**Q. Please provide a copy of NP's Annual Reports from 2007 to current.**

A. Attachment A provides Newfoundland Power's Annual Reports filed with the Board from 2007 to 2011.

**Newfoundland Power's Annual Reports from 2007 to 2011**

# the Power you Require
# the People you Rely on

# 2007 ANNUAL REPORT

NEWFOUNDLAND POWER
A FORTIS COMPANY

# Corporate Profile

Aiden Maddox, Power Plant Maintenanceperson, Mechanical

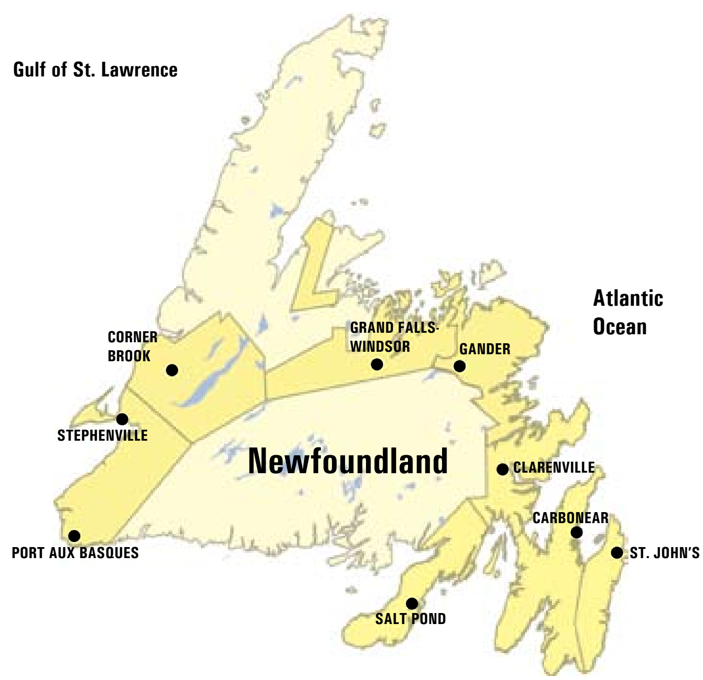
Newfoundland Power Inc. ("Newfoundland Power") operates an integrated generation, transmission and distribution system throughout the island portion of Newfoundland and Labrador.

For over 120 years, we have been committed to providing customers with safe, reliable electricity in the most cost-efficient manner possible. Our Company serves over 232,000 customers making up approximately 85% of all electricity consumers in the province.

Working together, Newfoundland Power and its employees continue to provide customers with the service they expect and deserve in an environmentally and socially responsible manner.

Our vision is to be a leader among North American electric utilities in terms of safety, reliability, customer service and efficiency.

All the common shares of Newfoundland Power are owned by Fortis Inc. (TSX:FTS), the largest investor-owned distribution utility in Canada, which serves almost 2,000,000 gas and electric customers, and has $10 billion of assets.

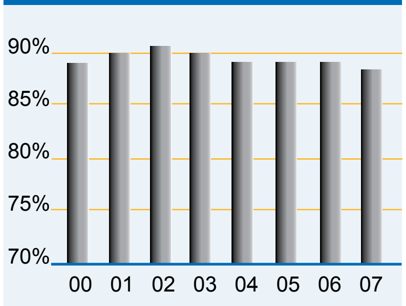



## Table of Contents

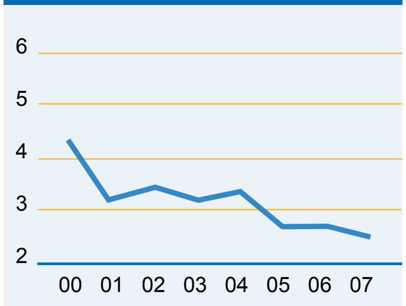
# Highlights

| Financial | 2007 | 2006 |
|---|---|---|
| Revenue ($000s) | 490,232 | 421,264 |
| Property, Plant and Equipment ($000s) | 1,169,322 | 1,119,820 |
| Long-term Debt ($000s) | 446,638 | 414,489 |
| Common Shareholder’s Equity ($000s) | 356,671 | 335,887 |
| Earnings Applicable to Common Shares ($000s) | 29,866 | 30,078 |
| Earnings per Common Share ($) | 2.89 | 2.91 |
| **Operating** | | |
| Customers (#) | 232,262 | 229,500 |
| Customer Satisfaction Rating (%) | 88 | 89 |
| Installed Generating Capacity (MW) | | |
| Hydroelectric | 95.9 | 92.1 |
| Diesel | 7.0 | 7.0 |
| Gas Turbine | 36.5 | 36.5 |
| Total | 139.4 | 135.6 |
| Peak Demand (MW) | 1,142 | 1,166 |
| Electricity Sales (GWh) | 5,093 | 4,995 |
| Operating Cost per Customer ($) | 213 | 212 |

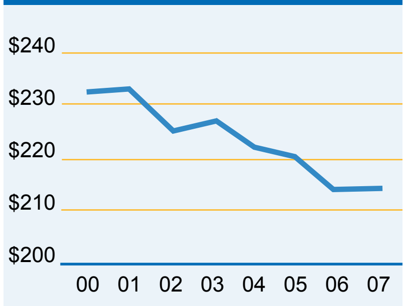
**Customer Satisfaction Rating**




**Outages per Customer**




**Operating Cost per Customer**



# Report to Shareholders

Every day our people are relied on to provide the power our customers require. In 2007, we maintained an excellent customer satisfaction rating of 88%, achieved record performance in safety, reduced the number of outages experienced by our customers and delivered on our financial results.

Our earnings of $29.9 million in 2007 were comparable to earnings of $30.1 million in 2006. Revenue from higher electricity sales was largely offset by a lower rate-setting return on equity for 2007. Higher electricity sales of 5,093 gigawatt hours ("GWh") in 2007 compared to 4,995 GWh for 2006 were due to an increase in the number of customers combined with an overall increase in average electricity usage.

Our rate-setting return on equity was reduced from 9.24% for 2006 to 8.60% in 2007 as a result of the operation of the Newfoundland and Labrador Board of Commissioners of Public Utilities (the "PUB") approved annual Automatic Adjustment Formula.

Improvements in each of our core areas – safety, reliability, customer service and environmental performance – contributed to an operating cost per customer of $213, which is comparable with 2006.

Throughout the years we have done many things to manage our own costs that have helped our customers. In fact, over the past five years we have successfully reduced our operating cost per customer by 14% on an inflation adjusted basis. This has had a direct impact on our ability to keep electricity rates as low as possible for our customers, which we know is very important to them.

Despite our ability to hold the line on our own operating costs, there were other costs, including depreciation and return on equity, that required us to request an increase to electricity rates for 2008. This was the first rate request we made to our regulator, the PUB, in five years.

As a result of negotiations between our Company, the Consumer Advocate and a mediator appointed by the PUB, and after a public hearing, the PUB approved an average 2.8% increase to our electricity rates effective January 1, 2008. When combined with an average rate decrease of 2.9% on July 1, 2007, our customers' electricity rates on January 1, 2008 were comparable, on average, to rates on January 1, 2007.

We are pleased our electricity rates for residential customers for 2008 remain comparable with those of 2007 and continue to be the lowest in Atlantic Canada. We are also pleased to provide knowledge, tools and resources to assist our customers in managing their own electricity costs.

Through our Bright Ideas campaign we have been providing our customers with easy, practical tips that are helping them become more energy efficient. Our approach is very direct and involves hands-on interaction with customers through community outreach programs, tradeshows and partnerships.

Our communications efforts have been effective, as the number of customers who contacted us about energy efficiency information in 2007 increased 55% compared to 2006. Visits to the Saving Energy section of our website were also up by 76% compared to 2006.

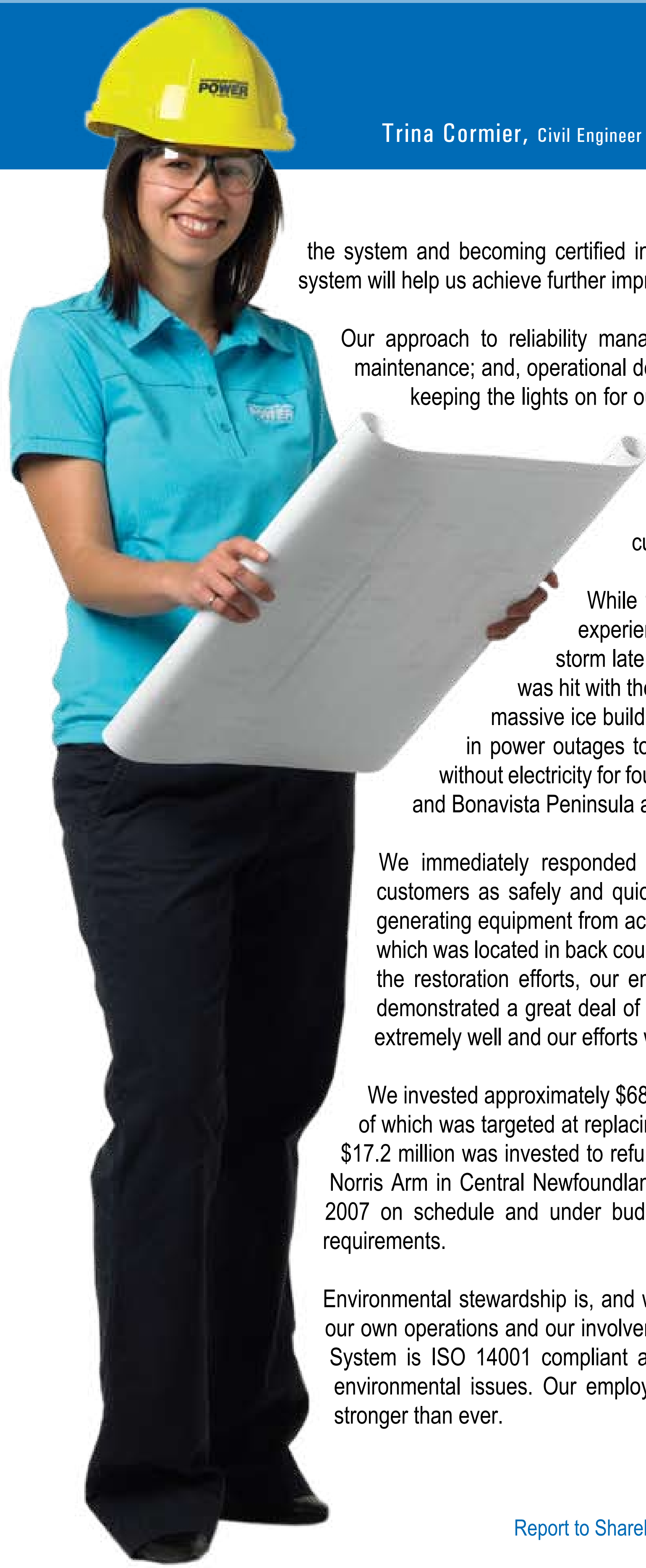
## Meeting our customers' needs starts with an unwavering commitment to safety.

The future direction of energy efficiency for our Company will be highly influenced by two things. One is the outcome and execution of a joint Conservation and Demand Management Potential study undertaken by our Company and Newfoundland and Labrador Hydro ("Hydro") in 2007. The second is our participation in the Government of Newfoundland and Labrador's Energy Conservation and Efficiency Partnership, which was announced in the provincial Energy Plan in September 2007.

Our customers place a high value on reliable service. In order to deliver on their expectations, we must first start with an unwavering commitment to safety. We deal with a lethal commodity and therefore must remain focused on the safety of our employees, the public and contractors. We did so throughout 2007 and as a result, we achieved our best performance on record for the severity of injuries, with only four days lost due to work-related injuries in 2007.

We strive to continually improve our safety results. In 2007, we implemented the internationally recognized Occupational Health and Safety Assessment Series 18001 Health and Safety Management System ("OHSAS 18001"). Implementing

Many of our employees worked long hours to restore power to our customers as safely and quickly as possible after a harsh winter storm on December 2, 2007.



Trina Cormier, Civil Engineer

the system and becoming certified in one year required a great deal of effort, however this system will help us achieve further improvements to our safety performance in 2008.

Our approach to reliability management consists of three aspects: capital investment; maintenance; and, operational deployment. This, combined with a workforce dedicated to keeping the lights on for our customers, enabled us to deliver record results for the number of outages experienced by our customers in 2007. Our outage frequency rate for 2007 was 2.46 compared to 2.64 in 2006. When translated into the overall impact on customers, we provided the power our customers required 99.93% of the time in 2007.

While the number of outages improved, the length of outages experienced by our customers was impacted by an extraordinary storm late in the year. On December 2, 2007, the electricity system was hit with the most severe storm damage in 13 years. High winds and massive ice buildup caused numerous downed power lines which resulted in power outages to approximately 20,000 customers, some of whom went without electricity for four days. Our customers in the Clarenville, Bonavista North and Bonavista Peninsula areas were impacted most by the storm.

We immediately responded with great determination to restore electricity for our customers as safely and quickly as possible. We mobilized employees and portable generating equipment from across the island to repair the extensive damages, much of which was located in back country creating further challenges for our crews. Throughout the restoration efforts, our employees worked incredibly hard to restore power, and demonstrated a great deal of empathy towards our customers. Overall, we responded extremely well and our efforts were greatly appreciated by many customers.

We invested approximately $68.5 million in our electricity system in 2007, a large portion of which was targeted at replacing or refurbishing deteriorated equipment. Approximately $17.2 million was invested to refurbish our Rattling Brook Hydroelectric Plant located near Norris Arm in Central Newfoundland. We successfully completed this project in November 2007 on schedule and under budget, while meeting all of the necessary environmental requirements.

Environmental stewardship is, and will continue to be, a core area of focus both in terms of our own operations and our involvement in the community. Our Environmental Management System is ISO 14001 compliant and continues to guide us in monitoring and managing environmental issues. Our employee-driven Environmental Commitment Program is also stronger than ever.

## Our strong performance in 2007 is the result of being focused on the right priorities.

Our commitment to the environment and community was recognized in 2007 with two awards. The Newfoundland and Labrador Environmental Industry Association presented us with their Environmental Performance award, and the St. John's Board of Trade honoured our employees with a Business Award of Excellence in the category of Contributions to the Community and Community Service. These awards speak to the care and integrity of our employees.

Earl Ludlow, President and Chief Executive Officer, and David Norris, Chair, Board of Directors

We wish to thank our employees for offering their talents, hard work and commitment throughout the year. Our ability to achieve record performance for safety and reliability, and receive awards for environmental stewardship and community involvement is a credit to their continued dedication to our customers and our Company.

We also take this opportunity to recognize our Board of Directors for their support and direction over the past year. We express our sincere thanks to Mr. Stanley Marshall upon his retirement after 15 years of service for his guidance and many valuable contributions. As well, a fond farewell is extended to Mr. Bruce Chafe who retired after serving on our Board for the past eight years. Best wishes for the future are conveyed to Mr. Karl Smith who resigned upon his appointment as President and Chief Executive Officer of FortisAlberta in May 2007 and Mr. Trevor Adey who resigned to focus on business interests.

In January 2008, we welcomed Mr. Barry Perry, Vice President, Finance, and Chief Financial Officer, Fortis Inc., and Mr. Jo Mark Zurel, President, Stonebridge Capital Inc., to our Board of Directors.

Our strong performance in 2007 is the result of being focused on the right priorities. Safety is first and foremost, followed by maintaining a balance between the cost of providing the power our customers require and the quality of service they rely on from our people. These priorities will remain a critical focus for us in the years ahead.

Sincerely,

David Norris
Chair, Board of Directors

Earl Ludlow
President and Chief Executive Officer

# Report on Operations

## Safety

Safety is a core value shared by all of our employees. In recent years we have been successful in improving our safety performance, and achieved record performance in 2007 for the severity of injuries. Our injury severity rate for 2007 was 0.7, which equates to four days lost due to work-related injuries.

While we are proud of our safety results, our goal is zero workplace injuries. The commitment of our employees to work safely will help us get there. Our safety management practices are also continuously being refined to follow "best practices".

A significant milestone in 2007 was the successful implementation of the internationally recognized OHSAS 18001. This safety standard will serve to: increase employee involvement through hazard recognition programs; strengthen safe work practices; ensure compliance to legislative requirements; and, improve safety communications throughout our Company. Implementing and achieving OHSAS 18001 compliance in one year was a very aggressive target. It was a Company-wide priority led by a dedicated group of employees.

Safety communication and training with employees, customers, contractors and the public remained a key part of safety programs in 2007. We continued our public safety advertising efforts throughout the

Our employees are committed to the safety of themselves and others, every day.


Kevin Gosse, Lineperson

year. We trained employees in several areas, including First Aid and CPR, transportation of dangerous goods and industrial ergonomics.

Throughout 2007, we maintianed our strong partnership with the Newfoundland and Labrador Association of Fire Chiefs and Firefighters. Electrical safety training was provided to approximately 176 firefighters throughout the island in 2007. We delivered children's safety demonstrations through our Hazard Hamlet Kit to over 4,000 children in 2007. These demonstrations outline potential electricity hazards in and around our homes and communities.

In 2007, we developed a brochure, The Right Tree in the Right Place, to educate customers on the importance of proper tree planting to avoid the dangers that exist when tree limbs come in contact with power lines. The brochure, which is available on our website, was also distributed through garden centres and nurseries across the island.

We are committed to maintaining high safety standards. In 2007, several incidents involving contractors remained a concern for us. We will continue to remind contractors, employers and the general public about the dangers surrounding the electricity system.

Our strong safety results reflect the Company's safety-oriented culture, well-developed safety management system and a commitment by employees and contractors to work safely. Safety performance will remain the most important aspect of our day-to-day operations.

## Reliability

2007 was the best year on record for the number of outages experienced by our customers. We reduced the number of outages per customer by 6.8% compared to 2006. We attribute the improvement in our reliability performance to the enhanced condition of our assets and the dedication of our employees. While overall system reliability was strong in 2007, the length of outages experienced by our customers was impacted by a severe winter storm late in the year.

## We were **ranked highest** among Canadian utilities of our size in **satisfying** residential **customers**.

Meeting our customers' expectations for safe, reliable service requires teamwork from our employees.

We invested $68.5 million in the electricity system in 2007. Approximately 57% of our capital expenditures was directed to plant and equipment replacement to enhance reliability for customers. The remaining capital investment was driven by commercial and residential construction activity, growth in cottage areas and increased replacement of plant to accommodate fibre optic cable installations by telecommunication companies in our province.

A project to refurbish our Rattling Brook Hydroelectric Plant accounted for approximately $17.2 million of our total capital expenditure in 2007. This project represented the largest project, in dollar terms, ever undertaken by the Company. The plant, which began operation in 1958, received extensive renovation, including replacement of the woodstave penstock, refurbishment of the surge tank, and replacement of electrical protection and control systems.

The Rattling Brook project results in improved plant production of 9%, from 69.8 GWh to 76.0 GWh, and improved plant capacity of 26%, from 11.2 megawatt ("MW") to 14.1 MW. Completion of this project provides for low-cost, clean electricity by displacing an additional 10,500 barrels of oil, for a total of approximately 129,000 barrels of oil per year. This will help minimize the impact of the cost of oil on electricity rates for our customers while benefiting the environment.

Substations play a critical role in interconnecting our electricity system and providing safe, reliable power to our customers. In 2007, we implemented a new approach to the way in which substation work is planned and executed.


**Patrick Barrington,** Customer Account Representative

The new strategy focuses on coordinating major operating maintenance and capital work on a substation basis to improve reliability and productivity. We refurbished and modernized 13 substations throughout our service territory in 2007.

We also completed rebuilds of three major transmission lines located on the Bonavista, Bay de Verde and Avalon Peninsulas.

On December 2, 2007, we experienced the harshest electricity system damage in over 13 years as a result of a severe winter storm. Approximately two kilometres of the main transmission line serving the Bonavista Peninsula was extensively damaged. This left approximately 20,000 customers without power. We immediately pulled together as a team to fulfill our commitment to restore power as safely and quickly as possible to meet customers' needs. Our ability to bring the system back to normal in four days was only possible as a result of the skills, hard work and dedication of numerous employees.

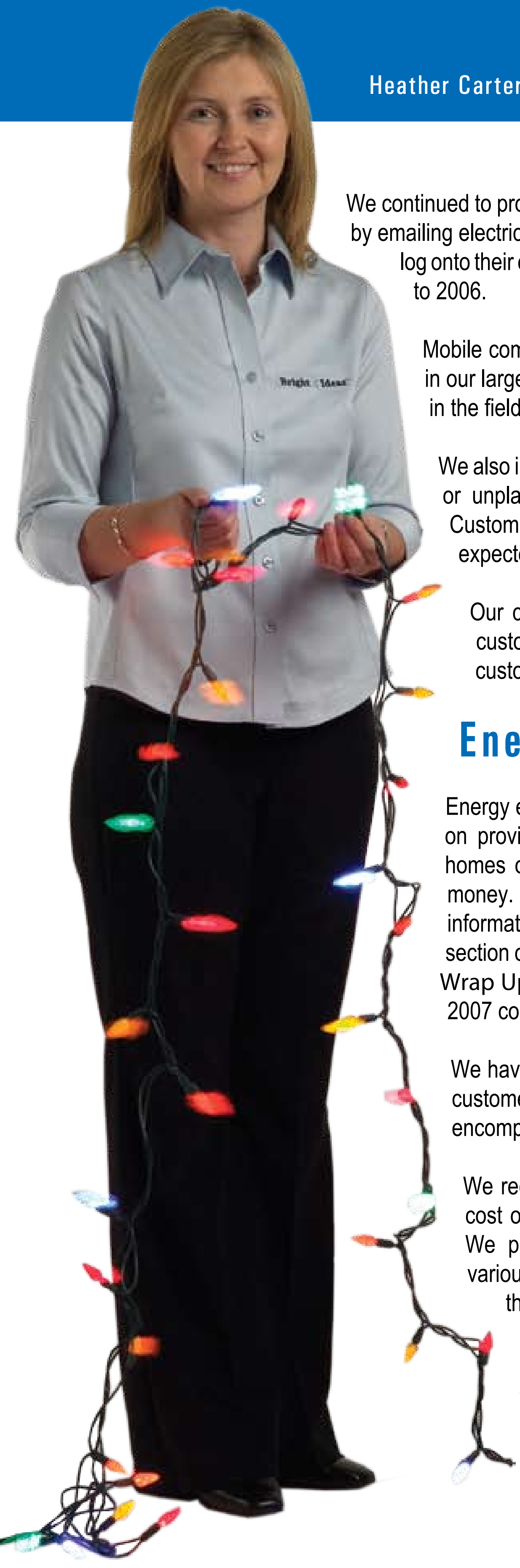
In 2008 we will invest approximately $51 million as we continue to enhance our operations and meet customers' needs for safe, reliable, least-cost electricity. Several projects will specifically target energy efficiency and demand reduction, as well as system additions for customer growth and replacements of deteriorated equipment.

## Customer Service

We achieved an overall customer satisfaction rating of 88% in 2007. Our customer satisfaction rating, which is derived from quarterly surveys with our customers, is a good indicator of how our customers view our service. The results of our own surveys were reinforced through an independent survey, which ranked our Company as the highest among Canadian utilities of our size in satisfying residential customers.

Resolving customer issues on the first call has a significant impact on both customer satisfaction and cost. We implemented many changes and new initiatives to help us serve our customers more efficiently and achieved our target of 87% for first call resolution.

We also continued to leverage technology. Landlords are electronically notified of tenancy changes and building contractors are electronically notified on the status of new service connections. An automated outbound calling service was introduced to notify customers of outstanding credit balances. Customers now receive more prompt information regarding their accounts or requests, and these initiatives improve service to customers and reduce operating costs.



**Heather Carter,** Energy Conservation Coordinator

We continued to promote electronic billing, or eBills. In 2007 we simplified the eBills process by emailing electricity bills directly to customers versus providing a link that required them to log onto their electricity account. Participation in eBills increased 64% in 2007 compared to 2006.

Mobile computing devices were installed in the line trucks for trouble service crews in our largest service area. These crews can now receive trouble calls electronically in the field and more effectively respond to customer outages.

We also introduced Outages Online, which allows customers to view any planned or unplanned outages that affect our electricity system through our website. Customers can receive information on which areas are affected by an outage, the expected restoration time and the cause of the outage.

Our customer service performance demonstrates our commitment to quality customer service. We will strive to maintain overall service levels to our customers while maximizing overall cost efficiency.

## Energy Efficiency

Energy efficiency is an area of increasing interest for our customers. Our focus is on providing the information our customers require to make changes in their homes or businesses that will help them reduce their energy usage and save money. The number of customers who contacted us about energy efficiency information in 2007 increased 55% compared to 2006. Visits to the Saving Energy section of our website were also up by 76% compared to 2006. Participation in our Wrap Up for Savings program is also up significantly, by approximately 60% in 2007 compared to 2006.

We have responded by increasing our efforts and means of communicating with customers on energy efficiency. Our approach is direct and practical, and is encompassed under our Bright Ideas campaign.

We recognize that partnering enhances effectiveness and reduces the overall cost of providing customers with energy efficiency information and programs. We partnered with federal, provincial and municipal governments, Hydro, various retailers and other organizations on several energy efficiency iniatives throughout 2007.

Our first-ever Energy Savings Community Challenge was held in the community of Petty Harbour/Maddox Cove in March 2007. The event was

We are also **pleased** to provide knowledge, tools and resources to **assist our customers** in managing their own electricity costs.

focused on encouraging customers to start making small changes to become more energy efficient by switching to compact fluorescent light (“CFLs”) bulbs.

Another outreach initiative was our SAVE Energy Event, which we held in Burin in September 2007, that included an energy efficiency tradeshow and door-to-door CFL delivery. This event was part of the Newfoundland and Labrador component of the Shared Atlantic Vision for Energy Efficiency (“SAVE”) Program, which was launched by the four Atlantic provincial energy ministers.

We held our first annual Holiday lightswitch program in 17 communities throughout the province in December. Customers could exchange two sets of incandescent outdoor holiday lights for two sets of light emitting diode (“LED”) holiday lights.

Through these community based events and partnerships, we distributed over 21,600 CFLs and 10,000 sets of LED holiday lights to customers, resulting in savings of approximately 2.5 million kilowatt hours of electricity per year.

In 2007, we took part in 75 tradeshows and conferences, all of which shared energy efficiency information with customers. Surveys have indicated that our electricity bill inserts are the preferred source of information on energy efficiency. Therefore, we leveraged the use of our monthly electricity bills to distribute approximately 2.8 million bill inserts throughout the year which contained energy efficiency advice.

We delivered approximately 6,400 CFLs to our customers in the Burin area as part of the first-ever SAVE Energy Event.

We have been diligent and successful in the area of **environmental responsibility** for the benefit of our **customers** and **communities**.

We made several enhancements to our website, including the introduction of an Energy Saving Tool Kit, Energy Use Calculators and a new Ask our Energy Expert option. All of these features are aimed at providing useful information to customers that can be accessed anytime, anywhere.

Throughout 2007, a Conservation and Demand Management Potential Study was conducted by an energy management consulting firm on behalf of our Company and Hydro. The results of the study provide a foundation for the assessment and design of customer energy efficiency programs for our province. We anticipate that this study, along with developments from the government-led Energy Conservation and Efficiency Partnership, will influence the way in which energy efficiency is promoted and encouraged in our province.

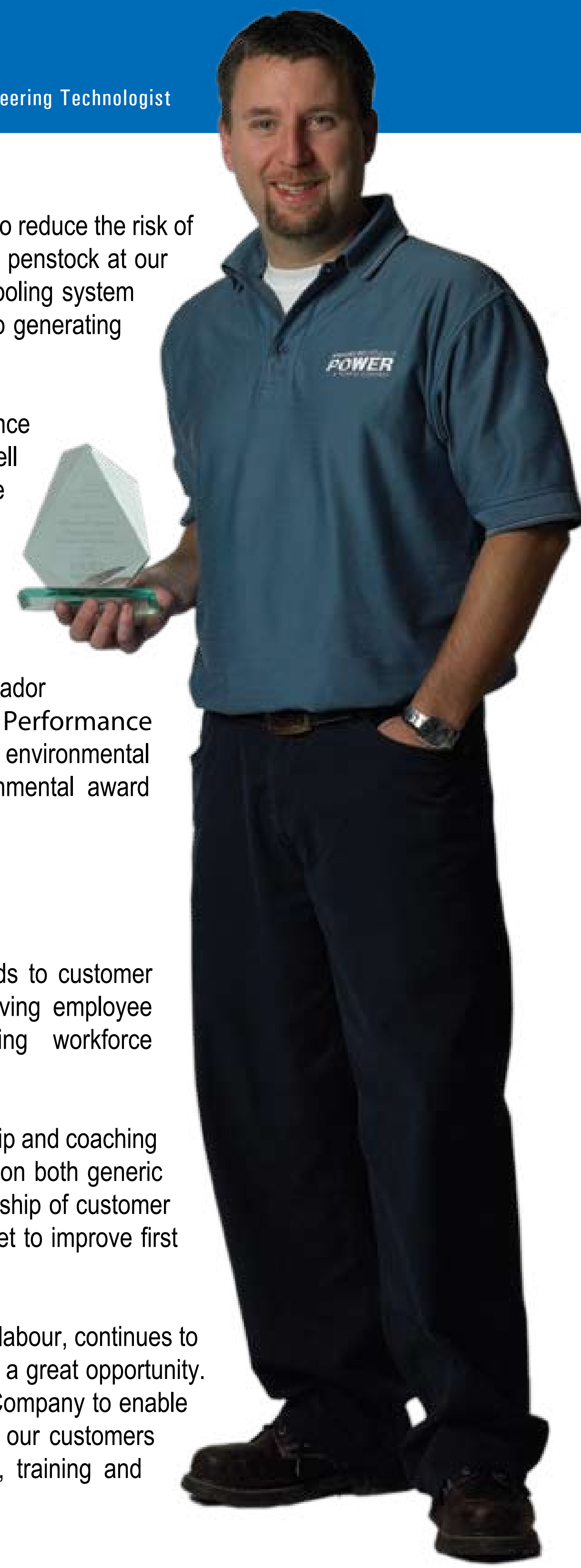
## Environment

We combine our commitment to education, the environment and the community through our annual EnviroFest, which is held in eight communities across the province during National Environment Week. We were proud to celebrate the 10th anniversary of our Environmental Commitment Program during EnviroFest in June 2007. The Government of Newfoundland and Labrador recognized the value of EnviroFest in terms of generating community support and environmental education in the province and partnered with us to celebrate our 10th anniversary.

While a large focus of our efforts are on environmental education and awareness, together with the community, we have planted approximately 1,700 trees over the past 10 years.

We have been successful in the area of environmental responsibility for the benefit of our customers and communities.


Our commitment to the environment often involves the children and youth of our province.




**Gerald French,** Engineering Technologist

Our 2007 Capital Budget included improvements to generation assets to reduce the risk of environmental contamination, including replacement of the woodstave penstock at our Rattling Brook Hydroelectric Plant, improvements to the bearing oil cooling system at three generating plants and replacement of heat exchangers at two generating plants.

An audit within our Generation section confirmed our continued compliance with the ISO 14001 standard. It also revealed that our facilities are well maintained and employees demonstrate a commitment to ensuring we operate in an environmentally responsible manner. An audit of our transmission and distribution assets also confirmed our continued compliance with these international standards for environmental performance.

In July 2007, we received an award from the Newfoundland and Labrador Environmental Industry Association ("NEIA") in the Environmental Performance category. The NEIA award recognizes significant achievements in environmental excellence, commitment and capability. This was our ninth environmental award received in nine years.

## Employees

We recognize that having knowledgeable, motivated employees leads to customer service excellence. Throughout 2007, we focused on further improving employee performance, enhancing customer service skills and managing workforce demographics.

Employee development efforts concentrated on improving the leadership and coaching skills of our front-line supervisors. Customer service training focused on both generic and job specific customer service skills to help employees take ownership of customer issues and find appropriate solutions. This is in keeping with our target to improve first call resolution.

Our aging workforce, combined with the declining availability of skilled labour, continues to be a large focus for us. We view it as both a significant challenge and a great opportunity. Our goal is to ensure that the necessary skills are maintained in our Company to enable us to continue providing the same level of safe, reliable service that our customers have come to expect and deserve. Strategic recruitment, retention, training and development will be the key to our success in this area.

We believe in the **power** of **one** and the **value** of **many**.

We actively participate in post-secondary and high school career fairs, host information sessions at post-secondary institutions and participate in a trade apprenticeship program. In 2007, we had 20 apprentice Power Line Technicians in training. This is the highest level since the early 1970s.

We are committed to employee development and providing various training opportunities to employees at all levels to enable both personal and corporate success.

## Community

Our primary responsibility is to provide safe, reliable electricity. Being a good corporate citizen is also very important to us. Our employees are committed to giving back to the communities in which we work and live. They contribute by volunteering their time, knowledge and by providing financial assistance in a wide variety of areas including health, safety, environment, education, arts and cultural programs.

Our support for cancer care in this province is touching the lives of our own employees and customers in many ways.

Although we help many charities across the province, our main corporate charity is The Power of Life Project. Through employee, customer and corporate donations, The Power of Life Project has significantly enhanced cancer care in this province. Our employees are proud to call this Project their own.

In 2007, The Power of Life Project pledged a donation of $350,000 to "PRIORITY: The Campaign for Cancer Care", an initiative of the Dr. H. Bliss Murphy Cancer Care Foundation. These funds have been earmarked for the purchase of a four-dimensional CT Simulator which will enable the province's cancer care teams to enhance the accuracy of radiation treatment planning.

We also continue to support the Canadian Blood Services Partners for Life program. Our employees, families and friends have generously given over 1,100 blood donations in the past three years – that is the highest number of donations made by any of the 32 organizations involved in the Partners for Life program in our province. To accomplish this, we held mobile blood donor clinics, promoted blood drives, and encouraged employees to get their family and friends involved in the program.

Our community investment program positively affects the lives of people in the province through various other organizations such as the Janeway Children's Hospital Foundation, the Newfoundland and Labrador Snowmobile Association, the Atlantic Salmon Federation and Junior Achievement of Newfoundland and Labrador.

We believe in the power of one and the value of many, and are very proud of all the work we have done in the community. In December 2007, we were delighted to have our efforts recognized by the St. John's Board of Trade as we were honoured with a Business Award of Excellence in the category of Contributions to the Community and Community Service. This was a great salute to all of our employees, retirees and families and a great conclusion to a very successful year.

# Management Discussion & Analysis

This Management Discussion and Analysis dated January 30, 2008, should be read in conjunction with Newfoundland Power Inc.'s (the "Company" or "Newfoundland Power") annual financial statements and notes thereto for the year ended December 31, 2007. Financial information herein reflects Canadian dollars and Canadian generally accepted accounting principles ("GAAP"), including certain accounting practices unique to rate-regulated entities. These accounting practices, which are disclosed in Notes 2 and 5 to the Company's 2007 annual financial statements, result in the recognition of revenues, expenses, regulatory assets and regulatory liabilities which would not occur in the absence of rate regulation and which affect the Company's reported earnings, cash flows and financial position.

Certain information herein is forward-looking and reflects management's current expectations regarding the Company's future financial and related performance. Wherever possible, the word "expects" and similar expressions have been used to identify the forward-looking statements. Certain material factors, estimates and assumptions, which are subject to inherent risks and uncertainties surrounding future expectations generally, have been applied in drawing the conclusions contained in the forward-looking statements. These are related to, but are not limited to, regulation; energy supply; competition; general economic conditions; health, safety and the environment; interest rates; insurance; weather; labour relations; licences and permits; capital resources; and, liquidity. Readers are cautioned to not place undue reliance on forward-looking statements because actual results could differ materially from the results discussed or implied in those statements. The Company disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

Additional information, including the Company's quarterly and annual financial statements, annual information form and management information circular, is available on SEDAR at www.sedar.com.

## OVERVIEW

### The Company

Newfoundland Power is a regulated electric utility that owns and operates an integrated generation, transmission and distribution system throughout the island portion of the Province of Newfoundland and Labrador (the "Province"). All of the Company's common shares are owned by Fortis Inc. ("Fortis"), the largest investor-owned distribution utility in Canada.

Newfoundland Power's primary business is electricity distribution. It generates approximately 10% of its electricity needs and purchases the remainder from Newfoundland and Labrador Hydro ("Hydro"). Newfoundland Power serves over 232,000 customers comprising approximately 85% of all electricity consumers in the Province.

Newfoundland Power's vision is to be a leader among North American electric utilities in terms of safety, reliability, customer service and efficiency. The Company's strategy is to operate sound distribution systems and to focus on the safe and reliable delivery of electricity service to its customers in the most cost-efficient manner possible. Newfoundland Power and its employees are committed to providing customers with the service they expect in an environmentally and socially responsible manner.

## Regulation

Newfoundland Power is regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities (the "PUB"). The Company operates under cost of service regulation whereby it is entitled the opportunity to recover, through customer rates, all reasonable and prudent costs incurred in providing electricity service to its customers, including a just and reasonable return on its rate base. The rate base is the net assets required to provide electricity service.

Between general rate hearings, customer rates are established annually through an automatic adjustment formula (the "Formula"). The Formula sets an appropriate rate of return on common equity ("ROE") which is used to determine the rate of return on rate base. The ROE is based upon the change in the forecast cost of common equity resulting from changes in long-term Canada bond yields. The Company's rate of return on rate base was reduced from 8.68%, with a range of 8.50% to 8.86% in 2006, to 8.47%, with a range of 8.29% to 8.65% in 2007 through the operation of the Formula.

## Financial Highlights

| | 2007 | 2006 | Change |
|---|---|---|---|
| Electricity Sales (gigawatt hours ("GWh")) | 5,092.8 | 4,995.1 | 97.7 |
| Earnings Applicable to Common Shares | | | |
| $ Millions | 29.9 | 30.1 | (0.2) |
| $ Per Share | 2.89 | 2.91 | (0.02) |
| ROE (%)[1] | 8.62 | 9.12 | (0.50) |
| Cash Flow from Operating Activites ($millions) | 49.3 | 57.1 | (7.8) |
| Total Assets ($millions) | 985.9 | 929.2 | 56.7 |

[1] Earnings applicable to common shares, divided by the average of common shareholder's equity at the beginning and end of the year. This ratio is a non-GAAP financial measure, does not have any standardized meaning prescribed by GAAP, and is unlikely to be comparable to similar ratios published by other companies. It is presented because it is commonly referred to by the users of the Company's financial statements in evaluating the results of operations and by the Company's regulator in the rate-setting process.

Electricity sales for the year ended December 31, 2007 increased by 97.7 GWh or 2% compared to 2006. The increase in electricity sales primarily reflects customer growth and an increase in average electricity usage. Modest sales growth is expected to continue in 2008.

Earnings for the year ended December 31, 2007 were $29.9 million, comparable to 2006. Additional earnings from higher electricity sales were largely offset by a reduction in Newfoundland Power's allowed returns on January 1, 2007. Higher operating costs, including amortization and finance charges, were offset by lower pension costs and a lower effective income tax rate.

Operation of the Formula resulted in a reduction in the Company's ROE, for the purpose of setting customer rates, from 9.24% for 2006 to 8.60% for 2007. The actual ROE in both 2007 and 2006 is broadly consistent with that reflected in customer rates.

The reduction in cash flow from operating activities was due primarily to reduced customer rates and temporary timing differences in non-cash working capital.

The increase in total assets was due primarily to continued investment in the electricity system and is consistent with the Company's strategy to provide safe and reliable electricity service at the lowest reasonable cost.

As a result of the Company's 2008 General Rate Application ("GRA"), in December 2007, the PUB has ordered that customer rates be increased by an average of approximately 2.8% effective January 1, 2008. This reflects a regulated ROE of 8.95% for 2008. It also contemplates the amortization of certain regulatory assets and liabilities, and the prospective recognition of future income taxes associated with pension costs. The 2008 general rate order is expected to yield earnings and cash flows that will enable the Company to maintain its investment grade credit ratings.

## RESULTS OF OPERATIONS

### Revenue:

| ($millions) | 2007 | 2006 | Change |
|---|---|---|---|
| Revenue from Rates | 477.1 | 407.7 | 69.4 |
| Amortization of Unbilled Revenue Liability | 2.7 | 3.1 | (0.4) |
| Other Revenue[2] | 10.4 | 10.5 | (0.1) |
| Total | 490.2 | 421.3 | 68.9 |

[2] Other revenue is composed primarily of pole attachment charges to various telecommunication companies.

Revenue increased by approximately $68.9 million, from $421.3 million in 2006 to $490.2 million in 2007. The increase resulted primarily from the flow-through of an additional $64.2 million in purchased power costs from Hydro effective January 1, 2007. The remaining increase primarily relates to electricity sales growth partially offest by the January 1, 2007 customer rate reduction attributable to the operation of the Formula.

Prior to 2006, revenue from electricity sales was recognized as bills were rendered to customers. Commencing in 2006, this revenue is recognized on an accrual basis. Unrecognized unbilled revenue at December 31, 2005 was deferred as a regulatory liability and is being amortized as revenue in accordance with PUB orders. Amortization of $2.7 million in 2007 and $3.1 million in 2006 effectively offset similar increases in income tax expense in these years attributable to the adoption of the accrual method of revenue recognition.

The PUB has ordered that the December 31, 2007 unamortized balance in the unbilled revenue liability of approximately $16.4 million be amortized as follows: 2008 – approximately $7.2 million, 2009 and 2010 – approximately $4.6 million in each year. Amortization for 2008 will include approximately $2.6 million to offset the expected remaining increase in income tax expense in that year attributable to the adoption of the accrual method of revenue recognition.

Purchased Power: Purchased power increased by approximately $69.6 million, from $257.2 million in 2006 to $326.8 million in 2007. This increase primarily reflects the flow-through of an additional $64.2 million of Hydro's purchased power costs to Newfoundland Power. A significant portion of the Hydro flow-through amount represents costs previously flowed-through the rate stabilization (balance sheet) account rather than purchased power cost increases. The remaining increase in purchased power costs primarily reflects electricity sales growth.

Operating Expense: Operating expense increased by approximately $0.8 million or 1.7%, from $46.7 million in 2006 to $47.5 million in 2007. The increase was due primarily to increased labour costs, reflecting both wage increases and costs incurred to repair major storm damage to certain distribution systems in December 2007, and to an increase in the PUB's annual assessment. Operating cost per customer was $213 in 2007 compared to $212 in 2006.

Pension and Early Retirement Program Costs: Pension and early retirement program costs decreased by approximately $1.6 million or 21.9%, from $7.3 million in 2006 to $5.7 million in 2007. The decrease was due primarily to higher returns on pension plan assets and to the conclusion in March 2007 of the amortization of retirement allowances associated with the Company's 2005 early retirement program. The increased returns on pension plan assets reflect higher levels of plan assets attributable to pension funding.

Amortization: Amortization of capital assets increased by approximately $1.1 million or 2.8%, from $38.9 million in 2006 to $40.0 million in 2007. The increase was due to continued investment in the electricity system.

Amortization True-Up Deferral: Amortization of capital assets is subject to periodic review by external experts via an amortization study. The PUB ordered the deferred recovery of approximately $5.8 million in each of 2006 and 2007 related to a variance in accumulated amortization identified in the 2002 amortization study. These deferrals were recorded as an increase in regulatory assets and a decrease in expenses of $5.8 million in each year. The PUB has ordered that the resultant regulatory asset of approximately $11.6 million be amortized over 2008 through 2010 as an increase in expenses of approximately $3.9 million in each year.

Finance Charges: Finance charges increased by approximately $0.8 million or 2.4%, from $32.7 million in 2006 to $33.5 million in 2007. This increase reflects increased borrowings to finance the Company's ongoing capital program and the August 2007 replacement of lower cost short-term borrowings with 5.901%, 30-year Series AL first mortgage sinking fund bonds.

Income Taxes: Income tax expense decreased by approximately $1.4 million, from approximately $13.6 million in 2006 to approximately $12.2 million in 2007. This decrease reflects lower pre-tax earnings and a decrease in the Company's effective income tax rate. The decrease in the Company's effective income tax rate was due primarily to an increase in capital cost allowance caused by capital expenditures arising from the refurbishment of the Company's Rattling Brook hydroelectric plant; and, the deduction for tax purposes of GRA costs incurred in 2007. The effective tax rate was also reduced by the allocation of the Part VI.1 tax liability and related Part I tax deduction from Fortis to Newfoundland Power in 2007. These tax reductions were partially offset by future income taxes recorded in accordance with PUB orders.

## FINANCIAL POSITION

Explanations of the primary causes of significant changes in the Company's balance sheets between December 31, 2006 and December 31, 2007 follow.

| ($millions) | Increase (Decrease) | Explanation |
|---|---|---|
| Accounts Receivable | 9.2 | Higher electricity consumption due to customer growth and colder weather; higher unbilled revenue as a result of an increase in Hydro's purchased power rate. |
| Total Regulatory Assets | 10.5 | Increase in other post-employment benefits asset, representing costs incurred but not expensed under cash method of accounting; increase in amortization true-up deferral pursuant to PUB order; partially offset by decrease in rate stabilization account due to its normal operation. |
| Income Tax Receivable | 1.8 | Income tax instalments in excess of current income tax expense. |
| Capital Assets | 29.3 | Normal annual investment in electricity system and additional investment due to refurbishment of Rattling Brook hydroelectric plant; offset partially by amortization and customer contributions in aid of construction. |
| Deferred Charges | 4.5 | Pension funding in excess of pension expense. |
| Accounts Payable and Accrued Charges | 3.5 | Increase in payable for purchased power due to increased electricity consumption; accrual of GRA costs; increase in accrued interest payable due primarily to issuance of $70 million, 5.901% Series AL bonds partially offset by retirement of $31.5 million, 11.875% Series AC bonds. |
| Total Regulatory Liabilities | (2.6) | Decrease in unbilled revenue liability due to PUB approved amortization. |
| Long-term Debt, including Current Portion | 29.0 | Financing of growth in rate base driven primarily by 2007 capital program. |
| Other Liabilities | 6.9 | Increase in liability for other post-employment benefits. |
| Retained Earnings | 20.8 | Earnings in excess of dividends, retained to finance growth in rate base driven primarily by 2007 capital program. |

## LIQUIDITY AND CAPITAL RESOURCES

The primary sources of liquidity and capital resources are net funds generated from operations, debt capital markets and bank credit facilities. These sources are used primarily to satisfy capital expenditures, servicing and repayment of debt, and dividends. A summary of cash flows and cash position follows.

| ($millions) | 2007 | 2006 | Change |
|---|---|---|---|
| Bank Indebtedness, Beginning of Year | (0.4) | (0.8) | 0.4 |
| Operating Activities | 49.3 | 57.1 | (7.8) |
| Investing Activities | | | |
| Net Capital Expenditures | (72.2) | (60.2) | (12.0) |
| Other | 2.5 | 2.9 | (0.4) |
| Financing Activities | | | |
| Bond Issued | 70.0 | - | 70.0 |
| Bond Retired | (31.5) | - | (31.5) |
| Bond Sinking Fund Payments | (5.0) | (4.3) | (0.7) |
| Net Credit Facility Borrowings | (1.7) | 23.7 | (25.4) |
| Dividends on Common Shares | (9.1) | (18.2) | 9.1 |
| Other | (0.8) | (0.6) | (0.2) |
| Cash (Bank Indebtedness), Beginning of Year | 1.1 | (0.4) | 1.5 |

### Operating Activities

The $7.8 million decrease in cash flow from operating activities was due primarily to the Company's January 1, 2007 customer rate decrease pursuant to the operation of the Formula and to an increase in non-cash working capital. The latter reflects temporary timing differences related to (i) the Company's equal payment plan for its electricity customers, (ii) income tax installments in excess of income tax expense, and (iii) the recovery through rates over 2008 through 2011 of Rattling Brook replacement energy costs paid in 2007.

### Investing Activities

The $12.4 million additional cash used in investing activities was due primarily to higher capital expenditures.

The Company's business is capital intensive. Capital investment is required to ensure continued and enhanced performance, reliability and safety of the electricity system and to meet customer growth. Capital investment also arises for information technology systems and for general facilities, equipment and vehicles. Capital expenditures, and capital asset repairs and maintenance expense, can vary from year-to-year depending upon both planned system expenditures and unplanned expenditures arising from weather or other unforeseen events.

The Company's annual capital plan requires prior PUB approval. Variances between actual and planned expenditures are generally subject to PUB review prior to inclusion in the Company's rate base.

A summary of 2007 and 2006 capital expenditures follows.

| ($millions) | 2007 | 2006 |
|---|---|---|
| Electricity System | | |
| Generation | 18.1 | 4.2 |
| Transmission | 4.4 | 4.5 |
| Substations | 5.1 | 4.4 |
| Distribution | 30.4 | 33.3 |
| Other | 14.2 | 13.8 |
| Total Capital Expenditures - Net of Salvage | 72.2 | 60.2 |

The $12.0 million increase in net capital expenditures, from $60.2 million in 2006 to $72.2 million in 2007, was due primarily to the refurbishment of the Company's Rattling Brook hydroelectric plant.

The Company's PUB approved 2008 capital plan provides for capital expenditures of approximately $50.8 million, approximately half of which is distribution related.

### Financing Activities

The Company has historically generated sufficient annual cash flows from operating activities to service annual interest and sinking fund payments on debt, to pay dividends and to finance a major portion of its annual capital program. Additional financing to fully fund the annual capital program is obtained through the Company's bank credit facilities and these borrowings are periodically refinanced along with any maturing bonds through the issuance of long-term first mortgage sinking fund bonds. The Company currently does not expect any material changes in these basic cash flow and financing dynamics over the foreseeable future.

Cash flow from financing activities totalled $21.9 million in 2007 compared to $0.6 in 2006. The $21.3 million increase was to fund reduced cash flow from operating activities and higher 2007 capital expenditures, and reflects a decrease in common dividends.

Debt: During 2007, the Company issued 30-year, 5.901% Series AL first mortgage sinking fund bonds in the amount of $70 million. Net proceeds of approximately $69.7 million were used to pay down credit facility borrowings of approximately $38.2 million and to retire matured 11.875% Series AC bonds totalling $31.5 million. The issuance of additional bonds is subject to PUB approval and to an earnings test whereby the ratio of (i) annual earnings applicable to common shares, before tax and bond interest, to (ii) annual bond interest incurred plus annual bond interest to be incurred on the contemplated bond issue, must be two times or higher. The Company expects to be able to issue bonds in the normal course for the foreseeable future.

Credit facilities with maturities that exceed one year require PUB approval. The Company borrowed $36.5 million under its credit facilities resulting in net reduction in credit facility borrowings in 2007 of $1.7 million. Credit facility details at December 31, 2007 and 2006 follow.

| ($millions) | 2007 | 2006 |
|---|---|---|
| Total Credit Facilities | 120.0 | 120.0 |
| Short-term Borrowings Outstanding | - | (0.3) |
| Long-term Borrowings Outstanding | (33.0) | (34.4) |
| Credit Facilities Available | 87.0 | 85.3 |

The Company's credit facilities are composed of a $20 million uncommitted demand facility, under which borrowings are classified as short-term, and a syndicated $100 million committed revolving term credit facility, under which borrowings are classified as long-term.

The committed facility matures in January 2009. The Company expects, along with PUB approval, that it will be able to either extend the existing facility or replace it with a substantially similar facility before maturity.

Contractual Obligations: Details, as at December 31, 2007, of all contractual obligations over the subsequent five years and thereafter, follow.

| ($millions) | Total | 2008 | 2009-2010 | 2011-2012 | 2013 Onward |
|---|---|---|---|---|---|
| Credit Facilities (unsecured) | 33.0 | - | 33.0 | - | - |
| First Mortgage Sinking Fund Bonds[3] | 413.6 | 4.6 | 9.1 | 9.1 | 390.8 |
| Total | 446.6 | 4.6 | 42.1 | 9.1 | 390.8 |

[3] First mortgage sinking fund bonds are secured by a first fixed and specific charge on capital assets owned or to be acquired by the Company and carry customary covenants.

**Credit Ratings and Capital Structure:** To ensure continued access to capital at reasonable cost, the Company endeavours to maintain its investment grade credit ratings. Throughout 2007 and 2006, the Company's investment grade bond ratings were, and currently are: Dominion Bond Rating Service, "A" and Moody's, "Baa1"; both with a "stable" rating outlook.

The Company's credit ratings are impacted by its earnings, cash flows, and the proportion of debt and equity in the capital structure. Newfoundland Power endeavours to maintain a capital structure composed of 55% debt and 45% equity. This capital structure is reflected in customer rates and is consistent with the Company's current investment grade credit ratings. The Company's capital structure at December 31, 2007 and 2006 follows.

| | 2007 | | 2006 | |
|---|---|---|---|---|
| | $millions | % | $millions | % |
| Total Debt[4] | 442.5 | 54.7 | 415.2 | 54.6 |
| Common Equity | 356.7 | 44.1 | 335.9 | 44.2 |
| Preferred Equity | 9.4 | 1.2 | 9.4 | 1.2 |
| Total | 808.6 | 100 | 760.5 | 100.0 |

[4] Includes cash or bank indebtedness.

The expected positive impact on earnings and cash flows from operating activities arising from the Company's 2008 GRA, along with an unchanged capital structure, should to enable the Company to maintain its current investment grade credit ratings in 2008.

**Dividends:** Dividends on common shares decreased by $9.1 million, from $18.2 million or $1.76 per share in 2006 to $9.1 million or $0.88 per share in 2007. Dividends were reduced to maintain a capital structure that includes approximately 45% equity. In both 2007 and 2006, the Company paid preferred share dividends of $0.6 million.

## RELATED PARTY TRANSACTIONS

The Company provides services to, and receives services from, its parent company, Fortis and other subsidiaries of Fortis. The Company also incurs charges from Fortis for the recovery of general corporate expenses incurred by Fortis. These transactions are in the normal course of business and are recorded at their exchange amounts.

Related party transactions included in revenue and operating expenses in 2007 and 2006, and in accounts receivable at December 31 of these years, follow.

| ($millions) | 2007 | 2006 |
|---|---|---|
| Revenue[5] | 4.1 | 3.7 |
| Operating Expenses | 0.9 | 1.0 |
| Accounts Receivable | 0.1 | 0.1 |

[5] Includes charges for electricity consumed.

## BUSINESS RISK MANAGEMENT

**Regulation:** The Company is subject to normal uncertainties facing entities that operate under cost of service regulation. It is dependent on PUB approval of customer rates that permit a reasonable opportunity to recover on a timely basis the estimated costs of providing electricity service, including a fair and reasonable return on rate base. The ability to recover the actual costs of providing service and to earn the approved rates of return depends on achieving the forecasts established in the rate-setting process. Between general rate applications, the setting of customer rates through the Formula can cause earnings and cash flows to increase or decrease due to corresponding changes in bond yields which are beyond the Company's control.

Electricity Prices: Increases in electricity rates to the Company's customers can cause changes in electricity consumption behaviour, which could negatively impact sales, and therefore earnings and cash flows. Electricity prices have risen in recent years due to the flow-through of the rising cost of oil used at Hydro's thermal generating station. Future changes or volatility in oil prices may affect electricity prices in a manner that affects sales.

Competition: The Company currently does not expect any significant loss in heating market share as oil prices remain high. Natural gas is not expected to enter the Company's service territory in the foreseeable future.

Purchased Power Costs: The Company is dependant on Hydro for 90% of its electricity requirements. Purchased power costs are based on a wholesale demand and energy rate structure. The demand and energy rate structure presents the risk of volatility in purchased power costs due to uncertainty in forcasting energy sales and peak billing demand.

With respect to demand charges, effective January 1, 2008, the PUB has ordered the discontinuance of the purchased power unit cost variance reserve (the "PPUCVR"), which limited volatility of purchased power costs, and the creation of a demand management incentive account. This account limits variations in the unit cost of purchased power related to demand by up to 1% of total demand costs reflected in customer rates, or approximately $0.5 million for 2008. The disposition of balances in this account, which would be determined by a further order of the PUB, will consider the merits of the Company's conservation and demand management activities. The elimination of the PPUCVR and the creation of the demand management incentive account are not expected to have a material impact on the Company's annual earnings and cash flows.

With respect to energy charges, as a result of January 1, 2007 changes in Hydro's rates, the marginal cost of purchased power now exceeds the average cost of purchased power that is embedded in customer rates. To the extent actual electricity sales in any period exceed forecast electricity sales used to set customer rates, the marginal purchased power expense will exceed related revenue. These supply cost dynamics had no material effect on 2007 earnings because they are, in accordance with PUB orders, to be recovered through the rate stabilization account. To address these supply cost dynamics, the PUB has ordered, for 2008 to 2010, that variations in purchased power expense caused by differences between the actual unit cost of energy and that reflected in customer rates be recovered from (returned to) customers through the Company's rate stabilization account. Beyond 2010, the manner in which incremental purchased power costs are recovered will be determined by the PUB.

Economic Conditions: Electricity sales are influenced by economic factors in the Company's service territory such as changes in employment levels, personal disposable income, energy prices and housing starts. Out-migration in rural areas, as well as declining birth rates and increasing death rates associated with an aging population, also affect sales.

Regulatory Assets and Liabilities: The accounting methods that give rise to, and the settlement of, regulatory assets and liabilities are determined by the PUB and may impact the Company's future cash flows.

Health, Safety and Environment: The Company is subject to numerous and increasing environmental, health and safety laws, regulations and guidelines governing hazardous substances and other waste materials. Electricity is itself a hazardous commodity. Damages and costs could potentially arise due to a variety of events, including severe weather, human error or misconduct, and equipment failure. There is no assurance that any costs which might arise would be recoverable through customer rates and, if substantial, unrecovered costs could have a material adverse effect on the results of operations, cash flows and financial position of the Company. A focus on safety and the environment is an integral and continuing aspect of the Company's core business strategy.

Interest Rates: Market driven changes in interest rates can cause fluctuations in interest costs associated with the Company's bank credit facilities. The Company periodically refinances its credit facilities in the normal course with fixed-rate first mortgage sinking fund bonds, which comprise most of its long-term debt, thereby significantly mitigating exposure to interest rate changes.

Insurance: While the Company maintains a comprehensive insurance program, the Company's transmission and distribution assets (i.e. poles and wires) are not covered under insurance for physical damages. This is customary in North America as the cost of the coverage is not considered economical. Insurance is subject to coverage limits as well as time-sensitive claims discovery and reporting provisions, and there is no assurance that the types of liabilities that may be incurred by the Company will be covered by insurance.

For material uninsured losses, the Company expects that it would seek regulatory relief. However, there is no assurance that regulatory relief would be received. Any major damage to the physical assets of the Company could result in repair costs and customer claims that are substantial in amount, and which could have a material adverse effect on the Company's results of operations, cash flows and financial position.

It is expected that existing insurance coverage will be maintained. However, there is no assurance that the Company will be able to obtain or maintain adequate insurance in the future at rates considered reasonable or that insurance will continue to be available on terms comparable to those now existing.

Weather: The physical assets of the Company are exposed to the effects of severe weather conditions and other acts of nature. Although the physical assets have been constructed, operated and maintained to withstand severe weather, there is no assurance that they will successfully do so in all circumstances. This could result in the interruption of electricity service in a manner that could have a material adverse effect on the Company's results of operations, cash flows and financial position.

Labour Relations: Approximately 55% of the employees of the Company are members of the International Brotherhood of Electrical Workers labour union which has entered into two collective bargaining agreements with the Company which expire on September 30, 2008. The inability to maintain or renew the collective bargaining agreements on acceptable terms could result in increased labour costs that are not currently provided for in customer rates, or service level declines associated with job action, which could have a material adverse effect on the results of operations, cash flows and financial position of the Company.

## ACCOUNTING CHANGES

Effective January 1, 2007, the Company adopted the revised Canadian Institute of Chartered Accountants ("CICA") Handbook Section 1506, Accounting Changes. Under this revised accounting standard, voluntary changes in accounting policy are made only if they result in the financial statements providing reliable and more relevant information. Adoption of this accounting standard had no impact on the Company's 2007 financial statements.

Financial Instruments: Effective January 1, 2007, the Company adopted Section 3855, Financial Instruments – Recognition and Measurement and Section 3861, Financial Instruments – Disclosure and Presentation, of the CICA Handbook. As a result, deferred financing charges of $3.1 million at December 31, 2007 have been netted against long-term debt on the Company's balance sheet and are being amortized as finance charges over the life of the related debt using the effective interest rate method. Prior to 2007, these costs were included in deferred charges on the Company's balance sheet and were amortized as finance charges over the life of the related debt using the straight-line method. The adoption of these accounting standards had no impact on the Company's 2007 earnings or on its risk management policies.

Change in Presentation: Prior to December 31, 2007, the regulatory provision for future removal and site restoration costs for capital assets, which is included in amortization expense because these costs are recoverable from customers through the amortization rates reflected in customer rates, was recorded in accumulated amortization. Actual costs of removal and site restoration incurred, net of salvage proceeds, were recorded against this provision in accumulated amortization. In the absence of rate regulation, future removal and site restoration costs, net of salvage proceeds, would be recognized as incurred rather than over the life of the related capital assets through amortization expense. The Company has changed the presentation of the accumulated provision for future removal and site restoration costs, from accumulated amortization to a long-term regulatory liability. This change in presentation has been applied retroactively, with restatement of 2006 comparative balances, and has had no impact on earnings. The effect of this change in presentation at December 31, 2007 was a $47.4 million (December 31, 2006 - $47.6 million) increase in total regulatory liabilities and corresponding increases in net capital assets.

## EMERGING ACCOUNTING CHANGES

International Financial Reporting Standards ("IFRS"): In 2006, the Canadian Accounting Standards Board ("AcSB") published a new strategic plan that will significantly affect financial reporting requirements for Canadian companies. The AcSB strategic plan outlines the convergence of Canadian GAAP with IFRS over an expected five year transitional period. While the Company has begun assessing the adoption of IFRS for 2011, the financial reporting impact of the transition to IFRS cannot be reasonably estimated at this time.

Rate-Regulated Operations: Given its strategic plan to adopt IFRS, the AcSB revisited the scope of its project on accounting for rate-regulated operations in recognition of the fact that IFRS do not currently provide any special guidance with respect to accounting practices that are unique to rate-regulated entities. As a result, it has removed certain guidance from the CICA Handbook. Newfoundland Power's preliminary assessment of these changes is that effective January 1, 2009 it will be required to (i) disclose separately on its balance sheets future income tax assets and liabilities that, in accordance with PUB approved accounting policies, are currently unrecognized along with corresponding regulatory liabilities and assets and (ii) include in these amounts the future income tax effects of the subsequent settlement of the regulatory assets and liabilities through customer rates. These changes would not affect earnings or cash flows. If calculated in accordance with the revised guidance, the net unrecognized future income tax liability now disclosed in Note 2 to the Company's 2007 annual financial statements would increase by approximately $30.7 million (2006 - increase of approximately $40.2 million) to $105.1 million at December 31, 2007 (December 31, 2006 - $123.0 million).

Future Income Tax: The PUB has ordered that future income tax on temporary timing differences between pension expense and pension funding be recognized and reflected in customer rates commencing January 1, 2008. This change is expected to both (i) yield additional cash flow from operating activities of approximately $0.5 million in 2008 and (ii) have no material impact on earnings.

Inventories: In March 2007, the AcSB approved a new standard with respect to inventories, effective for fiscal years beginning on or after January 1, 2008. The new standard requires inventories to be measured at the lower of cost or net realizable value; disallows the use of a last-in first-out inventory costing methodology; and, requires that, when circumstances which previously caused inventories to be written down below cost no longer exist, the amount of the write-down is to be reversed. This new standard is not expected to have a material impact on the Company's earnings, cash flows or financial position.

Disclosure: As a result of new Section 1535, Capital Disclosures, Newfoundland Power will be required to include additional information in the notes to the financial statements about its capital and the manner in which it is managed. This additional disclosure includes quantitative and qualitative information regarding an entity's objectives, policies and processes for managing capital. New accounting recommendations for disclosure and presentation of financial instruments will require disclosures of both qualitative and quantitative information that enables users of financial statements to evaluate the nature and extent of risks from financial instruments to which the Company is exposed. These requirements become effective January 1, 2008.

## CRITICAL ACCOUNTING ESTIMATES

Preparation of the Company's financial statements in accordance with GAAP requires management to make estimates and judgements that affect the reported amounts of assets and liabilities, revenue and expenses, and related disclosure of contingencies and commitments. Estimates and judgements are based on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances. Actual results may differ from these estimates and judgements under different assumptions or conditions. The critical accounting estimates involving the more significant estimates and judgements used in the preparation of the Company's financial statements follow.

Capital Asset Amortization: By its nature, capital asset amortization is an estimate based primarily on the useful lives of capital assets. Estimated useful lives are based on current facts and historical information and take into consideration the anticipated physical lives of the assets. The Company's amortization methodology, including amortization rates, accumulated amortization and estimated remaining service lives, is subject to a periodic study by external experts. The difference between actual accumulated amortization and that indicated by the amortization study is amortized and included in customer rates in a manner prescribed by the PUB.

The most recent amortization study, based on capital assets in service as at December 31, 2005, indicates an accumulated amortization variance of approximately $0.7 million. The PUB has ordered that it be amortized as a decrease in amortization expense equally over 2008-2011. The PUB has also ordered that revised amortization rates arising from the amortization study be implemented effective January 1, 2008. As a result, the total composite amortization rate will decline from 3.5% to 3.4%. It is managements' judgement that these changes will not have a significant impact on the Company's earnings, cash flow and financial position because the changes are reflected in 2008 customer rates.

The estimate of the future removal and site restoration costs, net of salvage proceeds, is based on historical experience and future expected cost trends. The balance of this regulatory liability at December 31, 2007 was $47.4 million (December 31, 2006 - $47.6 million). The net amount of estimated future removal and site restoration costs provided for and reported in amortization expense during 2007 was $3.5 million (2006 - $3.2 million).

Capitalized Overhead: Newfoundland Power capitalizes overhead costs which are not directly attributable to specific capital assets, but which relate to the overall capital expenditure program. Capitalization reflects estimates of the portions of various general expenses that relate to the overall capital expenditures program in accordance with a methodology ordered by the PUB. These general expenses capitalized ("GEC") are allocated over constructed capital assets and amortized over their estimated service lives. In 2007, GEC totalled $2.8 million (2006 - $2.7 million). Changes to the methodology for calculating and allocating general overhead costs to capital assets could have a material impact on the amounts recorded as operating expenses versus capital assets.

