydro's weighted DAFOR was 12.2% versus a target of 2.8%. The DAFOR was impacted by the major failure of Holyrood Unit 1, as described in the previous section. There were also issues with the excitation and fuel systems on Holyrood Unit 3 which affected the DAFOR. Hydro's overall weighted DAFOR for the period 2008 to 2012 (3.4%) is better than the equivalently weighted national average for the same period (5.6%). The following table provides a 2008-2012 comparison by unit type:

DAFOR Performance

	CEA (2008-2012)	NLH (2008-2012)	Weighting Factor
Thermal – Oil Fired	9.33	9.97	34%
Hydro	3.66	1.22	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 2012 and for the latest Canadian Electricity Association national average for the period 2008-2012 are included for comparison.

Generation Performance Indices				
Index		**Hydro**	**Thermal**	**Gas Turbine**
Failure Rate	NLH 2013	1.42	8.84	144.46
(Forced Outages per 8,760	NLH 2012	1.78	8.22	231.67
operating hours)	CEA '08-'12	2.06	7.11	22.30
Incapability	NLH 2013	7.97	53.96	26.73
Factor	NLH 2012	9.26	26.92	31.28
(Percent of Time)	CEA '08-'12	9.33	25.62	13.81
Derating Adjusted Forced	NLH 2013	0.55	36.58	
Outage Rate	NLH 2012	0.95	5.98	
(Percent of Time)	CEA '08-'12	3.66	9.23	
Utilization	NLH 2013			28.07
Forced Outage	NLH 2012			56.33
Probability (Percent of Time)	CEA '08-'12			11.84

3.1.1.1 (a) Hydro Unit Performance

As indicated in the above Generation Performance Indices table, all hydro unit measures improved in 2013 when compared to 2012. In addition, all measures are better than the latest five-year national averages. Of particular note, is that 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 deteriorated in 2013 in all measures. There was a decline in 2013 in the Incapability factor and derating adjusted forced outage rate measures and performance in these areas is now worse than the national five-year average. As indicated earlier, the decline is primarily due to the failure experienced at Holyrood Unit 1 and the resultant outage.

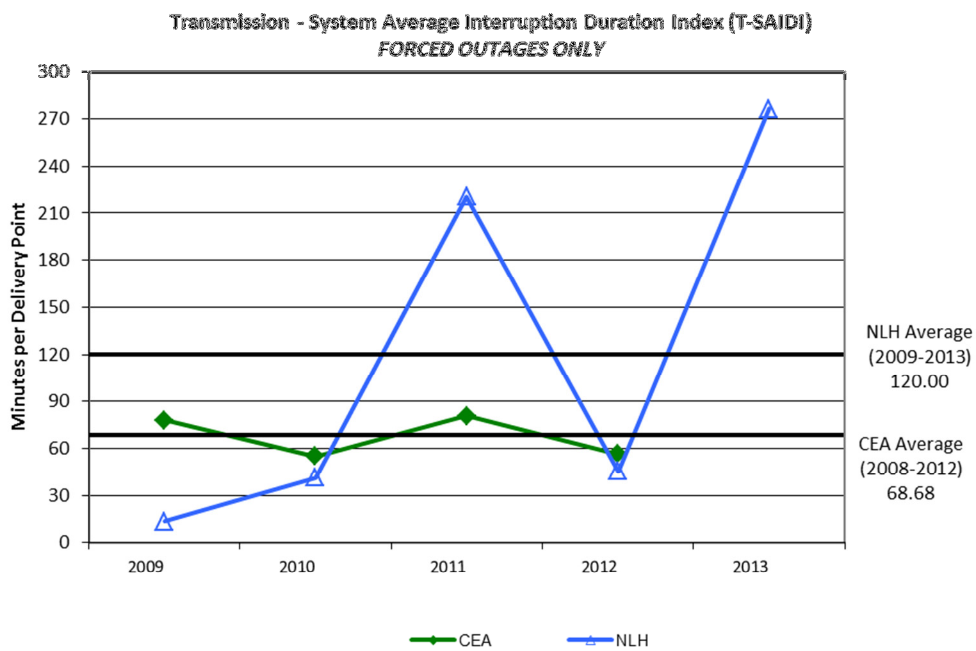
3.1.1.1 (c) Gas Turbine Unit Performance

The Generation Performance Indices table indicates that Hydro's gas turbines performance improved in 2013 from 2012 for all measures. The Stephenville unit returned to service after a 20 month forced outage. However, extended planned outage at Hardwoods and Happy Valley limited the improvements seen. All measures continue to be worse than the national average. 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.

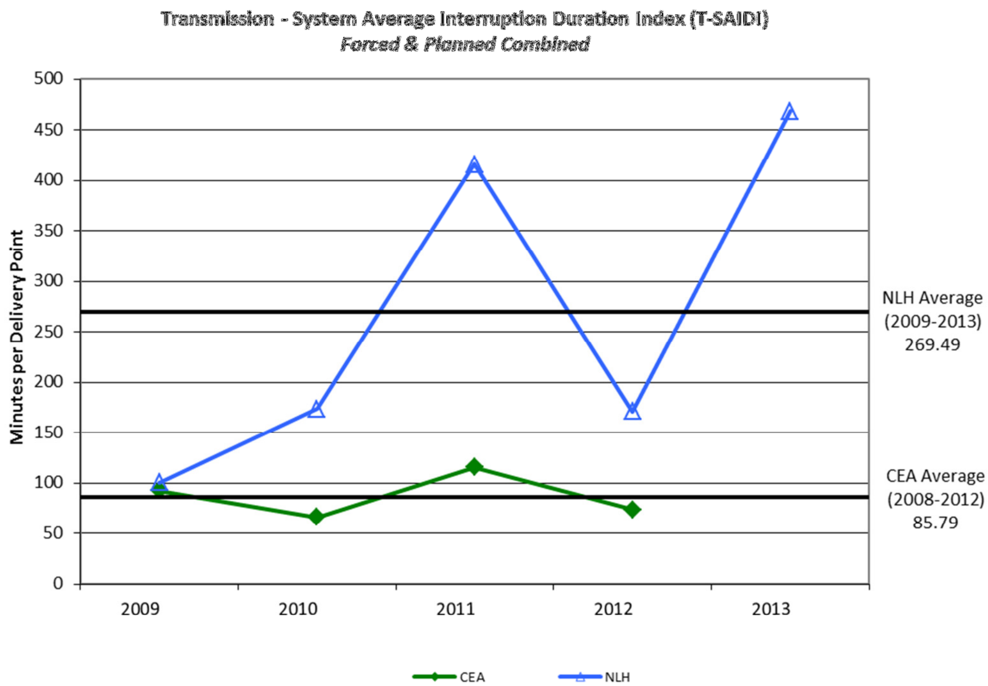
3.1.2 Reliability KPI: Transmission

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 120 minutes per delivery point (forced and planned combined). The total 2013 T-SAIDI was 469 minutes per delivery point, 131% above the 2013 target[4] of 203 minutes per delivery point. In comparison, the 2012 total was 171 minutes per delivery point. The forced outage duration in 2013 increased to 277 minutes from 46 minutes in 2012. The planned outage duration increased to 192 minutes from 125 minutes in 2013.



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



There were a number of forced outages and four planned outages in the fourth quarter. A summary of these outages follows:

Forced

On October 30, customers supplied by the Parson's Pond Terminal Station experienced an unplanned power outage of one hour and 25 minutes. The outage was caused by salt contamination on transmission line TL227 (Daniel's Harbour to Parson's Pond section). Customers were restored from the Cow Head Terminal Station via TL227 (Cow Head to Parson's Pond section).

On November 21, customers supplied by the Parson's Pond Terminal Station experienced an unplanned power outage of nine minutes. The outage was required to safely close the bypass switch on the recloser at Parson's Pond.

On November 28, all customers on the Great Northern Peninsula experienced a series of unplanned power outages. Refer to the table below for additional detail. The outages were caused by a damaged insulator and broken jumper on TL227 and a transformer lockout on T1 at Berry Hill.

Events on November 28, 2013					
Delivery Point Affected	**Start Time**	**Finish Time**	**Duration of Interruptions (mins)**	**MW Load**	**MW-Mins**
Cow Head	4:56:00	4:56:00	0	0.7	0.00
Parson's Pond	4:57:00	7:16:00	139	0.3	34.75
Daniel's Harbour	4:57:00	7:16:00	139	0.5	73.67
Hawke's Bay	4:57:00	6:13:00	76	2.7	202.92
Plum Point	4:57:00	7:19:00	142	1.6	225.78
Bear Cove	4:57:00	7:21:00	144	2.4	345.60
Main Brook	4:57:00	7:31:00	154	0.2	36.96
Roddickton	4:57:00	7:31:00	154	1.1	170.94
St. Anthony Total	4:57:00	6:52:00	115	5.1	586.50
St. Anthony Line 1	4:57:00	6:35:00	98	1.4	137.20
St. Anthony Line 2	4:57:00	6:52:00	115	1.1	126.50
St. Anthony Line 3	4:57:00	6:21:00	84	2.5	210.00
Wiltondale	5:16:00	5:19:00	3	0.1	0.30
Glenburnie	5:16:00	5:19:00	3	1.3	3.90
Rocky Harbour	5:16:00	5:19:00	3	1.9	5.70
Wiltondale	5:22:00	5:26:00	4	0.1	0.40
Glenburnie	5:22:00	5:26:00	4	1.4	5.60
Rocky Harbour	5:22:00	5:26:00	4	2.0	8.00
Hawke's Bay Line 1	6:17:00	6:34:00	17	1.1	18.70
Cow Head	4:57:00	9:15:00	258	0.6	154.80
St. Anthony Total	8:53:00	8:58:00	5	8.4	42.00
St. Anthony Line 1	8:53:00	8:57:00	4	2.1	8.40
St. Anthony Line 2	8:53:00	8:57:00	4	1.8	7.50
St. Anthony Line 3	8:53:00	8:58:00	5	3.8	19.00
Cow Head	10:17:00	16:50:00	393	1.0	393.00
Parson's Pond	10:37:00	16:39:00	362	0.4	144.80
		Totals	2,429	45.60	2,334.12

On November 21, customers supplied by the South Brook Terminal Station experienced unplanned power outages of two minutes and one minute. Both outages resulted from a trip of TL222 during a winter storm with high winds and wet snow.

There was another outage on November 21 affecting customers supplied by the South Brook Terminal Station. This was an unplanned power outage of eight hours and 50 minutes. The outage was caused by seven damaged structures in transmission line TL222; the result of a winter storm with high winds and wet snow. Customers were also impacted when the winter storm caused damage to the distribution system in South Brook.

On December 4, all customers on the Great Northern Peninsula, north of Cow Head experienced an unplanned power outage (see table below). The outages were caused by a tree contact on TL239. The following is a table summarizing the customer interruptions:

Delivery Point Affected	Start Time	Time of Restoration	Outage Duration (mins)	Load Loss (MW)	MW-Mins
Cow Head	7:36	7:44	11	1	11
Parson's Pond	7:36	7:45	9	0.5	4.5
Daniel's Harbour	7:36	7:45	9	0.5	4.5
Hawkes's Bay	7:36	7:44	8	4.3	34.4
Plum Point	7:36	7:47	11	2.3	25.3
Bear Cove	7:36	7:48	12	3.6	43.2
Main Brook	7:36	8:00	24	0.34	8.16
Roddickton	7:36	8:00	24	1.8	43.2
St Anthony	7:36	9:09	93	7.5	551.4

<u>Planned</u>

On November 3, customers supplied by the Bear Cove and Plum Point Terminal Stations experienced a planned power outage of six hours and 18 minutes. The outage was required to perform corrective and preventative maintenance on 138 kV equipment at Peter's Barren, to replace a potential transformer on C Phase on TL241 at Plum Point, to replace the TL241 potential transformer cabinet, and to perform preventative and corrective maintenance on all 138 kV equipment and switchgear at Bear Cove. Customers in Main Brook, Roddickton, and St. Anthony were supplied via the St. Anthony Diesel Plant during this outage.

On November 8, Newfoundland Power customers supplied by Springdale Terminal Station experienced a planned power outage of four hours and 39 minutes. The outage was required to remove a temporary station bypass, to commission a new breaker - B1L22, to perform preventive and corrective maintenance on disconnect switches, to doble test TL223 potential transformer, and to replace dead-end insulators in the station.

On December 18, customers supplied by the Bear Cove, Plum Point, Main Brook and Roddickton Terminal Stations experienced a planned power outage of 24 minutes. The outage was required to energize mobile substation P-235 at Hawke's Bay.

On December 19, customers supplied by the Conne River, English Harbour West, and Barachoix Terminal Stations and customers in the Bay d'Espoir distribution area experienced a planned power outage of 24 minutes. The outage was required to energize the new B13L20 circuit breaker.

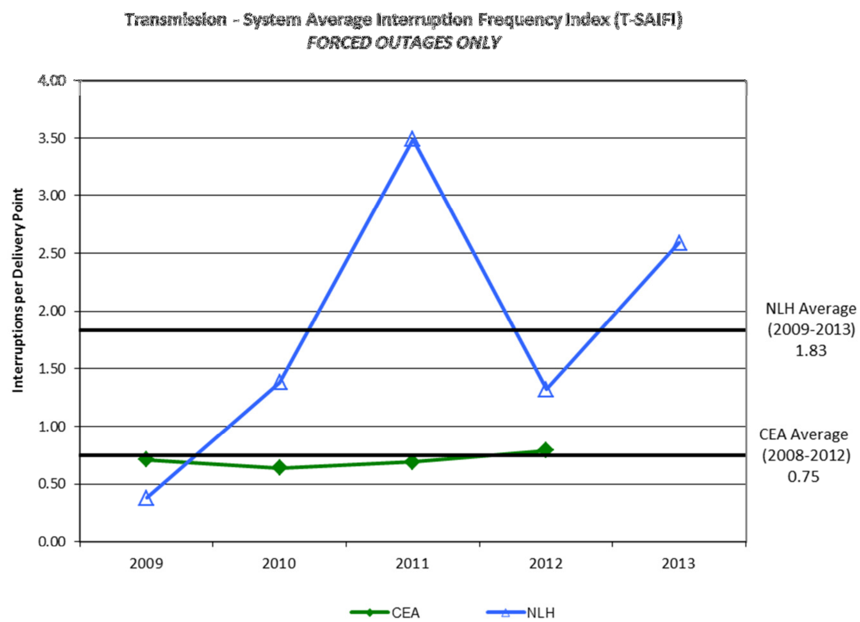
3.1.2 b) Transmission System Average Interruption Frequency Index (T-SAIFI) - *a reliability KPI for bulk transmission assets that measures the average number of sustained outages per delivery point*.

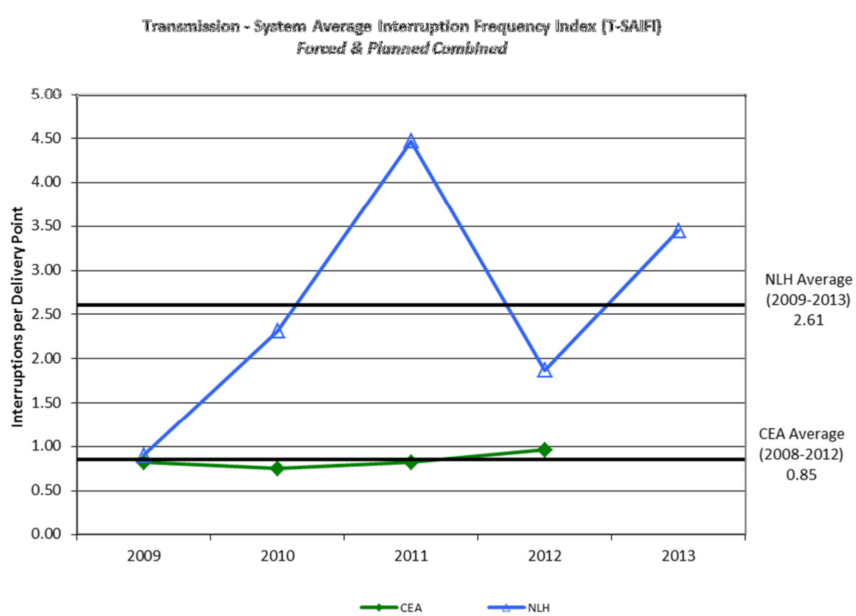
The fourth quarter T-SAIFI was 0.91 outages per bulk delivery point, with contributions of forced and planned outage frequency of 0.55 and 0.36, respectively. In comparison, the 2012 fourth quarter T-SAIFI was 0.52 outages per bulk delivery point. The increase in outage frequency was primarily the result of a higher number of planned outages this quarter.

The overall 2013 T-SAIFI was 3.45 outages per bulk delivery point which is significantly higher than last year's average of 1.91 outages per delivery point, an increase of 81%. The 2013 target was 1.66

outages per bulk delivery point and was not met. The number of forced outages per delivery point in 2013 (2.59) increased by 90% from 2012 (1.36). The number of planned outages per delivery point in 2013 (0.86) increased by 56% from 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, TL239, supplies up to nine delivery points. There are a number of other locations where a single line supplies three delivery points.



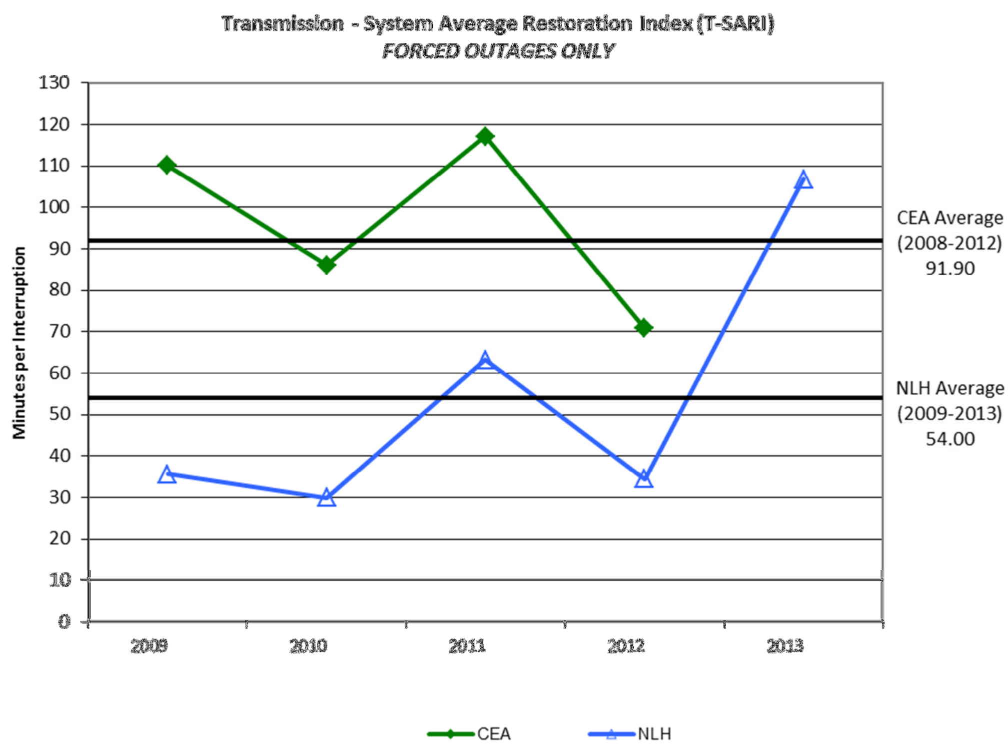


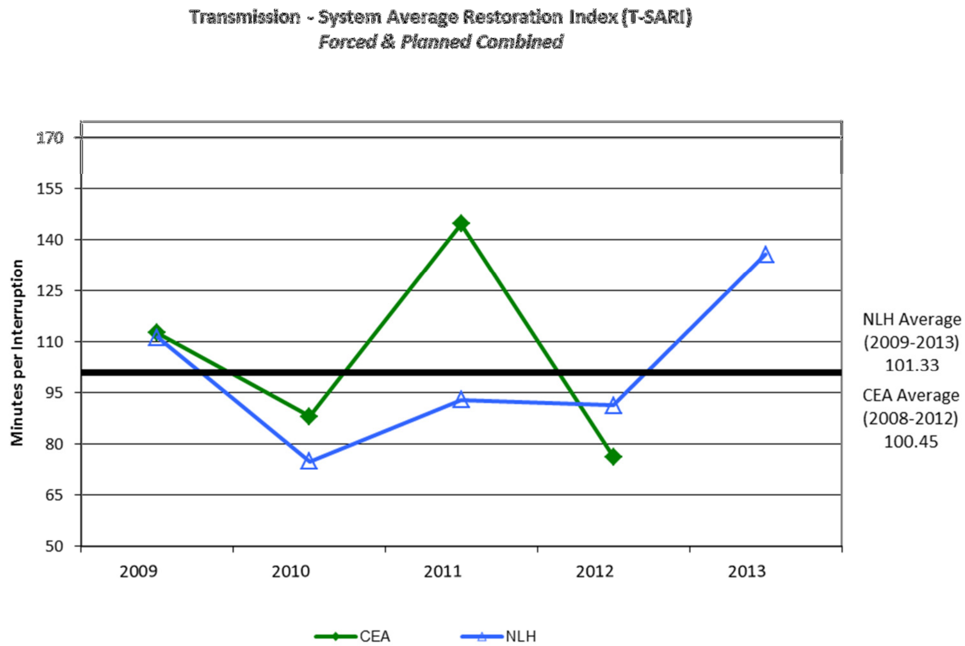
3.1.2 c) Transmission System Average Restoration Index (T-SARI) - *reliability KPI for bulk transmission assets which measures the average duration per transmission interruption. T-SARI is calculated by dividing T-SAIDI by T-SAIFI.*

Hydro's total transmission T-SARI was 131 minutes per interruption for the fourth quarter of 2013 compared to 62 minutes per interruption during the same quarter in 2012, a 111% increase. The forced outage component of T-SARI was 91 minutes per interruption compared to 41 minutes per interruption in 2012. The planned outage component of T-SARI was 192 minutes per interruption which is 4% lower than during the fourth quarter of 2012.

