Q. Please describe methods, techniques, channels and procedures used to communicate customer research and customer satisfaction results internally and externally. Include examples of recent internal and external communications and reports and summaries.

A. Internal communication of customer research and satisfaction results is communicated during meetings. For example, customer research completed by MQO Research for Hydro in 2012 was presented by MQO to members of the Customer Service and Corporate Communications departments in November of that year. Please refer to PUB-NLH-193 Attachment 1 for a copy of the presentation. The results of customer satisfaction surveys would also be communicated during meetings to the Vice President of Newfoundland and Labrador Hydro, Vice President of Corporate Relations and Customer Service, the Customer Service department, and to managers and supervisors of Transmission and Rural Operations. No customer satisfaction surveys have been completed since 2012, but are planned for 2014 as indicated in Hydro's response to PUB-NLH-189. Customer satisfaction results are communicated externally in Hydro’s Quarterly Reports filed with the Board. Please refer to the December 31, 2012 Quarterly Report (PUB-NLH-193 Attachment 2 pages 9, E27, and E28) for a summary of Hydro’s last customer satisfaction survey completed in 2012.

Residential Customer Satisfaction Research

MQO RESEARCH RECHERCHE
a group m5 company

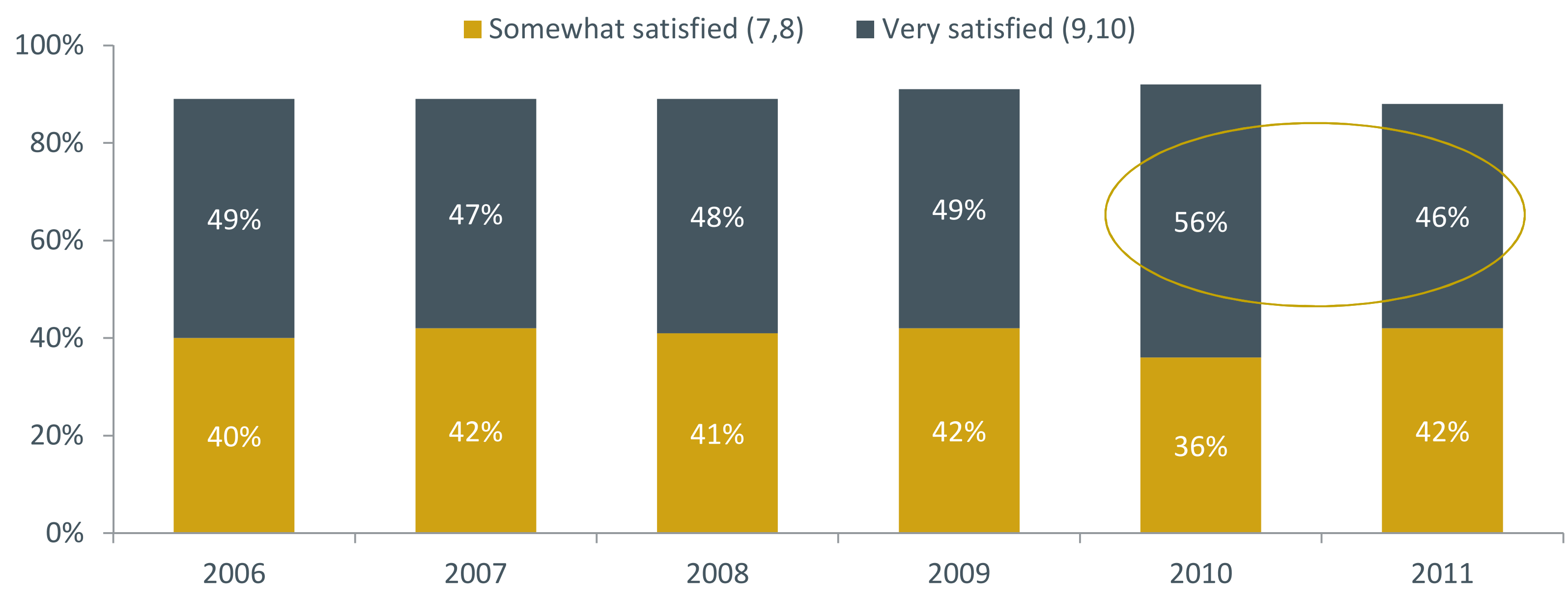
Study Methodology

- For a number of years, MQO Research has conducted Hydro's annual residential customer satisfaction tracking research.
- This research is conducted via telephone.
- The sampling unit is the adult household member who is responsible for paying the electricity bill and dealing with Hydro.
- A total of 725 residential customers complete this survey annually, which provides a margin of error of ±3.6%, 19 times out of 20.

Overall Satisfaction

- Customers are asked to rate their overall satisfaction with Hydro using a scale of 1 to 10 where 1 is ***'not at all satisfied'*** and 10 is ***'very satisfied'***.

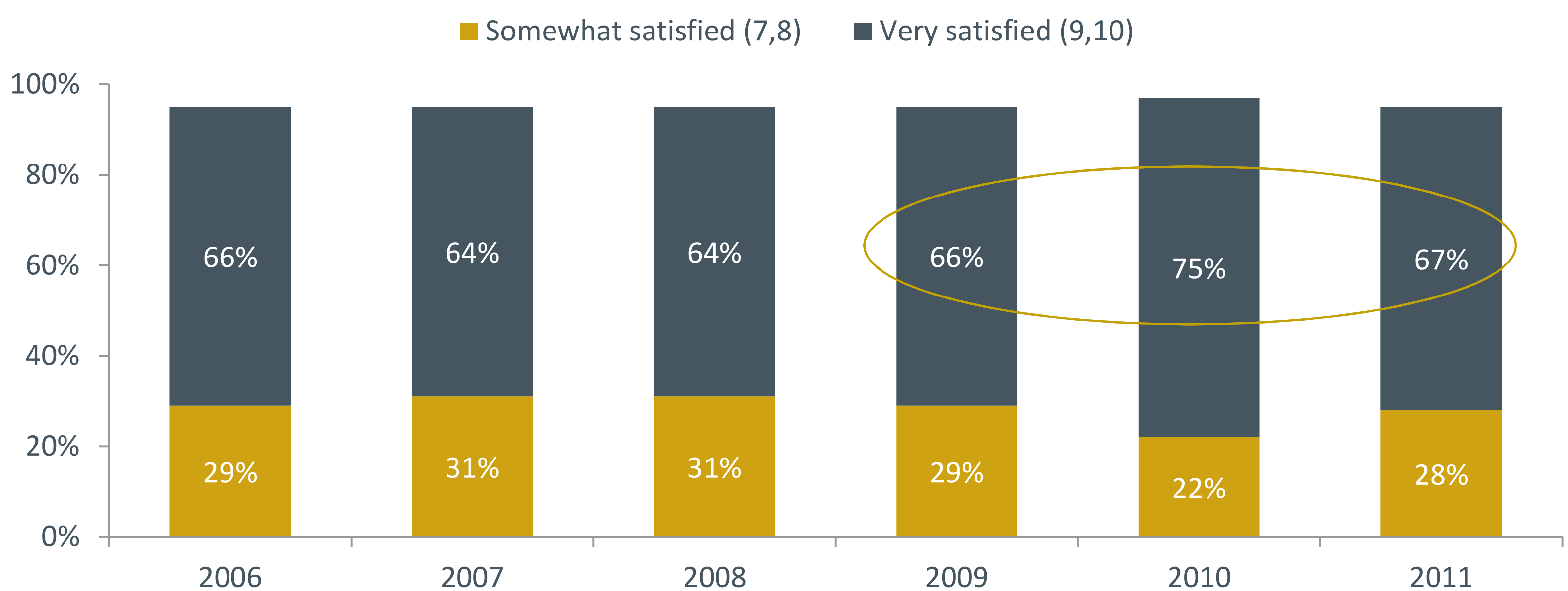
- Results have remained consistent. The vast majority of customers are either ***very satisfied*** or ***somewhat satisfied*** with the performance of Hydro. In 2011, there was a decrease in the proportion of customers who provided a rating of 9 or 10.



Q5. In general, <u>how satisfied are you with Hydro</u> on a scale of 1 to 10 where 1 means *'not at all satisfied'* and 10 means *'very satisfied'*?

Service Reliability

- To determine satisfaction with Hydro's service reliability, customers are asked to rate their satisfaction with the **supply of electricity** they receive from Hydro.
- In 2010, there was a ***significant increase*** in the proportion who provided a rating of 9 or 10.
- This research has consistently revealed that customers in both Central and Northern regions report greater satisfaction with Hydro's service reliability than those in Labrador.

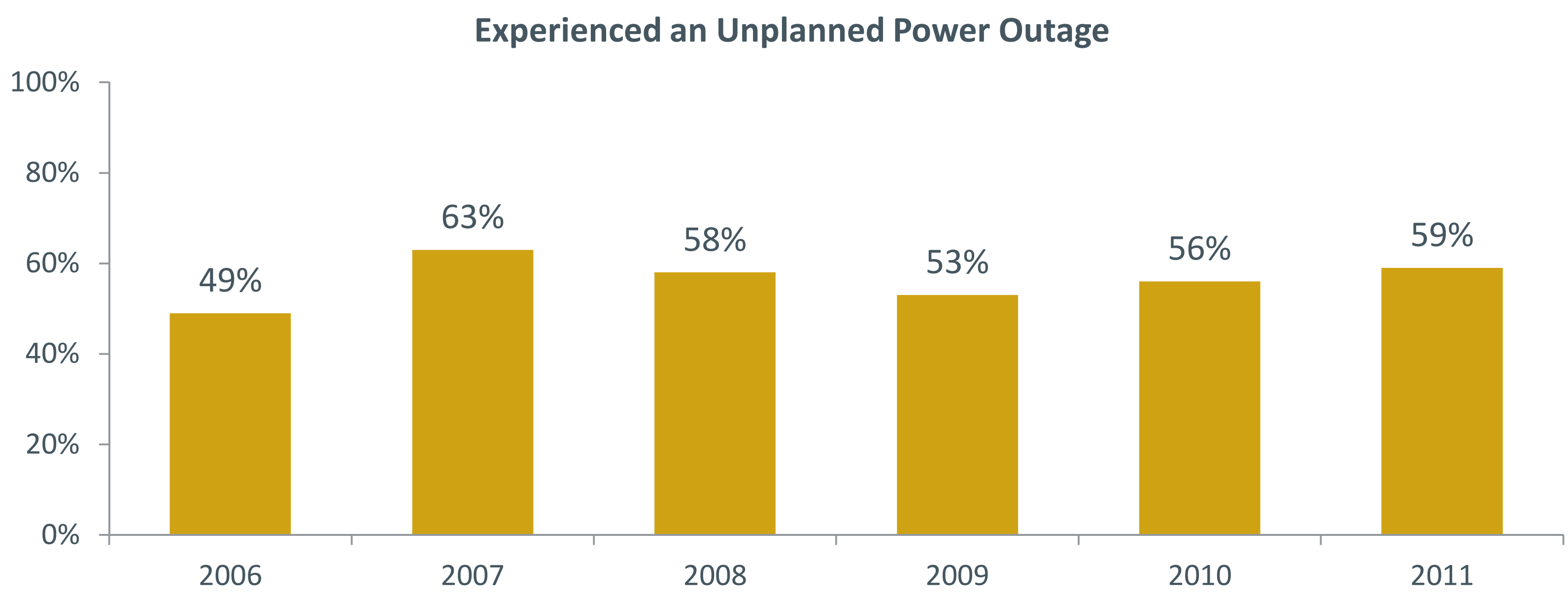


Q6A. On a scale of 1 to 10 where 1 means *'not at all satisfied'* and 10 means *'very satisfied'*, how satisfied are you with the supply of electricity you receive from Hydro?

Unplanned Power Outages

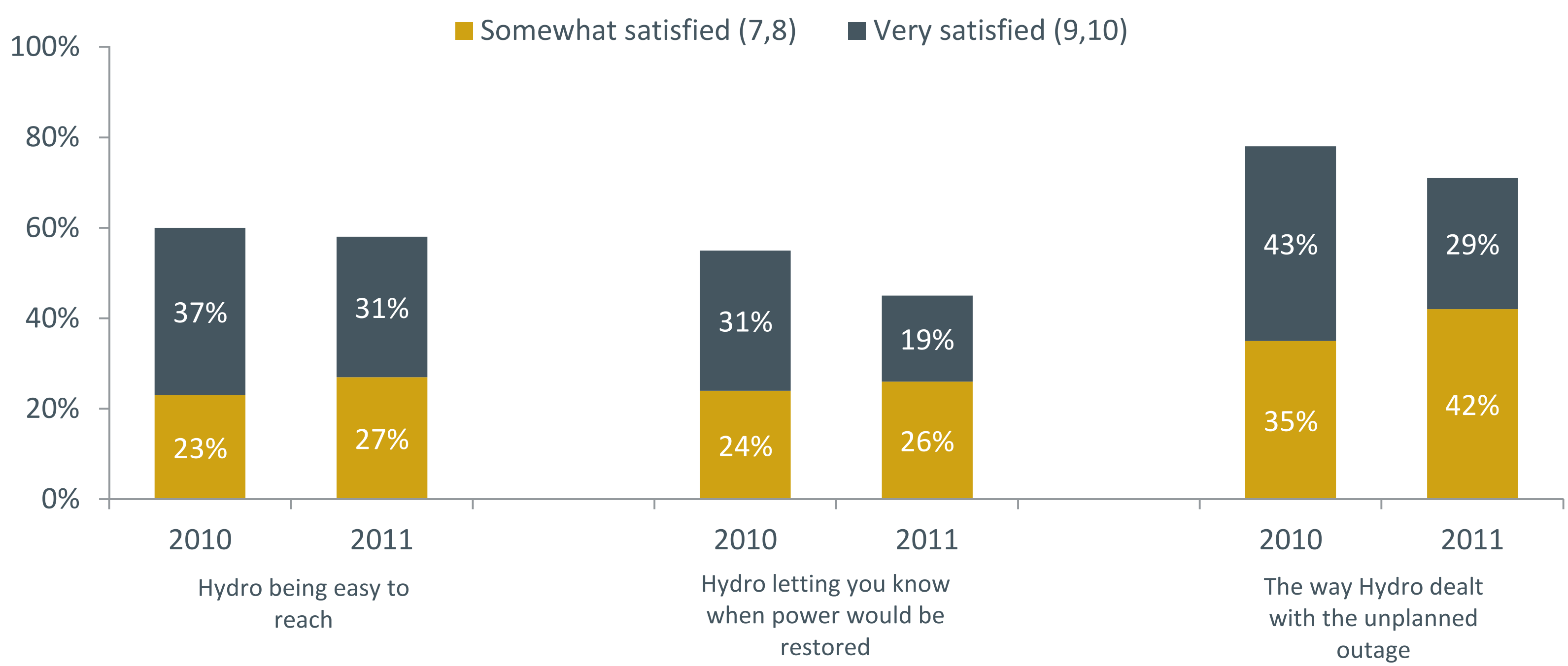
- The graph below details the percentage of residential customers who have ***experienced an unplanned power outage*** at their home which lasted longer than 30 minutes.

- After declining from 2007 to 2009, the percentage of customers reporting such an experience ***increased slightly*** over the past three years.



Unplanned Power Outages (cont'd)

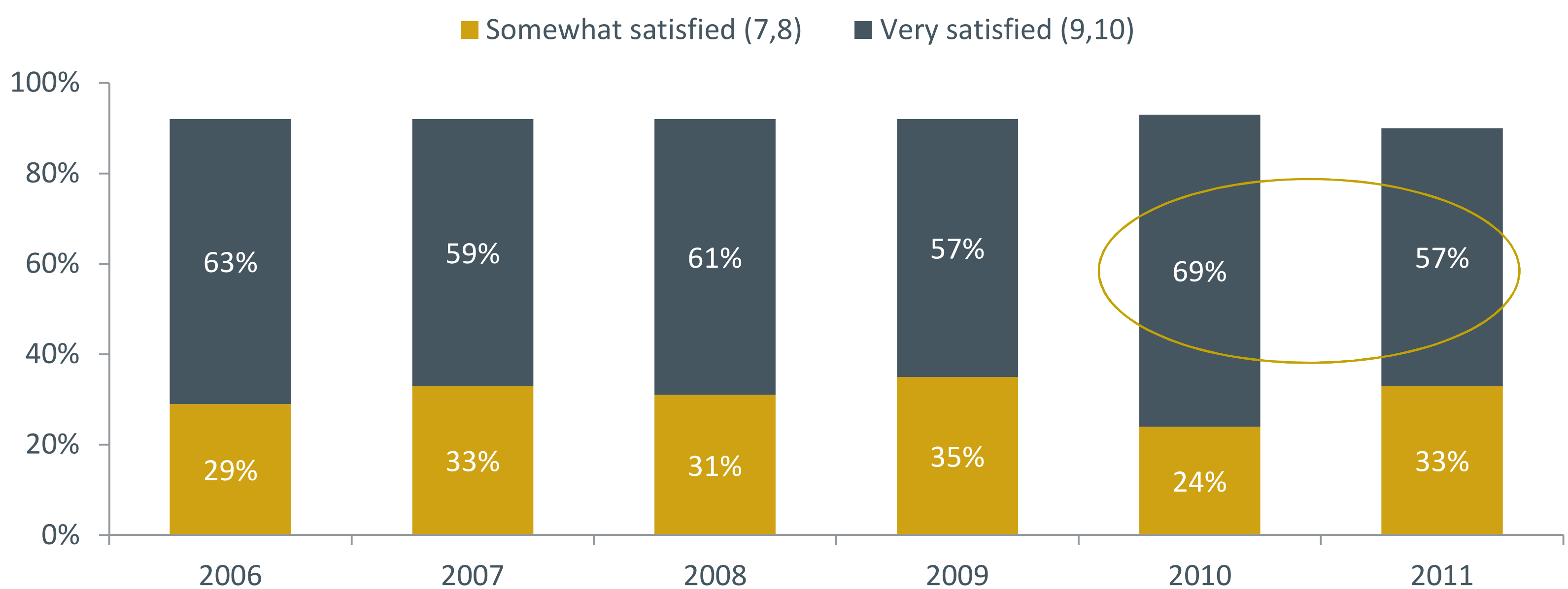
- Customers who experienced an unplanned power outage are asked to rate their satisfaction with various aspects of Hydro's service during that experience using a scale of 1 to 10.
- Looking back at the past two years, residential customers are ***moderately satisfied*** with the service received from Hydro during a recent power outage.
- It is important to note that for each of the three attributes, compared to 2010 there is a ***significant decrease*** in the percentage of customers who provided a rating of 9 or 10 (that is, those who are ***'very satisfied'***).



Customer Service

newfoundland labrador hydro
a nalcor energy company

- Customers are asked to rate their satisfaction with the **customer service** they receive from Hydro on a scale of 1 to 10, with 1 being ***'not at all satisfied'*** and 10 being ***'very satisfied'***.
- Results have consistently revealed that residential customers are ***satisfied*** with the customer service received from Hydro.
- Compared to 2010, the proportion of customers who provided a rating of 9 or 10 ***decreased significantly*** (from 69% in 2010 to 57% in 2011). However, the proportion of customers who provided a rating of 7 or 8 ***increased significantly***.



Q6B. On a scale of 1 to 10 where 1 means *'not at all satisfied'* and 10 means *'very satisfied'*, how satisfied are you with the overall customer service you receive from Hydro?

Summary

Focus Group Findings

Methodology

- 4 Focus Groups – 2 St. Anthony, 2 Goosebay.
- Dates: October 17th and 18th.
- Composition:
  - Mix of men and women.
  - Responsible for paying their power bill.
  - Ages between 25 and 65.
  - 3 per group to have more mediocre ratings.

Purpose

- Understand customer satisfaction with Hydro in more depth.
- Generate tactics to improve customer satisfaction.
- Update satisfaction tracking survey with questions reflecting new findings.

Ratings of Satisfaction

- Early in group, participants asked to rate Hydro - 1 – 10.

- Ratings generally high – 19 out of 33 were 8 or higher. 13 were 6 or 7 and 1, 5.

- Remember that we recruited to have a few per group who were recruited to have ratings of 5 and 6.

- Generally positive reaction so discussion positioned as areas of service where Hydro could improve.

Main Positives

- Very fast emergency or power out response.
- People "love" linesmen – the main face of Hydro in these communities.
- Community involvement – visible around town – act and conduct themselves as part of the community.
- Very consistent/reliable service in Goosebay.
- Keeping of diesel backup in St. Anthony.
- Safety of Employees.

Main "Areas for Improvement"

- Rates/monthly bill. More on this later.
- Frequent short outages in St. Anthony.
- Long wait times for new hook-ups/inspections.
- Lack of appointments/Specific time frames for hook-ups.
- Difficulty reaching local people – have to go through St. John's. (St. Anthony – "worst answering system you can have")
- Planned outages when weather is cooler.
- Accessing inspectors for energy audit money – Goosebay.
- Difficulty understanding usage – away, but bill is higher?
- Communication (energy efficient programs, power outages, appointments, what to do to save money)
- Linesmen great ambassadors, but not Hydro as a whole.