Employee Future Benefits: The Company's defined benefit pension plans and other post-employment benefit plans are subject to judgments utilized in the actuarial determination of the expense and related obligation. The primary assumptions utilized by management in determining pension expense and obligations are the discount rate for the accrued benefit obligation and the expected long-term rate of return on plan assets. Other assumptions are the average rate of compensation increase, average remaining service life of the active employee group, and employee and retiree mortality rates. Excluding the assumptions for the expected long-term rate of return on plan assets and average rate of compensation increase, the foregoing assumptions along with health care cost trend assumptions were utilized by management in determining other post-employment benefit plan costs and obligations. These assumptions were reviewed in 2007 and remain unchanged from 2006.

In accordance with PUB orders, Newfoundland Power expenses the cost of other post-employment benefits on a cash basis whereby differences between the cash payments during the year and the expense incurred in the year is deferred as a regulatory asset. Therefore, changes in assumptions cause changes in the regulatory asset and do not impact earnings. Other post-employment benefits costs deferred as a regulatory asset in 2007 totalled $6.7 million (2006 - $4.8 million) and the regulatory asset at December 31, 2007 was $34.5 million (2006 - $27.8 million).

Asset Retirement Obligations: The measurement of the fair value of asset retirement obligations ("AROs") requires the Company to make reasonable estimates about the method of settlement and settlement dates associated with legally obligated asset retirement costs. While the Company has AROs for its hydroelectric generation assets and certain distribution and transmission assets, there were no amounts recognized as at December 31, 2007 and 2006. The nature, amount and timing of AROs for generation assets cannot be reasonably estimated at this time as these assets are expected to effectively operate in perpetuity given their nature. In the event that environmental issues are identified or generation assets are decommissioned, AROs will be recorded at that time provided the costs can be reasonably estimated. It is managements' judgement that identified AROs for its remaining assets are immaterial.

Revenue Recognition: The Company recognizes electricity revenue on an accrual basis. Customer bills are issued throughout the month based on meter readings that establish electricity consumption by the customer since the last meter reading. The unbilled revenue accrual for each period is based on estimated electricity sales to customers for the period since the last meter reading at the rates approved by the PUB. The development of the electricity sales estimates requires analysis of electricity consumption on a historical basis in relation to key inputs such as the current price of electricity, population growth, economic activity, weather conditions and system losses. The estimation process for accrued unbilled electricity consumption will result in adjustments to electricity revenue in the period during which the difference between actual results and those estimated becomes known. As at December 31, 2007, the amount of accrued unbilled revenue was approximately $28.3 million (December 31, 2006 - $24.0 million). The increase in accrued unbilled revenue was a result of the increase in Hydro's purchased power rate effective January 1, 2007.

## SELECTED ANNUAL INFORMATION

| ($millions, except per share amounts) | 2007 | 2006 | 2005[6] |
|---|---|---|---|
| Results of Operations | | | |
| Revenue | 490.2 | 421.3 | 420.0 |
| Earnings Applicable to Common Shares | 29.9 | 30.1 | 30.7 |
| Financial Position | | | |
| Total Assets | 985.9 | 929.2 | 889.0 |
| Total Long-term Liabilities | 537.3 | 479.3 | 489.0 |
| Shareholders' Equity | 366.0 | 345.2 | 333.4 |
| Per Share Data | | | |
| Earnings Applicable to Common Shares[7] | 2.89 | 2.91 | 2.98 |
| Common Dividends Declared[7] | 0.88 | 1.76 | 2.24 |
| Preferred Dividends Declared[8] | 2.56 | 2.56 | 2.56 |

[6] Certain amounts have been reclassified to conform with the presentation for 2006 and 2007.

[7] Basic and fully diluted. Based on the weighted average number of common shares outstanding which was 10,320,270 common shares in each year.

[8] Based on the aggregate weighted average number of preference shares outstanding in each year, which was 935,223 in 2007, 935,323 in 2006 and 941,023 in 2005. In 2007, the Company repurchased 100 preference shares at $10 per share (2006 – 5,700 preference shares at $10 per share, 2005 - 700 preference shares at $10 per share).

The changes from 2006 to 2007 have been discussed previously in this Management Discussion and Analysis. The increase in total assets from 2005 to 2006 was due primarily to capital expenditures in the normal course. The decrease in total long-term liabilities from 2005 to 2006 reflects an increase in the current portion of long-term debt in 2006 caused by the maturity in 2007 of Series AC bonds. The decrease in common dividends from 2005 to 2006 reflects the retention of earnings in order to finance capital expenditures and maintain a capital structure composed of approximately 45% equity and 55% debt.

## QUARTERLY RESULTS

| (unaudited) | Fourth Quarter December 31 2007 | Fourth Quarter December 31 2006 | Third Quarter September 30 2007 | Third Quarter September 30 2006 | Second Quarter June 30 2007 | Second Quarter June 30 2006 | First Quarter March 31 2007 | First Quarter March 31 2006 |
|---|---|---|---|---|---|---|---|---|
| Electricity Sales (GWh) | 1,383.6 | 1,353.4 | 874.0 | 871.0 | 1,172.0 | 1,137.3 | 1,663.2 | 1,633.4 |
| Revenue ($millions) | 132.2 | 113.7 | 88.9 | 78.5 | 114.7 | 97.3 | 154.4 | 131.8 |
| Earnings Applicable to Common Shares ($millions) | 8.7 | 8.8 | 2.7 | 2.6 | 8.0 | 8.0 | 10.5 | 10.7 |
| Earnings per Common Share ($)[9] | 0.84 | 0.85 | 0.26 | 0.25 | 0.77 | 0.78 | 1.02 | 1.03 |

[9] Basic and fully diluted.

Seasonality: Sales, revenue and earnings are significantly higher in the first (winter) quarter and significantly lower in the third (summer) quarter compared to the remaining quarters. This reflects the seasonality of electricity consumption for heating. Beyond this, earnings in the third (summer) quarter are further reduced by higher operating expenses because certain costs, such as vegetation management, tend to be higher in the summer months.

The purchased power rate structure effective January 1, 2007 resulted in the Company paying more, on average, for each kilowatt hour ("kWh") of purchased power in the winter months and less, on average, for each kWh of purchased power in the summer months compared to 2006. For 2007, quarterly earnings were not impacted by this change as the Company recognized purchased power expense based on the forecast annual cost per kWh with estimated quarterly variances deferred to the PPUCVR. Effective January 1, 2008, the PPUCVR is no longer in effect. It is expected quarterly earnings in 2008 will reflect a seasonal shift from that experienced in 2007. Earnings are expected to be lower in the first and fourth quarters, and higher in the second and third quarters when compared to 2007.

Trending: On a year-over-year basis, quarterly sales increases primarily reflect moderate growth in the number of customers. On the same basis, quarterly revenue increases reflect both customer growth and the January 1, 2007 flow-through of Hydro's purchased power costs to Newfoundland Power's customers, partially offset by Newfoundland Power's January 1, 2007 Formula-driven rate decrease. These revenue dynamics did not impact quarterly earnings on a year-over-year basis because (i) the Hydro-driven revenue increase merely reflects the flow-through of a like increase in purchased power expense, and (ii) the earnings impacts of customer growth and the Formula were largely offsetting.

Beyond the impact of expected moderate customer growth, future quarterly earnings and earnings per share are expected to trend with the ROE reflected in customer rates. Future quarterly earnings are also expected to be impacted by a change in the recognition of purchased power costs.

## OUTLOOK

It is expected that the Company's strategy will be unchanged.

The PUB, through the Company's 2008 GRA, has provided Newfoundland Power with a reasonable opportunity to earn an ROE of 8.95% in 2008 and to maintain its investment grade credit ratings.

It is expected that customer rates in 2009 and 2010 will be determined by the operation of the Formula. The Company does not expect to file its next GRA until at least 2010 to set customer rates for 2011.

# Management Report

The accompanying 2007 Financial Statements of Newfoundland Power Inc. and all information in the 2007 Annual Report have been prepared by management, who are responsible for the integrity of the information presented, including amounts that must be based on estimates and informed judgments. These Financial Statements were prepared in accordance with accounting principles generally accepted in Canada, including selected accounting treatments that differ from those used by entities not subject to rate regulation. Financial information contained elsewhere in the 2007 Annual Report is consistent with that in the Financial Statements.

In meeting its responsibility for the reliability and integrity of the Financial Statements, management has developed and maintains a system of accounting and reporting which provides for the necessary internal controls to ensure transactions are properly authorized and recorded, assets are safeguarded and liabilities are recognized. The systems of the Company focus on the need for training of qualified and professional staff and the effective communication of management guidelines and policies. The effectiveness of the internal controls of Newfoundland Power Inc. is evaluated on an ongoing basis.

The Board of Directors oversees management's responsibility for financial reporting through an Audit & Risk Committee which is composed entirely of external independent directors. The Audit & Risk Committee oversees the external audit of the Company's annual Financial Statements and the accounting and financial reporting and disclosure processes and policies of the Company. The Audit & Risk Committee meets with management, the shareholders' auditors and the internal auditor to discuss the results of the audit, the adequacy of internal accounting controls and the quality and integrity of financial reporting. The Company's annual Financial Statements are reviewed by the Audit & Risk Committee with each of management and the shareholders' auditors before being recommended to the Board of Directors for approval. The shareholders' auditors have full and free access to the Audit & Risk Committee.

The Audit & Risk Committee has the duty to review the adoption of, and changes in, accounting principles and practices which have a material effect on the Company's financial statements and to review and report to the Board of Directors on policies relating to accounting and financial reporting and disclosure processes. The Audit & Risk Committee has the duty to review financial reports requiring the approval of the Board of Directors prior to submission to securities commissions or other regulatory authorities, to assess and review management's judgments that are material to reported financial information and to review the independence and fees of the shareholders' auditors.

The accompanying Financial Statements and Management Discussion and Analysis contained in the 2007 Annual Report were reviewed by the Audit & Risk Committee and, on their recommendation, were approved by the Board of Directors of Newfoundland Power Inc. Ernst & Young, LLP, independent auditors appointed by the shareholders of Newfoundland Power Inc. upon recommendation of the Audit & Risk Committee, have performed an audit of the 2007 Financial Statements and their report follows.

Earl Ludlow
President
and Chief Executive Officer

Jocelyn Perry
Vice President, Finance
and Chief Financial Officer

# Auditors' Report

To the Shareholders,
Newfoundland Power Inc.

We have audited the balance sheets of Newfoundland Power Inc. as at December 31, 2007 and 2006 and the statements of earnings, retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2007 and 2006 and the results of its operations and cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Ernst + Young LLP

Chartered Accountants
St. John's, Canada

January 18, 2008

## Statements of Earnings
**For the years ended December 31**
*($thousands except per share amounts)*

| | 2007 | 2006 |
|---|---|---|
| Revenue | $ 490,232 | $ 421,264 |
| Purchased Power | 326,778 | 257,157 |
| Net Margin | 163,454 | 164,107 |
| | | |
| Operating Expenses | 47,501 | 46,653 |
| Pension and Early Retirement Program Costs | 5,701 | 7,343 |
| Amortization | 39,955 | 38,922 |
| Amortization True-Up Deferral (Note 5) | (5,793) | (5,793) |
| Finance Charges (Note 6) | 33,462 | 32,677 |
| | 120,826 | 119,802 |
| | | |
| Earnings before Income Taxes | 42,628 | 44,305 |
| Income Taxes (Note 7) | 12,176 | 13,639 |
| | | |
| Net Earnings | 30,452 | 30,666 |
| Preference Share Dividends | 586 | 588 |
| | | |
| Net Earnings Applicable to Common Shares | $ 29,866 | $ 30,078 |
| Basic and Diluted Earnings per Common Share | $ 2.89 | $ 2.91 |

## Statements of Retained Earnings
**For the years ended December 31**
*($thousands)*

| | 2007 | 2006 |
|---|---|---|
| Balance, Beginning of the Year | $ 265,566 | $ 253,651 |
| Net Earnings | 30,452 | 30,666 |
| Dividends | | |
| Preference shares | (586) | (588) |
| Common shares | (9,082) | (18,163) |
| Balance, End of the Year | $ 286,350 | $ 265,566 |

See accompanying notes to financial statements.

# Balance Sheets
## As at December 31
*($thousands)*

| | 2007 | 2006 |
|---|---|---|
| **Assets** | | |
| Current assets | | (Note 4) |
| Cash | $ 1,067 | $ - |
| Accounts receivable | 70,792 | 61,604 |
| Regulatory assets (Note 5) | 7,086 | 5,509 |
| Materials and supplies | 5,248 | 4,923 |
| Prepaid expenses | 1,190 | 1,222 |
| Income tax receivable | 1,780 | - |
| | 87,163 | 73,258 |
| Capital assets (Note 8) | 746,474 | 717,137 |
| Deferred charges (Note 9) | 88,674 | 84,169 |
| Regulatory assets (Note 5) | 61,808 | 52,866 |
| Customer finance plans (Note 10) | 1,811 | 1,728 |
| | $ 985,930 | $ 929,158 |
| **Liabilities and Shareholders' Equity** | | |
| Current liabilities | | |
| Bank indebtedness | $ - | $ 400 |
| Short-term borrowings (Note 13) | - | 320 |
| Accounts payable and accrued charges | 68,685 | 65,213 |
| Regulatory liabilities (Note 5) | 9,332 | 2,885 |
| Current instalments of long-term debt (Note 14) | 4,550 | 35,720 |
| Income tax payable | - | 97 |
| | 82,567 | 104,635 |
| Regulatory liabilities (Note 5) | 60,281 | 69,306 |
| Other liabilities (Note 15) | 38,082 | 31,208 |
| Long-term debt (Note 14) | 438,977 | 378,769 |
| | 537,340 | 479,283 |
| Shareholders' equity | | |
| Common shares (Note 11) | 70,321 | 70,321 |
| Preference shares (Note 11) | 9,352 | 9,353 |
| Retained earnings | 286,350 | 265,566 |
| | 366,023 | 345,240 |
| | $ 985,930 | $ 929,158 |

Commitments (Note 19)

See accompanying notes to financial statements.

APPROVED ON BEHALF OF THE BOARD:

Chris Griffiths
Director

David Norris
Director

## Statements of Cashflows
### For the years ended December 31
*($thousands)*

| | 2007 | 2006 |
|---|---|---|
| Cash From (Used In) Operating Activities | | |
| Net earnings | $ 30,452 | $ 30,666 |
| Items not affecting cash | | |
| Amortization of capital assets | 39,955 | 38,922 |
| Amortization of deferred charges | 318 | 313 |
| Amortization of regulatory assets and liabilities | (5,156) | (4,681) |
| Regulatory deferrals | (6,359) | (4,851) |
| Future income taxes | - | (1,375) |
| Accrued employee future benefits | (7,407) | (5,872) |
| Change in non-cash working capital | (2,552) | 3,929 |
| | 49,251 | 57,051 |
| Cash From (Used In) Investing Activities | | |
| Capital expenditures (net of salvage) | (72,167) | (60,235) |
| Change in deferred charges | - | (59) |
| Long-term portion of finance programs | (84) | (204) |
| Contributions from customers and security deposits | 2,580 | 3,166 |
| | (69,671) | (57,332) |
| Cash From (Used In) Financing Activities | | |
| Change in short-term borrowings | (320) | 270 |
| Proceeds from long-term debt | 70,000 | 23,441 |
| Repayment of long-term debt | (37,851) | (4,250) |
| Payment of bond issue costs | (273) | - |
| Redemption of preference shares | (1) | (57) |
| Dividends | | |
| Preference shares | (586) | (588) |
| Common shares | (9,082) | (18,163) |
| | 21,887 | 653 |
| Increase in Cash | 1,467 | 372 |
| Bank Indebtedness, Beginning of the Year | (400) | (772) |
| Cash (Bank Indebtedness), End of the Year | $ 1,067 | $ (400) |

Supplementary Information to Statements of Cash Flows (Note 16)

See accompanying notes to financial statements.

# Notes to Financial Statements

## December 31, 2007

Tabular amounts are in thousands of dollars unless otherwise noted.

### 1. Description of Business

Newfoundland Power Inc. (the “Company” or “Newfoundland Power”) is a regulated electric utility that operates an integrated generation, transmission and distribution system throughout the island portion of Newfoundland and Labrador. The Company is regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities (the “PUB”) and serves over 232,000 customers comprising approximately 85% of all electricity consumers in the province. It generates approximately 10% of its energy needs and purchases the remainder from Newfoundland and Labrador Hydro (“Hydro”).

### 2. Summary of Significant Accounting Policies

These financial statements have been prepared in accordance with Canadian generally accepted accounting principles (“Canadian GAAP”). As a result of rate regulation, the timing of the recognition of certain assets, liabilities, revenues and expenses may differ from that otherwise expected under Canadian GAAP for entities not subject to rate regulation. These differences are disclosed below and in Note 5.

#### Regulation

The Company operates under cost of service regulation as administered by the PUB under the Public Utilities Act (Newfoundland and Labrador).

The Public Utilities Act provides for the PUB’s general supervision of the Company’s utility operations and requires the PUB to approve, among other things, customer rates, capital expenditures and the issue of securities. The Public Utilities Act also entitles the Company an opportunity to recover all reasonable and prudent costs incurred in providing electricity service to its customers, including a just and reasonable return on its rate base. The rate base consists of the net assets required by the Company to provide service to customers.

The determination of the forecast return on rate base, together with the forecast of all reasonable and prudent costs, establishes the revenue requirement upon which the Company’s customer rates are determined through a general rate hearing. Rates are bundled to include generation, transmission and distribution services.

Between general rate hearings, customer rates are established annually through the operation of an automatic adjustment formula that sets an appropriate annual rate of return on rate base based upon changes in the forecast cost of common equity. The forecast cost of common equity reflected in customer rates for 2007 was 8.60% (2006 – 9.24%). As a result of the Company’s 2008 General Rate Application (“GRA”), the forecast cost of common equity to be reflected in customer rates for 2008 is 8.95%.

#### Revenue Recognition

Revenue arising from the amortization of certain regulatory assets and liabilities is recognized in the manner prescribed by the PUB, as disclosed in Note 5. Otherwise, revenue is recognized under the accrual method.

#### Capital Assets

Capital assets are stated at values approved by the PUB as at June 30, 1966, with subsequent additions at cost. Contributions in aid of construction, which are funds received from customers and governments toward the cost of constructing certain capital assets, are netted against the cost of the related capital assets.

The Company capitalizes certain overhead costs not directly attributable to specific capital assets but which do relate to its overall capital expenditure program (general expenses capitalized or “GEC”). The methodology for calculating and allocating GEC among classes of capital assets is established by PUB order. In the absence of rate regulation, only those overhead costs directly attributable to construction activity would be capitalized. In 2007, GEC totalled $2.8 million (2006 - $2.7 million).

The Company capitalizes an allowance for funds used during construction ("AFUDC"), which represents the cost of debt and equity financing incurred during construction of capital assets. AFUDC is calculated in a manner prescribed by the PUB based on a capitalization rate that, depending on the source of financing, may be either (1) the Company's average short-term borrowing rate, (2) its rate of return on rate base, or (3) a blended average of these two rates. The PUB has ordered, effective January 1, 2008, that the Company's AFUDC capitalization rate be its weighted average cost of capital. In 2007, the cost of equity financing capitalized as an AFUDC and deducted from financing charges was approximately $0.2 million (2006 - $0.1 million). In the absence of rate regulation, this cost of equity financing would not be capitalized under Canadian GAAP.

Capital assets are amortized using the straight-line method by applying the amortization rates disclosed below to the average original cost, including GEC and AFUDC, of the related assets. A half-year of amortization is recognized on capital assets during the year in which they are placed into service and during the year of disposition.

The composite amortization rates for the Company's capital assets, as well as their service life ranges and average remaining service lives as at December 31, follow.

| | Composite Amortization Rate | | Service Life (Years) Range | | Service Life (Years) Average Remaining | |
|---|---|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 | 2007 | 2006 |
| Distribution | 3.3% | 3.3% | 16-65 | 16-65 | 23 | 23 |
| Transmission and substations | 2.8 | 2.8 | 31-65 | 31-65 | 26 | 26 |
| Generation | 2.2 | 2.3 | 13-75 | 13-75 | 32 | 32 |
| Transportation and communications | 8.7 | 8.5 | 5-30 | 5-30 | 5 | 5 |
| Buildings | 2.5 | 2.5 | 35-70 | 35-70 | 27 | 27 |
| Equipment | 9.2 | 9.3 | 5-25 | 5-25 | 5 | 5 |
| | 3.5% | 3.5% | | | | |

The Company's amortization methodology, including amortization rates, accumulated amortization and estimated remaining service lives, is subject to periodic review by external experts (the "Amortization Study"). The differences between actual accumulated amortization and that indicated by the Amortization Study (the "Amortization True-Up") is deferred as a regulatory asset (liability), and is amortized as an increase (decrease) in amortization expense and included in customer rates in a manner prescribed by the PUB. The most recent Amortization Study, based on capital assets in service as at December 31, 2005, indicates an Amortization True-Up of approximately $0.7 million. The PUB has ordered that it be amortized as a decrease in amortization expense equally over 2008-2011.

The PUB has ordered that revised amortization rates arising from the Company's most recent Amortization Study be implemented effective January 1, 2008. As a result, the total composite amortization rate will decline from 3.5% to 3.4%. This is not expected to have a material impact on earnings as the revised amortization rates are reflected in customer rates.

Upon disposition, the original cost of capital assets is removed from the capital asset accounts. That amount, net of salvage proceeds, is also removed from accumulated amortization. As a result, any gain or loss is charged to accumulated amortization and is effectively included in the Amortization True-Up arising from the next Amortization Study. In 2007, approximately $7.2 million (2006 - $4.8 million) of losses was charged to accumulated amortization. In the absence of rate-regulation, these amounts would have been recognized as losses upon disposition.

### Materials and Supplies

Materials and supplies represent fuel and materials required for construction or maintenance activities. They are carried at the lower of average cost and estimated net realizable value.

### Deferred Capital Stock Issue Costs

Capital stock issue costs are recognized as deferred charges and are amortized as finance charges on a straight-line basis over 20 years. In the absence of rate regulation, capital stock issue costs would be recognized as a reduction in share capital and would not be amortized.

### Future Income Taxes

Effective January 1, 1981, as prescribed by the PUB, future income tax liabilities are recognized, and recovered in customer rates, on temporary timing differences associated with the cumulative excess of capital cost allowance over amortization of capital assets, excluding GEC.

Future income tax expense (recovery) associated with the Company's regulatory reserves and certain regulatory deferrals is also recognized and included in the determination of customer rates. See Note 5.

Future income tax assets and liabilities associated with other temporary timing differences between the tax basis of assets and liabilities and their carrying amount are not recognized or included in customer rates. Unrecognized amounts are expected to be recovered from (refunded to) customers through rates when the income taxes actually become payable (recoverable). The Company's unrecognized net future income tax liability at December 31, 2007 was $74.4 million (2006 - $82.8 million).

### Employee Future Benefits
Newfoundland Power maintains defined contribution and defined benefit pension plans for its employees, and also provides other post-employment benefits ("OPEBs"). OPEBs are composed of retirement allowances for retiring employees as well as health, medical and life insurance for retirees and their dependants.

### Defined Contribution and Defined Benefit Pension Plans
Defined contribution pension plan costs are expensed as incurred.

The pension costs and accrued benefit obligations of the defined benefit pension plans are actuarially determined using the projected benefit method pro-rated on service and management's best estimate of expected plan investment performance, salary escalation and retirement ages of employees. Pension plan assets are valued using the market-related value where investment returns in excess of or below expected returns are recognized in asset value over a period of three years. The excess of the cumulative net actuarial gain or loss over 10% of the greater of the benefit obligation and the market-related value of plan assets is amortized over the estimated average remaining service period of active employees. The transitional obligation arising from the Company's January 1, 2000 adoption of Section 3461 of the Canadian Institute of Chartered Accountants ("CICA") Handbook is being amortized on a straight-line basis over the 18 year expected average remaining service period of plan members at that time. Unamortized past service costs are amortized over a range of 5 - 15 years. See Note 5.

### OPEBs
OPEBs costs, excluding retirement allowances arising from the Company's 2005 early retirement program, are expensed when benefits are paid. As ordered by the PUB, 2007 operating expenses include $0.1 million (2006 - $0.5 million) of retirement allowances associated with the Company's 2005 early retirement program. In the absence of rate regulation, OPEBs costs would be recognized as expense on an accrual basis as actuarially determined. The portion of the actuarially determined costs that is not recognized as an expense is deferred as a regulatory asset, as these costs are expected to be recovered in future customer rates in a manner determined by the PUB. See Note 5.

OPEBs costs and the accrued OPEB obligation are actuarially determined using the projected benefits method prorated on service and best estimate assumptions. The excess of any cumulative net actuarial gain or loss over 10% of the benefit obligation, along with unamortized past service costs, is amortized over the estimated average remaining service period of active employees. The transitional obligation arising from the Company's January 1, 2000 adoption of Section 3461 of the CICA Handbook is being amortized on a straight-line basis over the 18 year expected average remaining service period of plan members at that time. In each case, amortization is recognized as a change in both the OPEBs regulatory asset and the accrued OPEBs liability.

In the absence of rate regulation, OPEBs costs initially recognized in 2007 operating expenses would have been $6.7 higher (2006 - $4.8 higher).

### Financial Instruments
The Company has designated its financial instruments as follows:

(a) Cash is classified as "Held for Trading". After its initial fair value measurement, any change in fair value is recognized in earnings.
(b) Accounts receivable and loans under customer finance programs (Note 10) are classified as "Loans and Receivables". Short-term borrowings, bank indebtedness, accounts payable and accrued charges, security deposits (Note 15) and long-term debt are classified as "Other Financial Liabilities". Initial measurement is at fair value and incorporates transaction costs, including deferred debt issue costs. Subsequent measurement is at amortized cost using the effective interest method. For the Company, the measurement amount generally corresponds to cost.

### Asset Retirement Obligations
Under Canadian GAAP, the Company is required to record the fair value of future expenditures necessary to settle legal obligations associated with asset retirements even though the timing or method of settlement is conditional on future events. Newfoundland Power has determined that there are asset retirement obligations ("AROs") associated with its generation assets and some parts of its transmission and distribution system.

For generation assets, the legal obligation is the environmental remediation of the land and waterways to protect fish habitat. However, this obligation is conditional on the decision to decommission generation assets. The Company currently has no plans to decommission any of its hydroelectric generation assets as they are effectively operated in perpetuity. Therefore, the nature and fair value of this ARO is not determinable.

For the transmission and distribution system, the legal obligations, which pertain to the proper disposal of fuel storage tanks, used oil and asbestos, were determined to be immaterial. Therefore, no AROs have been recognized.

The Company will recognize AROs and offsetting capital assets when the nature and timing can reasonably be determined and the amount is material.

### Use of Accounting Estimates

The preparation of financial statements in accordance with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting periods. Additionally, certain estimates are necessary since the regulatory environment in which the Company operates may require amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions.

Estimates are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances. Due to changes in facts and circumstances and the inherent uncertainty involved in making estimates, actual results may differ from current estimates. Estimates are reviewed periodically and, as adjustments become necessary, are reported in earnings in the period during which they either, as appropriate, become known or included in customer rates.

## 3. Change in Accounting Policies

### 2007 Changes

Financial Instruments: Effective January 1, 2007, the Company retrospectively, without restatement, adopted Section 3855, Financial Instruments – Recognition and Measurement and Section 3861, Financial Instruments – Disclosure and Presentation, of the CICA Handbook. These sections require the Company to designate each of its financial instruments into one of five possible categories. The Company's designations and the related prescribed accounting policy are disclosed in Note 2.

As a result of the adoption of these accounting standards, deferred financing charges of $3.1 million at December 31, 2007 have been netted against long-term debt on the Company's balance sheet and are being amortized as finance charges over the life of the related debt using the effective interest method. Prior to 2007, these costs were included in deferred and other charges on the Company's balance sheet and were amortized as finance charges over the life of the related debt using the straight-line method. See Notes 6, 9 and 14. The adoption of these accounting standards had no impact on the Company's 2007 earnings or on its risk management policies.

Accounting Changes: Effective January 1, 2007, the Company adopted the revised CICA Handbook Section 1506, Accounting Changes. Under this revised accounting standard, voluntary changes in accounting policy are made only if they result in the financial statements providing reliable and more relevant information. Adoption of this accounting standard had no impact on the Company's 2007 financial statements.

### Emerging Changes

Inventories: Effective January 1, 2008, the Company will adopt the new CICA Handbook Section 3031, Inventory which requires inventories to be measured at the lower of cost or net realizable value; disallows the use of a last-in first-out inventory costing methodology; and, requires that, when circumstances which previously caused inventories to be written down below cost no longer exist, the amount of the write down is to be reversed. This new standard is not expected to have a material impact on the Company's earnings.

Capital Disclosures: The Company will also adopt, January 1, 2008, the new CICA Handbook Section 1535, Capital Disclosures. Newfoundland Power will be required to include additional information in the notes to the financial statements about its capital and the manner in which it is managed. This additional disclosure includes quantitative and qualitative information regarding an entity's objectives, policies and processes for managing capital.

Disclosure and Presentation of Financial Instruments: Sections 3861 and 3862 of the CICA Handbook set out new accounting recommendations for disclosure and presentation of financial instruments, which are effective for the Company beginning January 1, 2008. The new recommendations require disclosures of both qualitative and quantitative information that enables users of financial statements to evaluate the nature and extent of risks from financial instruments to which the Company is exposed.

Future Income Tax: The PUB has ordered that future income tax on temporary timing differences between pension expense and pension funding be recognized and included in the determination of customer rates commencing January 1, 2008. This is not expected to have a material impact on the Company's cash flows or earnings.

International Financial Reporting Standards ("IFRS"): In 2006, the Canadian Accounting Standards Board ("AcSB") published a new strategic plan that will significantly affect financial reporting requirements for Canadian companies. The AcSB strategic plan outlines the convergence of Canadian GAAP with IFRS over an expected five year transitional period. While the Company has begun assessing the adoption of IFRS for 2011, the financial reporting impact of the transition to IFRS cannot be reasonably estimated at this time.

Rate-Regulated Operations: Given its strategic plan to adopt IFRS, the AcSB revisited the scope of its project on accounting for rate-regulated operations in recognition of the fact that IFRS do not currently provide any special guidance with respect to accounting practices that are unique to rate-regulated entities. As a result, it has removed certain guidance from the CICA Handbook. Newfoundland Power's preliminary assessment of these changes is that effective January 1, 2009, it will be required to (i) disclose separately on its balance sheets future income tax assets and liabilities that, in accordance with PUB approved accounting policies, are currently unrecognized along with corresponding regulatory liabilities and assets and

(ii) include in these amounts the future income tax effects of the subsequent settlement of the regulatory assets and liabilities through customer rates. These changes would not affect earnings or cash flows. If calculated in accordance with the revised guidance, the net unrecognized future income tax liability now disclosed in Note 2 to the Company's 2007 annual financial statements would increase by approximately $30.7 million (2006 - increase of approximately $40.2 million) to $105.1 million at December 31, 2007 (December 31, 2006 - $123.0 million).

## 4. Change in Presentation

Prior to December 31, 2007, the regulatory provision for future removal and site restoration costs for capital assets was recorded in accumulated amortization, as these costs were recoverable in amortization rates from customers. Actual costs of removal and site restoration incurred, net of salvage proceeds, were recorded against this provision in accumulated amortization. In the absence of rate regulation, future removal and site restoration costs, net of salvage proceeds, would be recognized as incurred rather than over the life of the related capital assets through amortization expense. The Company has changed the presentation of the accumulated provision for future removal and site restoration costs, from accumulated amortization to a long-term regulatory liability. This change in presentation has been applied retroactively, with restatement of 2006 comparative balances, and has had no impact on earnings. The effect of this change in presentation at December 31, 2007 was a $47.4 million (December 31, 2006 - $47.6 million) increase in long-term regulatory liabilities and corresponding increases in net capital assets.

## 5. Regulatory Assets and Liabilities

Regulatory assets and liabilities arise as a result of the rate-setting process. Regulatory assets represent revenues associated with certain costs incurred in the current or prior periods that will be, or are expected to be, recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent reductions or limitations of increases in revenues associated with amounts that will be, or are expected to be, refunded to customers in future periods through the rate-setting process. The accounting methods underlying regulatory assets and liabilities, and their eventual settlement through the rate-setting process, are prescribed by the PUB and impact the Company's cashflows.

The Company's regulatory assets and liabilities, which will be, or are expected to be, reflected in customer rates in future periods, follow.

| | 2007 | | 2006 | |
|---|---|---|---|---|
| | Current | Non-current | Current | Non-current |
| Regulatory Assets | | | | |
| Rate stabilization account (i) | $ (70) | $ 1,761 | $ 3,122 | $ 432 |
| OPEBs asset (Note 2) | - | 34,527 | - | 27,782 |
| Weather normalization account (ii) | 1,366 | 9,151 | 1,126 | 10,683 |
| Early retirement program costs (Note 2) | - | - | 133 | - |
| Amortization true-up deferral (iii) | 3,862 | 7,724 | - | 5,793 |
| Pension deferral (iv) | 1,128 | 7,048 | 1,128 | 8,176 |
| Replacement energy deferral (v) | 383 | 764 | - | - |
| Deferred GRA costs (vi) | 417 | 833 | - | - |
| | $ 7,086 | $ 61,808 | $ 5,509 | $ 52,866 |
| Regulatory Liabilities | | | | |
| Municipal tax liability (vii) | $ 1,363 | $ 2,726 | $ - | $ 4,089 |
| Unbilled revenue liability (viii) | 7,210 | 9,236 | 2,714 | 16,446 |
| Purchased power unit cost variance reserve (ix) | 447 | 1,203 | - | 1,342 |
| Future removal and site restoration provision (x) | 312 | 47,116 | 171 | 47,429 |
| | $ 9,332 | $ 60,281 | $ 2,885 | $ 69,306 |

### (i) Rate Stabilization Account

The rate stabilization account passes through to the Company's customers amounts primarily related to changes in the cost and quantity of fuel used by Hydro to produce the electricity sold to the Company. Operation of this account has no earnings impact. On July 1 of each year customer rates are recalculated in order to amortize over the subsequent 12 months the balance in the rate stabilization account as of March 31 of the current year. In the absence of rate regulation these transactions would be accounted for in a similar manner, however, the amount and timing of the recovery or refund would not be subject to regulatory approval.

The marginal cost of purchased power exceeds the average cost that is embedded in customer rates. To the extent actual electricity sales in any period exceed forecast electricity sales used to set customer rates, marginal purchased power expense will exceed related revenue. The PUB has ordered, effective January 1, 2008, that variations in purchased power expense caused by differences between the actual unit cost of energy and that reflected in customer rates be recovered from (refunded to) customers through the rate stabilization account.

### (ii) Weather Normalization Account

The weather normalization account reduces earnings volatility by adjusting purchased power expense and electricity sales revenue to eliminate variances in purchases and sales caused by the difference between normal weather conditions, based on long-term averages, and actual weather conditions. In the absence of rate regulation these fluctuations would be recognized in earnings in the period in which they occurred.

The balance in the weather normalization account, because it is based on long-term averages for weather conditions, should tend to zero over time. However, the Company has indentified two non-reversing balances in the account arising from changes in purchased power rates and income tax rates. The PUB has ordered that a non-reversing balance of approximately $5.6 million be amortized equally over 2003-2007 as an increase in purchased power expense of approximately $1.7 million and a decrease in future income tax expense of approximately $0.6 million in each year. The PUB has ordered that a non-reversing balance of approximately $6.8 million be amortized equally over 2008-2012 as an increase in purchased power expense of approximately $2.1 million and a decrease in future income tax expense of approximately $0.7 million in each year.

The recovery period for the remaining balance in the weather normalization account is not determinable as it depends on future weather conditions. In the absence of rate regulation, revenue in 2007 would have been $1.8 million lower (2006 - $15.9 million lower), purchased power expense in 2007 would have been $3.8 million lower (2006 - $13.3 million lower) and future income tax expense in 2007 would have been $0.7 million higher (2006 - $0.9 million lower).

### (iii) Amortization True-Up Deferral

The PUB ordered the deferred recovery of approximately $5.8 million in each of 2006 and 2007; effectively extending the impact of the Amortization True-Up that arose from the Company's 2002 Amortization Study. The 2006 and 2007 deferrals were recorded as an increase in regulatory assets and a decrease in expenses of $5.8 million in each year. In the absence of rate regulation, these expense reductions would not have been recognized. In 2007, the PUB ordered that the resultant regulatory asset of approximately $11.6 million be amortized as an increase in expenses equally over 2008 - 2010.

### (iv) Pension Deferral

The PUB ordered that approximately $11.3 million of incremental pension costs arising from the Company's 2005 early retirement program to be deferred and amortized equally over a ten year period beginning April 1, 2005. In the absence of rate regulation, these costs would have been expensed in 2005.

### (v) Replacement Energy Deferral

In 2006, the PUB ordered the deferred recovery in 2007 of approximately $1.1 million related to the cost of replacement energy purchased during the refurbishment of the Company's Rattling Brook hydroelectric plant. The deferral was recorded in 2007 as an increase in regulatory assets of approximately $1.1 million, an increase in future income tax expense of approximately $0.7 million and a decrease in purchased power expense of approximately $1.8 million. The PUB has ordered that this regulatory asset be amortized equally over 2008-2010 as an increase in purchased power expense of approximately $0.6 million and a decrease in future income tax expense of approximately $0.2 million in each year.

### (vi) Deferred GRA Costs

In 2007, the PUB ordered that an estimated $1.3 million of external costs related to the Company's 2007 GRA be deferred and amortized equally over 2008 - 2010. In the absence of rate regulation, these costs would have been expensed in 2007.

### (vii) Municipal Tax Liability

The $4.1 million municipal tax liability results from a timing difference related to the recovery and payment of municipal taxes under the Company's PUB approved municipal tax collection policy. The PUB has ordered that this $4.1 million be amortized as other revenue equally over 2008 – 2010.

### (viii) Unbilled Revenue Liability

Prior to January 1, 2006, revenue from electricity sales was recognized as bills were rendered to customers. Subsequently, this revenue is recognized on an accrual basis. Unrecognized unbilled revenue at December 31, 2005 was deferred as a regulatory liability and is being amortized as revenue in accordance with PUB orders. Amortization for 2007 was approximately $2.7 million (2006 - $3.1 million). The PUB has ordered that the unamortized balance at December 31, 2007 be amortized as follows: 2008 – approximately $7.2 million, 2009 and 2010 – approximately $4.6 million in each year. In the absence of rate regulation, all of the unbilled revenue would have been recognized as revenue in 2005.

Amortization for 2006 and 2007, and approximately $2.6 million of 2008 amortization, effectively offset like increases in income tax expense expected in those years attributable to the January 1, 2006 adoption of the accrual method of revenue recognition for income tax purposes. See Note 7.

### (ix) Purchased Power Unit Cost Variance Reserve

The purchased power unit cost variance reserve limits variations in the cost of purchased power, associated with a demand and energy wholesale rate structure, to a PUB approved range. In the absence of rate regulation, such variations would be recognized in earnings in the period in which they occurred. In 2007, purchased power expense would have been approximately $0.5 million lower (2006 - $2.1 million lower) and future income tax expense would have been $0.2 million higher (2006 - $0.8 million higher).

The PUB has ordered that the December 31, 2006 balance in the reserve of approximately $1.3 million be amortized over 2008 – 2010 as a decrease in purchased power expense of approximately $0.7 million and an increase in future income tax expense of approximately $0.3 million in each year. The disposition of the remaining balance in the reserve will be determined by a further order of the PUB.

Effective January 1, 2008, the PUB has ordered the discontinuance of the purchased power unit cost variance reserve and the creation of a demand management incentive account. Through this account, variations in the unit cost of purchased power related to demand are limited, at the discretion of the PUB, to 1% of demand costs reflected in customer rates. Balances in this account will be shown as a regulatory asset or regulatory liability on Newfoundland Power's balance sheets. The disposition of balances in this account, which would be determined by a further order of the PUB, will consider the merits of the Company's conservation and demand management activities.

(x) Future Removal and Site Restoration Provision

Through the PUB approved amortization rates for capital assets, estimated removal and site restoration costs, net of estimated salvage proceeds, that are expected to be incurred in the future, are accrued over the lives of capital assets as an increase in amortization expense and a corresponding regulatory liability. Upon disposition, actual net costs are charged against the accrued regulatory liability and any remaining balance is effectively included in the Amortization True-Up arising from the next Amortization Study. In the absence of rate regulation, these net costs would be recognized as an operating expense when incurred. In 2007, amortization expense includes an approximately $3.5 million (2006 - $3.2 million) provision for estimated net future capital asset removal and site restoration costs. Actual net costs incurred in 2007 were approximately $3.7 million (2006 - $1.6 million).

## 6. Finance Charges

| | 2007 | 2006 |
|---|---|---|
| Interest on long-term debt | $ 33,718 | $ 32,759 |
| Interest on long-term committed credit facility | 1,437 | 1,234 |
| Interest on short-term uncommitted demand facility | 38 | 23 |
| Amortization of deferred debt issue costs (Note 3) | 256 | 202 |
| Amortization of capital stock issue costs (Note 2) | 62 | 62 |
| Interest on security deposits | 50 | 43 |
| Interest earned | (1,477) | (1,210) |
| AFUDC (Note 2) | (622) | (436) |
| | $ 33,462 | $ 32,677 |

## 7. Income Taxes

Income taxes vary from the amount that would be determined by applying statutory income tax rates to pre-tax earnings. A reconciliation of the combined federal and provincial statutory income tax rate to the Company's effective income tax rate follows.

| | 2007 | 2006 |
|---|---|---|
| Combined statutory income tax rate | 36.1% | 36.1% |
| Future income tax | - | (3.1) |
| GEC | (2.4) | (2.2) |
| Pension costs less than pension funding | (5.2) | (4.4) |
| Amortization of capital assets in excess of capital cost allowance | 3.3 | 6.3 |
| Amortization True-Up and GRA deferrals | (6.0) | (4.7) |
| Change in revenue recognition policy | 4.1 | 3.6 |
| Other timing differences not recorded | (1.3) | (0.8) |
| Effective income tax rate | 28.6% | 30.8% |

The composition of the Company's income tax provision follows.

| | 2007 | 2006 |
|---|---|---|
| Current income tax expense | $ 12,432 | $ 14,817 |
| Future income tax recovery | (256) | (1,178) |
| | $ 12,176 | $ 13,639 |

Pursuant to a settlement agreement with the Canada Revenue Agency, current income taxes in 2007 include approximately $2.7 million (2006 - $3.1 million) related to the Company's January 1, 2006 adoption of the accrual method of revenue recognition for income tax purposes. The final instalment, which is estimated to be approximately $2.6 million, is due in 2008.

As at December 31, 2007, the Company had approximately $0.2 million (December 31, 2006 - $0.3 million) in capital losses carried forward which have not been recognized in the financial statements.

## 8. Capital Assets

| | Cost | | Accumulated Amortization | | Net Book Value | |
|---|---|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 | 2007 | 2006 |
| Distribution | $ 661,455 | $ 640,760 | $ 236,195 | $ 225,466 | $ 425,260 | $ 415,294 |
| Transmission and substations | 219,490 | 211,233 | 85,671 | 81,647 | 133,819 | 129,586 |
| Generation | 156,530 | 137,863 | 42,621 | 39,980 | 113,909 | 97,883 |
| Transportation and communications | 32,547 | 33,237 | 15,679 | 16,350 | 16,868 | 16,887 |
| Land, buildings and equipment | 98,745 | 95,810 | 42,682 | 39,240 | 56,063 | 56,570 |
| Construction in progress | 555 | 917 | - | - | 555 | 917 |
| | $ 1,169,322 | $ 1,119,820 | $ 422,848 | $ 402,683 | $ 746,474 | $ 717,137 |

Distribution assets, which are used to distribute low voltage electricity to customers, include poles, towers and fixtures, low-voltage wires, transformers, overhead and underground conductors, street lighting, metering equipment and other related equipment. Transmission and substations assets, which are used to transmit high voltage electricity to distribution assets, include poles, high voltage wires and conductors, substations, support structures and other related equipment. Generation assets, which are used to generate electricity, include hydroelectric and thermal generating stations, gas and combustion turbines, dams, reservoirs and other related equipment. Transportation and communications assets include vehicles as well as telephone, radio and other communications equipment. Remaining land, buildings and equipment are used generally in the provision of electricity service but not specifically in the distribution, transmission or generation of electricity or specifically related to transportation and communications activities.

## 9. Deferred Charges

| | 2007 | 2006 |
|---|---|---|
| Deferred pension assets (Note 17) | $ 88,478 | $ 80,818 |
| Deferred debt issue costs (Notes 3 and 14) | - | 3,035 |
| Deferred credit facility costs | 59 | 118 |
| Deferred capital stock issue costs (Note 2) | 137 | 198 |
| | $ 88,674 | $ 84,169 |

## 10. Customer Finance Plans

Customer finance plans represent the non-current portion of loans to customers for certain new service requests and certain energy efficiency upgrades. The current portion is classified as accounts receivable. In the case of new service requests, and as prescribed by the PUB, interest is charged at a fixed rate of prime plus 3% for repayment periods up to 60 months and prime plus 4% for repayment periods of 61 months to 120 (maximum) months. In the case of energy efficiency upgrades, interest is charged at a fixed rate of prime plus 4% for a maximum repayment period of 60 months. In both cases, payments are made through the customers' monthly electricity bills and loans may be repaid at any time without penalty.

## 11. Capital Stock

Authorized

(a) an unlimited number of Class A and Class B Common Shares without nominal or par value. The shares of each class are inter-convertible on a share-for-share basis and rank equally in all respects including dividends. The Board of Directors may provide for the payment, in whole or in part, of any dividends to Class B shareholders by way of a stock dividend;

(b) an unlimited number of First Preference Shares and Second Preference Shares without nominal or par value, except that each Series A, B, D and G First Preference Share has a par value of $10. The issued First Preference Shares are entitled to cumulative preferential dividends and are redeemable at the option of the Company at a premium not in excess of the annual dividend rate. Series D and G First Preference Shares are subject to the operation of purchase funds and the Company has the right to purchase limited amounts of these shares at or below par.

Issued

| | 2007 | | 2006 | |
|---|---|---|---|---|
| | Number of Shares | Amount | Number of Shares | Amount |
| Class A Common Shares | 10,320,270 | $ 70,321 | 10,320,270 | $ 70,321 |
| First Preference Shares | | | | |
| 5.50% Series A | 179,225 | 1,792 | 179,225 | 1,792 |
| 5.25% Series B | 337,983 | 3,380 | 337,983 | 3,380 |
| 7.25% Series D | 212,065 | 2,121 | 212,165 | 2,122 |
| 7.60% Series G | 205,950 | 2,059 | 205,950 | 2,059 |
| | 935,223 | $ 9,352 | 935,323 | $ 9,353 |

During 2007, the Company repurchased 100 Series D First Preference Shares for cash consideration of $1,000.

## 12. Related Party Transactions

The Company provides services to, and receives services from, its parent Company, Fortis Inc. ("Fortis"), and other subsidiaries of Fortis. The Company also incurs charges from Fortis for the recovery of general corporate expenses incurred by Fortis. These transactions are in the normal course of business and are recorded at their exchange amounts.

Related party transactions included in revenue and operating expenses in 2007 and 2006, and in accounts receivable at December 31 of these years, follow.

| | 2007 | 2006 |
|---|---|---|
| Revenue | $ 4,078 | $ 3,730 |
| Operating expenses | $ 940 | $ 1,038 |
| Accounts receivable | $ 112 | $ 119 |

## 13. Credit Facilities

Newfoundland Power has unsecured bank credit facilities of $120 million composed of a syndicated $100 million committed revolving term credit facility which matures on January 20, 2009 and a $20 million uncommitted demand facility.

Borrowings under the committed facility have been classified as long-term as they are expected to remain outstanding for a period extending beyond one year from the balance sheet date. These borrowings are in the form of bankers acceptances bearing interest based on the daily Canadian Deposit Offering Rate for the date of borrowing plus a stamping fee. Standby fees on the unutilized portion of the committed facility are payable quarterly in arrears at a fixed rate of 0.1375%. Interest on the uncommitted facility is calculated at the daily prime rate and is payable monthly in arrears.

The utilized and unutilized credit facilities as at December 31 follow.

| | 2007 | 2006 |
|---|---|---|
| Total credit facilities | $ 120,000 | $ 120,000 |
| Short-term borrowings | - | (320) |
| Long-term borrowings (Note 14) | (33,000) | (34,431) |
| Credit facilities available | $ 87,000 | $ 85,249 |

## 14. Long-term Debt

| | 2007 | 2006 |
|---|---|---|
| First mortgage sinking fund bonds | | |
| 11.875% Series AC, due 2007 | $ - | $ 31,870 |
| 10.550% Series AD, due 2014 | 31,353 | 31,753 |
| 10.900% Series AE, due 2016 | 33,600 | 34,000 |
| 10.125% Series AF, due 2022 | 34,000 | 34,400 |
| 9.000% Series AG, due 2020 | 34,800 | 35,200 |
| 8.900% Series AH, due 2026 | 35,635 | 36,035 |
| 6.800% Series AI, due 2028 | 45,500 | 46,000 |
| 7.520% Series AJ, due 2032 | 71,250 | 72,000 |
| 5.441% Series AK, due 2035 | 58,200 | 58,800 |
| 5.901% Series AL, due 2037 | 69,300 | - |
| Long-term classification of credit facilities (Note 13) | 33,000 | 34,431 |
| | 446,638 | 414,489 |
| Less: current portion | 4,550 | 35,720 |
| | 442,088 | 378,769 |
| Less: deferred debt issue costs (Notes 3 and 9) | 3,111 | - |
| | $ 438,977 | $ 378,769 |

First mortgage sinking fund bonds are secured by a first fixed and specific charge on capital assets owned or to be acquired by the Company and by a floating charge on all other assets. They require an annual sinking fund payment of 1% of the original principal balance. Annual payments required to meet sinking fund instalments, maturities of long-term debt and long-term credit facilities in each of the next five years follow.

| | |
|---|---|
| 2008 | $ 4,550,000 |
| 2009 | $ 37,550,000 |
| 2010 | $ 4,550,000 |
| 2011 | $ 4,550,000 |
| 2012 | $ 4,550,000 |

## 15. Other Liabilities

| | 2007 | 2006 |
|---|---|---|
| Security deposits | $ 612 | $ 736 |
| OPEB liability (Note 17) | 34,527 | 27,782 |
| Defined benefit pension liability - unfunded (Note 17) | 1,485 | 1,486 |
| Defined contribution pension liability (Note 17) | 1,458 | 1,204 |
| | $ 38,082 | $ 31,208 |

Security deposits are advance cash collections from customers to guarantee the payment of electricity bills. The security deposit liability includes interest credited to customer deposits. The current portion is reported in accounts payable and accrued charges.

## 16. Supplementary Information to Statements of Cash Flows

| | 2007 | 2006 |
|---|---|---|
| Interest paid | $ 34,099 | $ 33,614 |
| Income taxes paid | $ 11,957 | $ 14,492 |
| Employee future benefits paid | $ 1,120 | $ 1,461 |

## 17. Employee Future Benefits

The Company's defined contribution plans are its individual and group registered retirement savings plans, and an unfunded supplementary employee retirement plan ("SERP"). Benefits are based upon employee earnings. The accrued benefit liability for the SERP is included in other liabilities on the Company's balance sheets. During 2007, the Company expensed approximately $1.0 million (2006 - $0.8 million) related to these plans.

The Company's defined benefit plans are its funded defined benefit pension plan, an unfunded pension uniformity plan ("PUP") and OPEBs. Both pension plans are closed to new entrants and provide benefits based on a percentage of the highest 36 consecutive months average base earnings and the employee's years of service.

The accrued benefit obligation for all of the Company's defined benefit plans, and the market-related value of plan assets for the Company's funded primary defined benefit pension plan, are measured for accounting purposes as at December 31 of each year.

The most recent actuarial valuation of the Company's defined benefit pension plans for funding purposes was as of December 31, 2005 and the next required valuation will be, at the latest, as of December 31, 2008. The corresponding dates for the Company's OPEBs are December 31, 2004 and December 31, 2007, respectively.

The accrued benefit asset for the Company's funded primary defined benefit pension plan is included in deferred charges on the Company's balance sheets. The accrued benefits liability for the PUP is included in other liabilities.

Details of the Company's defined benefits plans follow.

| | 2007 | | | 2006 | | |
|---|---|---|---|---|---|---|
| | | Unfunded | | | Unfunded | |
| | Funded | PUP | OPEB | Funded | PUP | OPEB |
| **Change in accrued benefit obligation** | | | | | | |
| Balance, beginning of year | $ 239,176 | $ 2,695 | $ 69,804 | $ 226,725 | $ 2,287 | $ 66,397 |
| Current service costs | 4,997 | - | 1,412 | 4,578 | 1 | 1,350 |
| Interest cost | 12,368 | 136 | 3,698 | 11,769 | 125 | 3,518 |
| Benefits paid | (12,596) | (215) | (1,120) | (12,295) | (204) | (2,837) |
| Actuarial (gains) losses | (8,468) | (58) | (3,383) | 4,973 | 235 | 1,376 |
| Plan amendments | - | - | - | 3,426 | 251 | - |
| Balance, end of year | $ 235,477 | $ 2,558 | $ 70,411 | $ 239,176 | $ 2,695 | $ 69,804 |
| **Change in fair value of plan assets** | | | | | | |
| Balance, beginning of year | $ 250,226 | $ - | $ - | $ 223,370 | $ - | $ - |
| Return on assets | 17,694 | - | - | 15,790 | - | - |
| Benefits paid | (12,596) | (215) | (1,120) | (12,295) | (204) | (2,837) |
| Actuarial (losses) gains | (7,714) | - | - | 11,234 | - | - |
| Employee contributions | 1,216 | - | - | 1,216 | - | - |
| Employer contributions | 10,905 | 215 | 1,120 | 10,911 | 204 | 2,837 |
| Balance, end of year | $ 259,731 | $ - | $ - | $ 250,226 | $ - | $ - |
| **Funded status** | | | | | | |
| Surplus (deficit), end of year | $ 24,254 | $ (2,558) | $ (70,411) | $ 11,050 | $ (2,695) | $ (69,804) |
| Unamortized net actuarial loss | 48,431 | 606 | 22,171 | 52,353 | 696 | 26,881 |
| Unamortized transitional obligation | 12,871 | 466 | 13,713 | 14,158 | 512 | 15,141 |
| Unamortized past service costs | 2,922 | 1 | - | 3,257 | 1 | - |
| Accrued benefit asset (liability), end of year | $ 88,478 | $ (1,485) | $ (34,527) | $ 80,818 | $ (1,486) | $ (27,782) |
| **Effect of 1% increase in health care cost trends on:** | | | | | | |
| Accrued benefit obligation | - | - | $ 12,403 | - | - | $ 12,296 |
| Service costs and interest cost | - | - | $ 988 | - | - | $ 942 |
| **Effect of 1% decrease in health care cost trends on:** | | | | | | |
| Accrued benefit obligation | - | - | $ (9,637) | - | - | $ (9,552) |
| Service costs and interest cost | - | - | $ (749) | - | - | $ (712) |

| | 2007 | | | 2006 | | |
|---|---|---|---|---|---|---|
| | | Unfunded | | | Unfunded | |
| | Funded | PUP | OPEB | Funded | PUP | OPEB |
| **Significant assumptions** | | | | | | |
| Discount rate during year | 5.25% | 5.25% | 5.25% | 5.25% | 5.25% | 5.25% |
| Discount rate as at December 31 | 5.50% | 5.50% | 5.50% | 5.25% | 5.25% | 5.25% |
| Expected long-term rate of return on plan assets | 7.50% | - | - | 7.50% | - | - |
| Rate of compensation increases | 4.00% | 4.00% | 4.00% | 4.00% | 4.00% | 4.00% |
| Health care cost trend increases as at December 31 | - | - | 4.50% | - | - | 4.50% |
| Expected average remaining service of active employees | 13 years | 13 years | 15 years | 15 years | 15 years | 15 years |
| **Net benefit expense** | | | | | | |
| Current service costs | $ 3,781 | $ - | $ 1,412 | $ 3,362 | $ 1 | $ 1,350 |
| Interest cost | 12,368 | 136 | 3,698 | 11,769 | 125 | 3,518 |
| Expected return on plan assets | (17,694) | - | - | (15,790) | - | - |
| Amortization of transitional obligation | 1,287 | 47 | 1,428 | 1,287 | 47 | 1,428 |
| Amortization of net actuarial loss | 3,168 | 31 | 1,327 | 3,455 | 16 | 1,347 |
| Amortization of past service costs | 335 | - | - | 578 | 251 | - |
| Regulatory adjustment (Note 5) | 1,128 | - | (6,745) | 1,128 | - | (4,806) |
| Net benefit expense | $ 4,373 | $ 214 | $ 1,120 | $ 5,789 | $ 440 | $ 2,837 |
| **Asset allocation** | | | | | | |
| Fixed income | 38% | - | - | 37% | - | - |
| Equities | 44% | - | - | 42% | - | - |
| Foreign equities | 18% | - | - | 21% | - | - |

## 18. Financial Instruments

### Fair Value

The Company's financial instruments consist of cash or bank indebtedness, accounts receivable, loans under customer finance plans, short-term borrowings, accounts payable and accrued charges, security deposits and long-term debt. These financial instruments, with the exception of long-term debt, have a carrying value which approximates fair value.

The estimated fair value of the Company's first mortgage bonds was $512.5 million at December 31, 2007 (2006 - $505.9 million). Fair value was estimated using present value techniques based on borrowing rates at year-end for debt with similar terms and maturities. The fair value estimate does not include exchange or settlement costs, as the Company does not intend to retire the debt prior to maturity.

### Credit Risk

Accounts receivable do not represent a significant concentration of credit risk as amounts are owed by a large number of customers on normal credit terms.

### Exchange Risk

Any exposure to foreign exchange rate fluctuations is immaterial.

### Interest Rate Risk

Long-term debt is primarily issued at fixed interest rates, thereby minimizing earnings and cash flow exposures caused by fluctuating interest rates. Such exposures are limited to borrowings under the Company's credit facilities. See Note 13.

## 19. Commitments

The Company is obligated to provide service to customers, resulting in ongoing capital expenditure commitments. Capital expenditures are subject to PUB approval. The PUB approved the 2008 capital plan which provides for net capital expenditures of approximately $50.8 million.

## 20. Comparative Figures

Certain comparative figures have been reclassified to conform with the current year's presentation.

## Corporate Information

Fortis Inc., the largest investor-owned distribution utility in Canada, serves almost 2,000,000 gas and electric customers and has $10 billion of assets. Its regulated holdings include a natural gas utility in British Columbia, Canada and electric utilities in five Canadian provinces and three Caribbean countries. Fortis Inc. owns non-regulated hydroelectric generation assets across Canada and in Belize and upper New York State. It also owns hotels and commercial real estate in Canada. Fortis Inc. shares are listed on the Toronto Stock Exchange and trade under the symbol FTS. Additional information can be accessed at www.fortisinc.com or www.sedar.com.

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Website: www.newfoundlandpower.com

# Ten Year Summary

| | 2007 | 2006[1] | 2005[1] | 2004 | 2003 | 2002 | 2001 | 2000 | 1999 | 1998 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Income Statement Items** ($thousands) | | | | | | | | | | |
| Revenue | 490,232 | 421,264 | 419,963 | 404,447 | 384,150 | 369,627 | 359,305 | 348,413 | 342,001 | 335,751 |
| Purchased power | 326,778 | 257,157 | 255,954 | 244,012 | 227,964 | 210,764 | 202,479 | 199,266 | 192,755 | 191,586 |
| Operating, pension and ERP costs | 53,202 | 53,996 | 53,812 | 51,755 | 51,799 | 50,767 | 52,908 | 52,486 | 52,709 | 52,641 |
| Amortization of capital assets[2] | 34,162 | 33,129 | 32,143 | 30,987 | 29,372 | 35,442 | 34,003 | 29,625 | 29,638 | 28,067 |
| Finance charges | 33,462 | 32,677 | 31,369 | 30,393 | 30,009 | 26,853 | 26,700 | 26,641 | 26,488 | 25,233 |
| Income taxes | 12,176 | 13,639 | 15,368 | 15,586 | 14,945 | 16,381 | 13,730 | 13,296 | 16,927 | 16,027 |
| Earnings applicable to common shares | 29,866 | 30,078 | 30,729 | 31,122 | 29,460 | 28,807 | 28,862 | 26,473 | 22,858 | 21,571 |
| **Balance Sheet Items** ($thousands) | | | | | | | | | | |
| Property, plant and equipment | 1,169,322 | 1,119,820 | 1,085,106 | 1,050,913 | 1,009,448 | 949,478 | 914,735 | 865,406 | 844,598 | 817,820 |
| Accumulated amortization | 422,848 | 402,683 | 387,815 | 420,836 | 407,319 | 381,003 | 369,659 | 353,078 | 344,506 | 330,453 |
| Net capital assets | 746,474 | 717,137 | 697,291 | 630,077 | 602,129 | 568,475 | 545,076 | 512,328 | 500,092 | 487,367 |
| Total assets | 985,930 | 929,158 | 889,013 | 825,310 | 744,375 | 704,598 | 667,289 | 628,252 | 608,336 | 588,320 |
| Long-term debt[4] | 443,527 | 414,489 | 395,298 | 328,558 | 332,208 | 335,858 | 263,758 | 280,158 | 283,208 | 286,258 |
| Preference shares | 9,352 | 9,353 | 9,410 | 9,417 | 9,429 | 9,709 | 9,709 | 9,890 | 9,890 | 9,890 |
| Common equity | 356,671 | 335,887 | 323,972 | 316,360 | 299,480 | 279,515 | 260,203 | 250,331 | 242,848 | 229,485 |
| Total capital | 809,550 | 759,729 | 728,680 | 654,335 | 641,117 | 625,082 | 533,670 | 540,379 | 535,946 | 525,633 |
| **Operating Statistics** (GWh) | | | | | | | | | | |
| Sources of Electricity (normalized) | | | | | | | | | | |
| Purchased | 5,013 | 4,876 | 4,873 | 4,841 | 4,725 | 4,604 | 4,495 | 4,432 | 4,292 | 4,259 |
| Generated | 381 | 417 | 426 | 424 | 425 | 424 | 416 | 423 | 450 | 429 |
| Total | 5,394 | 5,293 | 5,299 | 5,265 | 5,150 | 5,028 | 4,911 | 4,855 | 4,742 | 4,688 |
| Sales (normalized) | | | | | | | | | | |
| Residential | 3,044 | 2,981 | 2,987 | 2,972 | 2,909 | 2,843 | 2,775 | 2,707 | 2,672 | 2,652 |
| Commercial and street lighting | 2,049 | 2,014 | 2,017 | 2,007 | 1,973 | 1,922 | 1,892 | 1,848 | 1,828 | 1,788 |
| Total | 5,093 | 4,995 | 5,004 | 4,979 | 4,882 | 4,765 | 4,667 | 4,555 | 4,500 | 4,440 |
| Electricity sales per employee | 9.2 | 9.0 | 9.0 | 8.3 | 8.1 | 7.8 | 7.5 | 6.9 | 6.4 | 6.3 |
| **Customers** (year-end) | | | | | | | | | | |
| Residential | 201,045 | 198,568 | 196,412 | 193,912 | 191,314 | 188,925 | 186,828 | 185,287 | 183,921 | 182,324 |
| Commercial and street lighting | 31,217 | 30,932 | 30,889 | 30,552 | 30,339 | 30,147 | 30,051 | 29,923 | 29,720 | 29,786 |
| Total | 232,262 | 229,500 | 227,301 | 224,464 | 221,653 | 219,072 | 216,879 | 215,210 | 213,641 | 212,110 |
| **Operating cost per customer** ($)[3] | 213 | 212 | 218 | 220 | 225 | 223 | 231 | 230 | 235 | 243 |
| **Number of regular full-time employees** | 555 | 552 | 556 | 599 | 606 | 610 | 626 | 656 | 703 | 705 |

1 Certain comparative figures have been reclassified to conform with current year presentation.

2 Amount for 2007 and 2006 is net of a regulatory deferral of $5.8 million, as approved by the PUB.

3 Operating cost per customer is calculated excluding pension and early retirement program costs.

4 Net of deferred financing charges in 2007.

# Executive Team

**Ms. Lisa Hutchens,** Vice President, Customer Relations and Corporate Services

**Mr. Peter Alteen,** Vice President, Regulatory Affairs and General Counsel

**Mr. Phonse Delaney,** Vice President, Engineering and Operations

**Mr. Earl Ludlow,** President and Chief Executive Officer

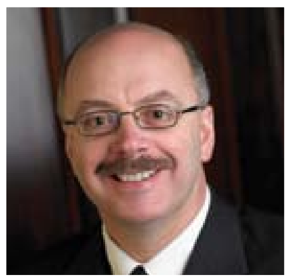
**Ms. Jocelyn Perry,** Vice President, Finance and Chief Financial Officer

# Board of Directors











**Ms. Peggy Bartlett**
President
Bartlett Enterprises Inc.
Grand Falls-Windsor,
Newfoundland & Labrador

**Mr. William Daley**
President & Chief Executive Officer
FortisOntario Inc.
Fort Erie, Ontario

**Mr. Ed Drover**
Regional Director
Freedom55 Financial
St. John's, Newfoundland & Labrador

**Mr. Peter Fenwick**
Owner/Operator
Inn at the Cape
Cape St. George,
Newfoundland & Labrador

**Mr. Chris Griffiths**
General Manager
Garrison Guitars (a division of Gibson Guitar Corp.)
St. John's, Newfoundland & Labrador

**Ms. Georgina Hedges**
Owner/Operator
The Doctor's Inn
Eastport, Newfoundland & Labrador

**Mr. Earl Ludlow**
President & Chief Executive Officer
Newfoundland Power Inc.
St. John's, Newfoundland & Labrador

**Mr. David Norris**
Corporate Director
St. John's, Newfoundland & Labrador

**Mr. Barry Perry**
Vice President, Finance &
Chief Financial Officer
Fortis Inc.
St. John's, Newfoundland & Labrador

**Mr. John Walker**
President & Chief Executive Officer
FortisBC Inc.
Kelowna, British Columbia

**Mr. Jo Mark Zurel**
President
Stonebridge Capital Inc.
St. John's, Newfoundland & Labrador

# Connected to our Communities

We are proud to provide our customers with safe, reliable service, and we are equally as proud that community groups throughout the province can count on us for support. In addition to supporting our primary corporate charity, The Power of Life Project, we were pleased to provide financial, in-kind and hands-on contributions to the following organizations and many more in 2007:


## HEALTH

The Dr. H. Bliss Murphy Cancer Care Foundation, The Burin Peninsula Health Care Foundation, The Western Memorial Health Care Foundation, The Children's Wish Foundation, The Newfoundland & Labrador Down Syndrome Society, Juvenile Diabetes Association, Arthritis Society of Newfoundland & Labrador, Alzheimer Society of Newfoundland & Labrador, Trinity Conception Health Foundation, Janeway Children's Hospital Foundation, Newfoundland & Labrador Region of the Canadian Red Cross, Mazol Shriners, Community Food Sharing Association, Coats for Kids, Leaning Disabilities of Newfoundland & Labrador, Heart and Stroke Foundation of Newfoundland & Labrador, Canadian Blood Services, Canadian Mental Health Association

## SAFETY

Newfoundland and Labrador Fire Chiefs and Firefighters Association, Firefighter Electricity Safety Training, Learn Not to Burn Program, Child Find Newfoundland & Labrador, School Electricity Safety Program, Safe Communities, Newfoundland & Labrador Safety Council, Crime Stoppers, Newfoundland & Labrador Snowmobile Association

## ENVIRONMENT

Atlantic Salmon Federation, Tree Canada, Newfoundland & Labrador Home Builders' Association, Hughes Brook Aquatic Centre, Thomas Howe Demonstration Forest, Trans Canada Trail Foundation, Marystown Community Pride, Rennies River Development Foundation

## EDUCATION & YOUTH

Junior Achievement of Newfoundland & Labrador, Memorial University of Newfoundland, College of the North Atlantic, Brother T.I. Murphy Resource Learning Centre, Newfoundland Science Fair Councils, Newfoundland Science Centre, Newfoundland & Labrador High School Athletic Federation, Scouts Canada, YMCA-YWCA, C.L.B., Newfoundland & Labrador School for the Deaf, R.E.A.L. Program, Special Olympics, Big Brothers and Big Sisters

## ARTS & CULTURE

Newfoundland Symphony Orchestra, Kiwanis Festivals, Newfoundland Symphony Youth Choir, Resource Centre for the Arts

Head Office

55 Kenmount Road, P.O. Box 8910
St. John's, NL A1B 3P6
Tel: (709) 737-2802
Fax: (709) 737-2903

Share Transfer Agent and Registrar

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1500 University Street, Suite 700
Montreal, QC H3A 3S8
Tel: (514) 982-7888
Fax: (514) 982-7635
www.computershare.com

Annual General Meeting

Thursday, April 24, 2008 at 8:00 a.m.
Main Boardroom, 3rd Floor
Newfoundland Power Inc.
55 Kenmount Road
St. John's, NL A1B 3P6

Investor Information

Peter Alteen, Corporate Secretary
55 Kenmount Road, P.O. Box 8910
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Website

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Email

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FortisAlberta Inc.
www.fortisalberta.com
FortisBC Inc.
www.fortisbc.com
Terasen Gas
www.terasengas.com
FortisOntario Inc.
www.fortisontario.com
Maritime Electric Company, Limited
www.maritimeelectric.com
Belize Electricity Limited
www.bel.com.bz
Caribbean Utilities Company, Ltd.
www.cuc-cayman.com
Fortis Properties Corporation
www.fortisproperties.com


Photography

Doug Greenslade, St. John's

Theresa Moulton, Burin

Ned Pratt, St. John's

Lee Ann Surette, St. John's

Design & Production

Corporate Communications

Newfoundland Power Inc.