Hydro's 2013 total transmission T-SARI was 136 minutes per interruption, compared to 90 minutes in 2012 and a 2013 target of 123 minutes. The forced outage component of T-SARI was 107 minutes per interruption, an increase of 105% over 2012. The planned outage component of T-SARI was 223 minutes per interruption, which is an approximately the same value as 2012. 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 deteriorated in 2013 and is now below the latest five-year national average. This can be seen in the chart below.

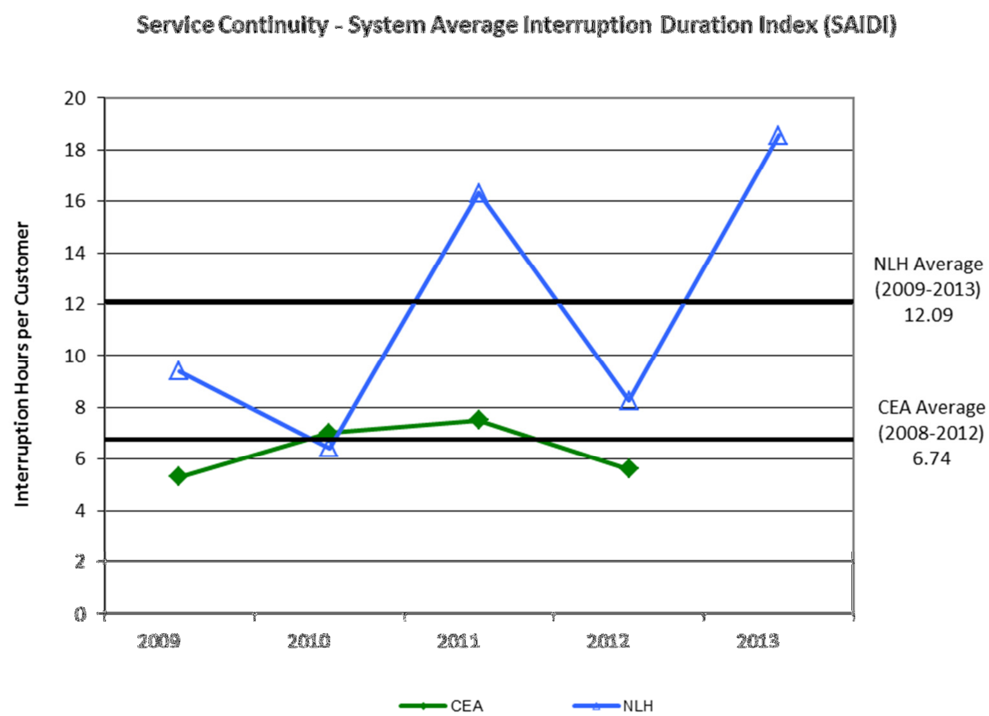



Transmission - System Average Restoration Index (T-SARI)
Forced & Planned Combined
Minutes per Interruption
170
155
140
125
110
95
80
65
50
2009
2010
2011
2012
2013
NLH Average
(2009-2013)
101.33
CEA Average
(2008-2012)
100.45
CEA
NLH

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 2013, the SAIDI was 4.35 hours per customer, compared to 3.43 hours per customer during the same quarter of 2012. The total 2013 SAIDI was 18.56 hours per customer, compared to 8.31 hours per customer in 2012. The performance in 2013 was 215% worse than the annual target of 5.90 hours per customer.



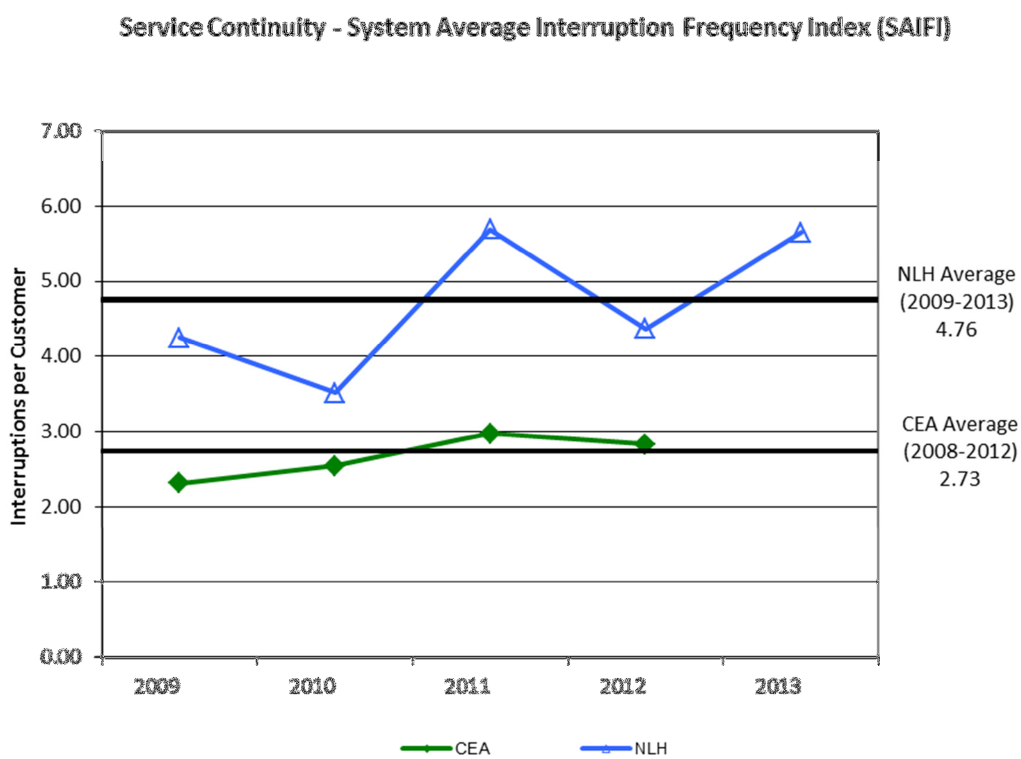
The outages during the fourth quarter resulted from a variety of causes. The following table presents a summary of the major interruptions.

Distribution System	Outage Date	Outage Cause	Customers Affected	Outage Duration (Hours)	Notes
Seal Cove Road	Nov 02, 2013	Tree Contacts	253	9.50	Trees fell on main feeder conductor. Trees had to be removed before customers could be restored
St. Anthony	Nov 18, 2013	Sched Outage-Planned	505	5.00	Planned outageto install new insulators on the main feeder line.
Bottom Waters	Nov 21, 2013	Tree Contacts	379	37.70	Tree fell on line and broke conductor
Bottom Waters	Nov 21, 2013	Adverse Weather	442	23.83	Insulator broke due to weather conditons. High winds and blowing wet snow.
Roddickton	Nov 21, 2013	Adverse Weather	554	12.38	Tree on line burnt off conductor
Kings Point	Nov 21, 2013	Tree Contacts	535	11.82	Trees fell on main feeder conductor. Trees had to be removed before customers could be restored
Glenbernie	Nov 21, 2013	Environment-Salt Spray	299	6.82	High Winds/Salt Spray
Wabush	Nov 21, 2013	Sched Outage-Planned	157	6.33	Planned outage - substation work
Parson's Pond	Nov 21, 2013	Adverse Weather	271	5.80	Recloser failed to close automatically. Workers closed the recloser locally.
St. Lewis	Nov 21, 2013	Weather-Gallop Conduc	129	5.17	Damaged insulator due to ice storm
Kings Point	Nov 21, 2013	Adverse Weather	632	3.82	Trees fell on main feeder conductor. Trees had to be removed before customers could be restored
South Brook	Nov 22, 2013	Tree Contacts	756	28.33	Trees fell on main feeder conductor. Trees had to be removed before customers could be restored
Bottom Waters	Nov 22, 2013	Adverse Weather	194	24.17	Main feeder line was damaged due to winter storm. Repairs to the line hardware were required before customer could be restored.
South Brook	Nov 22, 2013	Tree Contacts	596	23.75	Trees fell on main feeder conductor. Trees had to be removed before customers could be restored
Bottom Waters	Nov 22, 2013	Adverse Weather	194	22.33	Insulator and crossarm broken/winter storm damage
St. Anthony	Nov 23, 2013	Sched Outage-Planned	505	6.42	Install new equipment on main feeder
Wabush	Nov 24, 2013	Sched Outage-Planned	155	5.50	Planned outage - substation work
Bottom Waters	Nov 26, 2013	Adverse Environment	194	3.12	Wind broke pole at base
Wabush	Nov 29, 2013	Foreign Int-Vehicle	1455	7.58	Heavy Equipment contacted line
Farewell Head	Dec 02, 2013	Foreign Int-Vehicle	200	8.00	Truck hooked and broke main conductor/damaged pole

The remainder of the significant events in 2013 affecting 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 1.24 interruptions per customer, compared to 1.64 interruptions per customer during the same quarter of 2012, a 24% decrease. The total 2013 SAIFI was 5.65 interruptions per customer compared to 4.40 interruptions per customer in 2012, a 28% increase. The 2013 target of 3.65 interruptions per customer was not met; the performance in 2013 deteriorated from what had been an improvement in 2012.



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 2013**	**Fourth Quarter 2012**	**12 Mths to Date 2013**	**12 Mths to Date 2012**	**5 Year Average**
Central					
Interconnected	0.65	0.89	3.96	2.05	2.84
Isolated	0.01	0.85	2.85	2.68	3.49
Northern					
Interconnected	1.70	2.31	4.68	4.81	4.16
Isolated	1.44	5.03	4.80	8.65	6.20
Labrador					
Interconnected	1.42	1.10	8.41	5.44	6.64
Isolated	2.32	3.51	9.11	9.59	10.56
Total	1.24	1.64	5.65	4.40	4.76

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 2013**	**Fourth Quarter 2012**	**12 Mths to Date 2013**	**12 Mths to Date 2012**	**5 Year Average**
Central					
Interconnected	6.84	2.31	20.75	4.97	11.20
Isolated	0.05	2.13	2.55	4.93	2.94
Northern					
Interconnected	5.11	5.73	11.06	11.05	10.92
Isolated	0.94	5.36	6.07	6.89	6.27
Labrador					
Interconnected	2.06	2.17	27.95	9.28	16.27
Isolated	1.42	4.92	8.24	15.11	12.01
Total	4.35	3.43	18.56	8.31	12.09

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 2013	Fourth Quarter 2012	12 Mths to Date 2013	12 Mths to Date 2012	5 Year Average
Loss of Supply – Transmission	0.26	0.23	1.31	1.39	1.53
Loss of Supply – NF Power	0.00	0.00	0.00	0.01	0.01
Loss of Supply – Isolated	0.12	0.21	0.49	0.53	0.53
Loss of Supply – L'Anse au Loup	0.00	0.00	0.05	0.03	0.06
Distribution	0.86	1.20	3.79	2.45	2.63
Total	1.24	1.64	5.65	4.40	4.76

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 2013	Fourth Quarter 2012	12 Mths to Date 2013	12 Mths to Date 2012	5 Year Average
Loss of Supply – Transmission	0.55	0.23	4.35	1.70	3.65
Loss of Supply – NF Power	0.00	0.00	0.01	0.00	0.14
Loss of Supply – Isolated	0.04	0.10	0.21	0.34	0.24
Loss of Supply – L'Anse au Loup	0.00	0.00	0.05	0.00	0.04
Distribution	3.76	3.10	13.94	6.26	8.02
Total	4.35	3.43	18.56	8.31	12.09

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	0.06	0.15	0.59	6.69	0.65	6.84
Isolated	0.00	0.00	0.01	0.05	0.01	0.05
Northern						
Interconnected	0.12	0.60	1.58	4.50	1.70	5.11
Isolated	0.00	0.00	1.44	0.94	1.44	0.94
Labrador						
Interconnected	0.54	0.55	0.88	1.51	1.42	2.06
Isolated	0.18	0.38	2.13	1.04	2.32	1.42
Total	0.21	0.38	1.03	3.97	1.24	4.35

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.*

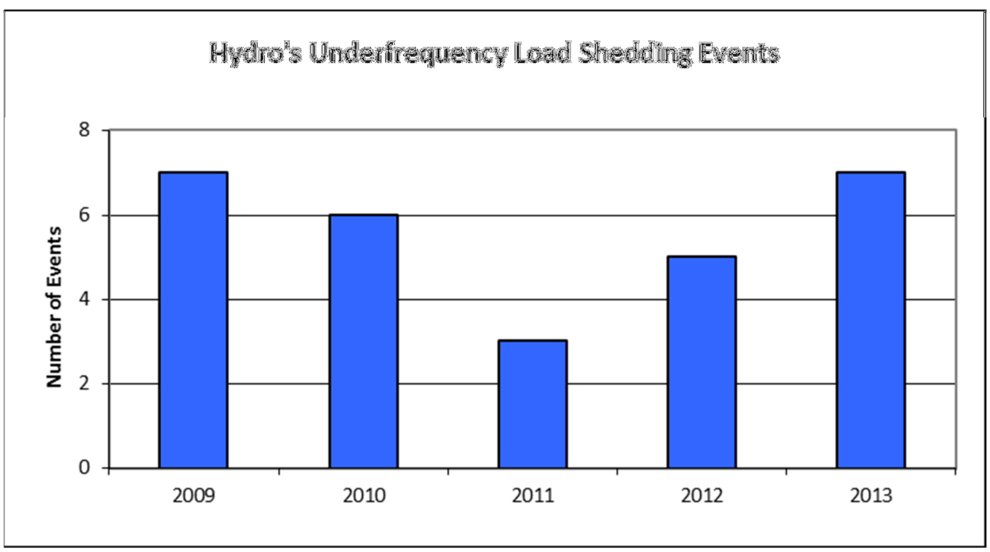
There was one underfrequency event during the fourth quarter of 2013, summarized as follows:

On November 29 at 1813 hours, Holyrood Generating Unit 1 tripped. The unit trip was the result of the main stop valve closing during daily valve testing. With the removal of generation (approximately 119 MW), the system frequency dropped to 58.78 Hz resulting in the activation of the under frequency protection at Newfoundland Power. Total system load at the time of the incident was 1,034 MW. There were 6,764 Newfoundland Power customers reported to be restored within ten minutes after the event occurred. (Unsupplied Energy: 175 MW-Mins).

Load Shed:

Newfoundland Power: 25 MW
Total Load Shed: 25 MW

In total, there were seven UFLS events in 2013. This represents two more events than the experience in 2012, and above the five-year average of 5.6 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 2013 to the same quarter in 2012.

Underfrequency Load Shedding Number of Events					
Customers	**Fourth Quarter**		**Year to Date**		**5 Year Average**
	2013	**2012**	**2013**	**2012**	**(2009–2013)**
NF Power	1	3	7	5	5.6
Industrials	0	0	0	1	1.6
Hydro Rural*	0	2	3	3	2.2
Total Events	1	3	7	5	5.6

Underfrequency Load Shedding Unsupplied Energy (MW-min)					
Customers	**Fourth Quarter**		**Year to Date**		**5 Year Average**
	2013	**2012**	**2013**	**2012**	**(2009–2013)**
NF Power	175	920	13,917	3,194	3,854
Industrials	0	0	0	140	115
Hydro Rural*	0	86	324	107	95
Total Events	175	1,006	14,241	3,440	4,064

* 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 six UFLS events in 2013 are summarized in Appendix C3.

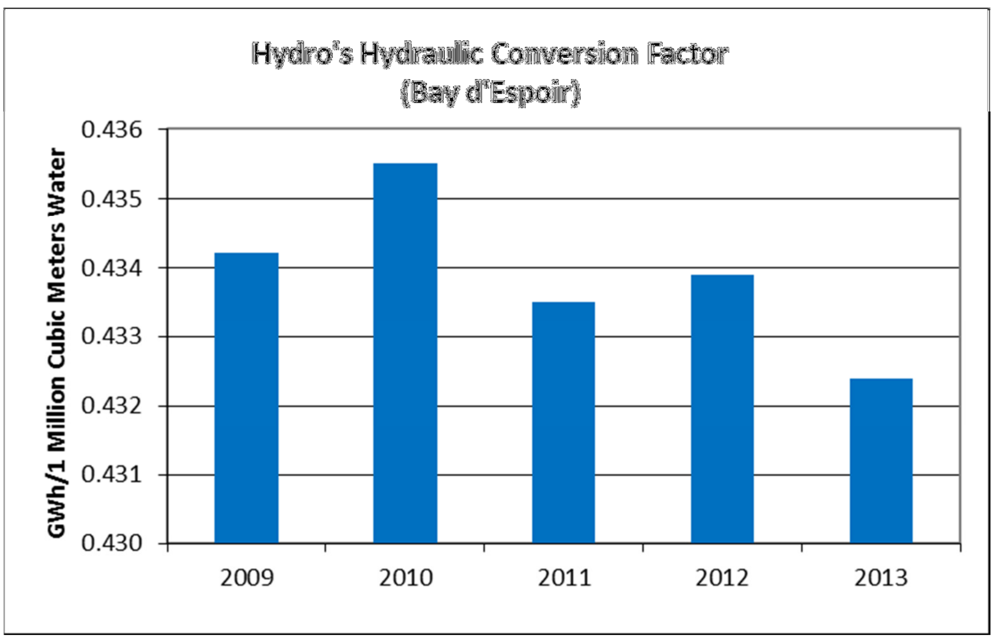
3.2 Operating Performance Indicators

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 2013, Hydro's hydraulic conversion factor for Bay d'Espoir was 0.4324 GWh/MCM. The performance in 2013 declined from 2012, primarily due to reservoir storages which were very high. This required that generation be operated at high levels in order to minimize spill or the potential for spill. The requirement to control the amount of spill resulted in less efficient operation of the hydro-electric generation.

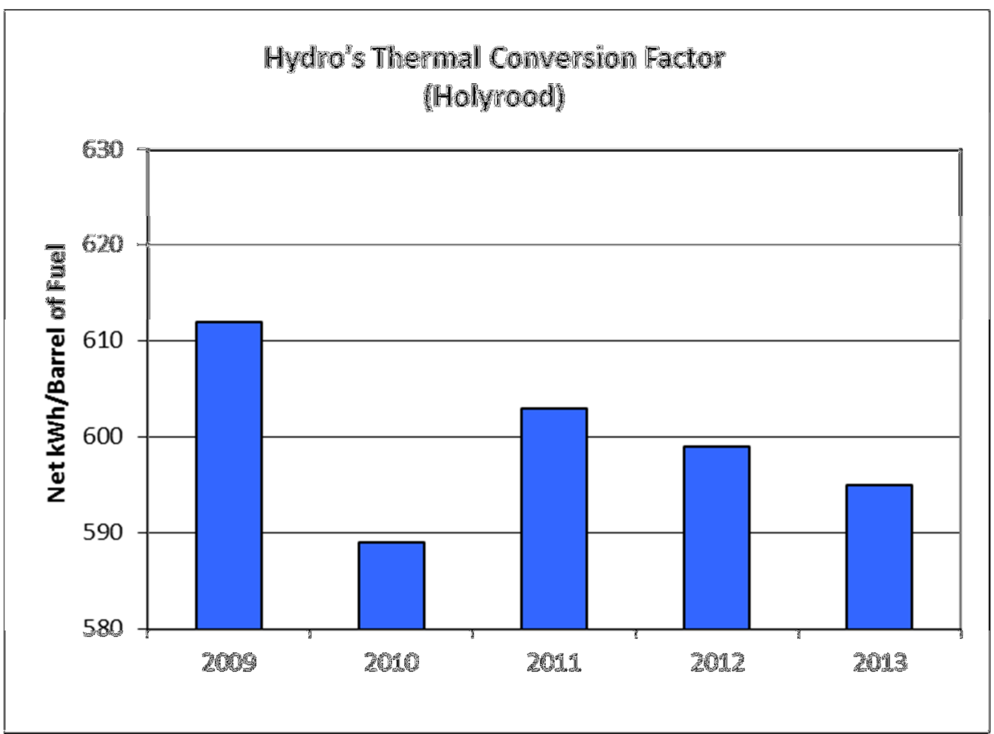


3.2.1 b) Thermal Conversion Factor - *a representative performance KPI for the oil-fired thermal generation assets located at Holyrood. This KPI tracks the efficiency in converting heavy fuel oil into electrical energy and is measured as the ratio of the net kWhs generated to the number of barrels of 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 2013, Hydro's net thermal conversion factor was 595 kWh per barrel, which is below the 2013 target of 607 kWh per barrel. The low energy conversion rate 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 2013 continued the decline which was seen in 2012 from an improvement in 2011.

Production at Holyrood was kept to a minimum in 2013 with units dispatched only as required for Avalon transmission support and system peak load considerations. The average net unit load while operating was 88 MW, up from 80 MW in 2012. Overall, net production from Holyrood for 2013 was 957 GWh, an 11.9% increase from 2012 production levels.



3.3 Financial Performance Indicators

2012 Financial results are not available at this time.

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[5].*

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.

There was no customer survey completed in 2013.

[5] 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

The 2013 financial results and 2014 targets for this table are not available at this time.