Understanding Rates/Prices

- An issue even in Goosebay with their low rates.
- Partly the total amount they have to pay.
- Partly the fact they feel they have no choice.
- There is no clear link between what the customer uses and what it costs.
- Perception that price increases are very regular and increases in their salary are not.
- Reaction to perception of high salaries of senior execs at Hydro.
- High profits at Hydro and the lack of competition.

Customer Suggestions - Costs

- Help customer find ways to use less.
- How to deal with no auditor for programs in Goosebay?
- Government could subsidize low income earners.
- Target high users to help them – pro-active.
- More concerned about their costs than the environmental advantages of using less.
- Promote existing rebates.
- Particularly concerned about seniors.

Dealing with non-emergencies

- Schedule specific appointments.
- Use of cell phones to confirm arrival time.
- More manpower at peak times.
- Sense that local office/contact would do a better job with this.

newfoundland labrador hydro
a nalcor energy company

Communication

- General sense that Hydro does more and offers more than they are aware of – blame this on communications efforts.
- No strong sense of Hydro beyond the local linesmen who are seen as folk heroes.
- Various suggestions – email, website, information spots (Labrador Morning), Open House, mail out with bill, seminars, 1-800 number to call with questions.
- Particular interest in their own consumption compared to previous years and neighbours.
- Facebook and automatic telephone messages.

Power Outages-St. Anthony

- More of an issue for short outages that are not weather related.
- Need more manpower.
- More preventive maintenance.
- Do an assessment of lines – why are frequent outages happening.

Local Office

- Feel that people they are calling do not know their situation or the area; “they don’t even know where St. Anthony is.”
- Related to communication – cant speak native language.
- Hire or train people for native language.
- Open the office again.
- Seniors want to pay in person.

Corporate Citizenship

newfoundland labrador hydro
a nalcor energy company

- Confusion in Goosebay – Nalcor is promoted more, not Hydro.
- Nalcor, not as positive because of Lower Churchill and sense of "bulldozing ahead."
- Need to be in the community more – linesmen are, but not rest of company.

Listening to Customers

- Don’t listen about costs. Rates are high.
- No choice.
- The process for a hook-up and vagueness about when the job will be done.
- New person in St. John’s – no idea of the area.
- The middleman between the customer and Hydro.
- Listen to seniors – always talking about expenses and lights.
- Linesmen are an “ordinary Joe” - people relate to them.
- Don’t get clear answers when talking on the phone.

Changes to Questionnaire

- We ask about energy efficiency – should also ask about helping customers save money.
- Survey asks about all employees together – suggest we separate into linesmen, other employees and maybe even senior management.
- Add rating on communicating with customers.
- More detail on costs – value for money.
- Outages – understand difference between short and longer outages.
- Making it clear or helping you understand what you are paying for.

Workshop Assignments

- One large group or split into groups?
- Consider the task based on the spirit of what the customer is saying.
- Please don't worry about what you can and cant do at this stage – let's not exclude any idea because it seems that it is not feasible.

- Costs – Value for Money.
- Communication Efforts.
- Local Office.
- Corporate Citizenship.
- Non-emergency Service.

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

February 14, 2013

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

ATTENTION: Ms. Cheryl Blundon
<u>Director of Corporate Services & Board Secretary</u>

Dear Ms. Blundon:

Enclosed are nine (9) copies of Newfoundland and Labrador Hydro's Quarterly Regulatory Report for the period ending December 31, 2012.

Please note that financial data throughout the report is not yet available. This includes the data in the financial section of the Annual Report on Key Performance Indicators (KPIs) at Appendix E. This data will be filed at a later date, once audited financial statements become available.

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 DECEMBER 31, 2012

Newfoundland and Labrador Hydro

Table of Contents

1 HIGHLIGHTS

HIGHLIGHTS
For the twelve months ended December 31, 2012

REGULATED	2012 Actual YTD	2012 Target/ Budget	2011 Actual YTD
Safety			
Lead:Lag Ratio[1]	230:1	600:1	578:1
All Injury Frequency Rate[1]	2.25	<u><</u>0.8	0.91
Production			
Quarter End Reservoir Storage (GWh)	2,173	1,010	2,260
Hydraulic Production (GWh)	4,595	4,682	4,512
Holyrood Fuel cost per barrel, current month ($) [2]	113	59	107
Holyrood Efficiency [2]	599	630	603
Electricity Delivery			
Sales including Wheeling (GWh)		7,068.9	6,628.7
Financial			
Revenue ($millions)		507.3	446.1
Expenses ($millions)		492.0	425.5
Net Operating Income ($millions)[3]		15.3	20.6
Current Rate Stabilization Plan (RSP) Balance ($millions)	(201.7)	(197.7)	(170.3)
Hydraulic	(32.7)	(40.2)	(32.7)
Utility	(64.9)	(54.5)	(55.9)
Industrial	(104.1)	(103.0)	(81.7)
Full Time Equivalent (FTE) Employees[4, 5, 6]			
Regulated		850.8	819.6
Non-Regulated		29.1	23.7

[1] Annual Target, and 2011 Actual
[2] Target based on approved 2007 Test Year forecast
[3] Does not include any earnings from CF(L)Co
[4] One FTE is the equivalent of actual paid regular hours - 2,080 hours per year in the operating environment and 1,950 hours per year in Hydro's head office environment.
[5] Annual Budget and 2011 Actual values
[6] 2012 Budget FTEs Regulated does not include vacancy adjustment of 27 FTEs

- Canadian Electricity Association presents Vice President's Award of Safety Excellence to Hydro (page 4)
- Hydro's Transmission Structure Corrosion Workshop Presentation (page 19)

2 SAFETY

Goal - To be a Safety Leader

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

Measurement	Year-to-date 2012 Actual	Annual 2012 Plan	Annual 2011 Actual
All Injury Frequency (AIF)	2.25	<0.8	0.91
Lost Time Injury Frequency (LTIF)	0.79	<0.2	0.13
Ratio of condition and incident reports to lost time and medical treatment injuries (lead/lag ratio)	230:1	600:1	578:1
Audit Work Protection Code Compliance	Completed		
Complete Work Method Development for Critical Tasks	87.33%	85%[1]	N/A

[1] Incorrectly reported as 100%; the Annual 2012 Plan was 85%.

Based on solid safety performance in 2011 and a downward trend in injuries over the past several years, the safety performance metrics for 2012 were set at an all injury frequency rate of 0.8 or less, a lost time injury frequency rate of 0.2 or less, and a lead/lag ration of 600:1 for Hydro. Although there was an increase in the number of injuries in 2012, preventing the metric targets from being met, the injuries were preventable, mainly low risk in nature and Hydro is still seeing overall continual improvement in injury performance.

Going forward, there is a targeted approach on injury prevention, communication and awareness, and visible leadership and support at all levels. There will also be a focus on supporting and recognizing the areas with exceptional safety performance to enable continued motivation and sustain a positive and strong safety culture.

Hydro continued its focus on planned safety objectives during the final quarter of 2012.

The public campaign for Power Line Hazards is ongoing. A new work group has been established in conjunction with Newfoundland Power, the Newfoundland Labrador Construction Safety Association (NLCSA), and Workplace Health, Safety and Compensation Commission (WHSCC), among others, to develop and deliver strategic initiatives around power line safety. Hydro also remains an active member of the WHSCC Technical Advisory Committee for Power Line Hazards (PLH), a technical resource for the WHSCC PLH Trainers Course. Hydro's three-year Safety Communication Plan efforts continue.

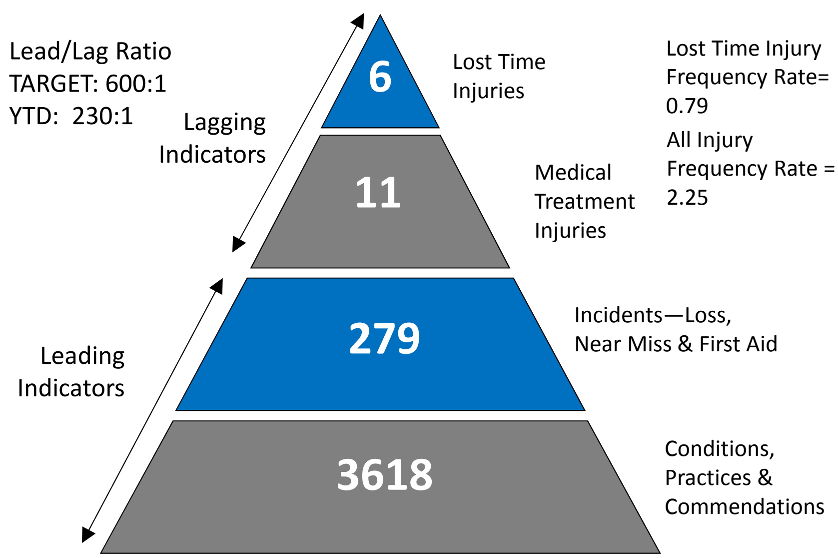
The development and enhancement of safety culture progresses with the (BeSafe) safety coaching workshops continued throughout the regions. Further sessions will be held into 2013.

From a key program perspective, Hydro remains focused on the areas of Grounding and Bonding, Work Methods and Work Protection Code (WPC). The Corporate Grounding and Bonding Committee has developed a training standard and course content, identified and trained trainers and commenced delivery to line operations staff. Further, work continues around the development of Work Methods for identified critical tasks. As the WPC Program reaches maturity, the focus will shift to evaluation with development of new software for the issuing of permits and a program audit application to assist the ongoing audit process.

In the fourth quarter, work also continued with respect to vulnerable workers, aimed at reducing exposures to new and younger workers. A new Local Orientation Standard has been developed and the “Green Hard Hat Program” that is used to enhance the visibility of new workers in the field has continued.

To further enhance the reporting of safety observations, Safe Workplace Observation Program (SWOP) training was delivered in the fourth quarter in partnership with the new Incident Investigation Training Program. Positive feedback has been received and training will continue into 2013.

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



2.1 Canadian Electricity Association presents Vice President's Award of Safety Excellence to Hydro

On October 2 at the Occupational Health and Safety Awards Reception in Ottawa, Hydro accepted the 2011 Canadian Electricity Association (CEA) Vice President's Award of Safety Excellence at the bronze award level in the Transmission/ Distribution category.

This award is given to a CEA corporate utility who reported both an All Injury Frequency Rate and a Lost Time Injury Severity Rate which ranked at or above the top quartile of the utilities within their reporting group within the 2011 reporting year.

John Hollohan, Jim Haynes and Paul Smith accept the CEA's Vice President's Award of Safety Excellence

2.2 ATV Training at Hydro Generation

Employees at Hydro Generation received hands on training in the safe operation of All Terrain Vehicles (ATVs) on October 29 and 30, 2012. The training provided workers with the knowledge and hands on experience necessary to operate these ATVs safely in all types of terrain. Training has proven to be of high value as one of the many controls required to operate ATVs without incident and injury.

Hydro Generation's employees receive ATV training

2.3 Be Alert, Be Seen, Be Safe

Drake O'Brien, son of Mike O'Brien, Senior Business Development engineer, in high visibility clothing.

In October 2012, a safety observation was made regarding the absence of adequate lighting in a parking lot. The underlying message was simple, for both drivers and pedestrians: Be Alert, Be Seen, Be Safe!

In recent years, reflective garments, flashing lights, and other aids have been used to try to improve user visibility. Studies have shown that fluorescent materials in yellow, red and orange improve driver detection of pedestrians during the day; while lamps, flashing lights and retro reflective materials in red and yellow, particularly those that take advantage of the motion from a pedestrian's limbs, improved pedestrian recognition at night.

3 ENVIRONMENT AND CONSERVATION

Goal - To be an Environmental Leader

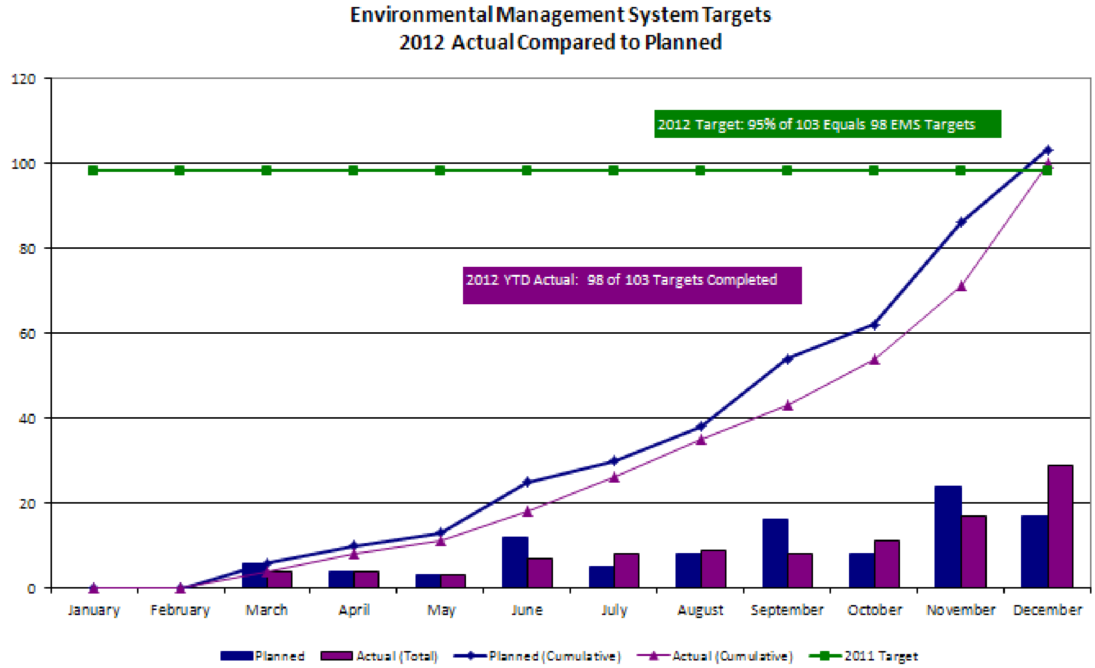
Hydro recognizes its commitment and responsibility to protect the environment.

Measurement	Year-to-date 2012 Actual	Annual 2012 Target	Annual 2011 Actual
Achievement of EMS targets[1]	96%	95%	93%
Variance from ideal production schedule at Holyrood Thermal Generating Station	6.9%	≤ 11.0%	9.8%
Annual energy savings from Residential and Commercial Conservation and Demand Management Programs	2.6 GWh	3.4 GWh	1.1 GWh
Annual energy savings from Industrial Conservation and Demand Management Programs	3.2 GWh	6.6 GWh	0.2 GWh
Annual energy savings from Internal Energy Efficiency Programs	0.26 GWh	0.15 GWh	0.17 GWh

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

3.1 Achievement of EMS Targets

See graph below displaying planned target completion schedules and actual to date. The annual target for 2012 was achieved.



3.2 Variance from Ideal Production Schedule at Holyrood Thermal Generating Station

Summary of 2012 Performance:

Minimum Hours						
2012	**Variance[1]**		**Ideal**		**Variance**	
Month	**Unit-Hours**	**Cumulative**	**Unit-Hours**	**Cumulative**	**Percent**	**Cumulative**
January	120.0	120.0	2,088	2,088	5.7%	5.7%
February	98.5	218.5	1,872	3,960	5.3%	5.5%
March	80.0	298.5	1,656	5,616	4.8%	5.3%
April	10.0	308.5	840	6,456	1.2%	4.8%
May	66.0	374.5	600	7,056	11.0%	5.3%
June	0.0	374.5	288	7,344	0.0%	5.1%
July	0.0	374.5	0	7,344	0.0%	5.1%
August	0.0	374.5	0	7,344	0.0%	5.1%
September	0.0	374.5	0	7,344	0.0%	5.1%
October	186.0	560.5	624	7,968	29.8%	7.0%
November	50.0	610.5	1,032	9,000	4.8%	6.8%
December	144.0	754.5	1,896	10,896	7.6%	6.9%

[1] Variance is the number of hours greater than or less than the ideal. Hours greater than the ideal represent hours of operation that ideally could have been avoided. Hours less than the ideal represent hours of operation where a single contingency could have resulted in a load interruption.

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

The energy savings for the residential and commercial portfolio continues to grow year over year. The largest component of the savings is due to the work on the direct installation program targeting the isolated communities in Labrador. The savings are lower than expected due to a number of factors, including a lower uptake in the components outside the direct installation initiative, as well as lower than expected savings in the first months of operation of the Isolated Systems Business Efficiency Program. Savings for the initial activities through the Block Heater Timer program are also not included as quality assurance is required to verify them.

3.2.2 Annual Energy Savings from Industrial Conservation and Demand Management Programs

Three projects have been completed through the Industrial program. The projects ranged in size and savings and addressed equipment replacement, lighting retrofits and process updates. There are other projects in various stages of feasibility research and review with economically viable projects moving to the implementation stage.

3.2.3 Annual Energy Savings from Internal Energy Efficiency Programs

Internal energy efficiency was very positive in 2012 with results exceeding the target. Some savings are realized from optimizing heating equipment and lighting in facilities through operational efforts. Retrofits of lighting and heating controls have resulted in the bulk of the savings.

4 Operational Excellence

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

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

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

Measurement	Year-to-date 2012 Actual	Annual 2012 Target	Annual 2011 Actual
Asset Management and Reliability			
Winter Availability[1]	99.97%	>98.0%	98.3%
Asset Management Strategy Execution plan implemented	Completed Targets	N/A	N/A
Financial Targets			
Annual Controllable Costs	To be Updated	Budget	-3.2%
Net Income	To be Updated	$15.3 million	$20.6 million
Return on Capital Employed	To be Updated	7.3%	7.9%
Project Execution			
Completion rate of capital projects by year end	82%	>94%	83%
All-project variance from original budget	18%	8%	5%
Customer Service			
Rural Residential Customer Satisfaction rate	80%	>90%	88%

[1] Winter Availability is applicable for the months of January, February, March and December. For 2012, Hydro has implemented a modified winter availability metric which tracks the number of unit unavailability hours for which there would not have been ample system generation available to supply the system load under the loss of the largest generating unit (N-1). These unavailability hours are compared against the total hours in the month to provide for a simple percentage.

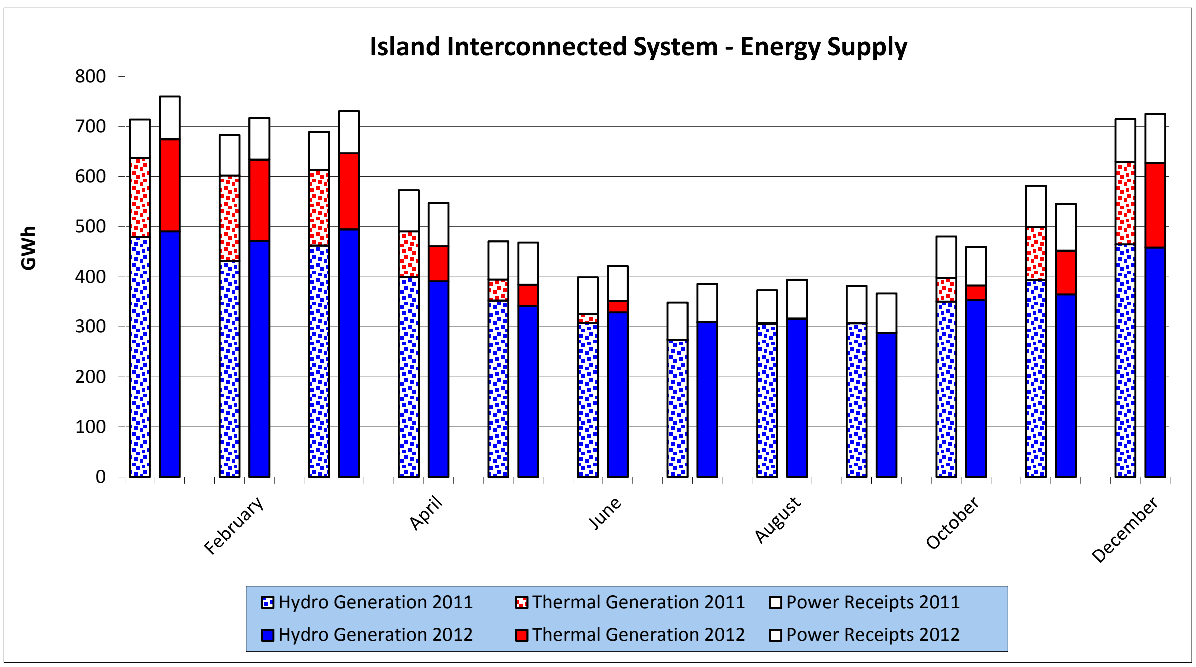
4.1 Energy Supply

4.1.1 Energy Supply - Island Interconnected System

Energy requirements from the Holyrood Generating station were slightly lower at the end of the fourth quarter of 2012 when compared to 2011. This was primarily due to reduced Avalon Peninsula requirements. Individual units are brought into service as required to meet customers' demand and for transmission support to the Avalon Peninsula. For the year, total thermal production was 29.5 GWh (3.3%) lower in 2012 than in 2011.