Printing

Dicks and Company Limited, St. John's

**Newfoundland Power Inc.**

P.O. Box 8910
St. John’s, NL
A1B 3P6

www.newfoundlandpower.com

**IN THE MATTER OF**
the 2007 Annual Returns
of Newfoundland Power
Inc. filed pursuant to
Section 59(2) of the
*Public Utilities Act.*

## AFFIDAVIT

I, Jocelyn Perry, of the Town of Conception Bay South in the Province of Newfoundland and Labrador, Chartered Accountant, make oath and say as follows:

1. That I am Vice-President, Finance and Chief Financial Officer of Newfoundland Power Inc.

2. That to the best of my knowledge, information and belief, the information contained in the 2007 Annual Report and accompanying returns of Newfoundland Power Inc., filed with the Board of Commissioners of Public Utilities pursuant to section 59(2) of the *Public Utilities Act* is true and accurate.

**SWORN** to before me at St. John's
in the Province of Newfoundland and Labrador
this 28th day of March, 2008:

Barrister – Newfoundland & Labrador

Jocelyn Perry

# Newfoundland Power Inc.
## Names and Addresses of Officers and Directors
## as of December 31, 2007

| Name | Address | Position Held |
|---|---|---|
| **Peter Alteen** | 38 Mansfield Crescent<br>St. John's, NL A1E 5E3 | Vice President, Regulatory Affairs and General Counsel;<br>Corporate Secretary |
| **Peggy Bartlett** | 173 Grenfell Heights<br>Grand Falls-Windsor, NL A2A 2J7 | Director |
| **William Daley** | 575 Kensington Court<br>Fort Erie, ON L2A 6R8 | Director |
| **Phonse Delaney** | 26 Cheyne Drive<br>St. John’s, NL A1A 5J6 | Vice President, Engineering and Operations |
| **E.M. (Ed) Drover** | 44 Long Pond Road<br>St. John’s, NL A1B 1N7 | Director |
| **Peter Fenwick** | 1250 Oceanview Drive, P.O. Box 39<br>Cape St. George, NL A0N 1E0 | Director |
| **Chris Griffiths** | 82 Lawrence Pond Road East<br>Conception Bay South, NL A1X 4C6 | Director |
| **Georgina Hedges** | 5 Burden’s Road<br>Eastport, NL A0G 1Z0 | Director |
| **Lisa Hutchens** | 88 Marine Drive<br>Logy Bay-Middle Cove-Outer Cove, NL<br>A1K 3C7 | Vice President, Customer Relations and Corporate Services |

**Newfoundland Power Inc.**
**Names and Addresses of Officers and Directors**
**as of December 31, 2007**

| Name | Address | Position Held |
|---|---|---|
| **Earl Ludlow** | 33 Ortega Drive<br>Paradise, NL A1L 1C8 | President and Chief Executive Officer;<br>Director |
| **Stanley Marshall** | 140 Ortega Drive<br>Paradise, NL A1L 2K9 | Director |
| **David Norris** | 23 Mountbatten Drive<br>St. John's, NL A1A 3Y1 | Chair, Board of Directors |
| **Jocelyn Perry** | 6 Maple Street<br>Conception Bay South, NL A1W 5M8 | Vice President, Finance<br>and Chief Financial Officer |
| **John Walker** | 617 Almandine Court<br>Kelowna, BC V1W 4Z5 | Director |

**Newfoundland Power Inc.**
**Computation of Rate Base**
**For The Year Ended December 31, 2007**
**(000s)**

| | 2007 | 2006 |
|---|---|---|
| Plant Investment - from Return 4 | $ 1,239,186 | $ 1,186,614 |
| Deduct: | | |
| Accumulated Amortization - from Return 5 | 516,478 | 494,851 |
| Contributions in Aid of Construction - from Return 9 | 24,217 | 23,142 |
| Weather Normalization Reserve - from Return 14 | (10,516) | (11,808) |
| Purchased Power Unit Cost Variance Reserve - from Return 14A | 1,650 | 1,342 |
| | 531,829 | 507,527 |
| | 707,357 | 679,087 |
| Add: | | |
| Contributions - Country Homes | 1,346 | 1,001 |
| | $ 708,703 | $ 680,088 |
| Average | 694,396 | 669,943 |
| Deferred Energy Replacement Costs | 574 | - |
| Deferred Regulatory Costs | 8,690 | - |
| Cash Working Capital Allowance - from Return 7 | 6,669 | 5,522 |
| Materials and Supplies Allowance - from Return 7A | 4,393 | 4,510 |
| Average Deferred Charges - from Return 8 | 96,784 | 94,338 |
| Average Unrecognized 2005 Unbilled Revenue - from Return 11A [1] | (17,803) | (21,396) |
| Average Rate Base at Year End - to Return 10 | $ 793,703 | $ 752,917 |

[1] As per Order No. P.U. 40 (2005), Newfoundland Power has deducted the average value of the Unrecognized 2005 Unbilled Revenue from rate base commencing in 2006.

**Newfoundland Power Inc.**
**Plant Investment**
**For The Year Ended December 31, 2007**
**(000s)**

| | Balance January 1 2007 | Adjustments[1] During 2007 | Additions During 2007 | Retirements During 2007 | Balance December 31 2007 |
|---|---|---|---|---|---|
| Power Generation: | | | | | |
| Hydro | $ 117,332 | $ 542 | $ 19,347 | $ 1,281 | $ 135,940 |
| Diesel | 3,032 | (27) | - | - | 3,005 |
| Gas Turbine | 17,498 | 54 | 39 | 6 | 17,585 |
| | 137,862 | 569 | 19,386 | 1,287 | 156,530 |
| Substations | 122,832 | 51 | 5,088 | 420 | 127,551 |
| Transmission | 90,298 | 1 | 4,559 | 1,022 | 93,836 |
| Distribution | 683,465 | (57) | 31,813 | 8,353 | 706,868 |
| General Property | 47,835 | 48 | 1,857 | 511 | 49,229 |
| Transportation | 21,543 | - | 2,328 | 1,840 | 22,031 |
| Communications | 11,693 | (567) | 115 | 725 | 10,516 |
| Computer Software | 29,179 | (1) | 2,328 | 878 | 30,628 |
| Computer Hardware | 9,506 | (45) | 1,348 | 1,226 | 9,583 |
| Government Contributions | 23,108 | 1 | - | - | 23,109 |
| Total Depreciable Plant | 1,177,321 | - | 68,822 | 16,262 | 1,229,881 |
| Non Depreciable Land | 9,293 | - | 12 | - | 9,305 |
| | $ 1,186,614 | $ - | $ 68,834 | $ 16,262 | |
| Plant Investment - to Return 3 | | | | | 1,239,186 |
| Work in Progress | | | | | 555 |
| Total Plant Investment[2] | | | | | **$ 1,239,741** |

[1] Adjustments are due to asset reclasssification and redistribution of original cost based on final work order details.
[2] Property, Plant and Equipment per Balance Sheet is net of Contributed Assets as reported on Return 9.

**Newfoundland Power Inc.**
**Capital Expenditure**
**For The Year Ended December 31, 2007**
**(000s)**

| | Approved By Board Order [1] | Actual | Variance Over (Under) |
|---|---|---|---|
| Generation - Hydro | $ 19,188 | $ 17,984 | (1,204) |
| Generation - Thermal | - | 37 | 37 |
| Substations | 3,968 | 5,077 | 1,109 |
| Transmission | 4,283 | 4,440 | 157 |
| Distribution | 24,103 | 30,429 | 6,326 |
| General Property | 1,995 | 1,574 | (421) |
| Transportation | 2,206 | 2,231 | 25 |
| Telecommunications | 101 | 110 | 9 |
| Information Systems | 3,457 | 3,523 | 66 |
| Unforeseen | 750 | - | (750) |
| General Expenses Capital | 2,800 | 2,850 | 50 |
| | $ 62,851 | $ 68,255 | $ 5,404 |
| Carryovers From Prior Years | | $ 230 | |

[1] As per Order Nos. P.U. 30 (2006) and P.U. 34 (2006).

**Newfoundland Power Inc.**
**Accumulated Amortization**
**For The Year Ended December 31, 2007**
**(000s)**

| | | |
|---|---|---|
| (A) | Balance - January 1, 2007 | $ 494,851 |
| | Add: | |
| | Amortization - Appropriated from Income | 39,955 |
| | Amortization of Contributions - Government | 94 |
| | Amortization of Contributions - Customers | 1,533 |
| | Salvage | 467 |
| | | 42,049 |
| | Deduct: | |
| | Cost of Removal (Net of Income Tax) | 4,160 |
| | Retirements | 16,262 |
| | | 20,422 |
| (B) | Balance - December 31, 2007 - to Return 3 [1] | **$ 516,478** |
| (C) | Amortization Rates - 2007 | |
| | Hydro | 2.03% |
| | Diesel | 3.54% |
| | Gas Turbine | 3.98% |
| | Substations | 2.60% |
| | Transmission | 3.27% |
| | Distribution | 3.29% |
| | General Property | 2.99% |
| | Transportation | 9.44% |
| | Telecommunications | 7.16% |
| | Computer Software | 10.00% |
| | Computer Hardware | 20.00% |
| (D) | Percentage of Accumulated Amortization to Total Depreciable Plant | 41.99% |
| (E) | Percentage of Current Amortization, including Amortization of Contributions, to Total Depreciable Plant | 3.38% |

[1] Accumulated amortization per Balance Sheet is net of amortization of Contributed Assets as reported on Return 9.

**Newfoundland Power Inc.**
**Accumulated Future Income Taxes**
**For The Year Ended December 31, 2007**
**(000s)**

| | | | | |
|---|---|---|---|---|
| **From - Plant Investments** | | | | |
| Balance - January 1, 2007 | | | $ | - |
| Add: | | | | |
| - CCA claimed on all property, plant and equipment - from Return 18 | $ | 36,074 | | |
| Less: | | | | |
| - Amortization expense on all property, plant and equipment (GEC excluded from post-1986 additions) | | 36,365 | | |
| Difference | $ | (291) | | |
| Income Tax @ 36.12% | | | $ | (105) |
| Balance - December 31, 2007 - to Return 3 (If negative, enter zero) | | | $ | 0 |
| **From - Replacement Energy Cost Deferral [1]** | | | | |
| Balance - January 1, 2007 | | | $ | - |
| Add: | | | | |
| - Energy replacement cost for 2007 associated with the refurbishment of the Rattling Brook Hydroelectric plant (Order No. P.U. 39 (2006)) | $ | 1,795 | | |
| Income Tax @ 36.12% | | | $ | 648 |
| Balance - December 31, 2007 - from Return 18 | | | $ | 648 |

[1] This deferral was recorded in 2007 as an increase in regulatory assets of approximately $1.1 million ($1,795 - $648), an increase in future income tax expense of approximately $0.7 million, and a decrease in purchased power expense of approximately $1.8 million. This regulatory asset will be amortized equally over the period 2008 -2010 as an increase in purchased power expense of approximately $0.6 million and a decrease in future tax expense of approximately $0.2 million in each year.

**Newfoundland Power Inc.**
**Working Capital Allowance**
**For The Year Ended December 31, 2007**
**(000s)**

(A) Calculation of Cash Working Capital Allowance

| | | |
|---|---|---|
| Operating Expenses for the Year - from Return 12 | | $ 379,980 |
| Less: Non-Regulated Expenses (Net of Income Tax) | | 111 |
| | | 379,869 |
| Add: Current Income Tax Expense - from Return 18 | | 12,432 |
| | | $ 392,301 |
| 2007 Working Capital Allowance ( @ 1.7% ) - to Return 3 | | **$ 6,669** |
| 2006 Working Capital Allowance | $ 5,522 | |

(B) In general, the Company's billing and collection procedures are consistent with those in place during the preceding year.

**Newfoundland Power Inc.**
**Materials and Supplies Allowance**
**For The Year Ended December 31, 2007**
**(000s)**

| | | 2007 | | | 2006 | | |
|---|---|---|---|---|---|---|---|
| | | **Balance Sheet** | **Expansion** | **Rate Base** | **Balance Sheet** | **Expansion** | **Rate Base** |
| Materials and Supplies - | Jan. | $ 4,906 | $ 898 | $ 4,008 | $ 5,324 | $ 974 | $ 4,350 |
| | Feb. | 5,210 | 953 | 4,257 | 5,429 | 994 | 4,435 |
| | Mar. | 5,791 | 1,060 | 4,731 | 5,495 | 1,006 | 4,489 |
| | Apr. | 5,702 | 1,043 | 4,659 | 5,678 | 1,039 | 4,639 |
| | May | 5,661 | 1,036 | 4,625 | 6,140 | 1,124 | 5,016 |
| | Jun. | 5,322 | 974 | 4,348 | 6,160 | 1,127 | 5,033 |
| | Jul. | 5,291 | 968 | 4,323 | 5,794 | 1,060 | 4,734 |
| | Aug. | 5,352 | 979 | 4,373 | 5,447 | 997 | 4,450 |
| | Sep. | 5,300 | 970 | 4,330 | 5,500 | 1,007 | 4,493 |
| | Oct. | 5,310 | 972 | 4,338 | 5,249 | 961 | 4,288 |
| | Nov. | 5,428 | 993 | 4,435 | 5,103 | 934 | 4,169 |
| | Dec. | 5,248 | 960 | 4,288 | 4,923 | 901 | 4,022 |
| | | | | $ 52,715 | | | $ 54,118 |
| Materials and Supplies Allowance<br>Monthly Average - to Return 3 | | | | **$ 4,393** | | | **$ 4,510** |

**Newfoundland Power Inc.**
**Deferred Charges**
**For The Year Ended December 31, 2007**
**(000s)**

| | Balance January 1 2007 | Additions During 2007 | Reductions During 2007 | Balance December 31 2007 | Average Deferred Charges 2007 |
|---|---|---|---|---|---|
| Deferred Pension Costs [1] | $ 90,122 | $ 10,905 | $ 4,373 | $ 96,654 | |
| Debt Discount & Expenses | 3,035 | 273 | 197 | 3,111 | |
| Capital Stock Issue Expense | 199 | - | 62 | 137 | |
| Deferred Credit Facility Issue Costs | 117 | - | 58 | 59 | |
| Deferred Retirement Allowances | 133 | - | 133 | - | |
| Deferred Charges Included in Average Rate Base - to Return 3 | **$ 93,606** | **$ 11,178** | **$ 4,823** | **$ 99,961** | **$ 96,784** |

[1] Includes pension costs associated with the 2005 Early Retirement Program which have been reclassifed as a regulatory asset (see Note 5 to the annual financial statements) and are being amortized to Deferred Pension Costs over a ten year period.

**Newfoundland Power Inc.**
**Contributions In Aid Of Construction**
**For The Year Ended December 31, 2007**
**(000s)**

| | | Customers | Government | Total |
|---|---|---|---|---|
| (A) | Gross Contributions - January 1, 2007 | $ 44,607 | $ 23,108 | $ 67,715 |
| | Less: Amortization to December 31, 2006 | 22,278 | 22,295 | 44,573 |
| | Unamortized Contributions - January 1, 2007 | 22,329 | 813 | 23,142 |
| | Contributions Received During 2007 | 2,702 | - | 2,702 |
| | Less: Amortization - 2007 | 1,533 | 94 | 1,627 |
| | | 1,169 | (94) | 1,075 |
| (B) | Balance - December 31, 2007 - to Return 3 | **$ 23,498** | **$ 719** | **$ 24,217** |

**Newfoundland Power Inc.**
**Amortization of Contributions In Aid Of Construction - Customers**
**For The Year Ended December 31, 2007**
**(000s)**

| | Gross Contributions | Amortized During 2007 | Amortized To Date | Unamortized Contributions |
|---|---|---|---|---|
| Prior 1976 | $ 4,526 | $ - | $ 4,526 | $ - |
| 1976 | 430 | - | 430 | - |
| 1977 | 657 | - | 657 | - |
| 1978 | 431 | - | 431 | - |
| 1979 | 536 | - | 536 | - |
| 1980 | 655 | - | 655 | - |
| 1981 | 653 | 21 | 644 | 9 |
| 1982 | 693 | 23 | 655 | 38 |
| 1983 | 1,090 | 36 | 993 | 97 |
| 1984 | 849 | 28 | 732 | 117 |
| 1985 | 1,090 | 36 | 900 | 190 |
| 1986 | 1,010 | 33 | 795 | 215 |
| 1987 | 936 | 31 | 702 | 234 |
| 1988 | 1,493 | 49 | 1,054 | 439 |
| 1989 | 1,774 | 58 | 1,187 | 587 |
| 1990 | 1,411 | 46 | 893 | 518 |
| 1991 | 1,421 | 47 | 850 | 571 |
| 1992 | 1,720 | 57 | 968 | 752 |
| 1993 | 997 | 33 | 525 | 472 |
| 1994 | 1,314 | 43 | 644 | 670 |
| 1995 | 1,875 | 62 | 852 | 1,023 |
| 1996 | 1,422 | 47 | 595 | 827 |
| 1997 | 2,232 | 73 | 851 | 1,381 |
| 1998 | 1,153 | 38 | 399 | 754 |
| 1999 | 1,539 | 51 | 477 | 1,062 |
| 2000 | 1,929 | 63 | 506 | 1,423 |
| 2001 | 1,439 | 47 | 330 | 1,109 |
| 2002 | 1,135 | 37 | 223 | 912 |
| 2003 | 1,708 | 56 | 283 | 1,425 |
| 2004 | 1,380 | 159 | 159 | 1,221 |
| 2005 | 1,870 | 154 | 154 | 1,716 |
| 2006 | 3,239 | 160 | 160 | 3,079 |
| 2007 | 2,702 | 44 | 44 | 2,658 |
| | **$ 47,309** | **$ 1,533** | **$ 23,811** | **$ 23,498** |

**Newfoundland Power Inc.**
**Return on Rate Base**
**For The Year Ended December 31, 2007**
**(000s)**

| | | 2007 | 2006 |
|---|---|---|---|
| (A) | Net Earnings - from Return 1 | $ 30,452 | $ 30,666 |
| | Non Deductible Expenses - Net of Income Tax [1] | 111 | 1,149 |
| | | 30,563 | 31,815 |
| | Add: | | |
| | Interest on Long Term Debt | 33,718 | 32,759 |
| | Other Interest [2] | 1,525 | 1,309 |
| | Interest Earned | (1,477) | (1,210) |
| | Interest During Construction | (622) | (436) |
| | Amortization of Debt Discount & Expenses | 256 | 193 |
| | Amortization of Capital Stock Issue Expenses | 62 | 62 |
| | | 33,462 | 32,677 |
| (B) | Regulated Earnings - to Return 10A | $ 64,025 | $ 64,492 |
| (C) | Average Rate Base - from Return 3 | $ 793,703 | $ 752,917 |
| (D) | Rate of Return on Average Rate Base | **8.07%** | **8.57%** |
| (E) | Maximum Rate of Return on Average Rate Base [3] | 8.65% | 8.86% |
| (F) | Rate of Return on Average Rate Base Above Maximum | 0.00% | 0.00% |
| (G) | Excess Revenue - Net of Income Tax | $ - | $ - |

[1] Non-deductible expenses for 2007 were reduced by approximately $760,000 as a result of the transfer of a Part V1.1 tax deduction from Fortis Inc. to Newfoundland Power.

[2] Includes interest on short-term debt and interest on security deposits.

[3] As per Order No. P.U. 40 (2006) for 2007 and Order No. P.U. 3 (2006) for 2006.

**Newfoundland Power Inc.**
**Determination of Excess Revenue**
**For The Year Ended December 31, 2007**
**(000s)**

| | | 2007 | 2006 |
|---|---|---|---|
| (A) | Average Rate Base - from Return 3 | $ 793,703 | $ 752,917 |
| (B) | Upper Limit of the Allowed Range of Return on Average Rate Base [1] | 8.65% | 8.86% |
| (C) | Upper Limit of Allowed Regulated Earnings | $ 68,655 | $ 66,708 |
| (D) | Regulated Earnings - from Return 10 | 64,025 | 64,492 |
| (E) | Excess Revenue - Net of Income Tax | - | - |
| (F) | Income Tax | - | - |
| (G) | Excess Revenue | $ - | $ - |

[1] As per Order No. P.U. 40 (2006) for 2007 and Order No. P.U. 3 (2006) for 2006.

**Newfoundland Power Inc.**
**Analysis of Revenue - Normalized**
**For The Year Ended December 31, 2007**

| | | 2007 | | | 2006 | | |
|---|---|---|---|---|---|---|---|
| | | Gigawatt Hours | Year End Customer Accounts | Revenue (000s) | Gigawatt Hours | Year End Customer Accounts | Revenue (000s) |
| Residential | 1.1 | 3,044.4 | 201,045 | $ 284,113 | 2,981.1 | 198,568 | $ 244,121 |
| General Service: | | | | | | | |
| 0 - 10 kW | 2.1 | 90.9 | 11,826 | 12,043 | 94.0 | 11,915 | 11,269 |
| 10 - 100 kW | 2.2 | 629.2 | 8,509 | 62,237 | 616.4 | 8,261 | 53,343 |
| 110 - 1000 kVA | 2.3 | 864.5 | 1,035 | 70,946 | 854.0 | 1,031 | 60,261 |
| 1000 kVA and Over | 2.4 | 427.6 | 66 | 29,880 | 413.7 | 61 | 24,556 |
| Street & Area Lighting | 4.1 | 36.2 | 9,781 | 12,214 | 35.9 | 9,664 | 11,658 |
| Forfeited Discounts | | | | 2,621 | | | 2,481 |
| Revenue From Rates | | 5,092.8 | 232,262 | 474,054 | 4,995.1 | 229,500 | 407,689 |
| Transfer from RSA [1] | | | | 3,044 | | | - |
| 2005 Unbilled Revenue Accrual [2] | | | | 2,714 | | | 3,086 |
| Total Reported Revenue | | | | 479,812 | | | 410,775 |
| Wheeling | | | | 490 | | | 437 |
| Non-Electrical Revenue | | | | 9,930 | | | 10,052 |
| Total Other Revenue | | | | 10,420 | | | 10,489 |
| Total Revenue - to Return 1 | | **5,092.8** | **232,262** | **$ 490,232** | **4,995.1** | **229,500** | **$ 421,264** |

[1] As approved in Order No. P.U. 42 (2006).

[2] 2005 Unbilled Revenue recognized in 2006 and 2007 to account for income tax effects arising from the tax settlement as prescribed in Order No. P.U. 40 (2005) and Order No. P.U. 39 (2006).

**Newfoundland Power Inc.**
**Reconciliation of the Unrecognized 2005 Unbilled Revenue Account**
**For the Year Ended December 31, 2007**
**(000s)**

| | |
|---|---|
| Unrecognized 2005 Unbilled Revenue - December 31, 2006 | $ 19,160 |
| 2005 Unbilled Revenue Recognized in 2007 | (2,714) [1] |
| Unrecognized 2005 Unbilled Revenue - December 31, 2007 | $ 16,446 |
| Average Unrecognized 2005 Unbilled Revenue - to Return 3 | $ 17,803 |

[1] In Order No. P.U. 39 (2006), the Board approved Newfoundland Power's proposal to recognize $2,714,000 of the 2005 Unbilled Revenue in 2007 to account for income tax effects arising from the June 2005 tax settlement with the Canada Revenue Agency.

**Newfoundland Power Inc.**
**Statement of Expenses**
**For The Year Ended December 31, 2007**
**(000s)**

| | 2007 | 2006 |
|---|---|---|
| **Operating Expenses** | | |
| Purchased Power | $ 326,778 | $ 257,157 |
| Power Produced | 2,480 | 2,688 |
| Administrative and Engineering Support | 5,585 | 5,315 |
| Environmental Policy | 581 | 496 |
| Substations | 2,311 | 2,530 |
| Transmission | 587 | 486 |
| Distribution | 6,575 | 6,721 |
| Communications | 1,399 | 1,467 |
| Fleet Operating and Maintenance Expense | 1,497 | 1,491 |
| | 347,793 | 278,351 |
| **General Expenses** | | |
| Customer Service | 10,273 | 10,034 |
| Financial Services | 1,646 | 1,527 |
| Information Systems | 2,752 | 2,685 |
| Pension Costs | 5,567 | 6,719 |
| Retirement Allowances | 345 | 842 |
| Corporate and Employee Services | 13,570 | 13,033 |
| | 34,153 | 34,840 |
| Total Operating & General Expenses | 381,946 | 313,191 |
| Less: Transfers to General Expenses Capital | 1,966 | 2,038 |
| Total Expenses [1] | **$ 379,980** | **$ 311,153** |

[1] Return 1, Page 31, Statement of Earnings for the Year Ended December 31, 2007 - Total of Purchased Power, Operating Expenses, and Pension and Early Retirement Program Costs.

**Explanation of Significant Expense Variances**
**For The Year Ended December 31, 2007**
**( 2007 vs. 2006 )**
**(000s)**

| | 2007 | 2006 | Increase (Decrease) |
|---|---|---|---|
| **Total Expenses** | **$ 379,980** | **$ 311,153** | **$ 68,827** |

Total expenses for 2007 increased by $68.8 million, or 22.1 per cent, over 2006. This increase was due primarily to higher purchased power costs.

The following is an explanation of significant variances for individual operating and general expense classes.

| | | | |
|---|---|---|---|
| **Purchased Power** | **$ 326,778** | **$ 257,157** | **$ 69,621** |

The increase in purchased power costs reflects the flow-through of an additional $64.2 million of Hydro's purchased power costs to Newfoundland Power. A significant portion of the Hydro flow-through amount represents costs previously flowed-through the rate stabilization (balance sheet) account rather than purchased power cost increases. The remaining increase in purchased power costs primarily reflects electricity sales growth.

| | | | |
|---|---|---|---|
| **Power Produced** | **$ 2,480** | **$ 2,688** | **$ (208)** |

The decrease in power produced costs was mainly due to operations at two hydroelectric plants; Rattling Brook and Pierre's Brook. Rattling Brook had higher penstock maintenance expenses and water power rentals in 2006. As well, Pierre's Brook had higher operational costs in 2006 mainly because of repairs required at the main valve.

| | | | |
|---|---|---|---|
| **Administrative and Engineering Support** | **$ 5,585** | **$ 5,315** | **$ 270** |

The increase in Administrative and Engineering Support costs reflects increased technical and supervision costs associated with the day to day operation of the electrical system. Expenditures in this class are approximately 70% labour and are impacted principally by changes in labour rates and fluctuations in work on the electrical system.

In 2007, an improvement in system reliabilty (excluding the December 2nd sleet storm) contributed to reduced Administrative and Engineering Support costs. However, this cost reduction was offset by an increase in labour rates and the impact of the December 2nd sleet storm which caused severe damage to the electricity system in the eastern part of the island.

| | | | |
|---|---|---|---|
| **Environmental Policy** | **$ 581** | **$ 496** | **$ 85** |

The increase in 2007 reflects an increase in the number and volume of spills and associated clean-up costs.

**Explanation of Significant Expense Variances**
**For The Year Ended December 31, 2007**
**( 2007 vs. 2006 )**
**(000s)**

| | 2007 | 2006 | Increase (Decrease) |
|---|---|---|---|
| **Substations** | $ 2,311 | $ 2,530 | $ (219) |

Substation costs were lower in 2007 as a result of a new approach to planning and executing substation work. This new approach reduced operating labour by coordinating major operating maintenance and capital work on an individual substation basis in an effort to improve reliabilty and productivity. The aim of the new approach is to refurbish and modernize the Company's substations on a priority basis over the next 10 years.

| | 2007 | 2006 | Increase (Decrease) |
|---|---|---|---|
| **Transmission** | $ 587 | $ 486 | $ 101 |

The increase in transmission costs in 2007 was the result of a more extensive vegetation management program to brushcut and clear dangerous trees along transmission line rights-of-way to address system reliability and public safety issues.

| | 2007 | 2006 | Increase (Decrease) |
|---|---|---|---|
| **Distribution** | $ 6,575 | $ 6,721 | $ (146) |

Distribution costs were lower in 2007 for two reasons: (1) a shift in vegetation management work from distribution to transmission line right-of-way, and (2) higher than normal amounts of pre-issued materials from stores in 2006 for customer-driven work. The decrease in costs was offset by higher distribution line maintenance costs as a result of major storm damage repairs required in December 2007.

| | 2007 | 2006 | Increase (Decrease) |
|---|---|---|---|
| **Communications** | $ 1,399 | $ 1,467 | $ (68) |

Communications costs were lower in 2007 as a result of a reduced rate for long distance telephone calls. Newfoundland Power entered into a new long distance telephone service agreement with Bell Aliant in November 2006 which reduced per minute long distance charges by 50% for all wireline calls (inbound and outbound). The rate decreased from 7 cents to 3.5 cents per minute and resulted in approximately $100,000 in long distance costs in 2007 compared to $173,000 in the previous year.

| | 2007 | 2006 | Increase (Decrease) |
|---|---|---|---|
| **Customer Service** | $ 10,273 | $ 10,034 | $ 239 |

The increase in Customer Service costs in 2007 was a result of additional temporary labour required to replace meter readers on sick leave, and additional costs associated with energy efficiency information and programs which were incurred in an effort to assist customers in better managing their electricity costs.

**Explanation of Significant Expense Variances**
**For The Year Ended December 31, 2007**
**( 2007 vs. 2006 )**
**(000s)**

| | 2007 | 2006 | Increase (Decrease) |
|---|---|---|---|
| **Financial Services** | $ 1,646 | $ 1,527 | $ 119 |

The increase in Financial Services costs in 2007 was due to an increase in labour costs resulting from employee transfers and reassignments.

| | 2007 | 2006 | Increase (Decrease) |
|---|---|---|---|
| **Information Systems** | $ 2,752 | $ 2,685 | $ 67 |

In addition to general website edits, significant support was required in 2007 to improve customer website security as well as the customer login process. Also, some software maintenance costs incurred in 2007 were not incurred in the previous year due to the timing of payments provided for in certain software maintenance agreements.

| | 2007 | 2006 | Increase (Decrease) |
|---|---|---|---|
| **Pension Costs** | $ 5,567 | $ 6,719 | $ (1,152) |

The decrease in pension costs was primarily due to higher returns on pension plan assets. The increased returns on pension plan assets reflect higher levels of plan assets.

| | 2007 | 2006 | Increase (Decrease) |
|---|---|---|---|
| **Retirement Allowances** | $ 345 | $ 842 | $ (497) |

The decrease in retirement allowances was mainly a result of the conclusion in March 2007 of the amortization of retirement allowances associated with the Company's 2005 early retirement program.

| | 2007 | 2006 | Increase (Decrease) |
|---|---|---|---|
| **Corporate and Employee Services** | $ 13,570 | $ 13,033 | $ 537 |

Higher corporate and employee services costs in 2007 were a result of costs associated with the Company's 2008 general rate application as well as an increase in the annual PUB assessment. The increase in the annual assessment in 2007 was related to higher assessable revenue and to a large rebate granted to Newfoundland Power in 2006 for prior year surpluses accumulated by the PUB

| | 2007 | 2006 | Increase (Decrease) |
|---|---|---|---|
| **General Expenses Capital** | $ 1,966 | $ 2,038 | $ (72) |

The decrease in General Expenses Capital (GEC) reflects reductions in those expense groupings (mostly pension costs) from which indirect allocations to GEC are derived.

**Newfoundland Power Inc.**
**Production and Sales Statistics - Normalized**
**For The Year Ended December 31, 2007**

| | 2007 | 2006 |
|---|---|---|
| Gigawatt Hours - Purchased | 5,013.1 | 4,875.8 |
| Gigawatt Hours - Produced | 381.4 | 416.9 |
| Total Purchased & Produced | 5,394.5 | 5,292.7 |
| Gigawatt Hours - Sold & Used [1] | 5,104.6 | 5,006.8 |
| Gigawatt Hours - Losses | 289.9 | 285.9 |
| Losses Expressed as a Percentage of Total Purchased & Produced | 5.4% | 5.4% |
| Purchased Power Annual Billing Demand in kW | 1,074,714 | 1,044,005 |

[1] Energy sold and used is reported on an accrual basis.

**Newfoundland Power Inc.**
**Weather Normalization Reserve**
**For The Year Ended December 31, 2007**
**(000s)**

| | |
|---|---|
| **Degree Day Normalization Reserve** | |
| Revenue Adjustment | |
| Heating Degree Days | $ (100) |
| Cooling Degree Days | - |
| Wind Speed Adjustments | 1,921 |
| Total Revenue Adjustment | 1,821 |
| Less : Power Purchased Adjustment | |
| Heating Degree Days | (210) |
| Cooling Degree Days | - |
| Wind Speed Adjustments | 2,311 |
| Total Power Purchased Adjustment | 2,101 |
| Net Adjustment (Before Tax) | (280) |
| Less: Income Tax @ 36.12% | (101) |
| **Net Transfer (To) From Reserve** | **$ (179)** |
| **Hydro Production Equalization Reserve** | |
| Transfer (To) From Reserve (Before Tax) | $ (11) |
| Amortization of Non-Reversing Portion of Reserve [1] | (1,732) |
| Net Adjustment (Before Tax) | (1,743) |
| Less: Income Tax @ 36.12% | (630) |
| **Net Transfer (To) From Reserve** | **$ (1,113)** |
| **Net Transfer (To) From Weather Normalization Reserve** | **$ (1,292)** |

| | General Ledger Accounts | | |
|---|---|---|---|
| | **Hydro Production Equalization Reserve Dr (Cr)** | **Degree Day Normalization Reserve Dr (Cr)** | |
| Balance of Reserve - December 31, 2006 | $ 4,981 | $ 6,827 | $ 11,808 |
| Net Transfer | (1,113) | (179) | (1,292) |
| Balance of Reserve - December 31, 2007 - to Return 3 | **$ 3,868** | **$ 6,648** | **$ 10,516** |

[1] As per Order No. P.U. 19 (2003).

**Newfoundland Power Inc.**
**Purchased Power Unit Cost Variance Reserve**
**For The Year Ended December 31, 2007**
**(000s)**

| | | |
|---|---|---|
| **Purchased Power Unit Cost Variance Reserve Transfer** | | |
| Purchased Power Cost Adjustment | | |
| Purchased Power Unit Cost Variance | $ | (1,003) |
| Deadband | | 521 |
| Unit Cost Variance Outside Deadband | **$** | **(482)** |
| Less: Income Tax @ 36.12% | | (174) |
| **Net Transfer (To) From Purchased Power Unit Cost Variance Reserve** | **$** | **(308)** |
| **General Ledger Account** | | |
| **Purchased Power Unit Cost Variance Reserve** | | |
| Balance of Reserve - December 31, 2006 | $ | (1,342) [1] |
| Net Transfer | | (308) [2] |
| **Balance of Reserve - December 31, 2007 - to Return 3** | **$** | **(1,650)** |

[1] In Order No. P.U. 32 (2007), the Board approved the amortization of the 2006 balance over a three-year period beginning in 2008.

[2] Newfoundland Power filed an application with the Board on February 29, 2008 in compliance wih Order No. P.U. 44 (2004) pertaining to the disposition of the 2007 balance.

**Newfoundland Power Inc.**
**Rate Stabilization Account**
**For The Year Ended December 31, 2007**
**(000s)**

| Month | Opening Balance | Adjustments | Revenue Billed During Month | Municipal Taxes | Excess Fuel Costs | Secondary Energy Costs | Interest Costs | Transfer To (From) Nfld. Hydro | Closing Balance |
|---|---|---|---|---|---|---|---|---|---|
| January | $ 3,554.1 | $ - | $ (6,048.3) | $ - | $ 8.5 | $ (0.1) | $ 25.1 | $ 2,412.1 | $ (48.6) |
| February | (48.6) | - | (2,704.0) | - | 2.0 | (0.3) | (0.4) | 2,286.1 | (465.2) |
| March | (465.2) | - | (2,280.3) | - | 5.1 | - | (3.3) | 2,264.7 | (479.0) |
| April | (479.0) | - | (2,136.5) | - | 5.3 | - | (3.4) | 1,919.8 | (693.8) |
| May | (693.8) | - | (1,916.6) | - | 30.4 | - | (4.9) | 1,621.8 | (963.1) |
| June | (963.1) | - | (1,643.3) | - | 2.5 | - | (6.8) | 1,319.8 | (1,290.9) |
| July | (1,290.9) | - | (856.8) | - | 4.1 | - | (9.1) | 486.8 | (1,665.9) |
| August | (1,665.9) | - | (452.1) | - | 9.6 | - | (11.8) | 451.8 | (1,668.4) |
| September | (1,668.4) | - | (441.1) | - | 2.9 | (18.5) | (11.8) | 488.1 | (1,648.8) |
| October | (1,648.8) | - | (505.7) | - | 19.3 | (0.3) | (11.6) | 634.0 | (1,513.1) |
| November | (1,513.1) | - | (583.5) | - | 7.6 | (0.1) | (10.7) | 722.6 | (1,377.2) |
| December | (1,377.2) | 3,044.0 [1] | (772.3) | (194.1) [2] | 6.4 | (0.6) | (9.7) | 993.5 | 1,690.0 |
| | | **$ 3,044.0** | **$ (20,340.5)** | **$ (194.1)** | **$ 103.7** | **$ (19.9)** | **$ (58.4)** | **$ 15,601.1** | |

[1] Represents the difference in the increase in revenue and the increase in purchased power costs resulting from the change in the base rate charged by Newfoundland and Labrador Hydro effective January 1, 2007 as per Order No. P.U. 42 (2006).

[2] Represents the difference between total municipal tax revenues collected in 2007 through the Municipal Tax Adjustment component of rates and the total of all taxes paid to municipalities in 2007.

**Newfoundland Power Inc.**
**Cost of Embedded Debt**
**For The Year Ended December 31, 2007**
**(000s)**

| | December 31 2007 | December 31 2006 | Total |
|---|---|---|---|
| Bonds | $ 413,638 | $ 380,058 | $ 793,696 |
| Bank Loans and Credit Facilities | 33,000 | 35,151 | 68,151 |
| | $ 446,638 | $ 415,209 | $ 861,847 |
| Average Debt - to Return 17 | | | $ 430,924 |
| Interest Expense - 2007 * | | | $ 33,972 |
| Cost of Embedded Debt | | | **7.88%** |

| *** Interest Expense - 2007** | **2007 Actual** | **Test Year 2004** | **Variance** |
|---|---|---|---|
| Interest on Long Term Debt | $ 33,718 | $ 30,164 | $ 3,554 [1] |
| Bank & Other Interest | 1,525 | 2,393 | (868) [1] |
| Amortization of Debt Discount & Expenses | 256 | 199 | 57 |
| | 35,499 | 32,756 | 2,743 |
| Less: Interest on Customer Deposits | 50 | 30 | 20 |
| Interest Earned | 1,477 | 950 | 527 [2] |
| Interest Expense - 2007 - to Return 16A | **$ 33,972** | **$ 31,776** | **$ 2,196** |

[1] The increase in interest on long term debt and the decrease in bank and other interest reflects increased borrowings to finance the Company's ongoing capital program and the August 2007 replacement of lower cost short-term borrowings with 5.901 per cent, 30-year Series AL first mortgage sinking fund bonds.

[2] Increase represents interest on overdue customer accounts which is a function of higher accounts receivable balances in 2007 and higher interest rates as compared to the 2004 test year.

**Newfoundland Power Inc.**
**Explanation of Significant Interest Expense Variances**
**For The Year Ended December 31, 2007**
**(000s)**

| | 2007 Actual | Test Year 2004 | Variance |
|---|---|---|---|
| Average Bonds | $ 396,848 | $ 330,383 | $ 66,465 [1] |
| Average Bank Loans and Credit Facilities | 34,076 | 48,222 | (14,146) [1] |
| Average Debt | $ 430,924 | $ 378,605 | $ 52,319 |
| Interest Expense - 2007 - from Return 16 | $ 33,972 | $ 31,776 | $ 2,196 |
| Cost of Embedded Debt | **7.88%** | **8.39%** | **(0.51%)** |

[1] The increase in total average debt is due to increased capital required to finance additional investment in property plant and equipment and to maintain a debt capitalization ratio close to 55% (see Return 17). The increase in average bonds and the decrease in average bank loans and credit facilities is due to the August 2007 replacement of short-term borrowings with Series AL first mortgage sinking fund bonds. The bonds were issued with a 30-year term at an interest rate of 5.901%.

**Newfoundland Power Inc.**
**Capital Structure**
**For The Year Ended December 31, 2007**
**(000s)**

| | Average | | Year-End | |
|---|---|---|---|---|
| | **Amount** | **Percent** | **Amount** | **Percent** |
| Debt - from Return 16 | $ 430,924 | 54.79% | $ 446,638 | 54.96% |
| Preference Shares - from Return 1 | 9,353 | 1.19% | 9,352 | 1.15% |
| Common Equity - from Return 19 | 346,279 | 44.02% | 356,671 | 43.89% |
| | **$ 786,556** | **100.00%** | **$ 812,661** | **100.00%** |

**Newfoundland Power Inc.**
**Regulated Average Capital**
**For The Year Ended December 31, 2007**
**(000s)**

| | Average | |
|---|---|---|
| | **Amount** | **Percent** |
| Debt - from Return 16 | $ 430,924 | 54.79% |
| Preference Shares - from Return 1 | 9,353 | 1.19% |
| Common Equity - from Return 19 | 346,279 | 44.02% |
| | **$ 786,556** | **100.00%** |

**Newfoundland Power Inc.**
**Calculation of Taxable Income and Income Tax Expense**
**For The Year Ended December 31, 2007**
**(000s)**

| | | | |
|---|---|---|---|
| Net Earnings - from Return 1 | | | $ 30,452 |
| Add: | Provision for current income tax | $ 12,418 | |
| | Provision for prior years taxes | 14 | |
| | Provision for future income taxes | 648 | |
| | Provision for Purchased Power Unit Cost Variance Reserve (PPUCVR) | (173) | |
| | Adjustment for weather normalization | (731) | 12,176 |
| Net Income Before Income Taxes | | | 42,628 |
| Add: | Amortization of capital assets net of deferred expense | 34,162 | |
| | Amortization of debt discount & expenses | 197 | |
| | Amortization of capital stock issue expenses | 62 | |
| | Amortization of credit facility costs | 59 | |
| | Business meals & related expenses | 169 | |
| | Special pension liability | 263 | |
| | Retirement allowances deducted in 2005 and expensed in 2006 | 135 | |
| | Tax settlement with CRA on 2005 Unbilled Revenue net of revenue inclusion | 4,799 | |
| | Stock option expense not deductible | 324 | |
| | Small tools in excess of $500 | 165 | |
| | Transfer to the PPUCVR | 483 | |
| | Transfer from weather normalization reserve | 2,024 | |
| | Other non deductible costs | 20 | 42,862 |
| | | | 85,490 |
| Less: | Capital cost allowance - to Return 6 | 36,074 | |
| | Cumulative eligible capital | 12 | |
| | General expenses capitalized | 2,850 | |
| | Interest charged to construction | 622 | |
| | Bond issue expenses | 107 | |
| | Deferred GRA costs | 1,250 | |
| | Replacement energy cost re Rattling Brook | 1,795 | |
| | Part VI.1 tax deduction | 27,277 | |
| | Capital gains on sale of land included in income | 147 | |
| | Difference in pension funding and accounting cost | 6,148 | 76,282 |
| Taxable Income | | | $ 9,208 |
| | Income Tax - Part 1 | | 3,326 |
| | Income Tax - Part VI.1 | | 9,092 |
| | Provision for prior years taxes | | 14 |
| Current Income Tax Expense - to Return 7 | | | 12,432 |
| | Provision for PPUCVR | | (173) |
| | Provision for weather normalization | | (731) |
| | Future income tax - to Return 6 | | 648 |
| Future Income Tax Provision | | | (256) |
| Total Tax Expense - to Return 1 | | | $ 12,176 |

**Newfoundland Power Inc.**
**Return on Average Common Equity**
**For The Year Ended December 31, 2007**
**(000s)**

| | 2007 | 2006 |
|---|---|---|
| Common Equity: | | |
| December 31, 2007, As Per Balance Sheet | $ 356,671 | |
| December 31, 2006, As Per Balance Sheet | 335,887 | |
| Common Equity, December 31, 2006 | | $ 335,887 |
| Common Equity, December 31, 2005 | | 323,972 |
| | $ 692,558 | $ 659,859 |
| **Average Common Equity** | **$ 346,279** | **$ 329,930** |
| Earnings Applicable to Common Shares - from Return 1 | $ 29,866 | $ 30,078 |
| Add: Non-Regulated Expenses - Net of Income Tax | 111 | 1,149 |
| | 29,977 | 31,227 |
| **Regulated Return on Average Common Equity** | **8.66%** | **9.46%** |

**Newfoundland Power Inc.**
**Assessable Revenue**
**(s. 13 of the *Public Utilities Act*)**
**For The Year Ended December 31, 2007**
**(000s)**

| | | | |
|---|---|---|---|
| Electrical Revenue: | | | |
| Revenue From Rates | (from Return 11) | $ 479,812 | |
| Weather Normalization Adjustment [1] | (from Return 14) | (1,821) | |
| | | 477,991 | |
| Municipal Taxes Billed | | 11,762 | |
| Revenue Billed - Rate Stabilization Account | (from Return 15) | 20,341 | |
| Total Electrical Revenue Billed | | | $ 510,094 |
| Other Revenue | (from Return 11) | | 10,420 |
| Assessable Revenue | | | $ 520,514 |

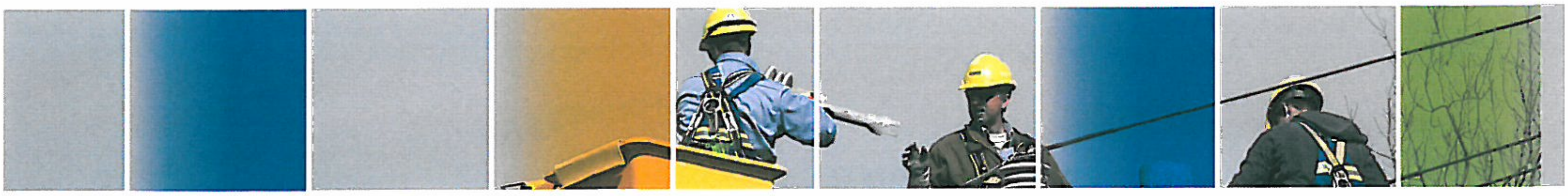
[1] Calculation of the Weather Normalization revenue adjustment (from Return 14) is as follows:

| | |
|---|---|
| Heating Degree Days | $ (100) |
| Cooling Degree Days | - |
| Wind Speed Adjustments | 1,921 |
| | $ 1,821 |

# Connected.

# 2008 Annual Report

NEWFOUNDLAND POWER
A FORTIS COMPANY



# Corporate Profile

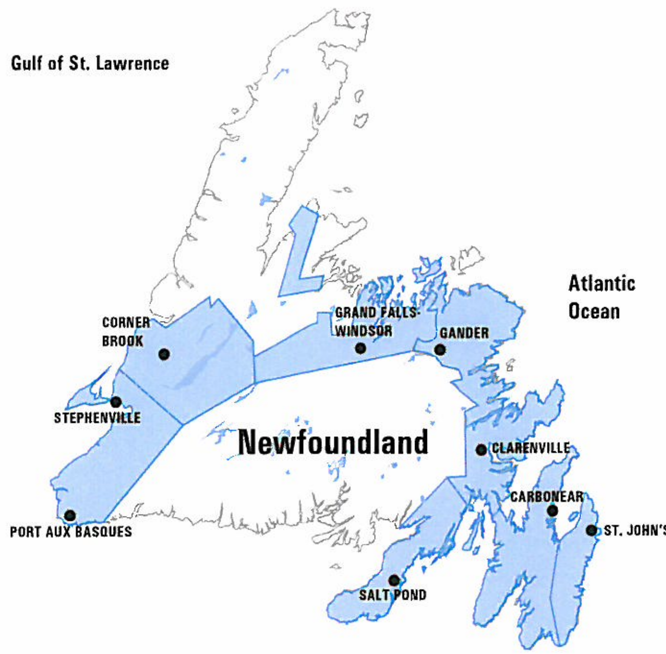
Newfoundland Power Inc. ("Newfoundland Power") operates an integrated generation, transmission and distribution system throughout the island portion of Newfoundland and Labrador.

For over 120 years, we have provided customers with safe, reliable electricity in the most cost-efficient manner possible. Our Company serves approximately 236,000 customers, about 85% of all electricity consumers in the province.

Working together with our employees, we continue to provide our customers with the service they expect and deserve in an environmentally and socially responsible manner.

Our vision is to be a leader among North American electric utilities in terms of safety, reliability, customer service and efficiency.

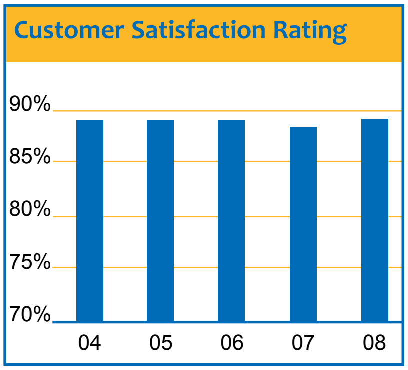
All the common shares of Newfoundland Power are owned by Fortis Inc. (TSX:FTS), the largest investor-owned distribution utility in Canada, which serves more than 2,000,000 gas and electric customers, and has assets exceeding $10.5 billion.

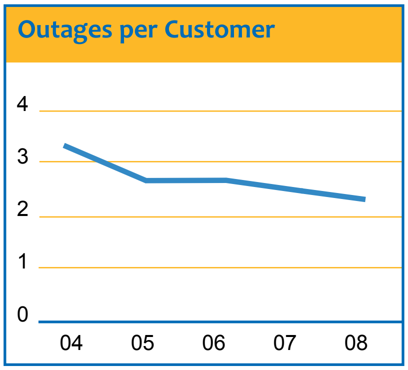


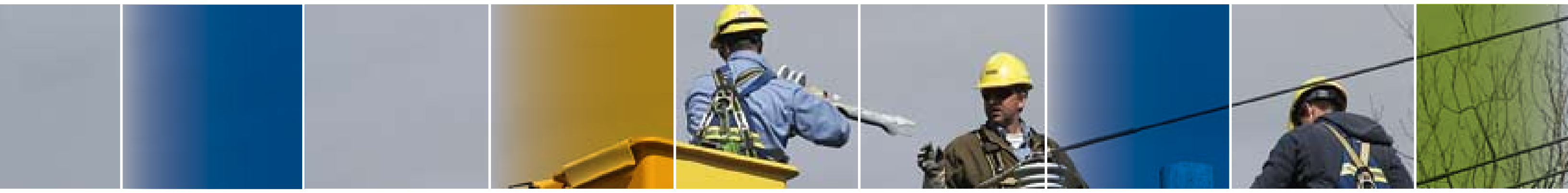

## Table of Contents

# Highlights

| Financial | 2008 | 2007 |
|---|---|---|
| Revenue *($000s)* | 516,889 | 491,709 |
| Property, Plant and Equipment *($000s)* | 1,219,066 | 1,173,642 |
| Long-term Debt *($000s)* | 441,088 | 446,638 |
| Common Shareholders' Equity *($000s)* | 373,738 | 356,671 |
| Earnings Applicable to Common Shares *($000s)* | 32,341 | 29,866 |
| Earnings per Common Share *($)* | 3.13 | 2.89 |
| **Operating** | | |
| Customers *(#)* | 235,778 | 232,262 |
| Customer Satisfaction Rating *(%)* | 89 | 88 |
| Generating Capacity *(MW)* | | |
| Hydroelectric | 96.6 | 95.9 |
| Diesel | 7.0 | 7.0 |
| Gas Turbine | 36.5 | 36.5 |
| Total | 140.1 | 139.4 |
| Peak Demand *(MW)* | 1,181 | 1,142 |
| Electricity Sales *(GWh)* | 5,208 | 5,093 |





# Report to Shareholders

Our daily operations focus on maintaining strong customer relationships. From electrical safety to the investments we make in our electricity system, our customers are impacted by every facet of what we do. In 2008, we achieved a strong customer satisfaction rating of 89%. This is a direct result of setting objectives to strengthen our **connections** with customers, communities and employees. Throughout the year, we invested in our electricity system; improved our operating performance in the areas of reliability and cost control; and, developed new community and environmental partnerships.

Earnings of $32.3 million in 2008 were $2.4 million higher than our earnings of $29.9 million in 2007. This was largely the result of a higher allowed rate-setting return on equity in 2008 and continued investment in our electricity system. Electricity sales increased by 2.3% to 5,208 gigawatt hours ("GWh") in 2008. And, our number of customers increased 1.5% to approximatley 236,000.

Our ability to hold the line on operating costs is a result of continually improving our business and managing our costs. In fact, we have maintained the same level of operating costs for the past five years.

Throughout 2008, we invested approximately $63 million to upgrade our electricity system and provide service to new customers. We invested $3.4 million to strengthen transmission lines on the Bonavista and southern Avalon Peninsulas; and, $1.5 million working with Newfoundland and Labrador Hydro ("Hydro") and two independent developers, to connect 54 megawatts ("MW") of renewable wind energy to the island's electricity system.

Our dedication to improving the electricity system, coupled with our commitment to provide quality service to our customers, enabled us to reduce the number of outages by 13% compared to 2007, and deliver electricity to our customers 99.97% of the time.

Over the next five years, we anticipate an increase in the number of retirements due to an aging workforce. As a result, we have undertaken initiatives to maximize knowledge and skill transfer between employees. Currently 13% of our line staff are training as apprentice linepersons, and 14% of our engineers are working toward their professional engineering designation.

**In 2008, we invested $63 million to upgrade our electricity system and provide service to new customers.**

In October, we were extremely saddened when a rare electrical incident claimed the life of a friend and colleague. This has made us even more resolved in our goal to eliminate workplace and public safety incidents.

2008 marked our first full year under the Occupational Health and Safety Assessment Series 18001 Health and Safety Management System ("OHSAS 18001"). Successful compliance with these internationally recognized standards demonstrates our commitment to continual improvement and ensuring the safety of our employees, contractors and the public.

We connected with Newfoundlanders and Labradorians in 2008 by helping them to save money, minimize our impact on the environment and reduce demand on our province's electricity system. We became a member of the provincial Energy Conservation and Efficiency Partnership ("ECEP"), under the provincial Energy Plan, and formed an energy efficiency partnership with Hydro. Together, we completed a Five-year Energy Conservation Plan, aimed at saving an estimated 70 GWh of energy annually by 2013, and launched a new joint energy efficiency brand called takeCHARGE - Saving Energy Starts Here!

Our connections with communities throughout the island are fostered through a shared commitment to our environment. Since 1997, we have initiated more than 300 partnerships with schools and environmental groups as part of our Environmental

Commitment Program. In 2008, we successfully completed initiatives to improve our corporate environmental performance, and educated communities about being green at our 11th annual *EnviroFest* celebrations, held island-wide.

Our years of dedication to maintaining a strong presence in our communities has led to enhanced connections with our customers, government partners and employees. In 2008, we connected with partners, such as Municipalities Newfoundland and Labrador, and the Newfoundland and Labrador Association of Fire Services, and forged new relationships with community-minded organizations like The HUB and the Newfoundland and Labrador Region of the Canadian Red Cross.

Our employees' reputation for giving of themselves to benefit others and better their communities has shaped who we are as a Company. In 2008, Canadian Blood Services honoured our employees' commitment to giving the gift of life with a national Honouring our Lifeblood Award. Since joining the *Partners for Life* program in 2004, we have made over 1,400 donations, helping to save up to 4,200 lives.

Our strong connections with our customers, enabled us to donate approximately $137,000 to our corporate charity, *The Power of Life Project*. Through supporting the Dr. H. Bliss Murphy Cancer Care Foundation and local cancer patients and their families, we are helping to make a difference in the lives of people fighting cancer in our province.

We thank our employees for offering their talents, hard work and commitment throughout the year. Our ability to maintain a sound electricity system, strengthen our operating performance, and connect with our communities is a direct result of their continued dedication to our customers and our Company.

**Paramount to our core beliefs and values is the safety of our employees, contractors and the public.**

**Earl Ludlow, President and Chief Executive Officer, and David Norris, Chair, Board of Directors**

In 2008, we welcomed the return of our long time colleague, Mr. Gary Smith, to his new position of Vice President, Engineering and Operations, and wished Mr. Phonse Delaney good luck as Vice President, Operations and Engineering, with FortisAlberta Inc.

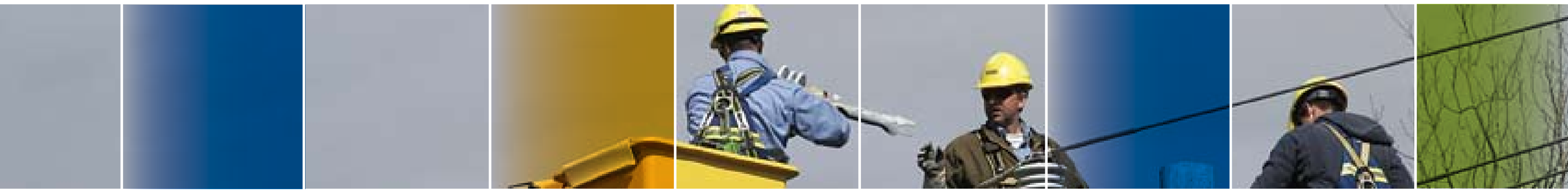
Mr. Peter Fenwick and Mr. Bill Daley retired from our Board of Directors after 6 years and 3 years of service, respectively, and we thank them for their invaluable contributions. It was also our pleasure to welcome three new Board members in 2008: Mr. Frank Davis, Corporate Director; Mr. Fred O'Brien, President and Chief Executive Officer, Maritime Electric Company, Limited; and, Mr. Bruce Simmons, President and Chief Executive Officer, Hammond Farm Ltd.

We are honoured to be able to contribute to the growth and prosperity of our great province through building strong connections with our customers, employees and communities.

Sincerely,

David Norris
Chair, Board of Directors

Earl Ludlow
President and Chief Executive Officer



# Report on Operations

## Safety

Our business involves delivering a commodity that can be very dangerous. For many of our employees, even routine activities performed on a daily basis can be extremely hazardous. Above all else, safety is our priority.

In 2008, tragedy struck when we lost a talented, young employee from our Clarenville office. On October 22, a line crew was dispatched to repair a string of insulators on a transmission line on the Bonavista Peninsula. Shortly after arriving at the site, a rare incident caused by a failure of the insulators claimed the life of our friend and colleague. This tragedy hit close to home for everyone in the Company, and sent waves of sadness throughout the island and the entire industry. This unforeseen tragedy has brought us closer and made us even more resolved in our goal to eliminate workplace and public safety incidents.

2008 was our first full year under the internationally recognized OHSAS 18001. This system improved our ability to capture and track information related to safe work practices and hazard recognition, and enhanced the way we manage safety.

Two successful external audits of our safety management system verified our compliance with legislative requirements and OHSAS 18001. The Workplace Health, Safety and Compensation Commission also conducted audits that provided further external validation of the effectiveness of our employee safety programs and performance.

In the third quarter, we enhanced a number of our critical worker protection systems by delivering comprehensive programs dealing with high voltage safety, including: hazard assessment through risk management/job planning; high voltage electricity system switching; and, safe work around de-energized equipment.

About half of our safety incidents in 2008 involved meter reading. In the fall, we began a complete review of meter reading practices, training and equipment in order to improve safety performance in this area.

To enhance the safety of our employees working around low voltage equipment, we implemented improved standards surrounding the installation and removal of

**2008 was our first full year under the internationally recognized OHSAS 18001.**

electrical meters, expanded our flame resistant clothing program, and enhanced our safety procedures and guidelines.

In 2008, we put our Hearing Conservation Program into action. This involved training our employees to identify the hazards associated with high noise exposures and the controls required when working in such environments.

Contractor safety education, awareness and training was also a key focus in 2008. The launch of our new contractor website provides easy online access to our safety training requirements, practices and policies. We also opened more direct lines of communication with our contractors, assigned clearer responsibilities for managing contractor relationships and put feedback mechanisms in place.

Throughout the year, we continued our safety education and training partnership with the Newfoundland and Labrador Association of Fire Services. We donated our third vehicle to the *Learn Not to Burn* program, which delivers messaging about the dangers of fire and electrical safety hazards to elementary school students across the province. And, with the help of our retirees, we delivered children's electrical safety demonstrations through our Hazard Hamlet program to over 2,600 students in 53 schools throughout the province.

**In 2008, we delivered electricity to our customers 99.97% of the time.**

In 2008, we conducted electrical safety training for approximately 190 firefighters throughout the island, and, at the request of the Royal Newfoundland Regiment, trained several of their members in preparation for their power restoration efforts in Afghanistan.

We are committed to arming our employees, contractors and the public with the knowledge they need to make safety conscious decisions when it comes to electricity. We put safety first every day.

## Reliability

Our ability to provide safe, reliable electricity to our customers at least cost is largely dependent upon the quality and condition of our electricity system. Our approach to reliability management consists of three aspects: capital investment; maintenance; and, operational deployment. In 2008, we reduced the number of customer outages by 13% compared to 2007, and delivered electricity to our customers 99.97% of the time.

Our 2008 capital investment of approximately $63 million focused on continuing to upgrade and strengthen our electricity system, and provide service to new customers. We upgraded transmission lines on the Bonavista Peninsula and southern shore of the

Avalon Peninsula, at a total cost of $3.4 million, and refurbished several of our substations across the island at a total cost of $2.4 million.

We implemented several initiatives in 2008 to improve operations and reduce operating costs, such as: helping to prevent outages by optimizing the performance of 43 distribution feeders in high growth areas; and, improving distribution system inspections through the use of handheld computers to streamline workflow for maintenance planners.

**In 2008, we achieved a strong customer satisfaction rating of 89%.**

In 2009, we plan to continue to invest in the electricity system with a capital budget of approximately $62 million. This investment will allow us to continue to offer reliable service and meet the growing needs of our customers.

The investments we make in our electricity system today help us to keep our customers connected tomorrow.

## Customer Service

In 2008, we achieved a strong 89% customer satisfaction rating. This is particularly significant given the pressures placed on our customers as a result of rising energy prices.

Because we know that a timely response to customer inquiries leads to increased customer satisfaction, we implemented new initiatives to help us serve our customers more efficiently. We made changes to bring our customer communications technology in line with best practices followed by top-rated utility Contact Centres in North America, and successfully answered customer inquiries on the first call 88% of the time.


**Our daily operations focus on maintaining strong customer connections.**

Technology continues to play an increasing role in customer service delivery. More of our customers are choosing to do business with us electronically. We had approximately 470,000 visits to our corporate website in 2008, up 20% over 2007.

We focused on improving many of our online offerings, such as: simplifying access to customer accounts; increasing the availability of customer information to 24 months; and, providing our customers with the ability to view multiple accounts with a single login.

The improvements we made to our electronic billing system, or *eBills*, allowed for a more timely and efficient response to customer requests. Ongoing promotion of *eBills* resulted in a 24% increase in 2008 participation levels compared to 2007. We have a high customer participation rate in electronic billing compared to other North American utilities.

Throughout 2008, we continued to install meters that can be read remotely where meter accessibility has been a recurring issue. These meters eliminate energy usage estimates for our customers and improve safety for our meter readers. We now have more than 12,000 of these meters in use across our service territory.