Newfoundland and Labrador Hydro
Key Performance Indicators (KPI)
Results for 2013 plus Targets/Budgets for 2014[1]

KPI	Measure Definition	Units	2009	2010	2011	2012	2013	2014T Target
Reliability								
Generation								
Weighted Capability Factor[2]	Availibility of Units for Supply	%	82.0	83.4	83.3	82.9	75.5	
Weighted DAFOR[2]	Unavailibility of Units due to Forced Outage	%	4.5	1.8	2.7	2.3	12.2	
Transmission[6,]								
T-SAIDI	Outage Duration per Delivery Point	Minutes / Point	100	173	432	171	468.5	
T-SAIFI	Number of Outages per Delivery Point	Number / Point	0.9	2.3	4.5	1.9	3.5	
T-SARI	Outage Duration per Interuption	Minutes / Outage	111	75	96	90	133.9	
Distribution								
SAIDI	Average Outage Duration for Customers	Hours / Customer	9.4	6.6	16.3	8.3	18.6	
SAIFI	Number of Outages for Customers	Number / Customer	4.3	3.5	5.7	4.4	5.7	
Under Frequency Load Shedding								
UFLS	Customer Load Interruptions Due to Generator Trip	Number of Events	7	6	3	5	7	
Operating								
Hydraulic Conversion Factor[3]	Net Generation / 1 Million m^3 Water	GWh / MCM	0.434	0.436	0.434	0.434	0.432	
Thermal Conversion Factor[4]	Net kWh / Barrel No. 6 HFO	kWh / BBL	612	589	603	599	595	
Financial (Regulated)								
Controllable Unit Cost[5]	Controllable OM&A$ / Energy Deliveries	$/MWh	$14.91	$14.25	$14.96	$14.93		
Generation Controllable Costs	Generation OM&A$ / Installed MW	$ / MW	$26,138	$25,465	$26,169	$25,131		
	Generation OM&A$ / Net Generation	$ / GWh	$8,267	$8,159	$7,833	$7,358		
Transmission Controllable Costs	Transmission OM&A$ / 230 kV Eqv Circuit Km	$ / Km	$3,870	$4,021	$4,275	$4,335		
Distribution Controllable Costs	Distribution OM&A$ / Circuit Km	$ / Km	$2,429	$2,755	$2,934	$2,960		
Other								
Percent Satisfied Customers [7] (Residential)	Satisfaction Rating	Max = 100%	91%	92%	88%	80%	N/A	

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.
7. There was no customer satisfaction survey completed for 2013.

Appendices

Appendix A: Rationale for Hydro's 2013 KPI Targets

KPI	Comment on KPI 2013 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 2013 target is set using the expected annual generation unit outage schedule combined with performance improvements relative to recent history.
Weighted DAFOR	The 2013 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 2013 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 2013 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	The 2013 target is based on November 2012 budget for 2013 Holyrood plant operation.
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 – 2013

There were eight significant events in 2013. The details follow:

Event 1

On January 11, there was a major system event affecting delivery points 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 0648 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 1500 hours. Unit 1 required a major refurbishment and repairs. It was released for service in early October.

Approximately one hour (0742 hours) following the loss of the Holyrood generating and terminal stations, 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 (0851 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.

Appendix C1: Significant Transmission Events – 2013 (Cont'd)

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	249.00	0.00	0.00
Deer Lake - NP	1/11/2013 7:43	1/11/2013 11:43	240.00	12.67	3,040.80
Port Aux Basques	1/11/2013 7:43	1/11/2013 11:20	217.00	15.74	3,415.58
Doyles	1/11/2013 7:43	1/11/2013 11:20	217.00	3.94	854.98
Grandy Brook	1/11/2013 7:43	1/11/2013 12:07	264.00	3.70	976.80
Bottom Brook - 400L	1/11/2013 7:43	1/11/2013 12:07	171.00	0.00	0.00
Stephenville	1/11/2013 7:43	1/11/2013 10:34	171.00	34.37	5,877.27
Massey Drive Bus B3 (1)	1/11/2013 7:43	1/11/2013 8:01	18.00	65.26	1,174.68
Massey Drive Bus B3 (2)	1/11/2013 8:10	1/11/2013 9:45	95.00	34.62	3,288.90
Massey Drive Bus B3 (3)	1/11/2013 7:43	1/11/2013 9:45	122.00	30.64	3,738.08
Massey Drive Bus B4	1/11/2013 7:43	1/11/2013 11:58	255.00	35.46	9,042.30
Wiltondale (1)	1/11/2013 7:43	1/11/2013 9:19	96.00	0.11	10.23
Glenburine (1)	1/11/2013 7:43	1/11/2013 9:19	96.00	2.13	204.67
Rocky Harbour (1)	1/11/2013 7:43	1/11/2013 9:19	96.00	3.09	296.77
Wiltondale (2)	1/11/2013 9:40	1/11/2013 9:47	7.00	0.05	0.36
Glenburine (2)	1/11/2013 9:40	1/11/2013 9:47	7.00	1.03	7.20
Rocky Harbour (2)	1/11/2013 9:40	1/11/2013 9:47	7.00	1.49	10.43
South Brook	1/11/2013 7:43	1/11/2013 7:48	5.00	3.79	18.95
Duck Pond Mine	1/11/2013 7:43	1/11/2013 23:59	976.00	8.57	8,364.32
St. Anthony	1/11/2013 8:01	1/11/2013 8:32	31.00	7.31	226.61
Roddickton	1/11/2013 8:01	1/11/2013 8:30	29.00	1.66	48.14
Cobb's Pond	1/11/2013 7:43	1/11/2013 9:12	89.00	60.00	5,340.00
Farewell Head	1/11/2013 7:43	1/11/2013 9:12	89.00	3.00	267.00
Glenwood	1/11/2013 7:43	1/11/2013 9:12	89.00	3.00	267.00
Grand Falls	1/11/2013 7:43	1/11/2013 10:03	140.00	60.00	8,400.00
Sunnyside - 100L	1/11/2013 7:43	1/11/2013 9:03	80.00	10.25	820.00
Sunnyside - 109L	1/11/2013 7:43	1/11/2013 9:03	80.00	11.81	944.80
Holyrood - 39L	1/11/2013 6:42	1/11/2013 6:43	1.00	0.00	0.00
Hardwoods (1)	1/11/2013 7:43	1/11/2013 8:00	17.00	159.72	2,715.24
Hardwoods (2)	1/11/2013 8:51	1/11/2013 9:14	23.00	108.09	2,486.07
Oxen Pond (1)	1/11/2013 6:48	1/11/2013 7:11	23.00	171.00	3,933.00
Oxen Pond (2)	1/11/2013 7:43	1/11/2013 8:03	20.00	115.49	2,309.80
Oxen Pond (3)	1/11/2013 8:51	1/11/2013 9:31	40.00	110.88	4,435.20
		Totals	4,020.00	967.99	72,515.19

(Unsupplied Energy: 72,515 MW-Mins)

Event 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, an investigation determined a revised design 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. (**Unsupplied Energy: 7,336 MW-Mins)**

Event 3

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 at 1304 hours. Attempts by Newfoundland Power to restore customers using generation on the Burin Peninsula failed.
(**Unsupplied Energy: 17,523 MW-Mins)**

Event 4

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	16.80
Parson's Pond	2/17/2013	16:07	16:13	5	0.6	3.20
Daniel's Harbour	2/17/2013	16:07	16:13	5	0.8	3.75
Hawke's Bay	2/17/2013	16:07	16:50	42	4.5	189.00
Plum Point	2/17/2013	16:07	16:13	5	2.3	11.50
Bear Cove	2/17/2013	16:07	16:13	5	3.5	17.50
Main Brook	2/17/2013	16:07	16:17	9	0.5	4.68
Roddickton	2/17/2013	16:07	16:17	9	1.3	11.70
St. Anthony	2/17/2013	16:07	16:17	9	7.5	67.50
Wiltondale	2/17/2013	16:24	16:32	7	0.3	2.10
Glenburine	2/17/2013	16:24	16:32	7	5.9	41.30
Rocky Harbour	2/17/2013	16:24	16:32	7	8.4	58.80
Cow Head	2/17/2013	16:24	17:04	39	1.8	70.20
Wiltondale	2/17/2013	17:53	17:54	1	0.1	0.10
Glenburine	2/17/2013	17:53	17:54	1	2.3	2.30
Rocky Harbour	2/17/2013	17:53	17:54	1	3.3	3.30
Cow Head	2/17/2013 - 2/18/2013	17:53	2:15	501	2.0	1002.00

(Unsupplied Energy: 1,506 MW-Mins)

Event 5

On March 22, customers supplied by the Conne River, English Harbour West, and Barachoix Terminal Stations experienced an unplanned power outage of four hours and 44 minutes. (284 mins). The outage occurred after transmission line TL220 was removed from service due to arcing on disconnect switch L20-1 at Conne River. The switch was repaired before TL220 was returned to service.
(**Unsupplied Energy: 2,442 MW-Mins)**

Appendix C1: Significant Transmission Events – 2013 (Cont'd)

Event 6

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.
(**Unsupplied Energy: 3,424 MW-Mins)**

Event 7

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.
(**Unsupplied Energy: 1,176 MW-Mins)**

Event 8

On November 28, all customers on the Great Northern Peninsula, experiencing a series of unplanned power outages, see the following table. The outages were caused by a damaged insulator on TL227, a broken jumper on TL227 and a transformer lockout on T1 at Berry Hill.

Appendix C1: Significant Transmission Events – 2013 (Cont'd)

Events on November 28, 2013

Delivery Point Affected	Start Time	Finish Time	Duration of Interruptions (mins)	MW Load	MW-Mins
Cow Head	4:56:00	4:56:00	0	0.7	0.00
Parson's Pond	4:57:00	7:16:00	139	0.3	34.75
Daniel's Harbour	4:57:00	7:16:00	139	0.5	73.67
Hawke's Bay	4:57:00	6:13:00	76	2.7	202.92
Plum Point	4:57:00	7:19:00	142	1.6	225.78
Bear Cove	4:57:00	7:21:00	144	2.4	345.60
Main Brook	4:57:00	7:31:00	154	0.2	36.96
Roddickton	4:57:00	7:31:00	154	1.1	170.94
St. Anthony Total	4:57:00	6:52:00	115	5.1	586.50
St. Anthony Line 1	4:57:00	6:35:00	98	1.4	137.20
St. Anthony Line 2	4:57:00	6:52:00	115	1.1	126.50
St. Anthony Line 3	4:57:00	6:21:00	84	2.5	210.00
Wiltondale	5:16:00	5:19:00	3	0.1	0.30
Glenburnie	5:16:00	5:19:00	3	1.3	3.90
Rocky Harbour	5:16:00	5:19:00	3	1.9	5.70
Wiltondale	5:22:00	5:26:00	4	0.1	0.40
Glenburnie	5:22:00	5:26:00	4	1.4	5.60
Rocky Harbour	5:22:00	5:26:00	4	2.0	8.00
Hawke's Bay Line 1	6:17:00	6:34:00	17	1.1	18.70
Cow Head	4:57:00	9:15:00	258	0.6	154.80
St. Anthony Total	8:53:00	8:58:00	5	8.4	42.00
St. Anthony Line 1	8:53:00	8:57:00	4	2.1	8.40
St. Anthony Line 2	8:53:00	8:57:00	4	1.8	7.50
St. Anthony Line 3	8:53:00	8:58:00	5	3.8	19.00
Cow Head	10:17:00	16:50:00	393	1.0	393.00
Parson's Pond	10:37:00	16:39:00	362	0.4	144.80
		Totals	2,429	45.60	2,334.12

(Unsupplied Energy: 2,334 MW-Mins)

Appendix C2: Significant Distribution Events – 2013 (Excluding Fourth Quarter)

- 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 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 1858 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 2227. The recloser tripped again at 2229, 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 2241, 2310 and at 0045 hours, the attempts resulted in trips of the station transformers (T1 and T2) and an outage to all customers (4,919) supplied by the HVGB station, of durations three, 15 and 8 minutes, respectively.

- By 0350 on March 5, Line 16 had been sectionalized and some of the customers supplied by this line were restored. At 0437 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 0513. Customers on Feeder 9 were restored at 0545 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 2100 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 0000 hours (midnight on March 23).

- On March 24, starting at 0610 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 generation requirements of the Happy Valley gas turbine for 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
Mar 24	Line 5	0630	1508	8 hrs and 38 mins	363
Mar 24	Line 6	0610	1515	9 hrs and 5 mins.	428
Mar 24	Line 17	0610	1515	9 hrs and 5 mins.	13

- Thirty customers in Mud Lake experienced an additional unplanned outage at 1515 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 1630 hours.

- On April 6, beginning at 0845 hours, all customers (1,541) on Fogo Island experienced a series of lengthy unplanned power outages. All customers were restored by 1100 hours on April 07. 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 customers (1,048) 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 customers (841) 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 45 minutes
  Line 6: six hours 50 minutes
  Line 7: six hours 15 minutes

- On April 25, at 1800 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 1920 hours.

- On May 14, all customers (1,606) 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.

- On July 2, all customers (31) 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 customers (282) 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 customers (97) 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 customers (265) 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 shut down 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 customers (5,630) 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.

Appendix C3: Underfrequency Load Shedding Events (Excluding Fourth Quarter)

- On January 16, Holyrood Generating Unit 3 tripped. The cause of the trip was a result of a vacuum trip alarm. It is suspected the alarm was falsely initiated via a faulty relay or a trip switch. The suspected relay has since been replaced and the trip switches have been calibrated and tested. 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 (Unsupplied Energy: 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 0300 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 (Unsupplied Energy: 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 1354 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 (Unsupplied Energy: 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 0005 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 (Unsupplied Energy: 220 MW-Mins).

- On April 16 at 1135 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 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 twenty two minutes after the event occurred. (Unsupplied Energy: 385 MW-Mins) There were 1,281 Hydro customers restored within three minutes after the event occurred. (Unsupplied Energy: 15 MW-Mins)

Appendix C3: Underfrequency Load Shedding Events (Excluding Fourth Quarter) (cont'd)

- On April 17 at 0700 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 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 twenty-nine minutes after the event occurred. (Unsupplied Energy: 11,792 MW-Mins) Customers were restored in blocks as generation became available to the system. There were 6,662 Hydro customers restored within forty minutes after the event occurred. (Unsupplied Energy: 288 MW-Mins)

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, 2014

Newfoundland and Labrador Hydro

newfoundland labrador hydro
a nalcor energy company

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1 HIGHLIGHTS

HIGHLIGHTS
For the three months ended March 31, 2014

REGULATED	2014 Actual YTD	2014 Target/ Budget	2013 Actual
Safety			
Lead:Lag Ratio[1]	656:1	600:1	458:1
All Injury Frequency Rate[1]	0.49	$\leq$0.8	1.04
Production			
Quarter End Reservoir Storage (GWh)	1,831	196	1,831
Hydraulic Production (GWh)	1,462	1,492	1,462
Holyrood Fuel cost per barrel, current month ($) [2]	115	55	111
Holyrood Efficiency [2]	593	630	606
Electricity Delivery			
Sales including Wheeling (GWh)	2,556.6	2,479.2	2,327.7
Financial[3]			
Revenue ($millions)	185.9	209.1	166.1
Expenses ($millions)	191.8	199.0	157.6
Net Operating Income ($millions)[4]	(5.9)	10.1	8.5
Current Rate Stabilization Plan (RSP) Balance ($millions)	(252.1)	(220.1)	(224.4)
Hydraulic	(68.6)	(45.7)	(53.4)
Utility	(43.4)	(52.2)	(61.5)
Industrial	3.6	0.7	(109.5)
Segregated Load	(15.4)	3.4	-
Utility Surplus	(117.4)	(117.5)	-
Industrial Surplus	(10.9)	(8.8)	-
Full Time Equivalent (FTE) Employees[5, 6]			
Regulated	780.0	875.7	778.4
Non-Regulated	67.1	81.1	31.5

[1] Annual Target, and 2013 Actual
[2] Target based on approved 2007 Test Year forecast
[3] The Regulated Hydro 2014 budget reflects proposed new customer rates effective January 1, 2014 based on General Rate Application evidence filed July 2013.
[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 2014 Budget and 2013 Actual values

- Review into Supply Disruptions of January 2 – 8, 2014 Released to the PUB (page 19)
- Hydro Sponsors JUMPFest 2014 (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 safety leader.

Measurement	Year-to-date 2014 Actual	Annual 2014 Plan	Annual 2013 Actual
All Injury Frequency (AIF)	0.49	≤0.8	1.16
Lost Time Injury Frequency (LTIF)	0.00	≤0.15	0.39[1]
Ratio of condition and incident reports to lost time and medical treatment injuries (lead/lag ratio)	656:1	600:1	404:1
Planned Grounding and Bonding Activities	In progress	100%	100%
Complete Work Method Activities for Critical Tasks	In progress	100%	96%

[1] Due to change in medical condition, a 2013 Medical Treatment was reclassified as a Lost Time. As per injury reporting criteria, the year end statistics for 2013 therefore were adjusted to reflect the change.

During the first quarter of 2014, Hydro finalized planned safety objectives for the year.

The Corporate Injury Prevention Campaign continued, focusing on the company's top three injury trends; slips, trips and falls, strains and sprains, and hand-related injuries. 2014 will also incorporate new workers and driving-related safety into the campaign.

Hydro will continue its focus in the areas of Grounding and Bonding, Work Methods and Work Protection Code. The Corporate Grounding and Bonding Committee will focus on a corporate standard and training package for plants and stations. Work Methods for critical tasks will continue, with a focus on ensuring methods for critical tasks completed in 2014 are field verified. The Work Protection Code program will continue with a focus on program auditing and implementing opportunities for improvement.

Field visibility of the Management and Safety Professionals continues to increase in all areas and will continue to be a focus in 2014.

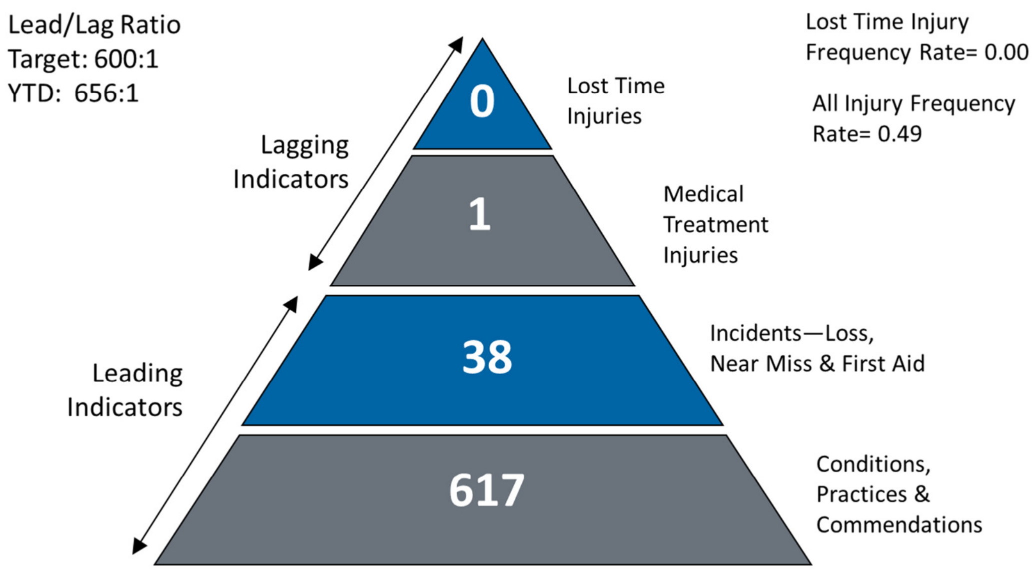
The public safety campaign around Power Line Hazards is ongoing, internally and externally. Hydro continues to partner with the Public Contact Work Group, with an increased focus on sharing of information among members. Utilization of media and increased communication to equipment operators will also be a focus for this group in 2014. Internally Hydro's Line Worker Focus Group will continue.

In 2014 Hydro's vision for safety is unchanged as we strive for world class safety performance, an entrenched safety culture in which all employees share a zero harm mindset; embrace Hydro's Safety

Credo and demonstrate personal ownership for their own safety and the safety of others; coach others for safe behaviors and see safety excellence as a source of organizational pride.

Hydro's Framework for Safety Excellence remains intact. We have a balanced focus on culture/behaviors vs. processes; continued focus on injury prevention awareness such as Slips/Trips/Falls, Hand/Tool Related Injuries and Sprains and Strains; a new focus on Driving Safety; and sustaining and improving on the positive change in safety performance demonstrated in 2013.

The following safety triangle summarizes Hydro's year-to-date performance for 2014.



2.1 Power Line Safety a Hot Topic for Construction Workers

Brian Lannon, Safety Specialist, stands in front of Hydro's booth

Hydro was proud to sponsor the 2014 Newfoundland and Labrador Construction Safety Association Conference held on March 4 at the Sheraton in St. John's. Hydro representatives participated in a booth at the trade show portion of the conference, featuring information on Hydro's efforts to advance and promote power line safety among construction workers in this province. Paul Smith, Manager, Safety, Health and Environment in Bishop's Falls delivered a presentation during the luncheon demonstrating, with specific examples, the serious dangers of working around power lines and the critical importance of knowing and being able to recognize the hazards.

2.2 Line Worker Apprentices attend Safety Meeting

On March 7, a safety meeting was held in Grand Falls-Windsor, with over 21 of Hydro's line worker apprentices. They were joined by Work Execution supervisors, as well as safety and health team members from across the company. Organized by Transmission and Rural Operations, the session provided an excellent opportunity for the group to openly discuss line worker safety. The meeting also provided an opportunity to review some recent safety incidents and to discuss the various lessons learned.

Line worker apprentices at the safety meeting in Grand Falls-Windsor

3 ENVIRONMENT AND CONSERVATION

Goal - To be an Environmental Leader

Hydro recognizes its commitment and responsibility to protect the environment.