Annual hydroelectric production was 82.6 GWh or 1.8% above the levels in 2011, primarily due to increased system load requirements and a decrease in Holyrood requirements. The increase in hydroelectric production was partially offset by an increase in energy purchases. Total energy receipts were up by 98.4 GWh or 15.5% in 2012 when compared to 2011. This increase was primarily due to increased generation from Star Lake and from the Exploits generation at Grand Falls, Bishop's Falls and Buchans.

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



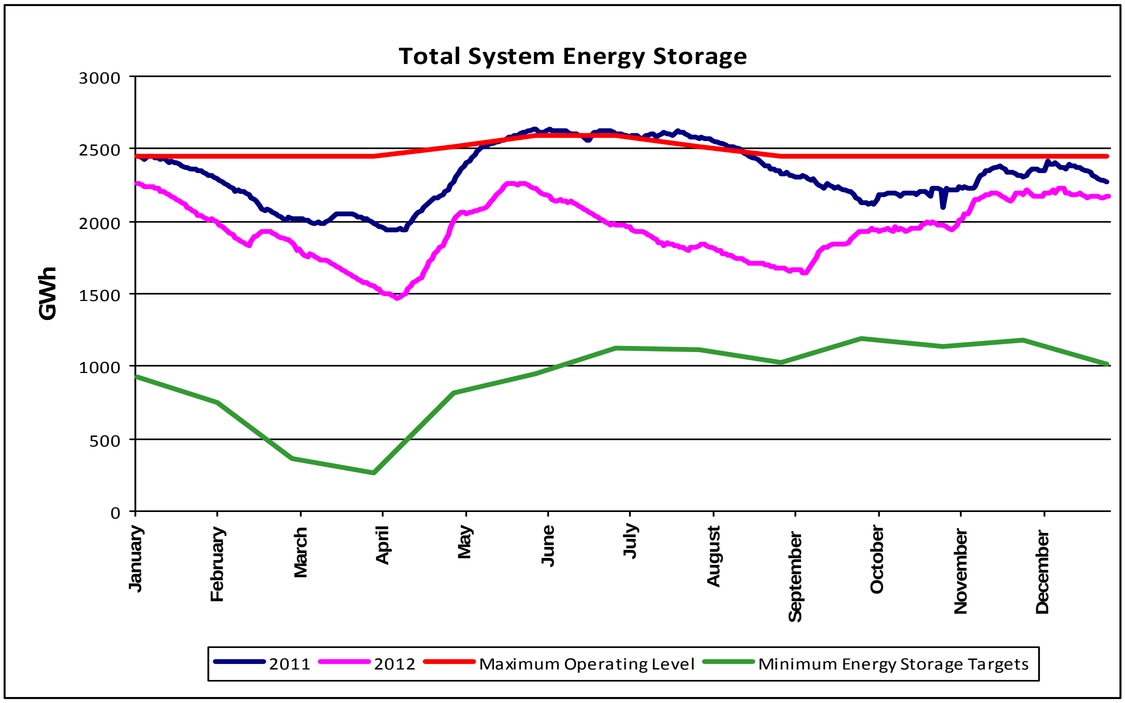
Island Interconnected System Production For the Year ended December 31, 2012					
	Year-to-date			**Annual Forecast (GWh)**	**2012 ($ 000)**
	2012 (GWh)	**2011 (GWh)**	**Forecast (GWh)**		
Production (net)					
Hydro	4,595.0	4,512.4	4,681.7	4,681.7	
Thermal	855.8	885.3	925.8	925.8	
Gas Turbines	(3.9)	(10.2)	(2.2)	(2.2)	
Diesels	(0.5)	1.7	(0.3)	(0.3)	
Total Production	**5,446.4**	**5,389.2**	**5,605.0**	**5,605.0**	
Energy Receipts					
Non Utility Generators					
Rattle Brook	14.6	18.7	13.5	13.5	1,181.4
Corner Brook Pulp and Paper Co-generation	47.8	50.5	46.8	46.8	6,906.2
St. Lawrence Wind	103.8	110.0	105.0	105.0	7,383.3
Fermeuse Wind	91.2	88.0	88.5	88.5	6,885.5
Total Non Utility Generators	**257.4**	**267.2**	**253.8**	**253.8**	**22,356.4**
Secondary and Others					
Deer Lake Power	6.2	3.9	3.6	3.6	320.7
Hydro Request to NP	0.1	0.1	0.0	0.0	133.9
Nalcor Energy[1]	730.3	634.2	713.5	713.5	
Total Secondary and Other	**736.6**	**638.2**	**717.1**	**717.1**	**454.6**
Total Purchases	**994.0**	**905.4**	**970.9**	**970.9**	
Island Interconnected Total Produced and Purchased	**6,440.4**	**6,294.6**	**6,575.9**	**6,575.9**	

Note: Nalcor Energy includes Star Lake and the Grand Falls, Bishop's Falls and Buchans generation.

4.1.2 System Hydrology

Reservoir levels continue to be favourable. Inflows into the aggregate reservoir system were 115% of average during the fourth quarter of 2012. Annual inflows were near normal, at 99% of average. The aggregate storage position was 89% of the maximum operating level (MOL) and 215% of the minimum storage target at year end.

There was no energy spilled from Hydro's reservoirs in 2012.



System Hydrology Storage Levels			
	2012 (GWh)	**2012 Minimum Target**	**2011 (GWh)**
Quarter End Storage Levels	2,173	1,010	2,260

4.1.3 Energy Supply – Labrador Interconnected System

The purchased and produced energy on the Labrador Interconnected System was higher in 2012 (38.1 GWh or 5.0%) when compared to 2011. This is primarily due to higher industrial sales at the Iron Ore Company of Canada (IOCC) and increased Hydro Rural requirements in Labrador East and West. The increase was partially offset by reduced secondary sales to CFB Goose Bay.

Labrador Interconnected System Production For the Year ended December 31, 2012				
	Year-to-date			**Annual Forecast (GWh)**
	2012 (GWh)	**2011 (GWh)**	**Forecast (GWh)**	
Production (net)				
Gas Turbines	(0.7)	(2.2)	(0.4)	(0.4)
Diesels	0.0	(0.7)	0.0	0.0
Total Production	**(0.7)**	**(2.9)**	**(0.4)**	**(0.4)**
Purchases				
CF(L)Co for Labrador (at border)	**801.3**	**765.4**	**832.8**	**832.8**
Labrador Interconnected Total Produced and Purchased	**800.6**	**762.5**	**832.4**	**832.4**

4.1.4 Fuel Prices

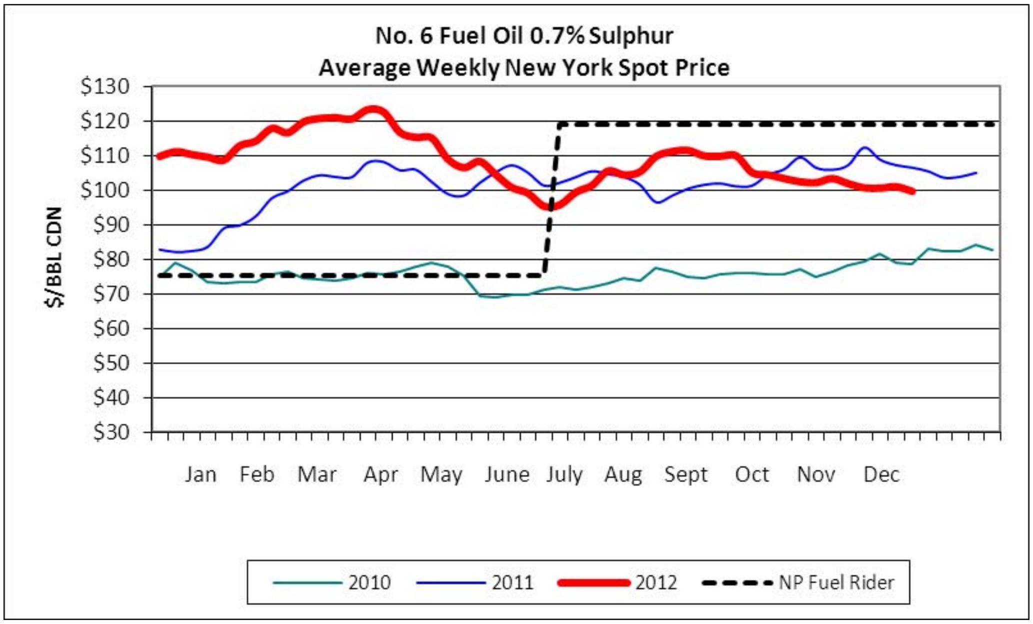
The fuel market prices for No. 6 fuel decreased slightly from approximately $104/bbl at the start of the quarter to $101/bbl at the end of the quarter. The quarter ending inventory cost was $113.60/bbl, lower than the current Newfoundland Power fuel price rider of $118.80/bbl. There is no Industrial Customer fuel price rider for 2012.

There was one shipment received during the fourth quarter of 2012:

November 8	225,149 bbls	$103.46

The inventory on December 31 was 180,936 barrels.

The following chart shows the No. 6 fuel prices year-to-date compared to 2010 and 2011, and the Newfoundland Power fuel rider price of $118.80/bbl.



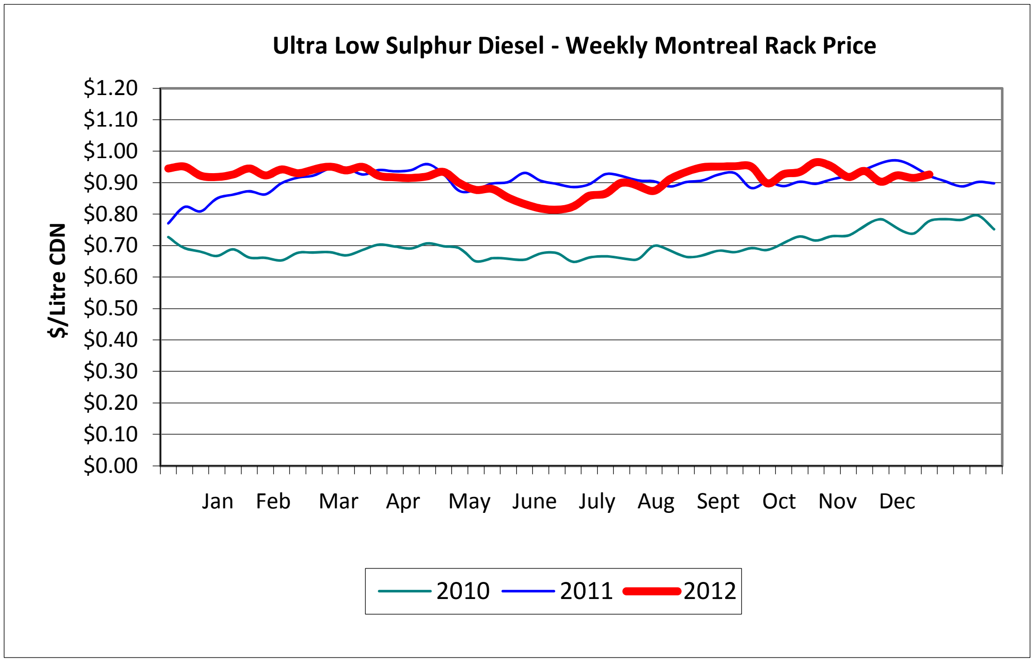
The following table provides the monthly forecast price of No. 6 fuel (0.7% sulphur) up to September 2013, landed on the Avalon Peninsula.

No. 6 Fuel Oil Sulphur
Forecast Price January 2013 – December 2013

Month	Price ($Cdn/bbl) 0.7%	Month	Price ($Cdn/bbl) 0.7%
January 2013	101.10	July 2013	104.90
February 2013	103.10	August 2013	104.80
March 2013	99.70	September 2013	103.90
April 2013	102.00	October 2013	104.90
May 2013	100.80	November 2013	106.30
June 2013	102.60	December 2013	103.80

Note: The forecast is based on the PIRA Energy Group price forecast available January 3, 2013 and an exchange rate forecast by Canadian financial institutions and the Conference Board of Canada.

The following chart shows Low Sulphur Diesel No. 1 fuel prices year-to-date compared to 2010 and 2011.



4.1.5 Energy Supply - Isolated Systems

Total isolated energy supply has decreased by almost 3% in 2012 compared to 2011.

Purchases from Hydro Québec for the L'Anse au Loup system have decreased by 3.6%. Decreased supply requirements (purchases and generation) on the L'Anse au Loup system account for 61% of the overall decrease in isolated supply. The decline in requirements on the L'Anse au Loup system is attributed to warmer weather in 2012 when compared to 2011. Environment Canada records show annual heating degree days for 2012 were 7% lower than in 2011.

Fish processing plants in St. Lewis, Black Tickle, and Little Bay Islands have not reopened this year and the closures are permanent. The decline in energy requirements in these communities accounts for almost 26% of overall decline in isolated supply.

The average cost of power purchased from Hydro Québec, based on Montreal rack fuel prices, has increased from $131 per megawatt hour in 2011 to $138 per megawatt hour in 2012. The average cost of power from NUGS, based on current diesel fuel prices, has increased from $275 per megawatt hour in 2011 to $289 per megawatt hour in 2012.

Isolated Systems Production
For the Year ended December 31, 2012

	Year-to-date						Annual Forecast (GWh)	$(000)[1]
	2012 (GWh)	$(000)[1]	2011 (GWh)	$(000)[1]	Forecast (GWh)	$(000)[1]		
Production (net)								
Diesels	45.6		47.3		49.0		49.0	
Purchases								
Non Utility Generators (NUGS)[2]	0.8	162.2	0.4	108.1	0.8	133.5	0.8	133.5
Hydro Québec	21.5	2,967.5	22.3	2,926.0	22.8	3,197.3	22.8	3,197.3
Total Purchases	**22.3**	**3,129.7**	**22.7**	**3,034.5**	**23.6**	**3,330.8**	**23.6**	**3,330.8**
Isolated Systems Total Produced and Purchased	**67.9**	**3,129.7**	**70.0**	**3,034.5**	**72.6**	**3,330.8**	**72.6**	**3,330.8**

[1] Purchases before taxes.
[2] NUGS includes purchases from Frontier Power and production at Nalcor's wind/hydrogen facility in Ramea. Cost is energy purchased from Frontier Power only.

4.2 Financial

Financial data for December 31, 2012 will follow when audited Financial Statements become available.

Hydro Regulated Operating Costs
(Chart)

This chart will not be available until the audited Financial Statements become available.

4.3 Capital Expenditures

Capital Expenditures for the year ended December 31, 2012 will be reported as a separate document.

4.4 Other

4.4.1 Hydro's Transmission Structure Corrosion Workshop Presentation

The Transmission Structure Corrosion Workshop held on October 3, was jointly presented by the Centre for Energy Advancement through Technological Innovation, Overhead Line Design Issues and Wind and Ice Storm Mitigation and Transmission Line Asset Management Interest Group Programs.

The keynote speaker opened the workshop with a review of the fundamentals of corrosion process, its economic impact, the problems it causes on transmission structures, and the difficulties utilities have encountered in detecting it, specifically limitations of the non-destructive evaluations available to date.

Asim Halder's presentation covered the economic impact of corrosion damage on utility structures, as well as the corrosion process, detection and mitigation. The results of two case studies conducted for Hydro's own system about corrosion damage of anchor rods and grillage foundations.

4.4.2 Hydro Employees receive 2012 President's Awards

The President's Awards are Nalcor's most prestigious form of recognition. In 2012, 26 employees were nominated, and 11 employees received awards at the ceremony, held in St. John's on November 29. The recipients were recognized by their peers and the Leadership Team, as champions of the Nalcor Energy corporate goals.

Among the recipients of the 2012 President's Awards were:

Safety: **Paul Smith** - TRO Central

Environment: **Hughie Ireland** - TRO Central

Business Excellence: **Leveson Kearley** - Hydro Generation, **Alberta Marche** - Project Execution and Technical Services; **Bob Moulton** - Project Execution and Technical Services

People: **Renee Hodder** - Project Execution and Technical Services; **Fred Reid** - TRO Central

Community: **Annette Higdon** - Holyrood; **Clarence Kelly** - Hydro Generation

5 OTHER ITEMS

5.1 Significant Issues

5.1.1 Ramea Wind-Hydrogen-Diesel Project Update

Overall Project Site Showing (l-r) the Diesel Plant/Storage Tanks, Meteorological Tower, Hydrogen Electrolyser, 3 Hydrogen Storage Tanks, Distribution Box Structure, 3 Wind Turbines, and Quonset Hut Housing the Hydrogen Genset.

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

Implementation and Operation
Some project deficiencies remained in this quarter as a project staff member was re-assigned to other project work. Project close-out is deferred to Q2 2013 to resolve reliability problems with the Hydrogen Genset and complete remaining project deficiencies. The Operations schedule was revised to commence in Q3 2013, pending completion of project close-out documentation.

Capital Costs

($000)

Actual Cost to December 2012	Actual Cost Recoveries to December 2012	Net Cost to December 2012	Budget to December 2008	Budget Reforecast to September 2010[1]
11,864	**11,864**	**0**	**8,794**	**2,486**

[1] Project Change Order #3 is under draft to reflect various cost increases and schedule delays associated with incomplete commissioning activities, H_2 Genset fire and project deficiencies.

Operating Costs
There is nothing to report for this period as operation is planned to start in Q3 2013.

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

5.2 Community

5.2.1 Hydro Employees walk for Ronald McDonald House

Teams across the province participated in the Red Shoe Crew Walk in support of the Ronald McDonald House. Hydro employees participated in walks in St. John's, Bishop's Falls, St. Anthony New Harbour and Bay d'Espoir.


The New Harbour Hydro Red Show Crew

The St. Anthony Red Shoe Crew

5.2.2 Silver Lights give back to the Community

Santa's sleigh made its way downtown as an estimated 60,000 people lined the streets to see the Santa Clause parade in St. John's on November 25.

The Silver Lights (a volunteer group of employees and retirees with over 25 years of service) constructed a "Christmas Eve on Sesame Street" float that was over 20 feet high. In a close race for best float over 20 feet, Silver Lights tied for third place along with Tim Horton's.

A number of Nalcor and Hydro employees/retirees.