We take great pride in connecting with our customers through providing service excellence.

## Energy Efficiency

While volatile energy prices and a growing awareness of the environment are causing energy efficiency to rise to the top of a larger number of priority lists, we have been promoting the benefits of using energy wisely to our customers for many years.

In 2008, we strengthened our commitment to helping our customers save energy, save money and protect our environment. We became an active partner in the provincial ECEP to coordinate and assist with provincial energy conservation and efficiency initiatives. We further demonstrated our commitment to energy efficiency by partnering with Hydro to achieve a common goal - to use our collective resources and experience to provide our customers with the information, tools and programs they need to be energy efficient.

takeCHARGE!
Saving Energy Starts Here

Together we completed a Five-year Energy Conservation Plan aimed at saving an estimated 70 GWh of energy annually by 2013. This plan is scheduled to begin in 2009.

In the fourth quarter, we launched the customer side of our energy efficiency partnership with a new brand, called takeCHARGE - Saving Energy Starts Here! together with an interative customer-focused website, takechargenl.ca. Over 5,200 customers visited our new takeCHARGE website in the less than two months since its launch.

We are committed to leading the charge on energy efficiency.

**We have initiated more than 300 environmental partnerships with local community groups and schools across the island.**

## Environment

We take our commitment to minimizing our impact on the environment very seriously. In 2008, we successfully completed a number of initiatives to reduce environmental risks and improve our environmental performance.

We completed equipment upgrades at three of our hydroelectric generating plants to improve management of our water resources; and, continued with our multi-year PCB Phase-out Program for the removal and disposal of PCB oil-filled electrical equipment. Approximately 75% of our feeders and 85% of our substations have been completed under this program.

In 2008, an external third party conducted an environmental compliance audit of our operations which confirmed that we continue to meet all environmental legislative requirements. An additional third party audit of our Environmental Management System ensured we continue to comply with the ISO 14001 international standard. This audit also concluded that our facilities are well maintained and our employees continue to demonstrate a commitment to ensuring we operate in an environmentally responsible manner.

We have initiated more than 300 environmental partnerships with local community groups and schools across the island as part of our Environmental Commitment Program.

In 2008, we celebrated our 11th annual employee-driven celebration of the environment. *EnviroFest* brings local, environmentally-friendly community partners together to educate Newfoundlanders and Labradorians about the importance of our environment and topics such as climate change, energy efficiency and environmental stewardship.

We remain strong in our pursuit to protect and improve our environment as we contribute to a greener future.

## Employees

Our employees are among the best in the business, and they take great pride in providing our customers with the dependable service they rely on every day. In 2008, we continued to support our employees through ongoing leadership, safety and environmental training, and personal and career development initiatives.

**Our employees have been instrumental in helping to build and maintain our strong reputation for customer service excellence.**

Our employees have been instrumental in helping to build and maintain our strong reputation for customer service excellence. Ensuring that we recognize our employees for their contributions is critical to our success. Feedback from an employee survey evaluating our employee recognition program revealed that it needed to change. We listened, and as a result, improved how we recognize service milestones.

As the pressures of an aging workforce continue, our focus on recruitment, retention and transfer of skills remains high on our list of priorities. In 2008, we completed many workforce management initiatives, such as participating in a variety of career fairs at post-secondary institutions and high schools, and continued our support of cooperative education and trade apprenticeship programs.

**Our employees helped restore power to the Turks and Caicos Islands.**

In September, our sister company, Fortis Turks and Caicos, was impacted when the Turks and Caicos Islands were struck by two Hurricanes, Hanna and Ike, within one week. The hurricanes caused extensive damage and power outages. We coordinated the Fortis response, which was comprised of 61 employees including linepersons, supervisors, technical support staff, along with line vehicles and equipment. The restoration involved two teams, each deployed for three weeks. Working together with Belize Electricity, Caribbean Utilities, FortisAlberta, FortisBC, FortisOntario and Maritime Electric we successfully assisted Fortis Turks and Caicos in restoring power to all customers on the islands.

We value the many contributions our employees have made in helping us build a strong foundation for continued success.

## Community

As a community-minded company, we are dedicated to supporting our local economy. We connected with our customers in 2008 by continuing our long-time relationships and forging new bonds with additional community partners.

Our commitment to giving the gift of life was honoured with a national award at the 9th annual Canadian Blood Services Honouring our Lifeblood event. We were recognized for the dedication of our employees to Canada's blood system and our commitment as a corporate *Partner for Life*. Since joining the *Partners for Life* program in 2004, our employees and their families have made over 1,400 donations, helping to save up to 4,200 lives. In 2008, we once again exceeded our corporate pledge of 300 donations, remaining one of the highest of any corporate partner in Atlantic Canada.

**Since joining the *Partners for Life* program, our employees have made over 1,400 donations, helping to save up to 4,200 lives.**

Our employees and customers continued to support cancer care in our province throughout 2008 by donating approximately $137,000 to our corporate charity, *The Power of Life Project*. Together with customer and employee donations, and the funds raised at employee-driven events, we have helped to secure the purchase of a new four dimensional CT Simulator for the Dr. H. Bliss Murphy Cancer Care Foundation to enhance the accuracy of radiation treatment planning.

Our Electrical Maintenance Team did their part to brighten the lives of cancer patients and their families by bringing light back to the Dr. H. Bliss Murphy Cancer Care Foundation's Garden of Hope, located just outside the cancer clinic in St. John's. Our Electrical Maintenance Team donated their time and skills to restore the garden to a place of tranquility for patients battling cancer, after the lights and wiring system were completely destroyed by vandals.

In 2008, we formed a new partnership with the Canadian Red Cross and the provincial government's Fire and Emergency Services to launch *Ready.Kit.GO!* This partnership is aimed at educating the people of Newfoundland and Labrador about the importance of being prepared, and how to respond appropriately during an emergency situation.

We demonstrated our commitment to sports in our province as a major sponsor of the 2008 Newfoundland and Labrador Summer Games. Always an active

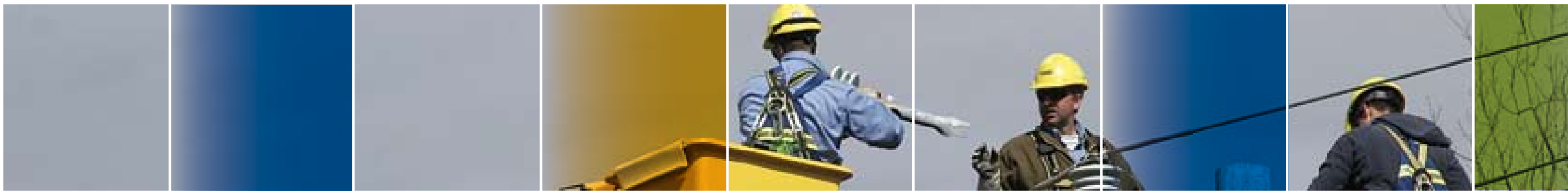
**Our Electrical Maintenance Team volunteered their time to restore light to the Garden of Hope.**

supporter, we ensured the games ran smoothly by providing all athletes, coaches and volunteers with identification pouches, and reliable transportation throughout the games.

We maximized a unique opportunity when we assisted The HUB in continuing to provide gainful employment to persons with disabilities. By donating two printing presses that were no longer required by the Company, we helped The HUB remain strong in its printing operations, one of the organization's main sources of revenue.

In 2008, we partnered with Municipalities Newfoundland and Labrador, and demonstrated our support at their annual conference. As sponsor of the opening ceremonies and host of a workshop on managing energy more efficiently we connected with municipalities by educating them on how to save energy and money.

Our employees pride themselves in maintaining strong connections to the places they call home.



# Management Discussion and Analysis

*This Management Discussion and Analysis dated February 5, 2009, should be read in conjunction with Newfoundland Power Inc.'s (the "Company" or "Newfoundland Power") annual financial statements and notes thereto for the year ended December 31, 2008. Financial information herein reflects Canadian dollars and Canadian generally accepted accounting principles ("Canadian GAAP"), including certain accounting practices unique to rate-regulated entities. These accounting practices, which are disclosed in Notes 2 and 4 to the Company's 2008 annual financial statements, result in the recognition of revenues, expenses, regulatory assets and regulatory liabilities which would not occur in the absence of rate regulation and which affect the Company's reported earnings, cash flows and financial position.*

*Certain information herein is forward-looking and reflects management's current expectations regarding the Company's future financial and related performance. The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to indentify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects management's current beliefs and is based on information currently available to the Company's management. Certain material factors, estimates and assumptions, which are subject to inherent risks and uncertainties surrounding future expectations generally, have been applied in drawing the conclusions contained in the forward-looking statements. These are related to, but are not limited to: regulation; energy supply; competition; general economic conditions; health, safety and the environment; interest rates; insurance; weather; labour relations; licences and permits; capital resources; and, liquidity. Readers are cautioned to not place undue reliance on forward-looking statements because actual results could differ materially from the results discussed or implied in those statements. The Company disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.*

*Additional information, including the Company's quarterly and annual financial statements, annual information form and management information circular, is available on SEDAR at www.sedar.com.*

## OVERVIEW

### The Company

Newfoundland Power is a regulated electricity utility that owns and operates an integrated generation, transmission and distribution system throughout the island portion of the Province of Newfoundland and Labrador. All the Company's common shares are owned by Fortis Inc. ("Fortis"), which is principally a diversified, international holding company for electricity and gas distribution utilities.

Newfoundland Power's primary business is electricity distribution. It generates approximately 8% of its electricity needs and purchases the remainder from Newfoundland and Labrador Hydro ("Hydro"). Newfoundland Power serves approximately 236,000 customers comprising about 85% of all electricity consumers in the Province.

Newfoundland Power's vision is to be a leader among North American electricity utilities in terms of safety, reliability, customer service and efficiency. The Company's strategy is to operate sound electricity distribution systems, and to focus on the safe and reliable delivery of electricity service to its customers in the most cost-efficient manner possible. Newfoundland

Power and its employees are committed to providing customers with the service they expect in an environmentally and socially responsible manner.

## Regulation

Newfoundland Power is regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities (the "PUB"). The Company operates under cost of service regulation whereby it is entitled the opportunity to recover, through customer rates, all reasonable and prudent costs incurred in providing electricity service to its customers, including a just and reasonable return on its rate base. The rate base is the net assets required to provide electricity service.

Between general rate hearings, customer rates are established annually through an automatic adjustment formula (the "Formula"). The Formula sets an appropriate rate of return on common equity ("ROE") which is used to determine the rate of return on rate base. The ROE is based upon the change in the forecast cost of common equity resulting from changes in long-term Canada bond yields.

Pursuant to its 2008 General Rate Application ("2008 GRA"), the Company's rate of return on rate base for ratemaking purposes was set at 8.37%, with a range of 8.19% to 8.55%, for 2008. This reflects a regulated ROE of 8.95% for 2008 compared to 8.60% for 2007. As a result of the 2008 GRA, customer rates increased by an average of approximately 2.8% effective January 1, 2008. The 2008 GRA also provided for the amortization of certain regulatory assets and liabilities, and the prospective recognition of future income taxes associated with pension costs.

## Financial Highlights

| | 2008 | 2007 | Change |
|---|---|---|---|
| Electricity Sales (gigawatt hours ("GWh")) | 5,208.2 | 5,092.8 | 115.4 |
| Earnings Applicable to Common Shares | | | |
| $ Millions | 32.3 | 29.9 | 2.4 |
| $ Per Share | 3.13 | 2.89 | 0.24 |
| ROE (%)[1] | 8.86 | 8.62 | 0.24 |
| Cash Flow from Operating Activites ($millions) | 85.0 | 49.3 | 35.7 |
| Total Assets ($millions) | 1,001.9 | 985.9 | 16.0 |

[1] *Earnings applicable to common shares, divided by the average of common shareholder's equity at the beginning and end of the year. This ratio is a non-GAAP financial measure, does not have any standardized meaning prescribed by GAAP, and is unlikely to be comparable to similar ratios published by other companies. It is presented because it is commonly referred to by the users of the Company's financial statements in evaluating the results of operations and by the Company's regulator in the rate-setting process.*

Electricity sales for the year ended December 31, 2008 increased by 115.4 GWh or 2.3% compared to 2007. The increase in electricity sales is comprised of an increase of (i) 1.4% due to customer growth, (ii) 0.6% due to higher average consumption, and (iii) 0.3% due to an additional day of sales in February 2008 (leap year).

Earnings for the year ended December 31, 2008 increased $2.4 million from $29.9 million in 2007 to $32.3 million in 2008. The increase was primarily the result of the 2.8% increase in customer rates which was effective January 1, 2008. Approximately $0.6 million of the $2.4 million increase in earnings resulted from operational performance during the course of 2008 which varied from the forecasts used to establish customer rates. The primary variances were: (i) lower debt costs; (ii) lower operating and pension costs; (iii) higher amortization related to higher than forecast capital expenditure; and, (iv) lower contribution from sales than that forecasted in customer rates, purchased power expense changes due to higher water inflows associated with the Company's hydroelectric generating facilities and demand management incentives.

As a result of the Company's 2008 GRA, the ROE reflected in customer rates was 8.95% for 2008 compared to 8.60% for 2007. The actual ROE in both 2008 and 2007 is broadly consistent with that reflected in customer rates.

The increase in cash flow from operating activities primarily reflects the January 1, 2008 customer rate increase, timing differences related to income tax instalments and collection of receivables, and a reduction in pension funding in 2008.

The increase in total assets was due primarily to continued investment in the electricity system and is consistent with the Company's strategy to provide safe and reliable electricity service at the lowest reasonable cost.

## RESULTS OF OPERATIONS

### Revenue:

| ($millions) | 2008 | 2007 | Change |
|---|---|---|---|
| Revenue from Rates | 496.4 | 477.1 | 19.3 |
| Amortization of Regulatory Liability | 8.6 | 2.7 | 5.9 |
| Other Revenue[2] | 11.9 | 11.9 | - |
| Total | 516.9 | 491.7 | 25.2 |

[2] *Other revenue is composed primarily of pole attachment charges to various telecommunication companies.*

Revenue increased by approximately $25.2 million, from $491.7 million in 2007 to $516.9 million in 2008. The increase primarily resulted from the January 1, 2008 rate increase and electricity sales growth.

The amortization of regulatory liabilities related to unbilled revenue and municipal tax is in accordance with PUB orders. These regulatory liabilities are described in Note 4 to the Company's 2008 annual audited financial statements.

**Purchased Power:** Purchased power expense increased by approximately $9.9 million, from $326.8 million in 2007 to $336.7 million in 2008. The increase was primarily due to electricity sales growth.

**Operating Expense:** Operating expense decreased by approximately $0.4 million from $47.5 million in 2007 to $47.1 million in 2008. The decrease was due primarily to timing of recognition of PUB assessments for 2008, lower insurance premiums and lower equipment maintenance costs, partially offset by wage and inflationary increases.

**Pension and Early Retirement Program Costs:** Pension and early retirement program costs decreased by approximately $2.7 million, or 47.4%, from $5.7 million in 2007 to $3.0 million in 2008. The decrease resulted from amortization of higher returns on pension plan assets experienced in the previous year, and a higher discount rate determined at December 31, 2007, associated with the Company's accrued benefit obligation. The discount rate is prescribed by GAAP and reflects market conditions.

**Amortization:** Amortization of capital assets increased by approximately $0.6 million, or 1.5%, from $40.0 million in 2007 to $40.6 million in 2008. Capital expenditures were $67.3 million in 2008. Higher amortization associated with these expenditures was partially offset by the decline in the composite amortization rate from 3.5% in 2007 to 3.4% in 2008, in accordance with PUB orders.

**Amortization True-Up Deferral:** Amortization of capital assets is subject to periodic review by external experts via an amortization study. The PUB ordered the deferred recovery of approximately $5.8 million in each of 2006 and 2007, $11.6 million in aggregate, related to a variance in accumulated amortization identified in the 2002 amortization study. These deferrals were recorded as an increase in regulatory assets and a decrease in expenses of $5.8 million in each year. Amortization of $3.9 million was recorded in 2008 in accordance with the PUB order that the resultant regulatory asset of approximately $11.6 million be amortized evenly over 2008 through 2010.

**Finance Charges:** Finance charges decreased by approximately $1.4 million, or 4.0%, from $34.9 million in 2007 to $33.5 million in 2008. This decrease primarily reflects the August 2007 refinancing of $31.5 million 11.875%, Series AC first mortgage sinking fund bonds with 5.901%, 30-year Series AL first mortgage sinking fund bonds.

**Income Taxes:** Income tax expense increased by approximately $6.9 million, from $12.2 million in 2007 to $19.1 million in 2008. This increase reflects higher pre-tax earnings and an increase in the Company's effective income tax rate. The increase in the effective income tax rate reflects a reduction in tax deductible pension funding and PUB ordered amortization and cost recovery deferrals, partially offset by the amortization of the 2005 unbilled revenue and higher capital cost allowance.

## FINANCIAL POSITION

Explanations of the primary causes of significant changes in the Company's balance sheets between December 31, 2007 and December 31, 2008 follow.

| *($millions)* | Increase (Decrease) | Explanation |
|---|---|---|
| Accounts Receivable | (7.3) | Lower electricity consumption in December primarily due to warmer weather and timing differences relating to the operation of the Company's equal payment plan, along with lower non-electric receivables resulting from timing of pension payments and customer payments for service. |
| Total Regulatory Assets | (3.5) | Decrease in Weather Normalization Account due to its normal operation; amortization of regulatory deferrals in accordance with PUB orders; and reduction in estimate for deferred GRA costs to reflect actual costs; partially offset by an increase in rate stabilization account due to its normal operation, and an increase in other post-employment benefits asset, representing costs incurred but not expensed under the cash method of accounting. |
| Capital Assets | 24.2 | Investment in electricity system, in accordance with 2008 capital program, offset partially by amortization and customer contributions in aid of construction. |
| Deferred Charges | 4.6 | Increase mainly due to pension funding in excess of pension expense. |
| Accounts Payable and Accrued Charges | (3.1) | Decrease primarily a result of timing of payment of trade payables and decreased purchased power costs due to warmer weather in December. |
| Total Regulatory Liabilities | (8.4) | Decrease primarily due to reduction in unbilled revenue liability and municipal tax liability due to PUB approved amortization. |
| Income Tax Payable/Receivable (net) | 9.4 | Current income tax expense in excess of income tax instalments paid. Lower instalments were required in 2008 based upon 2007 income taxes payable. |

| *($millions)* | Increase (Decrease) | Explanation |
|---|---|---|
| Other Liabilities | 6.9 | Increase in liability for other post-employment benefits. |
| Long-term Debt, including Current Portion | (5.4) | Decrease primarily relates to timing of operating cash flows and annual sinking fund payments on long-term debt. |
| Retained Earnings | 17.1 | Earnings in excess of dividends paid, retained to finance rate base growth. |

## LIQUIDITY AND CAPITAL RESOURCES

The primary sources of liquidity and capital resources are net funds generated from operations, debt capital markets and bank credit facilities. These sources are used primarily to satisfy capital expenditures, service and repay debt, and pay dividends. A summary of cash flows and cash position for 2008 and 2007 follows.

| ($millions) | 2008 | 2007 | Change |
|---|---|---|---|
| Cash (Bank Indebtedness), Beginning of Year | 1.1 | (0.4) | 1.5 |
| Operating Activities | 85.0 | 49.3 | 35.7 |
| Investing Activities | | | |
| Net Capital Expenditures | (67.3) | (72.2) | 4.9 |
| Other | 3.2 | 2.5 | 0.7 |
| | (64.1) | (69.7) | 5.6 |
| Financing Activities | | | |
| Bond Issued | - | 70.0 | (70.0) |
| Bond Retired | - | (31.5) | 31.5 |
| Bond Sinking Fund Payments | (4.6) | (5.0) | 0.4 |
| Net Credit Facility Borrowings | (1.0) | (1.7) | 0.7 |
| Dividends on Common Shares | (15.3) | (9.1) | (6.2) |
| Other | (0.5) | (0.8) | 0.3 |
| | (21.4) | 21.9 | (43.3) |
| Cash, End of Year | 0.6 | 1.1 | (0.5) |

### Operating Activities

Cash flow from operating activities totalled $85.0 million in 2008 compared to $49.3 million in 2007. The $35.7 million increase in cash flow from operating activities reflects (i) the January 1, 2008 rate increase, (ii) timing differences related to income tax instalments, (iii) timing differences related to electricity and other receivables, (iv) collections under the Company's equal payment plan for its electricity customers, (v) reduction of pension funding in 2008, and (vi) electricity sales growth.

### Investing Activities

Cash flow used in investing activities totalled $64.1 million in 2008 compared to $69.7 million in 2007. The $5.6 million decrease was due primarily to lower capital expenditures in 2008 compared to 2007. Higher capital expenditures in 2007 related to the Rattling Brook hydroelectric plant refurbishment project.

A summary of 2008 and 2007 capital expenditures follows.

| *($millions)* | **2008** | **2007** |
|---|---|---|
| Electricity System | | |
| Generation | 4.1 | 18.1 |
| Transmission | 5.3 | 4.4 |
| Substations | 7.5 | 5.1 |
| Distribution | 35.5 | 30.4 |
| Other | 14.9 | 14.2 |
| Total Capital Expenditures - Net of Salvage | 67.3 | 72.2 |

The Company's business is capital intensive. Capital investment is required to ensure continued and enhanced performance, reliability and safety of the electricity system, and to meet customer growth. Capital investment also arises for information technology systems and for general facilities, equipment and vehicles. Capital expenditures, and capital asset repairs and maintenance expense, can vary from year-to-year depending upon both planned system expenditures and unplanned expenditures arising from weather or other unforeseen events.

The Company's annual capital plan requires prior PUB approval. Variances between actual and planned expenditures are generally subject to PUB review prior to inclusion in the Company's rate base.

The Company's PUB approved 2009 capital plan provides for capital expenditures of approximately $61.6 million, approximately half of which relate to construction and capital maintenance of the electricity distribution system.

### Financing Activities

Cash flow used in financing activities totalled $21.4 million in 2008 compared to cash from financing activities of $21.9 million in 2007. The $43.3 million decrease in cash from financing activities in 2008 primarily related to higher operating cash flows and lower capital expenditures which reduced borrowing requirements in 2008. This was partially offset by higher common share dividends in 2008. Cash from financing activities in the previous year primarily related to the issuance of $70 million first mortgage sinking fund bonds which were partially used to repay $31.5 million in maturing first mortgage sinking fund bonds.

The Company has historically generated sufficient annual cash flows from operating activities to service annual interest and sinking fund payments on debt, to pay dividends and to finance a major portion of its annual capital program. Additional financing to fully fund the annual capital program is obtained through the Company's bank credit facilities and these borrowings are periodically refinanced along with any maturing bonds through the issuance of long-term first mortgage sinking fund bonds. The Company currently does not expect any material changes in these basic cash flow and financing dynamics over the foreseeable future.

**Pensions:** As at December 31, 2008, the fair value of the Company's primary defined benefit pension plan assets was $212.6 million compared to fair value of plan assets of $259.7 million as at December 31, 2007. Details of the changes are included in Note 16 to the Company's 2008 annual audited financial statements. The decrease in the fair value of pension plan assets during 2008 was mainly driven by unfavourable market conditions in 2008.

The decline in pension plan assets is expected to increase the Company's future special pension funding obligations, commencing in 2009. The amount of the increase will not be determinable until completion of the next actuarial valuation. Based on the last actuarial valuation as of December 31, 2005, pension funding obligations concluded in March 2008.

The next scheduled actuarial valuation is as at December 31, 2008 and this valuation is expected to be completed in the first quarter of 2009.

The Company does not expect any difficulty in its ability to meet future pension funding requirements as it expects the amounts will be financed from a combination of cash generated from operations and amounts available for borrowing under existing credit facilities.

**Debt:** The Company's credit facilities are comprised of a $100 million committed revolving term credit facility and a $20 million uncommitted demand facility. Details follow.

| *($millions)* | **2008** | **2007** |
|---|---|---|
| Total Credit Facilities | 120.0 | 120.0 |
| Long-term Borrowings Outstanding | (32.0) | (33.0) |
| Credit Facilities Available | 88.0 | 87.0 |

During the third quarter of 2008, the $100 million committed revolving facility was renegotiated on similar terms as the previous facility and matures in August 2011. Subject to lenders' approval, two years prior to maturity the Company may request an extension for a further period of 364 days, or alternatively, one year prior to maturity the Company may request an extension for a further period of up to one year and 364 days.

**Contractual Obligations**: Details, as at December 31, 2008, of all contractual obligations over the subsequent five years and thereafter, follow.

| *($millions)* | **Total** | **2009** | **2010-2011** | **2012-2013** | **2014 Onward** |
|---|---|---|---|---|---|
| Credit Facilities (unsecured) | 32.0 | - | 32.0 | - | - |
| First Mortgage Sinking Fund Bonds[3] | 409.1 | 4.6 | 9.1 | 9.1 | 386.3 |
| Total | 441.1 | 4.6 | 41.1 | 9.1 | 386.3 |

[3] *First mortgage sinking fund bonds are secured by a first fixed and specific charge on capital assets owned or to be acquired by the Company and carry customary covenants.*

**Credit Ratings and Capital Structure:** To ensure continued access to capital at reasonable cost, the Company endeavours to maintain its investment grade credit ratings. During 2008, the Company's investment grade bond ratings were reaffirmed, and currently are: Dominion Bond Rating Service, "A" and Moody's, "Baa1"; both with a "stable" rating outlook.

Newfoundland Power endeavours to maintain a capital structure composed of 55% debt and 45% equity. This capital structure is reflected in customer rates and is consistent with the Company's current investment grade credit ratings. The Company's capital structure at December 31, 2008 and 2007 follows.

| | **2008** | | **2007** | |
|---|---|---|---|---|
| | **$millions** | **%** | **$millions** | **%** |
| Total Debt[4] | 437.5 | 53.3 | 442.5 | 54.7 |
| Common Equity | 373.7 | 45.5 | 356.7 | 44.1 |
| Preferred Equity | 9.4 | 1.2 | 9.4 | 1.2 |
| Total | 820.6 | 100.0 | 808.6 | 100.0 |

[4] *Includes bank indebtedness, if applicable, net of cash.*

The Company currently expects it will be able to maintain its current investment grade credit ratings in 2009.

**Share Capital and Dividends:** For the year ended 2008 and 2007, the weighted average number of common shares outstanding was 10,320,270. There were no changes to the number of common and preferred shares outstanding during 2008.

Dividends on common shares, for 2008, compared to 2007, were $6.2 million higher. In 2008, common quarterly dividends increased to $0.37 per share compared to $0.22 per share in 2007. The increase in common share dividends was to maintain a capital structure that includes approximately 45% common equity.

## RELATED PARTY TRANSACTIONS

The Company provides services to, and receives services from, its parent company, Fortis and other subsidiaries of Fortis. The Company also incurs charges from Fortis for the recovery of general corporate expenses incurred by Fortis. These transactions are in the normal course of business and are recorded at their exchange amounts.

Related party transactions included in revenue, operating expenses and finance charges and included in accounts receivable as at December 31, 2008 and 2007 follow.

| *($millions)* | **2008** | **2007** |
|---|---|---|
| Revenue[5] | 4.2 | 4.1 |
| Operating Expenses | 1.5 | 0.9 |
| Finance Charges | 0.3 | - |
| Accounts Receivable | 0.2 | 0.1 |

[5] *Includes charges for electricity consumed.*

In May, 2008, the Company borrowed $32.5 million from Fortis as a short-term demand loan at an interest rate of 3.15%, which was indicative of Bankers' Acceptance rates at the time. This amount was fully repaid in the third quarter of 2008.

## BUSINESS RISK MANAGEMENT

**Regulation:** The Company is subject to normal uncertainties facing entities that operate under cost of service regulation. It is dependent on PUB approval of customer rates that permit a reasonable opportunity to recover on a timely basis the estimated costs of providing electricity service, including a fair and reasonable return on rate base. The ability to recover the actual costs of providing service and to earn the approved rates of return depends on achieving the forecasts established in the rate-setting process. Between general rate applications, the setting of customer rates through the Formula can cause earnings and cash flows to increase or decrease due to corresponding changes in bond yields which are beyond the Company's control.

**Economic Conditions:** Economic conditions primarily impact the performance of the Company's defined benefit pension plan, cost of capital and electricity sales. The impact on pensions and cost of capital are discussed below. Electricity sales are influenced by economic factors in the Company's service territory such as changes in employment levels, personal disposable income, energy prices and housing starts. Out-migration in rural areas, as well as declining birth rates and increasing death rates associated with an aging population also affect sales. Modest sales growth is currently expected for 2009; however, economic conditions may impact actual future sales.

**Pension:** The Company's defined benefit pension plan is impacted by economic conditions as it relates to the Company's future pension funding requirements, as discussed in the "Liquidity and Capital Resources" section of this Management Discussion and Analysis. Future pension obligations and related pension expense may also be impacted by economic conditions. The defined benefit pension plan is subject to judgments utilized in the actuarial determination of the pension obligation and the related pension expense. The primary assumptions utilized by management are the expected long-term rate of return on pension plan assets and the discount rate used to value the accrued benefit obligation. A discussion of the critical accounting estimates associated with pensions is provided in the "Critical Accounting Estimates" section of this Management Discussion and Analysis.

There is no assurance that the pension plan assets will earn the expected long-term rate of return in the future. Market driven changes impacting the performance of the pension plan assets may result in material variations in actual return on pension plan assets from the expected long-term return on the assets. This may cause material changes in future pension liabilities and pension expense. Market driven changes impacting the discount rate may also result in material variations in future pension liabilities and pension expense. In 2008, the Company experienced material changes in the actual return on pension plan assets and the discount rate. Any increase or decrease in future pension funding requirements and/or pension expense is expected to be recovered from or refunded to customers in future customer rates subject to forecast risk. There is no assurance that any cost which might arise as a result of recent or future changes in pension plan asset performance and discount rates will be recovered in future customer rates and, if substantial, unrecovered costs could have a material adverse effect on the results of operations, cash flows and financial position of the Company. The impact of current economic conditions on the Company's 2009 pension expense is discussed in the "Critical Accounting Estimates" section of this Management Discussion and Analysis.

There is also measurement uncertainty associated with pension expense, future funding requirements, the accrued benefit asset, accrued benefit liability and benefit obligation inherent in the actuarial valuation process.

**Capital Resources:** The recent volatility experienced in the global financial markets may increase the Company's cost of capital as well as impact timing of future long-term bond issues. Market driven changes in interest rates can cause fluctuations in interest costs associated with the Company's bank credit facilities. The Company periodically refinances its credit facilities in the normal course with fixed-rate first mortgage sinking fund bonds, which compose most of its long-term debt, thereby significantly mitigating exposure to short-term interest rate changes. The Company currently expects to issue long-term debt in 2009.

**Credit Ratings:** The Company does not anticipate any material adverse rating actions by the credit rating agencies in the near term. However, the current global financial crisis has placed increased scrutiny on rating agencies and rating agency criteria which may result in changes to credit rating practices and policies.

**Electricity Prices:** Increases in electricity rates can cause changes in customer electricity consumption, which could negatively impact sales and therefore earnings and cash flows. Electricity prices have risen in recent years due to the flow-through of the rising cost of oil used at Hydro's thermal generating station. Future changes or volatility in oil prices may affect electricity prices in a manner that affects sales.

**Competition:** The Company currently does not expect any significant loss in heating market share to its primary competitor which is furnace oil. Natural gas is not expected to enter the Company's service territory in the foreseeable future.

**Purchased Power Cost:** The Company is dependent on Hydro for approximately 92% of its electricity requirements. Purchased power costs are based on a wholesale demand and energy rate structure. The demand and energy rate structure presents the risk of volatility in purchased power costs due to uncertainty in forecasting energy sales and peak billing demand.

With respect to demand charges, effective January 1, 2008, the PUB ordered the discontinuance of the purchased power unit cost variance reserve (the "PPUCVR"), which limited volatility of purchased power cost, and its replacement with the demand management incentive account (the "DMI"). The DMI limits variations in the unit cost of purchased power related to demand up to 1% of total demand costs reflected in customer rates, or approximately $0.5 million for 2008. The disposition of balances in this account, which would be determined by a further order of the PUB, will consider the merits of the Company's conservation and demand management activities. The replacement of the PPUCVR with the DMI is not expected to have a material impact on the Company's annual earnings and cash flows.

With respect to energy charges, as a result of January 1, 2007 changes in Hydro's wholesale rates, the marginal cost of purchased power now exceeds the average cost of purchased power that is embedded in customer rates. To the extent actual electricity sales in any period exceed forecast electricity sales used to set customer rates, the marginal purchased power expense will exceed related revenue. These supply cost dynamics had no material effect on 2008 earnings because the PUB ordered, for 2008 to 2010, that variations in purchased power expense caused by differences between the actual unit cost of energy purchased and that reflected in customer rates be recovered from (returned to) customers through the Company's rate stabilization account. Beyond 2010, the manner in which incremental purchased power costs are recovered will be determined by the PUB.

**Regulatory Assets and Liabilities:** The accounting methods that give rise to, and the settlement of, regulatory assets and liabilities are determined by the PUB and may impact the Company's future cash flows.

**Health, Safety and Environment:** The Company is subject to numerous and increasing environmental, health and safety laws, regulations and guidelines governing hazardous substances and other waste materials. Electricity is itself a hazardous commodity. Damages and costs could potentially arise due to a variety of events, including severe weather, human error or misconduct, and equipment failure. There is no assurance that any costs which might arise would be recoverable through customer rates and, if substantial, unrecovered costs could have a material adverse effect on the results of operations, cash flows and financial position of the Company. A focus on safety and the environment is an integral and continuing component of the Company's core business strategy.

2008 was the Company's first full year under the internationally recognized Occupational Health and Safety Assessment Series 18001 Health and Safety Management System ("OHSAS 18001"). This improved the Company's ability to capture and track information related to safe work practices and hazard recognition, and enhanced safety management.

A key element of environmental management relates to the Company's environmental management system ("EMS"). The Company's EMS is designed to mitigate the risks associated with the potential release of hazardous substances into the air, water and soil as part of its day-to-day operations. The Company's EMS is compliant with the ISO 14001. One key hazard relates to the risk of air, soil and water contamination that could stem from the storage of large volumes of fuel and the use of other petroleum based products in day-to-day operating and maintenance activities. In addition, key hazards related to hydroelectric generation operations are the creation of artificial water flows that may disrupt natural habitats and the storage of large volumes of water for the purposes of electricity generation.

In conjunction with the operation of its EMS, the Company is materially compliant with the governing environmental laws under which it must operate. At December 31, 2008, there are no environmental liabilities included in Company's financial statements and there are no material unrecorded environmental liabilities.

**Insurance:** While the Company maintains a comprehensive insurance program, the Company's transmission and distribution assets (i.e. poles and wires) are not covered under insurance for physical damage. This is customary in North

America as the cost of the coverage is not considered economical. Insurance is subject to coverage limits as well as time-sensitive claims discovery and reporting provisions and there is no assurance that the types of liabilities that may be incurred by the Company will be covered by insurance.

For material uninsured losses, the Company expects that it would seek regulatory relief. However, there is no assurance that regulatory relief would be received. Any major damage to the physical assets of the Company could result in repair costs and customer claims that are substantial in amount and which could have a material adverse effect on the Company's results of operations, cash flows and financial position.

It is expected that existing insurance coverage will be maintained. However, there is no assurance that the Company will be able to obtain or maintain adequate insurance in the future at rates considered reasonable or that insurance will continue to be available on terms comparable to those now existing.

**Weather:** The physical assets of the Company are exposed to the effects of severe weather conditions and other acts of nature. Although the physical assets have been constructed, operated and maintained to withstand severe weather, there is no assurance that they will successfully do so in all circumstances. This could result in the interruption of electricity service in a manner that could have a material adverse effect on the Company's results of operations, cash flows and financial position.

**Labour Relations:** Approximately 54% of the employees of the Company are members of the International Brotherhood of Electrical Workers labour union (the "IBEW") which had entered into two collective bargaining agreements with the Company. The two agreements expired on September 30, 2008. The Company and the IBEW reached a tentative agreement in January 2009; however, the tentative agreement is subject to ratification by the members.

The inability to renew the collective bargaining agreements on acceptable terms could result in increased labour costs, or service level declines associated with job action, which could have a material adverse effect on the results of operations, cash flows and financial position of the Company.

## 2008 ACCOUNTING CHANGES

**Future Income Tax:** The PUB ordered that future income tax on temporary timing differences between pension expense and pension funding be recognized and included in the determination of customer rates commencing January 1, 2008. The Company recognized future income tax expense of $0.6 million during 2008, and a corresponding future income tax liability, in accordance with this order. This change had no impact on earnings for the period as the additional expense was reflected in customer rates effective January 1, 2008.

**Inventories:** Effective January 1, 2008, the Company adopted the new Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3031 - Inventory. It requires inventories to be measured at the lower of cost or net realizable value; disallows the use of a last-in first-out inventory costing methodology; and, requires that, when circumstances which previously caused inventories to be written down below cost no longer exist, the amount of the write down is to be reversed. As at January 1, 2008, inventories of $4.3 million (2007 - $4.1 million) were reclassified to capital assets on the balance sheet as they are held for the development, construction, maintenance and repair of other capital assets. Inventories expensed in 2008 and 2007 were immaterial.

**Capital Disclosures:** Effective January 1, 2008, the Company adopted the new CICA Handbook Section 1535 - Capital Disclosures. It requires Newfoundland Power to include additional information in the notes to the financial statements about its capital and the manner in which it is managed. This additional disclosure includes quantitative and qualitative information regarding objectives, policies and processes for managing capital. This new standard did not have any impact on the Company's 2008 financial results. The additional required disclosure is provided in Note 17 to the Company's 2008 annual audited financial statements.

**Disclosure and Presentation of Financial Instruments:** Effective January 1, 2008, the Company adopted Sections 3862 and 3863 of the CICA Handbook which set out new accounting recommendations for disclosure and presentation of financial instruments. The new recommendations require disclosure of both quantitative and qualitative information that enables users of financial statements to evaluate the nature and extent of risks from financial instruments to which the Company is exposed. These recommendations did not have any impact on the Company's financial results. The additional required disclosure is included in Note 18 to the Company's 2008 annual audited financial statements.

## FUTURE ACCOUNTING CHANGES

**International Financial Reporting Standards ("IFRS"):** In February 2008, the Accounting Standards Board ("AcSB") confirmed that the use of IFRS will be required in 2011 for publicly accountable enterprises in Canada. In April 2008, the AcSB issued an IFRS Omnibus Exposure Draft proposing that publicly accountable enterprises be required to apply IFRS, in full and without modification, on January 1, 2011. On June 27, 2008 the Canadian Securities Administrators ("CSA") issued Staff Notice 52-321, Early Adoption of IFRS which indicated that the CSA would be prepared to grant an exemption to allow Canadian financial statement issuers to adopt IFRS early on a case-by-case basis, provided that they could demonstrate that they met certain conditions. Newfoundland Power is not expecting to adopt IFRS early.

The adoption date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported by the Company for its year ended December 31, 2010, and of the opening balance sheet as at January 1, 2010. The AcSB proposes that CICA Handbook Section - Accounting Changes, paragraph 1506.30, which would require an entity to disclose information relating to a new primary source of GAAP that has been issued but is not yet effective and that the entity has not applied, not be applied with respect to the IFRS Omnibus Exposure Draft.

Newfoundland Power is continuing to assess the financial reporting impacts of the adoption of IFRS and, at this time, the impact on future financial position and results of operations is not reasonably determinable. Newfoundland Power does anticipate a significant increase in disclosure resulting from the adoption of IFRS and is continuing to assess the level of disclosure required as well as system changes that may be necessary to gather and process the required information.

The Company commenced its IFRS conversion project in 2007 and has established a formal project governance structure. Regular progress reports are provided to the Audit & Risk Committee of the Board of Directors of Newfoundland Power. An external expert advisor has been engaged to assist in the IFRS conversion project.

The Newfoundland Power IFRS conversion project consists of three phases: scoping and diagnostics, analysis and development, and implementation and review.

Phase One: scoping and diagnostics, which involved project planning and staffing and identification of differences between current Canadian GAAP and IFRS, has been completed. Identified areas of accounting difference of highest potential impact to the Company, based on existing IFRS, are rate regulated accounting, property plant and equipment, provisions and contingent liabilities, employee benefits, income taxes and initial adoption of IFRS under the provisions of IFRS 1 First-Time Adoption of IFRS.

Phase Two: analysis and development is nearing completion, and involves detailed diagnostics and evaluation of the financial impacts of various options and alternative methodologies provided for under IFRS; identification and design of operational and financial business processes; initial staff and audit committee training; analysis of IFRS 1 optional exemptions and mandatory exceptions to the general requirement for full retrospective application upon transition to IFRS; summarization of 2011 IFRS disclosure requirements; and, development of required solutions to address identified issues.

It is anticipated that the adoption of IFRS will have an impact on information system requirements. Newfoundland Power is assessing the need for system upgrades or modifications to ensure an efficient conversion to IFRS. As part of Phase Two, information system plans are being prepared for implementation in Phase Three. The degree of this impact is not reasonably determinable at this time.

The Company has completed a preliminary assessment of the impacts of adopting IFRS on debt covenants and other contractual arrangements; however, a final assessment cannot be completed at this time pending the outcome of the project on rate-regulated activities that was recently added to the International Accounting Standards Board's ("IASB") technical agenda.

The Company expects to identify transitional issues and propose to the PUB how those issues might be addressed within the framework of cost of service regulation.

Phase Three: implementation and review, expected to commence mid-year 2009, will involve the execution of changes to information systems and business processes; completion of formal authorization processes to approve recommended accounting policy changes; and, further training programs across the Company as necessary. It will culminate in the collection of financial information necessary to compile IFRS-compliant financial statements and reconciliations; embedding of IFRS in business processes; and, audit committee approval of IFRS compliant financial statements.

Newfoundland Power will continue to review all proposed and continuing projects of the IASB, particularly the project on rate-regulated activities that was recently added to the IASB's technical agenda, and proposed amendments to IFRS 1 for entities with operations subject to rate regulation, and will participate in any related processes as appropriate. In the event regulated assets and liabilities are not permissible under IFRS, this could result in increased volatility in the Company's earnings and balance sheet from that reported under Canadian GAAP.

**Rate-Regulated Operations:** Given its strategic plan to adopt IFRS, the AcSB revisited the scope of its project on accounting for rate-regulated operations in recognition of the fact that IFRS do not currently provide any special guidance with respect to accounting practices that are unique to rate-regulated entities. As a result, it has removed certain guidance from the CICA Handbook. Newfoundland Power's assessment of these changes is that effective January 1, 2009 it will be required to (i) disclose separately on its balance sheets future income tax assets and liabilities that, in accordance with PUB approved accounting policies, are currently unrecognized along with corresponding regulatory liabilities and assets, and (ii) include in these amounts the future income tax effects of the subsequent settlement of the regulatory assets and liabilities through customer rates. These changes would not affect earnings or cash flows. If calculated in accordance with the revised guidance, the net unrecognized future income tax liability now disclosed in Note 2 to the Company's 2008 annual financial statements would increase by approximately $30.3 million (2007 - increase of approximately $30.7 million) to $102.9 million at December 31, 2008 (December 31, 2007 - $105.1 million).

**Goodwill and Intangible Assets:** Effective January 1, 2009, the Company will adopt new CICA Handbook Section 3064 - Goodwill and Intangible Assets, which effectively converges Canadian GAAP for intangible assets with IFRS. The new standard provides more comprehensive guidance on the definition and initial recognition criteria of intangible assets, including internally generated intangible assets. The impact of the adoption of this standard on the Company's financial statements will result in the reclassification of certain assets currently included in capital assets to intangible assets. The items to be reclassified consist of computer software and land rights. As at December 31, 2008, $13.8 million and $2.3 million are included in capital assets related to computer software and land rights, respectively.

## CRITICAL ACCOUNTING ESTIMATES

Preparation of the Company's financial statements in accordance with GAAP requires management to make estimates and judgements that affect the reported amounts of assets and liabilities, revenue and expenses, and related disclosure of contingencies and commitments. Estimates and judgements are based on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances. Actual results may differ from these estimates and judgements under different assumptions or conditions. The critical accounting estimates involving the more significant estimates and judgements used in the preparation of the Company's financial statements follow.

**Capital Asset Amortization:** By its nature, capital asset amortization is an estimate based primarily on the useful lives of capital assets. Estimated useful lives are based on current facts and historical information and take into consideration the anticipated physical lives of the assets. The Company's amortization methodology, including amortization rates, accumulated amortization and estimated remaining service lives, is subject to a periodic study by external experts. The difference between actual accumulated amortization and that indicated by the amortization study is amortized and included in customer rates in a manner prescribed by the PUB.

The most recent amortization study, based on capital assets in service as at December 31, 2005, indicates an accumulated amortization variance of approximately $0.7 million. The PUB ordered that it be amortized as a decrease in amortization expense equally over 2008-2011. The PUB has also ordered that revised amortization rates arising from the amortization study be implemented effective January 1, 2008. As a result, the total composite amortization rate declined from 3.5% to 3.4% for 2008. It is management's judgement that these changes will not have a significant impact on the Company's earnings, cash flow and financial position because the changes are reflected in 2008 customer rates pursuant to the 2008 GRA.

The estimate of future removal and site restoration costs, net of salvage proceeds, is based on historical experience and future expected cost trends. The balance of this regulatory liability at December 31, 2008 was $48.0 million (December 31, 2007 - $47.4 million). The net amount of estimated future removal and site restoration costs provided for and reported in amortization expense during 2008 was $4.6 million (2007 - $3.5 million).

**Capitalized Overhead:** Newfoundland Power capitalizes overhead costs which are not directly attributable to specific capital assets, but which relate to the overall capital expenditure program. Capitalization reflects estimates of the portions of various general expenses that relate to the overall capital expenditures program in accordance with a methodology ordered by the PUB. These general expenses capitalized ("GEC") are allocated over constructed capital assets and amortized over their estimated service lives. In 2008, GEC totalled $2.8 million (2007 - $2.8 million). Changes to the methodology for calculating and allocating general overhead costs to capital assets could have a material impact on the amounts recorded as operating expenses versus capital assets. However, any change in the fundamental methodology for the calculation and allocation of GEC would require the approval of the PUB.

**Employee Future Benefits:** The Company's primary defined benefit pension plan is subject to judgments utilized in the actuarial determination of the pension expense and related obligation. The primary assumptions utilized by management in determining the pension expense and the accrued benefit obligation are the discount rate and the expected long-term rate of return on plan assets. All defined benefit pension plan assumptions are assessed and concluded in consultation with the Company's external actuarial advisor.

The discount rate as at December 31, 2008, which is utilized to determine the accrued benefit obligation and the 2009 pension expense, is 7.5% compared to the discount rate of 5.5% as at December 31, 2007. Discount rates reflect market interest rates on high quality bonds with cash flows that match the timing and amount of expected pension benefit payments. This methodology is consistent with that used to determine the discount rate in the previous year. The increase in discount rates reflects the increased credit spreads and cost of capital on investment grade corporate bonds.

The expected long-term rate of return on pension plan assets which is used to estimate the 2009 defined benefit pension expense is 7%. This compares to an expected long-term rate of return of 7.5% used in 2008. The actual rate of return on pension plan assets during 2008 was a loss of 16.6%. As in previous years, an actuary provided the Company with a range of expected long-term pension asset returns based on their internal modelling. The expected long-term return on pension plan assets of 7% falls within the conservative to normal range as indicated by the actuary.

In 2009, the Company expects the pension expense related to its primary defined benefit pension plan to decrease by approximately $0.8 million compared to 2008. This is driven by the higher discount rate, partially offset by the amortization of 2008 experience losses associated with the pension plan assets and a lower assumed long-term rate of return on pension assets for 2009. The impact of the decline in pension assets in 2008, as it relates to the 2009 pension expense, was also mitigated as the pension assets are valued using the market related method as outlined in Note 2 to the 2008 annual audited financial statements. Beyond 2009, pension expense is expected to increase as a result of the decline in pension plan assets in 2008.

The following table provides sensitivity to the changes in the primary assumptions associated with the Company's defined benefit pension plan.

| *($millions)* | **Pension Expense** |
|---|---|
| Impact of increasing rate of return on assets assumption by 100 basis points (bps) | (2.6) |
| Impact of decreasing the rate of return on assets assumption by 100 bps | 2.6 |
| Impact of increasing the discount rate assumption used during 2008 by 100 bps | (2.6) |
| Impact of decreasing the discount rate assumption used during 2008 by 100 bps | 3.6 |

Other assumptions are the average rate of compensation increase, average remaining service life of the active employee group, and mortality rates.

The Company's other post-retirement benefits are also subject to judgements utilized in the actuarial determination of the expense and related obligation. Assumptions utilized by management in determining other post-employment benefit plan costs and obligations include the health care cost trend rate and the foregoing assumptions, excluding the expected long-term rate of return on plan assets and average rate of compensation increase.

In accordance with PUB orders, Newfoundland Power expenses the cost of other post-employment benefits on a cash basis, whereby the difference between the cash payments during the year and the expense incurred in the year is deferred as a regulatory asset. Therefore, changes in assumptions cause changes in the regulatory asset and do not impact earnings. Other post-employment benefits costs deferred as a regulatory asset in 2008 totalled $6.6 million (2007 - $6.7 million) and the regulatory asset at December 31, 2008 was $41.1 million (2007 - $34.5 million).

**Asset Retirement Obligations:** The measurement of the fair value of asset retirement obligations ("AROs") requires the Company to make reasonable estimates about the method of settlement and settlement dates associated with legally obligated asset retirement costs. While the Company has AROs provided for its hydroelectric generation assets and certain distribution and transmission assets, there were no amounts recognized as at December 31, 2008 and December 31, 2007. The nature, amount and timing of AROs for generation assets cannot be reasonably estimated at this time as these assets are expected to effectively operate in perpetuity given their nature. In the event that environmental issues are identified or generation assets are decommissioned, AROs will be recorded at that time provided the costs can be reasonably estimated. It is management's judgement that identified AROs for its remaining assets are immaterial.

**Revenue Recognition:** The Company recognizes electricity revenue on an accrual basis. Customer bills are issued throughout the month based on meter readings that establish electricity consumption by the customer since the last meter reading. The unbilled revenue accrual for each period is based on estimated electricity sales to customers for the period since the last meter reading at the rates approved by the PUB. The development of the electricity sales estimates requires analysis of electricity consumption on a historical basis in relation to key inputs such as the current price of electricity, population growth, economic activity, weather conditions and system losses. The estimation process for accrued unbilled electricity consumption will result in adjustments to electricity revenue in the period during which the difference between actual results and those estimated becomes known. As at December 31, 2008, the amount of accrued unbilled revenue was approximately $30.5 million (December 31, 2007 - $28.3 million).

## SELECTED ANNUAL INFORMATION

| *($millions, except per share amounts)* | **2008** | **2007[6]** | **2006[6]** |
|---|---|---|---|
| Results of Operations | | | |
| Revenue | 516.9 | 491.7 | 422.4 |
| Net Earnings Applicable to Common Shares | 32.3 | 29.9 | 30.1 |
| Financial Position | | | |
| Total Assets | 1,001.9 | 985.9 | 929.2 |
| Total Long-term Liabilities | 534.6 | 537.7 | 479.3 |
| Shareholders' Equity | 383.1 | 366.0 | 345.2 |
| Per Share Data | | | |
| Earnings Applicable to Common Shares[7] | 3.13 | 2.89 | 2.91 |
| Common Dividends Declared[7] | 1.48 | 0.88 | 1.76 |
| Preferred Dividends Declared[8] | 2.56 | 2.56 | 2.56 |

[6] *Certain amounts have been reclassified to conform with the presentation for 2008.*

[7] *Basic and fully diluted. Based on the weighted average number of common shares outstanding, which was 10,320,270 common shares in each year.*

[8] *Based on the aggregate weighted average number of preference shares outstanding in each year, which was 935,223 in both 2008 and 2007 and 935,323 in 2006. In 2007, the Company repurchased 100 preference shares at $10 per share (2006 - 5,700 preference shares at $10 per share). No preference shares were repurchased by the Company in 2008.*

The changes from 2007 to 2008 have been discussed previously in this Management Discussion and Analysis. The increase in total assets from 2006 to 2007 was due primarily to continued investment in the electricity system and is consistent with the Company's strategy to provide safe and reliable electricity service at the lowest reasonable cost. The increase in total long-term liabilities from 2006 to 2007 reflects the reclassification of credit facility borrowings from current to non-current in 2007. The decrease in common dividends from 2006 to 2007 reflects the retention of earnings in order to finance capital expenditures and maintain a capital structure composed of approximately 45% equity and 55% debt.

## QUARTERLY RESULTS

| (unaudited) | First Quarter March 31 2008 | First Quarter March 31 2007 | Second Quarter June 30 2008 | Second Quarter June 30 2007 | Third Quarter September 30 2008 | Third Quarter September 30 2007 | Fourth Quarter December 31 2008 | Fourth Quarter December 31 2007 |
|---|---|---|---|---|---|---|---|---|
| Electricity Sales (GWh) | 1,716.2 | 1,663.2 | 1,183.0 | 1,172.0 | 896.8 | 874.0 | 1,412.2 | 1,383.6 |
| Revenue ($millions) | 164.9 | 154.8 | 118.9 | 115.1 | 94.1 | 89.2 | 139.0 | 132.6 |
| Earnings Applicable to Common Shares ($millions) | 6.2 | 10.5 | 10.1 | 8.0 | 8.1 | 2.7 | 7.9 | 8.7 |
| Earnings per Common Share ($)[9] | 0.60 | 1.02 | 0.98 | 0.77 | 0.79 | 0.26 | 0.76 | 0.84 |

[9] *Basic and fully diluted.*

### Seasonality

**Sales and Revenue:** Sales and revenue are significantly higher in the first quarter and significantly lower in the third quarter compared to the remaining quarters. This reflects the seasonality of electricity consumption for heating.

**Earnings:** Beyond the seasonality of sales and revenue, operating costs tend to be higher in the third quarter compared to the remaining quarters because certain maintenance procedures are more typically performed during the warmer seasons.

The purchased power rate structure effective January 1, 2007 resulted in the Company paying more, on average, for each kilowatt hour ("kWh") of power purchased in the fall and winter months and less, on average, during the spring and summer months. Quarterly revenue, however, continued to be based on customer rates that reflect the average annual cost per kWh. In 2007, differences between the estimated quarterly purchased power expense and that based on the actual cost per kWh were adjusted to the PPUCVR, with no effect on annual purchased power expense or cash flows. Pursuant to the Company's 2008 GRA, the PUB ordered that the PPUCVR be discontinued effective January 1, 2008. Quarterly purchased power expense for 2008 and future years is expected to reflect the actual cost per kWh. Prior to 2008, these sales, revenue and operating cost dynamics yielded higher earnings in the first (winter) quarter and much lower earnings in the third (summer) quarter compared to the remaining quarters.

### Trending

**Sales and Revenue:** Year-over-year quarterly electricity sales increases primarily reflect moderate customer growth. Quarterly revenue increases for 2008 compared to 2007 reflect electricity sales growth and the January 1, 2008 rate increase pursuant to the Company's 2008 GRA.

**Earnings:** Quarterly earnings for 2008 were not consistent with 2007. The variability of quarterly earnings for 2008 compared to 2007 was primarily due to a seasonal earnings shift as described under "Seasonality" in this Management Discussion and Analysis. In subsequent years, earnings in the first quarter and fourth quarter are expected to be lower and earnings in the second and third quarters are expected to be higher, compared to the remaining quarters.

Beyond the impact of expected moderate sales growth, future quarterly earnings and earnings per share are expected to trend with the ROE reflected in customer rates and rate base growth.

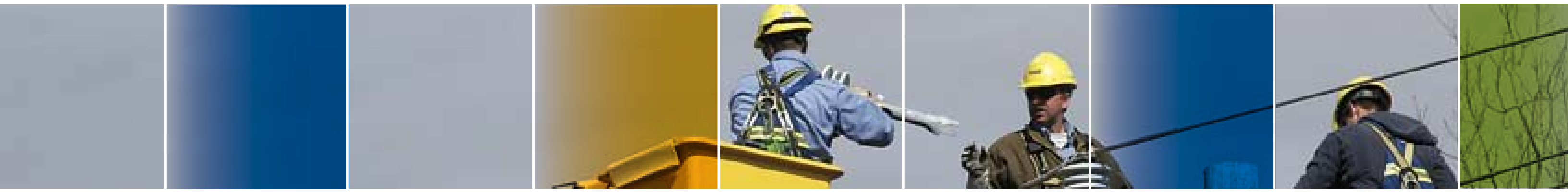
## OUTLOOK

It is expected that the Company's strategy will remain unchanged.

In accordance with the operation of the Formula, the Company's 2009 customer rates were not changed from 2008 customer rates. On December 22, 2008, the Company received an Order from the PUB continuing the Company's rate of return on rate base of 8.37%, with a range of 8.19% to 8.55% for 2009.

Newfoundland Power expects to maintain its investment grade credit ratings in 2009.

Newfoundland Power is regulated under a cost of service regime. Cost of service regulation entitles the Company to an opportunity to recover its reasonable cost of providing service, including its cost of capital, in each year. The Company is currently assessing the requirement for it to file an application with the PUB to recover increased costs in 2010, including any increased costs arising from recent economic conditions.



# Management Report

The accompanying 2008 Financial Statements of Newfoundland Power Inc. and all information in the 2008 Annual Report have been prepared by management, who are responsible for the integrity of the information presented, including the amounts that must, of necessity, be based on estimates and informed judgments. These Financial Statements were prepared in accordance with accounting principles generally accepted in Canada, including selected accounting treatments that differ from those used by entities not subject to rate regulation. Financial information contained elsewhere in the 2008 Annual Report is consistent with that in the Financial Statements.

In meeting its responsibility for the reliability and integrity of the Financial Statements, management has developed and maintains a system of accounting and reporting which provides for the necessary internal controls to ensure transactions are properly authorized and recorded, assets are safeguarded and liabilities are recognized. The systems of the Company focus on the need for training of qualified and professional staff and the effective communication of management guidelines and policies. The effectiveness of the internal controls of Newfoundland Power Inc. is evaluated on an ongoing basis.

The Board of Directors oversees management's responsibility for financial reporting through an Audit & Risk Committee which is composed entirely of external independent directors. The Audit & Risk Committee oversees the external audit of the Company's Annual Financial Statements and the accounting and financial reporting and disclosure processes and policies of the Company. The Audit & Risk Committee meets with management, the shareholders' auditors and the internal auditor to discuss the results of the audit, the adequacy of internal accounting controls and the quality and integrity of financial reporting. The Company's Annual Financial Statements are reviewed by the Audit & Risk Committee with each of management and the shareholders' auditors before the statements are recommended to the Board of Directors for approval. The shareholders' auditors have full and free access to the Audit & Risk Committee.

The Audit & Risk Committee has the duty to review the adoption of, and changes in, accounting principles and practices which have a material effect on the Company's financial statements and to review and report to the Board of Directors on policies relating to accounting and financial reporting and disclosure processes. The Audit & Risk Committee has the duty to review financial reports requiring the approval of the Board of Directors prior to submission to securities commissions or other regulatory authorities, to assess and review management's judgments that are material to reported financial information and to review shareholders' auditors' independence and auditors' fees.

The December 31, 2008 Financial Statements and Management Discussion and Analysis contained in the 2008 Annual Report were reviewed by the Audit & Risk Committee and, on their recommendation, were approved by the Board of Directors of Newfoundland Power Inc. Ernst & Young, LLP, independent auditors appointed by the shareholders of Newfoundland Power Inc. upon recommendation of the Audit & Risk Committee, have performed an audit of the 2008 Financial Statements and their report follows.

Earl Ludlow
President
and Chief Executive Officer

Jocelyn Perry
Vice President, Finance
and Chief Financial Officer

# Auditors' Report

To the Shareholders,
Newfoundland Power Inc.

We have audited the balance sheets of Newfoundland Power Inc. as at December 31, 2008 and 2007 and the statements of earnings, retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2008 and 2007 and the results of its operations and cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Ernst + Young LLP

Chartered Accountants
St. John's, Canada

January 22, 2009

## Statements of Earnings

**For the years ended December 31**

*(in thousands of Canadian dollars except per share amounts)*

| | 2008 | 2007 |
|---|---|---|
| Revenue | $ 516,889 | $ 491,709 |
| Purchased Power | 336,658 | 326,778 |
| **Net Margin** | 180,231 | 164,931 |
| | | |
| Operating Expenses | 47,132 | 47,501 |
| Pension and Early Retirement Program Costs | 3,040 | 5,701 |
| Amortization | 40,649 | 39,955 |
| Amortization True-Up Deferral *(Note 4)* | 3,862 | (5,793) |
| Finance Charges *(Note 5)* | 33,507 | 34,939 |
| | 128,190 | 122,303 |
| | | |
| **Earnings before Income Taxes** | 52,041 | 42,628 |
| Income Taxes *(Note 6)* | 19,146 | 12,176 |
| | | |
| **Net Earnings** | 32,895 | 30,452 |
| Preference Share Dividends | 554 | 586 |
| | | |
| **Net Earnings Applicable to Common Shares** | $ 32,341 | $ 29,866 |
| **Basic and Diluted Earnings per Common Share** | $ 3.13 | $ 2.89 |

## Statements of Retained Earnings

**For the years ended December 31**

*(in thousands of Canadian dollars)*

| | 2008 | 2007 |
|---|---|---|
| **Balance, Beginning of the Year** | $ 286,350 | $ 265,566 |
| Net Earnings | 32,895 | 30,452 |
| Dividends | | |
| Preference shares | (554) | (586) |
| Common shares | (15,274) | (9,082) |
| **Balance, End of the Year** | $ 303,417 | $ 286,350 |

*See accompanying notes to financial statements.*

## Balance Sheets
### As at December 31
*(in thousands of Canadian dollars)*

| | 2008 | 2007 |
|---|---|---|
| **Assets** | | |
| **Current assets** | | |
| Cash | $ 619 | $ 1,067 |
| Accounts receivable | 63,508 | 70,792 |
| Regulatory assets *(Note 4)* | 9,426 | 7,086 |
| Materials and supplies | 1,016 | 928 |
| Prepaid expenses | 1,292 | 1,190 |
| Income tax receivable | - | 1,780 |
| | 75,861 | 82,843 |
| **Capital assets** *(Note 7)* | 774,957 | 750,794 |
| **Deferred charges** *(Note 8)* | 93,273 | 88,674 |
| **Regulatory assets** *(Note 4)* | 55,988 | 61,808 |
| **Customer finance plans** *(Note 9)* | 1,776 | 1,811 |
| | $1,001,855 | $ 985,930 |
| **Liabilities and Shareholders' Equity** | | |
| **Current liabilities** | | |
| Accounts payable and accrued charges | $ 65,548 | $ 68,685 |
| Regulatory liabilities *(Note 4)* | 6,428 | 9,020 |
| Current instalments of long-term debt *(Note 13)* | 4,550 | 4,550 |
| Income tax payable | 7,633 | - |
| | 84,159 | 82,255 |
| **Regulatory liabilities** *(Note 4)* | 54,817 | 60,593 |
| **Other liabilities** *(Note 14)* | 45,001 | 38,082 |
| **Future income taxes** *(Note 6)* | 1,184 | - |
| **Long-term debt** *(Note 13)* | 433,604 | 438,977 |
| | 618,765 | 619,907 |
| **Shareholders' equity** | | |
| Common shares *(Note 10)* | 70,321 | 70,321 |
| Preference shares *(Note 10)* | 9,352 | 9,352 |
| Retained earnings | 303,417 | 286,350 |
| | 383,090 | 366,023 |
| | $1,001,855 | $ 985,930 |

Commitments *(Note 19)*

*See accompanying notes to financial statements.*

APPROVED ON BEHALF OF THE BOARD:

Chris Griffiths
Director

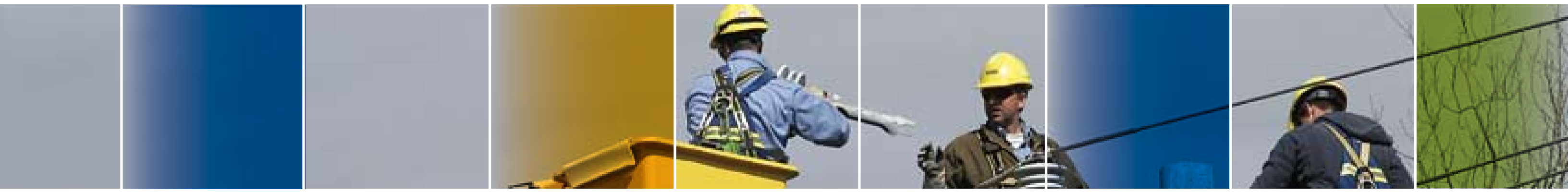
David Norris
Director

## Statements of Cash Flows
**For the years ended December 31**
*(in thousands of Canadian dollars)*

| | 2008 | 2007 |
|---|---|---|
| **Cash From (Used In) Operating Activities** | | |
| Net earnings | $ 32,895 | $ 30,452 |
| **Items not affecting cash** | | |
| Amortization of capital assets | 40,649 | 39,955 |
| Amortization of deferred charges | 298 | 318 |
| Change in regulatory assets and liabilities | 305 | (6,180) |
| Future income taxes | 1,184 | - |
| Accrued employee future benefits | (4,471) | (7,407) |
| Change in non-cash working capital | 14,191 | (7,887) |
| | 85,051 | 49,251 |
| **Cash From (Used In) Investing Activities** | | |
| Capital expenditures (net of salvage) | (67,333) | (72,167) |
| Long-term portion of finance programs | 35 | (84) |
| Contributions from customers and security deposits | 3,227 | 2,580 |
| | (64,071) | (69,671) |
| **Cash From (Used In) Financing Activities** | | |
| Change in short-term borrowings | - | (320) |
| Proceeds from long-term debt | 33,500 | 70,000 |
| Proceeds from related party loan *(Note 11)* | 32,500 | - |
| Repayment of long-term debt | (39,050) | (37,851) |
| Repayment of related party loan *(Note 11)* | (32,500) | - |
| Payment of debt financing costs | (50) | (273) |
| Redemption of preference shares | - | (1) |
| Dividends | | |
| Preference shares | (554) | (586) |
| Common shares | (15,274) | (9,082) |
| | (21,428) | 21,887 |
| **Increase (Decrease) in Cash** | (448) | 1,467 |
| **Cash (Bank Indebtedness), Beginning of the Year** | 1,067 | (400) |
| **Cash, End of the Year** | $ 619 | $ 1,067 |

*Supplementary Information to Statements of Cash Flows (Note 15)*

*See accompanying notes to financial statements.*



# Notes to Financial Statements

## December 31, 2008

**Tabular amounts are in thousands of Canadian dollars unless otherwise noted.**

### 1. Description of Business

Newfoundland Power Inc. (the "Company" or "Newfoundland Power") is a regulated electricity utility that operates an integrated generation, transmission and distribution system throughout the island portion of Newfoundland and Labrador. The Company is regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities (the "PUB") and serves approximately 236,000 customers comprising about 85% of all electricity consumers in the province. The Company is a wholly-owned subsidiary of Fortis Inc. ("Fortis"). Newfoundland Power has an installed generating capacity of 140 megawatt ("MW"), of which approximately 97 MW is hydroelectric generation. It generates approximately 8% of its energy needs and purchases the remainder from Newfoundland and Labrador Hydro ("Hydro").