Measurement	Year-to-date 2014 Actual	Annual 2014 Target	Annual 2013 Actual
Variance from ideal production schedule at Holyrood Thermal Generating Station	7.7%	≤ 10.0%	10.4%
Achievement of EMS targets[1]	7%	≥ 95%	95%
Annual energy savings from Residential and Commercial Conservation and Demand Management Programs	97 MWh	1,056 MWh	2,058 MWh
Conduct evaluation of Industrial Energy Efficiency Program (IEEP) and develop multi-year plan	Evaluation completed	Complete evaluation and plan for programming	Scope completed
Annual energy savings from Internal Energy Efficiency Programs	0	350 MWh	851 MWh

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

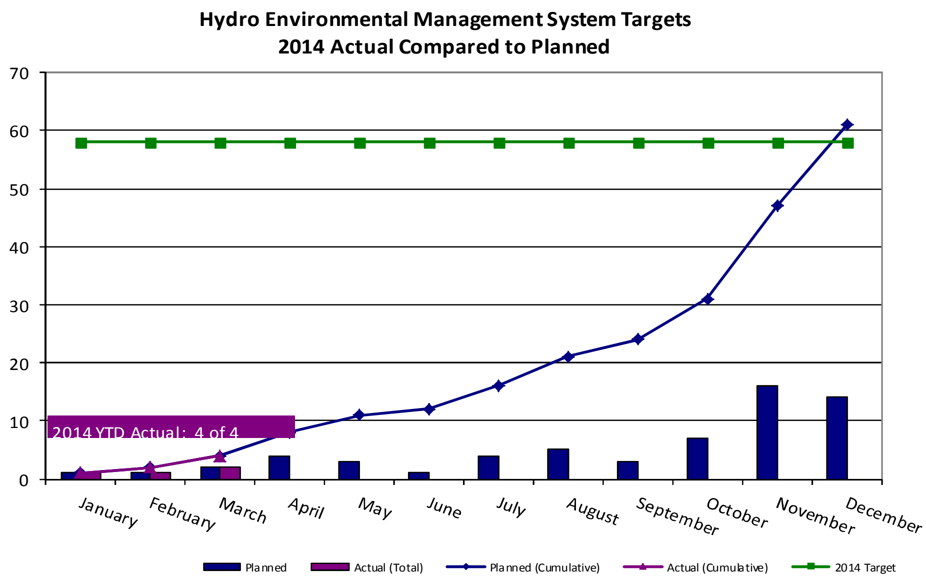
The following table demonstrates the year to date variance from ideal production schedule.

Minimum Hours

2014	Variance[1]		Ideal		Variance	
Month	Unit-Hours	Cumulative	Unit-Hours	Cumulative	Percent	Cumulative
January	312	312	2,088	2,088	14.9%	14.9%
February	71	383	2,016	4,104	3.5%	9.3%
March	96	479	2,136	6,240	4.5%	7.7%

[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.

The following table demonstrates the year-to-date variance from ideal production schedule.



Work continues with the Residential and Commercial Conservation and Demand Management (CDM) Programs to gain CDM savings.

Outreach for both residential and commercial programs has expanded to include presentations with community leaders including municipalities, Chambers of Commerce and others to engage community influencers in the discussion and promotion of energy efficiency and the takeCHARGE programs. These presentations have been well received and provide a good opportunity to move beyond mass marketing messages. They include information on the benefits of conservation as well as the types and amounts of support that Hydro is providing customers in managing their electricity bills.

The Isolated System Business Efficiency Program (ISBEP) has been in market since 2012 and has seen successful projects completed and the addition of the joint utility Business Efficiency Program (BEP) in November 2013 is now seeing activity with projects being explored for a number of customers in the education, retail and hospitality sector.

Planning is underway for the implementation of the third year of the Isolated Community Energy Efficiency program which will include direct install of lighting technologies in residential homes as well as exploration of new strategies for possible retail promotions of efficient technologies in rural and remote locations.

The evaluation of the Industrial Energy Efficiency Program has been completed by CLEAResult and is now being reviewed by the Energy Efficiency Department to determine the next steps forward in offering energy efficiency programming to Industrial Customers.

As in past years, internal energy efficiency projects have been identified in TRO regions and included in the EMS program to ensure tracking and completion. These projects and their associated milestones have been developed with the engagement of the Internal Energy Efficiency Advisor who will be a continued support in their completion.

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 2014 Actual	Annual 2014 Target	Annual 2013 Actual
Asset Management and Reliability			
Contingency Reserve[1]	92.6%	≥99.5%	97.5%
Asset Management Strategy Execution	Progressing as planned	Implement Plan	Completed as planned for 2013
Financial Targets			
Annual Controllable Costs	$31.7 million	$116.8 million (Budget)	$111.8 million
Net (Loss) Income	($5.9 million)	$28.8 million	$0.2 million
Project Execution			
Completion rate of capital projects by year end[2]	N/A	≥90%	82%
All-project variance from original budget[2]	N/A	8%	27%
Customer Service			
Customer Service Improvement Plan	N/A	Draft under review	Draft completed

[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

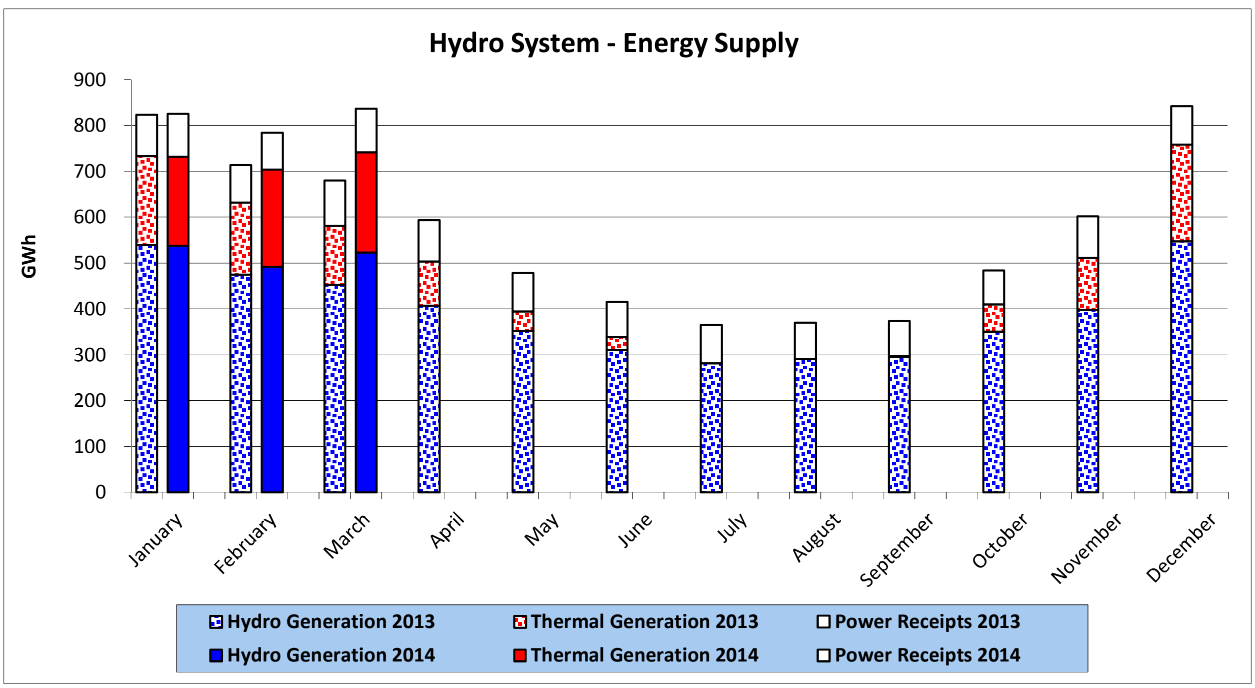
4.1.1 Energy Supply - Island Interconnected System

Energy requirements from the Holyrood Thermal Generating Station were significantly higher during the first quarter of 2014 when compared to the same period in 2013 (131.2 GWh or 29.2%). This was due to higher customer demand requirements on the system resulting from the colder temperatures. All three units at Holyrood were required to operate throughout the period.

Hydroelectric production for the first quarter of 2014 was 86.2 GWh or 5.9% above the levels in 2013, primarily due to the increased system load requirements and a slight decrease in overall energy purchases. Total energy purchases were down by 4.2 GWh or 1.5% in the first quarter of 2014 when compared to 2013. This decrease was primarily due to decreased generation by Exploits and the CBPP co-generation unit. The Exploits generation at Grand Falls experienced frazil ice issues late in 2013 which affected production through to the first half of January 2014. The decrease in energy purchases was partially offset by an increase in production at the St. Lawrence wind farm and increased energy receipts from CBPP's generation at Deer Lake Power.

During the period of January 2-8, 2014, Hydro experienced generation supply issues on the Island Interconnected System which resulted in a requirement for feeder interruptions, impacting both Hydro and Newfoundland Power customers. In addition, on January 4 and 5, there were widespread power outages resulting from 230 kV terminal station issues at Sunnyside and Holyrood. Hydro completed a comprehensive review of these events and filed its report with the Board near the end of the first quarter.

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



Hydro System Produced and Purchased
For the Quarter ended March 31, 2014

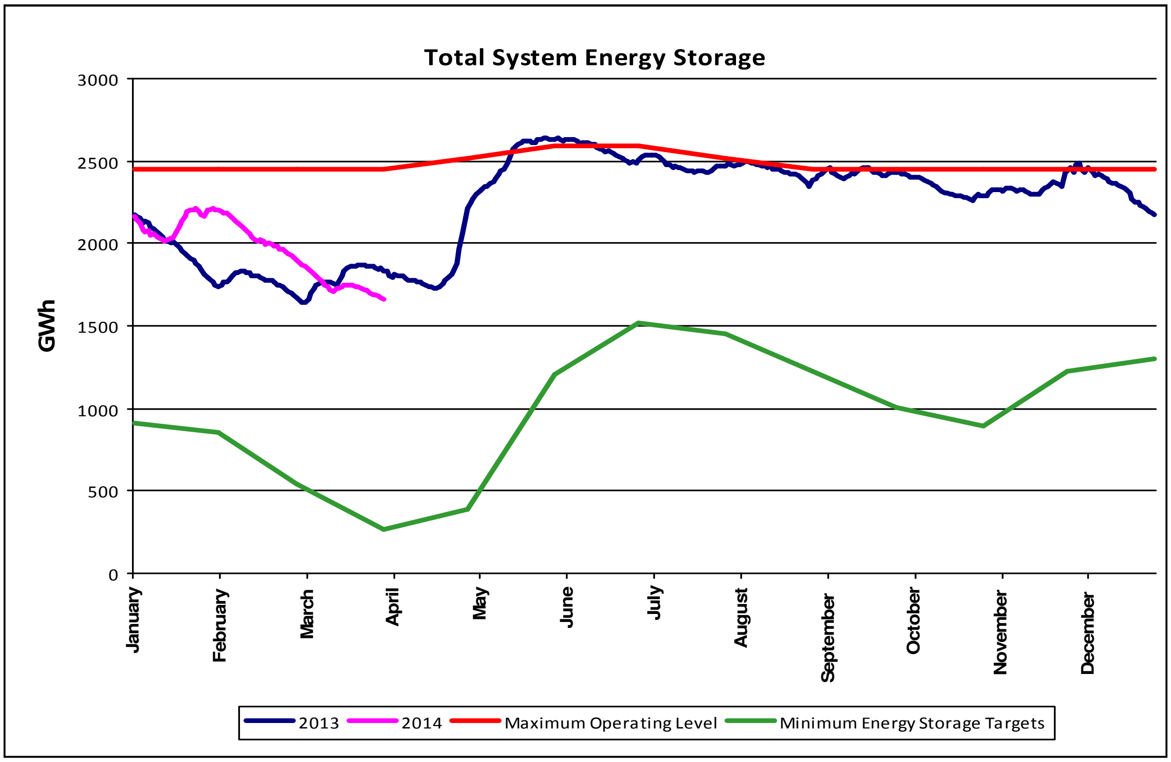
	Year-to-date			2014 Annual Forecast (GWh)	2014 ($000)
	2014 (GWh)	2013 (GWh)	2014 Forecast (GWh)		
Production (net)					
Hydro	1,548.3	1,462.1	1,439.2	4,580.2	N/A
Thermal	580.5	449.3	600.3	1,428.9	N/A
Gas Turbines	(1.0)	0.6	0.6	2.4	N/A
Diesels	2.0	0.8	0.1	0.4	N/A
Total Production	**2,129.8**	**1,912.8**	**2,040.2**	**6,011.9**	N/A
Energy Purchases					
Non Utility Generators					
Rattle Brook	1.2	2.8	1.9	15.0	**119.1**
Corner Brook Pulp and Paper Co-generation	13.1	16.4	15.4	51.4	**2,601.5**
St. Lawrence Wind					
Fermeuse Wind	25.3	27.6	26.6	84.4	**1,942.1**
Total Non Utility Generators	**69.6**	**69.2**	**76.9**	**255.6**	**6,805.7**
Secondary and Others					
Deer Lake Power	10.6	1.9	0.0	0.0	-
Hydro Request for NP Standby	3.3	0.8	0.0	0.0	**545.0**
Nalcor Energy[1]	183.7	199.5	191.7	770.3	
Total Secondary and Other	**197.6**	**202.2**	**191.7**	**770.3**	**545.0**
Total Purchases	**267.2**	**271.4**	**268.6**	**1,025.9**	
Hydro System Produced and Purchased	**2,397.0**	**2,184.2**	**2,308.8**	**7,037.8**	

[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 2014. Inflows into the aggregate reservoir system during the first three months were above average at 127%. There was a mild period with rain experienced during the second week of January which resulted in melting snow and increased inflows. Hydro conducted winter snow surveys in February and March. The result of the latter survey indicates that the snow pack water equivalent, over the aggregate reservoir system, is 85% of the 30 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 91% of the maximum operating level (MOL).

Reservoir levels at the end of the quarter were at 73% of the MOL and this compares with 79% of the MOL at the end of the first quarter in 2013. At the end of the quarter, reservoir levels were in excess of six times the minimum storage target.



System Hydrology Storage Levels			
	2014 (GWh)	2014 Minimum Target (GWh)	2013 (GWh)
Quarter End Storage Levels	1,662	262	1,831

4.1.3 Energy Supply – Labrador Interconnected System

The purchased and produced energy on the Labrador Interconnected System increased during the first quarter of 2014 (38.2 GWh or 13.0%) when compared to 2013. This is due to higher Hydro Rural requirements in Labrador East and West, owing to the colder temperatures and increased customer demand. The overall increase has been partially offset by lower industrial sales at the Iron Ore Company of Canada (IOCC).

Labrador Interconnected System Produced and Purchased
For the Quarter ended March 31, 2014

	Year-to-date			2014 Annual Forecast (GWh)
	2014 (GWh)	2013 (GWh)	2014 Forecast (GWh)	
Production (net)				
Gas Turbines	(0.4)	(0.6)	0.2	0.6
Diesels	0.0	0.0	0.1	0.2
Total Production	**(0.4)**	**(0.6)**	**0.3**	**0.8**
Purchases				
CF(L)Co for Labrador (at border)	**333.0**	**295.0**	**387.3**	**1,069.5**
Labrador Interconnected Total Produced and Purchased	**332.6**	**294.4**	**387.6**	**1,070.3**

4.1.4 Fuel Prices

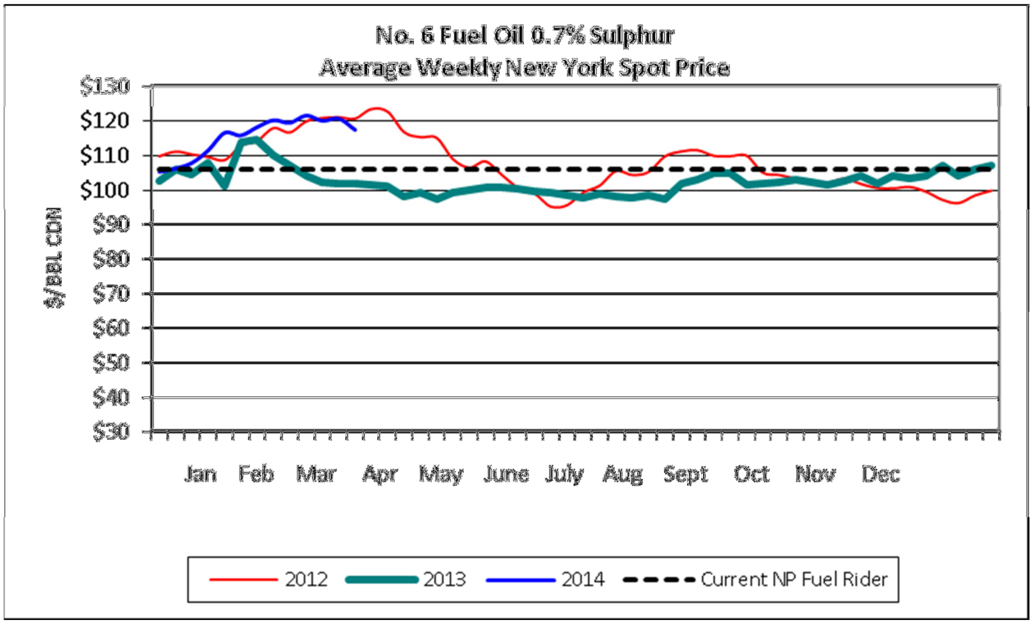
The fuel market prices for No. 6 fuel increased from approximately $107/bbl. at the beginning of the year to $114/bbl. at the end of the quarter. The quarter ending inventory cost was $116.18/bbl., in comparison with the current Newfoundland Power fuel price rider of $105.80/bbl. There is no Industrial Customer fuel price rider for 2014.

There were five shipments received during the first quarter of 2014:

January 9	214,181 bbls	$110.26
January 14	230,553 bbls	$112.71
January 28	216,367 bbls	$112.87
February 10	202,106 bbls	$118.69
March 12	202,886 bbls	$120.93

The inventory on March 31 was 381,765 barrels.

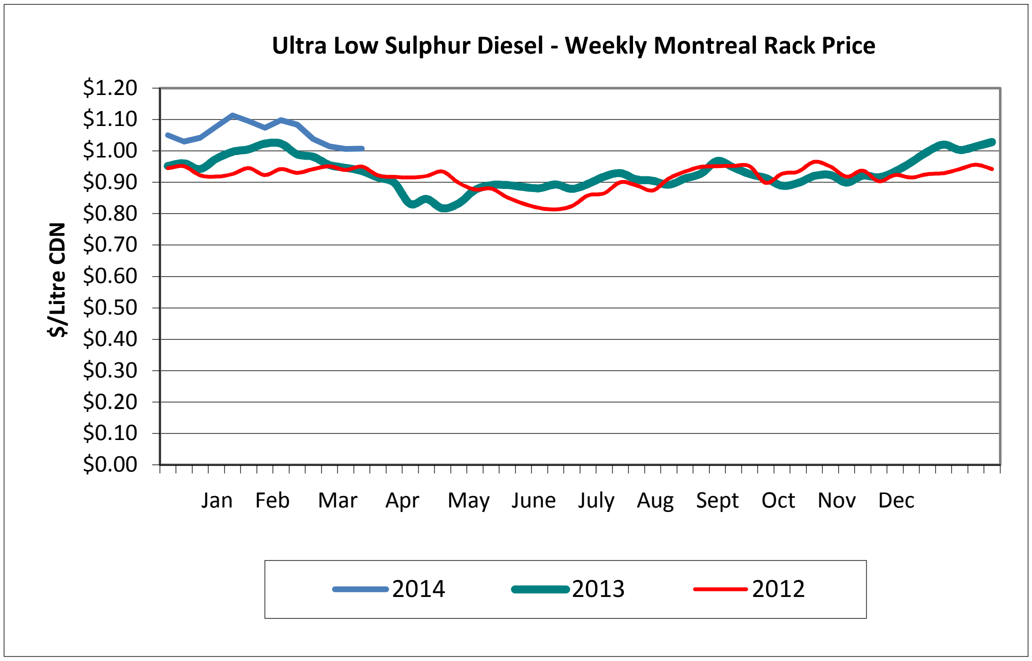
The following chart shows the No. 6 fuel prices year-to-date compared to 2012 and 2013, and the Newfoundland Power fuel rider price of $105.80/bbl.



The following table provides the monthly forecast price of No. 6 fuel (0.7% sulphur) up to March 2015, landed on the Avalon Peninsula.

No. 6 Fuel Oil Sulphur Forecast Price April 2014 –March 2015			
Month	**Price ($Cdn/bbl) 0.7%**	**Month**	**Price ($Cdn/bbl) 0.7%**
April 2014	112.10	October 2014	109.60
May 2014	112.50	November 2014	106.60
June 2014	114.40	December 2014	103.40
July 2014	117.10	January 2015	103.30
August 2014	118.80	February 2015	101.60
September 2014	116.60	March 2015	100.80
Note: The forecast is based on the PIRA Energy Group price forecast available March 25, 2014 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 2012 and 2013.



4.1.5 Energy Supply - Isolated Systems

Total isolated energy supply increased by 12% in the first quarter of 2014 over the first quarter of 2013 with the increase primarily attributed to colder weather in 2014 when compared to 2013. Net diesel production was 17% higher and energy purchases were 4% higher when comparing 2014 to 2013.

The average cost of power purchased from Hydro Québec, based on Montreal rack fuel prices has increased from $143 per megawatt hour in the first quarter of 2013 to $154 per megawatt hour in 2014. The average cost of power from the combined Non Utility Generators (NUGS) facilities in Ramea, based on current diesel fuel prices, has increased from $300 per megawatt hour in the first quarter of 2013 to $321 per megawatt hour in 2014.