5.3 Statement of Energy Sold

Statement of Energy Sold (GWh)

For the Year ended December 31, 2012

	YEAR TO DATE 2012 ACTUAL	YEAR TO DATE 2011 ACTUAL	YEAR TO DATE 2012* FORECAST	2012* ANNUAL FORECAST	ANNUAL % CHANGE
Island Interconnected					
Newfoundland Power	5,359	5,317	5,359	5,359	0.8%
Island Industrials	410	311	410	410	31.8%
Rural					
Domestic	240	239	240	240	0.4%
General Service	163	151	163	163	7.9%
Streetlighting	3	3	3	3	0.0%
Sub-total Rural	406	393	406	406	3.3%
Sub-Total Island Interconnected	6,175	6,021	6,175	6,175	2.6%
Island Isolated					
Domestic	6	6	6	6	0.0%
General Service	1	1	1	1	0.0%
Streetlighting	0	0	0	0	0.0%
Sub-Total Island Isolated	7	7	7	7	0.0%
Labrador Interconnected					
Labrador Industrials	180	129	180	180	39.5%
CFB Goose Bay	18	51	18	18	-64.7%
Hydro Quebec (includes Menihek)	42	42	42	42	0.0%
Export	1,597	1,530	1,597	1,597	4.4%
Rural					
Domestic	285	272	285	285	4.8%
General Service	240	218	240	240	10.1%
Streetlighting	2	1	2	2	0.0%
Sub-total Rural	527	491	527	527	7.3%
Sub-Total Lab. Interconnected	2,364	2,243	2,364	2,364	5.4%
Labrador Isolated					
Domestic	21	21	21	21	0.0%
General Service	15	15	15	15	0.0%
Streetlighting	0	0	0	0	0.0%
Sub-Total Labrador Isolated	36	36	36	36	0.0%
L'Anse au Loup					
Domestic	13	13	13	13	0.0%
General Service	8	8	8	8	0.0%
Streetlighting	0	0	0	0	0.0%
Sub-Total L'Anse au Loup	21	21	21	21	0.0%
Total Energy Sold (Before Rural Accrual)	8,603	8,328	8,603	8,603	3.3%
Rural Accrual	10	11	-	-	
Total Energy Sold	8,613	8,339	8,603	8,603	3.3%
Sales to Non-Regulated Customers**	1819	1700	1819	1,819	7.0%

* Rural GWh - Based on 2012 Budget, Spring 2011 Rural Load Forecast
Non-rural GWh - Based on 2012 Wholesale Industrial Revenue Budget
** Included in Total Energy Sold

5.4 Customer Statistics

Customer Statistics
For the Quarter ended December 31, 2012

	FOURTH QUARTER		ANNUAL	
	2012 ACTUAL	2011 ACTUAL	2012 FORECAST	2011 ACTUAL
Customers				
Rural	37,576	37,116	38,694	37,116
Industrial	6	5	6	5
CFB Goose Bay	1	1	1	1
Utility	1	1	1	1
Non-Regulated	3	3	3	3
Reading Days	30.2	30.6	N/A	30.2

APPENDICES

CIAC QUARTERLY ACTIVITY REPORT
For the Quarter ended December 31, 2012

TYPE OF SERVICE	CIAC'S QUOTED	CIAC'S OUTSTANDING PREVIOUS QTR.	TOTAL CIAC'S QUOTED	CIAC'S ACCEPTED	CIAC'S EXPIRED	TOTAL CIAC'S OUTSTANDING
Domestic						
Within Plan. Boundary	5	7	12	5	3	4
Outside Plan. Boundary	2	5	7	3	4	0
Sub-total	7	12	19	8	7	4
General Service	8	6	14	7	2	5
Total	15	18	33	15	9	9

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

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

CIAC QUARTERLY ACTIVITY REPORT
For the Quarter ended December 31, 2012

DATE QUOTED	SERVICE LOCATION	CIAC NO.	CIAC AMOUNT ($)	ESTIMATED CONST. COST ($)	ACCEPTED
DOMESTIC - WITHIN RESIDENTIAL PLANNING BOUNDARIES					
October 9, 2012	L'Anse au Loup	929827	$ 1,595.00	$ 2,320.00	Yes
October 10, 2012	Three Mile Rock	931545	$ 18,560.00	$ 21,025.00	
October 11, 2012	South Brook; Green Bay	935649	$ 3,357.50	$ 4,082.50	Yes
October 22, 2012	Change Islands	941246	$ 1,885.00	$ 2,900.00	
October 30, 2012	Westport	943391	$ 3,086.15	$ 725.00	Yes
DOMESTIC - OUTSIDE RESIDENTIAL PLANNING BOUNDARIES					
October 31, 2012	South Brook; Green Bay	756296	$ 96,377.00	$ 110,877.00	Yes
December 12, 2012	South Brook; Green Bay	942638	$ 1,872.50	$ 725.00	Yes
GENERAL SERVICE					
October 3, 2012	Happy Valley-Goose Bay	931563	$ -	$ 15,197.50	Yes
October 29, 2012	Cow Head	939794	$ -	$ 2,241.00	Yes
October 30, 2012	Happy Valley-Goose Bay	939374	$ -	$ 2,175.00	Yes
November 5, 2012	Happy Valley-Goose Bay	943312	$ -	$ 9,685.00	Yes
November 5, 2012	Happy Valley-Goose Bay	928379	$ 20,420.00	$ 77,625.00	Yes
November 27, 2012	Happy Valley-Goose Bay	945885	$ 1,831.18	$ 16,586.18	
December 3, 2012	Happy Valley-Goose Bay	945879	$ 4,350.00	$ 12,655.00	
December 5, 2012	Wabush	937925	$ 2,800.00	$ 10,540.00	Yes

CUSTOMER PROPERTY DAMAGE CLAIMS REPORT
For the Quarter ended December 31, 2012

Introduction

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

The report is divided into four sections as follows:

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

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

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

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

Definitions of Causes of Damage Claims

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

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

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

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

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

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

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

8. Waiting Investigation: Cause to be determined.

CUSTOMER PROPERTY DAMAGE CLAIMS REPORT - BY CAUSE

For the Quarter ended December 31, 2012

CAUSE	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	AMT. CLAIMED	AMT. PAID	#	AMOUNT	#	AMOUNT
System Operations	0	2	2	0	$ -	$ -	0	$ -	2	$ 1,262.00
Power Interruptions	0	1	1	0	$ -	$ -	0	$ -	1	$ -
Improper Workmanship	1	5	6	0	$ -	$ -	1	$ 845.00	6	$ 5,477.02
Weather Related	12	6	18	1	$ 1,250.00	$ 947.39	9	$ 6,188.84	9	$ 6,904.50
Equipment Failure	3	6	9	0	$ -	$ -	2	$ 969.79	7	$ 28,117.09
Third Party	0	0	0	0	$ -	$ -	0	$ -	0	$ -
Miscellaneous	2	2	4	1	$ 2,512.60	$ 2,512.60	1	$ 28,750.00	2	$ 2,000.00
Waiting Investigation	2	8	10	0	$ -	$ -	0	$ -	8	$ 3,188.00
Total	20	30	50	2	$ 3,762.60	$ 3,459.99	13	$ 36,753.63	35	$ 46,948.61

For the Quarter ended December 31, 2011

CAUSE	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	AMT. CLAIMED	AMT. PAID	#	AMOUNT	#	AMOUNT
System Operations	4	0	4	0	$ -	$ -	5	$ -	0	$ -
Power Interruptions	4	2	6	0	$ -	$ -	6	$ 4,081.62	0	$ -
Improper Workmanship	7	4	11	2	$ 9,527.63	$ 8,622.13	0	$ -	8	$ 7,642.95
Weather Related	12	9	21	0	$ -	$ -	14	$ 10,326.42	6	$ 4,024.47
Equipment Failure	3	2	5	3	$ 21,680.50	$ 152,582.00	2	$ 372.89	3	$ 8,174.68
Third Party	0	0	0	0	$ -	$ -	0	$ -	0	$ -
Miscellaneous	3	1	4	0	$ -	$ -	5	$ 4,397.89	0	$ -
Waiting Investigation	2	8	10	0	$ -	$ -	0	$ -	5	$ 13,221.77
Total	35	26	61	5	$ 31,208.13	$ 161,204.13	32	$ 19,178.82	22	$ 33,063.87

CUSTOMER PROPERTY DAMAGE CLAIMS REPORT - BY REGION

For the Quarter ended December 31, 2012

REGION	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	AMT. CLAIMED	AMT. PAID	#	AMOUNT	#	AMOUNT
Central Region	4	10	14	1	$ 2,512.60	$ 2,512.60	5	$ 32,340.00	8	$ 4,173.44
Northern Region	12	12	24	0	$ -	$ -	7	$ 4,209.79	17	$ 33,325.17
Labrador Region	4	8	12	1	$ 1,250.00	$ 947.39	1	$ 203.84	10	$ 9,450.00
Total	20	30	50	2	$ 3,762.60	$ 3,459.99	13	$ 36,753.63	35	$ 46,948.61

For the Quarter ended December 31, 2011

REGION	NUMBER RECEIVED	OUTSTANDING LAST QTR.	TOTAL	CLAIMS ACCEPTED			CLAIMS REJECTED		CLAIMS OUTSTANDING	
				#	AMT. CLAIMED	AMT. PAID	#	AMOUNT	#	AMOUNT
Central Region	11	9	20	2	$ 10,155.00	$ 8,389.50	10	$ 2,304.51	7	$ 9,174.88
Northern Region	18	9	27	2	$ 20,580.50	$ 152,342.00	16	$ 11,217.31	9	$ 5,204.15
Labrador Region	6	8	14	1	$ 472.63	$ 472.63	6	$ 5,657.00	6	$ 18,684.84
Total	35	26	61	5	$ 31,208.13	$ 161,204.13	32	$ 19,178.82	22	$ 33,063.87

FINANCIAL – REGULATED

Financial data will follow when audited financial statements are available.

Newfoundland and Labrador Hydro
Rate Stabilization Plan
December 31, 2012

Rate Stabilization Plan Report
December 31, 2012

Summary of Key Facts

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

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

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

	2007 Test Year Cost of Service			
	Net Hydraulic Production	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, 2012

		Actual		Cost of Service		Variance		Year-to-Date Due (To) From customers	Reference
Hydraulic production year-to-date		4,590.2 GWh		4,472.1 GWh		118.1 GWh	$	(10,830,537)	Page 4
No 6 fuel cost - Current month	$	113.29	$	58.98	$	54.31	$	84,592,255	Page 5
Year-to-date customer load - Utility		5,359.3 GWh		4,925.8 GWh		433.5 GWh	$	(97,564)	Page 8
Year-to-date customer load - Industrial		409.6 GWh		894.3 GWh		-484.7 GWh	$	(24,548,090)	Page 9
							$	49,116,064	

Rural rates			
Rural Rate Alteration (RRA) [(1)]	$	(7,037,680)	
Less : RRA to utility customer	$	(6,270,574)	Page 10
RRA to Labrador interconnected		(767,106)	
Fuel variance to Labrador interconnected	$	661,174	Page 6
Net Labrador interconnected	$	(105,932)	

Current plan summary [(2)]			
One year recovery			
Due (to) from utility customer [(2)]	$	(64,905,401)	Page 10
Due (to) from Industrial customers [(2)]	$	(104,079,983)	Page 11
Sub total		(168,985,384)	
Four year recovery			
Hydraulic balance	$	(32,675,763)	Page 4
Total plan balance	$	(201,661,147)	

[(1)] Beginning January 2011, the RRA includes a monthly credit of $98,295. This amount relates to the phase in of the application of the credit from secondary energy sales to CFB Goose Bay to the Rural deficit as stated in Section B, Clause 1.3(b) of the approved Rate Stabilization Plan Regulations which received final approval in Order No. P.U. 33 (2010) issued December 15, 2010.

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

Rate Stabilization Plan
Net Hydraulic Production Variation
December 31, 2012

	A 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							(32,737,147)
January	427,100,000	489,800,074	(62,700,074)	54.17	(5,391,211)	(198,633)	(38,326,991)
February	388,680,000	470,451,513	(81,771,513)	54.73	(7,103,738)	(232,549)	(45,663,278)
March	415,080,000	493,310,549	(78,230,549)	55.46	(6,886,772)	(277,062)	(52,827,112)
April	355,520,000	389,781,961	(34,261,961)	55.46	(3,016,140)	(320,529)	(56,163,781)
May	324,240,000	341,379,893	(17,139,893)	55.46	(1,508,855)	(340,774)	(58,013,410)
June	328,500,000	321,226,024	7,273,976	54.49	629,141	(351,996)	(57,736,265)
July	386,790,000	308,929,190	77,860,810	54.49	6,734,342	(350,315)	(51,352,238)
August	379,140,000	315,733,699	63,406,301	54.49	5,484,142	(311,580)	(46,179,676)
September	363,560,000	286,134,767	77,425,233	54.49	6,696,668	(280,195)	(39,763,203)
October	340,510,000	352,757,654	(12,247,654)	54.56	(1,060,686)	(241,263)	(41,065,152)
November	364,390,000	363,638,371	751,629	54.56	65,093	(249,163)	(41,249,222)
December	398,560,000	457,015,214	(58,455,214)	58.98	(5,472,521)	(250,280)	(46,972,023)
	4,472,070,000	4,590,158,909	(118,088,909)		(10,830,537)	(3,404,339)	(46,972,023)
Hydraulic Allocation [2]					10,891,921	3,404,339	14,296,260
Hydraulic variation at year end					61,384	-	(32,675,763)

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

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

	(from page 6) 12 month kWh	% of kWh to total	Allocation	Reallocate Rural	**(to pages 11 & 12)** Net
Utility	5,359,316,868	86.2%	12,328,828	913,395	13,242,223
Industrial	409,614,546	6.6%	942,297		942,297
Rural	445,624,295	7.2%	1,025,135	(1,025,135)	-
Total	6,214,555,709	100.0%	14,296,260	(111,740)	14,184,520
Labrador Inteconnected (write-off to income)				111,740	111,740
				-	14,296,260

Rate Stabilization Plan
No. 6 Fuel Variation
December 31, 2012

	A	B	C	D	E	F	G
	Actual Quantity No. 6 Fuel (bbl.)	Actual Quantity No. 6 Fuel for Non-Firm Sales (bbl.)	Net Quantity No. 6 Fuel (bbl.) **(A - B)**	Cost of Service No. 6 Fuel Cost ($Can/bbl.)	Actual Average No. 6 Fuel Cost ($Can/bbl.)	Cost Variance ($Can/bbl.) **(E - D)**	No.6 Fuel Variation ($) **(C X F)** **(to page 6)**
January	285,302	0	285,302	54.17	110.08	55.91	15,951,212
February	249,113	1	249,112	54.73	113.08	58.35	14,535,675
March	234,293	4	234,289	55.46	117.73	62.27	14,589,150
April	109,531	2	109,529	55.46	120.09	64.63	7,078,882
May	67,914	1	67,913	55.46	120.64	65.18	4,426,599
June	35,341	0	35,341	54.49	120.64	66.15	2,337,797
July	0	0	0	54.49	120.64	66.15	0
August	0	0	0	54.49	120.64	66.15	0
September	0	0	0	54.49	120.64	66.15	0
October	47,416	0	47,416	54.56	120.64	66.08	3,133,268
November	134,835	0	134,835	54.56	115.07	60.51	8,158,842
December	264,792	0	264,792	58.98	113.29	54.31	14,380,830
	1,428,536	8	1,428,528	55.47	114.80	59.33	84,592,255

Rate Stabilization Plan
Allocation of Fuel Variance - Year-to-Date
December 31, 2012

	A	B	C	D	E	F	G	H	I	J
	Twelve Months-to-Date				Year-to-Date Fuel Variance				Reallocate Rural Island Customers [1]	
	Utility	Industrial Customers	Rural Island Customers	Total	Utility	Industrial Customers	Rural Island Interconnected	Total	Utility	Labrador Interconnected
	(kWh)	(kWh)	(kWh)	(kWh)	($)	($)	($)	($)	($)	($)
				(A+B+C)	**(A/D X H)**	**(B/D X H)**	**(C/D X H)**		**(G X 89.10%)**	**(G X 10.90%)**
					(to page 7)			**(from page 5)**	**(to page 7)**	
January	5,387,374,077	310,709,943	443,384,150	6,141,468,170	13,992,606	807,006	1,151,600	15,951,212	1,026,076	125,524
February	5,411,960,615	318,486,236	446,787,595	6,177,234,446	26,709,984	1,571,845	2,205,058	30,486,887	1,964,707	240,351
March	5,444,552,052	323,780,517	450,230,292	6,218,562,861	39,465,522	2,346,964	3,263,551	45,076,037	2,907,824	355,727
April	5,416,033,886	334,510,476	449,217,858	6,199,762,220	45,561,878	2,814,038	3,779,003	52,154,919	3,367,092	411,911
May	5,397,954,002	347,942,112	447,071,118	6,192,967,232	49,317,947	3,178,943	4,084,628	56,581,518	3,639,404	445,224
June	5,397,155,554	371,316,326	445,616,103	6,214,087,983	51,173,512	3,520,662	4,225,141	58,919,315	3,764,601	460,540
July	5,411,227,178	393,584,930	444,143,442	6,248,955,550	51,020,654	3,710,981	4,187,680	58,919,315	3,731,223	456,457
August	5,417,227,542	409,252,423	444,944,673	6,271,424,638	50,894,231	3,844,880	4,180,204	58,919,315	3,724,562	455,642
September	5,397,489,558	409,873,231	445,251,708	6,252,614,497	50,861,346	3,862,296	4,195,673	58,919,315	3,738,345	457,328
October	5,380,451,580	410,641,120	445,226,094	6,236,318,794	53,536,538	4,085,959	4,430,086	62,052,583	3,947,207	482,879
November	5,347,160,714	409,003,027	445,081,465	6,201,245,206	60,541,353	4,630,793	5,039,279	70,211,425	4,489,998	549,281
December	5,359,316,868	409,614,546	445,624,295	6,214,555,709	72,950,782	5,575,655	6,065,818	84,592,255	5,404,644	661,174

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

Rate Stabilization Plan
Allocation of Fuel Variance - Monthly
December 31, 2012

	A	B	C	D	E	F	G
	Utility					**Industrial**	
	Fuel Variance		Rural Allocation		Total Fuel Variance	Fuel Variance	
	Year-to-Date Activity	Current Month Activity (1)	Year-to-Date Activity	Current Month Activity (1)	Activity for the month	Year-to-Date Activity	Current Month Activity (1)
	($)	($)	($)	($)	($)	($)	($)
					(B + D)		
	(from page 6)		**(from page 6)**		**(to page 10)**	**(from page 6)**	**(to page 11)**
January	13,992,606	13,992,606	1,026,076	1,026,076	15,018,682	807,006	807,006
February	26,709,984	12,717,378	1,964,707	938,631	13,656,009	1,571,845	764,839
March	39,465,522	12,755,538	2,907,824	943,117	13,698,655	2,346,964	775,119
April	45,561,878	6,096,356	3,367,092	459,268	6,555,624	2,814,038	467,074
May	49,317,947	3,756,069	3,639,404	272,312	4,028,381	3,178,943	364,905
June	51,173,512	1,855,565	3,764,601	125,197	1,980,762	3,520,662	341,719
July	51,020,654	(152,858)	3,731,223	(33,378)	(186,236)	3,710,981	190,319
August	50,894,231	(126,423)	3,724,562	(6,661)	(133,084)	3,844,880	133,899
September	50,861,346	(32,885)	3,738,345	13,783	(19,102)	3,862,296	17,416
October	53,536,538	2,675,192	3,947,207	208,862	2,884,054	4,085,959	223,663
November	60,541,353	7,004,815	4,489,998	542,791	7,547,606	4,630,793	544,834
December	72,950,782	12,409,429	5,404,644	914,646	13,324,075	5,575,655	944,862
		72,950,782		5,404,644	78,355,426		5,575,655

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

Rate Stabilization Plan
Load Variation - Utility
December 31, 2012

	A	B	C	D	E	F	G	H	I	J	K
	Firm Energy						Secondary Energy				
	Cost of Service Sales	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	645,272,533	70,472,533	54.17	0.08805	(145,587)	0	0	0.00841	0	(145,587)
February	518,600,000	605,772,822	87,172,822	54.73	0.08805	(102,601)	0	0	0.00841	0	(102,601)
March	524,700,000	612,210,811	87,510,811	55.46	0.08805	(1,597)	0	0	0.00841	0	(1,597)
April	429,200,000	441,536,421	12,336,421	55.46	0.08805	(225)	0	0	0.00841	0	(225)
May	358,700,000	373,354,613	14,654,613	55.46	0.08805	(268)	0	0	0.00841	0	(268)
June	298,400,000	328,298,760	29,898,760	54.49	0.08805	(46,580)	0	7,776,883	0.00841	(65,404)	(111,984)
July	293,400,000	304,522,712	11,122,712	54.49	0.08805	(17,328)	0	431,009	0.00841	(3,625)	(20,953)
August	287,000,000	308,501,923	21,501,923	54.49	0.08805	(33,499)	0	201,364	0.00841	(1,693)	(35,192)
September	297,700,000	287,756,026	(9,943,974)	54.49	0.08805	15,492	0	668,007	0.00841	(5,618)	9,874
October	360,200,000	377,830,840	17,630,840	54.56	0.08805	(25,509)	0	639,640	0.00841	(5,379)	(30,888)
November	439,300,000	452,476,305	13,176,305	54.56	0.08805	(19,064)	0	814,175	0.00841	(6,847)	(25,911)
December	543,800,000	610,688,673	66,888,673	58.98	0.08805	372,506	0	563,351	0.00841	(4,738)	367,768
	4,925,800,000	5,348,222,439	422,422,439			(4,260)	0	11,094,429		(93,304)	(97,564)

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

Rate Stabilization Plan
Load Variation - Industrial
December 31, 2012

	A	B	C	D	E	F
	Cost of Service Sales (kWh)	Actual Sales (kWh)	Sales Variance (kWh) **(B - A)**	Cost of Service No. 6 Fuel Cost ($)	Firm Energy Rate ($/kWh)	Load Variation ($) **$C \times \{(D/O^1) - E\}$** **(to page 11)**
January	78,300,000	32,959,121	(45,340,879)	54.17	0.03676	(2,231,865)
February	70,900,000	32,673,789	(38,226,211)	54.73	0.03676	(1,915,631)
March	76,600,000	38,353,336	(38,246,664)	55.46	0.03676	(1,960,973)
April	75,600,000	42,843,871	(32,756,129)	55.46	0.03676	(1,679,464)
May	69,500,000	36,611,217	(32,888,783)	55.46	0.03676	(1,686,265)
June	73,800,000	33,665,857	(40,134,143)	54.49	0.03676	(1,995,954)
July	77,500,000	31,814,448	(45,685,552)	54.49	0.03676	(2,272,037)
August	77,900,000	38,042,334	(39,857,666)	54.49	0.03676	(1,982,204)
September	73,000,000	29,220,566	(43,779,434)	54.49	0.03676	(2,177,242)
October	74,400,000	31,036,954	(43,363,046)	54.56	0.03676	(2,161,352)
November	74,100,000	29,316,482	(44,783,518)	54.56	0.03676	(2,232,153)
December	72,700,000	33,076,571	(39,623,429)	58.98	0.03676	(2,252,950)
	894,300,000	409,614,546	(484,685,454)			(24,548,090)

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

Rate Stabilization Plan
Summary of Utility Customer
December 31, 2012

	A	B	C	D	E	F	G
	Load Variation	Allocation Fuel Variance	Allocation Rural Rate Alteration [1]	Subtotal Monthly Variances	Financing Charges	Adjustment [2]	Cumulative Net Balance
	($)	($)	($)	($)	($)	($)	($)
				(A + B + C)			
	(from page 8)	**(from page 7)**					**(to page 12)**
Opening Balance							(55,939,780)
January	(145,587)	15,018,682	(681,410)	14,191,685	(339,415)	(6,007,487)	(48,094,997)
February	(102,601)	13,656,009	(681,360)	12,872,048	(291,816)	(5,639,745)	(41,154,510)
March	(1,597)	13,698,655	(622,573)	13,074,485	(249,705)	(5,699,683)	(34,029,413)
April	(225)	6,555,624	(594,473)	5,960,926	(206,473)	(4,110,704)	(32,385,664)
May	(268)	4,028,381	(482,226)	3,545,887	(196,500)	(3,475,931)	(32,512,208)
June	(111,984)	1,980,762	(469,092)	1,399,686	(197,268)	(3,128,864)	(34,438,654)
July	(20,953)	(186,236)	(477,990)	(685,179)	(208,957)	(4,742,030)	(40,074,820)
August	(35,192)	(133,084)	(422,902)	(591,178)	(243,154)	(4,800,336)	(45,709,488)
September	9,874	(19,102)	(293,596)	(302,824)	(277,342)	(4,484,994)	(50,774,648)
October	(30,888)	2,884,054	(419,661)	2,433,505	(308,075)	(5,885,216)	(54,534,434)
November	(25,911)	7,547,606	(402,367)	7,119,328	(330,888)	(7,048,667)	(54,794,661)
December	367,768	13,324,075	(722,924)	12,968,919	(332,467)	(9,504,969)	(51,663,178)
Year to date	(97,564)	78,355,426	(6,270,574)	71,987,288	(3,182,060)	(64,528,626)	4,276,602
Hydraulic allocation **(from page 4)**							(13,242,223)
Total	(97,564)	78,355,426	(6,270,574)	71,987,288	(3,182,060)	(64,528,626)	(64,905,401)

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

(2) The RSP adjustment rate for Utility is 1.555 cents per kwh effective July 1, 2012 to June 30, 2013.