### 2. Summary of Significant Accounting Policies

These financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). As a result of rate regulation, the timing of the recognition of certain assets, liabilities, revenues and expenses may differ from that otherwise expected under Canadian GAAP for entities not subject to rate regulation. These differences are disclosed below and in Note 4.

#### Regulation

The Company operates under cost of service regulation as administered by the PUB under the Public Utilities Act (Newfoundland and Labrador) ("Public Utilities Act").

The Public Utilities Act provides for the PUB's general supervision of the Company's utility operations and requires the PUB to approve, among other things, customer rates, capital expenditures and the issuance of securities. The Public Utilities Act also entitles the Company an opportunity to recover all reasonable and prudent costs incurred in providing electricity service to its customers, including a just and reasonable return on its rate base. The rate base consists of the net assets required by the Company to provide service to customers.

The determination of the forecast return on rate base, together with the forecast of all reasonable and prudent costs, establishes the revenue requirement upon which the Company's customer rates are determined through a general rate hearing. Rates are bundled to include generation, transmission and distribution services.

As a result of the Company's 2008 General Rate Application ("2008 GRA"), the forecast cost of common equity reflected in customer rates for 2008 is 8.95% (2007 - 8.60%). Between general rate hearings, customer rates are established annually through the operation of an automatic adjustment formula (the "Formula") that sets an appropriate annual rate of return on rate base based upon changes in the forecast cost of common equity. In accordance with the operation of the Formula, as approved by the PUB in 2008, the Company's rate of return on rate base was set at 8.37%, with a range of 8.19% to 8.55% for 2009, unchanged from 2008.

#### Revenue Recognition

Revenue arising from the amortization of certain regulatory assets and liabilities is recognized in the manner prescribed by the PUB, as disclosed in Note 4. Otherwise, revenue is recognized under the accrual method.

#### Capital Assets

Capital assets are stated at values approved by the PUB as at June 30, 1966, with subsequent additions at cost. Contributions in aid of construction represent the cost of utility capital assets contributed by customers and government. These contributions are recorded as a reduction in the cost of utility capital assets and are being reduced annually by an amount equal to the charge for amortization provided on the related assets.

The Company capitalizes certain overhead costs not directly attributable to specific capital assets but which do relate to its overall capital expenditure program (general expenses capitalized or "GEC"). The methodology for calculating and allocating GEC among classes of capital assets is established by PUB order. In the absence of rate regulation, only those overhead costs directly attributable to construction activity would be capitalized. In 2008, GEC totalled $2.8 million (2007 - $2.8 million).

The Company capitalizes an allowance for funds used during construction ("AFUDC"), which represents the cost of debt and equity financing incurred during construction of capital assets. Effective January 1, 2008, AFUDC is calculated in a manner prescribed by the PUB based on a capitalization rate that is the Company's weighted average cost of capital. Prior to that, AFUDC was calculated based on a capitalization rate that, depending on the source of financing, may be either (i) the Company's average short-term borrowing rate; (ii) its rate of return on rate base; or (iii) a blended average of these two rates. In 2008, the cost of equity financing capitalized as an AFUDC and deducted from financing charges was approximately $0.3 million (2007 - $0.2 million). In the absence of rate regulation, this cost of equity financing would be expensed.

Capital assets are amortized using the straight-line method by applying the amortization rates disclosed below to the average original cost, including GEC and AFUDC, of the related assets. A half-year of amortization is recognized on capital assets during the year in which they are placed into service and during the year of disposition.

The composite amortization rates for the Company's capital assets, as well as their service life ranges and average remaining service lives as at December 31, follow.

| | Composite Amortization Rate | | Service Life (Years) Range | | Service Life (Years) Average Remaining | |
|---|---|---|---|---|---|---|
| | 2008 | 2007 | 2008 | 2007 | 2008 | 2007 |
| Distribution | 3.1% | 3.3% | 16-65 | 16-65 | 23 | 23 |
| Transmission and substations | 2.9 | 2.8 | 31-65 | 31-65 | 26 | 26 |
| Generation | 2.6 | 2.2 | 13-75 | 13-75 | 32 | 32 |
| Transportation and communications | 8.9 | 8.7 | 5-30 | 5-30 | 5 | 5 |
| Buildings | 2.3 | 2.5 | 35-70 | 35-70 | 27 | 27 |
| Equipment | 9.0 | 9.2 | 5-25 | 5-25 | 5 | 5 |
| | 3.4% | 3.5% | | | | |

The Company's amortization methodology, including amortization rates, accumulated amortization and estimated remaining service lives, is subject to periodic review by external experts (the "Amortization Study"). The differences between actual accumulated amortization and that indicated by the Amortization Study (the "Amortization True-Up") is deferred as a regulatory asset (liability), and is amortized as an increase (decrease) in amortization expense and included in customer rates in a manner prescribed by the PUB. The most recent Amortization Study, based on capital assets in service as at December 31, 2005, indicates an Amortization True-Up of approximately $0.7 million. The PUB ordered that it be amortized as a decrease in amortization expense equally over 2008 - 2011. See Note 4.

Effective January 1, 2008, the PUB ordered the implementation of the revised amortization rates arising from the Company's most recent Amortization Study. As a result, the composite amortization rate declined to 3.4% in 2008 from 3.5% in 2007.

Upon disposition, the original cost of capital assets is removed from the capital asset accounts. That amount, net of salvage proceeds, is also removed from accumulated amortization. As a result, any gain or loss is charged to accumulated amortization and is effectively included in the Amortization True-Up arising from the next Amortization Study. In 2008, approximately $6.8 million (2007 - $7.2 million) of losses were charged to accumulated amortization. In the absence of rate-regulation, these amounts would have been recognized as losses upon disposition.

### Materials and Supplies

Effective January 1, 2008, in accordance with the adoption of the new Canadian Institute of Chartered Accountants ("CICA") Handbook section 3031 - Inventory, materials and supplies, representing fuel and materials required for maintenance activities, are carried at the lower of cost or net realizable value. This standard has been applied retroactively to 2007.

### Deferred Capital Stock Issue Costs

Capital stock issue costs are recognized as deferred charges and are amortized as finance charges on a straight-line basis over 20 years. In the absence of rate regulation, capital stock issue costs would be recognized as a reduction in share capital and would not be amortized.

### Future Income Taxes

Effective January 1, 1981, as prescribed by the PUB, future income tax liabilities are recognized, and recovered in customer rates, on temporary timing differences associated with the cumulative excess of capital cost allowance over amortization of capital assets, excluding GEC.

Future income tax expense (recovery) associated with the Company's regulatory reserves and certain regulatory deferrals is also recognized and included in the determination of customer rates. See Note 4.

Effective January 1, 2008, as prescribed by the PUB, future income taxes are recognized and recovered in customer rates on temporary timing differences between pension expense and pension funding.

Future income tax assets and liabilities associated with other temporary timing differences between the tax basis of assets and liabilities and their carrying amount are not recognized or included in customer rates. Unrecognized amounts are expected to be recovered from (refunded to) customers through rates when the income taxes actually become payable (recoverable). The Company's unrecognized net future income tax liability at December 31, 2008 was $72.6 million (2007 - $74.4 million).

### Employee Future Benefits

Newfoundland Power maintains defined contribution and defined benefit pension plans for its employees and also provides other post-employment benefits ("OPEBs"). OPEBs are composed of retirement allowances for retiring employees as well as health, medical and life insurance for retirees and their dependants.

### Defined Contribution and Defined Benefit Pension Plans

Defined contribution pension plan costs are expensed as incurred.

The pension costs and accrued benefit obligations of the defined benefit pension plans are actuarially determined using the projected benefit method pro-rated on service and management's best estimate of expected plan investment performance, salary escalation and retirement ages of employees. Pension plan assets are valued using the market-related value where investment returns in excess of or below expected returns are recognized in asset value over a period of three years. The excess of the cumulative net actuarial gain or loss over 10% of the greater of the benefit obligation and the market-related value of plan assets is amortized over the estimated average remaining service period of active employees. The transitional obligation arising from the Company's January 1, 2000 adoption of Section 3461 of the CICA Handbook is being amortized on a straight-line basis over the 18 year expected average remaining service period of plan members at that time. Unamortized past service costs are amortized over a range of 5 - 15 years. See Notes 4 and 16.

### OPEBs

OPEBs costs, excluding retirement allowances arising from the Company's 2005 Early Retirement Program ("ERP"), are expensed when benefits are paid. As ordered by the PUB, in 2007, the Company completed expensing the final portion of retirement allowances associated with its 2005 ERP in the amount of $0.1 million. In the absence of rate regulation, OPEBs costs would be recognized as expense on an accrual basis as actuarially determined. The portion of the actuarially determined costs that is not recognized as an expense is deferred as a regulatory asset, as these costs are expected to be recovered in future customer rates in a manner determined by the PUB. See Note 4.

OPEBs costs and the accrued OPEB obligation are actuarially determined using the projected benefits method prorated on service and best estimate assumptions. The excess of any cumulative net actuarial gain or loss over 10% of the benefit obligation, along with unamortized past service costs is amortized over the estimated average remaining service period of active employees. The transitional obligation arising from the Company's January 1, 2000 adoption of Section 3461 of the CICA Handbook is being amortized on a straight-line basis over the 18 year expected average remaining service period of plan members at that time. In each case, amortization is recognized as a change in both the OPEBs regulatory asset and the accrued OPEBs liability.

In the absence of rate regulation, OPEBs costs recognized in 2008 operating expenses would have been $6.5 million higher (2007 - $6.7 million higher).

### Financial Instruments

The Company has designated its financial instruments as follows:

(a) Cash is classified as "Held for Trading". After its initial fair value measurement, any change in fair value is recognized in earnings.

(b) Accounts receivable and loans under customer finance plans (Note 9) are classified as "Loans and Receivables". Short-term borrowings, bank indebtedness, accounts payable and accrued charges, security deposits (Note 14), and long-term debt are classified as "Other Financial Liabilities". Initial measurement is at fair value and incorporates transaction costs, including deferred debt issue costs. Subsequent measurement is at amortized cost using the effective interest method. For the Company, the measurement amount approximates cost.

### Asset Retirement Obligations

Under Canadian GAAP, the Company is required to record the fair value of future expenditures necessary to settle legal obligations associated with asset retirements even though the timing or method of settlement is conditional on future events. Newfoundland Power has determined that there are asset retirement obligations ("AROs") associated with its generation assets and some parts of its transmission and distribution system.

For generation assets, the legal obligation is the environmental remediation of the land and waterways to protect fish habitat. However, this obligation is conditional on the decision to decommission generation assets. The Company currently has no plans to decommission any of its hydroelectric generation assets as they are effectively operated in perpetuity. Therefore, the nature and fair value of any ARO is not currently determinable.

For the transmission and distribution system, the legal obligations, which pertain to the proper disposal of fuel storage tanks, used oil and asbestos, were determined to be immaterial. Therefore, no AROs have been recognized.

The Company will recognize AROs and offsetting capital assets if the nature and timing can reasonably be determined and the amount is material.

### Use of Accounting Estimates

The preparation of financial statements in accordance with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting periods. Additionally, certain estimates are necessary since the regulatory environment in which the Company operates may require amounts to be recorded at estimated values until these amounts are finalized pursuant to PUB Order.

Estimates are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances. Due to changes in facts and circumstances and the inherent uncertainty involved in making estimates, actual results may differ from current estimates. Estimates are reviewed periodically and, as adjustments become necessary, are reported in earnings in the period during which they either, as appropriate, become known or included in customer rates.

## 3. Change in Accounting Policies

### 2008 Changes

Future Income Tax: The PUB ordered that future income tax on temporary timing differences between pension expense and pension funding be recognized and included in the determination of customer rates commencing January 1, 2008. The Company recognized future income tax expense of $0.6 million during 2008, and a corresponding future income tax liability, in accordance with this order. This change had no impact on earnings for the year as the additional expense was reflected in customer rates effective January 1, 2008

Inventories: Effective January 1, 2008, the Company adopted the new CICA Handbook Section 3031 - Inventory. It requires inventories to be measured at the lower of cost or net realizable value; disallows the use of a last-in first-out inventory costing methodology; and, requires that, when circumstances which previously caused inventories to be written down below cost no longer exist, the amount of the write down is to be reversed. As at January 1, 2008, inventories of $4.3 million (2007 - $4.1 million) were reclassified to capital assets on the balance sheet as they are held for the development, construction, maintenance and repair of other capital assets. Inventories expensed in 2008 and 2007 were immaterial.

Capital Disclosures: Effective January 1, 2008, the Company adopted the new CICA Handbook Section 1535 - Capital Disclosures. It required the Company to disclose quantitative and qualitative information regarding objectives, policies and processes for managing capital. This new Standard did not have any impact on the Company's 2008 financial results. See Note 17.

Disclosure and Presentation of Financial Instruments: Effective January 1, 2008, the Company adopted Sections 3862 and 3863 of the CICA Handbook which set out new accounting recommendations for disclosure and presentation of financial instruments. The new recommendations require disclosure of both quantitative and qualitative information that enables users of financial statements to evaluate the nature and extent of risks from financial instruments to which the Company is exposed. These recommendations did not have any impact on the Company's financial results. The additional required disclosure is included in Note 18 to the Company's 2008 annual audited financial statements.

**Future Changes**

International Financial Reporting Standards ("IFRS"): In February 2008, the Accounting Standards Board ("AcSB") confirmed that the use of IFRS will be required in 2011 for publicly accountable enterprises in Canada. In April 2008, the AcSB issued an IFRS Omnibus Exposure Draft proposing that publicly accountable enterprises be required to apply IFRS, in full and without modification, on January 1, 2011. The transition date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported by the Company for its year ended December 31, 2010, and of the opening balance sheet as at January 1, 2010. The AcSB proposes that CICA Handbook Section - Accounting Changes, paragraph 1506.30, which would require an entity to disclose information relating to a new primary source of Canadian GAAP that has been issued but is not yet effective and that the entity has not applied, not be applied with respect to this Exposure Draft.

Newfoundland Power is continuing to assess the financial reporting impacts of the adoption of IFRS and, at this time, the impact on future financial position and results of operations is not reasonably determinable or estimable. Further, the Company anticipates a significant increase in disclosure resulting from the adoption of IFRS and is continuing to assess the level of disclosure required and any necessary system changes to gather and process the information.

Rate Regulated Operations: Given its strategic plan to adopt IFRS, the AcSB revisited the scope of its project on accounting for rate-regulated operations in recognition of the fact that IFRS do not currently provide any special guidance with respect to accounting practices that are unique to rate-regulated entities. As a result, it has removed certain guidance from the CICA Handbook. Newfoundland Power's assessment of these changes is that effective January 1, 2009 it will be required to (i) disclose separately on its balance sheets future income tax assets and liabilities that, in accordance with PUB approved accounting policies, are currently unrecognized along with corresponding regulatory liabilities and assets, and (ii) include in these amounts the future income tax effects of the subsequent settlement of the regulatory assets and liabilities through customer rates. These changes would not affect earnings or cash flows. If calculated in accordance with the revised guidance, the net unrecognized future income tax liability now disclosed in Note 2 to the Company's 2008 annual financial statements would increase by approximately $30.3 million (2007 - increase of approximately $30.7 million) to $102.9 million at December 31, 2008 (December 31, 2007 - $105.1 million).

Goodwill and Intangible Assets: Effective January 1, 2009, the Company will adopt new CICA Handbook Section 3064 - Goodwill and Intangible Assets, which effectively converges Canadian GAAP for intangible assets with IFRS. The new Standard provides more comprehensive guidance on the definition and initial recognition criteria of intangible assets, including internally generated intangible assets. Adoption of this standard on the Company's financial statements will result in the reclassification of certain assets currently included in capital assets to intangible assets. The items to be reclassified consist of certain computer software and land rights. As at December 31, 2008, $13.8 million and $2.3 million are included in capital assets related to certain computer software and land rights, respectively.

## 4. Regulatory Assets and Liabilities

Regulatory assets and liabilities arise as a result of the rate-setting process. Regulatory assets represent future revenues associated with certain costs incurred in the current or prior periods that will be, or are expected to be, recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent future reductions or limitations of increases in revenues associated with amounts that will be, or are expected to be, refunded to customers through the rate-setting process. The accounting methods underlying regulatory assets and liabilities, and their eventual settlement through the rate-setting process, are prescribed by the PUB and impact the Company's cashflows.

The Company's regulatory assets and liabilities, which will be, or are expected to be, reflected in customer rates in future periods, follow.

| | 2008 | | 2007 | |
|---|---|---|---|---|
| | Current | Non-current | Current | Non-current |
| Regulatory Assets | | | | |
| Rate stabilization account (i) | $ 2,486 | $ 4 | $ (70) | $ 1,761 |
| OPEBs *(Note 2)* | - | 41,074 | - | 34,527 |
| Weather normalization account (ii) | 1,366 | 4,544 | 1,366 | 9,151 |
| Amortization true-up deferral (iii) | 3,862 | 3,862 | 3,862 | 7,724 |
| Pension deferral (iv) | 1,128 | 5,920 | 1,128 | 7,048 |
| Replacement energy deferral (v) | 383 | 383 | 383 | 764 |
| Deferred GRA costs (vi) | 201 | 201 | 417 | 833 |
| | $ 9,426 | $ 55,988 | $ 7,086 | $ 61,808 |
| Regulatory Liabilities | | | | |
| Municipal tax liability (vii) | $ 1,363 | $ 1,364 | $ 1,363 | $ 2,726 |
| Unbilled revenue (viii) | 4,618 | 4,618 | 7,210 | 9,236 |
| Purchased power unit cost variance reserve (ix) | 447 | 448 | 447 | 1,203 |
| Future removal and site restoration provision (x) | - | 47,961 | - | 47,428 |
| Demand management incentive account (xi) | - | 426 | - | - |
| | $ 6,428 | $ 54,817 | $ 9,020 | $ 60,593 |

### (i) Rate Stabilization Account ("RSA")

The RSA passes through to the Company's customers amounts primarily related to changes in the cost and quantity of fuel used by Hydro to produce the electricity sold to the Company. Operation of this account has no earnings impact. On July 1 of each year, customer rates are recalculated in order to amortize over the subsequent twelve months the balance in the rate stabilization account as of March 31 of the current year. In the absence of rate regulation these transactions would be accounted for in a similar manner, however, the amount and timing of the recovery or refund would not be subject to PUB approval.

The marginal cost of purchased power for the Company currently exceeds the average cost that is embedded in customer rates. To the extent actual electricity sales in any period exceed forecast electricity sales used to set customer rates, marginal purchased power expense will exceed related revenue. The PUB ordered, effective January 1, 2008, that variations in purchased power expense caused by differences between the actual unit cost of energy and that reflected in customer rates be recovered from (refunded to) customers through the rate stabilization account.

### (ii) Weather Normalization Account

The weather normalization account reduces earnings volatility by adjusting purchased power expense and electricity sales revenue to eliminate variances in purchases and sales caused by the difference between normal weather conditions, based on long-term averages, and actual weather conditions. In the absence of rate regulation these fluctuations would be recognized in earnings in the period in which they occurred.

The balance in the weather normalization account, because it is based on long-term averages for weather conditions, should tend to zero over time. However, the Company indentified non-reversing balances in the account arising from changes in purchased power rates and income tax rates. Effective January 1, 2003, the PUB ordered that a non-reversing balance of approximately $5.6 million be amortized equally over 2003-2007 as an increase in purchased power expense of approximately $1.7 million and a decrease in future income tax expense of approximately $0.6 million in each year. Effective January 1, 2008, the PUB ordered that a non-reversing balance of approximately $6.8 million be amortized equally over 2008-2012 as an increase in purchased power expense of approximately $2.1 million and a decrease in future income tax expense of approximately $0.7 million in each year.

The recovery period for the outstanding balance in the weather normalization account is not determinable as it depends on future weather conditions. In the absence of rate regulation, revenue in 2008 would have been $7.6 million lower (2007 - $1.8 million lower), purchased power expense in 2008 would have been $14.6 million lower (2007 - $3.8 million lower) and future income tax expense in 2008 would have been $2.4 million higher (2007 - $0.7 million higher).

### (iii) Amortization True-Up Deferral

The PUB ordered the deferred recovery of approximately $5.8 million in each of 2006 and 2007, $11.6 million in aggregate, related to a variance in accumulated amortization identified in the 2002 amortization study. These deferrals were recorded as an increase in regulatory assets and a decrease in expenses of $5.8 million in each year. Amortization of $3.9 million was recorded in 2008 in accordance with the PUB order that the resultant regulatory asset of approximately $11.6 million be amortized evenly over 2008 through 2010. In the absence of rate regulation, $11.6 million would have been expensed in the original years incurred.

### (iv) Pension Deferral

The PUB ordered that approximately $11.3 million of incremental pension costs arising from the Company's 2005 early retirement program be deferred and amortized equally over a ten year period beginning April 1, 2005. In the absence of rate regulation, these costs would have been expensed in 2005.

### (v) Replacement Energy Deferral

Effective January 1, 2008, the PUB ordered that a $1.1 million regulatory asset related to the deferred recovery of the cost of replacement energy purchased during the refurbishment of the Company's Rattling Brook hydroelectric generating plant be amortized equally over 2008 - 2010 as an increase in purchased power expense of approximately $0.6 million and a decrease in future income tax expense of approximately $0.2 million in each year. In the absence of rate regulation, these costs would have been expensed in 2007.

### (vi) Deferred GRA Costs

In 2007, the PUB ordered that an estimated $1.3 million of external costs related to the Company's 2008 GRA be deferred and amortized evenly over 2008 - 2010. In early 2008, this estimate was reduced by $0.7 million to reflect actual costs. The actual costs of $0.6 million are being amortized evenly over 2008 - 2010. In the absence of rate regulation, the original accrued costs of $1.3 million would have been expensed in 2007, with the subsequent $0.7 million adjustment recorded as a reduction of expenses in 2008.

### (vii) Municipal Tax Liability

The $4.1 million municipal tax liability results from a timing difference related to the recovery and payment of municipal taxes under the Company's PUB approved municipal tax collection policy. The PUB ordered that this $4.1 million be amortized as other revenue equally over 2008 - 2010.

### (viii) Unbilled Revenue

Prior to January 1, 2006 revenue from electricity sales was recognized as bills were rendered to customers. Subsequent to this date, revenue is recognized on an accrual basis. The difference between revenue recognized on a billed basis and revenue recognized on an accrual basis as at December 31, 2005 was recorded on the balance sheet as a regulatory liability. As ordered by the PUB, the Company amortized approximately $7.2 million of this regulatory liability in 2008 (2007 - $2.7 million). The unamortized balance at December 31, 2008 will be amortized as follows: 2009 and 2010 – approximately $4.6 million in each year. In the absence of rate regulation, all the unbilled revenue would have been recognized as revenue during 2005.

### (ix) Purchased Power Unit Cost Variance Reserve

The purchased power unit cost variance reserve limited variation in the cost of purchased power associated with a demand and energy wholesale rate structure, to a PUB approved range.

Effective January 1, 2008, the PUB ordered the discontinuance of the purchased power unit cost variance reserve.

The PUB ordered that the December 31, 2006 balance in the reserve of approximately $1.3 million be amortized over 2008 - 2010 as a decrease in purchased power expense of approximately $0.7 million and an increase in future income tax expense of approximately $0.3 million in each year. In 2008, the PUB ordered that the balance in the account related to 2007 be transferred to the rate stabilization account in 2008.

### (x) Future Removal and Site Restoration Provision

This regulatory liability represents amounts collected in customer electricity rates over the life of certain capital assets which are attributable to removal and site restoration costs that are expected to be incurred in the future. Actual removal and site restoration costs, net of salvage proceeds, are recorded against the regulatory liability when incurred. The regulatory liability represents the amount of expected future removal and site restoration costs associated with capital assets in service as at December 31, calculated using current amortization rates as approved by the PUB. In the absence of rate regulation, removal and site restoration costs, net of salvage proceeds would be recognized as an operating expense when incurred.

### (xi) Demand Management Incentive Account

Through the demand management incentive account, variations in the unit cost of purchased power related to demand are limited, at the discretion of the PUB, to 1% of demand costs reflected in customer rates. Balances in this account are recorded as a regulatory asset or regulatory liability on Newfoundland Power's balance sheets. The disposition of balances in this account, which would be determined by a further order of the PUB, will consider the merits of the Company's conservation and demand management activities.

## 5. Finance Charges

| | 2008 | 2007 |
|---|---|---|
| Interest on first mortgage sinking fund bonds | $ 32,334 | $ 33,718 |
| Interest on committed revolving term credit facility | 1,187 | 1,437 |
| Interest on demand facility | 11 | 38 |
| Amortization of deferred debt issue costs | 235 | 256 |
| Amortization of capital stock issue costs *(Note 2)* | 62 | 62 |
| Interest on security deposits | 38 | 50 |
| Interest on related party loan | 258 | - |
| AFUDC *(Note 2)* | (618) | (622) |
| | $ 33,507 | $ 34,939 |

## 6. Income Taxes

Income taxes vary from the amount that would be determined by applying statutory income tax rates to pre-tax earnings. A reconciliation of the combined federal and provincial statutory income tax rate to the Company's effective income tax rate follows.

| | 2008 | 2007 |
|---|---|---|
| Statutory tax rate | 33.5% | 36.1% |
| Tax expense per financial statements | $ 19,146 | $ 12,176 |
| Accounting income per financial statements | 52,041 | 42,628 |
| | | |
| Expected tax expense (statutory rate) | 17,434 | 15,397 |
| Items capitalized vs. expensed | (926) | (1,029) |
| CCA vs. amortization | 1,088 | 1,402 |
| Pension funding vs. pension expense | (162) | (2,221) |
| Other timing differences | 265 | (562) |
| Unbilled revenue | 102 | 1,733 |
| Regulatory deferrals | 1,345 | (2,544) |
| Income tax expense | $ 19,146 | $ 12,176 |
| Effective tax rate | 36.8% | 28.6% |

The composition of the Company's income tax provision follows.

| | 2008 | 2007 |
|---|---|---|
| Current income tax expense | $ 20,346 | $ 12,432 |
| Future income tax recovery | (1,200) | (256) |
| | $ 19,146 | $ 12,176 |

Pursuant to a settlement agreement with the Canada Revenue Agency, current income taxes in 2008 include approximately $2.5 million (2007 - $2.7 million) related to the Company's January 1, 2006 adoption of the accrual method of revenue recognition for income tax purposes.

As at December 31, 2008, the Company had approximately $0.2 million (December 31, 2007 - $0.2 million) in capital losses carried forward which have not been recognized in the financial statements.

## 7. Capital Assets

| | Cost | | Accumulated Amortization | | Net Book Value | |
|---|---|---|---|---|---|---|
| | 2008 | 2007 | 2008 | 2007 | 2008 | 2007 |
| Distribution | $ 690,675 | $ 661,455 | $ 248,543 | $ 236,195 | $ 442,132 | $ 425,260 |
| Transmission and substations | 228,630 | 219,490 | 89,107 | 85,671 | 139,523 | 133,819 |
| Generation | 159,498 | 156,530 | 45,639 | 42,621 | 113,859 | 113,909 |
| Transportation and communications | 33,056 | 32,547 | 16,163 | 15,679 | 16,893 | 16,868 |
| Land, buildings and equipment | 100,706 | 98,745 | 44,657 | 42,682 | 56,049 | 56,063 |
| Construction in progress | 2,126 | 555 | - | - | 2,126 | 555 |
| Construction materials | 4,375 | 4,320 | - | - | 4,375 | 4,320 |
| | $1,219,066 | $1,173,642 | $ 444,109 | $ 422,848 | $ 774,957 | $ 750,794 |

Distribution assets are used to distribute low voltage electricity to customers and include poles, towers and fixtures, low voltage wires, transformers, overhead and underground conductors, street lighting, metering equipment and other related equipment.

Transmission and substations assets are used to transmit high voltage electricity to distribution assets and include poles; high voltage wires, switching equipment, transformers and other related equipment.

Generation assets are used to generate electricity and include hydroelectric and thermal generating stations, gas and combustion turbines, dams, reservoirs and other related equipment.

Transportation and communications assets include vehicles as well as telephone, radio and other communications equipment.

Land, buildings and equipment are used generally in the provision of electricity service but not specifically in the distribution, transmission or generation of electricity or specifically related to transportation and communication activities.

## 8. Deferred Charges

| | 2008 | 2007 |
|---|---|---|
| Deferred pension costs *(Note 16)* | $ 93,148 | $ 88,478 |
| Deferred credit facility costs | 50 | 59 |
| Deferred capital stock issue costs *(Note 2)* | 75 | 137 |
| | $ 93,273 | $ 88,674 |

## 9. Customer Finance Plans

Customer finance plans represent the non-current portion of loans to customers for certain new service requests and energy efficiency upgrades. The current portion of these loans is classified as accounts receivable. In the case of new service requests, and as prescribed by the PUB, interest is charged at a fixed rate of prime plus 3% for repayment periods up to 60 months and prime plus 4% for repayment periods of 61 months to 120 months. In the case of energy efficiency upgrades, interest is charged at a fixed rate of prime plus 4% for a maximum repayment period of 60 months. All loan instalments are made through the customers' monthly electricity bill payments. The balance of any loan may be repaid at any time without penalty.

## 10. Capital Stock

Authorized

(a) an unlimited number of Class A and Class B Common Shares without nominal or par value. The shares of each class are inter-convertible on a share-for-share basis and rank equally in all respects including dividends. The Board of Directors may provide for the payment, in whole or in part, of any dividends to Class B shareholders by way of a stock dividend;

(b) an unlimited number of First Preference Shares and Second Preference Shares without nominal or par value, except that each Series A, B, D and G First Preference Share has a par value of $10. The issued First Preference Shares are entitled to cumulative preferential dividends and are redeemable at the option of the Company at a premium not in excess of the annual dividend rate. Series D and G First Preference Shares are subject to the operation of purchase funds and the Company has the right to purchase limited amounts of these shares at or below par.

Issued

| | 2008 | | 2007 | |
|---|---|---|---|---|
| | Number of Shares | Amount | Number of Shares | Amount |
| Class A Common Shares | 10,320,270 | $ 70,321 | 10,320,270 | $ 70,321 |
| First Preference Shares | | | | |
| 5.50% Series A | 179,225 | 1,792 | 179,225 | 1,792 |
| 5.25% Series B | 337,983 | 3,380 | 337,983 | 3,380 |
| 7.25% Series D | 212,065 | 2,121 | 212,065 | 2,121 |
| 7.60% Series G | 205,950 | 2,059 | 205,950 | 2,059 |
| | 935,223 | $ 9,352 | 935,223 | $ 9,352 |

At December 31, 2008, Fortis held 230,194 or approximately 24.6% of the Company's issued and outstanding First Preference Shares.

## 11. Related Party Transactions

The Company provides services to, and receives services from, its parent Company, Fortis, and other subsidiaries of Fortis. The Company also incurs charges from Fortis for the recovery of general corporate expenses incurred by Fortis. Related party revenue primarily relates to electricity sales. These transactions are in the normal course of business and are recorded at their exchange amounts.

Related party transactions included in revenue, operating expenses and finance charges in 2008 and 2007, and in accounts receivable at December 31 of these years, follow.

| | 2008 | 2007 |
|---|---|---|
| Revenue | $ 4,225 | $ 4,078 |
| Operating expenses | $ 1,459 | $ 940 |
| Finance charges | $ 258 | $ - |
| Accounts receivable | $ 163 | $ 112 |

## 12. Credit Facilities

Newfoundland Power has unsecured bank credit facilities of $120 million comprised of a syndicated $100 million committed revolving term credit facility which matures on August 29, 2011 and a $20 million demand facility.

During the year, the $100 million committed revolving facility was renegotiated on similar terms as the previous facility. Subject to lenders approval, two years prior to maturity the Company may request an extension for a further period of 364 days, or alternatively, one year prior to maturity the Company may request an extension for a further period of up to one year and 364 days.

Borrowings under the committed facility have been classified as long-term as they are expected to remain outstanding for a period extending beyond one year from the balance sheet date and management intends to refinance these amounts in the future with the issuance of other long-term debt. These borrowings are in the form of bankers acceptances bearing interest based on the daily Canadian Deposit Offering Rate for the date of borrowing plus a stamping fee. Standby fees on the unutilized portion of the committed facility are payable quarterly in arrears at a fixed rate of 0.1375%. Interest on the demand facility is calculated at the daily prime rate and is payable monthly in arrears.

The utilized and unutilized credit facilities as at December 31 follow.

| | 2008 | 2007 |
|---|---|---|
| Total credit facilities | $ 120,000 | $ 120,000 |
| Borrowings under committed facility *(Note 13)* | (32,000) | (33,000) |
| Credit facilities available | $ 88,000 | $ 87,000 |

## 13. Long-term Debt

| | 2008 | 2007 |
|---|---|---|
| First mortgage sinking fund bonds | | |
| 10.550% $40 million Series AD, due 2014 | $ 30,953 | $ 31,353 |
| 10.900% $40 million Series AE, due 2016 | 33,200 | 33,600 |
| 10.125% $40 million Series AF, due 2022 | 33,600 | 34,000 |
| 9.000% $40 million Series AG, due 2020 | 34,400 | 34,800 |
| 8.900% $40 million Series AH, due 2026 | 35,235 | 35,635 |
| 6.800% $50 million Series AI, due 2028 | 45,000 | 45,500 |
| 7.520% $75 million Series AJ, due 2032 | 70,500 | 71,250 |
| 5.441% $60 million Series AK, due 2035 | 57,600 | 58,200 |
| 5.901% $70 million Series AL, due 2037 | 68,600 | 69,300 |
| Long-term classification of credit facilities *(Note 12)* | 32,000 | 33,000 |
| | 441,088 | 446,638 |
| Less: current installments of long-term debt | 4,550 | 4,550 |
| | 436,538 | 442,088 |
| Less: deferred debt issue costs | 2,934 | 3,111 |
| | $ 433,604 | $ 438,977 |

First mortgage sinking fund bonds are secured by a first fixed and specific charge on capital assets owned or to be acquired by the Company and by a floating charge on all other assets. They require an annual sinking fund payment of 1% of the original principal balance.

Future payments required to meet sinking fund instalments, maturities of long-term debt and long-term credit facilities follow.

| | |
|---|---|
| 2009 | $ 4,550,000 |
| 2010 | $ 4,550,000 |
| 2011 | $ 36,550,000 |
| 2012 | $ 4,550,000 |
| 2013 | $ 4,550,000 |
| 2014 and after | $ 386,338,000 |

## 14. Other Liabilities

| | 2008 | 2007 |
|---|---|---|
| Security deposits | $ 785 | $ 612 |
| OPEBs liability *(Note 16)* | 41,074 | 34,527 |
| Defined benefit pension liability - unfunded *(Note 16)* | 1,480 | 1,485 |
| Defined contribution pension liability *(Note 16)* | 1,662 | 1,458 |
| | $ 45,001 | $ 38,082 |

Security deposits are advance cash collections from certain customers to guarantee the payment of electricity bills. The security deposit liability includes interest credited to customer deposits. The current portion of security deposits is reported in accounts payable and accrued charges.

## 15. Supplementary Information to Statements of Cash Flows

| | 2008 | 2007 |
|---|---|---|
| Interest paid | $ 33,794 | $ 34,099 |
| Income taxes paid | $ 8,665 | $ 11,957 |
| Employee future benefits paid | $ 1,175 | $ 1,120 |

## 16. Employee Future Benefits

The Company's defined contribution plans are its individual and group registered retirement savings plans, and an unfunded supplementary employee retirement plan ("SERP"). Benefits are based upon employee earnings. The accrued benefit liability for the SERP is included in other liabilities on the Company's balance sheets (Note 14). During 2008, the Company expensed approximately $1.0 million (2007 - $1.0 million) related to these plans.

The Company's defined benefit plans are its funded defined benefit pension plan, an unfunded pension uniformity plan ("PUP") and OPEBs. Both pension plans are closed to new entrants and provide benefits based on a percentage of the highest 36 consecutive months average base earnings and the employee's years of service.

The accrued benefit obligation for all of the Company's defined benefit plans, and the market-related value of plan assets for the Company's funded primary defined benefit pension plan, are measured for accounting purposes as at December 31 of each year.

The most recent actuarial valuation of the Company's defined benefit pension plans for funding purposes was as of December 31, 2005 and the next required valuation will be performed as of December 31, 2008. The corresponding dates for the Company's OPEBs are December 31, 2007 and December 31, 2010, respectively.

The accrued benefit asset for the Company's funded primary defined benefit pension plan is included in deferred charges on the Company's balance sheets. The accrued benefits liability for the PUP is included in other liabilities.

Details of the Company's defined benefits plans follow.

| | 2008 | | | 2007 | | |
|---|---|---|---|---|---|---|
| | | Unfunded | | | Unfunded | |
| | Funded | PUP | OPEB | Funded | PUP | OPEB |
| **Change in accrued benefit obligation** | | | | | | |
| Balance, beginning of year | $ 235,477 | $ 2,558 | $ 70,411 | $ 239,176 | $ 2,695 | $ 69,804 |
| Current service costs | 4,844 | - | 1,384 | 4,997 | - | 1,412 |
| Interest cost | 12,740 | 135 | 3,901 | 12,368 | 136 | 3,698 |
| Benefits paid | (12,926) | (215) | (1,175) | (12,596) | (215) | (1,120) |
| Actuarial (gains) losses | (49,744) | (309) | (14,885) | (8,468) | (58) | (3,383) |
| Balance, end of year | $ 190,391 | $ 2,169 | $ 59,636 | $ 235,477 | $ 2,558 | $ 70,411 |

| | 2008 | | | 2007 | | |
|---|---|---|---|---|---|---|
| | | Unfunded | | | Unfunded | |
| | Funded | PUP | OPEB | Funded | PUP | OPEB |
| **Change in fair value of plan assets** | | | | | | |
| Balance, beginning of year | $ 259,731 | $ - | $ - | $ 250,226 | $ - | $ - |
| Return on assets | 19,169 | - | - | 17,694 | - | - |
| Benefits paid | (12,926) | (215) | (1,175) | (12,596) | (215) | (1,120) |
| Actuarial (losses) gains | (59,993) | - | - | (7,714) | - | - |
| Employee contributions | 1,193 | - | - | 1,216 | - | - |
| Employer contributions | 5,425 | 215 | 1,175 | 10,905 | 215 | 1,120 |
| Balance, end of year | $ 212,599 | $ - | $ - | $ 259,731 | $ - | $ - |
| **Funded status** | | | | | | |
| Surplus (deficit), end of year | $ 22,209 | $ (2,169) | $ (59,636) | $ 24,254 | $ (2,558) | $ (70,411) |
| Unamortized net actuarial loss | 56,768 | 269 | 6,277 | 48,431 | 606 | 22,171 |
| Unamortized transitional obligation | 11,584 | 419 | 12,285 | 12,871 | 466 | 13,713 |
| Unamortized past service costs | 2,587 | 1 | - | 2,922 | 1 | - |
| Accrued benefit asset (liability), end of year | $ 93,148 | $ (1,480) | $ (41,074) | $ 88,478 | $ (1,485) | $ (34,527) |
| **Effect of 1% increase in health care cost trends on:** | | | | | | |
| Accrued benefit obligation | - | - | $ 8,319 | - | - | $ 12,403 |
| Service costs and interest cost | - | - | $ 1,013 | - | - | $ 988 |
| **Effect of 1% decrease in health care cost trends on:** | | | | | | |
| Accrued benefit obligation | - | - | $ (6,707) | - | - | $ (9,637) |
| Service costs and interest cost | - | - | $ (808) | - | - | $ (749) |
| **Significant assumptions** | | | | | | |
| Discount rate during year | 5.50% | 5.50% | 5.50% | 5.25% | 5.25% | 5.25% |
| Discount rate as at December 31 | 7.50% | 7.50% | 7.50% | 5.50% | 5.50% | 5.50% |
| Expected long-term rate of return on plan assets | 7.50% | - | - | 7.50% | - | - |
| Rate of compensation increases | 4.00% | 4.00% | 4.00% | 4.00% | 4.00% | 4.00% |
| Health care cost trend increases as at December 31 | - | - | 4.50% | - | - | 4.50% |
| Expected average remaining service of active employees | 12 years | 12 years | 15 years | 13 years | 13 years | 15 years |
| **Net benefit expense** | | | | | | |
| Current service costs | $ 3,651 | $ - | $ 1,384 | $ 3,781 | $ - | $ 1,412 |
| Interest cost | 12,740 | 135 | 3,901 | 12,368 | 136 | 3,698 |
| Expected return on plan assets | (19,169) | - | - | (17,694) | - | - |
| Amortization of transitional obligation | 1,287 | 47 | 1,428 | 1,287 | 47 | 1,428 |
| Amortization of net actuarial loss | 1,911 | 28 | 1,009 | 3,168 | 31 | 1,327 |
| Amortization of past service costs | 335 | - | - | 335 | - | - |
| Regulatory adjustment *(Note 4)* | 1,128 | - | (6,547) | 1,128 | - | (6,745) |
| Net benefit expense | $ 1,883 | $ 210 | $ 1,175 | $ 4,373 | $ 214 | $ 1,120 |
| **Asset allocation** | | | | | | |
| Fixed income | 48% | - | - | 38% | - | - |
| Equities | 32% | - | - | 44% | - | - |
| Foreign equities | 20% | - | - | 18% | - | - |

## 17. Capital Management

Newfoundland Power's primary objectives when managing capital are (i) to ensure continued access to capital at reasonable cost, and (ii) to provide an adequate return to its common shareholder commensurate with the level of risk associated with the shareholder's investment in the Company.

The Company requires ongoing access to capital because its business is capital intensive. Capital investment is required to ensure continued and enhanced performance, reliability and safety of its electricity system and to meet customer growth.

The Company operates under cost of service regulation. The cost of capital is ultimately borne by its customers. Access to capital at reasonable cost is a core aspect of the Company's business strategy, which is to operate a sound electricity system and to focus on the safe and reliable delivery of electricity service to its customers in the most cost-efficient manner possible.

The capital managed by the Company is composed of debt (first mortgage sinking fund bonds, bank credit facilities and cash/bank indebtedness), common equity (common shares and retained earnings) and preferred equity.

The Company has historically generated sufficient cash flows from operating activities to service interest and sinking fund payments on debt, to pay dividends and to finance a major portion of its capital expenditure programs. Additional financing to fully fund capital expenditure programs is obtained through the Company's bank credit facilities and these borrowings are periodically refinanced along with any maturing bonds through the issuance of additional bonds. These basic cash flow and capital management dynamics are consistent with previous periods and are currently not expected to change materially over the foreseeable future.

Newfoundland Power endeavours to maintain a capital structure comprised of approximately 55% debt and 45% equity. This capital structure is reflected in customer rates. It is also consistent with the Company's current investment grade credit ratings, thereby ensuring continued access to capital at reasonable cost. Newfoundland Power maintains this capital structure primarily by managing its common share dividends.

A summary of the Company's capital structure follows.

| | December 31, 2008 | | December 31, 2007 | |
|---|---|---|---|---|
| | $ | % | $ | % |
| Debt | 437,535 | 53.3 | 442,460 | 54.7 |
| Common equity | 373,738 | 45.5 | 356,671 | 44.1 |
| Preferred equity | 9,352 | 1.2 | 9,352 | 1.2 |
| | 820,625 | 100.0 | 808,483 | 100.0 |

The issuance of debt with a maturity that exceeds one year requires the prior approval of the Company's regulator. The issuance of first mortgage sinking fund bonds is subject to an earnings covenant whereby the ratio of (i) annual earnings applicable to common shares, before bond interest and tax, to (ii) annual bond interest incurred plus annual bond interest to be incurred on the contemplated bond issue, must be two times or higher. Under its committed credit facility, the Company must also ensure that its Debt to Capitalization ratio does not exceed 0.65:1.00 at any time. During the year end at December 31, 2008 the Company was in compliance with all of its debt covenants.

## 18. Financial Instruments

The Company's financial instruments and their designations are (i) held for trading: cash; (ii) loans and receivables: accounts receivable and customer finance plans; and, (iii) other financial liabilities: short-term borrowings, accounts payable and accrued charges, security deposits, due to related party and long-term debt, including current portion.

Carrying Values: Cash is carried at fair value. The carrying value of long-term debt, including current portion, is measured at amortized cost using the effective interest method and is net of unamortized debt issue costs. The carrying value of the remaining financial instruments approximates amortized cost.

Fair Values: The fair value of long-term debt, including current portion, is calculated by discounting the future cash flows of each debt instrument at the estimated yield-to-maturity for the same or similar debt instruments at the balance sheet date. Since the Company does not intend to settle its debt instruments before maturity, the fair value estimate does not represent an actual liability and, therefore, does not include exchange or settlement costs.

The estimated fair value of the Company's first mortgage sinking fund bonds was $505.1 million at December 31, 2008 and $512.5 million at December 31, 2007.

The fair value of the Company's remaining financial instruments approximates their carrying value, reflecting either their nature, short-term maturity or normal trade credit terms.

Credit Risk: There is risk that Newfoundland Power may not be able to collect all of its accounts receivable and amounts owing under its customer finance plans. These financial instruments, which arise in the normal course of business, do not represent a significant concentration of credit risk as amounts are owed by a large number of customers on normal credit terms. The requirement for security deposits for certain customers, which are advance cash collections from customers to guarantee payment of electricity billings, further reduces the exposure to credit risk. The maximum exposure to credit risk is the net carrying value of these financial instruments.

Newfoundland Power manages credit risk primarily by executing its credit and collection policy, including the requirement for security deposits, through the resources of its Customer Relations Department.

The aging of accounts receivable and amounts owing under customer finance plans at December 31, 2008, follows.

| | **December 31, 2008** |
|---|---|
| Not past due | $ 34, 275 |
| Past due 1-30 days | 27,268 |
| Past due 31-60 days | 3,633 |
| Past due 61-90 days | 957 |
| Past due over 90 days | 423 |
| | 66,556 |
| Less: allowance for doubtful accounts | (1,272) |
| | $ 65,284 |

Liquidity Risk: The Company's financial position could be adversely affected if it failed to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures, repayment of maturing debt, and pension funding obligations.

The ability to arrange such financing is subject to numerous factors, including the results of operations and financial position of the Company, conditions in the capital and bank credit markets, ratings assigned by ratings agencies and general economic conditions. These factors are mitigated by the legal requirement as outlined in the Electrical Power Control Act which requires rates be set to enable the Company to achieve and maintain a sound credit rating in the financial markets of the world.

Newfoundland Power manages short-term liquidity risk primarily by maintaining bank credit facilities. The Company has unsecured facilities of $120 million, comprised of a syndicated $100 million committed revolving term credit facility and a $20 million demand facility.

Newfoundland Power manages long-term liquidity risk primarily by maintaining its investment grade credit ratings. See Note 17.

As at December 31, 2008, the fair value of the Company's primary defined benefit pension plan assets was $212.6 million compared to fair value of plan assets of $259.7 million as at December 31, 2007. The decrease in the fair value of pension plan assets during 2008 was mainly the result of unfavourable market conditions in 2008. The decline in pension plan assets is currently expected to increase the Company's future pension funding obligations. The amount of the increase will not be determinable until completion of next actuarial valuation. The next scheduled actuarial valuation is as at December 31, 2008 and this valuation is expected to occur in the first quarter of 2009. The Company does not expect any difficulty in its ability to meet future pension funding requirements as it expects the amounts will be financed from a combination of cash generated from operations and amounts available for borrowing under existing credit facilities.

The contractual maturities of the Company's financial liabilities at December 31, 2008 follow.

| | Total | 2009 | 2010-2011 | 2012-2013 | 2014 Oward |
|---|---|---|---|---|---|
| Accounts payable and accrued charges | 65.5 | 65.5 | - | - | - |
| Security deposits | 1.3 | 0.5 | 0.8 | - | - |
| Credit facilities (unsecured) | 32.0 | - | 32.0 | - | - |
| First mortgage sinking fund bonds[7] | 409.1 | 4.6 | 9.1 | 9.1 | 386.3 |
| | 507.9 | 70.6 | 41.9 | 9.1 | 386.3 |

[7] *First mortgage sinking fund bonds are secured by a first fixed and specific charge on capital assets owned or to be acquired by the Company and carry customary covenants.*

Market Risk: Exposure to foreign exchange rate fluctuations is immaterial.

Market driven changes in interest rates and changes in the Company's credit ratings can cause fluctuations in interest costs associated with the Company's bank credit facilities. Each level of change in the Company's credit ratings causes a 25 basis points change in the interest rate on the Company's committed revolving term credit facility. For the year ended December 31, 2008, each 25 basis points change in interest rates on the Company's credit facilities would have caused a $73,000 change in credit facility interest costs and a $49,000 change in earnings (2007 - $84,000 and $56,000, respectively).

The Company periodically refinances its credit facilities in the normal course with fixed-rate first mortgage sinking fund bonds, which comprised approximately 93% of its total debt at December 31, 2008, thereby mitigating exposure to interest rate changes.

Changes in interest rates and/or changes in the Company's credit ratings can affect the interest rate on first mortgage sinking fund bonds at the time of issue. No bonds were issued for the twelve month period ended December 31, 2008.

The Company's defined benefit pension plan is impacted by economic conditions. There is no assurance that the pension plan assets will earn the expected long-term rate of return in the future. Market driven changes impacting the performance of the pension plan assets may result in material variations in actual return on pension plan assets from the expected long-term return on the assets. This may cause material changes in future pension liabilities and pension expense. Market driven changes impacting the discount rate may also result in material variations in future pension liabilities and pension expense.

## 19. Commitments

The Company is obligated to provide service to customers, resulting in ongoing capital expenditure commitments. Capital expenditures are subject to PUB approval. The Company's 2009 capital plan provides for capital expenditures of approximately $61.6 million.

## 20. Comparative Figures

The comparative financial statements have been reclassified from statements previously presented to conform to the presentation of the current year financial statements.

# Ten Year Summary

| | 2008 | 2007[1] | 2006[1] | 2005[1] | 2004 | 2003 | 2002 | 2001 | 2000 | 1999 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Income Statement Items** *($thousands)* | | | | | | | | | | |
| Revenue | 516,889 | 491,709 | 422,405 | 419,963 | 404,447 | 384,150 | 369,627 | 359,305 | 348,413 | 342,001 |
| Purchased power | 336,658 | 326,778 | 257,157 | 255,954 | 244,012 | 227,964 | 210,764 | 202,479 | 199,266 | 192,755 |
| Operating, pension and ERP costs | 50,172 | 53,202 | 53,996 | 53,812 | 51,755 | 51,799 | 50,767 | 52,908 | 52,486 | 52,709 |
| Amortization of capital assets[2] | 44,511 | 34,162 | 33,129 | 32,143 | 30,987 | 29,372 | 35,442 | 34,003 | 29,625 | 29,638 |
| Finance charges | 33,507 | 34,939 | 33,819 | 31,369 | 30,393 | 30,009 | 26,853 | 26,700 | 26,641 | 26,488 |
| Income taxes | 19,146 | 12,176 | 13,639 | 15,368 | 15,586 | 14,945 | 16,381 | 13,730 | 13,296 | 16,927 |
| Earnings applicable to common shares | 32,341 | 29,866 | 30,078 | 30,729 | 31,122 | 29,460 | 28,807 | 28,862 | 26,473 | 22,858 |
| **Balance Sheet Items** *($thousands)* | | | | | | | | | | |
| Property, plant and equipment | 1,219,066 | 1,173,642 | 1,119,820 | 1,085,106 | 1,050,913 | 1,009,448 | 949,478 | 914,735 | 865,406 | 844,598 |
| Accumulated amortization | 444,109 | 422,848 | 402,683 | 387,815 | 420,836 | 407,319 | 381,003 | 369,659 | 353,078 | 344,506 |
| Net capital assets | 774,957 | 750,794 | 717,137 | 697,291 | 630,077 | 602,129 | 568,475 | 545,076 | 512,328 | 500,092 |
| Total assets | 1,001,855 | 985,930 | 929,158 | 889,013 | 825,310 | 744,375 | 704,598 | 667,289 | 628,252 | 608,336 |
| Long-term debt[3] | 438,154 | 443,527 | 414,489 | 395,298 | 328,558 | 332,208 | 335,858 | 263,758 | 280,158 | 283,208 |
| Preference shares | 9,352 | 9,352 | 9,353 | 9,410 | 9,417 | 9,429 | 9,709 | 9,709 | 9,890 | 9,890 |
| Common equity | 373,738 | 356,671 | 335,887 | 323,972 | 316,360 | 299,480 | 279,515 | 260,203 | 250,331 | 242,848 |
| Total capital | 821,244 | 809,550 | 759,729 | 728,680 | 654,335 | 641,117 | 625,082 | 533,670 | 540,379 | 535,946 |
| **Operating Statistics** *(GWh)* | | | | | | | | | | |
| Sources of Electricity (normalized) | | | | | | | | | | |
| Purchased | 5,088 | 5,013 | 4,876 | 4,873 | 4,841 | 4,725 | 4,604 | 4,495 | 4,432 | 4,292 |
| Generated | 426 | 381 | 417 | 426 | 424 | 425 | 424 | 416 | 423 | 450 |
| Total | 5,514 | 5,394 | 5,293 | 5,299 | 5,265 | 5,150 | 5,028 | 4,911 | 4,855 | 4,742 |
| Sales (normalized) | | | | | | | | | | |
| Residential | 3,130 | 3,044 | 2,981 | 2,987 | 2,972 | 2,909 | 2,843 | 2,775 | 2,707 | 2,672 |
| Commercial and street lighting | 2,078 | 2,049 | 2,014 | 2,017 | 2,007 | 1,973 | 1,922 | 1,892 | 1,848 | 1,828 |
| Total | 5,208 | 5,093 | 4,995 | 5,004 | 4,979 | 4,882 | 4,765 | 4,667 | 4,555 | 4,500 |
| Electricity sales per employee | 9.5 | 9.2 | 9.0 | 9.0 | 8.3 | 8.1 | 7.8 | 7.5 | 6.9 | 6.4 |
| **Customers** *(year-end)* | | | | | | | | | | |
| Residential | 204,204 | 201,045 | 198,568 | 196,412 | 193,912 | 191,314 | 188,925 | 186,828 | 185,287 | 183,921 |
| Commercial and street lighting | 31,574 | 31,217 | 30,932 | 30,889 | 30,552 | 30,339 | 30,147 | 30,051 | 29,923 | 29,720 |
| Total | 235,778 | 232,262 | 229,500 | 227,301 | 224,464 | 221,653 | 219,072 | 216,879 | 215,210 | 213,641 |
| **Operating cost per customer** *($)*[4] | 208 | 213 | 212 | 218 | 220 | 225 | 223 | 231 | 230 | 235 |
| **Number of regular full-time employees** | 551 | 555 | 552 | 556 | 599 | 606 | 610 | 626 | 656 | 703 |

1 *Certain comparative figures have been reclassified to conform with current year presentation.*

2 *Amount for 2007 and 2006 is net of a regulatory deferral of $5.8 million, as approved by the PUB.*

3 *Net of deferred financing charges in 2008 and 2007.*

4 *Operating cost per customer is calculated excluding pension and early retirement program costs.*

# Board of Directors

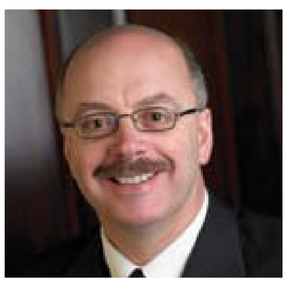
**Peggy Bartlett**
President
Bartlett Enterprises Inc.
Grand Falls-Windsor,
Newfoundland & Labrador

**Frank Davis**
Corporate Director
St. John's,
Newfoundland & Labrador

**Ed Drover**
Financial Advisor & President
Ringwood Wealth Management Inc.
St. John's,
Newfoundland & Labrador

**Chris Griffiths**
Operations Manager
Gibson Guitar Canada Ltd.
St. John's,
Newfoundland & Labrador

**Georgina Hedges**
Owner/Operator
The Doctor's Inn
Eastport,
Newfoundland & Labrador



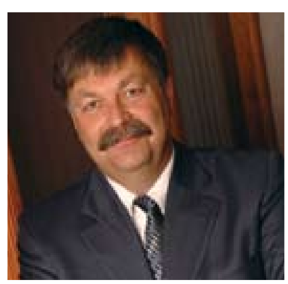
**Earl Ludlow**
President & Chief Executive Officer
Newfoundland Power Inc.
St. John's,
Newfoundland & Labrador

**David Norris**
Corporate Director
St. John's,
Newfoundland & Labrador

**Fred O'Brien**
President & Chief Executive Officer
Maritime Electric Company, Limited
Charlottetown,
Prince Edward Island

**Barry Perry**
Vice President, Finance &
Chief Financial Officer
Fortis Inc.
St. John's,
Newfoundland & Labrador

**Bruce Simmons**
President & Chief Executive Officer
Hammond Farm Ltd.
Corner Brook,
Newfoundland & Labrador



**John Walker**
President & Chief Executive Officer
FortisBC Inc.
Kelowna,
British Columbia

**Jo Mark Zurel**
President
Stonebridge Capital Inc.
St. John's,
Newfoundland & Labrador

# Executive Team

Jocelyn Perry, Vice President, Finance and Chief Financial Officer

Gary Smith, Vice President, Engineering and Operations

Earl Ludlow, President and Chief Executive Officer

Lisa Hutchens, Vice President, Customer Relations and Corporate Services

Peter Alteen, Vice President, Regulatory Affairs and General Counsel

# Connected to our Communities

We are proud that community groups throughout the province can count on us for support. We were pleased to provide financial, in-kind and hands-on assistance to the following organizations and many more in 2008:

## Health

The Dr. H. Bliss Murphy Cancer Care Foundation, PRIORITY: The Campaign for Cancer Care, The Burin Peninsula Health Care Foundation, The Western Memorial Health Care Foundation, The Children's Wish Foundation, The Newfoundland & Labrador Down Syndrome Society, Juvenile Diabetes Research Foundation, The Arthritis Society (Newfoundland and Labrador Division), Alzheimer Society of Newfoundland & Labrador, Trinity Conception Placentia Health Care Foundation, Janeway Children's Hospital Foundation, Newfoundland & Labrador Region of the Canadian Red Cross, Community Food Sharing Association, Coats for Kids, Learning Disabilities Association of Newfoundland & Labrador, Heart and Stroke Foundation of Newfoundland & Labrador, Canadian Blood Services, Canadian Mental Health Association, The HUB

## Safety

Newfoundland and Labrador Association of Fire Services, Firefighter Electricity Safety Training, Learn Not to Burn Program, Child Find Newfoundland & Labrador, School Electricity Safety Program, Safety Services Newfoundland Labrador, Newfoundland & Labrador Crime Stoppers, Newfoundland & Labrador Snowmobile Federation, Triple Bay Eagles Ground Search and Rescue

## Environment

Atlantic Salmon Federation, Tree Canada, Newfoundland & Labrador Home Builders' Association, Thomas Howe Demonstration Forest, Trans Canada Trail Foundation, Marystown Community Pride, Rennies River Development Foundation

## Education & Youth

Junior Achievement of Newfoundland & Labrador, Memorial University of Newfoundland, College of the North Atlantic, Newfoundland & Labrador Science Centre, Newfoundland & Labrador High School Athletic Federation, Scouts Canada, Church Lads' Brigade, Newfoundland School for the Deaf, Special Olympics, Newfoundland and Labrador Summer Games

## Arts & Culture

Newfoundland Symphony Orchestra, Kiwanis Music Festival Association, Resource Centre for the Arts

# Investor Information

Head Office
55 Kenmount Road, P.O. Box 8910
St. John's, NL A1B 3P6
Tel: (709) 737-2802
Fax: (709) 737-5300

Share Transfer Agent and Registrar
Computershare Trust Company of Canada
1500 University Street, Suite 700
Montreal, QC H3A 3S8
Tel: (514) 982-7888
Fax: (514) 982-7635
computershare.com

Annual General Meeting
Wednesday, May 6, 2009 at 8:00 a.m.
Main Boardroom, 3rd Floor
Newfoundland Power Inc.
55 Kenmount Road
St. John's, NL A1B 3P6

Investor Information
Peter Alteen, Corporate Secretary
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Tel: (709) 737-5859
palteen@newfoundlandpower.com

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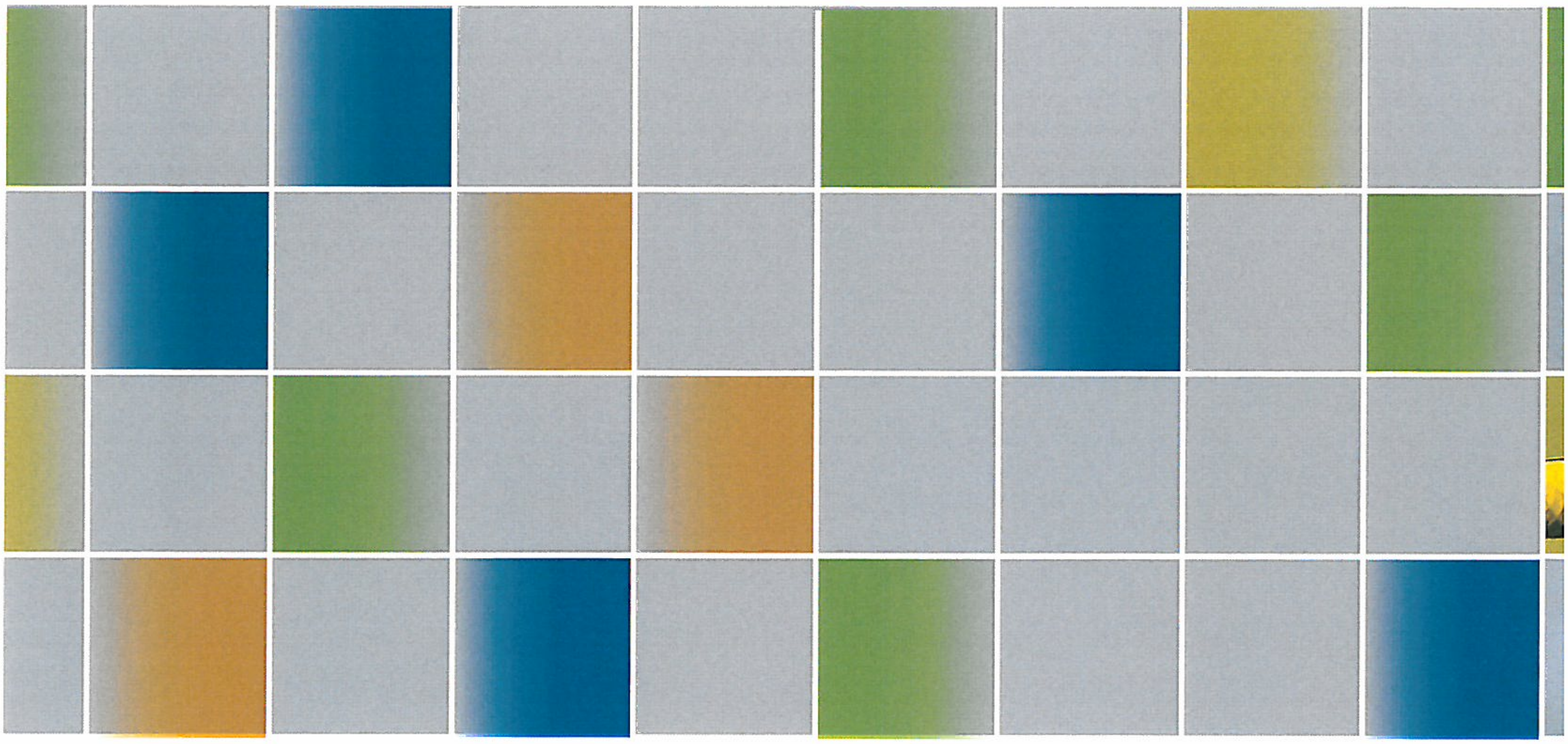
Fortis Websites
Fortis Inc.
fortisinc.com
FortisAlberta Inc.
fortisalberta.com
FortisBC Inc.
fortisbc.com
Terasen Gas
terasengas.com
FortisOntario Inc.
fortisontario.com
Maritime Electric Company, Limited
maritimeelectric.com
Belize Electricity Limited
bel.com.bz
Caribbean Utilities Company, Ltd.
cuc-cayman.com
Fortis Properties Corporation
fortisproperties.com
Fortis Turks and Caicos
provopowercompany.com

Photography, Design and Production

Corporate Communications
Newfoundland Power Inc.

Printing

Dicks and Company Limited, St. John's, NL



Newfoundland Power Inc.

P.O. Box 8910
St. John's, NL
A1B 3P6

newfoundlandpower.com

**IN THE MATTER OF**
the 2008 Annual Returns
of Newfoundland Power
Inc. filed pursuant to
Section 59(2) of the
*Public Utilities Act.*

## AFFIDAVIT

I, Jocelyn Perry, of the Town of Conception Bay South in the Province of Newfoundland and Labrador, Chartered Accountant, make oath and say as follows:

1. That I am Vice-President, Finance and Chief Financial Officer of Newfoundland Power Inc.

2. That to the best of my knowledge, information and belief, the information contained in the 2008 Annual Report and accompanying returns of Newfoundland Power Inc., filed with the Board of Commissioners of Public Utilities pursuant to section 59(2) of the *Public Utilities Act* is true and accurate.