Isolated Systems Produced and Purchased
For Quarter ended March 31, 2014

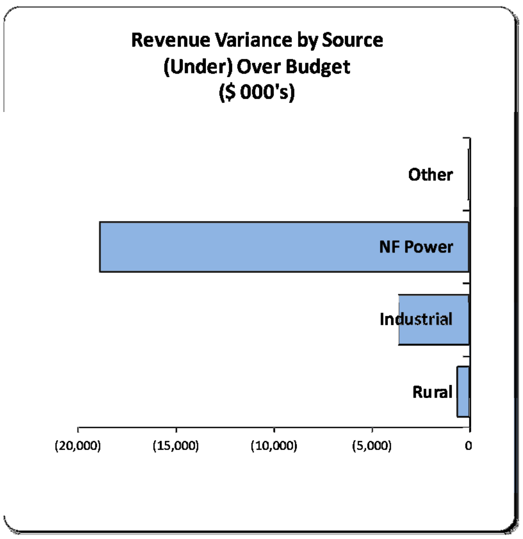
	Year-to-date						2014 Annual Forecast	
	2014		2013		2014 Forecast		(GWh)	$(000)[1]
	(GWh)	$(000)[1]	(GWh)	$(000)[1]	(GWh)	$(000)[1]		
Production (net)								
Diesels	15.0		12.8		13.8		52.7	
Purchases								
Non Utility Generators (NUGS)[2]	0.3	104.8	0.4	109.1	0.3	97.0	0.7	211.6
Hydro Québec	7.6	1171.3	7.2	1038.4	7.1	1011.3	23.2	3169.6
Total Purchases	**7.9**	**1276.1**	**7.6**	**1147.5**	**7.4**	**1108.3**	**23.9**	**3381.2**
Isolated Systems Total Produced and Purchased	**22.9**		**20.4**		**21.2**		**76.6**	

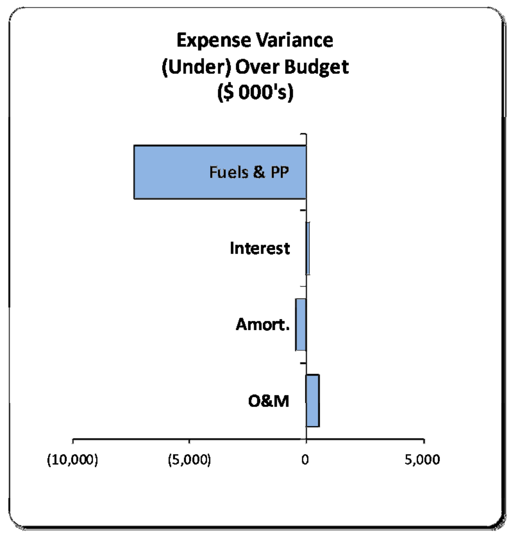
[1] Purchases before taxes.
[2] NUGS includes Frontier Power and Nalcor's wind/hydrogen facility in Ramea.

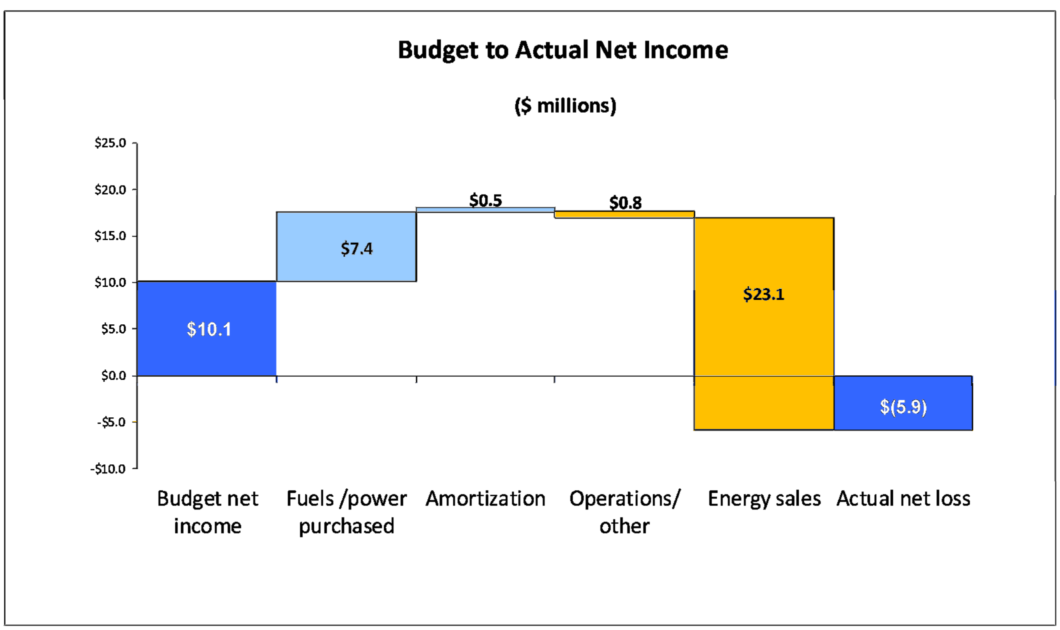
4.2 Financial

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, 2014







Statement of Income - Regulated Operations
For the three months ended March 31, 2014
($000)

First Quarter 2014 Actual	First Quarter 2014 Budget	First Quarter 2013 Actual		Year-to-date 2014 Actual	Year-to-date 2014 Budget	Year-to-date 2013 Actual	2014 Annual Budget
			Revenue				
185,424	208,520	165,503	Energy sales	185,424	208,520	165,503	598,039
495	580	634	Other revenue	495	580	634	2,323
185,919	209,100	166,137		185,919	209,100	166,137	600,362
			Expenses				
31,678	31,191	32,295	Operating costs	31,678	31,191	32,295	116,756
26	-	69	Loss on disposal of property, plant and equipment	26	-	69	2,760
99,963	113,362	73,551	Fuels	99,963	113,362	73,551	246,512
22,500	16,478	16,194	Power purchased	22,500	16,478	16,194	59,199
13,751	14,205	12,672	Amortization	13,751	14,205	12,672	56,916
23,927	23,783	22,815	Interest	23,927	23,783	22,815	89,406
191,845	199,019	157,596		191,845	199,019	157,596	571,549
(5,926)	10,081	8,541	**Net (loss) income**	(5,926)	10,081	8,541	28,813

NOTE: The Regulated Operations 2014 budget proposed new customer rates effective January 1, 2014 based on General Rate Application evidence filed July 2013.

4.3 Capital Expenditures

Capital Expenditures - Overview
For the Quarter ended March 31, 2014
($000)

	PU Board Approved Budget	First Quarter Actuals	Year To Date Actuals	Forecast Remaining Expenditures
Generation	32,298	1,423	1,423	30,875
Transmission and Rural Operations	71,360	7,291	7,291	64,068
General Properties	7,949	1,249	1,249	6,701
Allowance for Unforeseen Events	1,000	434	434	566
Projects Approved by PU Board Order	1,917	631	631	1,286
New Projects Under $50,000 Approved by Hydro	84	-	-	84
Total 2014 Capital Budget	114,608	11,028	11,028	103,580
2014 FEED costs for 2015 projects[1]	-	106	106	-
Total 2014 Capital plus 2015 FEED	114,608	11,134	11,134	103,580

[1] These costs represent Front End Engineering and Design (FEED) costs incurred in 2014 related to 2015 capital projects.

2014 Capital Budget Approved by Board Order No. P.U. 42(2013)	$97,805
Carryover Projects 2013 to 2014	15,456
New Project Approved by Board Order No. P.U. 38(2013)	1,263
2014 New Projects Under $50,000 approved by Hydro	84
Total Approved Capital Budget	$114,608

5 OTHER ITEMS

5.1 Ramea Wind-Hydrogen-Diesel Project Update

Figure 1: Overview of Ramea WHD site with the town in the background

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
The operations and optimization component of Phase I of the project was originally scheduled to commence in the first quarter of 2014. Due to technical challenges associated with project equipment in Phase I, Nalcor has decided to pursue an alternative concept to achieve the original project objectives. In 2012, Nalcor applied to take part in the Atlantic Innovation Fund which is administrated by the Atlantic Canada Opportunities Agency. In 2013, Nalcor was successful in achieving funding for Phase II of the project. Phase II consists of the addition of a Hydrogen Fuel Cell to the system along with a multi-year operational and optimization component. The fuel cell installation will address the technical challenges that have not allowed the EMS to operate at its full potential.

A detailed description of the challenges, along with information about Phase II can be found in Appendix F titled "Ramea Wind-Hydrogen-Diesel Project Update". Phase II commenced in early 2014 and the operational and optimization components will follow the successful installation and integration of the Fuel Cell.

Capital Costs

($000)

Actual Cost to December 2013	Actual Cost Recoveries to December 2013	Net Cost to December 2013	Budget to December 2008	Budget Reforecast to September 2010
11,869	**11,869**	**0**	**8,794**	**2,486**

Operating Costs

During 2014, preventative and corrective maintenance on project equipment (excluding the diesel plant and associated systems) has been conducted and the costs associated are reported below.

($000)

Approved Budget 2014	Actual Amount to March 31, 2014	Total Commitments to March 31, 2014
203	47	47

Reliability and Safety Issues

Wind turbine number 8 has not operated in 2014 due to ongoing maintenance issues. During the reporting period an investigation was carried out by the Original Equipment Manufacturer and corrective maintenance is scheduled to take place in May.

5.2 Review into Supply Disruptions of January 2-8, 2014 Released to the PUB

On March 24, Hydro released its review of the January supply disruptions and submitted its report to the Public Utilities Board. Following the service interruption in early January, Hydro initiated an extensive review process to identify any contributing actions, conditions and factors so that Hydro can take the necessary actions to overcome similar challenges in the future. The process was a complete examination of the events leading up to and during the January service disruptions, which helped Hydro identify what went well and the necessary areas for improvement. Hydro's review is publicly available online at www.nlh.nl.ca.

5.3 Community

5.3.1 Hydro Sponsors JUMPFest 2014

Caryn Philips, Protection and Control Engineer, spoke on behalf of Hydro at the event

On February 12, the Heart & Stroke Foundation hosted JUMPFest 2014 sponsored by Hydro at the Techniplex in St. John's. The event brought together 850 kids in grades three to six from around the Avalon to participate in a morning of skipping and fun demonstrations. Jump Rope for Heart encourages kids to get active by skipping rope while they collect pledges for heart disease and stroke research. The program gives children the chance to jump and play alongside 750,000 other kids in more than 4,000 schools across Canada. The efforts of the Heart & Stroke Foundation are an example of how the commitment of individuals and organizations are vital to creating healthy children and communities.

5.3.2 Bridge Day Challenges Students with Popsicle Sticks

On March 8, Nalcor and Hydro employees volunteered at the 23rd Annual Bridge Day at the Johnson Geo Centre in St. John's. As a part of National Engineering and Geoscience Month, Bridge Day brings together junior high and high school students interested in engineering and geoscience for a bridge building competition. Students designed and assembled the bridges out of popsicle sticks which were then tested and judged. Outside of the bridge building competition, students were able to browse different booths from engineering and geoscience related organizations.

Bridge Day judges, Gerard Piercey, Manager, Civil Engineer and Rob Baker, Civil Engineer, inspect a popsicle stick bridge

5.4 Statement of Energy Sold

Statement of Energy Sold (GWh)

For the Quarter ended March 31

	YEAR TO DATE			2014[1]	
	2014 ACTUAL	2013 ACTUAL	2014 YTD BUDGET	ANNUAL BUDGET	ANNUAL % CHANGE
Island Interconnected					
Newfoundland Power	2,074	1,884	1,975	5,740	10.1%
Island Industrials	94	88	122	600	6.8%
Rural					
Domestic	93	84	80	249	10.7%
General Service	50	48	48	165	4.2%
Streetlighting	1	1	1	3	0.0%
Sub-total Rural	144	133	129	417	8.3%
Sub-Total Island Interconnected	2,312	2,105	2,226	6,757	9.8%
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	71	64	114	334	10.9%
CFB Goose Bay	0	0	0	10	0.0%
Hydro Quebec (includes Menihek)	18	16	15	42	12.5%
Export	233	288	199	1,295	-19.1%
Rural					
Domestic	135	116	124	314	16.4%
General Service	98	86	110	300	14.0%
Streetlighting	0	0	0	2	0.0%
Sub-total Rural	233	202	234	616	15.3%
Sub-Total Lab. Interconnected	555	570	562	2,297	-2.6%
Labrador Isolated					
Domestic	7	7	6	22	0.0%
General Service	4	3	4	19	33.3%
Streetlighting	0	0	0	0	0.0%
Sub-Total Labrador Isolated	11	10	10	41	10.0%
L'Anse au Loup					
Domestic	5	5	4	15	0.0%
General Service	3	2	2	8	50.0%
Streetlighting	0	0	0	0	0.0%
Sub-Total L'Anse au Loup	8	7	6	23	14.3%
Total Energy Sold	2,888	2,693	2,806	9,125	7.2%
Sales to Non-Regulated Customers[2]	323	367	328	1,672	-12.0%

[1] Based on 2014 Budget, Spring 2013 Rural Load Forecast

[2] Included in Total Energy Sold

5.5 Customer Statistics

Customer Statistics
For the Quarter ended March 31

	FIRST QUARTER		ANNUAL	
	2014 ACTUAL	2013 ACTUAL	2014 Budget	2013 ACTUAL
Customers				
Rural	38,077	37,676	37,983	38,022
Industrial	5	4	5	5
CFB Goose Bay	1	1	1	1
Utility	1	1	1	1
Non-Regulated	4	3	3	4
Reading Days	29.6	29.4	N/A	29.7

APPENDICES

CIAC QUARTERLY ACTIVITY REPORT
For the Quarter ended March 31, 2014

TYPE OF SERVICE	CIACs QUOTED	CIACs OUTSTANDING PREVIOUS QTR.	TOTAL CIACs QUOTED	CIACs ACCEPTED	CIAC'S EXPIRED	TOTAL CIACs OUTSTANDING
Domestic						
Within Plan. Boundary	0	7	7	1	2	5
Outside Plan. Boundary	2	4	6	2	1	3
Sub-total	2	11	13	3	3	8
General Service	0	5	5	1	2	2
Total	2	16	18	4	5	10

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, 2014

DATE QUOTED	SERVICE LOCATION	CIAC NO.	CIAC AMOUNT	ESTIMATED CONST. COST	ACCEPTED
DOMESTIC - WITHIN RESIDENTIAL PLANNING BOUNDARIES					
Nil					
DOMESTIC - OUTSIDE RESIDENTIAL PLANNING BOUNDARIES					
January 20, 2014	South Brook; Green Bay	1016648	96377	110877	Yes
March 12, 2014	Wabush	1005692	451757	481007	
GENERAL SERVICE					
Nil					

CUSTOMER PROPERTY DAMAGE CLAIMS REPORT
For the Quarter ended March 31, 2014

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, 2014

CAUSE	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	$ AMT. CLAIMED	$ AMT. PAID	#	$ AMOUNT	#	$ AMOUNT
System Operations	3	1	4	0	$ -	$ -	4	$ 2,930	0	$ -
Power Interruptions	5	0	5	0	$ -	$ -	6	$ 3,087	0	$ -
Improper Workmanship	1	6	7	2	$ 2,655	$ 2,679	1	$ 469	4	$ 6,538
Weather Related	10	10	20	7	$ 8,318	$ 3,483	8	$ 10,597	4	$ 3,962
Equipment Failure	0	5	5	4	$ 10,444	$ 34,948	3	$ 10,715	0	$ -
Third Party	0	0	0	0	$ -	$ -	0	$ -	0	$ -
Miscellaneous	5	0	5	1	$ 1,800	$ 567	3	$ 1,306	1	$ 1,447
Awaiting Investigation	2	8	10	0	$ -	$ -	1	$ -	5	$ 1,498
Total	26	30	56	14	$ 23,216	$ 41,675	26	$ 29,103	14	$ 13,444

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	1	$ 762
Power Interruptions	0	1	1	0	$ -	$ -	0	$ -	1	$ -
Improper Workmanship	1	6	7	3	$ 13,181	$ 12,095	1	$ 2,159	5	$ 3,541
Weather Related	17	9	26	4	$ 6,196	$ 2,580	16	$ 8,343	6	$ 7,265
Equipment Failure	1	7	8	0	$ -	$ -	2	$ 1,595	5	$ 17,564
Third Party	0	0	0	1	$ 48,000	$ 48,000	0	$ -	0	$ -
Miscellaneous	1	2	3	0	$ -	$ -	2	$ 3,106	1	$ -
Awaiting Investigation	4	8	12	0	$ -	$ -	1	$ -	6	$ 16,265
Total	25	35	60	8	$ 67,376	$ 62,674	24	$ 15,702	25	$ 45,397

CUSTOMER PROPERTY DAMAGE CLAIMS REPORT - BY REGION

For the Quarter ended March 31, 2014

REGION	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	$ AMT. CLAIMED	$ AMT. PAID	#	$ AMOUNT	#	$ AMOUNT
Central Region	6	11	17	2	$ 606	$ 673	10	$ 10,479	4	$ 4,368
Northern Region	15	14	29	11	$ 17,611	$ 8,316	12	$ 17,424	5	$ 7,630
Labrador Region	5	5	10	1	$ 5,000	$ 32,686	4	$ 1,201	5	$ 1,447
Total	26	30	56	14	$ 23,216	$ 41,675	26	$ 29,103	14	$ 13,444

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	$ 49,546	$ 49,246	5	$ 4,436	2	$ 469
Northern Region	20	17	37	3	$ 5,445	$ 2,214	17	$ 10,767	15	$ 35,633
Labrador Region	2	10	12	2	$ 12,386	$ 11,215	2	$ 500	8	$ 9,295
Total	25	35	60	8	$ 67,376	$ 62,674	24	$ 15,702	25	$ 45,397

FINANCIAL – REGULATED

Balance Sheet - Regulated Operations
As at March 31
($000)

	Mar-14	Mar-13
ASSETS		
Current assets		
Cash and cash equivalents	314	375
Accounts receivable	90,131	76,679
Current portion of regulatory assets	2,157	2,157
Current portion of sinking funds	70,648	-
Inventory	77,311	66,539
Prepaid expenses	6,006	3,637
	246,567	149,387
Property, plant, and equipment	1,461,076	1,438,958
Sinking funds	204,109	267,100
Regulatory assets	62,515	62,520
Total assets	1,974,267	1,917,965
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	53,755	42,111
Accrued interest	17,454	17,454
Current portion of long-term debt	81,139	8,150
Current portion of regulatory liabilities	183,533	170,973
Deferred credits	943	1,914
Due to related parties	899	3,779
Promissory notes	80,739	32,410
	418,462	276,791
Long-term debt	1,046,125	1,124,448
Regulatory liabilities	69,009	53,959
Asset retirement obligations	24,307	24,307
Employee future benefits	62,868	58,908
Contributed capital	100,000	100,000
Retained earnings	225,457	239,715
Accumulated other comprehensive income	28,039	39,837
Total liabilities and shareholder's equity	1,974,267	1,917,965

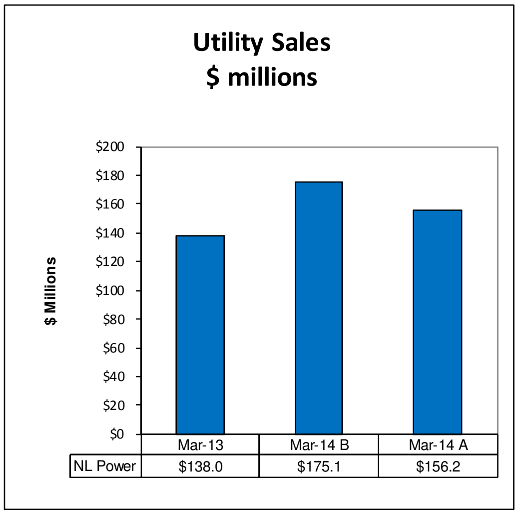
Statement of Retained Earnings - Regulated Operations
For the three months ended March 31, 2014
($000)

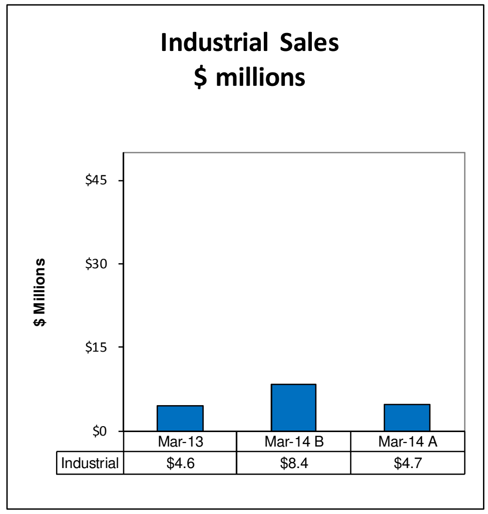
First Quarter 2014 Actual	First Quarter 2013 Actual		Year-to-date 2014 Actual	Year-to-date 2013 Actual
231,383	231,174	Balance, beginning of period	231,383	231,174
(5,926)	8,541	Net (loss) income	(5,926)	8,541
225,457	239,715	Balance, end of period	225,457	239,715

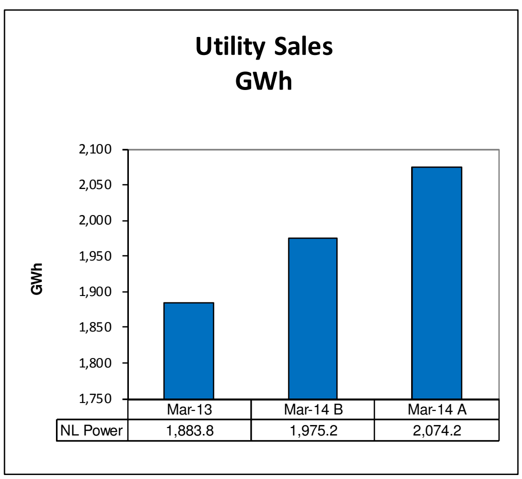
Statement of Comprehensive Income - Regulated Operations
For the three months ended March 31, 2014
($000)

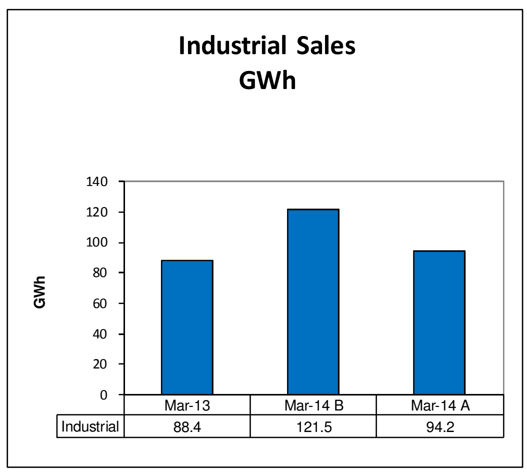
First Quarter 2014 Actual	First Quarter 2014 Budget	First Quarter 2013 Actual		Year-to-date 2014 Actual	Year-to-date 2014 Budget	Year-to-date 2013 Actual	2014 Annual Budget
(5,926)	10,081	8,541	Net (loss) income	(5,926)	10,081	8,541	28,813
			Other comprehensive income (loss)				
4,072	-	(1,703)	Change in fair value of sinking fund investments	4,072	-	(1,703)	-
(1,854)	10,081	6,838	Total comprehensive (loss) income	(1,854)	10,081	6,838	28,813