Rate Stabilization Plan
Summary of Industrial Customers
December 31, 2012

	A	B	C	D	E	F
	Load Variation	Allocation Fuel Variance	Subtotal Monthly Variances	Financing Charges	Adjustment [1]	Cumulative Net Balance
	($)	($)	($)	($)	($)	($)
			(A + B)			
	(from page 9)	**(from page 7)**				**(to page 12)**
Opening Balance						(81,653,349) [2]
January	(2,231,865)	807,006	(1,424,859)	(495,432)	335,764	(83,237,876)
February	(1,915,631)	764,839	(1,150,792)	(505,046)	329,688	(84,564,026)
March	(1,960,973)	775,119	(1,185,854)	(513,092)	377,270	(85,885,702)
April	(1,679,464)	467,074	(1,212,390)	(521,111)	408,808	(87,210,395)
May	(1,686,265)	364,905	(1,321,360)	(529,149)	364,160	(88,696,744)
June	(1,995,954)	341,719	(1,654,235)	(538,167)	336,127	(90,553,019)
July	(2,272,037)	190,319	(2,081,718)	(549,430)	316,147	(92,868,020)
August	(1,982,204)	133,899	(1,848,305)	(563,477)	368,472	(94,911,330)
September	(2,177,242)	17,416	(2,159,826)	(575,874)	296,782	(97,350,248)
October	(2,161,352)	223,663	(1,937,689)	(590,673)	315,338	(99,563,272)
November	(2,232,153)	544,834	(1,687,319)	(604,100)	302,752	(101,551,939)
December	(2,252,950)	944,862	(1,308,088)	(616,167)	338,508	(103,137,686)
Year to date	(24,548,090)	5,575,655	(18,972,435)	(6,601,718)	4,089,816	(21,484,337)
Hydraulic allocation **(from page 4)**						(942,297)
Total	(24,548,090)	5,575,655	(18,972,435)	(6,601,718)	4,089,816	(104,079,983)

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

Rate Stabilization Plan
Overall Summary
December 31, 2012

	A	B	C	D
	Hydraulic Balance	Utility Balance	Industrial Balance	Total To Date
	($)	($)	($)	($)
				(A + B + C)
	(from page 4)	**(from page 10)**	**(from page 11)**	
Opening Balance	(32,737,147)	(55,939,780)	(81,653,349)	(170,330,276)
January	(38,326,991)	(48,094,997)	(83,237,876)	(169,659,864)
February	(45,663,278)	(41,154,510)	(84,564,026)	(171,381,814)
March	(52,827,112)	(34,029,413)	(85,885,702)	(172,742,227)
April	(56,163,781)	(32,385,664)	(87,210,395)	(175,759,840)
May	(58,013,410)	(32,512,208)	(88,696,744)	(179,222,362)
June	(57,736,265)	(34,438,654)	(90,553,019)	(182,727,938)
July	(51,352,238)	(40,074,820)	(92,868,020)	(184,295,078)
August	(46,179,676)	(45,709,488)	(94,911,330)	(186,800,494)
September	(39,763,203)	(50,774,648)	(97,350,248)	(187,888,099)
October	(41,065,152)	(54,534,434)	(99,563,272)	(195,162,858)
November	(41,249,222)	(54,794,661)	(101,551,939)	(197,595,822)
December	(32,675,763)	(64,905,401)	(104,079,983)	(201,661,147)

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

2012 ANNUAL REPORT
ON
KEY PERFORMANCE INDICATORS

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

NEWFOUNDLAND AND LABRADOR HYDRO

newfoundland labrador hydro
a nalcor energy company

TABLE OF CONTENTS

1 Introduction

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

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

Within each of these categories, KPI data is reported on a historic basis for Hydro. Where appropriate, KPIs are subcategorized based on whether they relate to generation, transmission, distribution or overall corporate activity. For most of the Reliability KPIs, data from the Canadian Electricity Association (CEA) is provided in this report, as has been the case in prior years. CEA data has been published only to 2011. CEA data is unavailable for underfrequency load shedding, a reliability KPI, as this measure is unique to Hydro's Island Interconnected System. In the Operating category, the KPIs used to measure performance relate to two specific facilities within Hydro's system: Bay d'Espoir and Holyrood. For these two generation plants, performance is measured and compared on a year-over-year basis.

Section 2 of this report provides an overview of Hydro's KPI performance in 2012 compared with the prior year as well as a comparison of actual KPI results compared with targets. This is followed by a detailed analysis of each individual KPI within the four categories named above in Section 3.

Section 3.3 Financial Performance Indicators are not yet available but will follow after the audited financial statements are available.

The 2012 financial data and 2013 targets in Section 4 Data Table of Key Performance Indicators are not available at this time. This section will be re-filed after the financial data is available and the 2013 target levels have been established.

2 Overview of Key Performance Indicator Results

2.1 Performance in 2012 versus 2011

Generation performance continued to improve in some areas in 2012, particularly with the thermal units. The Capability Factor for the Holyrood Generating Station improved significantly from 2011 and is now better than the latest CEA five-year average. The hydro plants experienced a decreased performance in this area due to an extended planned maintenance outage on Bay d'Espoir Unit 4. The performance of gas turbines was impacted by the failure of the Stephenville Gas Turbine which occurred in December 2011. The unit was not available in 2012 due to this forced outage.

The underfrequency load shedding performance met the target in 2012 with a total of five events and remains under the previous five-year average of 5.4 events per year. Performance in this area deteriorated from the three events experienced in 2011, which was the best performance since these events started being recorded in 1998.

Transmission and Distribution reliability improved significantly in 2012 from 2011. Improvements were seen in all areas and measures are comparable to the values seen before 2011. In 2011, there were a number of severe weather related events which caused numerous and lengthy outages, primarily in the Northern and Central regions.

The operating KPIs for energy conversion showed a slight reduction in performance for the Holyrood fuel conversion rate. Unit operating time continued to be minimized in 2012, with units placed on line only as required to support Avalon transmission and system peak loads.

The hydraulic conversion factor at Bay d'Espoir improved slightly in 2012 from 2011. In 2011, high water levels required the operation of the plant to reduce and control the spill of water, particularly during the summer months. This was not required in 2012 as the water levels were more in-line with normal levels.

Hydro's 2012 operating and maintenance costs are not available at this time. Financial KPI data will be provided at a later date.

The final category of KPIs called "Customer-Related" deals with Hydro's residential customer satisfaction. Customer satisfaction in 2012 of 80%, was the lowest of the previous five-years.

2.2 Performance in 2012 versus 2012 Target

The table below summarizes Hydro's KPI performance in 2012 compared to targets set for each measure. Targets were met with respect to the generation forced outage rate, transmission SAIDI, the number of underfrequency load shedding events and the hydraulic conversion rate. Other targets were not met due to a number of challenges further described in this report.

The rationale for the 2012 targets was summarized in the May 2012 report to the Board entitled *2011 Annual Report on Key Performance Indicators*. The 2012 rationale is included in this report as Appendix A.

Hydro's KPI Targets and Operating Results for 2012

Category	KPI	Units	2012 Target	2012 Results	Target Achieved
Reliability	Weighted Capability Factor (WCF)	%	84.9	82.9	No
	DAFOR	%	2.7	2.3	Yes
	T-SAIDI	Minutes/Point	265[1]	171[2]	Yes
	T-SAIFI	Number/Point	2.0[1]	1.9[2]	Yes
	T-SARI	Minutes/Outage	133[1]	90[2]	Yes
	SAIDI	Hours/Customer	5.9	8.3	No
	SAIFI	Number/Customer	3.7	4.4	No
	Underfrequency Load Shedding	# of events	6	5	Yes
Operating	Hydraulic CF	GWh/MCM	0.433	0.434	Yes
	Thermal CF	kWh/BBL	630	599	No
Financial	Controllable Unit Cost	$/MWh	Not Available	Not Available	
Other	Customer Satisfaction (Residential)	Max=100%	>90%	80%	No

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

3 Performance Indices

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

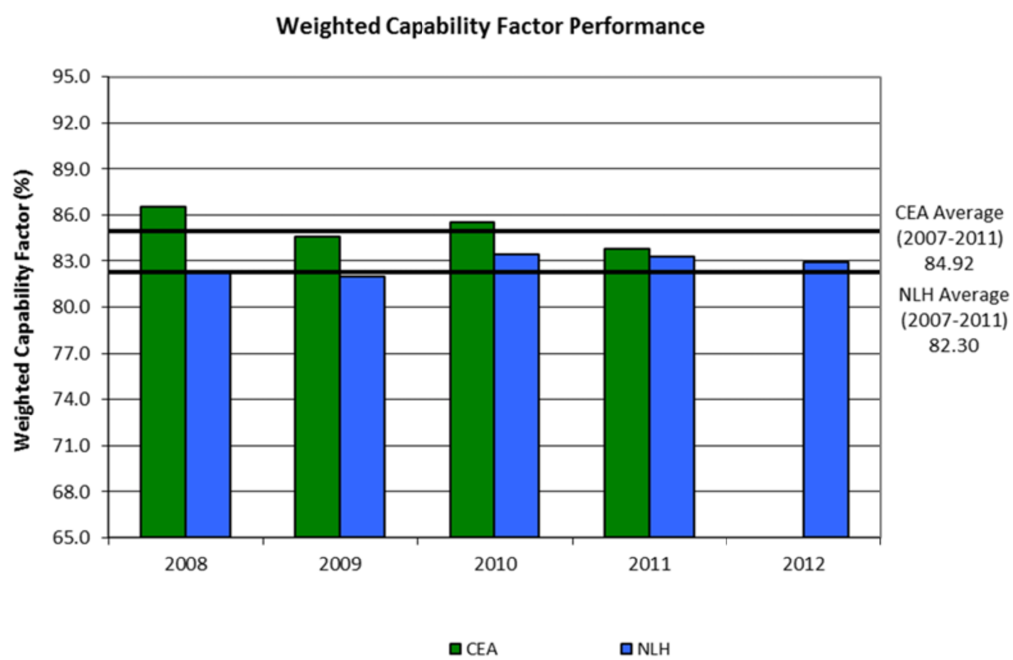
3.1 Reliability Performance Indicators

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

3.1.1 Reliability KPI: Generation

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

In 2012, Hydro's WCF was 82.9%. This is lower than the target of 84.9%; however, it does reflect an improvement over the 2007 to 2011 five-year average of 82.3%.



Thermal unit performance improved in 2012 to 76% from 67% in 2011. Holyrood Unit 1 had the lowest capability factor of 70% and Unit 2 had the highest capability factor of 83%. Unit 3 had a capability factor of 75%. There were no major equipment failures in 2012.

Overall, the hydraulic unit performance declined slightly in 2012, to 91% compared to 93% in 2011. There were no major issues with the hydraulic generation and all units, except Bay d'Espoir Unit 4, experienced a capability factor above 90%. The capability factor of this unit was reduced to 68% in 2012 due to an extended planned outage required for a stator rewind.

Gas turbine performance decreased to 53% in 2012 from 71% in 2011. The capability factor for the Stephenville unit was 0%. The Stephenville unit failed in December 2011 due to a stator ground fault. This unit is not anticipated to be available again until repairs are completed in the spring of 2013. Calculation details for weighted capability as well as a list of factors that may impact KPI performance are in Appendix B of this report.

The table below provides a comparison by unit type along with the weightings applied to the CEA values to provide for the comparison to Hydro for the period 2007-2011. Hydro's hydro generation capability was slightly better than the comparable weighted national average. The weighted average is lower for Hydro's thermal-oil fired units and gas turbines.

Capability Factor Performance

	CEA (2007-2011)	NLH (2007-2011)	Weighting Factor
Hydro	91.31	92.79	50%
Thermal - Oil Fired	74.13	62.41	33%
Gas Turbine	87.21	70.05	17%

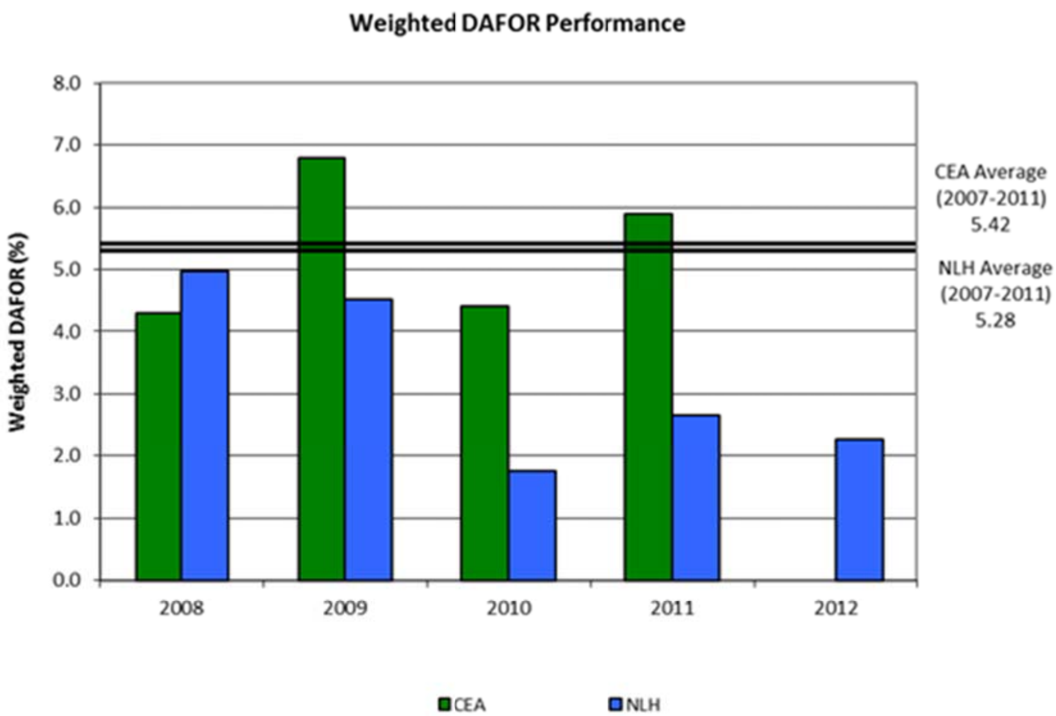
The weighted national average is developed by using national average capabilities values for the unit types in Hydro's system (hydro, oil-fired thermal and gas turbine) and applying weightings to these based upon the maximum continuous ratings of Hydro's generation. The quoted CEA value is therefore not a CEA published value but a re-stated value to facilitate a comparison to Hydro.

3.1.1 b) Weighted Derating-Adjusted Forced Outage Rate (DAFOR) - *a reliability KPI for generation assets that includes Hydro's thermal and hydroelectric generation assets on the interconnected systems[3]. DAFOR measures the percentage of the time that a unit or group of units is unable to generate at its Maximum Continuous Rating (MCR) due to forced outages. The KPI is weighted to reflect differences in generating unit sizes.*

In 2012, Hydro's weighted DAFOR was 2.3% versus a target of 2.7%. The DAFOR was impacted by a hydrogen leak, high vibration on No. 1 bearing, and a problem with the turning gear, all associated with Holyrood Unit 1. There was also a problem with the condenser on Holyrood Unit 3 which affected the DAFOR. Hydro's overall weighted DAFOR from 2007 to 2011 of 5.3%, is slightly better than the equivalently weighted national average for the same period of 5.4%. The following table provides a 2007-2011 comparison by unit type:

DAFOR Performance

	CEA (2007-2011)	NLH (2007-2011)	Weighting Factor
Thermal - Oil Fired	9.84	13.81	34%
Hydro	3.19	0.97	66%



[3] DAFOR is not applicable to the gas turbines because of the gas turbines' low operating hours.

3.1.1.1 Generation Equipment Performance

The table below highlights the various performance indices for Hydro's generation facilities. Indices for 2011 and for the latest Canadian Electricity Association (CEA) national average for the period 2007-2011 are included for comparison.

Generation Performance Indices

Index		Hydro	Thermal	Gas Turbine
Failure Rate	NLH 2012	2.33	9.87	231.67
(Forced Outages per 8,760	NLH 2011	2.12	2.95	137.66
operating hours)	CEA '07-'11	2.01	7.52	21.58
Incapability	NLH 2012	9.35	24.04	32.88
Factor	NLH 2011	6.56	33.32	24.90
(Percent of Time)	CEA '07-'11	8.69	25.87	12.79
Derating Adjusted Forced	NLH 2012	1.05	6.24	
Outage Rate	NLH 2011	0.82	7.88	
(Percent of Time)	CEA '07-'11	3.19	9.84	
Utilization	NLH 2012			55.05
Forced Outage	NLH 2011			10.45
Probability (Percent of Time)	CEA '07-'11			10.04

3.1.1.1 (a) Hydro Unit Performance

As indicated in the above Generation Performance Indices table, all hydro unit measures deteriorated in 2012 when compared to 2011. However, the hydraulic unit derating adjusted forced outage rate continues to be significantly better than the latest five-year national average.

3.1.1.1 (b) Thermal Unit Performance

Thermal unit performance improved in 2012 in the measures of derating adjusted forced outage rate and incapability factor. Performance in both of these measures is better than the national five-year averages. There was a significant decline in 2012 in the failure rate measure and performance is now worse than the national five-year average.