**SWORN** to before me at St. John's
in the Province of Newfoundland and Labrador
this 1st day of April, 2009:

Barrister – Newfoundland & Labrador

Jocelyn Perry

**Newfoundland Power Inc.**
**Names and Addresses of Officers and Directors**
**as of December 31, 2008**

| Name | Address | Position Held |
|---|---|---|
| **Peter Alteen** | 38 Mansfield Crescent<br>St. John's, NL A1E 5E3 | Vice President, Regulatory Affairs and General Counsel;<br>Corporate Secretary |
| **Peggy Bartlett** | 173 Grenfell Heights<br>Grand Falls-Windsor, NL A2A 2J7 | Director |
| **Frank Davis** | 2 Crabapple Place<br>St. John's, NL A1A 5L7 | Director |
| **E.M. (Ed) Drover** | 44 Long Pond Road<br>St. John’s, NL A1B 1N7 | Director |
| **Chris Griffiths** | 27 Knapps Road<br>St. Philip's, NL A1M 2A6 | Director |
| **Georgina Hedges** | 5 Burden’s Road<br>Eastport, NL A0G 1Z0 | Director |
| **Lisa Hutchens** | 88 Marine Drive<br>Logy Bay-Middle Cove-Outer Cove, NL<br>A1K 3C7 | Vice President, Customer Relations and Corporate Services |
| **Earl Ludlow** | 33 Ortega Drive<br>Paradise, NL A1L 2L1 | President and Chief Executive Officer;<br>Director |
| **David Norris** | 23 Mountbatten Drive<br>St. John's, NL A1A 3Y1 | Chair, Board of Directors |

**Newfoundland Power Inc.**
**Names and Addresses of Officers and Directors**
**as of December 31, 2008**

| Name | Address | Position Held |
|---|---|---|
| **Fred O'Brien** | 389 Church Street<br>Alberton, PEI C0B 1B0 | Director |
| **Barry Perry** | 14 Collingwood Crescent<br>Mount Pearl, NL A1N 5C6 | Director |
| **Jocelyn Perry** | 6 Maple Street<br>Conception Bay South, NL A1W 5M8 | Vice President, Finance<br>and Chief Financial Officer |
| **Bruce Simmons** | 1 Hammond Drive<br>Little Rapids, NL A2H 2W1 | Director |
| **Gary Smith** | 89 Cheyne Drive<br>St. John's, NL A1A 5W5 | Vice President, Engineering and<br>Operations |
| **John Walker** | 617 Almandine Court<br>Kelowna, BC V1W 4Z5 | Director |
| **Jo Mark Zurel** | 16 Regent Street<br>St. John's, NL A1A 5A4 | Director |

**Newfoundland Power Inc.**
**Computation of Average Rate Base**
**For The Year Ended December 31, 2008**
**($000's)**

| | 2008 | 2007[1] |
|---|---|---|
| **Net Plant Investment** | | |
| Plant Investment - Return 4 | 1,286,039 | 1,239,186 |
| Accumulated Amortization - Return 6 | (539,654) | (516,478) |
| Contributions in Aid of Construction - Return 7 | (25,884) | (24,217) |
| | 720,501 | 698,491 |
| | | |
| **Additions to Rate Base** | | |
| Deferred Charges - Return 8 | 100,723 | 96,850 |
| Deferred Energy Replacement Costs - Return 9 | 766 | 1,147 |
| Amortization True-up Deferral - Return 9 | 7,724 | 11,586 |
| Customer Finance Programs - Return 10 | 1,776 | 1,811 |
| Weather Normalization Reserve - Return 17 | 5,910 | 10,516 |
| | 116,899 | 121,910 |
| | | |
| **Deductions from Rate Base** | | |
| Municipal Tax Liability - Return 9 | 2,727 | 4,089 |
| Unrecognized 2005 Unbilled Revenue - Return 9 | 9,236 | 16,446 |
| Customer Security Deposits - Return 10 | 785 | 612 |
| Accrued Pension Obligation - Return 10 | 3,142 | 2,943 |
| Future Income Taxes - Return 23 | 1,184 | - |
| Demand Management Incentive Account - Return 18 | 426 | - |
| Purchased Power Unit Cost Variance Reserve - Return 19 | 895 | 1,650 |
| | 18,395 | 25,740 |
| | | |
| **Year End Rate Base** | 819,005 | 794,661 |
| | | |
| **Average Rate Base Before Allowances** | 806,833 | 777,494 |
| | | |
| **Rate Base Allowances** | | |
| Materials and Supplies Allowance - Return 11 | 4,327 | 4,393 |
| Cash Working Capital Allowance - Return 12 | 9,716 | 6,669 |
| | | |
| **Average Rate Base at Year End** | 820,876 | 788,556 |

[1] To calculate the 2008 average rate base, the computation of the 2007 rate base has been restated to reflect the methodology approved in Order No. P.U. 32 (2007).

**Newfoundland Power Inc.**
**Plant Investment**
**For The Year Ended December 31, 2008**
**($000's)**

| | Opening Balance | Adjustments[1] | Additions | Retirements | Year End Balance |
|---|---|---|---|---|---|
| Power Generation | | | | | |
| Hydro | 135,940 | (426) | 3,791 | 712 | 138,593 |
| Diesel | 3,005 | - | - | - | 3,005 |
| Gas Turbine | 17,585 | - | 315 | 1 | 17,899 |
| | 156,530 | (426) | 4,106 | 713 | 159,497 |
| Substations | 127,551 | 338 | 6,616 | 1,036 | 133,469 |
| Transmission | 93,836 | (9) | 5,672 | 1,233 | 98,266 |
| Distribution | 706,868 | 94 | 36,676 | 5,707 | 737,931 |
| General Property | 49,229 | 3 | 1,757 | 353 | 50,636 |
| Transportation | 22,031 | - | 2,494 | 2,057 | 22,468 |
| Communications | 10,516 | - | 278 | 206 | 10,588 |
| Computer Software | 30,628 | - | 2,251 | 1,891 | 30,988 |
| Computer Hardware | 9,583 | - | 1,653 | 1,549 | 9,687 |
| Government Contributions | 23,109 | - | - | - | 23,109 |
| | 1,073,351 | 426 | 57,397 | 14,032 | 1,117,142 |
| Total Depreciable Plant | 1,229,881 | - | 61,503 | 14,745 | 1,276,639 |
| Non Depreciable Land | 9,305 | - | 95 | - | 9,400 |
| Plant Investment Included In Rate Base | 1,239,186 | - | 61,598 | 14,745 | 1,286,039 |
| Construction Work In Progress | | | | | 2,126 |
| Total Plant Investment[2] | | | | | 1,288,165 |

[1] Adjustments are due to asset reclasssification and redistribution of original cost based on final project details.

[2] A reconciliation of the Total Plant Investment used in the calculation of average rate base for 2008 to the plant investment shown in in Return 1 is as follows:

| | |
|---|---|
| 2008 Capital Assets shown in Return 1 (Note 7 to Financial Statements) | 1,219,066 |
| Add: Contributions in Aid of Construction - Return 7 | 73,468 |
| Deduct: Inventories Included in Plant Investment for Financial Reporting purposes | (4,369) |
| 2008 Total Plant Investment | 1,288,165 |

**Newfoundland Power Inc.**
**Capital Expenditure**
**For The Year Ended December 31, 2008**
**($000's)**

| | Approved By Board[1] | Actual | Variance[2] |
|---|---|---|---|
| Generation | | | |
| Hydro | 3,385 | 3,619 | 234 |
| Thermal | 100 | 301 | 201 |
| | 3,485 | 3,920 | 435 |
| Substations | 7,177 | 7,095 | (82) |
| Transmission | 4,978 | 5,316 | 338 |
| Distribution | 28,566 | 37,053 | 8,487 |
| General Property | 977 | 1,073 | 96 |
| Transportation | 2,214 | 2,384 | 170 |
| Telecommunications | 224 | 266 | 42 |
| Information Systems | 3,607 | 3,734 | 127 |
| Unforeseen | 1,150 | 400 | (750) |
| General Expenses Capital | 2,800 | 2,765 | (35) |
| | 55,178 | 64,006 | 8,828 |
| Carryover From Prior Years | | 764 | |

'1 Order Nos. P.U 27 (2007), P.U. 3 (2008), P.U. 18 (2008), P.U. 19 (2008) and P.U. 24 (2008).

[2] Variance explanations are provided in Newfoundland Power Inc.'s 2008 Capital Expenditure Report filed with the Board on February 27, 2009.

**Newfoundland Power Inc.**
**Accumulated Amortization**
**For The Year Ended December 31, 2008**
**($000's)**

| | | |
|---|---|---|
| 1 | Opening Balance - January 1, 2008 | 516,478 |
| 2 | | |
| 3 | Add: | |
| 4 | Amortization of Fixed Assets[1] | 40,649 |
| 5 | Amortization of Contributions - Government - Return 7 | 94 |
| 6 | Amortization of Contributions - Customers - Return 7 | 1,290 |
| 7 | Salvage | 393 |
| 8 | | 42,426 |
| 9 | | |
| 10 | | |
| 11 | Deduct: | |
| 12 | Cost of Removal (Net of Income Tax) | 4,505 |
| 13 | Retirements | 14,745 |
| 14 | | 19,250 |
| 15 | | |
| 16 | Closing Balance - December 31, 2008[2] | 539,654 |
| 17 | | |
| 18 | | |
| 19 | | |
| 20 | | |

21 [1] The amortization rates for 2008 are from the 2006 Depreciation Study based on plant
22 in service at December 31, 2005 and approved in Order No. P.U. 32 (2007).

| | | |
|---|---|---|
| 24 | Hydro | 2.17% |
| 25 | Diesel | 4.28% |
| 26 | Gas Turbine | 4.81% |
| 27 | Substations | 2.63% |
| 28 | Transmission | 3.28% |
| 29 | Distribution | 3.14% |
| 30 | General Property | 2.94% |
| 31 | Transportation | 10.28% |
| 32 | Telecommunications | 6.18% |
| 33 | Computer Software | 10.00% |
| 34 | Computer Hardware | 20.00% |
| 35 | | |

36 [2] The accumulated amortization shown in Return 1 (Note 7 to the Financial Statements)
37 is before adjustment for contributions in aid of construction and site restoration costs.

| | | |
|---|---|---|
| 38 | | |
| 39 | Accumulated Amortization shown in Return 1 (Note 7) | 444,109 |
| 40 | Add: Amortization of Contributions - Return 7 | 47,584 |
| 41 | Add: Site Restoration Costs - Return 1 (Note 4) | 47,961 |
| 42 | 2008 Accumulated Amortization for Average Rate Base | 539,654 |

**Newfoundland Power Inc.**
**Contributions in Aid of Construction**
**For The Year Ended December 31, 2008**
**($000's)**

| | | Customers | Government | Total |
|---|---|---|---|---|
| 1 | Gross Contributions to January 1, 2008 | 47,309 | 23,108 | 70,417 |
| 2 | | | | |
| 3 | Add: Contributions Received in 2008 | 3,051 | - | 3,051 |
| 4 | | | | |
| 5 | Gross Contributions to December 31, 2008 | 50,360 | 23,108 | 73,468 |
| 6 | | | | |
| 7 | | | | |
| 8 | Amortizations to January 1, 2008 | 23,811 | 22,389 | 46,200 |
| 9 | | | | |
| 10 | Add: Amortization in 2008 | 1,290 | 94 | 1,384 |
| 11 | | | | |
| 12 | Amortizations to December 31, 2008 | 25,101 | 22,483 | 47,584 |
| 13 | | | | |
| 14 | | | | |
| 15 | Unamortized Contributions to December 31, 2008 | 25,259 | 625 | 25,884 |

**Newfoundland Power Inc.**
**Deferred Charges**
**For The Year Ended December 31, 2008**
**($000's)**

| | Balance January 1 2008 | Additions During 2008 | Reductions During 2008 | Balance December 31 2008 |
|---|---|---|---|---|
| Deferred Pension Costs[1] | 96,654 | 5,425 | 1,883 | 100,196 |
| Capital Stock Issue Expenses | 137 | - | 62 | 75 |
| Deferred Credit Facility Issue Costs[2] | 59 | 50 | 59 | 50 |
| Deferred Hearing Costs[3] | 603 | - | 201 | 402 |
| Deferred Charges Included in Rate Base | 97,453 [4] | 5,475 | 2,205 | 100,723 |

[1] The December 31, 2008 balance includes $7.0 million in pension costs associated with the 2005 Early Retirement Program. These pension costs were originally $11.3 million and are being amortized over ten years, beginning April 1, 2005.

[2] Newfoundland Power incurred $50,000 in costs in 2008 associated with the amendment of its Comitted Credit Facility. The amendment was approved in Order No. P.U. 22 (2008).

[3] The Board approved a 3-year amortization of hearing costs associated with its 2008 General Rate Application in Order No. P.U. 32 (2007).

[4] Deferred charges included in rate base for 2007 is $96,850,000 as shown in Return 3. This differs from the January 1, 2008 balance of $97,453,000 shown above because the 2007 deferred charges did not include $603,000 of deferred hearing costs.

**Newfoundland Power Inc.**
**Regulatory Deferrals**
**For The Year Ended December 31, 2008**
**($000's)**

| | Balance January 1 2008 | 2008 Amortization | Balance December 31 2008 |
|---|---|---|---|
| **Cost Recovery Deferrals**[1] | | | |
| Deferred Energy Replacement Costs | 1,147 | 381 | 766 |
| Amortization True-up Deferral | 11,586 | 3,862 | 7,724 |
| | | | |
| **Revenue Deferrals**[1] | | | |
| Municipal Tax Liability | 4,089 | 1,362 | 2,727 |
| Unrecognized 2005 Unbilled Revenue | 16,446 | 7,210 [2] | 9,236 |

[1] In Order No. P.U. 32 (2007), the Board approved a 3-year amortization of these cost recovery and revenue deferrals.

[2] In Order No. P.U. 32 (2007), the Board approved (i) the recognition of $2,592,000 of the 2005 Unbilled Revenue to offset the 2008 tax settlement payment; and (ii) the amortization over a 3-year period of the remaining balance of the 2005 Unbilled Revenue of $13,854,000 or $4,618,000 per year.

**Newfoundland Power Inc.**
**Other Rate Base Assets and Liabilities**
**For The Year Ended December 31, 2008**
**($000's)**

| | Balance January 1 2008 | Change During 2008 | Balance December 31 2008 |
|---|---|---|---|
| **Assets** | | | |
| Customer Finance Programs[1] | 1,811 | (35) | 1,776 |
| | | | |
| **Liabilities** | | | |
| Accrued Pension Obligation[2] | 2,943 | 199 | 3,142 |
| | | | |
| Customer Security Deposits[3] | 612 | 173 | 785 |

[1] Comprised of loans provided to customers related to customer conservation programs and contributions in aid of construction.

[2] Executive and Senior Management supplemental pension benefits comprised of a defined benefit plan (PUP) and a defined contribution plan (SERP). The PUP was closed to new entrants in 1999.

[3] Security deposits received from customers for electrical service in accordance with the Board-approved Schedule of Rates, Rules and Regulations.

**Newfoundland Power Inc.**
**Materials and Supplies Allowance**
**For The Year Ended December 31, 2008**
**($000's)**

| | **2008**[1] | **2007** |
|---|---|---|
| Opening - January 1, 2008 | 5,248 | - |
| January | 5,356 | 4,906 |
| February | 5,543 | 5,210 |
| March | 5,663 | 5,791 |
| April | 5,365 | 5,702 |
| May | 5,448 | 5,661 |
| June | 5,562 | 5,322 |
| July | 5,271 | 5,291 |
| August | 5,369 | 5,352 |
| September | 5,191 | 5,300 |
| October | 5,249 | 5,310 |
| November | 5,145 | 5,428 |
| December | 5,391 | 5,248 |
| Total | 69,801 | 64,521 |
| | | |
| Average | 5,369 | 5,377 |
| | | |
| Less: Expansion (19.4%) | 1,042 | 984 [2] |
| | | |
| Materials and Supplies Allowance | 4,327 | 4,393 |

[1] The 2008 materials and supplies allowance calculation reflects a 13-month average as approved by the Board in Order No. P.U. 32 (2007).

[2] The expansion factor used in 2007 was 18.3%.

# Newfoundland Power Inc.
## Cash Working Capital Allowance
## For The Year Ended December 31, 2008
## ($000's)

| | 2008[1] | 2007 |
|---|---|---|
| Gross Operating Costs | 382,799 [2] | 379,980 |
| Income Taxes - Return 22 | 20,131 | 12,432 |
| Muncipal Taxes Paid | 12,394 | - |
| Non-regulated Expenses (net of income taxes) | (995) | (111) |
| Total operating expenses | 414,329 | 392,301 |
| Cash Working Capital Factor | 2.1% | 1.7% |
| | 8,701 | 6,669 |
| HST Adjustment | 1,015 | - |
| Cash Working Capital Allowance | 9,716 | 6,669 |

[1] The 2008 cash working capital allowance is calculated based on the method used to calculate the 2008 Test Year average rate base approved by the Board in Order No. P.U. 32 (2007).

[2] In accordance with the methodology approved in Order No. P.U. 32 (2007), gross operating costs for 2008 used in the calculation of the 2008 cash working capital allowance are net of non-cash related amortizations.

**Newfoundland Power Inc.**
**Return on Average Rate Base**
**For The Year Ended December 31, 2008**
**($000's)**

| | **2008**[1] | **2007** |
|---|---|---|
| Net Earnings from Return 1 | 32,895 | 30,452 |
| Add: Non-regulated (net of income taxes) | 995 | 111 |
| | 33,890 | 30,563 |
| | | |
| Finance Costs | | |
| Interest on Long-term Debt | 32,334 | 33,718 |
| Other Interest | 1,456 | 1,525 |
| Amortization of Capital Stock Issue Expenses | - | 62 |
| Amortization of Debt Issue Expenses | 235 | 256 |
| Interest Earned[2] | - | (1,477) |
| AFUDC | (618) | (622) |
| | 33,407 | 33,462 |
| | | |
| Regulated Earnings | 67,297 | 64,025 |
| | | |
| Average Rate Base from Return 3 | 820,876 | 793,703 |
| | | |
| Rate of Return on Average Rate Base | 8.20% | 8.07% |
| | | |
| Average Rate Base from Return 3 | 820,876 | 793,703 |
| | | |
| Upper Limit of the Allowed Range of Return on Average Rate Base[3] | 8.55% | 8.65% |
| | | |
| Upper Limit of Allowed Regulated Earnings | 70,185 | 68,655 |
| | | |
| Regulated Earnings | 67,297 | 64,025 |
| | | |
| Excess Revenue net of Income Taxes | - | - |
| | | |
| Income Taxes | - | - |
| | | |
| Excess Revenue | - | - |

[1] The 2008 return on average rate base is calculated in accordance with the methodology approved in Order No. P.U 32 (2007).

[2] Beginning in 2008, interest earned is classified as a component of other revenue. Prior to 2008, interest earned reduced financing costs.

[3] Order No. P.U. 32 (2007).

**Newfoundland Power Inc.**
**Details of Normalized Sales and Revenue**
**For The Year Ended December 31, 2008**
**($000's)**

| | | 2008 | | | 2007 | | |
|---|---|---|---|---|---|---|---|
| | | Gigawatt Hours | Year End Customer Accounts | Revenue | Gigawatt Hours | Year End Customer Accounts | Revenue |
| **Revenue From Rates** | | | | | | | |
| Domestic | 1.1 | 3,130.3 | 204,204 | 302,916 | 3,044.4 | 201,045 | 284,113 |
| | | | | | | | |
| General Service: | | | | | | | |
| 0 - 10 kW | 2.1 | 88.8 | 11,920 | 11,742 | 90.9 | 11,826 | 12,043 |
| 10 - 100 kW | 2.2 | 641.8 | 8,626 | 63,129 | 629.2 | 8,509 | 62,237 |
| 110 - 1000 kVA | 2.3 | 878.5 | 1,061 | 72,997 | 864.5 | 1,035 | 70,946 |
| 1000 kVA and Over | 2.4 | 432.3 | 65 | 31,208 | 427.6 | 66 | 29,880 |
| Total General Service | | 2,041.4 | 21,672 | 179,076 | 2,012.2 | 21,436 | 175,106 |
| | | | | | | | |
| Street & Area Lighting | 4.1 | 36.5 | 9,902 | 12,722 | 36.2 | 9,781 | 12,214 |
| Forfeited Discounts | | - | - | 2,646 | - | - | 2,621 |
| Revenue From Rates | | 5,208.2 | 235,778 | 497,360 | 5,092.8 | 232,262 | 474,054 |
| | | | | | | | |
| **Adjustments and Transfers** | | | | | | | |
| Transfer From (To) RSA [1] | | | | (948) | | | 3,044 |
| 2005 Unbilled Revenue Accrual [2] | | | | 7,210 | | | 2,714 |
| Total Adjustments and Transfers | | | | 6,262 | | | 5,758 |
| | | | | | | | |
| **Other Revenue** | | | | | | | |
| Joint Use Revenue | | | | 8,861 | | | 8,568 |
| Wheeling Revenue | | | | 615 | | | 490 |
| Amortization of Municipal Tax Liability[3] | | | | 1,362 | | | - |
| Interest on Overdue Customer Accounts[4] | | | | 1,155 | | | 1,477 |
| Other Non-Electrical Revenue | | | | 1,274 | | | 1,362 |
| Total Other Revenue | | | | 13,267 | | | 11,897 |
| | | | | | | | |
| **Total Revenue - Return 1** | | | | **516,889** | | | **491,709** |

[1] The transfer to the RSA in 2008 is related to the operation of the Energy Supply Cost Variance Adjustment ($388) as approved by the Board in Order No. P.U. 32 (2007) and the 2008 Income Tax True-up adjustment ($560) approved by the Board in Order No. 10 (2008). The 2007 transfer from the RSA is related to recovery of 2007 supply costs resulting from changes in Hydro's rates to Newfoundland Power.

[2] Revenue amortizations approved by the Board in Order Nos. P.U. 32 (2007) and P.U. 39 (2006).

[3] The Board approved a 3-year amortization of the municipal tax liability in Order No. P.U 32 (2007) beginning in 2008.

[4] Beginning in 2008, interest on overdue customer accounts has been classified as a component of Other Revenue. For comparison purposes, Other Revenue for 2007 is restated to include interest on overdue customer accounts.

**Newfoundland Power Inc.**
**Normalized Production and Sales Statistics**
**For The Year Ended December 31, 2008**
**($000's)**

| | 2008 | 2007 |
|---|---|---|
| Gigawatt Hours - Purchased | 5,088.0 | 5,013.1 |
| Gigawatt Hours - Produced | 425.8 | 381.4 |
| Total Purchased & Produced | 5,513.8 | 5,394.5 |
| Gigawatt Hours - Sold & Used | 5,219.9 | 5,104.6 |
| Gigawatt Hours - Losses | 293.9 | 289.9 |
| Losses Expressed as a Percentage of Total Purchased & Produced | 5.3% | 5.4% |
| Purchased Power Annual Billing Demand in kW | 1,074,714 | 1,074,714 |

**Newfoundland Power Inc.**
**Rate Stabilization Account**
**For The Year Ended December 31, 2008**
**($000's)**

| Month | Opening Balance | Adjustments | RSA Billed During Month | Municipal Taxes | Excess Fuel Costs | Secondary Energy Costs | Interest Costs | Transfer To (From) Nfld. Hydro | Closing Balance |
|---|---|---|---|---|---|---|---|---|---|
| January | 1,690.0 | - | (949.9) | - | 16.8 | (0.4) | 11.8 | 1,010.2 | 1,778.5 |
| February | 1,778.5 | - | (928.0) | - | 3.0 | - | 12.4 | 914.3 | 1,780.2 |
| March | 1,780.2 | (1,041.6) [1] | (872.0) | (11.7) [2] | 2.4 | (0.1) | 12.4 | 957.1 | 826.7 |
| April | 826.7 | - | (822.7) | - | 4.7 | - | 5.8 | 745.1 | 759.6 |
| May | 759.6 | - | (674.9) | - | 13.5 | - | 5.3 | 634.0 | 737.5 |
| June | 737.5 | - | (567.9) | - | 10.5 | - | 5.1 | 511.0 | 696.2 |
| July | 696.2 | - | (1,372.7) | - | 36.1 | (2.8) | 4.9 | 2,083.2 | 1,444.9 |
| August | 1,444.9 | - | (2,186.0) | - | 29.6 | - | 10.1 | 2,116.5 | 1,415.1 |
| September | 1,415.1 | - | (2,170.3) | - | 124.5 | - | 9.9 | 2,156.8 | 1,536.0 |
| October | 1,536.0 | - | (2,434.5) | - | 5.8 | (0.1) | 10.7 | 2,805.6 | 1,923.5 |
| November | 1,923.5 | - | (2,977.9) | - | 14.9 | - | 13.4 | 3,117.5 | 2,091.4 |
| December | 2,091.4 | (388.7) [3] | (3,369.6) | 56.0 [4] | 50.6 | (0.6) | 14.6 | 4,036.3 | 2,490.0 |
| | | (1,430.3) | (19,326.4) | 44.3 | 312.4 | (4.0) | 116.4 | 21,087.6 | |

[1] This is the total of the transfer of $560,000 related to the 2008 Income Tax True-up approved in Order No. P.U. 10 (2008) and $481,611 related to the disposition of the 2007 year-end balance in the Purchased Power Unit Cost Variance Reserve approved in Order No. P.U. 6 (2008).

[2] This adjustment relates to property taxes paid in 2007.

[3] This is the Energy Supply Cost Variance for 2008 approved in Order No. P.U. 32 (2007).

[4] This is the difference between total municipal taxes collected from customers through rates and the total taxes paid to municipalities for 2008.

**Newfoundland Power Inc.**
**Weather Normalization Reserve**
**For The Year Ended December 31, 2008**
**($000's)**

| | |
|---|---|
| **Degree Day Normalization Reserve Transfer** | |
| Revenue Adjustment | |
| Heating Degree Days | 6,993 |
| Cooling Degree Days | - |
| Wind Speed Adjustments | 582 |
| Total Revenue Adjustment | 7,575 |
| Less : Power Purchased Adjustment | |
| Heating Degree Days | 7,994 |
| Cooling Degree Days | - |
| Wind Speed Adjustments | 657 |
| Total Power Purchased Adjustment | 8,651 |
| Net Adjustment (Before Tax) | (1,076) |
| Less: Income Tax @ 33.5% | (361) |
| Net Adjustment (After Tax) | (715) |
| Amortization of Weather Normalization Reserve[1] | (1,366) |
| Net Transfer (To) From Degree Day Normalization Reserve | (2,081) |
| **Hydro Production Equalization Reserve Transfer** | |
| Transfer (To) From Reserve (Before Tax) | (3,797) |
| Less: Income Tax @ 33.5% | (1,272) |
| Net Transfer (To) From Hydro Production Equalization Reserve | (2,525) |
| **Net Transfer (To) From Weather Normalization Reserve** | **(4,606)** |

| | Weather Normalization Account Balances | | |
|---|---|---|---|
| | **Balance at January 1 2008** | **Net Transfers** | **Balance at December 31 2008[2]** |
| Degree Day Reserve | 6,648 | (2,081) | 4,567 |
| Hydro Equalization Reserve | 3,868 | (2,525) | 1,343 |
| | 10,516 | (4,606) | 5,910 |

[1] This is the amortization of a non-reversing balance in the degree day normalization reserve as approved by the Board in Order No. P.U. 32 (2007).

[2] A positive balance in the weather normalization reserve reflects amounts to be recovered from customers in future periods. A negative balance in the weather normalization reserve reflects amounts owed to customers.

**Newfoundland Power Inc.**
**Demand Management Incentive Account**
**For The Year Ended December 31, 2008**
**($000's)**

**Demand Management Incentive Account Transfer**

| | |
|---|---|
| Demand Supply Cost Variance | (1,170) |
| Demand Management Incentive[1] | 529 |
| Supply Cost Variance Outside Deadband | (641) |
| Less: Income Tax @ 33.5% | (215) |
| **Net Transfer (To) From Demand Management Incentive Account** | **(426)** |

**Demand Management Incentive Account Balance**

| | |
|---|---|
| Balance at January 1, 2008 | - |
| Net Transfer (To) From Demand Management Incentive Account | (426) |
| Balance at December 31, 2008[2] | (426) |

[1] The demand management incentive of $529,000 is plus/minus 1% of test year wholesale demand charges. The Demand Management Incentive Account definition was approved by the Board in Order No. P.U. 32 (2007).

[2] In accordance with Order No. P.U. 32 (2007), Newfoundland Power filed an application with the Board on February 27, 2008 pertaining to the disposition of the 2008 year end balance in the Demand Management Incentive Account.

**Newfoundland Power Inc.**
**Purchased Power Unit Cost Variance Reserve**
**For The Year Ended December 31, 2008**
**($000's)**

| | |
|---|---|
| **Purchased Power Unit Cost Variance Reserve Balance** | |
| Balance at January 1, 2008 | (1,650) |
| Transfer to RSA[1] | 308 |
| 2008 Amortization[2] | 447 |
| Balance at December 31, 2008 | (895) |

[1] In Order No. P.U. 6 (2008), the Board approved a transfer to the RSA of $308,000 for the disposition of the balance in the Purchased Power Unit Cost Variance Reserve (the "PPUCVR") related to adjustments arising from its operation in 2007.

[2] In Order No. P.U. 32 (2007), the Board approved a 3-year amortization of the 2006 year end balance in the Purchased Power Unit Cost Variance Reserve of $1,342,000. The balance in the PPUCVR will be fully amortized at December 31, 2010. Beginning in 2008, the PPUCVR has been replaced by the Demand Management Incentive Account.

**Newfoundland Power Inc.**
**Statement of Operating & General Expenses**
**For The Year Ended December 31, 2008**
**($000's)**

| | 2008 | 2007 | Variances [1] |
|---|---|---|---|
| Operating Expenses | | | |
| Purchased Power | 336,658 | 326,778 | 9,880 |
| Power Produced | 2,552 | 2,480 | 72 |
| Administrative and Engineering Support | 5,604 | 5,585 | 19 |
| Environmental Policy | 398 | 581 | (183) |
| Substations | 2,123 | 2,311 | (188) |
| Transmission | 585 | 587 | (2) |
| Distribution | 6,592 | 6,575 | 17 |
| Communications | 1,394 | 1,399 | (5) |
| Fleet Operating and Maintenance Expense | 1,572 | 1,497 | 75 |
| | 357,478 | 347,793 | 9,685 |
| General Expenses | | | |
| Customer Service | 10,363 | 10,273 | 90 |
| Financial Services | 1,494 | 1,646 | (152) |
| Information Systems | 2,487 | 2,752 | (265) |
| Pension Costs | 3,040 | 5,567 | (2,527) |
| Retirement Allowances | 307 | 345 | (38) |
| Corporate and Employee Services | 13,458 | 13,570 | (112) |
| | 31,149 | 34,153 | (3,004) |
| Total Operating & General Expenses | 388,627 | 381,946 | 6,681 |
| Less: Transfers to General Expenses Capitalized | 1,797 | 1,966 | (169) |
| **Total Expenses [2]** | **386,830** | **379,980** | **6,850** |

[1] Variances are explained in Return 21.
[2] This is equal to the total of purchased power costs, operating expenses and pension costs shown in Return 1.

# Newfoundland Power Inc.
# Explanation of Expense Variances
# 2008 versus 2007
# ($000's)

| | 2008 | 2007 | Increase (Decrease) |
|---|---|---|---|
| **Total Expenses** | **386,830** | **379,980** | **6,850** |

Total expenses for 2008 increased by $6.8 million, or 1.8 per cent over 2007. This increase was due primarily to higher purchased power expense, offset by lower pension expense associated with a change in the discount rate.

The following is an explanation of significant variances for individual operating and general expense classes.

| | 2008 | 2007 | Increase (Decrease) |
|---|---|---|---|
| **Purchased Power** | **336,658** | **326,778** | **9,880** |

The increase in Purchased Power expense in 2008 was a result of higher energy sales as well as the impact of the 2008 leap year which amounted to one extra day of purchases. In addition, the PUB ordered the deferred recovery in 2007 of the cost of replacement energy purchased during the refurbishment of the Company's Rattling Brook hydroelectric plant. This deferral was recorded in 2007 as a decrease in Purchased Power expense and is being amortized as an increase in expense equally over the period 2008-2010.

| | 2008 | 2007 | Increase (Decrease) |
|---|---|---|---|
| **Power Produced** | **2,552** | **2,480** | **72** |

The increase in Power Produced cost was the result of increased expenses related to water power rental rates, snow clearing and vegetation management.

| | 2008 | 2007 | Increase (Decrease) |
|---|---|---|---|
| **Administrative and Engineering Support** | **5,604** | **5,585** | **19** |

Administrative and Engineering Support costs were in line with 2007. The 2008 Administrative and Engineering Support costs were higher than 2007 due to inflation impacts. The increases in 2008 costs due to inflation were offset by the costs associated with the December 2nd 2007 sleet storm on the Bonavista Peninsula.

| | 2008 | 2007 | Increase (Decrease) |
|---|---|---|---|
| **Environmental Policy** | **398** | **581** | **(183)** |

The decrease in Environmental Policy cost in 2008 was a result of lower operating cost attributable to oil spills. The decrease in cost is attributed to the lower number and volume of spills during 2008, and an accounting change in the allocation of cost to equipment retirement.

# Newfoundland Power Inc.
## Explanation of Expense Variances
## 2008 versus 2007
## ($000's)

| | 2008 | 2007 | Increase (Decrease) |
|---|---|---|---|
| **Substations** | **2,123** | **2,311** | **(188)** |

Substations operating costs were lower in 2008 as a result of staff being relocated to additional capital projects associated with the interconnection of two wind farms and the in-service failure of the Pierre's Brook transformer.

| | 2008 | 2007 | Increase (Decrease) |
|---|---|---|---|
| **Transmission** | **585** | **587** | **(2)** |

Transmission operating costs for 2008 were in line with costs for 2007.

| | 2008 | 2007 | Increase (Decrease) |
|---|---|---|---|
| **Distribution** | **6,592** | **6,575** | **17** |

Distribution operating costs for 2008 were in line with costs for 2007. Increases due to inflation were offset by improvements in breakdown maintenance and no significant storm damage in 2008.

| | 2008 | 2007 | Increase (Decrease) |
|---|---|---|---|
| **Communications** | **1,394** | **1,399** | **(5)** |

Communications operating costs for 2008 were in line with costs for 2007.

| | 2008 | 2007 | Increase (Decrease) |
|---|---|---|---|
| **Fleet Operating and Maintenance Expense** | **1,572** | **1,497** | **75** |

The increase in Fleet Operating and Maintenance Expense is primarily the result of higher fuel costs.

| | 2008 | 2007 | Increase (Decrease) |
|---|---|---|---|
| **Customer Service** | **10,363** | **10,273** | **90** |

Customer Service operating costs were in line with 2007. An increase in conservation and demand management (CDM) expenditures was partially offest by a reduction in uncollectible bills.

**Newfoundland Power Inc.**
**Explanation of Expense Variances**
**2008 versus 2007**
**($000's)**

| | 2008 | 2007 | Increase (Decrease) |
|---|---|---|---|
| **Financial Services** | **1,494** | **1,646** | **(152)** |

The decrease in Financial Services cost in 2008 when compared to 2007 was a result of staff reductions following the 2007 GRA.

| | 2008 | 2007 | Increase (Decrease) |
|---|---|---|---|
| **Information Systems** | **2,487** | **2,752** | **(265)** |

Information Systems operating costs were lower in 2008 as a result of changes in the payment schedule for software maintenance expenses. The 2007 Information Systems operating costs were higher than normal due to corporate website improvements and the implementation of added security features.

| | 2008 | 2007 | Increase (Decrease) |
|---|---|---|---|
| **Pension Costs** | **3,040** | **5,567** | **(2,527)** |

Pension costs were lower in 2008 as a result of amortization of higher than expected returns on pension plan assets experienced during 2007, and a higher discount rate determined as at December 31, 2007 in accordance with CICA reporting requirements.

| | 2008 | 2007 | Increase (Decrease) |
|---|---|---|---|
| **Retirement Allowances** | **307** | **345** | **(38)** |

The 2007 Retirement Allowances of $345,000 included $135,000 associated with the amortization of the 2005 Early Retirement Program cost. Excluding the 2005 ERP amortization, the 2008 Retirement Allowance variance was $97,000 above 2007. The increase in 2008 resulted from a higher number of severances compared with 2007.

| | 2008 | 2007 | Increase (Decrease) |
|---|---|---|---|
| **Corporate and Employee Services** | **13,458** | **13,570** | **(112)** |

Lower Corporate and Employee Services costs in 2008 reflect the timing of recognition of PUB assessment expenses. This was partially offset by increased energy efficiency program advertising and increased labour costs.

| | 2008 | 2007 | Increase (Decrease) |
|---|---|---|---|
| **General Expenses Capitalized** | **1,797** | **1,966** | **(169)** |

The decrease in General Expenses Capitalized (GEC) reflects reductions in those expense groupings (mostly pension costs) from which indirect allocations to GEC are derived.

**Newfoundland Power Inc.**
**Calculation of Taxable Income and Income Tax Expense**
**For The Year Ended December 31, 2008**
**($000's)**

| | | | |
|---|---|---|---|
| Net Earnings from Return 1 | | | 32,895 |
| Add: | Provision for current income tax | 19,943 | |
| | Provision for prior years taxes | 188 | |
| | Provision for future income taxes | 1,184 | |
| | Provision for Purchased Power Unit Cost Variance Reserve (PPUCVR) | 415 | |
| | Provision for Replacement Energy Costs | (216) | |
| | Provision for Weather Normalization | (2,368) | 19,146 |
| Net Income Before Income Taxes | | | 52,041 |
| Add: | Amortization of capital assets net of deferred expense | 40,649 | |
| | Amortization of debt discount & expenses | 177 | |
| | Amortization of capital stock issue expenses | 62 | |
| | Amortization of credit facility costs | 59 | |
| | Business meals & related expenses | 190 | |
| | Special pension liability | 198 | |
| | Replacement Energy Cost | 598 | |
| | Revenue re: Agreement With CRA | 7,513 | |
| | Stock option expense not deductible | 367 | |
| | Small tools in excess of $500 | 175 | |
| | Deferred Depreciation Costs | 3,862 | |
| | Deferred GRA Expenses | 201 | |
| | Other non deductible costs | 27 | 54,078 |
| | | | 106,119 |
| Less: | Capital cost allowance | 39,119 | |
| | Cumulative eligible capital | 11 | |
| | Credit Facility Costs | 50 | |
| | Revenue re: Agreement With CRA | 7,210 | |
| | General expenses capitalized | 2,765 | |
| | Interest charged to construction | 618 | |
| | Bond issue expenses | 107 | |
| | Deferred GRA costs | 5 | |
| | Part VI.1 tax deduction | 34,899 | |
| | Capital gains on sale of land included in income | 59 | |
| | Difference in pension funding and accounting cost | 2,300 | 87,143 |
| Taxable Income | | | 18,976 |
| | Weather Normalization deducted as future tax | | 2,368 |
| | Provision for PPUCVR | | (415) |
| | Income Tax - Part 1 | | 6,357 |
| | Income Tax - Part VI.1 | | 11,633 |
| | Provision for prior years taxes | | 188 |
| Current Income Tax Expense | | | 20,131 |
| | Provision for PPUCVR | | 415 |
| | Provision for Replacement Energy Costs | | (216) |
| | Provision for Weather Normalization | | (2,368) |
| | Future income tax | | 1,184 |
| Future Income Tax Provision | | | (985) |
| Total Tax Expense | | | 19,146 |

**Newfoundland Power Inc.**
**Accumulated Future Income Taxes**
**For The Year Ended December 31, 2008**
**($000's)**

| | | |
|---|---|---|
| **Plant Investments** | | |
| Balance on January 1, 2008 | | - |
| Add: CCA claimed on all property, plant and equipment - from Return 22 | 39,119 | |
| Less: Amortization expense on all property, plant and equipment (GEC excluded from post-1986 additions) | 37,135 | |
| Difference | 1,984 | |
| Future Income Tax Rate @ 29% | | 575 |
| Balance on December 31, 2008 (if negative enter 0) | | 575 |
| **Pension and Early Retirement Costs** | | |
| Balance on January 1, 2008 | | - |
| Add: Pension Funding | 4,183 | |
| Less: Pension Expense (including Special Pension Costs) | 2,081 | |
| Difference | 2,102 | |
| Future Income Tax Rate @ 29% | | 609 |
| Balance on December 31, 2008 | | 609 |
| **Total Accumulated Future Income Taxes** | | **1,184** |

**Newfoundland Power Inc.**
**Average Regulated Capital Structure**
**For The Year Ended December 31, 2008**
**($000's)**

## Average Book Capital Structure

| | Year-End December 31 2008 | Year-End December 31 2007 | Average | Percent |
|---|---|---|---|---|
| Total Debt[1] | 438,154 | 443,527 | 440,841 | 54.06% |
| Preference Shares | 9,352 | 9,352 | 9,352 | 1.15% |
| Common Equity | 373,738 | 356,671 | 365,205 | 44.79% |
| | 821,244 | 809,550 | 815,398 | 100.00% |

## Regulated Average Capital Structure[2]

| | Average 2008 | Percent |
|---|---|---|
| Total Debt | 440,841 | 54.06% |
| Preference Shares | 9,352 | 1.15% |
| Common Equity | 365,205 | 44.79% |
| | 815,398 | 100.00% |

[1] Beginning in 2008, debt for average capital structure is net of unamortized debt discount and issue expenses. For comparative purposes, debt for 2007 is also shown net of unamortized debt discount and expense.

[2] In Order No. P.U. 19 (2003), the Board ordered that the proportion of regulated common equity in the capital structure shall not exceed 45%. In years where the average common equity percentage is below 45% of the average invested capital, the regulated average capital structure will equal the average book capital structure.

**Newfoundland Power Inc.**
**Cost of Embedded Debt**
**For The Year Ended December 31, 2008**
**($000's)**

| | | December 31 2008 | December 31 2007 |
|---|---|---|---|
| **Average Debt** | | | |
| Bonds | | 409,088 | 413,638 |
| Credit Facilities | | 32,000 | 33,000 |
| | | 441,088 | 446,638 |
| Debt Discount and Issue Expenses[1] | | (2,934) | (3,111) |
| | | 438,154 | 443,527 |
| Average Debt | **A** | 440,841 | 427,851 |
| **Interest Expense[2]** | | | |
| Interest on Bonds | | 32,334 | 33,718 |
| Interest on Credit Facilities | | 1,445 | 1,437 |
| Interest on Bank Indebtedness | | 11 | 38 |
| Amortization of Debt Discount and Issue Costs | | 235 | 256 |
| | **B** | 34,025 | 35,449 |
| **Embedded Cost of Debt** | **B/A** | **7.72%** | **8.29%** |

[1] Beginning in 2008, unamortized debt discount and issue expenses are included in the calculation of average debt. In 2007, unamortized debt discount and expenses were included in deferred charges.

[2] Interest earned and interest on overdue accounts have been re-classified as Other Revenue beginning in 2008. For comparative purposes, the 2007 interest expense has been restated to reflect this reclassification. Total financing costs for 2008 and 2007 as reported in Return 1 are as follows:

| | 2008 | 2007 |
|---|---|---|
| Interest Expense (B) from above | 34,025 | 35,449 |
| Add: Amortization of Capital Stock Issue Expenses | 62 | 62 |
| Add: Interest on Security Deposits | 38 | 50 |
| Less: AFUDC | (618) | (622) |
| Interest Expense Reported in Return 1 | 33,507 | 34,939 |

# Newfoundland Power Inc.
## Explanation of Variances in Cost of Debt
## For The Year Ended December 31, 2008
## ($000's)

| | Actual 2008 | Test Year 2008 | Variance |
|---|---|---|---|
| **Average Debt** | 440,841 | 440,691 | 150 |
| | | | |
| **Embedded Cost of Debt** | 7.72% | 7.93% | -0.21% |
| | | | |
| **Details of the Embedded Cost of Debt** | | | |
| Interest on Bonds | 32,334 | 32,334 | - |
| Interest on Credit Facilities | 1,445 | 2,393 | (948) [1] |
| Interest on Bank Indebtedness | 11 | - | 11 |
| Amortization of Debt Discount and Issue Costs | 235 | 236 | (1) |
| | | | |
| | 34,025 | 34,963 | (938) |

**Explanation of Variances**

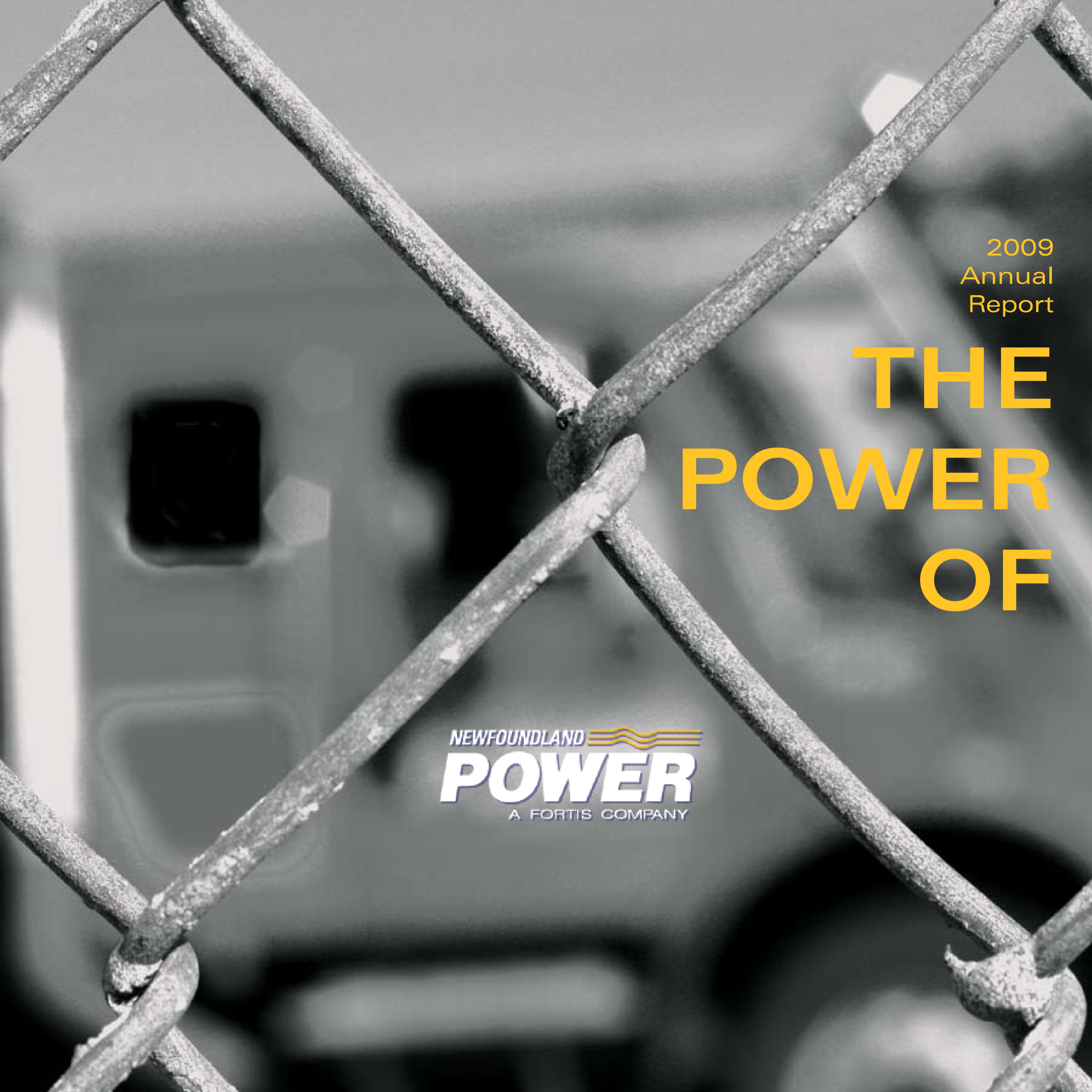
[1] The reduction in interest costs is primarily related to reductions in actual borrowing rates driven by market conditions in 2008. The short-term rates used in the 2008 Test Year were based on forecast information from the five major Canadian Banks in August of 2007 and indicated an average short-term rate of 5.75% for 2008. Actual short-term rates in 2008 ranged from a high of 4.82% in January to a low of 2.28% in December.

**Newfoundland Power Inc.**
**Regulated Return on Average Common Equity**
**For The Year Ended December 31, 2008**
**($000's)**

| | | 2008 | 2007 |
|---|---|---|---|
| 1 | **Average Common Equity** | | |
| 2 | | | |
| 3 | Common Equity at December 31, 2008 | 373,738 | |
| 4 | | | |
| 5 | Common Equity at December 31, 2007 | 356,671 | 356,671 |
| 6 | | | |
| 9 | Common Equity at December 31, 2006 | | 335,887 |
| 10 | | | |
| 11 | Average Common Equity | 365,205 | 346,279 |
| 12 | | | |
| 13 | | | |
| 14 | **Regulated Return on Average Common Equity** | | |
| 15 | | | |
| 16 | Earnings Applicable to Common Shares - Return 1 | 32,341 | 29,866 |
| 17 | | | |
| 18 | Add: Non-Regulated Expenses (net of income taxes) | 995 | 111 |
| 19 | | | |
| 20 | | 33,336 | 29,977 |
| 21 | | | |
| 22 | | | |
| 23 | **Regulated Return on Average Common Equity** | **9.13%** | **8.66%** |

**Newfoundland Power Inc.**
**Assessable Revenue**
**(s. 13 of the *Public Utilities Act* )**
**For The Year Ended December 31, 2008**
**($000's)**

| | | |
|---|---|---|
| Revenue From Rates from Return 14 | 497,360 | |
| Weather Normalization Revenue Adjustment from Return 17 | (7,575) | |
| | 489,785 | |
| Municipal Taxes Billed | 12,338 | |
| Billing per the Rate Stabilization Account from Return 16 | 19,326 | |
| Total Electrical Revenue Billed | | 521,449 |
| Other Revenue from Return 14 | | 13,267 |
| **Assessable Revenue** | | **534,716** |



2009 Annual Report

# THE POWER OF

NEWFOUNDLAND POWER
A FORTIS COMPANY

# Corporate Profile

Newfoundland Power Inc. ("Newfoundland Power") operates an integrated generation, transmission and distribution system throughout the island portion of Newfoundland and Labrador.

For over 120 years, we have provided customers with safe, reliable electricity in the most cost-efficient manner possible. Our Company serves over 239,000 customers, approximately 85% of all electricity consumers in the province.

Our employees continue to provide our customers with the service they expect and deserve in an environmentally and socially responsible manner.

Our vision is to be a leader among North American electric utilities in terms of safety, customer service, reliability and efficiency.

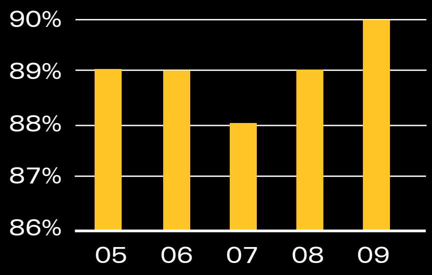
All the common shares of Newfoundland Power are owned by Fortis Inc. (TSX:FTS), the largest investor-owned distribution utility in Canada, which serves approximately 2,100,000 gas and electricity customers, and has assets exceeding $12 billion.

# Highlights

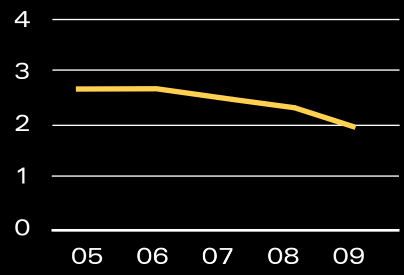
| Financial | 2009 | 2008 |
|---|---|---|
| Revenue *($000s)* | 527,179 | 516,889 |
| Property, Plant and Equipment *($000s)* | 1,230,371 | 1,181,433 |
| Long-term Debt *($000s)* | 482,388 | 441,088 |
| Common Shareholders' Equity *($000s)* | 381,185 | 373,738 |
| Earnings Applicable to Common Shares *($000s)* | 32,628 | 32,341 |
| Earnings per Common Share *($)* | 3.16 | 3.13 |

| Operating | | |
|---|---|---|
| Customers *(#)* | 239,307 | 235,778 |
| Customer Satisfaction Rating *(%)* | 90 | 89 |
| Generating Capacity *(MW)* | | |
| Hydroelectric | 96.6 | 96.6 |
| Diesel | 7.0 | 7.0 |
| Gas Turbine | 36.5 | 36.5 |
| Total | 140.1 | 140.1 |
| Peak Demand *(MW)* | 1,219 | 1,181 |
| Electricity Sales *(GWh)* | 5,299 | 5,208 |

## Customer Satisfaction Rating




## Outages per Customer




take CHARGE
take CHARGE
take CHARGE
take CHARGE

Report to

# Shareholders

Throughout 2009, Newfoundland Power demonstrated the power of its commitment to customers. This resulted in a 90% overall customer satisfaction rating. Our strong connection with our customers and communities shows the improvements we have made across many aspects of our business are delivering results.

In 2009, we achieved our best year on record for the lowest number of safety incidents; continued to make strategic investments in our electricity system; maintained our strong level of reliability; and, increased our focus on energy efficiency. We did all of this while continuing to strengthen relationships with community partners.

Our earnings of $32.6 million in 2009 increased by $0.3 million over 2008. Electricity sales increased 1.7% to 5,299 gigawatt hours (“GWh”) in 2009, and our number of customers grew 1.7% to over 239,000.

Newfoundland Power filed an application with the Newfoundland and Labrador Board of Commissioners of Public Utilities (“PUB”) in 2009, to set electricity rates for 2010. Following a public hearing, the PUB approved an overall average increase of 3.5% in electricity rates, effective January 1, 2010. When combined with the 6.6% average decrease on July 1, 2009, electricity rates in January 2010 are, on average, lower than those in January 2009, with residential rates remaining the lowest in Atlantic Canada.

While our goal will always be zero accidents, in 2009 we recorded our least number of safety incidents in over 40 years. This was the result of a refocused employee commitment to putting safety first, supported by several corporate initiatives.

Early in the year we launched our *Safety…Live it!* theme to motivate employees to share in the responsibility of safety both on and off-the-job. Our new safety television advertisement helped to maximize awareness about electrical hazards among the general public. We responded to contractor contacts with electrical equipment with a new safety campaign called, *Know where the line is!* And, we partnered with safety conscious groups, such as the Newfoundland and Labrador Safety Construction Association, to prevent vandalism to our electricity system.

We take the responsibility of providing safe, reliable electricity to our customers at the lowest possible cost very seriously. In 2009, we allocated over 30% of our capital expenditures to connecting a record number of new customers, and over 60% to upgrading and modernizing components of the provincial electricity system. We spent approximately $4.5 million to upgrade transmission lines, including two on the Bonavista Peninsula, $5.2 million to replace the penstock at our Rocky Pond Hydroelectric Plant; and, $4.5 million to refurbish and modernize substations across the island. Such investments aided in reducing the number of outages experienced by our customers by 14% over 2008. In 2009, we delivered electricity to our customers 99.97% of the time.


POWER

We combined forces with Newfoundland and Labrador Hydro ("Hydro") to launch 4 takeCHARGE Energy Savers Rebate Programs. Our presence at community events combined with the strategic marketing of our takeCHARGE partnership, resulted in approximately 50,000 visits to *takechargenl.ca* and almost 2,000 participants in our rebate programs in 2009.

Energy efficiency also took on an increased focus at our 12th annual *EnviroFest* celebrations, held across the island. Attended by more than 5,500 people and over 300 community groups, our *EnviroFest* events highlight the importance of our environment for future generations. We have planted almost 2,000 trees as part of our *EnviroFestivities*, beautifying green spaces throughout the province.

When we work together, the impact on our communities and our province can be invaluable. In 2009, we raised over $165,000 for our corporate charity, *The Power of Life Project.* This was made possible by generous donations from our customers and employees, our annual corporate donation, and funds raised at employee-driven events. *The Project* helped to enhance cancer care in several areas of the province. We donated 5 chemotherapy chairs to the Cancer Centre Western Region, a blanket warmer to the Burin Cancer Centre, and presented the second $100,000 installment of our $350,000 commitment to the Dr. H. Bliss Murphy Cancer Centre Capital Campaign. To date, *The Project* has provided in excess of $1.5 million in monetary and in-kind donations to cancer care, with every dollar going to research, treatment and awareness initiatives in this province!

Since joining Canadian Blood Services' *Partners for Life* program in 2004, our employees and their families have made approximately 1,700 blood donations, helping to save up to 5,100 lives. In 2009, we were proud to be the highest donor of all corporate partners in Atlantic Canada.

We wish to thank our employees for offering their talents, hard work and commitment throughout the year. Our ability to achieve a record performance for safety, maintain a strong electricity system, increase our focus on energy efficiency, and provide our customers with customer service excellence is a credit to their valued contributions.

We express our sincerest appreciation for the Board of Directors continued support and direction. We also thank Mr. Chris Griffiths, who retired from our Board after 6 years of service, for his perspective and guidance.

It is the power of our people that continues to deliver results. Their unrelenting dedication to putting safety first, developing relationships with our customers, preserving our environment and serving our communities has shaped the way we do business. We are committed to continuing this proud tradition for many years to come!

Sincerely,

David Norris
Chair, Board of Directors

Earl Ludlow
President and Chief Executive Officer


DANGER
HIGH VOLTAGE
KEEP OUT

# The Power of Safety

We are dedicated to the safety of our employees, contractors and the public. It is the foundation of our Company and our very top priority! The power of safety education and awareness remained an ongoing focus for the Company in 2009, resulting in our lowest number of safety incidents on record. This can be attributed to our employees' dedication to working safely, reinforced by streamlined work processes and several new safety initiatives.

Early in 2009, we launched an electronic safety application called PREVENT. This single access point for reporting and tracking incidents increased our ability to identify problem areas and take preventative action. We also strengthened employee participation in the health and safety process. This involved restructuring our Occupational Health and Safety Committees island-wide, and updating work methods used in the construction, operations, and maintenance of distribution and transmission lines.

An increased concentration on Meter Reader safety throughout the year resulted in significant improvements. For the first time in 5 years, there were no lost-time or medical-aid injuries involving the Meter Reading group.

We maximized the power of our safety messaging with targeted communications to key audiences in 2009. The launch of our internal campaign, *Safety...Live it!,* called upon our employees to share in the responsibility of safety at work and at home. Our *Know where the line is!* campaign targeted contractors with important messaging about working around electrical equipment. We reminded the public about electrical hazards with a new safety television advertisement. And, we partnered with Crime Stoppers to prevent acts of vandalism to our electricity system.

We continued our 25-year history of firefighter electrical safety seminars, educating over 240 firefighters. And, with the help of our retirees and employee volunteers, we were able to educate approximately 3,000 school children about electrical safety.

The successful completion of an external audit of our Health and Safety Management System in 2009, confirmed our continued compliance with the Occupational Health and Safety Assessment Series 18001 Health and Safety Management System international standards.

Our daily operations focus on a core set of values which have been largely shaped by our responsibility to our customers and our community. The most powerful of these values is, and always will be, SAFETY.


POWER

# The Power of Reliability

Our ability to provide electricity to our customers in a safe and reliable manner is directly related to the quality and condition of our electricity system. Over the years, our electricity system has become increasingly stronger due to the strategic capital investments we have made throughout our service territory.

Over the past 5 years, we have invested in excess of $300 million in capital expenditures, including approximately $70 million in 2009. More than 60% of our 2009 capital spending involved upgrading and modernizing our electricity system. We allocated $4.5 million to upgrading transmission lines, including 2 on the Bonavista Peninsula, $5.2 million to replacing the penstock at our Rocky Pond Hydroelectric Plant, and $4.5 million to refurbishing and modernizing substations across the island.

Over 30% of our capital budget went to providing service to a record number of new customers in 2009. Throughout the year, we connected over 5,000 services, and our total number of customers grew to over 239,000.

2009 was our best year on record for the number and length of outages. We reduced the number of outages experienced by our customers by 14% compared to 2008, and delivered electricity to our customers 99.97% of the time. We will continue to make strategic investments in the future in order to maintain this level of integrity.

In 2010, we plan to invest approximately $65 million in capital projects, which will allow us to continue providing safe, reliable service to our customers at the lowest cost possible.

Investments that are focused on maintaining a strong electricity system will not only enable us to sustain our current level of RELIABILITY, but also help us to maintain the lowest electricity rates in Atlantic Canada!

## The Power of
# Energy Efficiency

Promoting energy efficiency in Newfoundland and Labrador benefits our customers, our environment, and the Company! In 2009, we focused on assisting our customers to reduce the amount of energy they use in their homes and businesses, and save money.

We partnered with Hydro under our joint energy efficiency partnership, takeCHARGE – Saving Energy Starts Here!, to launch our takeCHARGE Energy Savers Rebate Programs. These programs provide our commercial customers with rebates on energy efficient lighting, and our residential customers with rebates on insulation, programmable and electronic thermostats, and ENERGY STAR® windows. We promoted the new takeCHARGE programs through traditional and social media, tradeshows, seminars at municipalities and customer conferences, and point-of-purchase booths at building supply stores throughout the province.

From November 14th – 20th, we celebrated the first ever takeCHARGE Energy Efficiency Week in Newfoundland and Labrador. Throughout the week, we talked one-on-one with customers in their homes and provided energy saving advice on a television series called *Winter Warm-Up*. This was supported by a customer contest and media campaign to increase awareness about energy efficiency.

These initiatives are expected to achieve 15 GWh of energy savings annually by 2013. This is the same as removing almost 1,400 electrically-heated homes from the province’s electricity system.

By the end of 2009, almost 2,000 customers had taken advantage of our rebate programs, and close to 50,000 customers visited our energy efficiency website, *takechargenl.ca*.

Internal energy efficiency initiatives in 2009 involved completing energy audits at a number of our facilities, and installing energy efficient lighting in several of our buildings.

By encouraging our customers to be ENERGY EFFICIENT through our takeCHARGE partnership, we are giving them the power to save energy, save money and positively impact the future of our environment.


CUSTOMER SERVICE
take
CHARGE

The Power of

# Customer Service

We all work together to provide customer service excellence. It is rewarding to know that it is recognized by those who matter most, our customers. We attribute our 90% customer satisfaction rating to our employees' determination to provide the highest level of service every day.

Offering our customers choice can be very powerful. In 2009, we increased customer convenience by offering an alternative to how our customers choose to do business with us. Since introducing e-correspondence in the second quarter, over 25,000 customers have chosen email as their primary means of communication. We also installed new software in our Customer Contact Centre to help us manage and respond to this increase in electronic inquiries. The number of customers who opted to receive their electricity bills electronically also increased in 2009, growing by 20% over the previous year.

We continued to install automated meters in new developments throughout the island and where meter accessibility has been an issue. The ability to read these meters remotely has allowed us to address numerous safety issues and decreased our need to estimate bills. We currently have almost 19,000 of these meters in use across our service territory.

Enhancing our relationships with our customers has been a continued focus over the last several years. In 2009, we increased our participation at tradeshows around the province, and set up mall displays to meet and talk with our customers on a one-on-one basis.

Our strong customer satisfaction rating demonstrates the power of our employees' commitment to delivering the SERVICE EXCELLENCE our customers expect and deserve from us!


NEWFOUNDLAND
A FORTIS

# The Power of Employees

No matter what role our employees play, they each bring special skills and talents to our Company. We enhanced the power of our employees in 2009 through development opportunities, and recruitment and training initiatives. The development of a new work methods team combined years of knowledge and experience from across the Company in support of transmission and distribution functions. Instrumental in the development and implementation of work procedures, operational practices, and tool and equipment specifications, our employees use the power of teamwork to identify best practices to ensure everyone is working safely and effectively.

We underwent a significant reorganization in the second quarter, bringing a larger number of employees from across the Company together to create and maintain a safe work environment. This new structure works at the grassroots level to increase employee involvement in the safety process.

Working towards maximizing knowledge transfer and smooth employee succession, we continued our Powerline Technician Apprentice Program in 2009. The job skill and training requirements associated with this program enable us to provide the same level of safe, reliable service our customers have come to expect, despite the pressures of an aging workforce.

We also focused on a number of recruitment initiatives in 2009. We developed succession plans for key positions within our Engineering and Operations Departments. Our participation in career fairs at Memorial University of Newfoundland and College of the North Atlantic campuses increased. And, we hired 19 work term students as part of our continued support of Cooperative Programs.

In 2009, the Company and its Union, IBEW Local 1620, ratified 2 Collective Agreements, which will remain in effect for 3 years, until September 2011.

We believe in a strategic and consistent approach to the development of our organization's most valued assets, our EMPLOYEES, who individually and collectively contribute to our corporate success.

## The Power of

# Environment

We believe in the power of our environment. That's why we take our pledge to operate in an environmentally responsible manner very seriously.

In 2009, we completed several projects to reduce the environmental risks associated with operating our electricity system. Such projects involved: replacing the wooden penstock at our Rocky Pond Hydroelectric Plant with steel; replacing aged transformers to reduce the risk of oil leakage; and, removing and disposing of PCB oil-filled electrical equipment. To date, approximately 78% of our feeders and 87% of our substations have been completed under the PCB Phase-out Program.

Throughout the year, we also invested capital to make our electricity system more energy efficient. By raising the spillway at our Rose Blanche Hydroelectric Plant, we successfully increased the plant's energy output. The incremental energy will help to defer new hydroelectric developments and serve to displace the use of additional oil from Hydro's Holyrood Generating Plant. 2009 also marked the first of a 3-year project involving replacing streetlights across the island with energy efficient High Pressure Sodium lights. The new lights provide the same quality of lighting while consuming 35% less energy.

An external audit of our Environmental Management System in 2009 verified our continued compliance with the ISO 14001 international standard. It further confirmed that our facilities are well-maintained and our employees continue to demonstrate a commitment to working in an environmentally responsible manner.

2009 also marked the 12$^{th}$ anniversary of our annual employee-driven *EnviroFest* celebrations. During Environment Week, we hosted 8 events across the island, attended by thousands of people and over 300 community groups. To date, our employees and community volunteers have planted approximately 2,000 trees as part of our *EnviroFestivities*, helping to improve our environment and beautify green spaces throughout the province.

We pride ourselves on taking a leadership role in creating public awareness about the importance of preserving our environment for future generations. In 2009, we paid particular attention to educating participants and communities about the benefits of being energy efficient.

Our commitment to the ENVIRONMENT is not only a part of normal business operations, but also a partnership with our customers and communities to build a greener tomorrow.


TOYS PROVIDED BY
THE EMPLOYEES OF
NEWFOUNDLAND POWER
POWER
POWER

# The Power of Community

Our history of community involvement stems from the devotion our employees have to the places in which they live and work. With area offices and facilities located throughout the island, the power of our contributions can be seen from coast to coast.