Sales - Regulated Operations
For the three months ended March 31, 2014









Revenue Summary - Regulated Operations
For the three months ended March 31, 2014
($000)

First Quarter 2014 Actual	First Quarter 2014 Budget	First Quarter 2013 Actual		Year-to-date 2014 Actual	Year-to-date 2014 Budget	Year-to-date 2013 Actual	2014 Annual Budget
			REVENUE				
			Industrial				
681	1,562	1,117	Corner Brook Pulp and Paper Ltd.	681	1,562	1,117	6,293
577	1,860	12	Vale Inco	577	1,860	12	13,578
2,589	3,888	2,583	North Atlantic Refinery	2,589	3,888	2,583	15,652
2	-	3	C.F.B. Goose Bay	2	-	3	835
892	776	918	Teck Cominco Limited	892	776	918	3,129
7	279	-	Praxair	7	279	-	1,523
4,748	8,365	4,633	**Total Industrial**	4,748	8,365	4,633	41,010
			Utility				
156,200	175,050	137,980	Newfoundland Power Inc.	156,200	175,050	137,980	475,497
			Rural				
24,476	25,105	22,890	Interconnected and diesel	24,476	25,105	22,890	81,532
495	580	634	**Other**	495	580	634	2,323
185,919	209,100	166,137	**Total**	185,919	209,100	166,137	600,362
			ENERGY SALES (GWh)				
			Industrial				
11.3	17.4	17.1	Corner Brook Pulp and Paper Ltd.	11.3	17.4	17.1	70.6
11.7	27.9	0.2	Vale Inco	11.7	27.9	0.2	211.5
53.3	62.7	52.6	North Atlantic Refinery	53.3	62.7	52.6	254.7
-	-	-	C.F.B. Goose Bay	-	-	-	9.7
17.8	11.1	18.5	Teck Cominco Limited	17.8	11.1	18.5	44.9
0.1	2.4	-	Praxair	0.1	2.4	-	18.1
94.2	121.5	88.4	**Total Industrial**	94.2	121.5	88.4	609.5
			Utility				
2,074.2	1,975.2	1,883.8	Newfoundland Power Inc.	2,074.2	1,975.2	1,883.8	5,740.2
			Rural				
388.2	382.5	355.5	Interconnected and diesel	388.2	382.5	355.5	1,104.6
2,556.6	2,479.2	2,327.7	**Total**	2,556.6	2,479.2	2,327.7	7,454.3

Statement of Cash Flows - Regulated Operations
For the three months ended March 31, 2014
($000)

	Year-to-date 2014	Year-to-date 2013
Operating activities		
Net (loss) income	(5,926)	8,541
Adjusted for items not involving cash flow		
Amortization	13,751	12,765
Accretion of long-term debt	140	130
Employee future benefits	1,315	2,018
Loss on disposal of property, plant and equipment	26	100
	9,306	23,554
Changes in non-cash balances		
Accounts receivable	(4,920)	3,506
Inventory	(13,337)	(14,866)
Prepaid expenses	(3,264)	(688)
Regulatory assets	(398)	304
Regulatory liabilities	(1,723)	22,773
Accounts payable and accrued liabilities	(13,041)	2,812
Accrued interest	(11,213)	(11,213)
Due to related parties	168	1,906
	(38,422)	28,088
Financing activities		
Decrease in long-term receivable	172	188
Increase (decrease) in deferred credits	241	(24)
Increase (decrease) promissory notes	47,926	(12,373)
	48,339	(12,209)
Investing activities		
Additions to property, plant and equipment	(11,572)	(10,928)
Increase in sinking funds	(4,759)	(7,056)
Proceeds on disposal of property, plant and equipment	2	-
	(16,329)	(17,984)
Net decrease in cash	(6,412)	(2,105)
Cash position, beginning of period	6,726	2,480
Cash position, end of period	314	375

FINANCIAL - NON-REGULATED

Balance Sheet - Non-Regulated Activities
As at March 31
($000)

	Mar-14	Mar-13
ASSETS		
Current assets		
Accounts receivable	7,135	3,335
Prepaid expenses	639	-
	7,774	3,335
Investment in CF(L)Co.	444,309	433,347
Total assets	452,083	436,682
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	1,864	1,830
Promissory notes	2,260	7,590
Derivative liabilities	5,954	202
	10,078	9,622
Share capital	22,504	22,504
Lower Churchill Development Corp	15,400	15,400
Retained earnings	404,464	389,853
Accumulated other comprehensive loss	(363)	(697)
Total liabilities and shareholder's equity	452,083	436,682

Statement of Income - Non-Regulated Activities
For the three months ended March 31, 2014
($000)

First Quarter 2014 Actual	First Quarter 2014 Budget	First Quarter 2013 Actual		Year-to-date 2014 Actual	Year-to-date 2014 Budget	Year-to-date 2013 Actual	2014 Annual Budget
			Revenue				
26,847	12,814	16,244	Energy sales	26,847	12,814	16,244	65,960
26,847	12,814	16,244		26,847	12,814	16,244	65,960
			Expenses				
6,787	6,969	7,917	Operating costs	6,787	6,969	7,917	30,253
1,131	942	1,798	Power purchased	1,131	942	1,798	6,107
-	-	-	Amortization	-	-	-	89
5,780	-	230	Other income and expense	5,780	-	230	-
200	-	(163)	Interest	200	-	(163)	-
13,898	7,911	9,782		13,898	7,911	9,782	36,449
12,949	4,903	6,462	Net operating income	12,949	4,903	6,462	29,511
13,392	12,971	15,850	Equity in CF(L)Co	13,392	12,971	15,850	13,020
2,493	2,044	3,017	Preferred dividends	2,493	2,044	3,017	8,175
15,885	15,015	18,867		15,885	15,015	18,867	21,195
28,834	19,918	25,329	**Net income**	28,834	19,918	25,329	50,706

Statement of Retained Earnings - Non-Regulated Activties
For the three months ended March 31, 2014
($000)

First Quarter 2014 Actual	First Quarter 2013 Actual		Year-to-date 2014 Actual	Year-to-date 2013 Actual
388,653	373,578	Balance, beginning of period	388,653	373,578
28,834	25,329	Net income	28,834	25,329
(13,023)	(9,054)	Dividends	(13,023)	(9,054)
404,464	389,853	Balance, end of period	404,464	389,853

Statement of Comprehensive Income - Non-Regulated Activities
For the three months ended March 31, 2014
($000)

First Quarter 2014 Actual	First Quarter 2014 Budget	First Quarter 2013 Actual		Year-to-date 2014 Actual	Year-to-date 2014 Budget	Year-to-date 2013 Actual	2014 Annual Budget
28,834	19,918	25,329	Net income	28,834	19,918	25,329	50,706
			Other comprehensive loss				
172	-	(785)	Share of CF(L)Co other comprehensive income (loss)	172	-	(785)	-
29,006	19,918	24,544	Total comprehensive income	29,006	19,918	24,544	50,706

Statement of Cash Flows - Non-Regulated Activities
For the three months ended March 31, 2014
($000)

	Year-to-date 2014	Year-to-date 2013
Operating activities		
Net income	28,834	25,329
Adjusted for items not involving cash flow		
Unrealized loss on derivatives	5,781	230
Equity in CF(L)Co	(13,392)	(16,637)
	21,223	8,922
Changes in non-cash balances		
Accounts receivable	(2,329)	153
Accounts payable and accrued liabilities	56	(394)
	18,950	8,681
Financing activities		
(Decrease) increase in promissory notes	(5,927)	373
Dividends	(13,023)	(9,054)
	(18,950)	(8,681)
Net change in cash	-	-
Cash position, beginning of period	-	-
Cash position, end of period	-	-

Supplementary Schedule - Regulated Operations
For the three months ended March 31, 2014
($000)

First Quarter 2014 Actual	First Quarter 2014 Budget	First Quarter 2013 Actual		Year-to-date 2014 Actual	Year-to-date 2014 Budget	Year-to-date 2013 Actual	2014 Annual Budget
			Other revenue				
110	162	174	Sundry	110	162	174	653
315	393	402	Pole attachments	315	393	402	1,570
70	25	58	Supplier's discount	70	25	58	100
495	580	634	**Total other revenue**	495	580	634	2,323
			Interest				
28,869	28,273	27,571	Gross interest	28,869	28,273	27,571	107,527
141	141	130	Accretion of long-term debt	141	141	130	514
539	539	539	Amortization of foreign exchange losses	539	539	539	2,157
(219)	(248)	(656)	Allowance for funds used during construction	(219)	(248)	(656)	(4,622)
(5,403)	(4,922)	(4,769)	Interest earned	(5,403)	(4,922)	(4,769)	(16,170)
23,927	23,783	22,815	**Total interest**	23,927	23,783	22,815	89,406

Cost Recoveries - Regulated Operations
For the three months ended March 31, 2014
($000)

First Quarter 2014 Actual	First Quarter 2014 Budget	First Quarter 2013 Actual		Year-to-date 2014 Actual	Year-to-date 2014 Budget	Year-to-date 2013 Actual	2014 Annual Budget
-	5	2	Executive Leadership	-	5	2	14
308	296	240	Human Resources and Organizational Effectiveness	308	296	240	1,217
1,259	1,202	1,270	Finance / CFO	1,259	1,202	1,270	4,861
8	19	5	Engineeering Services	8	19	5	27
36	41	30	Regulated Operations	36	41	30	167
1,611	1,563	1,547		1,611	1,563	1,547	6,286

Newfoundland and Labrador Hydro
Rate Stabilization Plan
March 31, 2014

Rate Stabilization Plan Report
March 31, 2014

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, 2014

	Actual	Cost of Service	Variance	Year-to-Date Due (To) From customers	Reference
Hydraulic production year-to-date	1,551.2 GWh	1,230.9 GWh	320.3 GWh	$ (27,852,952)	Page 4
No 6 fuel cost - Current month	$ 115.08	$ 55.46	$ 59.62	$ 55,502,991	Page 5
Year-to-date customer load - Utility	2,074.2 GWh	1,618.1 GWh	456.1 GWh	$ (441,693)	Page 8
Year-to-date customer load - Industrial	94.2 GWh	225.8 GWh	-131.6 GWh	$ (6,599,044)	Page 9
				$ 20,609,302	

Rural rates		
Rural Rate Alteration (RRA) [1]	$ (3,333,706)	
Less : RRA to utility customer	$ (2,970,331)	Page 10
RRA to Labrador interconnected	(363,375)	
Fuel variance to Labrador interconnected	$ 428,896	Page 6
Net Labrador interconnected	$ 65,521	

Current plan summary		
One year recovery		
Due (to) from utility customer	$ (43,381,295)	Page 10
Due (to) from Industrial customers	$ 3,586,627	Page 11
Sub total	(39,794,668)	
Four year recovery		
Hydraulic balance	$ (68,551,858)	Page 4
Segregated Load Variation		Page 12
Utility Customer	$ 359,314	
Industrial Customer	$ (15,796,490)	
Sub Total	$ (15,437,176)	
Utility RSP Surplus	$ (117,442,511)	Page 13
Industrial RSP Surplus	$ (10,858,193)	Page 14
Total plan balance	$ (252,084,406)	

[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
March 31, 2014

	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 12)**
Opening balance							(39,801,010)
January	427,100,000	536,781,236	(109,681,236)	54.17	(9,430,845)	(241,493)	(49,473,348)
February	388,680,000	491,548,118	(102,868,118)	54.73	(8,936,464)	(300,180)	(58,709,992)
March	415,080,000	522,832,527	(107,752,527)	55.46	(9,485,643)	(356,223)	(68,551,858)
April							
May							
June							
July							
August							
September							
October							
November							
December							
	1,230,860,000	1,551,161,881	(320,301,881)		(27,852,952)	(897,896)	(68,551,858)
Hydraulic Allocation [(2)]							
Hydraulic variation at year end					(27,852,952)	(897,896)	(68,551,858)

(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, 2014

	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	311,974	0	311,974	54.17	104.55	50.38	15,717,272
February	330,404	0	330,404	54.73	114.37	59.64	19,705,279
March	336,807	0	336,807	55.46	115.08	59.62	20,080,440
April							
May							
June							
July							
August							
September							
October							
November							
December							
	979,185	0	979,185				55,502,991

Rate Stabilization Plan
Allocation of Fuel Variance - Year-to-Date
March 31, 2014

	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	5,603,728,914	348,666,137	459,258,079	6,411,653,130	13,736,759	854,706	1,125,807	15,717,272	1,003,094	122,713
February	5,664,560,418	354,489,796	462,266,852	6,481,317,066	30,958,705	1,937,405	2,526,441	35,422,551	2,251,059	275,382
March	5,796,147,497	357,155,092	469,518,334	6,622,820,923	48,574,999	2,993,162	3,934,830	55,502,991	3,505,934	428,896
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, 2014

	A	B	C	D	E	F	G
	Utility					**Industrial**	
	Fuel Variance		Rural Allocation		Total Fuel Variance Activity for the month	Fuel Variance	
	Year-to-Date Activity	Current Month Activity [(1)]	Year-to-Date Activity	Current Month Activity [(1)]		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	13,736,759	13,736,759	1,003,094	1,003,094	14,739,853	854,706	854,706
February	30,958,705	17,221,946	2,251,059	1,247,965	18,469,911	1,937,405	1,082,699
March	48,574,999	17,616,294	3,505,934	1,254,875	18,871,169	2,993,162	1,055,757
April							
May							
June							
July							
August							
September							
October							
November							
December							
		48,574,999		3,505,934	52,080,933		2,993,162

(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, 2014

	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	701,822,280	127,022,280	54.17	0.08805	(262,412)	0	0	0.00841	0	(262,412)
February	518,600,000	668,138,074	149,538,074	54.73	0.08805	(176,004)	0	0	0.00841	0	(176,004)
March	524,700,000	704,231,084	179,531,084	55.46	0.08805	(3,277)	0	0	0.00841	0	(3,277)
April											
May											
June											
July											
August											
September											
October											
November											
December											
	1,618,100,000	2,074,191,438	456,091,438			(441,693)	0	0		0	(441,693)

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

Rate Stabilization Plan
Load Variation - Industrial
March 31, 2014

	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	28,925,453	(49,374,547)	54.17	0.03676	(2,430,419)
February	70,900,000	31,688,409	(39,211,591)	54.73	0.03676	(1,965,011)
March	76,600,000	33,620,893	(42,979,107)	55.46	0.03676	(2,203,614)
April						
May						
June						
July						
August						
September						
October						
November						
December						
	225,800,000	94,234,755	(131,565,245)			(6,599,044)

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

Rate Stabilization Plan
Summary of Utility Customer
March 31, 2014

	A	B	C	D	E	F	H
	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							(80,173,930)
January		14,739,853	(1,016,527)	13,723,326	(486,455)	(3,740,713)	(70,677,772)
February		18,469,911	(1,030,686)	17,439,225	(428,837)	(3,561,176)	(57,228,560)
March		18,871,169	(923,118)	17,948,051	(347,234)	(3,753,552)	(43,381,295)
April							
May							
June							
July							
August							
September							
October							
November							
December							
Year to date	0	52,080,933	(2,970,331)	49,110,602	(1,262,526)	(11,055,441)	36,792,635
Hydraulic allocation **(from page 4)**							0
Total	0	52,080,933	(2,970,331)	49,110,602	(1,262,526)	(11,055,441)	(43,381,295)

(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.

Rate Stabilization Plan
Summary of Industrial Customers
March 31, 2014

	A	B	C	D	E	F
	Load Variation	Allocation Fuel Variance	Subtotal Monthly Variances	Financing Charges	Adjustment	Cumulative Net Balance
	($)	($)	($)	($)	($)	($)
			(A + B)			
	(from page 9)	**(from page 7)**				**(to page 12)**
Opening Balance						566,125
January		854,706	854,706	3,435	0	1,424,266
February		1,082,699	1,082,699	8,642	0	2,515,607
March		1,055,757	1,055,757	15,263	0	3,586,627
April						
May						
June						
July						
August						
September						
October						
November						
December						
Year to date		2,993,162	2,993,162	27,340	0	3,020,502
Hydraulic allocation **(from page 4)**						0
Total		2,993,162	2,993,162	27,340	0	3,586,627

Rate Stabilization Plan
Load Variation January - December 2014
March 31, 2014

	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 [1]
		($)	($)		($)	($)	($)
			(A + B)			(D + E)	(C +F)
	(from page 8)			**(from page 9)**			**(to page 15)**
Opening Balance			790,787			(8,991,282)	(8,200,495)
January	(262,412)	4,798	533,173	(2,430,419)	(54,555)	(11,476,256)	(10,943,083)
February	(176,004)	3,235	360,404	(1,965,011)	(69,632)	(13,510,899)	(13,150,495)
March	(3,277)	2,187	359,314	(2,203,614)	(81,977)	(15,796,490)	(15,437,176)
April							
May							
June							
July							
August							
September							
October							
November							
December							
Total	(441,693)	10,220	359,314	(6,599,044)	(206,164)	(15,796,490)	(15,437,176)

(1) Per Board Order No. P.U. 29(2013), the load variation from the Industrial and Utility Customers as of September 1, be held in a separate account until its disposition.

Rate Stabilization Plan
Utility RSP Surplus
March 31, 2014

	A	B	C	D
	Industrial Customer Adjustment	Utility Payout	Financing Charges	Cumulative Balance
	($)	($)	($)	($)
	(from page 10)			**(to page 15)**
Opening Balance				(115,330,446)
January			(699,767)	(116,030,213)
February			(704,013)	(116,734,226)
March			(708,285)	(117,442,511)
April				
May				
June				
July				
August				
September				
October				
November				
December				
Year to date	-	-	(2,112,065)	(2,112,065)
Total			(2,112,065)	(117,442,511)

Rate Stabilization Plan
Industrial RSP Surplus
March 31, 2014

	A	B	C	D	E
	Industrial Surplus	Teck Allocation [1]	Industrial Drawdown	Financing Charges	Cumulative Balance
	($)	($)	($)	($)	($)
	(from page 11)		**(from page 11)**		**(to page 15)**
Opening Balance					(10,858,146)
January		66,308		(65,882)	(10,857,720)
February		62,040		(65,879)	(10,861,559)
March		69,269		(65,903)	(10,858,193)
April					
May					
June					
July					
August					
September					
October					
November					
December					
Year to date	0	197,617	0	(197,664)	(47)
Total	0	197,617	0	(197,664)	(10,858,193)

(1) Per Board Order No. P.U. 29(2013), the RSP drawdown adjustment rate for Teck Resources is 1.111 cents per kwh effective September 1, 2013.

Rate Stabilization Plan
Overall Summary
March 31, 2014

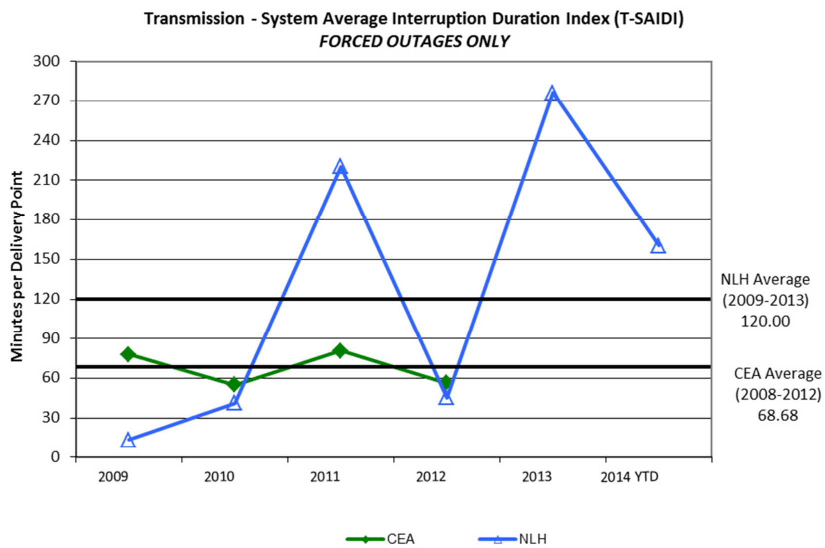
	A	B	C	D	E	F	G
	Hydraulic Balance	Utility Balance	Industrial Balance	Segregated Load Balance	Utility RSP Surplus	Industrial RSP Surplus	Total To Date
	($)	($)	($)	($)	($)	($)	($)
							(A + B + C + D + E + F)
	(from page 4)	**(from page 10)**	**(from page 11)**	**(from page 12)**	**(from page 13)**	**(from page 14)**	
Opening Balance	(39,801,010)	(80,173,930)	566,125	(8,200,495)	(115,330,446)	(10,858,146)	(253,797,902)
January	(49,473,348)	(70,677,772)	1,424,266	(10,943,083)	(116,030,213)	(10,857,720)	(256,557,870)
February	(58,709,992)	(57,228,560)	2,515,607	(13,150,495)	(116,734,226)	(10,861,559)	(254,169,225)
March	(68,551,858)	(43,381,295)	3,586,627	(15,437,176)	(117,442,511)	(10,858,193)	(252,084,406)
April							
May							
June							
July							
August							
September							
October							
November							
December							

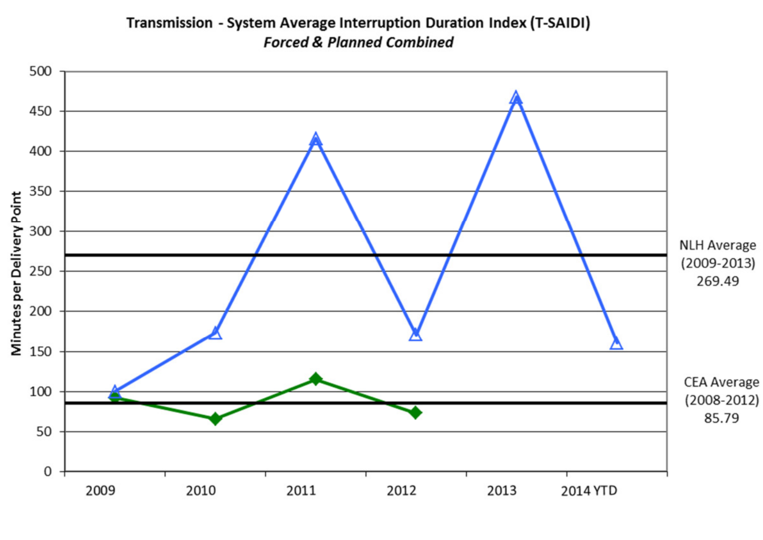
Performance Indices

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 160.2 minutes per delivery point (forced and planned combined) compared to 213.0 minutes per delivery point for the same quarter last year, a decrease of 25%. The forced component was 160.2 minutes per delivery point, compared to 201.6 minutes per delivery point in 2013, a decrease of 21%. There were no planned outages in the first quarter of 2014 compare to 11.4 minutes per delivery point in 2013.