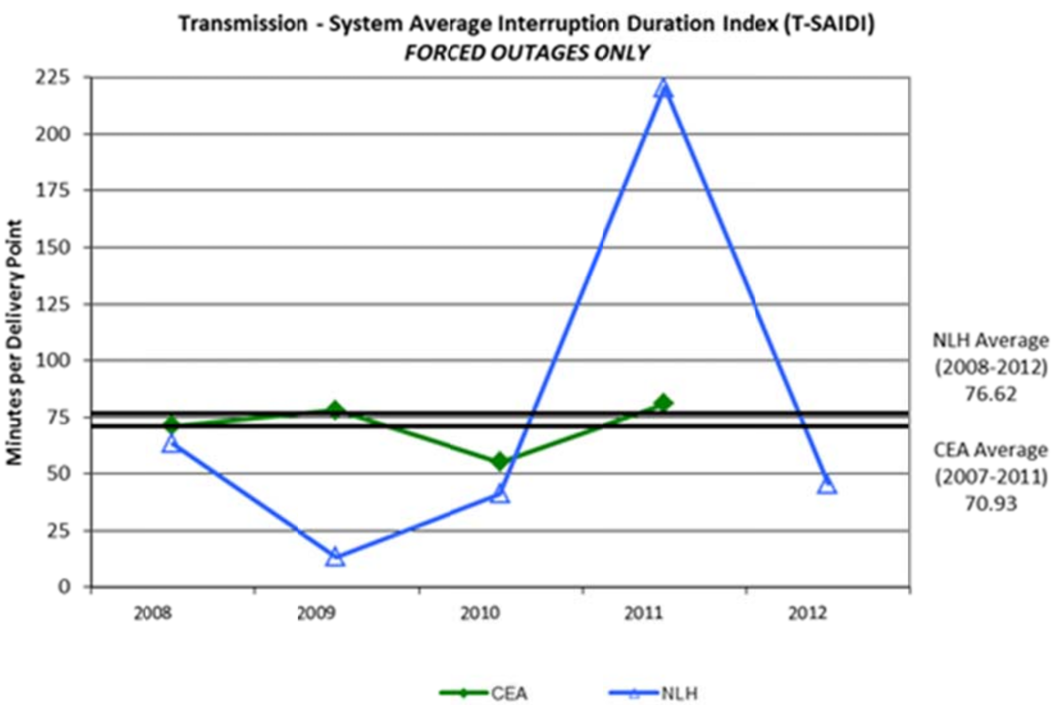
3.1.1.1 (c) Gas Turbine Unit Performance

The Generation Performance Indices table also indicates that Hydro's gas turbines performance declined significantly in 2012 from 2011 for all measures, and continues to be below the national average. This was primarily due a failure at the Stephenville gas turbine in December 2011 which rendered the unit inoperable for all of 2012. The failure rate calculation is very volatile due to the normally low operating hours of Hydro's gas turbines. Of particular importance to Hydro's use of gas turbines is the utilization forced outage probability (UFOP). The measure describes the degree to which a standby unit can be called upon to supply load when requested. The Stephenville failure had a significant effect on these measures.

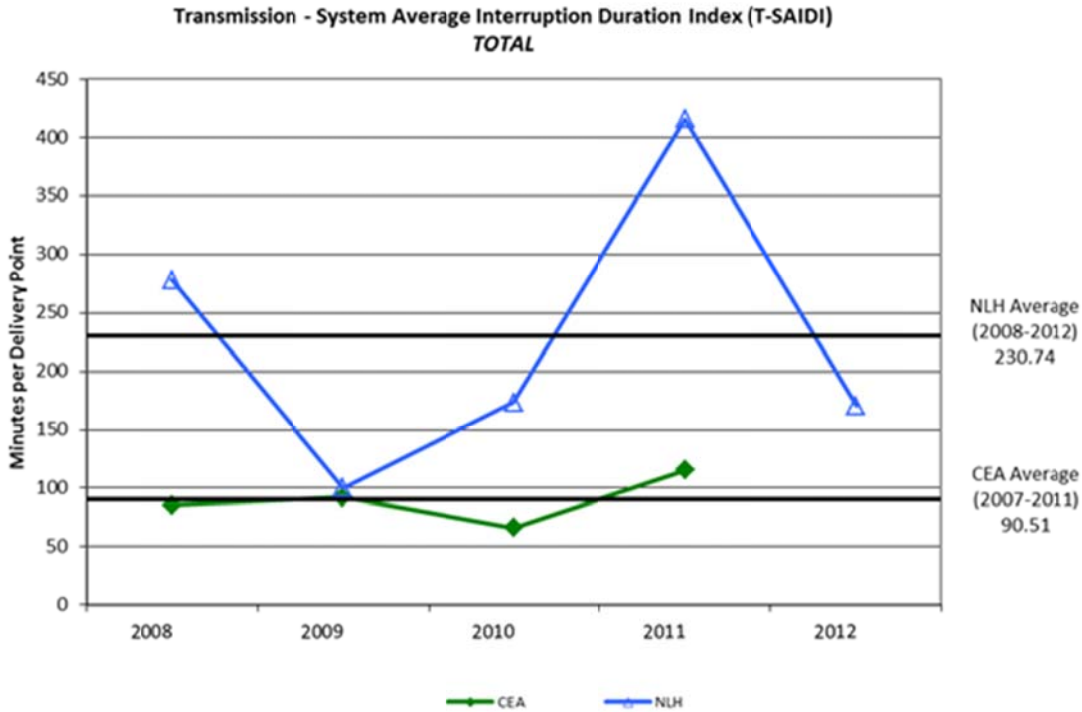
3.1.2 Reliability KPI: Transmission

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

The fourth quarter T-SAIDI was 32.4 minutes per delivery point (forced and planned combined). The total 2012 T-SAIDI was 171 minutes per delivery point, 35% below the 2012 target[4] of 265 minutes per delivery point. In comparison, the 2011 total was 432 minutes per delivery point. The forced outage duration in 2012 decreased to 46 minutes from 221 minutes in 2011. The planned outage duration decreased to 125 minutes from 211 minutes in 2011. Of note is that, for the fourth quarter, the contribution of the force outage duration was 56% of the 2012 total.



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



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

Forced

On October 12, customers served by the Hawke's Bay and Parsons Pond Terminal Stations experienced a series of unplanned outages due to salt contamination. Refer to the following table for details:

Date	Delivery Point	Time of Incident	Time of Restoration	Outage Duration	Cause of Outage
October 12	Hawke's Bay	1727	1730	3 minutes	Salt Contamination
October 12	Hawke's Bay	1828	1829	1 minute	Salt Contamination
October 12	Hawke's Bay	1831	1837	6 minutes	Salt Contamination
October 12	Parson's Pond	1459	1506	7 minutes	Salt Contamination
October 12	Parson's Pond	1620	1642	22 minutes	Salt Contamination

On October 14, all customers supplied by the South Brook Terminal Station experienced an unplanned outage of 35 minutes in duration. Crews found a jumper burnt off voltage regulator T1B1-VR1 at the station. Disconnect switch L22T1 was opened by Hydro's Energy Control Centre immediately, resulting in the unplanned outage. The jumper was repaired and the station was restored to service. The jumper burnt off due a severely corroded connector. Some customers continued to experience an outage due to faults on the distribution system during this time.

On October 16, customers north of Plum Point on the Great Northern Peninsula (GNP) experienced unplanned outages. The table below outlines the outage details (all were a result of salt contaminated equipment):

Date	Delivery Point	Time of Incident	Time of Restoration	Outage Duration	Cause of Outage
October 16	Bear Cove	445	907	4 hrs & 22 mins	138 kV Bus Lockout at Bear Cove TS and trip of TL241 and TL 244.
October 16	Plum Point	657	859	2 hrs & 2 mins	TL241 trip and Plum Point Reactor R1 locked.
October 16	St. Anthony	445	500	15 minutes*	138 kV Bus Lockout at Bear Cove TS and trip of TL241 and TL244.
October 16	Main Brook	445	500	15 minutes*	138 kV Bus Lockout at Bear Cove TS and trip of TL241 and TL244.
October 16	Roddickton	445	500	15 minutes*	138 kV Bus Lockout at Bear Cove TS and trip of TL241 and TL244.
*Note: Customers in St. Anthony, Main Brook, and Roddickton were restored via St. Anthony Diesel Plant.					

On October 24, customers served by the Happy Valley Terminal Station experienced an unplanned power outage of 32 minutes in duration. This outage occurred after transmission line L1301 tripped due to the operation of the lockout relay on transformer T31 at Churchill Falls. Personnel were working on the transformer, which was out of service, but the gas pressure relay was not blocked. This relay should have been blocked prior to starting work on the transformer.

On November 17, all customers supplied by the Farewell Head Terminal Station experienced an unplanned outage of ten minutes in duration. Newfoundland Power's Cobb's Pond Substation tripped due to a lockout of transformer T2. This lockout also tripped transmission line 142L which supplies Farewell Head via the Boyd Cove Substation and transmission line TL254.

On December 22, Newfoundland Power customers supplied by transmission line TL215 in the Port Aux Basque area experienced an unplanned outage of three minutes in duration. The outage occurred after high winds tripped TL215. Since the circuit breaker B1L15 was bypassed at the Doyles Terminal Station, TL214 tripped to isolate the fault. Newfoundland Power customers in the Doyles area were also affected by this event.

On December 24, all customers supplied by transmission line TL227 in Parson's Pond Area experienced an unplanned outage of one hour and two minutes in duration. The outage was caused by salt contamination on the line. The section of TL227 between the Parson's Pond and Daniel's Harbour Terminal Stations was isolated and customers were restored by closing in the Cow Head end of TL227.

On December 26, all customers supplied by the Rocky Harbour Terminal Station experienced an unplanned outage of 53 minutes in duration. All customers supplied by the Glenburnie and Wiltondale Terminal Stations experienced unplanned outages of one hour and 39 minutes in duration. The outage was caused by a tree coming into contact with transmission line TL226. The tree broke a conductor between Rocky Harbour and Wiltondale Stations. Rocky Harbour customers were restored from Berry Hill whilst Wiltondale and Glenburnie customers were restored from Deer Lake. The conductor was repaired on December 27.

On December 30, all customers supplied by the Rocky Harbour, Glenburnie, and Wiltondale Terminal Stations experienced an unplanned outage of two minutes in duration. The outage was caused by heavy snow build-up on transmission line TL226.

On December 30, all customers supplied by the Rocky Harbour, Glenburnie, and Wiltondale Terminal Stations experienced another unplanned outage of 49 minutes in duration. Similar to the events on December 26, the outage was caused by a tree contacting transmission line TL226. The tree broke a conductor between Rocky Harbour and Wiltondale Stations. Rocky Harbour customers were restored from Berry Hill while Wiltondale and Glenburnie customers were restored from Deer Lake. The conductor was repaired on December 31.

Planned

On November 4, all customers supplied by the Main Brook and Roddickton Terminal Stations experienced a planned outage of five hours and 14 minutes in duration. The outage was required to perform maintenance on Bus B1 PTs and install disconnect switch SST-1 at the St. Anthony Airport Terminal Station. Customers in the St. Anthony area were supplied by the St. Anthony Diesel plant.

On November 22, Newfoundland Power customers supplied by the Doyles Terminal Station experienced a planned outage of two hours and 50 minutes in duration. The outage was required to remove jumpers from circuit breaker B1L15 and to install a bypass around this breaker, to facilitate its replacement. Newfoundland Power customers in the Port Aux Basque area were supplied by local Newfoundland Power generation.

On December 31, all customers supplied by the Rocky Harbour Terminal Station experienced a planned outage of three minutes in duration. The short outage was required to restore TL226 following the completion of repairs to the conductor, broken during the previous day.

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

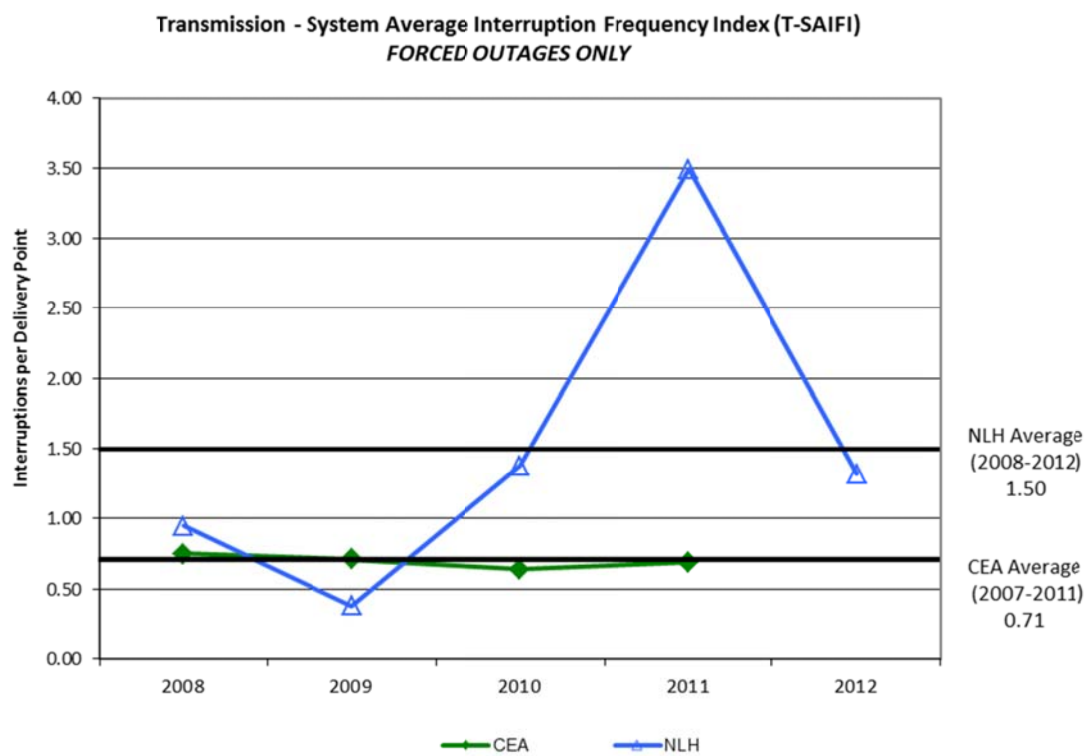
Appendix C1 lists all of the significant transmission events in 2012. Significant events are identified as those resulting in forced outages with an unsupplied energy of greater than 1,000 MW-mins. Unsupplied energy is a calculation of the outage duration multiplied by the load, in MW, at the delivery point before it was interrupted. This measures the energy that could have been supplied if the delivery had not been interrupted.

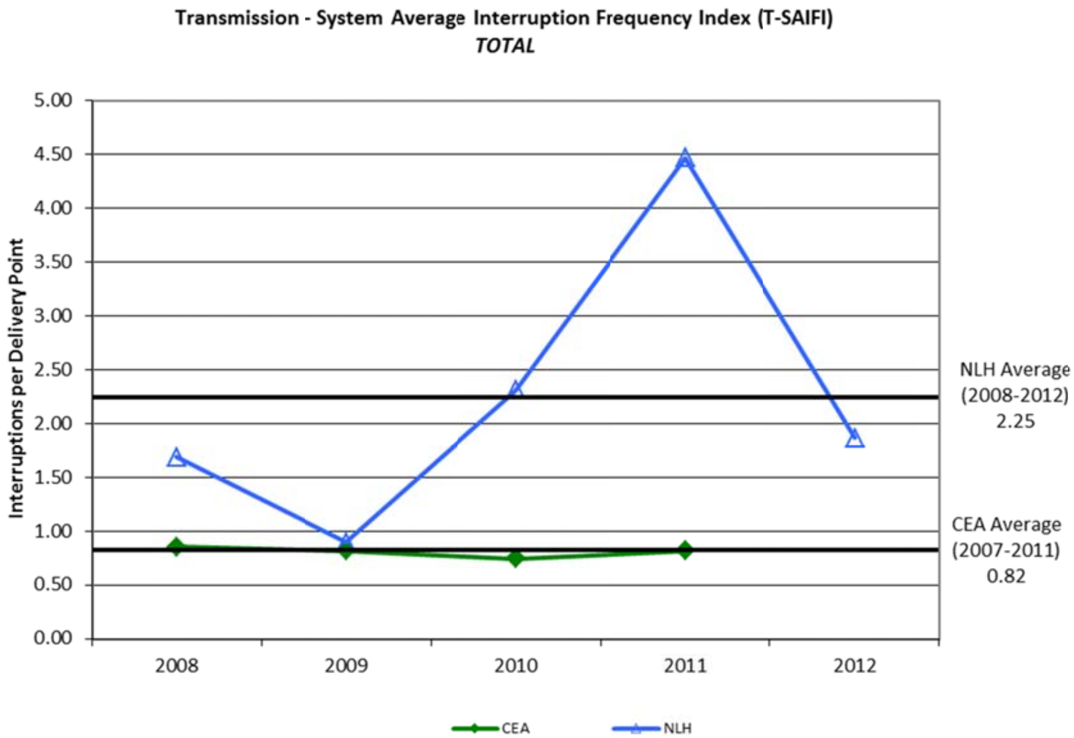
3.1.2 b) Transmission System Average Interruption Frequency Index (T-SAIFI) - *a reliability KPI for bulk transmission assets that measures the average number of sustained outages per delivery point*.

The fourth quarter T-SAIFI was 0.52 outages per bulk delivery point, with contributions of forced and planned outage frequency of 0.45 and 0.07, respectively. In comparison, the 2011 fourth quarter T-SAIFI was 2.71 outages per bulk delivery point. The decrease in outage frequency was the result of a lower number of forced outages this quarter.

The overall 2012 T-SAIFI was 1.88 outages per bulk delivery point which is significantly lower than last year's average of 4.52 outages per delivery point, a decrease of 58%. The 2012 target was 2.00 outages per bulk delivery point and this target was met. The number of forced outages per delivery point in 2012 (1.32) decreased 62% from 2011 (3.49). The frequency of planned outages per delivery point decreased by 46%; to 0.55 in 2012.

The frequency of Hydro's forced delivery point outages has been generally higher than the national average. This result is expected and can generally be attributed to the number of delivery points that are supplied by a single transmission line. The most severe example is on the Great Northern Peninsula, where one line, TL-239, supplies up to nine delivery points. There are a number of other locations where a single line supplies three delivery points.



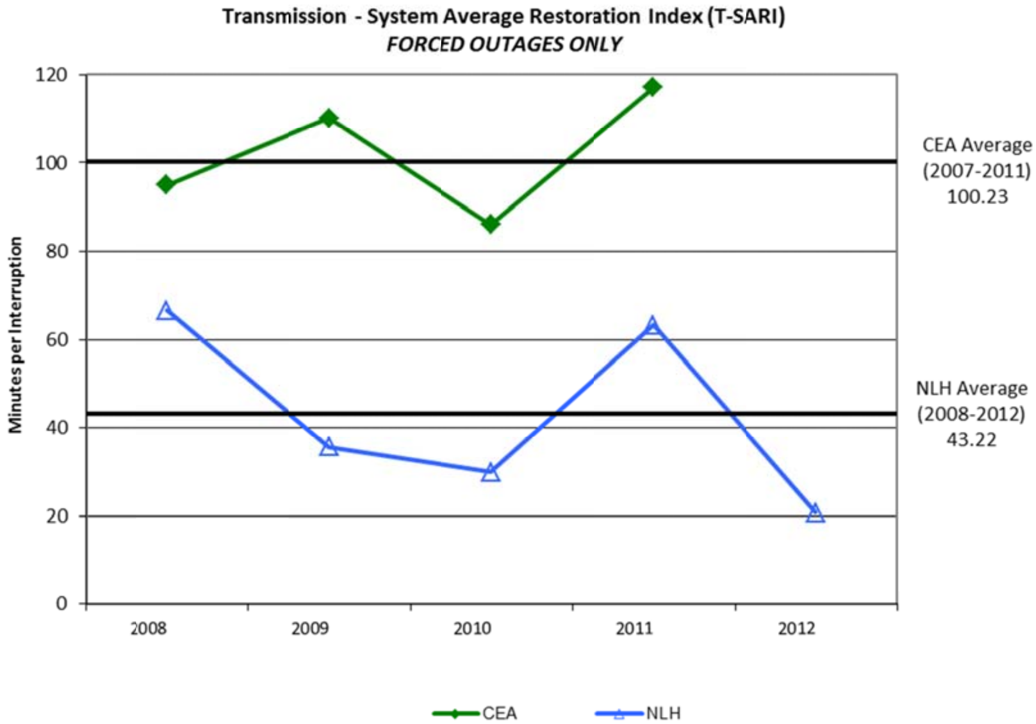


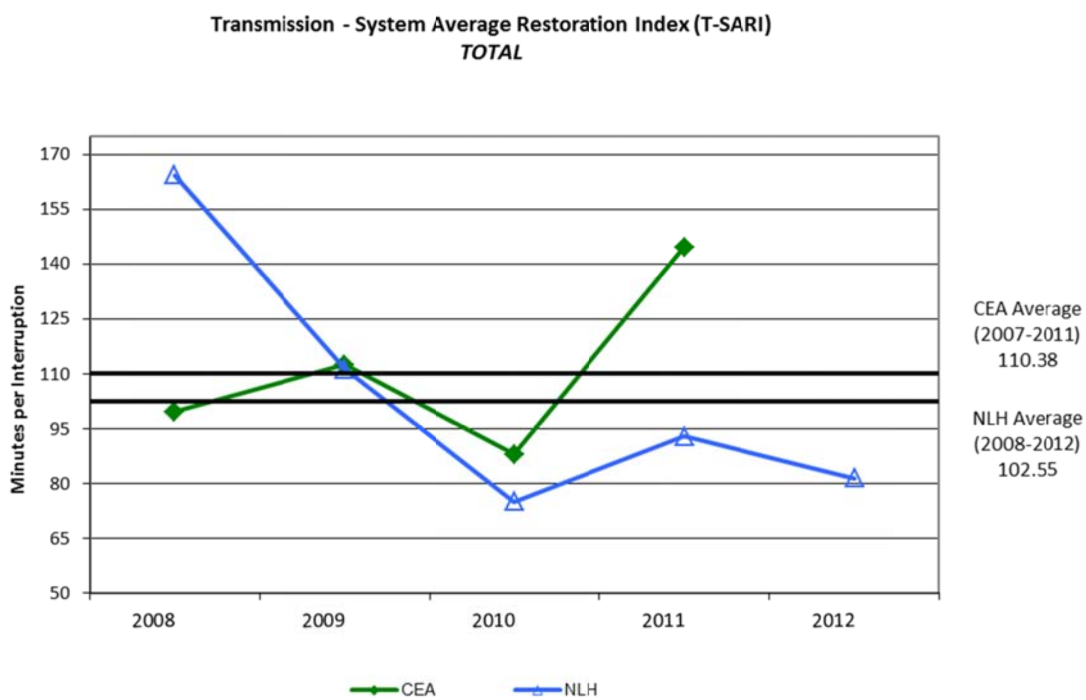
3.1.2 c) Transmission System Average Restoration Index (T-SARI) - *reliability KPI for bulk transmission assets which measures the average duration per transmission interruption. T-SARI is calculated by dividing T-SAIDI by T-SAIFI.*

Hydro's total transmission T-SARI was 62.4 minutes per interruption for the fourth quarter of 2012 compared to 98.4 minutes per interruption during the same quarter in 2011, a 37% decrease. The forced outage component of T-SARI was 40.8 minutes per interruption compared to 79.8 minutes per interruption in 2011. The planned outage component of T-SARI was 200.4 minutes per interruption which is 6% higher than during the fourth quarter of 2011.