In 2009, we contributed over $165,000 to our corporate charity, *The Power of Life Project*, which helped to enhance cancer care through several area-specific donations. We donated 5 chemotherapy chairs to the Cancer Centre Western Region, a blanket warmer to the Burin Cancer Centre, and the second $100,000 installment of our $350,000 commitment to the Dr. H. Bliss Murphy Cancer Centre Capital Campaign.

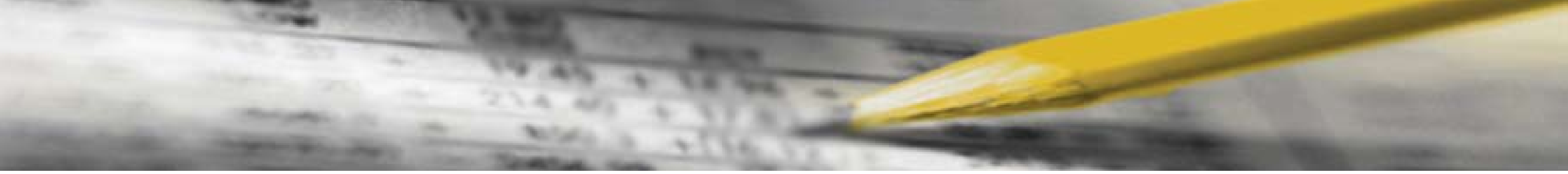
We have donated in excess of $1.5 million to cancer care to date. This is the result of continuous contributions from our customers and employees, our annual corporate donation, and employee-driven fundraisers, such as annual snowmobile runs, and golf and softball tournaments. Working as a team we have, and will continue to, make a difference in the fight against cancer in Newfoundland and Labrador. And, every dollar goes to research, treatment and awareness initiatives in this province.

In support of prostate cancer awareness, we stepped up our support of *Motorcycle Ride for Dad* in 2009. In addition to assisting with education and awareness, we hosted over 600 bikes at our Kenmount Road location on *Ride Day*. Together we raised about $130,000 toward the fight against prostate cancer in Newfoundland and Labrador.

We formed a new community partnership in 2009 with our sponsorship of *East Meets West*, a unique initiative aimed at increasing tourism on the east and west coasts of the island. We also strengthened our relationship with Municipalities Newfoundland and Labrador through presentations, seminars and participation in several municipal events.

Our employees and their families demonstrated their commitment to giving the gift of life throughout the year. In 2009, we were the highest of any corporate partner in Atlantic Canada, second only to the Canadian Forces Base in Gagetown, New Brunswick. Since joining Canadian Blood Services' *Partners for Life* program in 2004, Newfoundland Power employees and their families have made approximately 1,700 blood donations, helping to save up to 5,100 lives.

As one of the oldest existing businesses in the province, we have one of the longest histories of COMMUNITY involvement, and it is our employees who have made all the difference.



# Management Discussion and Analysis

*This Management Discussion and Analysis ("MD&A") dated February 4, 2010, should be read in conjunction with Newfoundland Power Inc.'s (the "Company" or "Newfoundland Power") annual financial statements and notes thereto for the year ended December 31, 2009. The MD&A has been prepared in accordance with National Instrument 51-102 Continuous Disclosure Obligations. Financial information herein reflects Canadian dollars and Canadian generally accepted accounting principles ("Canadian GAAP"), including certain accounting practices unique to rate regulated entities. These accounting practices, which are disclosed in Notes 2 and 4 to the Company's 2009 annual audited financial statements, result in the recognition of revenues, expenses, regulatory assets and regulatory liabilities which would not occur in the absence of rate regulation and which affect the Company's reported earnings, cash flows and financial position.*

*Certain information herein is forward-looking and reflects management's current expectations regarding the Company's future financial and related performance. The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects management's current beliefs and is based on information currently available to the Company's management. Certain material factors, estimates and assumptions, which are subject to inherent risks and uncertainties surrounding future expectations generally, have been applied in drawing the conclusions contained in the forward-looking statements. These are related to, but are not limited to: regulation; energy supply; competition; general economic conditions; health, safety and the environment; interest rates; insurance; weather; labour relations; licences and permits; capital resources and liquidity. Readers are cautioned to not place undue reliance on forward-looking statements because actual results could differ materially from the results discussed or implied in those statements. The Company undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise.*

*Additional information, including the Company's quarterly and annual financial statements, annual information form and management information circular, is available on SEDAR at www.sedar.com.*

## OVERVIEW

### The Company

Newfoundland Power is a regulated electricity utility that owns and operates an integrated generation, transmission and distribution system throughout the island portion of the Province of Newfoundland and Labrador. All the Company's common shares are owned by Fortis Inc. ("Fortis"), which is principally a diversified, international holding company for electricity and gas distribution utilities.

Newfoundland Power's primary business is electricity distribution. It generates approximately 8% of its electricity needs and purchases the remainder from Newfoundland and Labrador Hydro ("Hydro"). Newfoundland Power serves over 239,000 customers, approximately 85% of all electricity consumers in the Province.

Newfoundland Power's vision is to be a leader among North American electricity utilities in terms of safety, reliability, customer service and efficiency. The key goals of the Company are to operate sound electricity distribution systems, deliver safe reliable electricity to customers at the lowest reasonable cost and conduct business in an environmentally and socially responsible manner.

## Regulation

Newfoundland Power is regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities (the "PUB"). The Company operates under cost of service regulation whereby it is entitled the opportunity to recover, through customer rates, all reasonable and prudent costs incurred in providing electricity service to its customers, including a just and reasonable return on its rate base. The rate base is the value of the net assets required to provide electricity service.

Between general rate hearings, customer rates are established annually through an automatic adjustment formula (the "Formula"). The Formula sets an appropriate rate of return on common equity ("ROE") which is used to determine the rate of return on rate base. In accordance with operation of the Formula, the Company's rate of return on rate base for ratemaking purposes for 2009 remained unchanged from 2008 at 8.37%, with a range of 8.19% to 8.55%. This reflects a regulated ROE of 8.95%, unchanged from 2008.

## Financial Highlights

| | **2009** | **2008** | **Change** |
|---|---|---|---|
| Electricity Sales *(gigawatt hours ("GWh"))* | 5,299.0 | 5,208.2 | 90.8 |
| Earnings Applicable to Common Shares | | | |
| $ Millions | 32.6 | 32.3 | 0.3 |
| $ Per Share | 3.16 | 3.13 | 0.03 |
| ROE *(%)*[1] | 8.64 | 8.86 | (0.22) |
| Cash Flow from Operating Activities *($millions)* | 59.4 | 85.0 | (25.6) |
| Total Assets *($millions)* | 1,188.0 | 1,001.9 | 186.1 |

[1] *Earnings applicable to common shares, divided by the average of common shareholder's equity at the beginning and end of the year. This ratio is a non-GAAP financial measure, does not have any standardized meaning prescribed by GAAP and is unlikely to be comparable to similar ratios published by other companies. It is presented because it is commonly referred to by the users of the Company's financial statements in evaluating the results of operations and by the Company's regulator in the rate setting process.*

Electricity sales for the year ended December 31, 2009 increased by 90.8 GWh or 1.7% compared to 2008. The increase in electricity sales is comprised of an increase of (i) 1.5% due to customer growth and (ii) 0.2% due to higher average consumption.

Earnings for the year ended December 31, 2009 increased $0.3 million from $32.3 million in 2008 to $32.6 million in 2009. Additional earnings from higher electricity sales and other revenue, a lower effective tax rate and changes in purchase power expense due to higher water inflows in 2008 associated with the Company's hydroelectric generating facilities were partially offset by increased operating, amortization, finance and demand costs.

The decrease in cash flow from operating activities primarily reflects higher income tax installments and timing of payments relating to 2008 income taxes. Timing differences in other non-cash working capital items also contributed to lower cash flow from operating activities.

The increase in total assets was predominantly due to the adoption of Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3465, Income Taxes (see Note 2 of the Company's 2009 annual audited financial statements). The remaining increase resulted from continued investment in the electricity system, and is consistent with the Company's strategy to provide safe, reliable electricity service at the lowest reasonable cost.

Pursuant to the Company's 2010 General Rate Application ("2010 GRA"), in December 2009, the PUB ordered that customer electricity rates be increased by an overall average of approximately 3.5% effective January 1, 2010. The Company's rate of return on rate base for ratemaking purposes was set at 8.23%, with a range of 8.05% to 8.41%, for 2010. This reflects a regulated ROE of 9.00% for 2010. The Formula remains unchanged however it is subject to review in 2010. The 2010 GRA also provided for the amortization of certain regulatory assets and liabilities and the creation of a pension expense variance deferral account ("PEVDA") to deal with differences between defined benefit pension expense calculated in accordance with GAAP and pension expense approved by the PUB for rate setting purposes. The 2010 general rate order is expected to yield earnings and cash flows that will enable the Company to maintain its investment grade credit ratings.

## RESULTS OF OPERATIONS

### Revenue:

| *($millions)* | **2009** | **2008** | **Change** |
|---|---|---|---|
| Revenue from Rates | 508.8 | 496.4 | 12.4 |
| Amortization of Regulatory Liabilities | 6.0 | 8.6 | (2.6) |
| Other Revenue[1] | 12.4 | 11.9 | 0.5 |
| Total | 527.2 | 516.9 | 10.3 |

[1] *Other revenue is composed largely of pole attachment charges to various telecommunication companies.*

Revenue increased by approximately $10.3 million, from $516.9 million in 2008 to $527.2 million in 2009. The increase primarily resulted from electricity sales growth.

The amortization of regulatory liabilities related to unbilled revenue and municipal tax is in accordance with PUB orders. These regulatory liabilities are described in Note 4 to the Company's 2009 annual audited financial statements.

Other revenue increased by approximately $0.5 million, from $11.9 million in 2008 to $12.4 million in 2009. The increase was primarily related to land sales and higher joint use revenue, partially offset by lower interest on customer accounts.

**Purchased Power:** Purchased power expense increased by approximately $9.0 million, from $336.7 million in 2008 to $345.7 million in 2009. The increase was primarily due to electricity sales growth and higher demand charges from Hydro.

**Operating Expense:** Operating expense increased by approximately $2.2 million from $47.1 million in 2008 to $49.3 million in 2009. Wage and inflationary increases, increased costs associated with the 2010 GRA and higher PUB assessment costs due to timing of recognition of these costs in 2008, were partially offset by reductions in insurance and travel costs.

**Pension and Early Retirement Program Costs:** Pension and early retirement program costs decreased by approximately $0.3 million from $3.0 million in 2008 to $2.7 million in 2009. The decrease was primarily due to a higher discount rate at December 31, 2008, which is used to determine the Company's accrued benefit pension obligation associated with its Defined Benefit Pension Plan. This was partially offset by 2008 experience losses associated with the pension plan assets and a lower assumed long-term rate of return on pension assets for 2009. The impact of the decline in pension plan assets in 2008, as it relates to 2009 pension expense, was also mitigated as the pension assets are valued using the market related value as outlined in Note 2 to the 2009 annual audited financial statements.

**Amortization:** Amortization of property, plant and equipment and intangible assets increased by approximately $1.2 million, from $40.6 million in 2008 to $41.8 million in 2009. Higher amortization was associated with capital and intangible asset expenditures of $74.1 million in 2009.

**Amortization True-Up Deferral:** Amortization of property, plant and equipment and intangible assets is subject to periodic review by external experts via an amortization study. Based on a 2002 amortization study, the PUB ordered the deferred recovery of approximately $11.6 million, $5.8 million in each of 2006 and 2007, related to a variance in accumulated amortization. These deferrals were recorded as an increase in regulatory assets and a decrease in expenses in each year, to be amortized evenly over 2008 through 2010. The Company has recorded $3.9 million of amortization in both 2009 and 2008. This regulatory asset is described further in Note 4 to the Company's 2009 annual audited financial statements.

**Finance Charges:** Finance charges increased by approximately $1.1 million from $33.5 million in 2008 to $34.6 million in 2009. This increase primarily related to higher interest costs associated with the $65 million first mortgage bond issue in May 2009, partially offset by lower short term interest rates which are reflective of current market conditions.

**Income Taxes:** Income tax expense decreased by approximately $3.0 million, from $19.1 million in 2008 to $16.1 million in 2009. This decrease primarily reflects a lower effective income tax rate resulting from the amortization of regulatory deferrals and a reduction in the statutory tax rate.

## FINANCIAL POSITION

Explanations of the primary causes of significant changes in the Company's balance sheets between December 31, 2008 and December 31, 2009 follow.

| *($millions)* | **Increase (Decrease)** | **Explanation** |
|---|---|---|
| Cash | 4.7 | Increase due to timing of payments related to the Company's credit facilities. |
| Accrued Pension | 4.7 | Pension funding in excess of pension expense. |
| Total Regulatory Assets | 143.4 | Increase primarily due to the adoption of CICA Handbook Section 3465, *Income Taxes* (see Note 3 of the Company's 2009 annual audited financial statements). |
| Income Tax Payable / Receivable (Net) | (11.8) | Decrease related to timing of income tax installments. Higher installments were required in 2009 based upon 2008 income taxes. |
| Property, Plant and Equipment | 28.4 | Investment in electricity system, in accordance with 2009 capital expenditure program, offset partially by amortization and customer contributions in aid of construction. |
| Total Regulatory Liabilities | 17.3 | Increase primarily due to the adoption of CICA Handbook Section 3465, *Income Taxes* (see Note 3 of the Company's 2009 annual audited financial statements). |
| Other Post-Employment Benefits | 5.6 | Increase in employee future benefit liability. |
| Total Future Income Taxes | 122.3 | Increase primarily due to the adoption of CICA Handbook Section 3465, *Income Taxes* (see Note 3 of the Company's 2009 annual audited financial statements). |
| Long-term Debt, including Current Portion | 41.1 | Represents additional debt required to finance growth in rate base and ongoing operating activities. |
| Retained Earnings | 7.4 | Earnings, in excess of dividends, retained to finance rate base growth. |

## LIQUIDITY AND CAPITAL RESOURCES

The primary sources of liquidity and capital resources are net funds generated from operations, debt capital markets and bank credit facilities. These sources are used primarily to satisfy capital and intangible asset expenditures, service and repay debt, and pay dividends. A summary of cash flows and cash position for 2009 and 2008 follows.

| *($millions)* | **2009** | **2008** | **Change** |
|---|---|---|---|
| Cash, Beginning of Year | 0.6 | 1.1 | (0.5) |
| Operating Activities | 59.4 | 85.0 | (25.6) |
| Investing Activities | | | |
| Capital and Intangible Asset Expenditures | (74.1) | (67.3) | (6.8) |
| Other | 4.5 | 3.2 | 1.3 |
| | (69.6) | (64.1) | (5.5) |
| Financing Activities | | | |
| Bond Issue | 65.0 | - | 65.0 |
| Net Credit Facility Repayments | (18.5) | (1.0) | (17.5) |
| Dividends on Common Shares | (25.2) | (15.3) | (9.9) |
| Bond Sinking Fund Payments | (5.2) | (4.6) | (0.6) |
| Other | (1.2) | (0.5) | (0.7) |
| | 14.9 | (21.4) | 36.3 |
| Cash, End of Year | 5.3 | 0.6 | 4.7 |

### Operating Activities

Cash flow from operating activities totalled $59.4 million in 2009 compared to $85 million in 2008. The $25.6 million decrease in cash flow from operating activities reflects (i) higher income tax installments for 2009, (ii) timing of payments relating to 2008 income taxes, (iii) timing differences related to collection of electricity and other receivables and (iv) collections under the Company's equal payment plan for its electricity customers.

### Investing Activities

Cash flow used in investing activities totalled $69.6 million in 2009 compared to $64.1 million in 2008. The $5.5 million increase was due primarily to higher capital expenditures in 2009 compared to 2008. A summary of 2009 and 2008 capital and intangible asset expenditures follows.

| *($millions)* | **2009** | **2008** |
|---|---|---|
| Electricity System | | |
| Generation | 8.8 | 4.1 |
| Transmission | 4.4 | 5.2 |
| Substations | 8.2 | 7.5 |
| Distribution | 38.8 | 35.5 |
| Intangible Assets and Other | 13.9 | 15.0 |
| Capital and Intangible Asset Expenditures | 74.1 | 67.3 |

The Company's business is capital intensive. Capital investment is required to ensure continued and enhanced performance, reliability and safety of the electricity system, and to meet customer growth. All costs considered to be repairs and maintenance are expensed as incurred. Capital investment also arises for information technology systems and for general facilities, equipment and vehicles. Capital expenditures, and property, plant and equipment repairs and maintenance expense, can vary from year-to-year depending upon both planned electricity system expenditures and unplanned expenditures arising from weather or other unforeseen events.

The Company's annual capital plan requires prior PUB approval. Variances between actual and planned expenditures are generally subject to PUB review prior to inclusion in the Company's rate base.

The PUB has approved the Company's 2010 capital plan which provides for capital expenditures of approximately $64.7 million, approximately half of which relate to construction and capital maintenance of the electricity distribution system.

## Financing Activities

Cash flow from financing activities totalled $14.9 million in 2009 compared to cash used in financing activities of $21.4 million in 2008. The $36.3 million increase in cash from financing activities was primarily required to finance lower cash from operations, higher capital expenditures and payment of higher common share dividends to maintain a capital structure composed of 55% debt and 45% common equity.

The Company has historically generated sufficient annual cash flows from operating activities to service annual interest and sinking fund payments on debt, to pay dividends and to finance a major portion of its annual capital program. Additional financing to fully fund the annual capital program is primarily obtained through the Company's bank credit facilities and these borrowings are periodically refinanced along with any maturing bonds through the issuance of long-term first mortgage sinking fund bonds. The Company currently does not expect any material changes in these basic cash flow and financing dynamics over the foreseeable future.

**Debt:** In May 2009, the Company issued 30-year, 6.606% Series AM first mortgage bonds in the amount of $65 million. Net proceeds from this issuance were used to repay amounts outstanding under the Company's credit facilities. These amounts were previously borrowed primarily in relation to the Company's capital expenditure program. The issuance of additional bonds is subject to PUB approval and to an earnings test whereby the ratio of (i) annual earnings, before tax and bond interest, to (ii) annual bond interest incurred plus annual bond interest to be incurred on the contemplated bond issue, must be two times or higher. The Company expects to be able to issue bonds in the normal course for the foreseeable future.

The Company's credit facilities are comprised of a $100 million committed revolving term credit facility and a $20 million uncommitted demand facility. Details follow.

| *($millions)* | **2009** | **2008** |
|---|---|---|
| Total Credit Facilities | 120.0 | 120.0 |
| Borrowing, Committed Facility | (13.5) | (32.0) |
| Credit Facilities Available | 106.5 | 88.0 |

The committed facility matures in August 2011. Subject to lenders' approval, two years prior to maturity, the Company may request an extension for a further period of 364 days. During 2009, the Company opted not to extend the committed facility for the additional 364 days. In 2010, one year prior to maturity, the Company may request an extension for a further period of up to one year and 364 days.

**Pensions:** As at December 31, 2009, the fair value of the Company's primary defined benefit pension plan assets was $242.7 million compared to fair value of plan assets of $212.6 million as at December 31, 2008. The fair value of plan assets at the beginning of 2008 was $259.7 million. Details of the changes are included in Note 8 to the Company's 2009 annual audited financial statements. The increase in the fair value of pension plan assets during 2009 was mainly driven by the recovery of global financial market conditions.

In April 2009, Newfoundland Power received the Actuarial Valuation Report for its defined benefit pension plan. This report included the funding status of the plan as at December 31, 2008 on a going concern and solvency basis.

The going concern and solvency valuation was based on an adjusted market related value method to determine the actuarial value of assets. Under this method, investment gains (losses) arising during a given year are spread on a straight line basis over three years; within a 5% corridor of the fair value of the assets for the solvency valuation. The actuarial value of the assets, determined as at December 31, 2008 under the adjusted market value method for the going concern and solvency valuation was $251.4 million and $222.7 million, respectively.

Based on the report, the solvency deficit as at December 31, 2008 was $6.9 million ($7.7 million inclusive of interest). The solvency deficit is being funded over a five-year period, commencing in 2009. The Company fulfilled its 2009 annual solvency deficit funding requirement of $1.5 million during the second quarter of 2009.

The Company does not expect any difficulty in its ability to meet future pension funding requirements as it expects the amounts will be financed from a combination of cash generated from operations and amounts available for borrowing under existing credit facilities.

**Contractual Obligations:** Details, as at December 31, 2009, of all contractual obligations over the subsequent five years and thereafter, follow.

| *($millions)* | **Total** | **2010** | **2011-2012** | **2013-2014** | **2015 Onward** |
|---|---|---|---|---|---|
| Credit Facilities (unsecured) | 13.5 | - | 13.5 | - | - |
| First Mortgage Sinking Fund Bonds[1] | 468.9 | 5.2 | 10.4 | 39.0 | 414.3 |
| Pension Solvency Deficit[2] | 6.2 | 1.5 | 3.1 | 1.6 | - |
| Total | 488.6 | 6.7 | 27.0 | 40.6 | 414.3 |

1 *First mortgage sinking fund bonds are secured by a first fixed and specific charge on capital assets owned or to be acquired by the Company and carry customary covenants.*

2 *Pension funding requirements based on the Actuarial Valuation Report associated with the Company's defined benefit pension plan, completed as at December 31, 2008. This does not include routine funding requirements for current service cost.*

**Credit Ratings and Capital Structure:** To ensure continued access to capital at reasonable cost, the Company endeavours to maintain its investment grade credit ratings. Details of the Company's investment grade bond ratings as at December 31, 2009 and 2008 follow.

| | 2009 | | 2008 | |
|---|---|---|---|---|
| **Rating Agency** | **Rating** | **Outlook** | **Rating** | **Outlook** |
| Moody's Investors Service | A2 | Stable | Baa1 | Stable |
| Dominion Bond Rating Service | A | Stable | A | Stable |

On August 3, 2009, Moody's upgraded Newfoundland Power's investment grade bond rating from "Baa1" to "A2". Moody's also assigned a "Baa1" issuer rating to Newfoundland Power. The Company's investment grade bond rating and rating outlook from Dominion Bond Rating Service remain unchanged from 2008.

Newfoundland Power endeavours, by managing common share dividends, to maintain a capital structure composed of 55% debt and 45% common equity. This capital structure is reflected in customer rates and is consistent with the Company's current investment grade credit ratings. The Company's capital structure as at December 31, 2009 and 2008 follows.

| | 2009 | | 2008 | |
|---|---|---|---|---|
| | **$millions** | **%** | **$millions** | **%** |
| Total Debt[1] | 473.9 | 54.8 | 437.5 | 53.3 |
| Common Equity | 381.2 | 44.1 | 373.7 | 45.5 |
| Preferred Equity | 9.1 | 1.1 | 9.4 | 1.2 |
| Total | 864.2 | 100.0 | 820.6 | 100.0 |

[1] *Includes bank indebtedness, or net of cash, if applicable.*

The Company currently expects it will be able to maintain its current investment grade credit ratings in 2010.

**Capital Stock and Dividends:** For the years ended 2009 and 2008, the weighted average number of common shares outstanding was 10,320,270. Dividends on common shares, for 2009, compared to 2008, were $9.9 million higher. In 2009, common quarterly dividends increased to $0.61 per share compared to $0.37 per share in 2008. The increase in common share dividends was to maintain an average capital structure that includes approximately 45% common equity.

During 2009, the Company redeemed 24,125 preference shares for consideration of approximately $0.2 million.

## RELATED PARTY TRANSACTIONS

The Company provides services to, and receives services from, its parent company, Fortis and other subsidiaries of Fortis. The Company also incurs charges from Fortis for the recovery of general corporate expenses incurred by Fortis. These transactions are in the normal course of business and are recorded at their exchange amounts.

Related party transactions included in revenue, operating expenses, finance charges and included in accounts receivable as at December 31, 2009 and 2008 follow.

| *($millions)* | **2009** | **2008** |
|---|---|---|
| Revenue[1] | 4.5 | 4.2 |
| Operating Expenses | 1.6 | 1.5 |
| Finance Charges | - | 0.3 |
| Accounts Receivable | 0.1 | 0.2 |

1 *Includes charges for electricity consumed.*

In 2008, the Company borrowed $32.5 million from Fortis as a short-term demand loan at an interest rate of 3.15%, which was indicative of Bankers' Acceptance rates at the time. This amount was fully repaid in 2008. There were no amounts borrowed from Fortis in 2009.

## FINANCIAL INSTRUMENTS

The carrying values of financial instruments included in current assets, current liabilities, other financial assets, and other financial liabilities approximate their fair value, reflecting their nature, short-term maturity or normal trade credit terms. The fair value of long-term debt is calculated by discounting the future cash flows of each debt instrument at the estimated yield-to-maturity equivalent to benchmark government bonds, with similar terms to maturity, plus a market credit risk premium equal to that of issuers of similar credit quality. Since the Company does not intend to settle its debt instruments before maturity, the fair value estimate does not represent the actual liability, and therefore, does not include exchange or settlement costs.

The estimated fair value of the Company's first mortgage sinking fund bonds was $577.6 million at December 31, 2009 and $505.1 million at December 31, 2008. The reason for the significant change was the issuance of $65 million 30-year first mortgage sinking fund bonds during the second quarter of 2009.

## BUSINESS RISK MANAGEMENT

**Regulation:** The Company is subject to normal uncertainties facing entities that operate under cost of service regulation. It is dependent on PUB approval of customer electricity rates that permit a reasonable opportunity to recover on a timely basis the estimated costs of providing electricity service, including a fair and reasonable return on rate base. The ability to recover the actual costs of providing service and to earn the approved rates of return depends on achieving the forecasts established in the rate setting process. Between general rate applications, the setting of customer rates through the Formula can cause earnings and cash flows to increase or decrease due to corresponding changes in bond yields which are beyond the Company's control.

**Economic Conditions:** Economic conditions primarily impact the performance of the Company's defined benefit pension plan, cost of capital and electricity sales. The impact on pensions and cost of capital are discussed below. Electricity sales are influenced by economic factors in the Company's service territory such as changes in employment levels, personal disposable income, energy prices and housing starts. Out-migration in rural areas, as well as declining birth rates and increasing death rates associated with an aging population also affect sales. Modest sales growth is currently expected for 2010; however, economic conditions may impact actual future sales.

**Pension:** The Company's defined benefit pension plan is impacted by economic conditions as it relates to the Company's future pension funding requirements, as discussed in the "Liquidity and Capital Resources" section of this MD&A. Future pension obligations and related pension expense may also be impacted by economic conditions. The defined benefit pension plan is subject to judgments utilized in the actuarial determination of the pension obligation and the related pension expense. The primary assumptions utilized by management are the expected long-term rate of return on pension plan assets and the discount rate used to value the accrued benefit obligation. A discussion of the critical accounting estimates associated with pensions is provided in the "Critical Accounting Estimates" section of this MD&A.

There is no assurance that the pension plan assets will earn the expected long-term rate of return in the future. Market driven changes impacting the performance of the pension plan assets may result in material variations in actual return on pension plan assets from the expected long-term return on the assets. This may cause material changes in future pension liabilities and pension expense. Financial market fluctuations may also impact the discount rate resulting in material variations in future pension liabilities and pension expense.

As discussed under the "Financial Highlights" section of this MD&A, for 2010 and onwards, the PUB has approved the creation of a PEVDA to deal with the differences between defined benefit pension expense calculated in accordance with Canadian GAAP and pension expense approved by the PUB for rate setting purposes. Variations in pension expense from that approved by the PUB for rate setting purposes would be recovered from (returned to) customers through the Company's rate stabilization account. This deferral account substantially mitigates the Company's earnings risk associated with the volatility of its defined benefit pension expense.

There is also measurement uncertainty associated with pension expense, future funding requirements, the accrued benefit asset, accrued benefit liability and benefit obligation inherent in the actuarial valuation process.

**Capital Resources:** Global financial market conditions could increase the Company's cost of capital as well as impact timing of future long-term bond issues. Market driven changes in interest rates could cause fluctuations in interest costs associated with the Company's bank credit facilities. The Company periodically refinances its credit facilities in the normal course with fixed-rate first mortgage sinking fund bonds, which compose most of its long-term debt, thereby significantly mitigating exposure to short-term interest rate changes.

**Credit Ratings:** The Company does not anticipate any material adverse rating actions by the credit rating agencies in the near term. However, the recent volatility in the global financial markets has placed increased scrutiny on rating agencies and rating agency criteria which may result in changes to credit rating practices and policies.

**Electricity Prices:** Increases in electricity rates can cause changes in customer electricity consumption, which could negatively impact sales and therefore earnings and cash flows. Electricity prices have risen in recent years primarily due to the flow-through of the rising cost of oil used at Hydro's thermal generating station. Future changes or volatility in oil prices may affect electricity prices in a manner that affects sales.

Effective July 1, 2009, there was an overall average decrease in electricity rates charged to customers of approximately 6.6%. The decrease is a result of the normal annual operation of Hydro's Rate Stabilization Plan. Variances in the cost of fuel used to generate electricity Hydro sells to Newfoundland Power are captured and flowed-through to the Company's customers through the operation of the Rate Stabilization Plan. This reduction in customer rates had no impact on earnings for Newfoundland Power.

**Competition:** The Company currently does not expect any significant loss in heating market share to its primary competitor which is furnace oil. Natural gas is not expected to enter the Company's service territory in the foreseeable future.

**Purchased Power Cost:** The Company is dependent on Hydro for approximately 92% of its electricity requirements. Purchased Power costs are based on a wholesale demand and energy rate structure. The demand and energy rate structure presents the risk of volatility in purchased power costs due to uncertainty in forecasting energy sales and peak billing demand.

Effective January 1, 2008, the PUB ordered the operation of the demand management incentive account (the "DMI"). The DMI limits variations in the unit cost of purchased power related to demand up to 1% of total demand costs reflected in customer rates, or approximately $0.5 million for 2009. The disposition of balances in this account, which would be determined by a further order of the PUB, will consider the merits of the Company's conservation and demand management activities.

With respect to energy charges, as a result of January 1, 2007 changes in Hydro's wholesale rates, the marginal cost of purchased power now exceeds the average cost of purchased power that is embedded in customer rates. To the extent actual electricity sales in any period exceed forecast electricity sales used to set customer rates, the marginal purchased power expense will exceed related revenue. These supply cost dynamics had no material effect on 2009 earnings because the PUB ordered, for 2008 to 2010, that variations in purchased power expense caused by differences between the actual unit cost of energy purchased and that reflected in customer rates be recovered from (returned to) customers through the Company's rate stabilization account. Pursuant to the Company's 2010 GRA, the PUB has ordered the continued use of the energy supply cost variance reserve.

**Regulatory Assets and Liabilities:** The accounting methods that give rise to, and the settlement of, regulatory assets and liabilities are determined by the PUB and may impact the Company's future cash flows.

**Health, Safety and Environment:** The Company is subject to numerous and increasing environmental, health and safety laws, regulations and guidelines governing hazardous substances and other waste materials. Electricity is itself a hazardous commodity. Damages and costs could potentially arise due to a variety of events, including severe weather, human error or misconduct, and equipment failure. There is no assurance that any costs which might arise would be recoverable through customer rates and, if substantial, unrecovered costs could have a material adverse effect on the results of operations, cash flows and financial position of the Company. A focus on safety and the environment is an integral and continuing component of the Company's core business strategy.

2009 was the Company's second full year under the internationally recognized Occupational Health and Safety Assessment Series 18001 Health and Safety Management System. Continuing to meet this standard improves the Company's ability to capture and track information related to safe work practices and hazard recognition, and enhanced safety management.

A key element of environmental management is the Company's environmental management system ("EMS"). The Company's EMS is designed to mitigate the risks associated with the potential release of hazardous substances into the air, water and soil as part of its day-to-day operations. The Company's EMS is compliant with the International Organization for Standardization 14001 standard. One key hazard relates to the risk of air, soil and water contamination that could stem from the storage of large volumes of fuel and the use of other petroleum based products in day-to-day operating and maintenance activities. In addition, key hazards related to hydroelectric generation operations are the creation of artificial water flows that may disrupt natural habitats and the storage of large volumes of water for the purposes of electricity generation.

In conjunction with the operation of its EMS, the Company is materially compliant with the governing environmental laws under which it must operate. At December 31, 2009, there are no environmental liabilities included in the Company's annual audited financial statements and there are no material unrecorded environmental liabilities.

**Insurance:** While the Company maintains a comprehensive insurance program, the Company's transmission and distribution assets (i.e. poles and wires) are not covered under insurance for physical damage. This is customary in North America as the cost of the coverage is not considered economical. Insurance is subject to coverage limits as well as time-sensitive claims discovery and reporting provisions and there is no assurance that the types of liabilities that may be incurred by the Company will be covered by insurance.

For material uninsured losses, the Company expects that it would seek regulatory relief. However, there is no assurance that regulatory relief would be received. Any major damage to the physical assets of the Company could result in repair costs and customer claims that are substantial in amount and which could have a material adverse effect on the Company's results of operations, cash flows and financial position.

It is expected that existing insurance coverage will be maintained. However, there is no assurance that the Company will be able to obtain or maintain adequate insurance in the future at rates considered reasonable or that insurance will continue to be available on terms comparable to those now existing.

**Weather:** The physical assets of the Company are exposed to the effects of severe weather conditions and other acts of nature. Although the physical assets have been constructed, operated and maintained to withstand severe weather, there is no assurance that they will successfully do so in all circumstances. This could result in the interruption of electricity service in a manner that could have a material adverse effect on the Company's results of operations, cash flows and financial position.

**Labour Relations:** Approximately 54% of the employees of the Company are members of the International Brotherhood of Electrical Workers labour union (the "IBEW") which had entered into two collective bargaining agreements with the Company. The two agreements expire on September 30, 2011. The inability to maintain or renew the collective bargaining agreements on acceptable terms could result in increased labour costs, or service level declines associated with job action, which could have a material adverse effect on the results of operations, cash flows and financial position of the Company.

## 2009 ACCOUNTING CHANGES

**Goodwill and Intangible Assets:** Effective January 1, 2009, the Company adopted the new CICA Handbook Section 3064, *Goodwill and Intangible Assets*, which effectively converges Canadian GAAP for goodwill and intangible assets with International Financial Reporting Standards ("IFRS"). Adoption of this standard resulted in the reclassification of certain assets previously included in property, plant and equipment to intangible assets. The items that were reclassified consist of certain computer software and land rights. As at December 31, 2008, $13.8 million and $2.3 million were reclassified to intangible assets on the balance sheet related to certain computer software and land rights, respectively.

**Rate Regulated Operations:** Effective January 1, 2009, the Accounting Standards Board ("AcSB") amended: (i) CICA Handbook Section 1100, *Generally Accepted Accounting Principles* removing the temporary exemption providing relief to entities subject to rate regulation from the requirement to apply the Section to the recognition and measurement of assets and liabilities arising from rate regulation; and (ii) Section 3465, *Income Taxes* to require the recognition of future income tax liabilities and assets as well as offsetting regulatory assets and liabilities by entities subject to rate regulation.

Effective January 1, 2009, with the removal of the temporary exemption in Section 1100, the Company must now apply Section 1100 to the recognition of assets and liabilities arising from rate regulation. Certain assets and liabilities arising from rate regulation continue to have specific guidance under a primary source of Canadian GAAP that applies only to the particular circumstances described therein, including those arising under Section 3061, *Property, Plant and Equipment*, Section 3465, *Income Taxes*, and Section 3475, *Disposal of Long-Lived Assets and Discontinued Operations*. The assets and liabilities arising from rate regulation, as described in Note 4 to the 2009 Annual Financial Statements, do not have specific guidance under a primary source of Canadian GAAP. Therefore, Section 1100 directs the Company to adopt accounting policies that are developed through the exercise of professional judgment and the application of concepts described in Section 1000, *Financial Statement Concepts*. In developing these accounting policies, the Company may consult other sources including pronouncements issued by bodies authorized to issue accounting standards in other jurisdictions. Therefore, in accordance with Section 1100, the Company has determined that its regulatory assets and liabilities qualify for recognition under Canadian GAAP and this recognition is consistent with U.S. Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation*. Therefore, there was no effect on the Company's financial statements as at January 1, 2009 due to the removal of the temporary exemption in Section 1100.

Effective January 1, 2009, the impact of the amendment to Section 3465, *Income Taxes* is the recognition of future income tax assets and liabilities and related regulatory liabilities and assets for the amount of future income taxes expected to be refunded to, or recovered from, customers in future electricity rates. In accordance with the revised standard, as at January 1, 2009, the Company's future income tax liability increased by approximately $118 million with a corresponding change to regulatory assets and liabilities of approximately $118 million. Included in the amounts are the future income tax effects of the expected subsequent settlement of the related regulatory assets and liabilities through future customer rates. This change does not affect the Company's earnings or cash flows.

**Credit Risk and the Fair Value of Financial Assets and Liabilities:** Effective January 1, 2009, the Company adopted the new Emerging Issues Committee Abstract ("EIC-173") of the CICA Handbook, which was issued on January 20, 2009. EIC-173 requires the Company's own credit risk and the credit risk of its counter parties be taken into account in determining the fair value of a financial instrument. There was no effect on the Company's financial statements as a result of adopting EIC-173.

## FUTURE ACCOUNTING CHANGES

**International Financial Reporting Standards ("IFRS"):** In October 2009, the AcSB issued a third and final Omnibus Exposure Draft confirming that publicly accountable enterprises in Canada will be required to apply IFRS, in full and without modification, beginning January 1, 2011. The Company's expected IFRS transition date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported by the Company for the year ended December 31, 2010, and of amounts reported on the Company's opening IFRS balance sheet as at January 1, 2010.

The Company is continuing to assess the financial reporting impacts of adopting IFRS in 2011. While the full impact on future financial position and results of operations is not fully determinable or estimable at this time, proposals put forth by the International Accounting Standards Board ("IASB") in its July 2009 Exposure Draft – *Rate Regulated Activities*, if adopted, should reduce earnings' volatility that may have otherwise resulted under IFRS, in the absence of an accounting standard for rate regulated activities. The Company does anticipate a significant increase in disclosure resulting from the adoption of IFRS and is identifying and assessing these additional disclosure requirements, as well as system changes that will be necessary to compile the required disclosures.

Differences between IFRS and Canadian GAAP, in addition to those referenced below under "Accounting Policy Impacts and Decisions", may continue to be identified based on further detailed analysis by the Company, the outcome of a final standard on accounting for rate regulated activities and other changes in IFRS prior to the Company's conversion to IFRS in 2011.

**IFRS Conversion Project:** The Company commenced its IFRS conversion project in 2007 and has established a formal project governance structure which includes the Audit & Risk Committee and senior management. An external advisor has been engaged to assist in the IFRS conversion project. Project progress reports are provided to the Company's Audit & Risk Committee on a quarterly basis. The Company has also engaged its external auditors, Ernst & Young, LLP, to review accounting policy determinations as they are arrived at and agreed to internally by the Company's project team.

The Company's IFRS conversion project consists of three phases: (i) scoping and diagnostics, (ii) analysis and development, and (iii) implementation and review.

**Phase One:** Scoping and diagnostics, which involved project planning and staffing and identification of differences between current Canadian GAAP and IFRS, was completed in the first half of 2008. The identified areas of accounting difference of highest potential impact to the Company, based on existing IFRS at the time, were identified to include: rate regulated accounting; property, plant and equipment; provisions and contingent liabilities; employee benefits; income taxes; and initial adoption of IFRS under the provisions of IFRS 1, *First-Time Adoption of International Financial Reporting Standards* ("IFRS 1").

**Phase Two:** Analysis and development is nearing completion and involves detailed diagnostics and evaluation of the financial impacts of various options and alternative methodologies provided for under IFRS; identification and design of operational and financial business processes; initial staff training and Audit & Risk Committee orientation; analysis of IFRS 1 optional exemptions and mandatory exceptions to the general requirement for full retrospective application upon transition; summarization of 2011 IFRS disclosure requirements; and development of required solutions to address identified issues.

**Phase Three:** Implementation and review has commenced and involves the execution of changes to information systems and business processes; completion of formal authorization processes to approve recommended accounting policy changes; and further training programs across the Company, as necessary. It will culminate in the collection of financial information necessary to compile IFRS-compliant financial statements and reconciliations; embedding of IFRS in business processes; and Audit & Risk Committee approval of IFRS-compliant interim and annual financial statements for 2011.

**Accounting for Rate Regulated Activities under IFRS:** IFRS does not currently provide specific guidance with respect to accounting for rate regulated activities. However, in December 2008, the IASB initiated a project on accounting for rate regulated activities and whether or not rate regulated entities could or should recognize assets or liabilities as a result of rate regulation imposed by a regulatory body.

On July 23, 2009, the IASB issued Exposure Draft - *Rate Regulated Activities* together with a request for public comments by November 20, 2009. Based on the current project timeline of the IASB, a final standard is expected to be issued in the second quarter of 2010. A project update with respect to both direction and timing is expected to result from the IASB's February 2010 meeting.

Based on the Exposure Draft, as it currently exists, regulatory assets and liabilities arising from activities subject to cost of service regulation would be recognized under IFRS based on the measurement of their expected present value. Subject to finalizing a methodology for estimating expected present value, the ability to record regulatory assets and liabilities, as proposed, should reduce the earnings' volatility of the Company that may have otherwise resulted under IFRS in the absence of an accounting standard for rate regulated activities, but will result in the requirement to provide enhanced balance sheet presentation and note disclosures. Continued uncertainty as to the final outcome of the Exposure Draft, and a final standard on accounting for rate regulated activities under IFRS, has resulted in the Company being unable to reasonably estimate and conclude on the impact on the Company's future financial position and results of operations with respect to differences, if any, in accounting for rate regulated activities under IFRS versus Canadian GAAP.

**Accounting Policy Impacts and Decisions:** The Company has completed an initial assessment of the impacts of adopting IFRS, based on the standards as they currently exist, and has identified the following as having the greatest potential to impact the Company's accounting policies, financial reporting and information systems requirements upon conversion to IFRS. However, final conclusions cannot be reached at this time pending a final IFRS standard on accounting for rate regulated activities.

(a) *Property, Plant and Equipment*

IFRS and Canadian GAAP contain the same basic principles of accounting for property, plant and equipment; however, differences in application do exist. Specifically, there may be changes in accounting for:

i. the amount of capitalized overheads;
ii. the capitalization of major inspections that were previously expensed under Canadian GAAP;
iii. the capitalization of depreciation for which future economic benefits of that asset are absorbed in the production of another asset;
iv. the capitalization of borrowing costs in accordance with IAS 23, *Borrowing Costs*; and,
v. the recognition of gains and losses on property, plant and equipment.

However, the IASB's Exposure Draft - *Rate Regulated Activities* proposes that, in the case of qualifying rate regulated entities, amounts approved by the regulator for inclusion in the cost of self-constructed property, plant and equipment for rate-making purposes shall also be included in the cost of these assets for financial reporting purposes, even if the entity would not otherwise be permitted to include these costs in the cost of its property, plant and equipment based on application of IAS 16, *Property, Plant and Equipment*.

IAS 16, *Property, Plant and Equipment* also requires an allocation of the amount initially recognized in respect of an item of property, plant and equipment to its significant parts and the depreciation of each such part separately. This method of componentizing property, plant and equipment may result in an increase in the number of component parts that are recorded and depreciated and, as a result, may impact the calculation of depreciation expense.

The Exposure Draft - *Rate Regulated Activities* proposes a new transitional exemption for qualifying rate regulated entities that will allow them to use, as of the date of transition, the carrying amount of property, plant and equipment under Canadian GAAP as the deemed cost under IFRS. The Company will likely avail of this exemption, should the Exposure Draft be adopted as proposed.

The final estimate of the impact of applying IAS 16, *Property, Plant and Equipment* by the Company, and elective options with respect to accounting for property, plant and equipment upon transition to IFRS, cannot be made at this time pending a final standard on accounting for rate regulated activities.

(b) *Provisions and Contingent Liabilities*

IAS 37, *Provisions, Contingent Liabilities and Contingent Assets* requires a provision to be recognized when (i) there is a present obligation as a result of a past transaction or event; (ii) it is probable that an outflow of resources will be required to settle the obligation; and (iii) a reliable estimate can be made of the obligation. Under Canadian GAAP the criterion for recognition is "likely", which is a higher threshold than "probable". It is possible, therefore, that some contingent liabilities which would meet the recognition criterion under IFRS would not have been recognized under Canadian GAAP.

In January 2010, the IASB published an Exposure Draft - *Measurement of Liabilities* in IAS 37 ("ED/2010/1"). The publication of ED/2010/1 is part of a larger IASB project which has been ongoing since 2005 and which is intended to result in a new IFRS to replace IAS 37. ED/2010/1 is open for public comment until April 12, 2010. Based on comments received on ED/2010/1, and previous tentative decisions by the IASB with respect to other aspects of IAS 37, a final IFRS to replace IAS 37 is planned for release in the third quarter of 2010.

(c) *Employee Benefits*

IAS 19, *Employee Benefits* requires the past service cost of defined benefit plans to be expensed on an accelerated basis, with vested past service costs being expensed immediately and unvested past service costs being recognized on a straight-line basis until the benefits become vested. Under Canadian GAAP, past service costs are generally amortized on a straight-line basis over the expected average remaining service period of active employees in the defined benefit plan.

IAS 19, *Employee Benefits* requires defined benefit pension plan assets to be measured at fair market value for the purposes of determining pension expense. Under Canadian GAAP, pension plan assets of the Company are currently measured at the market-related value as described in Note 2 in the Company's 2009 annual audited financial statements. In addition, actuarial gains and losses under IFRS are permitted to be recognized directly in equity rather than through earnings, and IFRS 1 also provides an option to recognize immediately in retained earnings all cumulative actuarial gains and losses existing as at the date of transition to IFRS.

The Company maintains a defined benefit pension plan and supplementary and other post-employment benefit plans which will be subject to different accounting treatment under IFRS as compared to Canadian GAAP. The full extent of the impact of applying IAS 19, *Employee Benefits* cannot be made at this time, pending a final standard on accounting for rate regulated activities.

(d) *Income Taxes*

IAS 12, *Income Taxes* prescribes that an entity account for the tax consequences of transactions and other events in the same way that it accounts for the transactions and other events themselves. Therefore, where transactions and other events are recognized in earnings, the recognition of deferred tax assets or liabilities which arise from those transactions should also be recorded in earnings. For transactions that are recognized outside of the statement of earnings, either in other comprehensive income or directly in equity, any related tax effects should also be recognized outside of the statement of earnings.

The most significant impact of IAS 12, *Income Taxes* on the Company will be derived directly from the accounting policy decisions made under IAS 16, *Property, Plant and Equipment* and other IFRS, if applicable. In addition, the Company currently accounts for income taxes based on regulatory decisions. Therefore, the impact on the Company of accounting for the tax consequences of transactions and other events under IFRS versus Canadian GAAP cannot be fully determined at this time pending a final IFRS standard on accounting for rate regulated activities.

(e) *IFRS 1, First-Time Adoption of International Financial Reporting Standards*

IFRS 1 provides the framework for the first time adoption of IFRS and specifies that, in general, an entity shall apply the principles under IFRS retrospectively. IFRS 1 also specifies that the adjustments that arise on retrospective conversion to IFRS from Canadian GAAP should be directly recognized in retained earnings. Certain optional exemptions and mandatory exceptions to retrospective application are provided for under IFRS 1.

The Company has completed an analysis of IFRS 1. While preliminary decisions have been made with respect to the elective exemptions available upon transition, final decisions cannot be made at this time pending a final IFRS standard on the accounting for rate regulated activities.

(f) *Information Systems*

It is anticipated that the adoption of IFRS will have some impact on information systems requirements. The Company has assessed the need for system upgrades or modifications to ensure an efficient conversion to IFRS. The extent of the impact on the Company's information systems is largely dependent upon the final IFRS standard on accounting for rate regulated activities and is, therefore, not fully determinable at this time.

The IASB has a number of on-going projects on its agenda, in addition to the project on accounting for rate regulated activities, that may result in changes to existing IFRS prior to the Company's conversion to IFRS in 2011. The Company continues to monitor these projects and the impact that any resulting IFRS changes may have on its accounting policies, financial position or results of operations under IFRS for 2011 and beyond.

## CRITICAL ACCOUNTING ESTIMATES

Preparation of the Company's financial statements in accordance with Canadian GAAP requires management to make estimates and judgements that affect the reported amounts of assets and liabilities, revenue and expenses, and related disclosure of contingencies and commitments. Estimates and judgements are based on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances. Actual results may differ from these estimates and judgements under different assumptions or conditions. The critical accounting estimates involving the more significant estimates and judgements used in the preparation of the Company's 2009 annual audited financial statements follow.

**Property, Plant and Equipment and Intangible Assets Amortization:** By its nature, amortization is an estimate based primarily on the useful lives of assets. Estimated useful lives are based on current facts and historical information, and take into consideration the anticipated physical lives of the assets. Newfoundland Power's amortization methodology, including amortization rates, accumulated amortization and estimated remaining service lives, is subject to a periodic study by external experts. The difference between actual accumulated amortization and that indicated by the amortization study is amortized and included in customer rates in a manner prescribed by the PUB.

The most recent amortization study, based on property, plant and equipment and intangible assets in service as at December 31, 2005, indicated an accumulated amortization variance of approximately $0.7 million. The PUB ordered that this variance be amortized equally over 2008-2011 and that the revised amortization rates arising from the amortization study be implemented effective January 1, 2008. As a result, the total composite amortization rate declined from 3.5% to 3.4%. These changes did not have a significant impact on the Company's earnings, cash flow or financial position because the changes were reflected in the customer rates effective January 1, 2008. As part of the 2010 GRA, the PUB ordered the next amortization study to be based on property, plant and equipment and intangible assets in service as at December 31, 2009.

The estimate of future removal and site restoration costs, net of salvage proceeds, is based on historical experience and future expected cost trends. The balance of this regulatory liability at December 31, 2009 was $48.7 million (December 31, 2008 - $48.0 million). The net amount of estimated future removal and site restoration costs provided for and reported in amortization expense during 2009 was $4.8 million (2008 - $4.6 million).

**Capitalized Overhead:** Newfoundland Power capitalizes overhead costs which are not directly attributable to specific capital assets, but which relate to the overall capital expenditure program. Capitalization reflects estimates of the portions of various general expenses that relate to the overall capital expenditures program in accordance with a methodology ordered by the PUB. These general expenses capitalized ("GEC") are allocated over constructed property, plant and equipment and amortized over their estimated service lives. In 2009, GEC totalled $3.0 million (2008 - $2.8 million). Changes to the methodology for calculating and allocating general overhead costs to property, plant and equipment could have a material impact on the amounts recorded as operating expenses versus property, plant and equipment. However, any change in the fundamental methodology for the calculation and allocation of GEC would require the approval of the PUB.

**Employee Future Benefits:** The Company's primary defined benefit pension plan is subject to judgments utilized in the actuarial determination of the expense and related obligation. The primary assumptions utilized by management in determining the pension expense and the accrued benefit obligation are the discount rate and the expected long-term rate of return on plan assets. All defined benefit pension plan assumptions are assessed and concluded in consultation with the Company's external actuarial advisor.

The discount rate as at December 31, 2009, which is utilized to determine the accrued benefit obligation and the 2010 pension expense, is 6.5% compared to the discount rate of 7.5% as at December 31, 2008. Discount rates reflect market interest rates on high quality bonds with cash flows that match the timing and amount of expected pension benefit payments. This methodology is consistent with that used to determine the discount rate in the previous year. The decrease in discount rates reflects the decreased credit spreads and cost of capital on investment grade corporate bonds.

The expected long-term rate of return on pension plan assets which is used to estimate the 2010 defined benefit pension expense is 7.0%, consistent with 2009. The actual rate of return on pension plan assets during 2009 was approximately 17.1%. As in previous years, an actuary provided the Company with a range of expected long-term pension asset returns based on their internal modelling. The expected long-term return on pension plan assets of 7.0% falls within the normal to optimistic range as indicated by the actuary.

In 2010, the Company expects the pension expense related to its primary defined benefit pension plan to increase by approximately $4.8 million compared to 2009. This is primarily driven by the amortization of 2008 experience losses associated with the pension plan assets and a lower discount rate.

The following table provides sensitivity to the changes in the primary assumptions associated with the Company's defined benefit pension plan:

| *($millions)* | **Pension Expense**[1] |
|---|---|
| Impact of increasing rate of return on assets assumption by 100 basis points (bps) | (2.5) |
| Impact of decreasing the rate of return on assets assumption by 100 bps | 2.5 |
| Impact of increasing the discount rate assumption used during 2009 by 100 bps | (0.5) |
| Impact of decreasing the discount rate assumption used during 2009 by 100 bps | 2.2 |

[1] *The volatility of future pension expense has been significantly mitigated with the PUB approved PEVDA in which pension expense calculated in accordance with Canadian GAAP and pension expense approved by the PUB for rate setting purposes would be recovered from (returned to) customers through the Company's rate stabilization account.*

Other assumptions are the average rate of compensation increase, average remaining service life of the active employee group, and mortality rates.

The Company's other post-retirement benefits are also subject to judgements utilized in the actuarial determination of the expense and related obligation. Assumptions utilized by management in determining other post-employment benefit plan costs and obligations include the health care cost trend rate and the foregoing assumptions, excluding the expected long-term rate of return on plan assets and average rate of compensation increase.

In accordance with PUB orders, Newfoundland Power expenses the cost of other post-employment benefits on a cash basis, whereby the difference between the cash payments during the year and the expense incurred in the year is deferred as a regulatory asset. Therefore, changes in assumptions cause changes in the regulatory asset and do not impact earnings. Other post-employment benefits costs deferred as a regulatory asset in 2009 totalled $5.6 million (2008 - $6.6 million) and the regulatory asset at December 31, 2009 was $46.7 million (2008 - $41.1 million).

**Asset Retirement Obligations:** The measurement of the fair value of asset retirement obligations ("AROs") requires the Company to make reasonable estimates about the method of settlement and settlement dates associated with legally obligated asset retirement costs. While the Company has AROs for its generation assets and certain distribution and transmission assets, there were no amounts recognized as at December 31, 2009 and December 31, 2008. The nature, amount and timing of AROs for hydroelectric generation assets cannot be reasonably estimated at this time as these assets are expected to effectively operate in perpetuity given their nature. In the event that environmental issues are identified or hydroelectric generation assets are decommissioned, AROs will be recorded at that time provided the costs can be reasonably estimated. It is management's judgment that identified AROs for its remaining assets are immaterial.

**Revenue Recognition:** The Company recognizes electricity revenue on an accrual basis. Customer bills are issued throughout the month based on meter readings that establish electricity consumption by the customer since the last meter reading. The unbilled revenue accrual for each period is based on estimated electricity sales to customers for the period since the last meter reading at the rates approved by the PUB. The development of the electricity sales estimates requires analysis of electricity consumption on a historical basis in relation to key inputs such as the current price of electricity, population growth, economic activity, weather conditions and electricity system losses. The estimation process for accrued unbilled electricity consumption will result in adjustments to electricity revenue in the period during which the difference between actual results and those estimated becomes known. As at December 31, 2009, the amount of accrued unbilled revenue was approximately $29.3 million (December 31, 2008 - $30.5 million).

## SELECTED ANNUAL INFORMATION

| ($millions, except per share amounts) | 2009 | 2008 | 2007[1] |
|---|---|---|---|
| Results of Operations | | | |
| Revenue | 527.2 | 516.9 | 491.7 |
| Net Earnings Applicable to Common Shares | 32.6 | 32.3 | 29.9 |
| Finance Position | | | |
| Total Assets | 1,188.0 | 1,001.9 | 985.9 |
| Total Long-term Liabilities | 716.4 | 534.6 | 537.7 |
| Shareholders' Equity | 390.3 | 383.1 | 366.0 |
| Per Share Data | | | |
| Earnings Applicable to Common Shares[2] | 3.16 | 3.13 | 2.89 |
| Common Dividends Declared[2] | 2.44 | 1.48 | 0.88 |
| Preferred Dividends Declared[3] | 2.56 | 2.56 | 2.56 |

1 *Certain amounts have been reclassified to conform with the presentation for 2009.*
2 *Basic and fully diluted. Based on the weighted average number of common shares outstanding, which was 10,320,270 common shares in each year.*
3 *Based on the aggregate weighted average number of preference shares outstanding in each year, which was 911,098 in 2009 and 935,223 in both 2008 and 2007. In 2009, the Company repurchased 24,125 preference shares at $10 per share (2007 – 100 preference shares at $10 per share; no preference shares were repurchased in 2008).*

The changes from 2008 to 2009 have been discussed previously in this MD&A. The increase in net earnings from 2007 to 2008 was primarily the result of a 2.8% increase in customer rates which was effective January 1, 2008. The increase in total assets from 2007 to 2008 was due primarily to continued investment in the electricity system and is consistent with the Company's strategy to provide safe and reliable electricity service at the lowest reasonable cost. The increase in common dividends from 2007 to 2008 was to maintain a capital structure composed of approximately 45% common equity and 55% debt.

## QUARTERLY RESULTS

| | First Quarter March 31 | | Second Quarter June 30 | | Third Quarter September 30 | | Fourth Quarter December 31 | |
|---|---|---|---|---|---|---|---|---|
| *(unaudited)* | 2009 | 2008 | 2009 | 2008 | 2009 | 2008 | 2009 | 2008 |
| Electricity Sales *(GWh)* | 1,762.9 | 1,716.2 | 1,177.2 | 1,183.0 | 885.0 | 896.8 | 1,473.9 | 1,412.2 |
| Revenue *($millions)* | 169.7 | 164.9 | 118.1 | 118.9 | 92.9 | 94.1 | 146.5 | 139.0 |
| Earnings Applicable to Common Shares *($millions)* | 6.2 | 6.2 | 10.7 | 10.1 | 7.1 | 8.1 | 8.6 | 7.9 |
| Earnings per Common Share *($)*[1] | 0.60 | 0.60 | 1.04 | 0.98 | 0.68 | 0.79 | 0.84 | 0.76 |

1 *Basic and fully diluted.*

## Seasonality

**Sales and Revenue:** Sales and revenue are significantly higher in the first quarter and significantly lower in the third quarter compared to the remaining quarters. This reflects the seasonality of electricity consumption for heating.

**Earnings:** Beyond the seasonality of electricity consumption for heating quarterly earnings are impacted by the purchased power rate structure. The Company pays more, on average, for each kilowatt hour (“kWh”) of purchased power in the winter months and less, on average, for each kWh of purchased power in the summer months.

These sales, revenues and cost dynamics are expected to yield lower earnings in the first quarter compared to remaining quarters within any given year.

## Trending

**Sales and Revenue:** Year-over-year quarterly electricity sales increases primarily reflect modest customer growth.

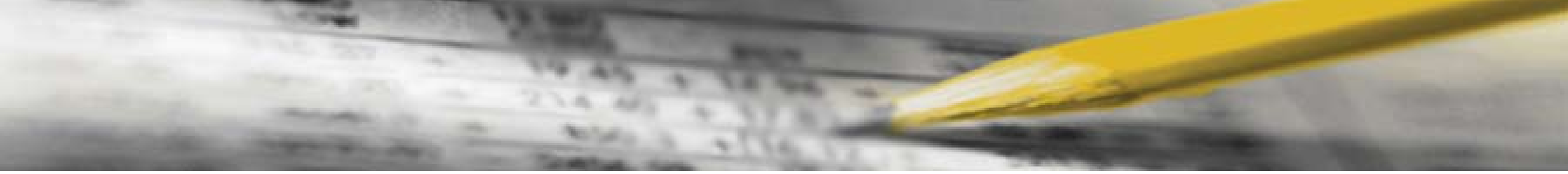
**Earnings:** Beyond the impact of expected moderate sales growth, future quarterly earnings and earnings per share are expected to trend with the ROE reflected in customer rates and rate base growth.

# OUTLOOK

The Company’s strategy will remain unchanged.

Newfoundland Power is regulated under a cost of service regime. Cost of service regulation entitles the Company to an opportunity to recover its reasonable cost of providing service, including its cost of capital, in each year. The PUB, through the Company’s 2010 GRA, has provided Newfoundland Power with a reasonable opportunity to earn a ROE of 9.0% in 2010. Newfoundland Power expects to maintain its investment grade credit ratings in 2010.

Newfoundland Power is currently assessing the requirement to file an application with the PUB to recover expected increased costs in 2011.



# Management Report

The accompanying 2009 Financial Statements of Newfoundland Power Inc. and all information in the 2009 Annual Report have been prepared by management, who are responsible for the integrity of the information presented, including the amounts that must, of necessity, be based on estimates and informed judgments. These Financial Statements were prepared in accordance with accounting principles generally accepted in Canada, including selected accounting treatments that differ from those used by entities not subject to rate regulation. Financial information contained elsewhere in the 2009 Annual Report is consistent with that in the Financial Statements.

In meeting its responsibility for the reliability and integrity of the Financial Statements, management has developed and maintains a system of accounting and reporting which provides for the necessary internal controls to ensure transactions are properly authorized and recorded, assets are safeguarded and liabilities are recognized. The systems of the Company focus on the need for training of qualified and professional staff and the effective communication of management guidelines and policies. The effectiveness of the internal controls of Newfoundland Power Inc. is evaluated on an ongoing basis.

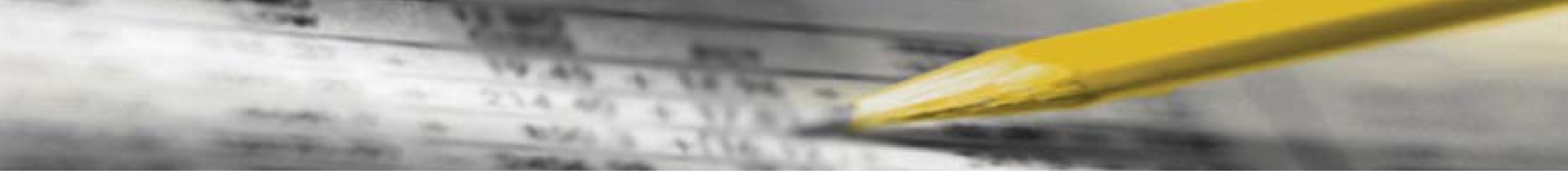
The Board of Directors oversees management's responsibility for financial reporting through an Audit & Risk Committee which is composed entirely of external independent directors. The Audit & Risk Committee oversees the external audit of the Company's Annual Financial Statements and the accounting and financial reporting and disclosure processes and policies of the Company. The Audit & Risk Committee meets with management, the shareholders' auditors and the internal auditor to discuss the results of the audit, the adequacy of internal accounting controls and the quality and integrity of financial reporting. The Company's Annual Financial Statements are reviewed by the Audit & Risk Committee with each of management and the shareholders' auditors before the statements are recommended to the Board of Directors for approval. The shareholders' auditors have full and free access to the Audit & Risk Committee.

The Audit & Risk Committee has the duty to review the adoption of, and changes in, accounting principles and practices which have a material effect on the Company's financial statements and to review and report to the Board of Directors on policies relating to accounting and financial reporting and disclosure processes. The Audit & Risk Committee has the duty to review financial reports requiring the approval of the Board of Directors prior to submission to securities commissions or other regulatory authorities, to assess and review management's judgments that are material to reported financial information and to review shareholders' auditors' independence and auditors' fees.

The December 31, 2009 Financial Statements and Management Discussion and Analysis contained in the 2009 Annual Report were reviewed by the Audit & Risk Committee and, on their recommendation, were approved by the Board of Directors of Newfoundland Power Inc. Ernst & Young, LLP, independent auditors appointed by the shareholders of Newfoundland Power Inc. upon recommendation of the Audit & Risk Committee, have performed an audit of the 2009 Financial Statements and their report follows.

Earl Ludlow
President
and Chief Executive Officer

Jocelyn Perry
Vice President, Finance
and Chief Financial Officer



# Auditors' Report

To the Shareholders,
Newfoundland Power Inc.