There were 17 significant forced outages and no planned outages in this quarter. A summary of the forced outages follows:

Forced

On January 4 and 5, there were three significant events that resulted in Island wide power outages and significant customer impact.

The first event occurred at 09:05 hours at the Sunnyside Terminal Station, when a transformer lockout occurred on T1. Circuit breaker B1L03 failed to isolate T1, and resulted in a trip of transmission lines TL203 and TL237, isolating the Avalon Peninsula from the remainder of the power system. This resulted in the interruption of the following generation: Holyrood Plant, Cat Arm Plant, Hinds Lake Plant, Paradise River Plant, Star Lake Plant, Upper Salmon Plant, and Stephenville Gas Turbine.

The second event occurred at 15:33 hours on January 4. A second attempt was made to restore transformer T4 at Sunnyside. Breaker B3T4 was closed and resulted in the opening of disconnect switch B1T4 under load. The protection at Sunnyside did not operate as expected to clear the arcing fault, which resulted in the operation of the protection on the remote ends of transmission lines TL202 and TL206 at the Bay d'Espoir Generating Plant (BDE). Protection at Bay d'Espoir did not operate to trip transmission line TL202 as expected. Breakers B3B4 and B4B5 were slow in operating. The lockout protection operated and resulted in the trip of transmission line TL204 and BDE Units 5 and 6 (loss of 150 MW of generation). The Avalon Peninsula was isolated from the remainder of the power system at Sunnyside Terminal Station. The Come by Chance Oil Refinery was also interrupted. This disturbance resulted in the interruption of the Cat Arm Plant. The Holyrood units had not been restored following the events earlier in the morning.

The third event occurred at 21:27 hours on January 5 during an attempt to put Holyrood generating Unit 1 on line (this unit had tripped on the previous day as a result of the events at Sunnyside). The unit disconnect switch B1T1 was closed at Holyrood as a first step before the generator is synchronized to the system. An issue with the 230 kV unit breaker, B1L17, resulted in unit lockout operations on Holyrood Units 1, 2, and 3 and a breaker failure operation. The protection operated and tripped Holyrood Units 2 and 3 and transmission lines TL217, TL218, and TL242. The St. John's area continued to be supplied via TL201 from Western Avalon (at a reduced customer loading). The 138 kV loop from Western Avalon to Holyrood was not available.

The following tables outline the delivery point customer interruptions:

Events on January 4, 2014 (09:05 hrs)

Delivery Point Affected	Start Time	Finish Time	Duration of Interruptions (mins)	MW Load	MW-Mins
Hardwoods	1/4/2014 9:05	1/4/2014 9:52	47	268	12,596
Oxen Pond	1/4/2014 9:05	1/4/2014 10:43	98	286	28,067
Holyrood - 39L	1/4/2014 9:05	1/4/2014 14:01	296	29	9,320
Holyrood - 38L	1/4/2014 9:05	1/4/2014 14:07	302	46	13,771
Western Avalon - 64L	1/4/2014 9:05	1/4/2014 14:44	339	94	27,735
Western Avalon - Bus B2	1/4/2014 9:05	1/4/2014 14:01	296	46	16,780
Vale (Long Harbour)	1/4/2014 9:05	1/4/2014 12:22	197	6	1,143
Sunnyside - rural (T5)	1/4/2014 9:05	1/4/2014 20:07	662	9	6,091
Sunnyside - TL219	1/4/2014 9:05	1/4/2014 20:07	662	29	20,445
Linton Lake	1/4/2014 9:05	1/4/2014 20:07	662	17	11,985
Bay L'Argent	1/4/2014 9:05	1/4/2014 20:07	662	17	4,653
Monkstown	1/4/2014 9:05	1/4/2014 20:07	662	17	2,397
Duck Pond Mine	1/4/2014 9:05	1/4/2014 12:46	221	9	1,923
Wiltondale	1/4/2014 9:05	1/4/2014 9:33	28	0.1	4
Glenburine	1/4/2014 9:05	1/4/2014 9:33	28	3	78
Rocky Harbour	1/4/2014 9:05	1/4/2014 9:33	28	4	118
Grandy Brook	1/4/2014 9:05	1/4/2014 9:33	28	5	132
St Alban's	1/4/2014 9:05	1/4/2014 10:19	74	5	548
Conne River	1/4/2014 9:05	1/4/2014 10:37	92	2	187
English Harbour West	1/4/2014 9:05	1/4/2014 10:37	92	4	362
Barachoix	1/4/2014 9:05	1/4/2014 10:37	92	7	619
Come By Chance T2	1/4/2014 9:05	1/4/2014 13:18	N/A (BES: 253 mins)	N/A	N/A
		Totals			158,954

Events on January 4, 2014 (15:33 hrs)

Delivery Point Affected	Start Time	Finish Time	Duration of Interruptions (mins)	MW Load	MW-Mins
Hardwoods	1/4/2014 15:33	1/4/2014 15:55	22	164	3,608
Oxen Pond	1/4/2014 15:33	1/4/2014 16:06	33	166	5,478
Holyrood - 38L	1/4/2014 15:33	1/4/2014 16:10	37	24	870
Western Avalon	1/4/2014 15:33	1/4/2014 16:18	45	61	2,750
Come By Chance	1/4/2014 15:33	1/4/2014 15:39	6	15	91
Duck Pond Mine	1/4/2014 15:33	1/4/2014 17:47	134	5	724
Wiltondale	1/4/2014 15:33	1/4/2014 15:43	10	0.1	1
Glenburine	1/4/2014 15:33	1/4/2014 15:43	10	3	29
Rocky Harbour	1/4/2014 15:33	1/4/2014 15:43	10	4	43
Grandy Brook	1/4/2014 15:33	1/4/2014 15:39	6	5	28
St Alban's (1)	1/4/2014 15:33	1/4/2014 15:43	10	8	75
St Alban's (2)	1/4/2014 15:58	1/4/2014 16:23	25	8	200
Conne River	1/4/2014 15:33	1/4/2014 15:43	10	2	22
English Harbour	1/4/2014 15:33	1/4/2014 15:43	10	4	43
Barachoix	1/4/2014 15:33	1/4/2014 15:43	10	7	74
Come By Chance	1/4/2014 15:33	1/4/2014 15:39	N/A (BES: 6 mins)	N/A	N/A
Holyrood - 39L	1/4/2014 15:33	1/4/2014 16:39	N/A (BES: 66 mins)	N/A	N/A
		Totals			14,036

Delivery Point Affected	Start Time	Finish Time	Duration of Interruptions (mins)	MW Load	MW-Mins
Holyrood - 38L	1/5/2014 21:27	1/5/2014 21:31	4	37	146
Holyrood - 39L	1/5/2014 21:27	1/6/2014 8:42	675	17	11,610
Western Avalon - 64L	1/5/2014 21:27	1/6/2014 0:22	175	83	14,525
Western Avalon - Bus B2	1/5/2014 21:27	1/6/2014 0:36	189	41	7,749
		Totals			34,030

In addition to the above, the generation supply issues experienced into January resulted in the requirement for feeder interruptions by both Hydro and Newfoundland Power (NP). Following are tables of the customer impact experienced by both utilities as a result of these feeder interruptions.

Newfoundland Power - Feeder Interruptions

Date	Time	Feeder Rotations	Average Duration (minutes)
Thursday January 2, 2014	4:13 pm to 10:45 pm	77	88
Friday January 3, 2014	6:57 am to 7:36 pm	141	44
Sunday January 5, 2014	7:23 am to 8:29 pm	158	54
Monday January 6, 2014	5:17 am to 10:48 am	39	47
Wednesday January 8, 2014	3:23 pm to 5:42 pm	32	25

Hydro - Feeder Interruptions

Date	Time	Feeder Rotations	Average Duration (minutes)
Thursday January 2, 2014	4:13 pm to 10:50 pm	6	30
Friday January 3, 2014	7:00 am to 7:30 pm	25	30
Sunday January 5, 2014	5:04 pm to 7:03 pm	5	60
Wednesday January 8, 2014	3:32 pm to 4:30 pm	3	30

On January 8, NP customers supplied by transmission line 64L from the Western Avalon Terminal Station experienced an unplanned power outage of five minutes. The outage occurred after transformer T3 became overloaded. Transmission line 39L was opened at NP's Bay Roberts Substation and Western Avalon T5 was out of service. (It had faulted on January 4.)

On January 8, NP customers supplied by transmission line 64L from the Western Avalon Terminal Station experienced another unplanned power outage, this time of four minutes in duration. The outage occurred after transformer T4 became overloaded. Transmission line 39L was opened at NP's Bay Roberts Substation and Western Avalon T5 was out of service. (It had faulted on January 4.)

On January 14, customers supplied by the South Brook Terminal Station experienced an unplanned power outage of one hour and 45 minutes. The outage occurred after a squirrel came in contact with the bushings on transformer T1, resulting in a lockout of the transformer.

On January 22, all customers on the Great Northern Peninsula, north of Cow Head, experienced an unplanned power outage. The outage was caused by a tree contact on TL239. See the following table for details regarding the delivery point impact.

Delivery Point Affected	Start Time	Time of Restoration	Outage Duration (mins)	Load Loss (MW)	MW-Mins
Cow Head	23:56	0:05	9	1.1	9.9
Parson's Pond	23:56	0:13	17	0.5	8.5
Daniel's Harbour	23:56	0:13	17	0.7	11.9
Hawkes's Bay	23:56	0:13	17	4.1	69.7
Plum Point	23:56	0:16	20	2.5	50
Bear Cove	23:56	0:18	22	3.8	83.6
Main Brook	23:56	0:23	27	0.4	10.8
Roddickton	23:56	0:23	27	1.6	43.2
St Anthony	23:56	0:23	27	6.3	551.4
Total					839

On January 26, customers supplied by the Grandy Brook Terminal Station experienced an unplanned power outage of eight hours and 46 minutes. The outage occurred after a crossarm failed at a structure in transmission line TL250 during an extreme wind storm. There were wind gusts of over 130 km/h recorded on this day.

On January 28, customers supplied by the Monkstown and Bay L'Argent Terminal Stations experienced an unplanned power outage of three hours and 10 minutes. The outage occurred after a crossarm failed at a structure in transmission line TL212 during an extreme wind storm. There were wind gusts of over 120 km/h recorded on this day.

On February 16, all customers on the Great Northern Peninsula, north of Cow Head, experienced an unplanned power outage. Refer to the table below for details of the customer impact. The outages were caused by a tree contact on TL239 that resulted in a lockout operation on transformer T1 at the Berry Hill Terminal Station. The protection on T1 operated due an incorrect relay setting. This setting has since been corrected.

Event -TL239 Trip/BHL T1 Lockout					
Delivery Point Affected	**Start Time**	**Time of Restoration**	**Outage Duration (mins)**	**Load Loss (MW)**	**MW-Mins**
Cow Head	10:39	10:49	10	2	20
Parson's Pond	10:39	10:44	10	0.4	4
Daniel's Harbour	10:39	10:44	5	1	5
Hawkes's Bay	10:39	10:44	5	5.8	29
Plum Point	10:39	10:44	5	3.5	17.5
Bear Cove	10:39	10:44	5	5	25
Main Brook	10:39	10:45	6	0.4	2.4
Roddickton	10:39	10:45	6	2.2	13.2
St Anthony	10:39	10:45	6	9.3	55.8

On February 16, customers served by the Glenburnie, Wiltondale, Rocky Harbour, and Cow Head Terminal Stations experienced two unplanned power outages. Refer to the table below for details of the customer impact. The outages were caused by a broken insulator on TL227. Transmission line TL227 had been previously interconnected to TL226, due to the lockout of T1 at Berry Hill Terminal Station.

Event - TL226 Trip (10:50)					
Delivery Point Affected	**Start Time**	**Time of Restoration**	**Outage Duration (mins)**	**Load Loss (MW)**	**MW-Mins**
Glenburine	10:50	10:51	1	2.9	2.9
Wiltondale	10:50	10:51	1	0.1	0.1
Rocky Harbour	10:50	10:51	1	4.2	4.2
Cow Head	10:50	10:51	1	2.3	2.3

Event - TL226 Trip (10:53)					
Delivery Point Affected	**Start Time**	**Time of Restoration**	**Outage Duration (mins)**	**Load Loss (MW)**	**MW-Mins**
Glenburine	10:53	10:54	1	2.9	2.9
Wiltondale	10:53	10:54	1	0.1	0.1
Rocky Harbour	10:53	10:54	1	4.2	4.2
Cow Head	10:53	10:54	1	2.3	2.3

On February 17, NP customers supplied by transmission line TL215 from the Doyles Terminal Station experienced an unplanned power outage of three minutes. The line outage was caused by high winds in the area (greater than 100 km/h).

On February 19, Vale at Long Harbour experienced an unplanned power outage of two hours and 52 minutes. The outage was caused by transformer T1 tripping due a protection coordination issue with Vale's protection. These protection issues have since been resolved.

On February 23, customers supplied by the Bottom Waters Terminal Station experienced three unplanned power outages of 11 hours and 30 minutes in total. The first outage was caused by a bus lockout operation for a trip of transformer T1. The other two outages occurred during the restoration of T1. The transformer trip was caused by a faulty pressure/vacuum switch. The switch required isolation before T1 could be re-energized.

On March 16, NP customers supplied by transmission line TL215 from the Doyles Terminal Station experienced two unplanned power outages of five minutes and 41 minutes. The outages were caused by high winds in the area (greater than 110 km/h). The first outage was caused by the trip of transmission line TL215 and the second was caused by the trip of transmission line TL214.

On March 16, NP customers supplied by the Doyles Terminal Station experienced an unplanned power outage of 41 minutes. The outage was caused by high winds in the area (greater than 110 km/h) which tripped transmission line TL214.

On March 26, all customers on the Great Northern Peninsula, north of Cow Head, experienced a series of unplanned power outages, see the tables below. The outages were caused by trips of transmission lines TL239 and TL227 due to high winds in the area (greater than 160 km/h). There were reports of a wind gust at Norris Point measuring at 201 km/h.

Event - TL227 Trips March 26, 2014

Delivery Point Affected	Start Time	Time of Restoration	Outage Duration (mins)	Load Loss (MW)	MW-Mins
Cow Head	22:14	22:15	1	1.3	1.3
Cow Head	22:16	23:07	51	1.3	66.3

Event -TL239 Trip - Mar 26 22:19 hrs

Delivery Point Affected	Start Time	Time of Restoration	Outage Duration (mins)	Load Loss (MW)	MW-Mins
Parson's Pond	22:19	22:20	1	0.6	0.6
Daniel's Harbour	22:19	22:20	1	0.7	0.7
Hawkes's Bay	22:19	22:20	1	4.4	4.4
Plum Point	22:19	22:20	1	2.6	2.6
Bear Cove	22:19	22:20	1	4	4
Main Brook	22:19	22:20	1	0.4	0.4
Roddickton	22:19	22:20	1	2	2
St Anthony	22:19	22:20	1	6.8	6.8

Event -TL239 Trip - Mar 26 22:28 hrs

Delivery Point Affected	Start Time	Time of Restoration	Outage Duration (mins)	Load Loss (MW)	MW-Mins
Parson's Pond	22:28	22:30	2	0.5	1
Daniel's Harbour	22:28	22:30	2	0.7	1.4
Hawkes's Bay	22:28	22:30	2	4	8
Plum Point	22:28	22:30	2	2.4	4.8
Bear Cove	22:28	22:30	2	3.4	6.8
Main Brook	22:28	22:30	2	0.4	0.8
Roddickton	22:28	22:30	2	1.6	3.2
St Anthony	22:28	22:30	2	6.4	12.8

Event -TL239 Trip - Mar 26 22:34 hrs

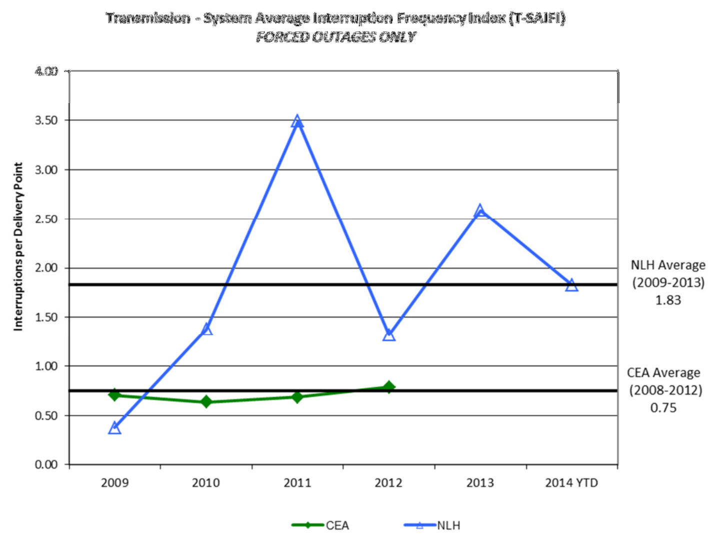
Delivery Point Affected	Start Time	Time of Restoration	Outage Duration (mins)	Load Loss (MW)	MW-Mins
Parson's Pond	22:34	22:36	2	0.5	1
Daniel's Harbour	22:34	22:36	2	0.7	1.4
Hawkes's Bay	22:34	22:36	2	4	8
Plum Point	22:34	22:36	2	2.5	5
Bear Cove	22:34	22:36	2	4	8
Main Brook	22:34	22:37	3	0.4	1.2
Roddickton	22:34	22:37	3	2	6
St Anthony	22:34	22:37	3	7.2	21.6

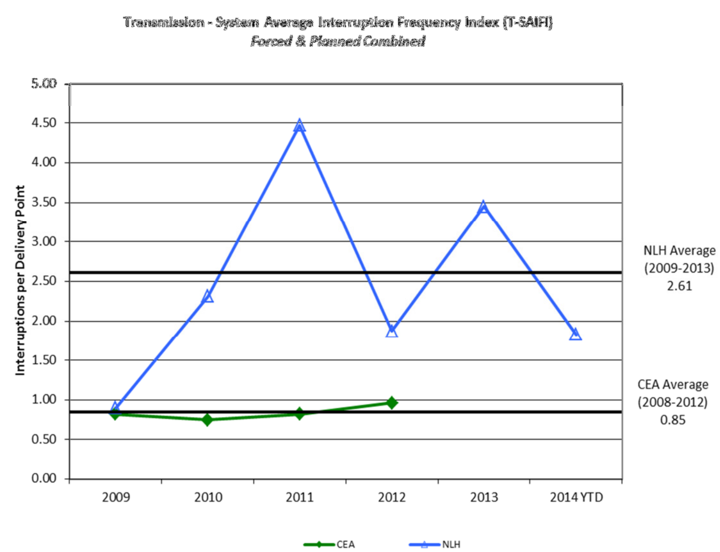
<u>Planned</u>

There were no planned outages this quarter.

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*.

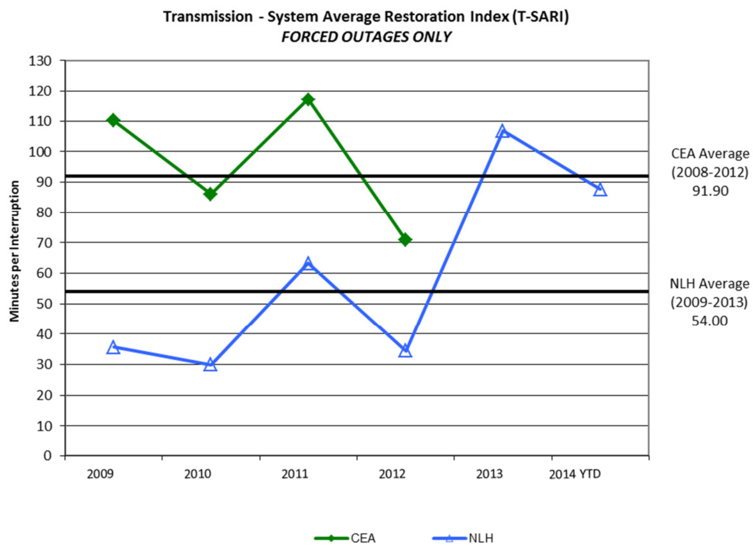
The first quarter T-SAIFI was 1.83 outages per bulk delivery point compared to 1.76 outages per bulk delivery point last year, a 4% increase. There were no planned outages this quarter. This is compared to 1.62 (forced) and 0.14 (planned) for the first quarter of 2013.