Hydro's 2012 total transmission T-SARI was 90 minutes per interruption, compared to 94 minutes in 2011 and a 2012 target of 133 minutes. The forced outage component of T-SARI was 34.8 minutes per interruption, a decrease of 44% over 2011. The planned outage component of T-SARI was 226 minutes per interruption, which is an increase of 9% over 2011. Since T-SARI is the ratio of T-SAIDI to T-SAIFI, this increase is driven by greater increase in T-SAIDI relative to T-SAIFI.

Hydro's total T-SARI performance continues to be better than the latest five-year national average. This can be seen in the chart below.

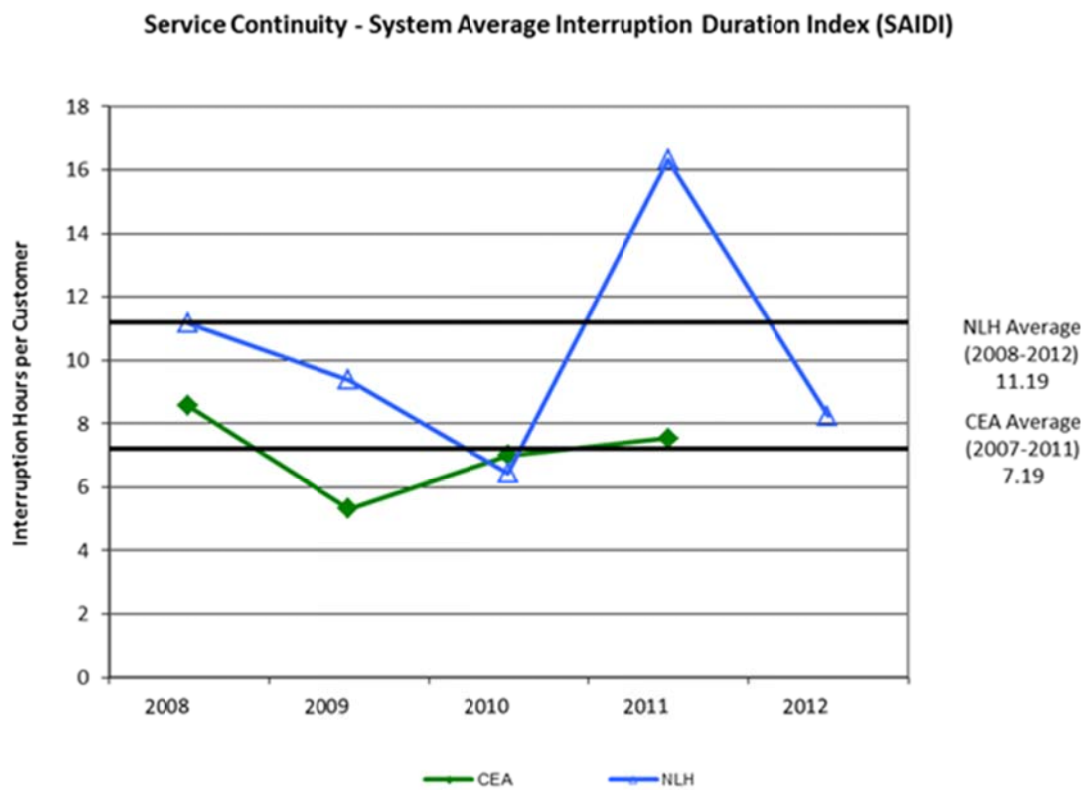

Transmission - System Average Restoration Index (T-SARI)
FORCED OUTAGES ONLY
Minutes per Interruption
120
100
80
60
40
20
0
2008
2009
2010
2011
2012
CEA Average
(2007-2011)
100.23
NLH Average
(2008-2012)
43.22
CEA
NLH


Transmission - System Average Restoration Index (T-SARI)
TOTAL
Minutes per Interruption
170
155
140
125
110
95
80
65
50
2008
2009
2010
2011
2012
CEA Average
(2007-2011)
110.38
NLH Average
(2008-2012)
102.55
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 2012, the SAIDI was 3.41 hours per customer, compared to 9.57 hours per customer during the same quarter of 2011. The total 2012 SAIDI was 8.25 hours per customer, compared to 16.32 hours per customer in 2011. The performance in 2012 was worse than the annual target of 5.90 hours per customer but showed a considerable improvement over the previous year.



A summary of the major interruptions during the fourth quarter is as follows:

- On October 6, all customers (166) in Rigolet, Labrador experienced an unplanned power outage. The outage occurred when Diesel Units 2065 and 2051 experienced mechanical problems with their actuators. All customers were restored at 1340 hours. Outage duration was five hours and 40 minutes.

- On November 4, 146 customers serviced by Line 18 in Labrador City experienced two emergency planned power outages. The outages were requested by the local emergency response team due to a fire in an unfinished apartment building. Total customer outage time was nearly six hours.

- On November 25, all customers (105) in Black Tickle, Labrador experienced an unplanned power outage. The outage occurred after mobile generator 2 tripped off-line. All customers were restored at 1838 hours. The cause of the mobile tripping could not be determined. The total customer outage duration was five hours and 48 minutes.

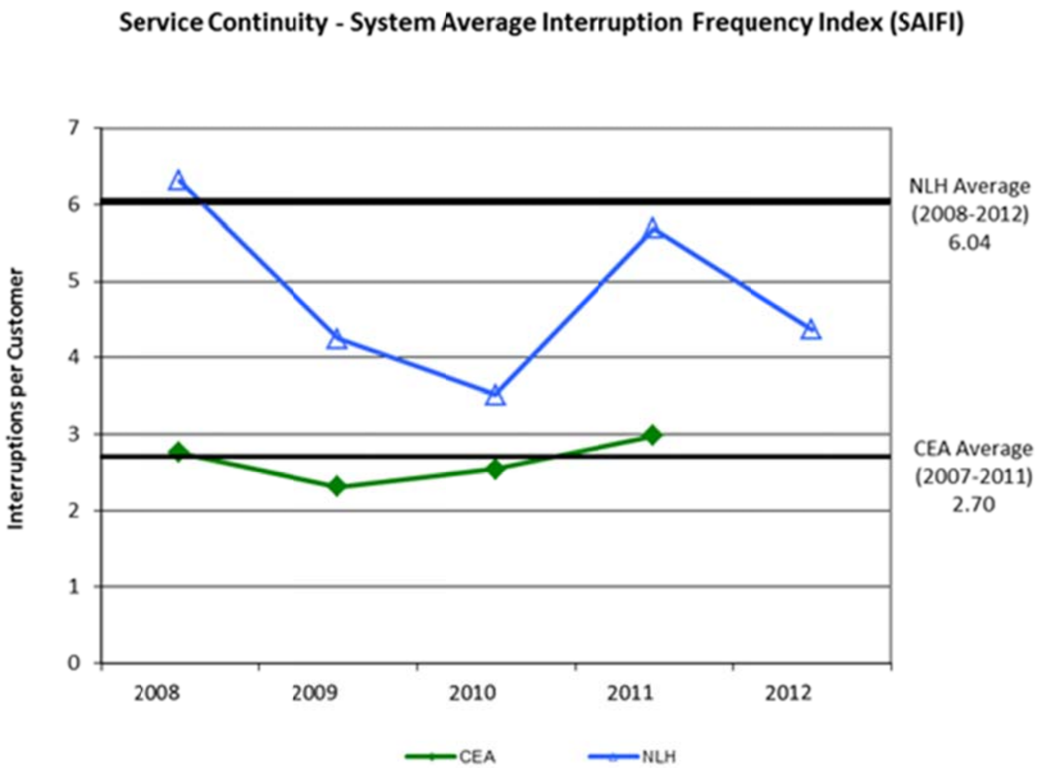
- On December 6, 95 customers in Nain, Labrador experienced an unplanned power outage. The outage occurred when a vehicle hit and broke a utility pole. A community wide outage was required to isolate the affected area to perform maintenance. During this outage all Nain customers (452) experienced an unplanned power outage from 0300 hours to 0310 hours. The damaged pole was repaired and all the 95 customers initially impacted were restored. The total customer outage duration was 15 hours and 30 minutes.

- On December 16, at 0000 hours (Labrador time), 50 customers in Nain, Labrador experienced an emergency planned power outage. The outage was required to repair an after cooler on Unit 2085. All customers were restored at 0640 hours with Unit 2085. The total customer outage duration was six hours and 40 minutes.

The remainder of the significant events in 2012, which affected the distribution systems (i.e., outages generally to a complete system with duration of greater than five hours), are contained in Appendix C2.

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

In the fourth quarter the SAIFI was 1.64 interruptions per customer, compared to 1.85 interruptions per customer during the same quarter of 2011, an 11% decrease. The total 2012 SAIFI was 4.37 interruptions per customer compared to 5.70 interruptions per customer in 2011, a 23% decrease. The 2012 target of 3.7 interruptions per customer was not met; however, the performance in 2012 shows an improvement from 2011.



3.1.3.1 Additional Information

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

Rural Systems Service Continuity Performance by Area

SAIFI (Number per Period)

Area	Fourth Quarter 2012	Fourth Quarter 2011	12 Mths to Date 2012	12 Mths to Date 2011	5 Year Average (2007–2011)
Central					
Interconnected	0.89	7.80	2.08	2.91	3.00
Isolated	0.32	1.19	0.88	6.22	3.19
Northern					
Interconnected	2.31	2.94	4.81	6.38	4.54
Isolated	5.03	1.11	8.65	5.26	6.34
Labrador					
Interconnected	1.10	2.07	5.44	8.17	6.34
Isolated	3.51	2.73	9.59	8.28	11.35
Total	1.64	1.85	4.37	5.70	4.86

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

SAIDI (Hours per Period)

Area	Fourth Quarter 2012	Fourth Quarter 2011	12 Mths to Date 2012	12 Mths to Date 2011	5 Year Average (2007–2011)
Central					
Interconnected	2.31	10.71	4.98	16.86	9.99
Isolated	0.87	0.99	2.02	3.83	2.38
Northern					
Interconnected	5.73	16.78	11.05	25.21	11.11
Isolated	5.36	0.61	6.89	3.84	5.97
Labrador					
Interconnected	2.17	5.01	9.28	11.34	11.23
Isolated	4.92	1.17	15.11	10.92	15.51
Total	3.41	9.57	8.25	16.32	10.40

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

Rural Systems Service Continuity Performance by Origin

SAIFI (Number per Period)

Area	Fourth Quarter 2012	Fourth Quarter 2011	12 Mths to Date 2012	12 Mths to Date 2011	5 Year Average (2007–2011)
Loss of Supply – Transmission	0.23	0.68	1.40	2.59	1.85
Loss of Supply – NF Power	0.00	0.01	0.01	0.01	0.01
Loss of Supply – Isolated	0.20	0.12	0.49	0.50	0.57
Loss of Supply – L'Anse au Loup	0.00	0.03	0.03	0.05	0.05
Distribution	1.20	1.01	2.45	2.53	2.38
Total	1.64	1.85	4.37	5.70	4.86

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

SAIDI (Hours per Period)

Area	Fourth Quarter 2012	Fourth Quarter 2011	12 Mths to Date 2012	12 Mths to Date 2011	5 Year Average (2007–2011)
Loss of Supply – Transmission	0.23	3.44	1.70	6.12	3.48
Loss of Supply – NF Power	0.00	0.49	0.00	0.49	0.14
Loss of Supply – Isolated	0.08	0.02	0.27	0.13	0.24
Loss of Supply – L'Anse au Loup	0.00	0.01	0.00	0.03	0.03
Distribution	3.10	5.61	6.26	9.55	6.58
Total	3.41	9.57	8.25	1631.00	10.47

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

Rural Systems Service Continuity Performance by Type

Area	Scheduled SAIFI	Scheduled SAIDI	Unscheduled SAIFI	Unscheduled SAIDI	Total SAIFI	Total SAIDI
Central						
Interconnected	0.32	1.16	0.57	1.15	0.89	2.31
Isolated	0.16	0.05	0.16	0.82	0.32	0.88
Northern						
Interconnected	0.73	1.84	1.58	3.90	2.31	5.73
Isolated	0.32	0.57	4.71	4.79	5.03	5.36
Labrador						
Interconnected	0.47	1.66	0.63	0.52	1.10	2.17
Isolated	0.88	2.87	2.64	2.05	3.51	4.92
Total	0.49	1.50	1.14	1.91	1.64	3.41

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

3.1.4 Reliability KPI: Other

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

There were three underfrequency events during the fourth quarter of 2012, summarized as follows:

On October 17, Holyrood Generating Unit #1 tripped due to a faulty vibration probe on the unit's Turbine Instrumentation System. With the removal of generation (approximately 71 MW) the system frequency dropped to 58.58 Hz resulting in the activation of the under frequency protection at Hydro and Newfoundland Power. Total system load at the time of the incident was 706 MW. A total of 1,278 Hydro customers were restored nine minutes after the event occurred, and 16,545 Newfoundland Power customers were reported to be restored within eleven minutes after the event occurred. Customers were restored in stages after capacitor banks on the Avalon were placed in service.

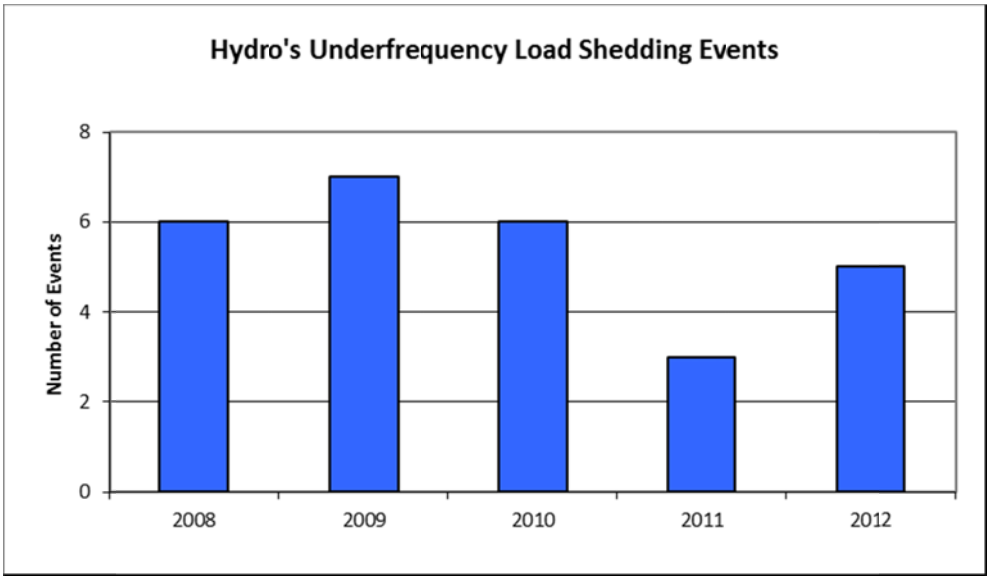
Load Shed:	Hydro: 4 MW
	Newfoundland Power: 39 MW
	Total Load Shed: 43 MW

On November 21, at 1438 hours, Holyrood Generating Unit #2 tripped. With the removal of generation (approximately 98 MW) the system frequency dropped to 58.55 Hz resulting in the activation of the under frequency protection at Hydro and Newfoundland Power. Total system load at the time of the incident was 903 MW. Hydro customers (1,282) were restored ten minutes after the event occurred, (50 MW-mins). Newfoundland Power customers (12,071) were reported to be restored within two to fourteen minutes after the event occurred, (399 MW-mins).

Load Shed:	Hydro: 5 MW
	Newfoundland Power: 54 MW
	Total Load Shed: 59 MW

On November 25, at 1124 hours Holyrood Generating Unit #2 tripped again. With the removal of generation (approximately 60 MW) the system frequency dropped to 58.79 Hz resulting in the activation of the under frequency protection at Newfoundland Power. Total system load at the time of the incident was 722 MW. Newfoundland Power customers (6,660) were reported to be restored within sixteen minutes after the event occurred. The load was 16 MW for 91.5 MW-mins.

In total, there were five UFLS events in 2012. This represents two more events than what were experienced in 2011, but below the five-year average of 5.4 events. Refer to the graph below which compares the UFLS events over the past five years to this year's performance.



The following table compares the UFLS events in the fourth quarter of 2012 to the same quarter in 2011.

Underfrequency Load Shedding Number of Events					
Customers	Fourth Quarter 2012	Fourth Quarter 2011	Year to Date 2012	Year to Date 2011	5 Year Average (2008–2012)
NF Power	3	1	5	3	5.4
Industrials	0	0	1	0	2.8
Hydro Rural*	2	0	3	0	2.8
Total Events	3	1	5	3	5.4

Underfrequency Load Shedding Unsupplied Energy (MW-min)					
Customers	Fourth Quarter 2012	Fourth Quarter 2011	Year to Date 2012	Year to Date 2011	5 Year Average (2008–2012)
NF Power	920	24	3,194	324	1,643
Industrials	0	0	140	0	217
Hydro Rural*	86	0	107	0	44
Total Events	1,006	24	3,440	324	1,904

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

The details of the previous two UFLS events in 2012 are summarized in Appendix C3.

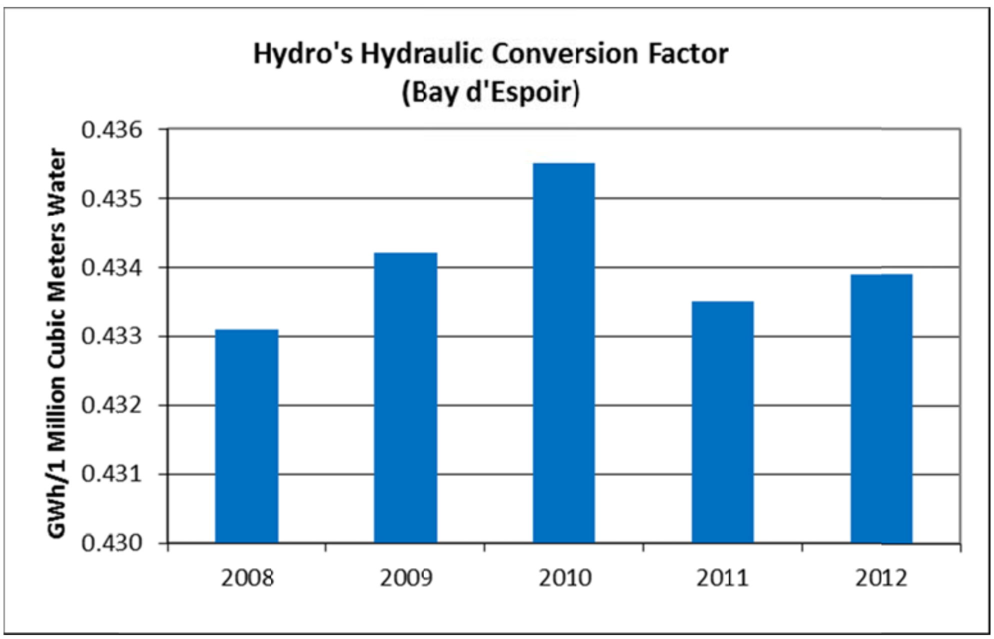
3.2 Operating Performance Indicators

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

3.2.1 Operating KPI: Generation

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

In 2012, Hydro's hydraulic conversion factor for Bay d'Espoir was 0.4339 GWh/MCM. The performance in 2012 improved slightly from that in 2011, primarily due to reservoir storages which had returned to normal levels and allowed for more efficient operation of the hydro-electric generation. In 2011, reservoirs were very high and there was a significant amount of spill which required that generation be operated at high levels in order to minimize the same.