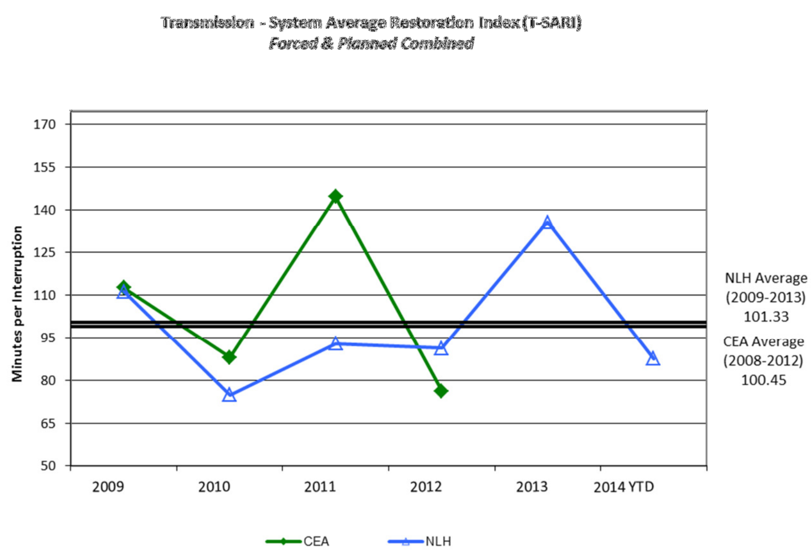




c) Transmission System Average Restoration Index (T-SARI) - *a reliability KPI for bulk transmission assets which measures the average duration per transmission interruption. T-SARI is calculated by dividing T-SAIDI by T-SAIFI.*

Hydro's total transmission T-SARI was 87.6 minutes per interruption for the first quarter versus 121.2 minutes per interruption for 2013. The forced outage component of T-SARI was 87.6 minutes per interruption. This compares with 124.2 minutes per interruption for the same quarter in 2013, a decrease of 29%. There were no planned outages in the first quarter of 2014, compared to 84 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 seven underfrequency events during this quarter. These events are summarized as follows:

On January 10, 2014, at 18:56 hours, Holyrood Generating Unit 2 tripped. The trip of Unit 2 occurred when a compressor failure resulted in an outage to a 600V power centre. This power centre supplies auxiliary equipment associated with Unit 2 turbine/boiler. Unit 2 was restored to service at 01:23 hours January 11, 2014. With the removal of generation (approximately 155 MW) the system frequency dropped to 58.25 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 1,306 MW. Hydro customers (2,210) were restored within three minutes. NP customers (21,067) were restored in 22 load blocks. The first customers were restored in seven minutes and all customers were reported to be restored within 28 minutes after the event occurred.

On January 12, 2014, at 17:36 hours, Holyrood Generating Unit 3 tripped. The underfrequency trip on Unit 3 occurred when a main feed water isolator did not electrically open. As a result Unit 3 tripped on low drum level. Hydro determined that the problem was with a control power signal from the local control system. Repairs were made and the unit was restored to service at 18:30 hours, January 12. With the removal of generation (approximately 66 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 1,030 MW. All NP customers (5,750) were restored within ten minutes after the event occurred.

On January 15, 2014, at 09:09 hours, TL201 (from the Western Avalon to Hardwoods terminal stations) tripped and remained open. The fault created a system disturbance which activated the rate of change (df/dt) underfrequency load shedding protection at NP. The decline in system frequency achieved a maximum value of 0.56 Hz/Sec. All NP customers (3,307) were restored within one minute after the event occurred. Total Hydro system load at the time of the incident was 998 MW. Upon investigation through line patrol, it was determined that two phases on structure 157 had fallen to the ground after the insulators had separated. The immediate cause is suspected to be a mechanical insulator failure due to high winds and adverse weather. The insulators were replaced and the line was restored to service at 22:29 hours on January 15.

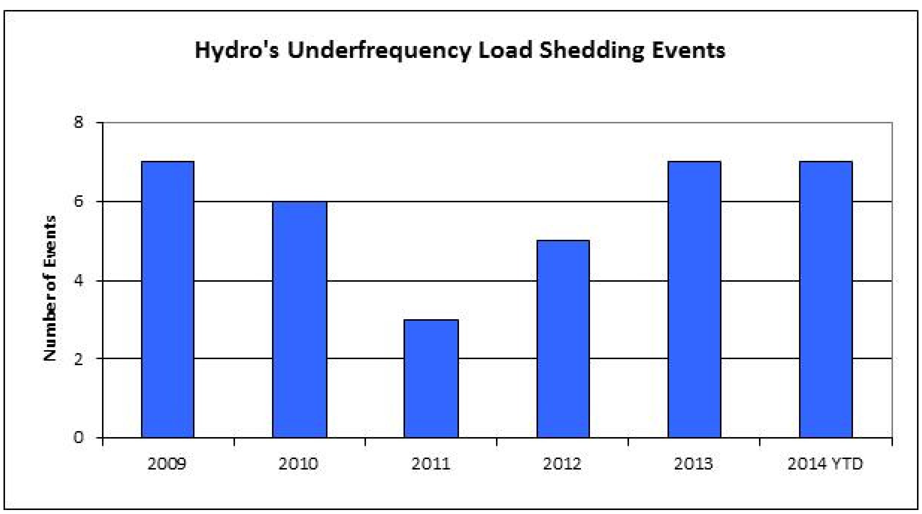
On January 27, 2014, at 16:50 hours, Holyrood Generating Unit 1 tripped. Hydro's investigation into the cause of the trip on Unit 1 determined that a circuit breaker supplying the burner management system was inadvertently tripped as corrective maintenance was carried out on another piece of equipment located in the same electrical cabinet. With the removal of generation (approximately 120 MW), the system frequency dropped to 58.56 Hz resulting in the activation of the under frequency protection at Newfoundland Power. Total system load at the time of the incident was 1,248 MW. All NP customers (11,061) were reported to be restored within 18 minutes after the event occurred.

On January 30, 2014, at 05:09 hours, Bay d'Espoir Generating Unit 6 tripped. The unit trip was caused by the failure of the rectifying transformer associated with the unit excitation system. The spare transformer was installed. With the removal of generation (approximately 64 MW), the system frequency dropped to 58.71 Hz resulting in the activation of the under frequency protection at Newfoundland Power and Corner Brook Pulp and Paper. Total system load at the time of the incident was 1,060 MW. All NP customers (6,087) were reported to be restored within four minutes after the event occurred.

On February 17, 2014, at 04:22 hours, Bay d'Espoir Generating Unit 6 tripped. The unit trip was again caused by the failure of the rectifying transformer (this time the spare unit). With the removal of generation (approximately 67 MW), the system frequency dropped to 58.58 Hz resulting in the activation of the under frequency protection at Newfoundland Power. Total system load at the time of the incident was 1,053 MW. There were 15,108 NP customers reported to be restored within five minutes after the event occurred. Unit 6 remains out of service.

On March 18, 2014, at 22:03 hours, while taking Bay d'Espoir Unit 4 offline, the unit breaker mis-operated, causing a bus lockout of Bus 2 at Bay d'Espoir, and tripping Unit 3 offline. With the removal of generation (approximately 59 MW), the system frequency dropped to 58.72 Hz resulting in the activation of the under frequency protection at Newfoundland Power and Corner Brook Pulp and Paper. Total system load at the time of the incident was 1,184 MW. There were 7,225 NP customers reported to be restored within five minutes after the event occurred.

Refer to the graph below which compares the UFLS events over the past five years to the year-to-date 2014 performance.



Underfrequency Load Shedding Number of Events

Customers	First Quarter 2014	First Quarter 2013	Year to Date 2014	Year to Date 2013	5 Year Average (2009–2013)
NF Power	7	4	7	4	5.6
Industrials	2	0	2	0	1.6
Hydro Rural*	1	1	1	1	2.2
Total Events	7	4	7	4	5.6

Underfrequency Load Shedding Unsupplied Energy (MW-min)

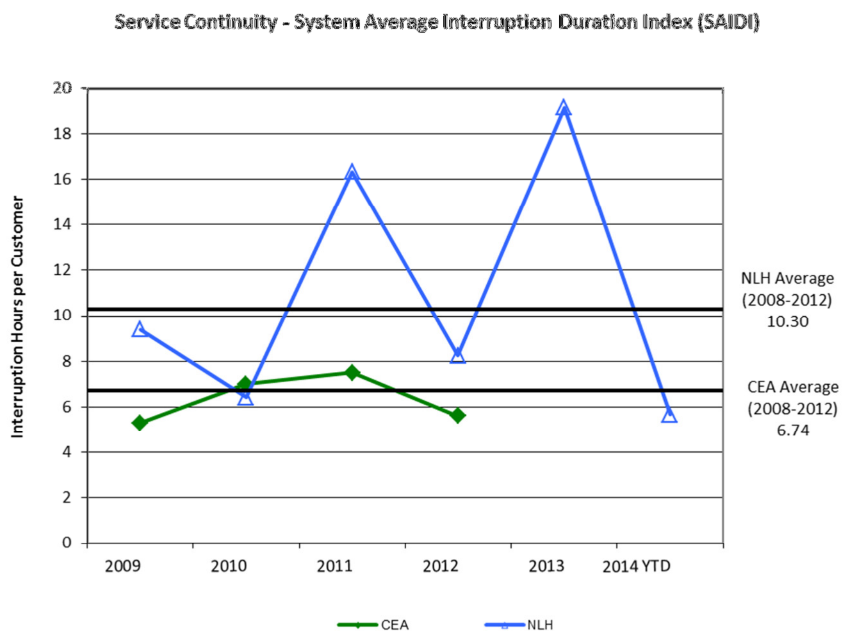
Customers	First Quarter 2014	First Quarter 2013	Year to Date 2014	Year to Date 2013	5 Year Average (2009–2013)
NF Power	3,078	1,565	3,078	1,565	3,854
Industrials	130	0	130	0	115
Hydro Rural*	36	21	36	21	99
Total Events	3,244	1,586	3,244	1,586	4,050

* 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 5.67 hours per customer compared to 4.28 hours per customer in 2013, an increase of 32%.



A summary of the major interruptions follows:

On January 1 from 17: 45 to 23:44 hours (Labrador time), customers in Happy Valley-Goose Bay, Labrador serviced by feeder L16 experienced two unplanned and one emergency planned power outage. The outages occurred due to unbalanced loading on the feeder. See the following for outages details:

Outage 1:	17:45 - 18:17 hours (32 minutes)	3,984 customers
Outage 2:	17:57 - 18:11 hours (14 minutes)	1,019 customers
	(Emergency planned outage for switching operations)	
Outage 3:	18:15 - 23:44 hours (5 hours 29 minutes)	1,019 customers

On January 22, at 20:00 hours (Labrador time), 391 customers in Labrador City, Labrador supplied by Line 13 experienced an unplanned power outage. The outage occurred when a piece of jumper conductor burned off a pole. All customers were restored at 22:00 hours.

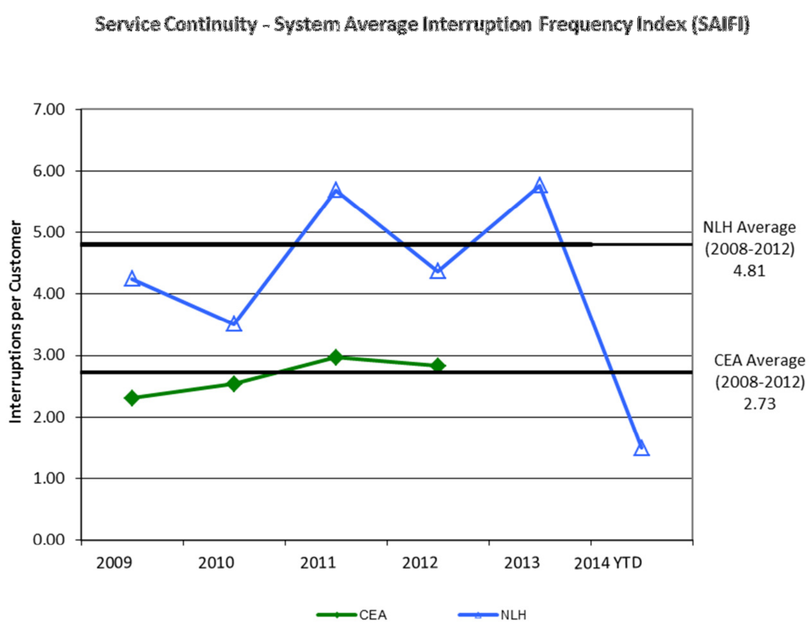
On January 26, 2014, at 09:55 hours, all customers (1369) serviced by the Barachoix Terminal Station, including the communities of Gaultois, Harbour Breton, Hermitage, and Seal Cove experienced an unplanned power outage. The outage occurred due to line damage caused by extreme weather and high winds. Hydro crews safely made the necessary repairs and all customers were restored by 18:55 hours. Delays in restoration were due to distance and travel time in extreme weather, the investigation into the cause of the outage, and the repair time.

On January 26, 2014, at 08:48 hours, all customers (921) serviced by the Grandy Brook Terminal Station, including the communities of Burgeo, Grand Bruit, and La Poile, experienced an unplanned power outage. The outage occurred when the 138 kV transmission tine TL250 tripped out of service due to a failed cross arm. There were extreme high winds at the time. Hydro crews safely made the necessary repairs and all customers were restored by 17:35 hours. Delays in restoration were due to distance and travel time in extreme weather, the investigation into the cause of the outage, and the repair time.

On January 26, 2014, at 09:33 hours, all customers (813) serviced by the English Harbour West Terminal Station, including the communities of Boxey, Belleoram, Coombs Cove, English Harbour West, Mose Ambrose, Pools Cove, Rencontre East, St. Jacques, and Wreck Cove experienced an unplanned power outage. The exact cause of the outage is unknown, however it was most likely due to the extreme weather and high winds experienced at the time. All customers were restored by 13:23 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 of 2014, the SAIFI was 1.49 interruptions per customer compared to 2.10 interruptions per customer in 2013, a 29% decrease.



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 2014	First Quarter 2013	12 Mths to Date 2014	12 Mths to Date 2013	5 Year Average
Central					
Interconnected	1.18	1.49	3.71	3.11	2.89
Isolated	0.75	0.70	2.90	1.93	3.34
Northern					
Interconnected	1.79	2.14	4.55	6.24	4.42
Isolated	4.54	1.89	7.46	8.44	6.78
Labrador					
Interconnected	1.10	2.80	6.85	7.72	6.74
Isolated	1.65	3.16	7.53	10.96	10.20
Total	1.49	2.10	5.16	5.81	4.88

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 2014	First Quarter 2013	12 Mths to Date 2014	12 Mths to Date 2013	5 Year Average
Central					
Interconnected	3.94	6.37	18.94	10.19	11.85
Isolated	0.08	1.21	1.42	4.43	2.62
Northern					
Interconnected	9.26	3.55	17.85	13.97	12.58
Isolated	27.36	1.87	31.59	7.98	11.25
Labrador					
Interconnected	1.87	3.11	26.91	11.82	16.12
Isolated	0.96	4.18	5.00	15.82	11.43
Total	5.67	4.28	20.53	11.65	12.94

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 2014	First Quarter 2013	12 Mths to Date 2014	12 Mths to Date 2013	5 Year Average
Loss of Supply – Transmission	0.35	0.47	1.20	1.70	1.55
Loss of Supply – NF Power	0.00	0.00	0.01	0.01	0.01
Loss of Supply – Isolated	0.12	0.14	0.46	0.50	0.52
Loss of Supply – L'Anse au Loup	0.05	0.05	0.05	0.05	0.06
Distribution	0.97	1.45	3.43	3.54	2.73
Total	1.49	2.10	5.16	5.80	4.88

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 2014	First Quarter 2013	12 Mths to Date 2014	12 Mths to Date 2013	5 Year Average
Loss of Supply – Transmission	2.01	0.84	5.54	2.48	3.96
Loss of Supply – NF Power	0.00	0.00	0.05	0.00	0.14
Loss of Supply – Isolated	0.05	0.03	0.23	0.17	0.23
Loss of Supply – L'Anse au Loup	0.06	0.05	0.06	0.05	0.04
Distribution	3.54	3.36	14.65	8.95	8.57
Total	5.67	4.28	20.53	11.65	12.94

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 (Fourth Quarter 2014)

Area	Scheduled		Unscheduled		Total	
	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI
Central						
Interconnected	0.03	0.06	1.15	3.88	1.18	3.94
Isolated	0.00	0.00	0.75	0.08	0.75	0.08
Northern						
Interconnected	0.00	0.00	1.79	9.26	1.79	9.26
Isolated	0.23	0.52	4.30	26.85	4.54	27.37
Labrador						
Interconnected	0.22	0.07	0.88	1.79	1.10	1.87
Isolated	0.00	0.00	1.65	0.96	1.65	0.96
Total	0.08	0.07	1.41	5.60	1.49	5.67

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

Ramea Wind-Hydrogen-Diesel Project Update

Nalcor Energy

May 14, 2014

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1 Project Description

In 2007, Hydro applied to the Board for approval to proceed with the construction of a Wind-Hydrogen Diesel Generation Project (the Project) at Ramea, pursuant to Section 41(3) of the Act. The Project is a research and development project focused on renewable energy generation, storage, and grid integration in an isolated diesel powered community. The main objective of the Project has been to integrate existing diesel generators in Ramea with wind turbines and hydrogen equipment. Integration is made possible through the use of the Energy Management System (EMS). The EMS is the control system developed by Nalcor Energy (Nalcor) that monitors operating conditions and dispatches the various generation sources. Nalcor owns all Intellectual Property associated with the EMS. Wind turbines provide energy to the Ramea electrical grid during high load periods. When the load is low, the wind energy is used to produce hydrogen gas. This gas is converted back to electricity through a hydrogen fueled generation source when wind speeds are too low to operate the wind turbines. The renewable generation provided by the wind turbines and the hydrogen system is used to offset diesel fuel consumption.

2 Project Reporting

In Order No. P.U. 31(2007), the Board granted the approval of the construction and installation of the Wind-Hydrogen-Diesel System as proposed. Hydro was directed to provide a quarterly update on the status of the Wind-Hydrogen-Diesel System in each quarterly report to the Board, setting out details as to implementation and operation of this system, capital and operating costs, variances from budget, reliability and safety issues. Hydro was also directed to file a report to the Board within ninety days of the conclusion of the operational testing phase addressing in detail Hydro’s conclusions and plans in relation to the Wind-Hydrogen-Diesel System.

The initial schedule for the Project, as outlined in Order No. P.U. 31(2007), called for construction of the Project to be completed at the end of 2008, followed by a three-year operational phase, ending in 2011. However, as outlined in the quarterly reports that have been submitted to-date, these milestones have not been met and the operational phase of the project has not started. As with any research and development project, there have been challenges along the way and these challenges have resulted in project delays. One of the major challenges faced by the Project was the reliability issues surrounding the hydrogen genset. The genset is the hydrogen fueled generator that is used to generate electricity when there is no wind power available. It was provided by Natural Resources Canada as an in-kind contribution and it has not functioned with the reliability needed from a piece of equipment operating in a utility environment. Nalcor has spent considerable time and resources troubleshooting the genset issues but an acceptable level of performance has not been obtained.

3 Project Update

Installation and commissioning of all major equipment of Phase I was completed in 2012 and the capital component of the Project was closed at the end of 2013. In 2011, an operating business unit was established so that preventative maintenance could be performed on other project equipment as the genset issues were being dealt with. The costs associated with this business unit have not been included in the quarterly reports to-date. These costs are not considered part of the Operational Phase of the completed Project, as this phase had not started however, they are an important part of the overall financial picture and will be included in all future reporting.

The EMS has functioned as designed but has not been fully utilized. It is operating all systems in automatic mode except the hydrogen genset. The EMS has the ability to start and stop project equipment automatically. This is to ensure that the correct generation source is dispatched according to current system conditions. Due to reliability issues, the hydrogen genset has been placed in manual mode which means that the EMS can only operate it when the operator turns it on. While the genset is in manual mode, the EMS will bypass it when dispatching generating sources. This is how the system has been running since the end of 2012. The operator has used the gensets in manual mode and generated electricity from hydrogen but the run times have been limited.

4 Ramea Wind-Hydrogen-Diesel Project Phase II

A major milestone for the project is the development of a fully utilized EMS that controls all project equipment. In order to achieve this, the EMS will need to operate all equipment in automatic mode for a continuous period of time. This will allow Nalcor to collect valuable data that will be studied to inform decisions regarding future installations of the EMS and renewable generation and energy storage in other communities. To achieve this goal, it has been determined that a reliable hydrogen fueled generation source is required. In 2012, Nalcor submitted a proposal to the Atlantic Canada Opportunities Agency (ACOA) through the Atlantic Innovation Fund (AIF) for Phase II of the Project. Phase II of the Project will be a five-year project that will include installation, optimization and commercialization of the components. Phase II will build on the work completed in Phase I and will include the installation and integration of a hydrogen fuel cell to the existing system, modifications to the EMS and upgrades to existing equipment to increase the penetration of wind and hydrogen generated energy into the isolated community energy supply mix.

In 2013, ACOA accepted the proposal and approved approximately $2.3 million (representing 55.5 per cent of the total Project cost) towards Phase II of the Project. Work on Phase II began in early 2014 and commissioning of the fuel cell is expected to be completed during the spring of 2015. The operations phase of the Project will begin after the fuel cell is commissioned and will run until March 31, 2017. Once this operations phase is complete, Nalcor will provide the report as directed in Board Order No. P.U. 31(2007).

5 Future Reporting

Beginning this quarter, Nalcor will include updates on Phase II in its quarterly reports to the Board. This will include an update on the operating costs associated with maintaining existing equipment and a summary of the capital expenditure associated with the addition of the fuel cell. It is important to note that these operating costs are Nalcor specific costs and are not part of Hydro’s regulated operations. If desired, Nalcor can provide an updated presentation to members of the Board to discuss the Project in more detail.