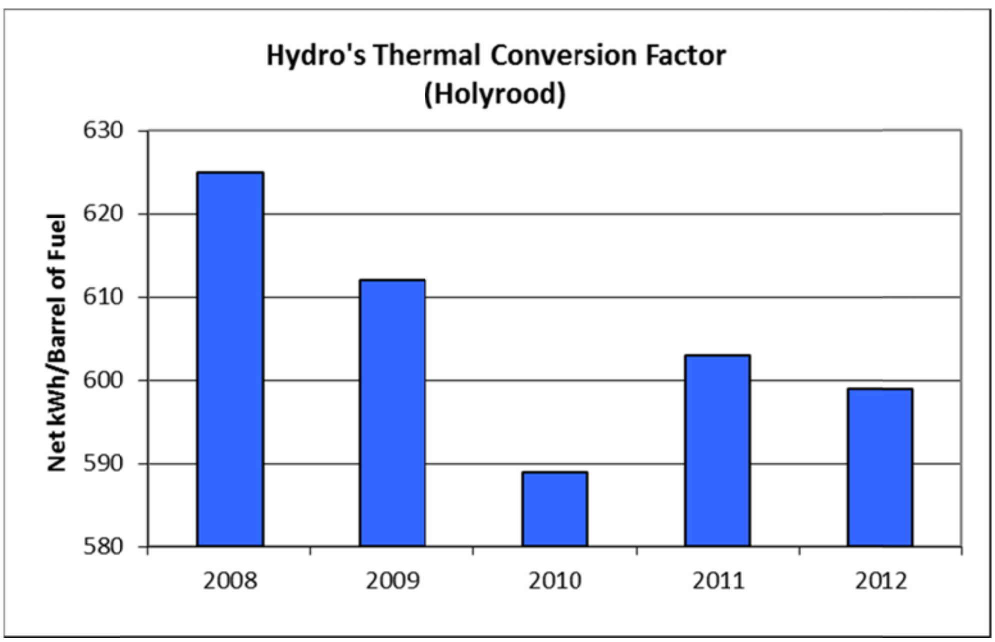


3.2.1 b) Thermal Conversion Factor - *a representative performance KPI for the oil-fired thermal generation assets located at Holyrood. This KPI tracks the efficiency in converting heavy fuel oil into electrical energy and is measured as the ratio of the net kWhs generated to the number of barrels of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

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

In 2012, Hydro's net thermal conversion factor was 599 kWh per barrel, which is significantly below the 2012 target of 630 kWh per barrel. This reduction is primarily related to operating the plant at lower generating levels due to the high volume of water resources and energy receipts relative to the system load requirements. The experience in 2012 declined slightly from an improvement in 2011.

Production at Holyrood was kept to a minimum in 2012 with units dispatched only as required for Avalon transmission support and system peak load considerations. The average net unit load while operating was 80 MW, up from 75 MW in 2011. Overall, net production from Holyrood for 2012 was 856 GWh, a 3.3% decrease from 2011 production levels.



3.3 Financial Performance Indicators

2012 Financial results are not available at this time.

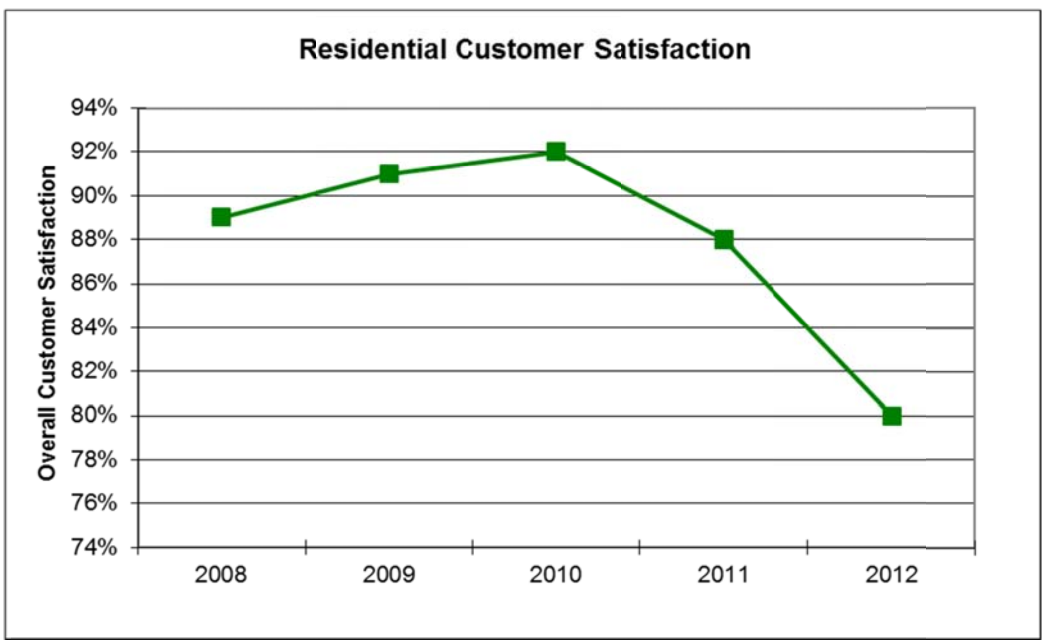
3.4 Customer-Related Performance Indicators

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.

Hydro targeted a 2012 residential satisfaction rate of ≥90%, up two points from the 2011 actual results of 88%. The 2012 residential customer satisfaction survey shows that the majority of customers (80%) are either *very satisfied* (46% provided a rating of 9 or 10, on a scale of 1 to 10) or *somewhat satisfied* (34% provided a rating of 7 or 8, on a scale of 1 to 10) with Hydro. Compared with 2011, the proportion of customers who provided a rating of 9 or 10 held steady at 46%, while the proportion that provided a rating of 7 or 8 decreased from 42% in 2011 to 34% in 2012.

Overall in 2012, there was a slippage in the proportion of customers who provided a rating of 7 or 8 and an increase in the proportion of customers who provided a rating of 5 or 6. Customer satisfaction with the reliability of service appears to be the indicator for the slippage.



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 2012 financial results and 2013 targets for this table are not available at this time.

Newfoundland and Labrador Hydro
Key Performance Indicators (KPI)
Results for 2012 plus Targets/Budgets for 2013[1]

KPI	Measure Definition	Units	2008	2009	2010	2011	2012	2013T
Reliability								Target
Generation								
Weighted Capability Factor[2]	Availibility of Units for Supply	%	82.3	82.0	83.4	83.3	82.9	N/A
Weighted DAFOR[2]	Unavailibility of Units due to Forced Outage	%	5.0	4.5	1.8	2.7	2.3	N/A
Transmission[6,]								
T-SAIDI	Outage Duration per Delivery Point	Minutes / Point	278	100	173	432	171	N/A
T-SAIFI	Number of Outages per Delivery Point	Number / Point	1.7	0.9	2.3	4.5	1.9	N/A
T-SARI	Outage Duration per Interuption	Minutes / Outage	164	111	75	96	90	N/A
Distribution								
SAIDI	Average Outage Duration for Customers	Hours / Customer	11.2	9.4	6.6	16.3	8.3	N/A
SAIFI	Number of Outages for Customers	Number / Customer	6.3	4.3	3.5	5.7	4.4	N/A
Under Frequency Load Shedding								
UFLS	Customer Load Interruptions Due to Generator Trip	Number of Events	6	7	6	3	5	6
Operating								
Hydraulic Conversion Factor[3]	Net Generation / 1 Million m^3 Water	GWh / MCM	0.433	0.434	0.436	0.434	0.434	N/A
Thermal Conversion Factor[4]	Net kWh / Barrel No. 6 HFO	kWh / BBL	625	612	589	603	599	630
Financial (Regulated)								
Controllable Unit Cost[5]	Controllable OM&A$ / Energy Deliveries	$/MWh	$14.05	$14.91	$14.25	$14.96	N/A	N/A
Generation Controllable Costs	Generation OM&A$ / Installed MW	$ / MW	$26,217	$26,138	$25,465	$26,169	N/A	N/A
	Generation OM&A$ / Net Generation	$ / GWh	$7,362	$8,267	$8,159	$7,833	N/A	N/A
Transmission Controllable Costs	Transmission OM&A$ / 230 kV Eqv Circuit Km	$ / Km	$4,023	$3,870	$4,021	$4,275	N/A	N/A
Distribution Controllable Costs	Distribution OM&A$ / Circuit Km	$ / Km	$2,305	$2,429	$2,755	$2,934	N/A	N/A
Other								
Percent Satisfied Customers (Residential)	Satisfaction Rating	Max = 100%	89%	91%	92%	88%	80%	≥90%

Notes:
1. Historical data has been updated and/or corrected where applicable.
2. The 2012 targets for weighted capability factor and DAFOR are based on the annual generation outage schedule.
3. For the Bay d'Espoir hydroelectric plant.
4. For the Holyrood thermal plant.
5. Energy deliveries have been normalized for weather, customer hydrology, and industrial strikes. No adjustments have been made for AC Stephenville mill closure.
6. The 2012 targets for T-SAIFI and T-SAIDI are based on the combination of forced and planned outage performance.

Appendices

Appendix A: Rationale for Hydro's 2012 KPI Targets

KPI	Comment on KPI 2012 Target
Reliability	Hydro has adopted a target setting approach wherein known factors that affect reliability performance are incorporated into the target setting process wherever practical. This approach also uses percentage improvements and past performance levels to set target levels for continuous improvements.
Weighted Capability Factor	The 2012 target is set using the expected annual generation unit outage schedule combined with performance improvements relative to recent history.
Weighted DAFOR	The 2012 target is set using the expected annual generation unit outage schedule combined with performance improvements relative to recent history.
Transmission SAIDI, SAIFI, and SARI	The 2012 targets for forced outage performance are set based upon recent performance improvements. The planned outage contribution to total performance is set using the annual transmission terminals maintenance outage plan.
Distribution SAIDI & SAIFI	Improvements relative to the most recent five-year average.
Underfrequency Load Shedding	The 2012 target is based upon improvement over the most recent five-year average.
Operating	
Hydraulic Conversion Factor	Hold at the previous target value.
Thermal Conversion Factor	Per Board Order No. P.U. 14 (2004)
Financial	
Controllable Unit Cost	Unavailable
Generation, Transmission & Distribution Controllable Cost	Unavailable
Other	
Customer Satisfaction	Targeting continuous improvement.

Appendix B: Computation of Weighted Capability Factor and Factors Impacting Performance

Weighted Capability Factor is calculated using the following formula:

$$1-\frac{\sum_{all\ units}\left(\frac{unit\ total\ equivalent\ outage\ time \times unit\ MCR}{unit\ hours}\right)}{\sum_{all\ units} unit\ MCR}$$

Where,

MCR = Maximum Continuous Rating, the gross maximum electrical output, measured in megawatts, for which a generating unit has been designed and/or has been shown capable of producing continuously. MCR would only change if the generating capability of a unit is permanently altered by virtue of equipment age, regulation, or capital modifications. Such changes to MCR are infrequent and have not actually taken place within Hydro since the 1980's when two units at Holyrood were uprated due to modifications made to these units.

Unit hours = the sum of hours that a unit is in commercial service. This measure includes time that a unit is operating, shut down, on maintenance, or operating under some form of derating. Unit hours will only be altered in the infrequent event that a unit is removed from commercial service for an extended period of time.

Unit total equivalent outage time = the period of time a unit is wholly or partially unavailable to generate at its MCR. For the purposes of calculating outage time, the degree to which a unit is derated is converted to an outage equivalency. Thus, a unit that is able to generate at 75% load for four days would have an equivalent outage time of one full day out of four. Factors that can affect unit total equivalent outage time are classified by CEA under nine categories, which are outlined in Appendix A to this Report. Hydro tracks the time that each unit spends in each of these nine states and calculates the weighted capability accordingly.

Unit total equivalent outage time is the measure that is most likely to impact Weighted Capability Factor on a year-to-year basis, since MCR and unit hours are unlikely to change.

Appendix B: Computation of Weighted Capability Factor and Factors Impacting Performance (Cont'd)

Factors that Affect Unit Total Equivalent Outage Time

1. **Sudden Forced Outage.** An occurrence wherein a unit trips or becomes immediately unavailable.
2. **Immediately Deferrable Forced Outage**. An occurrence wherein a unit must be made unavailable within a very short time (10 minutes).
3. **Deferrable Forced Outage**. An occurrence or condition wherein a unit must be made unavailable within the next week.
4. **Starting Failure**. A condition wherein a unit is unable to start.
5. **Planned Outage**. A condition where a unit is unavailable because it is on its annual inspection and maintenance.
6. **Maintenance Outage**. A condition where a unit is unavailable due to repair work. Maintenance outage time covers outages that can be deferred longer than a week, but cannot wait until the next annual planned maintenance period.
7. **Forced Derating**. A condition that limits the usable capacity of a unit to something less than MCR. The derating is forced in nature, typically because of the breakdown of a subsystem on the unit.
8. **Scheduled Derating**. A condition that limits the usable capacity of a unit to something less than MCR, but is done by virtue of the decision of the unit operator. Scheduled deratings are less common than forced deratings, but can arise, for example, when a unit at Holyrood is derated to remove a pump from service.
9. **Common Mode Outages**. Common mode outages are rare, and arise when an event causes multiple units to become unavailable. An example might be the operation of multiple circuit breakers in a switchyard at Holyrood due to a lightning strike, rendering up to three units unavailable.

Note: There are hundreds of CEA equipment codes for generator subsystems that track the cause for the time spent in each of the above categories.

Appendix C1: Significant Transmission Events - 2012

- On May 26, all customers served by the Happy Valley Terminal Station experienced an unplanned power outage of one hour and 31 minutes in duration. At the time there was a planned outage underway to transmission line L1301 and the Happy Valley Gas Turbine was in service supplying customers. A gas alarm occurred on the gas turbine unit transformer - T3. The planned work was cancelled on L1301, but before the line could be restored, the gas turbine tripped. Customers were restored after L1301 was returned to service. **Unsupplied Energy: 1,456 MW-mins.**

- On September 11, all Newfoundland Power customers east of the Western Avalon Terminal Station experienced an unplanned outage due to the high winds of Hurricane Leslie which tracked over the Avalon Peninsula. The following table provides additional detail:

Delivery Point Interruptions on Sept 11, 2012

Delivery Point Affected	Start Time	Finish Time	Duration of Interruptions (mins)	MW Load	MW-Mins
Hardwoods (Outage 1)	Sep 11, 2012 08:09	Sep 11, 2012 08:38	29.00	73.35	2,127.15
Hardwoods (Outage 2)	Sep 11, 2012 08:52	Sep 11, 2012 09:06	14.00	42.00	588.00
Oxen Pond	Sep 11, 2012 08:09	Sep 11, 2012 09:19	70.00	94.28	6,599.60
Holyrood - 38L (1)	Sep 11, 2012 08:09	Sep 11, 2012 08:48	39.00	9.82	382.98
Holyrood - 38L (2)	Sep 11, 2012 08:52	Sep 11, 2012 10:20	88.00	5.84	81.76
Holyrood - 39L (1)	Sep 11, 2012 08:09	Sep 11, 2012 08:35	26.00	0.00	0.00
Holyrood - 39L (2)	Sep 11, 2012 08:52	Sep 11, 2012 09:16	24.00	0.00	0.00
Western Avalon 64L (1)	Sep 11, 2012 08:01	Sep 11, 2012 08:05	4.00	0.00	0.00
Western Avalon 64L (2)	Sep 11, 2012 08:09	Sep 11, 2012 08:29	20.00	32.06	641.20
Western Avalon 64L (3)	Sep 11, 2012 08:31	Sep 11, 2012 08:34	3.00	3.43	10.29
Western Avalon 64L (4)	Sep 11, 2012 08:52	Sep 11, 2012 08:59	7.00	27.65	193.55
Western Avalon 64L (5)	Sep 11, 2012 09:14	Sep 11, 2012 09:29	15.00	33.22	66.44
Western Avalon Bus 2	Sep 11, 2012 08:09	Sep 11, 2012 09:58	109.00	2.10	228.90
		Total	448.00	211.61	10,919.87

The initial outage was caused by multiple faults that occurred on NP's 138 kV loop between the Western Avalon and Holyrood Terminal Stations. Combined with other system conditions and the nature and duration of these faults, the protection equipment on Hydro's 230 KV transmission lines responded and tripped. Investigation has determined that there was no fault on the 230 kV transmission system during this time and system stability was not lost. The slow clearing 138 kV faults created a severe 230 kV voltage dip and caused the protection operations which led to the outage.

A second outage occurred after transmission line TL237 faulted between the Come by Chance and Western Avalon Terminal Stations. This fault was also caused by the hurricane force winds resulting in the line conductors slapping together. **Total Unsupplied Energy: 10,541 MW-mins.**

Appendix C1: Significant Transmission Events – 2012 (Cont'd)

- On October 24, customers served by the Happy Valley Terminal Station experienced an unplanned power outage of 32 minutes in duration. This outage occurred after transmission line L1301 tripped due to the operation of the lockout relay on transformer T31 at Churchill Falls. Personnel were working on the transformer, which was out of service, but the gas pressure relay was not blocked. This relay should have been blocked prior to starting work on the transformer. **Unsupplied Energy: 1,186 MW-mins.**

Appendix C2: Significant Distribution Events – 2012 (Excluding Fourth Quarter)

- On February 12, there was an unplanned outage affecting approximately 20 customers in La Poile. The outage occurred during a high wind and heavy rain storm. Due to the poor visibility caused by the weather conditions (high winds which later caused snow squalls), attempts to bring in a crew by helicopter were delayed until February 14. The cause of the outage was a blown fuse at a pole-mounted disconnect switch, associated with the customer feeder. Total outage time to the customers was more than 51 hours.

- On March 14, all customers (105) in Black Tickle experienced a lengthy power outage caused by a fire in the diesel plant. The fire damaged most of the overhead electrical conductors in the power plant engine hall. Power was restored to the community on March 15 after the maintenance personnel successfully and safely completed the temporary repairs to one of the three generator units damaged in the fire. A mobile unit was transported to the site and used to supply customers.

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

- On January 14, Holyrood Generating Unit # 1 and Unit # 2 tripped due a fault on the 66 kV line supplying station service to the generating plant. With the removal of generation (approximately 142 MW) the system frequency dropped below 58.3 Hz resulting in the activation of the underfrequency protection at Newfoundland Power (18,940 customers), Hydro (2,200 Customers) and Corner Brook Pulp and Paper. Total system load at the time of the incident was 1,055 MW. Hydro indicated to Newfoundland Power and Corner Brook Pulp and Paper that power could be restored ten minutes after the event occurred and power was restored to all customers affected by the underfrequency in 40 minutes.

- On May 22, Cat Arm Generating Unit # 1 tripped after the fire protection deluge system operated on the unit transformer, T1. Personnel investigated, however, there was no fire or indication of a fire found at the transformer. With the removal of generation (approximately 60 MW) the system frequency dropped to 58.7 Hz resulting in the activation of the underfrequency protection at Newfoundland Power. This underfrequency event affected 6,046 Newfoundland Power customers for up to four minutes for a total load loss of 48 MW-mins. Total system load at the time of the incident was 570 MW.

Appendix D: List of U.S.-Based Peers for Financial KPI Benchmarking

Generation and Corporate Peer Group:

Alcoa Power Generating Inc.
Allete, Inc.
Aquila, Inc.
Avista Corporation
Buckeye Power, Inc.
Cleco Power LLC
Electric Energy, Inc.
Entergy Mississippi, Inc.
Hawaiian Electric Company, Inc.
Indiana-Kentucky Electric Corporation
Kentucky Power Company
Ohio Valley Electric Corporation
Portland General Electric Company
Public Service Company of New Hampshire
Puget Sound Energy, Inc.
Savannah Electric and Power Company
Sierra Pacific Power Company
Southern Electric Generating Company
Southern Indiana Gas and Electric Company
The Empire District Electric Company

Transmission Peer Group:

AEP Texas North Company
Allete, Inc.
Aquila, Inc.
Avista Corporation
Central Illinois Public Service Company
Delmarva Power & Light Company
Entergy Mississippi, Inc.
Kentucky Utilities Company
MDU Resources Group, Inc.
Mississippi Power Company
New York State Electric & Gas Corporation
Northern Indiana Public Service Company
Northern States Power Company (Wisconsin)
Oklahoma Gas and Electric Company
Public Service Company of Colorado
Public Service Company of Oklahoma
Sierra Pacific Power Company
Southwestern Electric Power Company
Tucson Electric Power Company
Westar Energy, Inc.