We have audited the balance sheets of Newfoundland Power Inc. ("the Company") as at December 31, 2009 and 2008 and the statements of earnings, retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2009 and 2008 and the results of its operations and cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Chartered Accountants
St. John's, Canada

January 25, 2010

# Statements of Earnings

**For the years ended December 31**

*(in thousands of Canadian dollars except per share amounts)*

| | 2009 | 2008 |
|---|---|---|
| Revenue | $ 527,179 | $ 516,889 |
| Purchased power | 345,656 | 336,658 |
| **Gross Margin** | 181,523 | 180,231 |
| Operating expenses | 49,315 | 47,132 |
| Pension and early retirement program costs | 2,673 | 3,040 |
| Amortization | 41,825 | 40,649 |
| Amortization true-up deferral *(Note 4)* | 3,862 | 3,862 |
| Finance charges *(Note 5)* | 34,555 | 33,507 |
| | 132,230 | 128,190 |
| **Earnings Before Income Taxes** | 49,293 | 52,041 |
| Income taxes *(Note 6)* | 16,092 | 19,146 |
| **Net Earnings** | 33,201 | 32,895 |
| Preference share dividends | 573 | 554 |
| **Net Earnings Applicable to Common Shares** | $ 32,628 | $ 32,341 |
| **Basic and Diluted Earnings per Common Share** | $ 3.16 | $ 3.13 |

# Statements of Retained Earnings

**For the years ended December 31**

*(in thousands of Canadian dollars)*

| | 2009 | 2008 |
|---|---|---|
| **Balance, Beginning of the Year** | $ 303,417 | $ 286,350 |
| Net earnings | 33,201 | 32,895 |
| Dividends | | |
| Preference shares | (573) | (554) |
| Common shares | (25,181) | (15,274) |
| **Balance, End of the Year** | $ 310,864 | $ 303,417 |

*See accompanying notes to financial statements.*

# Balance Sheets

## As at December 31

*(in thousands of Canadian dollars)*

| | 2009 | 2008 *(restated - see Note 3)* |
|---|---|---|
| **Assets** | | |
| **Current assets** | | |
| Cash | $ 5,308 | $ 619 |
| Accounts receivable | 64,553 | 63,508 |
| Regulatory assets *(Note 4)* | 11,023 | 9,426 |
| Materials and supplies | 934 | 1,016 |
| Prepaid expenses | 1,376 | 1,292 |
| Income taxes receivable | 4,194 | - |
| | 87,388 | 75,861 |
| **Property, plant and equipment** *(Note 7)* | 787,218 | 758,812 |
| **Regulatory assets** *(Note 4)* | 197,783 | 55,988 |
| **Accrued pension** *(Note 8)* | 97,802 | 93,148 |
| **Intangible assets** *(Note 9)* | 16,113 | 16,145 |
| **Other assets** *(Note 10)* | 1,717 | 1,901 |
| | $ 1,188,021 | $ 1,001,855 |
| **Liabilities and Shareholders' Equity** | | |
| **Current liabilities** | | |
| Accounts payable and accrued charges | $ 65,727 | $ 65,548 |
| Regulatory liabilities *(Note 4)* | 9,374 | 6,428 |
| Current installments of long-term debt *(Note 12)* | 5,200 | 4,550 |
| Future income taxes *(Notes 2, 3 & 6)* | 1,068 | - |
| Income taxes payable | - | 7,633 |
| | 81,369 | 84,159 |
| **Regulatory liabilities** *(Note 4)* | 69,207 | 54,817 |
| **Other post-employment benefits** *(Note 8)* | 46,713 | 41,074 |
| **Other liabilities** *(Note 13)* | 3,960 | 3,927 |
| **Future income taxes** *(Notes 2, 3 & 6)* | 122,426 | 1,184 |
| **Long-term debt** *(Note 12)* | 474,050 | 433,604 |
| | $ 797,725 | $ 618,765 |
| **Shareholders' equity** | | |
| Common shares *(Note 14)* | 70,321 | 70,321 |
| Preference shares *(Note 14)* | 9,111 | 9,352 |
| Retained earnings | 310,864 | 303,417 |
| | 390,296 | 383,090 |
| | $ 1,188,021 | $ 1,001,855 |

Commitments *(Note 18)*

APPROVED ON BEHALF OF THE BOARD:

*See accompanying notes to financial statements.*

Jo Mark Zurel
Director

David Norris
Director

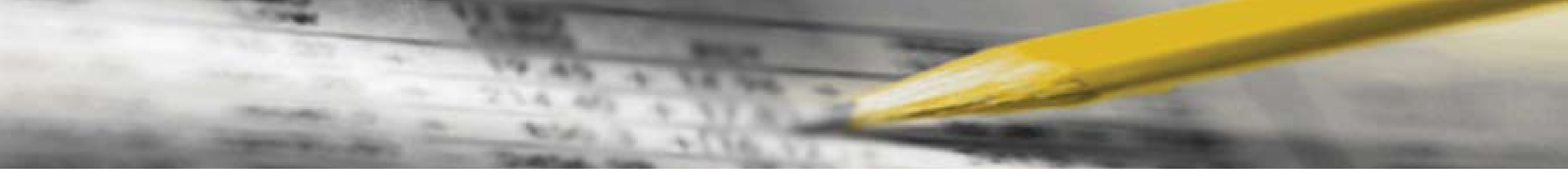
# Statements of Cash Flows

**For the years ended December 31**

*(in thousands of Canadian dollars)*

| | 2009 | 2008 |
|---|---|---|
| **Cash From (Used In) Operating Activities** | | |
| Net earnings | $ 33,201 | $ 32,895 |
| **Items not affecting cash** | | |
| Amortization of property, plant and equipment | 38,935 | 37,547 |
| Amortization of intangible assets and other | 3,162 | 3,400 |
| Change in regulatory assets and liabilities | 691 | 305 |
| Future income taxes | 502 | 1,184 |
| Employee future benefits | (4,416) | (4,471) |
| | 72,075 | 70,860 |
| Change in non-cash working capital | (12,695) | 14,191 |
| | 59,380 | 85,051 |
| **Cash From (Used In) Investing Activities** | | |
| Capital expenditures | (71,267) | (64,959) |
| Intangible asset expenditures | (2,808) | (2,374) |
| Contributions from customers | 4,575 | 3,054 |
| Other | (107) | 208 |
| | (69,607) | (64,071) |
| **Cash From (Used In) Financing Activities** | | |
| Repayment of committed credit facility | (18,500) | (1,000) |
| Proceeds from long-term debt | 65,000 | - |
| Repayment of long-term debt | (5,200) | (4,550) |
| Proceeds from related party loan | - | 32,500 |
| Repayment of related party loan | - | (32,500) |
| Payment of debt financing costs | (389) | (50) |
| Redemption of preference shares | (241) | - |
| Dividends | | |
| Preference shares | (573) | (554) |
| Common shares | (25,181) | (15,274) |
| | 14,916 | (21,428) |
| **Increase (Decrease) in Cash** | 4,689 | (448) |
| Cash, Beginning of the Year | 619 | 1,067 |
| **Cash, End of the Year** | 5,308 | 619 |
| **Cash Flows Include the Following Elements** | | |
| Interest paid | $ 34,468 | $ 33,794 |
| Income taxes paid | $ 25,057 | $ 8,665 |

*See accompanying notes to financial statements.*



# Notes to Financial Statements

## December 31, 2009

Tabular amounts are in thousands of Canadian dollars unless otherwise noted.

## 1. Description of the Business

Newfoundland Power Inc. (the "Company" or "Newfoundland Power") is a regulated electricity utility that operates an integrated generation, transmission and distribution system throughout the island portion of Newfoundland and Labrador. The Company is regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities (the "PUB") and serves over 239,000 customers comprising approximately 85% of all electricity consumers in the Province. The Company is a wholly-owned subsidiary of Fortis Inc. ("Fortis"). Newfoundland Power has an installed generating capacity of 140 megawatts ("MW"), of which approximately 97 MW is hydroelectric generation. It generates approximately 8% of its energy needs and purchases the remainder from Newfoundland and Labrador Hydro ("Hydro").

## 2. Summary of Significant Accounting Policies

These financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). As a result of rate regulation, the timing of the recognition of certain assets, liabilities, revenues and expenses may differ from that otherwise expected under Canadian GAAP for entities not subject to rate regulation. These differences are disclosed below and in Note 4.

### Regulation

The Company operates under cost of service regulation as administered by the PUB under the Public Utilities Act (Newfoundland and Labrador) ("Public Utilities Act").

The Public Utilities Act provides for the PUB's general supervision of the Company's utility operations and requires the PUB to approve, among other things, customer rates, capital expenditures and the issuance of securities. The Public Utilities Act also entitles the Company an opportunity to recover all reasonable and prudent costs incurred in providing electricity service to its customers, including a just and reasonable return on its rate base. The rate base consists of the net assets required by the Company to provide service to customers.

The determination of the forecast return on rate base, together with the forecast of all reasonable and prudent costs, establishes the revenue requirement upon which the Company's customer rates are determined through a general rate hearing. Rates are bundled to include generation, transmission and distribution services.

Between general rate hearings, customer rates are established annually through the operation of an automatic adjustment formula that sets an appropriate annual rate of return on rate base based upon changes in the forecast cost of common equity. The forecast cost of common equity reflected in customer rates for 2009 was 8.95% (2008 - 8.95%). As a result of the Company's 2010 General Rate Application ("GRA"), the forecast cost of common equity to be reflected in customer rates for 2010 is 9.00%. The Company's approved rate of return on rate base in 2010 is 8.23%, with a range of 8.05% to 8.41%.

## Revenue Recognition

Revenue arising from the amortization of certain regulatory assets and liabilities is recognized in the manner prescribed by the PUB, as disclosed in Note 4. Otherwise, revenue is recognized under the accrual method when service is rendered.

## Property, Plant and Equipment

Property, plant and equipment are stated at values approved by the PUB as at June 30, 1966, with subsequent additions at cost.

Contributions in aid of construction represent the cost of utility property, plant and equipment contributed by customers and government. These contributions are recorded as a reduction in the cost of utility property, plant and equipment.

The Company capitalizes certain overhead costs not directly attributable to specific property, plant and equipment but which do relate to its overall capital expenditure program (general expenses capitalized or "GEC"). The methodology for calculating and allocating GEC among classes of property, plant and equipment is established by PUB order. In the absence of rate regulation, only those overhead costs directly attributable to construction activity would be capitalized. In 2009, GEC totalled $3.0 million (2008 - $2.8 million).

The Company capitalizes an allowance for funds used during construction ("AFUDC"), which represents the cost of debt and equity financing incurred during construction of property, plant and equipment. AFUDC is calculated in a manner prescribed by the PUB based on a capitalization rate that is the Company's weighted average cost of capital. In 2009, the cost of equity financing capitalized as an AFUDC and deducted from financing charges was approximately $0.3 million (2008 - $0.3 million). In the absence of rate regulation, this cost of equity financing would be expensed.

Property, plant and equipment are amortized using the straight-line method by applying the amortization rates approved by the PUB and disclosed below to the average original cost, including GEC and AFUDC, of the related assets.

## 2. Summary of Significant Accounting Policies (cont'd)

### Property, Plant and Equipment (cont'd)

The composite amortization rates for the Company's property, plant and equipment, as well as their service life ranges and average remaining service lives as at December 31, follow.

| | Composite Amortization Rate | | Service Life (Years) Range | | Service Life (Years) Average Remaining | |
|---|---|---|---|---|---|---|
| | 2009 | 2008 | 2009 | 2008 | 2009 | 2008 |
| Distribution | 3.1% | 3.1% | 16-65 | 16-65 | 23 | 23 |
| Transmission and substations | 2.9 | 2.9 | 31-65 | 31-65 | 26 | 26 |
| Generation | 2.6 | 2.6 | 13-75 | 13-75 | 32 | 32 |
| Transportation and communications | 8.9 | 8.9 | 5-30 | 5-30 | 5 | 5 |
| Buildings | 2.3 | 2.3 | 35-70 | 35-70 | 27 | 27 |
| Equipment | 9.0 | 9.0 | 5-25 | 5-25 | 5 | 5 |
| | 3.4% | 3.4% | | | | |

The Company's amortization methodology, including amortization rates, accumulated amortization and estimated remaining service lives, is subject to periodic review by external experts (the "Amortization Study"). The differences between actual accumulated amortization and that indicated by the Amortization Study (the "Amortization True-Up") is deferred as a regulatory asset (liability), and is amortized as an increase (decrease) in amortization expense and included in customer rates in a manner prescribed by the PUB. See Note 4. The most recent Amortization Study, based on property, plant and equipment in service as at December 31, 2005, indicates an Amortization True-Up of approximately $0.7 million. The PUB ordered that it be amortized as a decrease in amortization expense equally over 2008 - 2011. The next amortization study, as ordered by the PUB pursuant to the 2010 GRA, will be based on property, plant and equipment in service as at December 31, 2009.

Upon disposition, the original cost of property, plant and equipment is removed from the asset accounts. That amount, net of salvage proceeds, is also removed from accumulated amortization. As a result, any gain or loss is charged to accumulated amortization and is effectively included in the Amortization True-Up arising from the next Amortization Study. In 2009, approximately $6.8 million (2008 - $6.8 million) of losses were charged to accumulated amortization. In the absence of rate regulation, these amounts would have been recognized as losses upon disposition.

### Materials and Supplies

Materials and supplies, representing fuel and materials required for maintenance activities, are carried at the lower of cost or net realizable value. Materials and supplies expensed in 2009 and 2008 were immaterial.

## Intangible Assets

Intangible assets are recorded at cost and amortized over their estimated useful lives on a straight-line basis. The weighted average amortization rates for intangible assets in 2009 were 10.0% for computer software (2008 – 10.0%) and 1.6% for land rights (2008 – 1.6%). There was no impact to the Company's financial statements as a result of intangible asset impairments for the years ended December 31, 2009 and 2008.

## Future Income Taxes

Effective January 1, 1981, as prescribed by the PUB, future income tax liabilities are recognized and recovered in customer rates on temporary timing differences associated with the cumulative excess of capital cost allowance over amortization of property, plant and equipment, excluding GEC.

Effective January 1, 2008, as prescribed by the PUB, future income taxes are recognized and recovered in customer rates on temporary timing differences between pension expense and pension funding.

Future income tax expense (recovery) associated with the Company's regulatory reserves and certain regulatory deferrals is also recognized and included in the determination of customer rates. See Note 4.

Future income tax assets and liabilities associated with other temporary timing differences between the tax basis of assets and liabilities and their carrying amount are not recognized or included in customer rates. Effective January 1, 2009, the impact of the amendment to CICA Handbook Section 3465, *Income Taxes* is the recognition of future income tax assets and liabilities and related regulatory liabilities and assets for the amount of future income taxes expected to be refunded to, or recovered from, customers in future electricity rates. See Note 3.

## Employee Future Benefits

Newfoundland Power maintains defined contribution and defined benefit pension plans for its employees and also provides other post-employment benefits ("OPEBs"). OPEBs are composed of retirement allowances for retiring employees as well as health, medical and life insurance for retirees and their dependants.

## Defined Contribution and Defined Benefit Pension Plans

Defined contribution pension plan costs are expensed as incurred.

The pension costs and accrued benefit obligations of the defined benefit pension plans are actuarially determined using the projected benefit method pro-rated on service and management's best estimate of expected plan investment performance, salary escalation and retirement ages of employees. Pension plan assets are valued using the market-related value where investment returns in excess of or below expected returns are recognized in asset value over a period of three years. The excess of the cumulative net actuarial gain or loss over 10% of the greater of the benefit obligation and the market-related value of plan assets is amortized over the estimated average remaining service period of active employees. The transitional obligation arising from the Company's January 1, 2000 adoption of Section 3461 of the CICA Handbook is being amortized on a straight-line basis over the 18 year expected average remaining service period of plan members at that time. Unamortized past service costs are amortized over a range of 5 - 15 years. See Notes 4 and 8.

## 2. Summary of Significant Accounting Policies (cont'd)

### Defined Contribution and Defined Benefit Pension Plans (cont'd)

Effective January 1, 2010, pursuant to the 2010 GRA, the PUB ordered the creation of a pension expense variance deferral account ("PEVDA"). This account will be charged or credited with the amount by which annual pension expense, recorded in accordance with Canadian GAAP, differs from amounts approved in rates by the PUB. Each year, at March 31, the balance in the PEVDA will be transferred to the Company's Rate Stabilization Account and disposed of in accordance with the operation of the Rate Stabilization Account. See Note 4.

### Other Post-Employment Benefits ("OPEBs")

OPEBs costs are expensed when benefits are paid. In the absence of rate regulation, OPEBs costs would be expensed on an accrual basis as actuarially determined. The portion of the actuarially determined costs that is not recognized as an expense is deferred as a regulatory asset, as these costs are expected to be recovered in future customer rates in a manner determined by the PUB. See Note 4.

OPEBs costs and the accrued OPEBs obligation are actuarially determined using the projected benefits method prorated on service and best estimate assumptions. The excess of any cumulative net actuarial gain or loss over 10% of the benefit obligation, along with unamortized past service costs is amortized over the estimated average remaining service period of active employees. The transitional obligation arising from the Company's January 1, 2000 adoption of Section 3461 of the CICA Handbook is being amortized on a straight-line basis over the 18 year expected average remaining service period of plan members at that time. See Note 8.

In the absence of rate regulation, OPEBs costs recognized in 2009 operating expenses would have been $5.6 million higher (2008 - $6.5 million higher).

### Financial Instruments

The Company has designated its financial instruments as follows:

(a) Cash is classified as "Held for Trading". After its initial fair value measurement, any change in fair value is recognized in earnings.

(b) Certain accounts receivable and loans under customer finance plans (Note 10) are classified as "Loans and Receivables".

(c) Short-term borrowings, bank indebtedness, accounts payable and accrued charges, security deposits (Note 13) and long-term debt are classified as "Other Financial Liabilities".

Initial measurement of Loans and Receivables and Other Financial Liabilities are at fair value and incorporates transaction costs, including debt issue costs. Subsequent measurement is at amortized cost using the effective interest method. For the Company, the measurement amount approximates cost.

## Asset Retirement Obligations

Under Canadian GAAP, the Company is required to record the fair value of future expenditures necessary to settle legal obligations associated with asset retirements even though the timing or method of settlement is conditional on future events. Newfoundland Power has determined that there are asset retirement obligations ("AROs") associated with its hydroelectric generation assets and some parts of its transmission and distribution system.

For hydroelectric generation assets, the legal obligation is the environmental remediation of the land and waterways to protect fish habitat. However, this obligation is conditional on the decision to decommission generation assets. The Company currently has no plans to decommission any of its hydroelectric generation assets as they are effectively operated in perpetuity. Therefore, the nature and fair value of any ARO is not currently determinable.

The legal obligations for the transmission and distribution system pertain to the proper disposal of used oil and obligations related to other Company facilities consist of the removal of fuel storage tanks and asbestos. These obligations were determined to be immaterial and therefore no AROs have been recognized.

The Company will recognize AROs and offsetting property, plant and equipment if the nature and timing can reasonably be determined and the amount is material.

## Use of Accounting Estimates

The preparation of financial statements in accordance with Canadian GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting periods. Estimates and judgments are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances. Additionally, certain estimates are necessary since the regulatory environment in which the Company operates often require amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. Due to changes in facts and circumstances and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates are reviewed periodically and, as adjustments become necessary, are reported in earnings in the period in which they either, as appropriate, become known or included in customer rates.

# 3. Change in Accounting Policies

## 2009 Changes

Rate Regulated Operations: Effective January 1, 2009, the Accounting Standards Board ("AcSB") amended: (i) CICA Handbook Section 1100, *Generally Accepted Accounting Principles* ("Section 1100"), removing the temporary exemption providing relief to entities subject to rate regulation from the requirement to apply the Section to the recognition and measurement of assets and liabilities arising from rate regulation; and (ii) CICA Handbook Section 3465, *Income Taxes* ("Section 3465") to require the recognition of future income tax liabilities and assets as well as offsetting regulatory assets and liabilities by entities subject to rate regulation.

# 3. Change in Accounting Policies (cont'd)

## 2009 Changes (cont'd)

(i) With the removal of the temporary exemption in Section 1100, the Company must now apply this Section to the recognition of assets and liabilities arising from rate regulation. Certain assets and liabilities arising from rate regulation continue to have specific guidance under a primary source of Canadian GAAP that applies only to the particular circumstances described therein, including those arising under CICA Handbook Section 3061, *Property, Plant and Equipment*, Section 3465, *Income Taxes*, and Section 3475, *Disposal of Long-Lived Assets and Discontinued Operations*. The assets and liabilities arising from rate regulation, as described in Note 4 do not have specific guidance under a primary source of Canadian GAAP. Therefore, Section 1100 directs the Company to adopt accounting policies that are developed through the exercise of professional judgment and the application of concepts described in CICA Handbook Section 1000, *Financial Statement Concepts*. In developing these accounting policies, the Company may consult other sources including pronouncements issued by bodies authorized to issue accounting standards in other jurisdictions. In accordance with Section 1100, the Company has determined that its regulatory assets and liabilities qualify for recognition under Canadian GAAP and this recognition is consistent with U.S. Financial Accounting Standard Board's Accounting Standard Codification 980, *Regulated Operations*. There was no effect on the Company's financial statements as at January 1, 2009 due to the removal of the temporary exemption in Section 1100.

(ii) The impact of the amendment to Section 3465 is the recognition of future income tax assets and liabilities and related regulatory liabilities and assets for the amount of future income taxes expected to be refunded to, or recovered from, customers in future electricity rates. In accordance with the revised standard, as at January 1, 2009, the Company's future income tax liability increased by approximately $118 million with a corresponding net change to regulatory assets and liabilities of approximately $118 million. Included in the amounts are the future income tax effects of the subsequent settlement of the related regulatory assets and liabilities through future customer rates. This change does not affect the Company's earnings or cash flows.

Goodwill and Intangible Assets: Effective January 1, 2009, the Company adopted the new CICA Handbook Section 3064, *Goodwill and Intangible Assets*, which effectively converges Canadian GAAP for goodwill and intangible assets with International Financial Reporting Standards. Adoption of this standard resulted in the reclassification of certain assets previously included in property, plant and equipment to intangible assets. The items that were reclassified consist of certain computer software and land rights. As at December 31, 2008, $13.8 million and $2.3 million were reclassified to intangible assets on the balance sheet related to computer software and land rights, respectively.

## Future Changes

International Financial Reporting Standards ("IFRS"): In February 2008, the AcSB confirmed that the use of IFRS will be required in 2011 for publicly accountable enterprises in Canada. In October 2009, the AcSB issued a third and final Omnibus Exposure Draft confirming that publicly accountable enterprises in Canada will be required to apply IFRS, in full and without modification, beginning January 1, 2011. The transition date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported by the

Company for the year ended December 31, 2010, and of the opening balance sheet as at January 1, 2010. The AcSB requires that CICA Handbook Section 1506, *Accounting Changes*, paragraph 30, which requires an entity to disclose information relating to a new primary source of Canadian GAAP that has been issued but is not yet effective and that the entity has not applied, not be applied with respect to this Exposure Draft. Newfoundland Power is continuing to assess the financial reporting impacts of adopting IFRS.

In July 2009, the IASB issued the Exposure Draft – *Rate Regulated Activities*, with a final standard expected to be issued in the second quarter of 2010. Based on the Exposure Draft as it currently exists, regulatory assets and liabilities arising from activities subject to cost of service regulation can be recognized under IFRS when certain conditions are met. The ability to record regulatory assets and liabilities, as proposed, should reduce the earnings' volatility for the Company that may have otherwise resulted under IFRS in the absence of an accounting standard for rate regulated activities. However, uncertainty as to the final outcome of this Exposure Draft, and the final standard on accounting for rate regulated activities under IFRS, has resulted in the Company being unable to reasonably estimate and conclude on the impact on the Company's future financial position and results of operations with respect to differences, if any, in accounting for rate regulated activities under IFRS versus Canadian GAAP.

Newfoundland Power does anticipate a significant increase in disclosure resulting from the adoption of IFRS, and is identifying and assessing the additional disclosure requirements, as well as implementing systems changes that will be necessary to compile the required disclosures.

## 4. Regulatory Assets and Liabilities

Regulatory assets and liabilities arise as a result of the rate setting process. Regulatory assets represent future revenues associated with certain costs incurred in the current or prior periods that will be, or are expected to be, recovered from customers in future periods through the rate setting process. Regulatory liabilities represent future reductions or limitations of increases in revenues associated with amounts that will be, or are expected to be, refunded to customers through the rate setting process. The accounting methods underlying regulatory assets and liabilities, and their eventual settlement through the rate setting process, are prescribed by the PUB and impact the Company's cash flows.

## 4. Regulatory Assets and Liabilities (cont'd)

The Company's regulatory assets and liabilities which will be, or are expected to be, reflected in customer rates in future periods, follow.

| | 2009 | | 2008 | |
|---|---|---|---|---|
| | Current | Non-current | Current | Non-current |
| Regulatory Assets | | | | |
| Rate stabilization account *(i)* | $ - | $ 1,836 | $ 2,486 | $ 4 |
| OPEBs *(Note 8)* | - | 46,713 | - | 41,074 |
| Weather normalization account *(ii)*[1] | 2,102 | 3,929 | 1,366 | 4,544 |
| Amortization true-up deferral *(iii)* | 3,862 | - | 3,862 | 3,862 |
| Pension deferral *(iv)* | 1,128 | 4,793 | 1,128 | 5,920 |
| Replacement energy deferral *(v)*[1] | 600 | - | 383 | 383 |
| Deferred GRA costs *(vi)* | 451 | 500 | 201 | 201 |
| Conservation and demand management deferral *(vii)* | 339 | 1,018 | - | - |
| Future income taxes *(Note 3)* | 2,541 | 138,994 | - | - |
| | $ 11,023 | $ 197,783 | $ 9,426 | $ 55,988 |
| Regulatory Liabilities | | | | |
| Rate stabilization account *(i)* | $ 418 | $ - | $ - | $ - |
| Municipal tax liability *(viii)* | 1,363 | - | 1,363 | 1,364 |
| Unbilled revenue *(ix)* | 4,618 | - | 4,618 | 4,618 |
| Purchased power unit cost variance reserve *(x)*[1] | 688 | - | 447 | 448 |
| Future removal and site restoration provision *(xi)* | - | 48,660 | - | 47,961 |
| Demand management incentive account *(xii)* | - | - | - | 426 |
| Future income taxes *(Note 3)* | 2,287 | 20,547 | - | - |
| | $ 9,374 | $ 69,207 | $ 6,428 | $ 54,817 |

[1] *Balances in 2009 include future income taxes. Balances in 2008 were recorded net of future income taxes.*

**(i) Rate Stabilization Account ("RSA")**

On July 1 of each year, customer rates are recalculated in order to recover from or refund to customers, over the subsequent twelve months, the balance in the RSA as of March 31 of the current year. The amount and timing of the recovery or refund is subject to PUB approval.

The RSA passes through to the Company's customers amounts primarily related to changes in the cost and quantity of fuel used by Hydro to produce the electricity sold to the Company. In the absence of rate regulation these transactions would be accounted for in a similar manner however the amount and timing of the recovery or refund would not be subject to PUB approval.

The RSA passes through, to the Company's customers, variations in purchased power expense caused by differences between the actual unit cost of energy and that reflected in customer rates ("energy supply cost variance"). The marginal cost of purchased power for the Company currently exceeds the average cost that is embedded in customer rates. To the extent actual electricity sales in any period exceed forecast electricity sales used to set customer rates, marginal purchased power expense will exceed related revenue. In the absence of rate regulation, purchased power expense would have been $2.9 million higher (2008 - $0.4 million lower). Pursuant to the 2010 GRA, the PUB ordered continued use of the energy supply cost variance until a further order of the Board.

The RSA is also adjusted from time-to-time by other amounts as approved by the Board. In 2008, the Company included an amount to the demand management incentive account as described in (xii) below.

Effective January 1, 2010, the PUB approved the PEVDA as described in Note 2 to capture the difference between the annual pension expense approved for rate setting purposes and actual pension expense calculated in accordance with Canadian GAAP. The balance in this account will be transferred to the RSA on March 31 in the year in which the difference arises.

**(ii) Weather Normalization Account**

The weather normalization account reduces earnings volatility by adjusting purchased power expense and electricity sales revenue to eliminate variances in purchases and sales caused by the difference between normal weather conditions, based on long-term averages, and actual weather conditions. In the absence of rate regulation these fluctuations would have been recognized in earnings in the period in which they occurred.

The balance in the weather normalization account, because it is based on long-term averages for weather conditions, should tend to zero over time. However, the Company identified non-reversing balances in the account arising from changes in purchased power rates and income tax rates. In 2008, the PUB ordered that a non-reversing balance of approximately $6.8 million be amortized equally over 2008 - 2012 as an increase in purchased power expense of approximately $2.1 million and a decrease in future income tax expense of approximately $0.7 million in each year.

The recovery period for the remaining balance in the Weather Normalization Account is not determinable as it depends on future weather conditions. In the absence of rate regulation, revenue in 2009 would have been $5.8 million lower (2008 - $7.6 million lower), purchased power expense in 2009 would have been $8.8 million lower (2008 - $14.6 million lower) and future income tax expense in 2009 would have been $1.0 million higher (2008 - $2.4 million higher).

## 4. Regulatory Assets and Liabilities (cont'd)

**(iii) Amortization True-Up Deferral**

The PUB ordered the deferred recovery of approximately $5.8 million in each of 2006 and 2007, $11.6 million in aggregate, related to a variance in accumulated amortization identified in the 2002 Amortization Study. These deferrals were recorded as an increase in regulatory assets and a decrease in expenses of $5.8 million in each year. Amortization of $3.9 million was recorded in 2009 and 2008 in accordance with the PUB order that the resultant regulatory asset of approximately $11.6 million be amortized evenly over 2008 through 2010. In the absence of rate regulation, $11.6 million would have been expensed in the original years incurred.

**(iv) Pension Deferral**

The PUB ordered that approximately $11.3 million of incremental pension costs arising from the Company's 2005 early retirement program be deferred and amortized to pension expense equally over a ten year period beginning April 1, 2005. In the absence of rate regulation, these costs would have been expensed in 2005.

**(v) Replacement Energy Deferral**

In 2008, the PUB ordered that a $1.1 million regulatory asset, related to the deferred recovery of the cost of replacement energy purchased during the refurbishment of the Company's Rattling Brook Hydroelectric Generating Plant, be amortized equally over 2008 – 2010. This increased purchased power expense by approximately $0.6 million and decreased future income tax expense by approximately $0.2 million in each year. In the absence of rate regulation, these costs would have been expensed in 2007.

**(vi) Deferred GRA Costs**

In 2007, the PUB ordered that external costs related to the Company's 2008 GRA be deferred and amortized evenly over 2008 – 2010 as an increase to operating expense. The actual external costs totalled $0.6 million. In the absence of rate regulation, these costs would have been expensed as incurred.

In 2009, the PUB ordered that an estimated $0.8 million of external costs related to the Company's 2010 GRA be deferred and amortized equally over 2010-2012. In the absence of rate regulation, these costs would have been expensed in 2009.

**(vii) Conservation and Demand Management Deferral**

In 2009, the PUB ordered the deferral of $1.4 million of costs, associated with the implementation of conservation and demand management programs. In 2009, the PUB ordered that these costs be amortized evenly over 2010 – 2013 as an increase to operating expense. In the absence of rate regulation, these costs would have been expensed in 2009.

**(viii) Municipal Tax Liability**

The municipal tax liability results from a timing difference related to the recovery and payment of municipal taxes. This arose as a result of the PUB approved municipal tax rate adjustment. The PUB ordered that this liability be amortized as other revenue equally over 2008 - 2010. In the absence of rate regulation, these costs would have been recorded as revenue as incurred.

**(ix) Unbilled Revenue**

Prior to January 1, 2006, revenue from electricity sales was recognized as bills were rendered to customers. Subsequent to this date, revenue is recognized on an accrual basis. The difference between revenue recognized on a billed basis and revenue recognized on an accrual basis as at December 31, 2005 was recorded on the balance sheet as a regulatory liability. As ordered by the PUB, the Company amortized as an increase to revenue approximately $4.6 million of this regulatory liability in 2009 (2008 - $7.2 million). The remaining unamortized balance at December 31, 2009 will be amortized in 2010. In the absence of rate regulation, all the unbilled revenue would have been recognized as revenue during 2005.

**(x) Purchased Power Unit Cost Variance Reserve**

In 2008, the PUB ordered the discontinuance of the purchased power unit cost variance reserve and that the December 31, 2006 balance in the reserve of approximately $1.3 million be amortized over 2008 – 2010 as a decrease to purchased power. In 2008, the PUB ordered that the balance in the account related to 2008 be transferred to the RSA. In the absence of rate regulation, the balance in the account would have been expensed as incurred.

**(xi) Future Removal and Site Restoration Provision**

This regulatory liability represents amounts collected in customer electricity rates over the life of certain property, plant and equipment which are attributable to removal and site restoration costs that are expected to be incurred in the future. Actual removal and site restoration costs, net of salvage proceeds, are recorded against the regulatory liability when incurred. The regulatory liability represents the amount of expected future removal and site restoration costs associated with property, plant and equipment in service as at December 31, calculated using current amortization rates as approved by the PUB. In the absence of rate regulation, removal and site restoration costs, net of salvage proceeds, would have been recognized as an operating expense when incurred.

**(xii) Demand Management Incentive Account ("DMI")**

Through the DMI, variations in the unit cost of purchased power related to demand are limited, at the discretion of the PUB, to 1% of demand costs reflected in customer rates. In 2008, $0.4 million was transferred to this account. The PUB ordered the disposition of this balance, adjusted for income taxes, through the RSA effective July 1, 2009. The disposition of any future balances in this account, which would be determined by a further order of the PUB, will consider the merits of the Company's conservation and demand management activities. In the absence of rate regulation, purchased power expense would have been $0.6 million lower in 2008 and would have had no impact in 2009.

## 5. Finance Charges

| | 2009 | 2008 |
|---|---|---|
| Interest - first mortgage sinking fund bonds | $ 34,547 | $ 32,334 |
| Interest - committed credit facility | 396 | 1,187 |
| Interest - related party loan | - | 258 |
| Interest - other | 15 | 49 |
| Total interest expense | 34,958 | 33,828 |
| Amortization - debt issue costs | 235 | 235 |
| Amortization - capital stock issue costs | 37 | 62 |
| AFUDC *(Note 2)* | (675) | (618) |
| | $ 34,555 | $ 33,507 |

## 6. Income Taxes

Income taxes vary from the amount that would be determined by applying statutory income tax rates to pre-tax earnings. A reconciliation of the combined federal and provincial statutory income tax rate to the Company's effective income tax rate follows.

| | 2009 | 2008 |
|---|---|---|
| Accounting income per financial statements | $ 49,293 | $ 52,041 |
| Statutory tax rate | 33.0% | 33.5% |
| Expected tax expense *(statutory rate)* | 16,267 | 17,434 |
| Item capitalized vs. expensed | (1,003) | (926) |
| Capital cost allowance vs. amortization | 1,113 | 1,088 |
| Pension funding vs. pension expense | 232 | (162) |
| Other timing difference | (276) | 265 |
| Unbilled revenue | (1,524) | 102 |
| Regulatory deferrals | 1,283 | 1,345 |
| Income tax expense | $ 16,092 | $ 19,146 |
| Effective tax rate | 32.6% | 36.8% |

The composition of the Company's income tax provision follows.

| | 2009 | 2008 |
|---|---|---|
| Current income tax expense | $ 15,590 | $ 20,346 |
| Future income tax expense *(recovery)* | 3,382 | (1,200) |
| Regulatory adjustment *(Note 3)* | (2,880) | - |
| | $ 16,092 | $ 19,146 |

Pursuant to a settlement agreement with the Canada Revenue Agency, current income taxes in 2008 included approximately $2.5 million related to the Company's January 1, 2006 adoption of the accrual method of revenue recognition for income tax purposes. Current income taxes for 2009 onwards are not affected by this agreement.

| | 2009 | 2008 |
|---|---|---|
| **Future income tax liability** | | |
| Property, plant and equipment/intangibles | $ 78,011 | $ 575 |
| Regulatory assets and liabilities | 24,768 | - |
| Employee future benefits | 19,575 | 609 |
| Debt financing costs | 1,140 | - |
| **Net future income tax liability** | $ 123,494 | $ 1,184 |
| | | |
| Current future income tax liability | 1,068 | - |
| Long-term future income tax liability | 122,426 | 1,184 |
| **Net future income tax liability** | $ 123,494 | $ 1,184 |

As at December 31, 2009, the Company had no capital losses (2008 - $0.2 million) carried forward which have not been recognized in the financial statements.

## 7. Property, Plant and Equipment

| | Cost | | Accumulated Amortization | | Net Book Value | |
|---|---|---|---|---|---|---|
| | **2009** | **2008** | **2009** | **2008** | **2009** | **2008** |
| Distribution | $ 718,921 | $ 690,675 | $ 261,404 | $ 248,543 | $ 457,517 | $ 442,132 |
| Transmission and substations | 234,154 | 221,985 | 88,199 | 84,812 | 145,955 | 137,173 |
| Generation | 168,087 | 159,498 | 49,478 | 45,639 | 118,609 | 113,859 |
| Transportation and communications | 33,426 | 33,056 | 16,710 | 16,163 | 16,716 | 16,893 |
| Land, buildings and equipment | 68,553 | 69,718 | 27,362 | 27,464 | 41,191 | 42,254 |
| Construction in progress | 2,967 | 2,126 | - | - | 2,967 | 2,126 |
| Construction materials | 4,263 | 4,375 | - | - | 4,263 | 4,375 |
| | $1,230,371 | $1,181,433 | $ 443,153 | $ 422,621 | $ 787,218 | $ 758,812 |

Distribution assets are used to distribute low voltage electricity to customers and include poles, towers and fixtures, low voltage wires, transformers, overhead and underground conductors, street lighting, metering equipment and other related equipment.

Transmission and substations assets are used to transmit high voltage electricity to distribution assets and include poles, high voltage wires, switching equipment, transformers and other related equipment.

Generation assets are used to generate electricity and include hydroelectric and thermal generating stations, gas and combustion turbines, dams, reservoirs and other related equipment.

Transportation and communications assets include vehicles as well as telephone, radio and other communications equipment.

## 7. Property, Plant and Equipment (cont'd)

Land, buildings and equipment are used generally in the provision of electricity service but not specifically in the distribution, transmission or generation of electricity or specifically related to transportation and communication activities.

## 8. Employee Future Benefits

The Company's defined contribution plans are its individual and group registered retirement savings plans, and an unfunded supplementary employee retirement plan ("SERP"). Benefits are based upon employee earnings. The accrued benefit liability for the SERP is included in other liabilities on the Company's balance sheets (Note 13). During 2009, the Company expensed approximately $1.2 million (2008 - $1.0 million) related to these plans.

The Company's defined benefit plans are its funded defined benefit pension plan, an unfunded pension uniformity plan ("PUP") and OPEBs. Both pension plans are closed to new entrants and provide benefits based on a percentage of the highest 36 consecutive months average base earnings and the employee's years of service.

The accrued benefit obligation for all of the Company's defined benefit plans, and the market-related value of plan assets for the Company's funded primary defined benefit pension plan, are measured for accounting purposes as at December 31 of each year.

The most recent actuarial valuation of the Company's defined benefit pension plans for funding purposes was as of December 31, 2008 and the next valuation is expected to be as of December 31, 2011. The most recent actuarial valuation of the Company's OPEBs was December 31, 2008.

The accrued benefit asset for the Company's funded primary defined benefit pension plan is included in accrued pension on the Company's balance sheets. The accrued benefits liability for the PUP is included in other liabilities (Note 13).

Details of the Company's defined benefit plans follow.

| | 2009 | | | 2008 | | |
|---|---|---|---|---|---|---|
| | | Unfunded | | | Unfunded | |
| | Funded | PUP | OPEB | Funded | PUP | OPEB |
| **Change in accrued benefit obligation** | | | | | | |
| Balance, beginning of year | $190,391 | $ 2,169 | $ 59,636 | $235,477 | $ 2,558 | $ 70,411 |
| Current service costs | 3,420 | - | 1,008 | 4,844 | - | 1,384 |
| Interest cost | 13,923 | 154 | 4,485 | 12,740 | 135 | 3,901 |
| Benefits paid | (12,131) | (215) | (1,304) | (12,926) | (215) | (1,175) |
| Plan amendments | - | - | 1,004 | - | - | - |
| Actuarial (gains) losses | 26,333 | 210 | 4,838 | (49,744) | (309) | (14,885) |
| Balance, end of year | $221,936 | $ 2,318 | $69,667 | $190,391 | $ 2,169 | $ 59,636 |
| **Change in fair value of plan assets** | | | | | | |
| Balance, beginning of year | $212,599 | $ - | $ - | $259,731 | $ - | $ - |
| Return on assets | 17,386 | - | - | 19,169 | - | - |
| Benefits paid | (12,131) | (215) | (1,304) | (12,926) | (215) | (1,175) |
| Actuarial (losses) gains | 18,725 | - | - | (59,993) | - | - |
| Employee contributions | 1,286 | - | - | 1,193 | - | - |
| Employer contributions | 4,866 | 215 | 1,304 | 5,425 | 215 | 1,175 |
| Balance, end of year | $242,731 | $ - | $ - | $212,599 | $ - | $ - |
| **Funded status** | | | | | | |
| Surplus (deficit), end of year | $ 20,795 | $ (2,318) | $ (69,667) | $ 22,209 | $ (2,169) | $ (59,636) |
| Unamortized net actuarial loss | 64,376 | 474 | 11,093 | 56,768 | 269 | 6,277 |
| Unamortized transitional obligation | 10,297 | 373 | 10,857 | 11,584 | 419 | 12,285 |
| Unamortized past service costs | 2,334 | 1 | 1,004 | 2,587 | 1 | - |
| Accrued benefit asset (liability), end of year | $ 97,802 | $ (1,470) | $ (46,713) | $ 93,148 | $ (1,480) | $ (41,074) |
| **Effect of 1% increase in health care cost trends on:** | | | | | | |
| Accrued benefit obligation | - | - | $ 9,439 | - | - | $ 8,319 |
| Service costs and interest cost | - | - | $ 830 | - | - | $ 1,013 |
| **Effect of 1% decrease in health care cost trends on:** | | | | | | |
| Accrued benefit obligation | - | - | $ (7,606) | - | - | $ (6,707) |
| Service costs and interest cost | - | - | $ (655) | - | - | $ (808) |

## 8. Employee Future Benefits (cont'd)

| | 2009 | | | 2008 | | |
|---|---|---|---|---|---|---|
| | | Unfunded | | | Unfunded | |
| | Funded | PUP | OPEB | Funded | PUP | OPEB |
| **Significant assumptions** | | | | | | |
| Discount rate during year | 7.50% | 7.50% | 7.50% | 5.50% | 5.50% | 5.50% |
| Discount rate as at December 31 | 6.50% | 6.50% | 6.70% | 7.50% | 7.50% | 7.50% |
| Expected long-term rate of return on plan assets | 7.00% | - | - | 7.50% | - | - |
| Rate of compensation increases | 4.00% | 4.00% | 4.00% | 4.00% | 4.00% | 4.00% |
| Health care cost trend increases as at December 31 | - | - | 4.50% | - | - | 4.50% |
| Expected average remaining service of active employees | 11 years | 11 years | 14 years | 12 years | 12 years | 15 years |
| **Net benefit expense** | | | | | | |
| Current service costs | $ 2,134 | $ - | $ 1,008 | $ 3,651 | $ - | $ 1,384 |
| Interest cost | 13,923 | 154 | 4,485 | 12,740 | 135 | 3,901 |
| Expected return on plan assets | (17,386) | - | - | (19,169) | - | - |
| Amortization of transition obligation | 1,287 | 47 | 1,428 | 1,287 | 47 | 1,428 |
| Amortization of net actuarial loss | - | 5 | 22 | 1,911 | 28 | 1,009 |
| Amortization of past service costs | 253 | - | - | 335 | - | - |
| Regulatory adjustment *(Note 4)* | 1,128 | - | (5,639) | 1,128 | - | (6,547) |
| Net benefit expense | $ 1,339 | $ 206 | $ 1,304 | $ 1,883 | $ 210 | $ 1,175 |
| **Asset allocation** | | | | | | |
| Fixed income | 40% | - | - | 48% | - | - |
| Equities | 40% | - | - | 32% | - | - |
| Foreign equities | 20% | - | - | 20% | - | - |

## 9. Intangible Assets

| | Cost | | Accumulated Amortization | | Net Book Value | |
|---|---|---|---|---|---|---|
| | 2009 | 2008 | 2009 | 2008 | 2009 | 2008 |
| Computer software | $ 30,533 | $ 30,988 | $ 16,892 | $ 17,193 | $ 13,641 | $ 13,795 |
| Land rights | 6,754 | 6,645 | 4,282 | 4,295 | 2,472 | 2,350 |
| | $ 37,287 | $ 37,633 | $ 21,174 | $ 21,488 | $ 16,113 | $ 16,145 |

## 10. Other Assets

| | 2009 | 2008 |
|---|---|---|
| Customer finance plans | $ 1,679 | $ 1,776 |
| Capital stock issue costs | 38 | 75 |
| Credit facility costs | - | 50 |
| | $ 1,717 | $ 1,901 |

Customer finance plans represent the non-current portion of loans to customers for certain new service requests and energy efficiency upgrades. The current portion of these loans is classified as accounts receivable. In the case of new service requests, and as prescribed by the PUB, interest is charged at a fixed rate of prime plus 3% for repayment periods up to 60 months and prime plus 4% for repayment periods of 61 months to 120 months. In the case of energy efficiency upgrades, interest is charged at a fixed rate of prime plus 4% for a maximum repayment period of 60 months. All loan instalments are made through the customers' monthly electricity bill payments. The balance of any loan may be repaid at any time without penalty.

## 11. Credit Facilities

Newfoundland Power has unsecured bank credit facilities of $120 million comprised of a syndicated $100 million committed revolving term credit facility which matures on August 29, 2011 and a $20 million demand facility.

Borrowings under the committed facility have been classified as long-term as they are expected to remain outstanding for a period extending beyond one year from the balance sheet date and management intends to refinance these amounts in the future with the issuance of other long-term debt. These borrowings are in the form of bankers acceptances bearing interest based on the daily Canadian Deposit Offering Rate for the date of borrowing plus a stamping fee. Standby fees on the unutilized portion of the committed facility are payable quarterly in arrears at a fixed rate of 0.10%. Interest on the demand facility is calculated at the daily prime rate and is payable monthly in arrears.

The utilized and unutilized credit facilities as at December 31 follow.

| | 2009 | 2008 |
|---|---|---|
| Total credit facilities | $ 120,000 | $ 120,000 |
| Borrowings under committed facility *(Note 12)* | (13,500) | (32,000) |
| Credit facilities available | $ 106,500 | $ 88,000 |

## 12. Long-term Debt

| | 2009 | 2008 |
|---|---|---|
| First mortgage sinking fund bonds | | |
| 10.550% $40 million Series AD, due 2014 | $ 30,553 | $ 30,953 |
| 10.900% $40 million Series AE, due 2016 | 32,800 | 33,200 |
| 10.125% $40 million Series AF, due 2022 | 33,200 | 33,600 |
| 9.000% $40 million Series AG, due 2020 | 34,000 | 34,400 |
| 8.900% $40 million Series AH, due 2026 | 34,835 | 35,235 |
| 6.800% $50 million Series AI, due 2028 | 44,500 | 45,000 |
| 7.520% $75 million Series AJ, due 2032 | 69,750 | 70,500 |
| 5.441% $60 million Series AK, due 2035 | 57,000 | 57,600 |
| 5.901% $70 million Series AL, due 2037 | 67,900 | 68,600 |
| 6.606% $65 million Series AM, due 2039 | 64,350 | - |
| Long-term classification of credit facilities *(Note 11)* | 13,500 | 32,000 |
| | 482,388 | 441,088 |
| Less: current installments of long-term debt | 5,200 | 4,550 |
| | 477,188 | 436,538 |
| Less: debt issue costs | 3,138 | 2,934 |
| | $ 474,050 | $ 433,604 |

In 2009, the Company issued $65 million in Series AM first mortgage sinking fund bonds. The bonds were issued with a 30-year term at an interest rate of 6.606%.

First mortgage sinking fund bonds are secured by a first fixed and specific charge on property, plant and equipment owned or to be acquired by the Company and by a floating charge on all other assets. They require an annual sinking fund payment of 1% of the original principal balance.

Future payments required to meet sinking fund instalments, maturities of long-term debt and long-term credit facilities follow.

| | |
|---|---|
| 2010 | $ 5,200,000 |
| 2011 | $ 18,700,000 |
| 2012 | $ 5,200,000 |
| 2013 | $ 5,200,000 |
| 2014 | $ 33,753,000 |
| 2015 and after | $ 414,335,000 |

## 13. Other Liabilities

| | 2009 | 2008 |
|---|---|---|
| Defined benefit pension liability - unfunded *(Note 8)* | $ 1,470 | $ 1,480 |
| Security deposits | 581 | 785 |
| Defined contribution pension liability *(Note 8)* | 1,909 | 1,662 |
| | $ 3,960 | 3,927 |

Security deposits are advance cash collections from certain customers to guarantee the payment of electricity bills. The security deposit liability includes interest credited to customer deposits. The current portion of security deposits is reported in accounts payable and accrued charges.

## 14. Capital Stock

*Authorized*

(a) an unlimited number of Class A and Class B Common Shares without nominal or par value. The shares of each class are inter-convertible on a share-for-share basis and rank equally in all respects including dividends. The Board of Directors may provide for the payment, in whole or in part, of any dividends to Class B shareholders by way of a stock dividend;

(b) an unlimited number of First Preference Shares and Second Preference Shares without nominal or par value, except that each Series A, B, D and G First Preference Share has a par value of $10. The issued First Preference Shares are entitled to cumulative preferential dividends and are redeemable at the option of the Company at a premium not in excess of the annual dividend rate. Series D and G First Preference Shares are subject to the operation of purchase funds and the Company has the right to purchase limited amounts of these shares at or below par.

*Issued*

| | 2009 | | 2008 | |
|---|---|---|---|---|
| | **Number of Shares** | **Amount** | **Number of Shares** | **Amount** |
| Class A common shares | 10,320,270 | $ 70,321 | 10,320,270 | $ 70,321 |
| First preference shares | | | | |
| 5.50% Series A | 179,225 | 1,792 | 179,225 | 1,792 |
| 5.25% Series B | 337,983 | 3,380 | 337,983 | 3,380 |
| 7.25% Series D | 210,890 | 2,109 | 212,065 | 2,121 |
| 7.60% Series G | 183,000 | 1,830 | 205,950 | 2,059 |
| | 911,098 | $ 9,111 | 935,223 | $ 9,352 |

At December 31, 2009, Fortis held 230,194 or approximately 25.3% of the Company's issued and outstanding First Preference Shares.

## 15. Related Party Transactions

The Company provides services to, and receives services from, its parent Company, Fortis, and other affiliates. The Company also incurs charges from Fortis for the recovery of general corporate expenses incurred by Fortis. Related party revenue primarily relates to electricity sales. These transactions are in the normal course of business and are recorded at their exchange amounts.

## 15. Related Party Transactions (cont'd)

Related party transactions included in revenue, operating expenses and finance charges in 2009 and 2008, and in accounts receivable at December 31 of these years, follow.

| | 2009 | | 2008 | |
|---|---|---|---|---|
| | Fortis | Other Affiliates | Fortis | Other Affiliates |
| Revenue | $ 181 | $ 4,313 | $ 173 | $ 4,052 |
| Operating expenses | 1,561 | 68 | 1,352 | 93 |
| Finance charges | - | - | 258 | - |
| Accounts receivable | $ 52 | $ 26 | $ 31 | $ 132 |

## 16. Capital Management

Newfoundland Power's primary objectives when managing capital are (i) to ensure continued access to capital at reasonable cost, and (ii) to provide an adequate return to its common shareholder commensurate with the level of risk associated with the shareholder's investment in the Company.

The Company requires ongoing access to capital because its business is capital intensive. Capital investment is required to ensure continued and enhanced performance, reliability and safety of its electricity systems and to meet customer growth.

The Company operates under cost of service regulation. The cost of capital is ultimately borne by its customers. Access to capital at reasonable cost is a core aspect of the Company's business strategy, which is to operate a sound electricity system and to focus on the safe and reliable delivery of electricity service to its customers in the most cost-efficient manner possible.

The capital managed by the Company is composed of debt (first mortgage sinking fund bonds, bank credit facilities and cash/bank indebtedness), common equity (common shares and retained earnings) and preference equity.

The Company has historically generated sufficient cash flows from operating activities to service interest and sinking fund payments on debt, to pay dividends and to finance a major portion of its capital expenditure programs. Additional financing to fully fund capital expenditure programs is obtained through the Company's credit facilities and these borrowings are periodically refinanced along with any maturing bonds through the issuance of additional bonds. These basic cash flow and capital management dynamics are consistent with previous periods and are currently not expected to change materially over the foreseeable future.

Newfoundland Power endeavours to maintain a capital structure comprised of approximately 55% debt and 45% common equity. This capital structure is reflected in customer rates. It is also consistent with the Company's current investment grade credit ratings, thereby ensuring continued access to capital at reasonable cost. The Company maintains this capital structure primarily by managing its common share dividends.

A summary of the Company's capital structure as at December 31 follows.

| | 2009 | | 2008 | |
|---|---|---|---|---|
| | $ | % | $ | % |
| Debt[1] | 473,942 | 54.8 | 437,535 | 53.3 |
| Common equity | 381,185 | 44.1 | 373,738 | 45.5 |
| Preference equity | 9,111 | 1.1 | 9,352 | 1.2 |
| | 864,238 | 100.0 | 820,625 | 100.0 |

*1 Includes bank indebtedness or net of cash, if applicable.*

The issuance of debt with a maturity that exceeds one year requires the prior approval of the Company's regulator. The issuance of first mortgage sinking fund bonds is subject to an earnings covenant whereby the ratio of (i) annual earnings, before bond interest and tax, to (ii) annual bond interest incurred plus annual bond interest to be incurred on the contemplated bond issue, must be two times or higher. Under its committed credit facility, the Company must also ensure that its Debt to Capitalization ratio does not exceed 0.65:1.00 at any time. During the year, and as at December 31, 2009, the Company was in compliance with all of its debt covenants.

## 17. Financial Instruments

The Company has designed its financial instruments as at December 31 as follows:

| | 2009 | | 2008 | |
|---|---|---|---|---|
| | Carrying Value | Estimated Fair Value | Carrying Value | Estimated Fair Value |
| **Held for trading** | | | | |
| Cash | 5,308 | 5,308 | 619 | 619 |
| **Loans and receivables** | | | | |
| Accounts receivable | 64,553 | 64,553 | 63,508 | 63,508 |
| Customer finance plans[1] | 1,679 | 1,679 | 1,776 | 1,776 |
| **Other financial liabilities** | | | | |
| Accounts payable and accrued charges | 65,727 | 65,727 | 65,548 | 65,548 |
| Security deposits[2] | 581 | 581 | 785 | 785 |
| Long-term debt, including current portion | 479,250 | 577,553 | 438,154 | 505,121 |

*1 Included in other assets on the balance sheet.*
*2 Included in other liabilities on the balance sheet.*

Fair Values: The fair value of long-term debt, including current portion, is calculated by discounting the future cash flows of each debt instrument at the estimated yield-to-maturity equivalent to benchmark government bonds, with similar terms to maturity, plus a market credit risk premium equal to that of issuers of similar credit quality. Since the Company does not intend to settle its debt instruments before maturity, the fair value estimate does not represent an actual liability and, therefore, does not include exchange or settlement costs.

## 17. Financial Instruments (cont'd)

The fair value of the Company's remaining financial instruments approximates their carrying value, reflecting their nature, short-term maturity or normal trade credit terms.

The fair value of the Company's financial instruments reflects a point-in-time estimate based on current and relevant market information about the instruments as at the balance sheet date. The estimates cannot be determined with precision as they involve uncertainties and matters of judgment, and therefore, may not be relevant in predicting the Company's future earnings or cash flows.

Credit Risk: There is risk that Newfoundland Power may not be able to collect all of its accounts receivable and amounts owing under its customer finance plans. These financial instruments, which arise in the normal course of business, do not represent a significant concentration of credit risk as amounts are owed by a large number of customers on normal credit terms. The requirement for security deposits for certain customers, which are advance cash collections from customers to guarantee payment of electricity billings, further reduces the exposure to credit risk. The maximum exposure to credit risk is the net carrying value of these financial instruments.

Newfoundland Power manages credit risk primarily by executing its credit and collection policy, including the requirement for security deposits, through the resources of its Customer Relations Department.

The aging of accounts receivable and amounts owing under customer finance plans, past due but not impaired, as at December 31 follow.

| | 2009 | 2008 |
|---|---|---|
| Not past due | $ 33,042 | $ 34,275 |
| Past due 1-30 days | 28,564 | 26,660 |
| Past due 31-60 days | 3,755 | 3,391 |
| Past due 61-90 days | 846 | 830 |
| Past due over 90 days | 25 | 128 |
| | $ 66,232 | $ 65,284 |

Liquidity Risk: The Company's financial position could be adversely affected if it failed to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and repayment of maturing debt.

The ability to arrange such financing is subject to numerous factors, including the results of operations and financial position of the Company, conditions in the capital and bank credit markets, ratings assigned by ratings agencies and general economic conditions. These factors are mitigated by the legal requirement as outlined in the *Electrical Power Control Act* which requires rates be set to enable the Company to achieve and maintain a sound credit rating in the financial markets of the world.

Newfoundland Power manages short-term liquidity risk primarily by maintaining bank credit facilities. The Company has unsecured facilities of $120 million, comprised of a syndicated $100 million committed revolving term credit facility and a $20 million demand facility.

Newfoundland Power manages long-term liquidity risk primarily by maintaining its investment grade credit ratings. See Note 16.

As at December 31, 2009, the fair value of the Company's primary defined benefit pension plan assets was $242.7 million. The fair value of plan assets at the beginning of 2008 was $259.7 million. The decrease in the fair value of pension plan assets since the beginning of 2008 was mainly driven by unfavourable market conditions.

In April 2009, Newfoundland Power received the Actuarial Valuation Report for its defined benefit pension plan as of December 31, 2008. Based on the report, the solvency ratio of the plan is 92.4% which translated into a solvency deficit of $6.9 million ($7.7 million inclusive of interest). The solvency deficit is required to be funded over a 5 year period, commencing in 2009. The Company does not expect any difficulty in its ability to meet future pension funding requirements as it expects the amounts will be financed from a combination of cash generated from operations and amounts available for borrowing under existing credit facilities.

The contractual maturities of the Company's financial liabilities at December 31, 2009 follow.

| *(millions)* | **Total** | **2010** | **2011-2012** | **2013-2014** | **2015 onward** |
|---|---|---|---|---|---|
| Accounts payable and accrued charges | 65.7 | 65.7 | - | - | - |
| Security deposits | 1.7 | 1.1 | 0.6 | - | - |
| Credit facilities *(unsecured)* | 13.5 | - | 13.5 | - | - |
| Interest mortgage sinking fund bonds | 579.6 | 35.8 | 70.5 | 67.6 | 405.7 |
| First mortgage sinking fund bonds[1] | 468.9 | 5.2 | 10.4 | 39.0 | 414.3 |
| Total | 1,129.4 | 107.8 | 95.0 | 106.6 | 820.0 |

[1] *First mortgage sinking fund bonds are secured by a first fixed and specific charge on property, plant and equipment owned or to be acquired by the Company and by a floating charge on all other assets.*

Market Risk: Exposure to foreign exchange rate fluctuations is immaterial.

Market driven changes in interest rates and changes in the Company's credit ratings can cause fluctuations in interest costs associated with the Company's bank credit facilities. For the year ended December 31, 2009, each 25 basis points change in interest rates on the Company's credit facilities would have caused a $43,000 change in credit facility interest costs and a $29,000 change in earnings (2008 - $73,000 and $49,000, respectively).

The Company periodically refinances its credit facilities in the normal course with fixed-rate first mortgage sinking fund bonds thereby significantly mitigating exposure to interest rate changes.

Changes in interest rates and/or changes in the Company's credit ratings can affect the interest rate on first mortgage sinking fund bonds at the time of issue.

## 17. Financial Instruments (cont'd)

The Company's defined benefit pension plan is impacted by economic conditions. There is no assurance that the pension plan assets will earn the expected long-term rate of return in the future. Market driven changes impacting the performance of the pension plan assets may result in material variations from the expected long-term return on the assets. This may cause material changes in future pension liabilities and pension expense. Market driven changes impacting the discount rate may also result in material variations in future pension liabilities and pension expense. Effective January 1, 2009, pursuant to the 2010 GRA, the operation of the PEVDA is expected to significantly mitigate the impact on the Company's pension expense as described in Note 2.

## 18. Commitments

The Company is obligated to provide service to customers, resulting in ongoing capital expenditure commitments. Capital expenditures are subject to PUB approval. The Company's 2010 capital plan provides for capital expenditures of approximately $64.7 million and was approved by the PUB in November 2009.

## 19. Comparative Figures

The comparative financial statements have been reclassified from statements previously presented to conform to the presentation of the current year financial statements.

# Ten Year Summary

| | 2009[1] | 2008[1] | 2007[1] | 2006[1] | 2005 | 2004 | 2003 | 2002 | 2001 | 2000 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Income Statement Items** *($thousands)* | | | | | | | | | | |
| Revenue | 527,179 | 516,889 | 491,709 | 422,405 | 419,963 | 404,447 | 384,150 | 369,627 | 359,305 | 348,413 |
| Purchased power | 345,656 | 336,658 | 326,778 | 257,157 | 255,954 | 244,012 | 227,964 | 210,764 | 202,479 | 199,266 |
| Operating, pension and ERP costs | 51,988 | 50,172 | 53,202 | 53,996 | 53,812 | 51,755 | 51,799 | 50,767 | 52,908 | 52,486 |
| Amortization of capital assets[2] | 45,687 | 44,511 | 34,162 | 33,129 | 32,143 | 30,987 | 29,372 | 35,442 | 34,003 | 29,625 |
| Finance charges | 34,555 | 33,507 | 34,939 | 33,819 | 31,369 | 30,393 | 30,009 | 26,853 | 26,700 | 26,641 |
| Income taxes | 16,092 | 19,146 | 12,176 | 13,639 | 15,368 | 15,586 | 14,945 | 16,381 | 13,730 | 13,296 |
| Earnings applicable to common shares | 32,628 | 32,341 | 29,866 | 30,078 | 30,729 | 31,122 | 29,460 | 28,807 | 28,862 | 26,473 |
| **Balance Sheet Items** *($thousands)* | | | | | | | | | | |
| Property, plant and equipment | 1,230,371 | 1,181,433 | 1,173,642 | 1,119,820 | 1,085,106 | 1,050,913 | 1,009,448 | 949,478 | 914,735 | 865,406 |
| Intangible assets[3] | 37,287 | 37,633 | - | - | - | - | - | - | - | - |
| Accumulated amortization | 464,327 | 444,109 | 422,848 | 402,683 | 387,815 | 420,836 | 407,319 | 381,003 | 369,659 | 353,078 |
| Net capital assets | 803,331 | 774,957 | 750,794 | 717,137 | 697,291 | 630,077 | 602,129 | 568,475 | 545,076 | 512,328 |
| Total assets | 1,188,021 | 1,001,855 | 985,930 | 929,158 | 889,013 | 825,310 | 744,375 | 704,598 | 667,289 | 628,252 |
| Long-term debt[4] | 479,250 | 438,154 | 443,527 | 414,489 | 395,298 | 328,558 | 332,208 | 335,858 | 263,758 | 280,158 |
| Preference shares | 9,111 | 9,352 | 9,352 | 9,353 | 9,410 | 9,417 | 9,429 | 9,709 | 9,709 | 9,890 |
| Common equity | 381,185 | 373,738 | 356,671 | 335,887 | 323,972 | 316,360 | 299,480 | 279,515 | 260,203 | 250,331 |
| Total capital | 869,546 | 821,244 | 809,550 | 759,729 | 728,680 | 654,335 | 641,117 | 625,082 | 533,670 | 540,379 |
| **Operating Statistics** *(GWh)* | | | | | | | | | | |
| Sources of Electricity (normalized) | | | | | | | | | | |
| Purchased | 5,188 | 5,088 | 5,013 | 4,876 | 4,873 | 4,841 | 4,725 | 4,604 | 4,495 | 4,432 |
| Generated | 426 | 426 | 381 | 417 | 426 | 424 | 425 | 424 | 416 | 423 |
| Total | 5,614 | 5,514 | 5,394 | 5,293 | 5,299 | 5,265 | 5,150 | 5,028 | 4,911 | 4,855 |
| Sales (normalized) | | | | | | | | | | |
| Residential | 3,203 | 3,130 | 3,044 | 2,981 | 2,987 | 2,972 | 2,909 | 2,843 | 2,775 | 2,707 |
| Commercial and street lighting | 2,096 | 2,078 | 2,049 | 2,014 | 2,017 | 2,007 | 1,973 | 1,922 | 1,892 | 1,848 |
| Total | 5,299 | 5,208 | 5,093 | 4,995 | 5,004 | 4,979 | 4,882 | 4,765 | 4,667 | 4,555 |
| Electricity sales per employee | 9.3 | 9.5 | 9.2 | 9.0 | 9.0 | 8.3 | 8.1 | 7.8 | 7.5 | 6.9 |
| **Customers** *(year-end)* | | | | | | | | | | |
| Residential | 207,335 | 204,204 | 201,045 | 198,568 | 196,412 | 193,912 | 191,314 | 188,925 | 186,828 | 185,287 |
| Commercial and street lighting | 31,972 | 31,574 | 31,217 | 30,932 | 30,889 | 30,552 | 30,339 | 30,147 | 30,051 | 29,923 |
| Total | 239,307 | 235,778 | 232,262 | 229,500 | 227,301 | 224,464 | 221,653 | 219,072 | 216,879 | 215,210 |
| **Operating cost per customer** *($)*[5] | 214 | 208 | 213 | 212 | 218 | 220 | 225 | 223 | 231 | 230 |
| **Number of regular full-time employees** | 572 | 551 | 555 | 552 | 556 | 599 | 606 | 610 | 626 | 656 |

1 *Certain comparative figures have been reclassified to conform with current year presentation.*
2 *Amount for 2007 and 2006 is net of a regulatory deferral of $5.8 million, as approved by the PUB.*
3 *Beginning in 2008, intangible assets were reported separately on the Balance Sheet.*
4 *Net of deferred financing charges in 2009, 2008 and 2007.*
5 *Operating cost per customer is calculated excluding pension and early retirement program costs.*


Jocelyn Perry
Vice President, Finance and Chief Financial Officer
Peter Alteen
Vice President, Regulation and Planning
Gary Smith
Vice President, Customer Operations and Engineering
Earl Ludlow
President and Chief Executive Officer

# Connected to our Communities

We are proud that community groups throughout the province can count on us for support. We were pleased to provide financial, in-kind and hands-on assistance to the following organizations and many more in 2009:

## Health

The Dr. H. Bliss Murphy Cancer Care Foundation, PRIORITY: The Campaign for Cancer Care, The Burin Peninsula Health Care Foundation, The Western Memorial Health Care Foundation, The Children's Wish Foundation, The Newfoundland & Labrador Down Syndrome Society, Juvenile Diabetes Research Foundation, The Arthritis Society (Newfoundland and Labrador Division), Alzheimer Society of Newfoundland & Labrador, Trinity Conception Placentia Health Care Foundation, Janeway Children's Hospital Foundation, Learning Disabilities Association of Newfoundland & Labrador, Heart and Stroke Foundation of Newfoundland & Labrador, Canadian Blood Services, Canadian Mental Health Association

## Safety

Newfoundland & Labrador Association of Fire Services, Firefighter Electricity Safety Training, Learn Not to Burn Program, Child Find Newfoundland & Labrador, School Electricity Safety Program, Safety Services Newfoundland Labrador, Newfoundland & Labrador Crime Stoppers, Newfoundland & Labrador Snowmobile Federation, Triple Bay Eagles Ground Search and Rescue

## Environment

Atlantic Salmon Federation, Tree Canada, Newfoundland & Labrador Home Builders' Association, Thomas Howe Demonstration Forest, Trans Canada Trail Foundation, Marystown Community Pride, Rennies River Development Foundation, Corner Brook Stream Development Corporation

## Education & Youth

Junior Achievement of Newfoundland & Labrador, Memorial University of Newfoundland, College of the North Atlantic, Newfoundland & Labrador Science Centre, Newfoundland & Labrador High School Athletic Federation, Scouts Canada, Church Lads' Brigade, Special Olympics

## Community

Newfoundland & Labrador Region of the Canadian Red Cross, Community Food Sharing Association, Coats for Kids, Habitat for Humanity, Community Services Council Newfoundland & Labrador

## Arts & Culture

Newfoundland Symphony Orchestra, Kiwanis Music Festival Association, Resource Centre for the Arts

# Board of Directors

Peggy Bartlett
President
Bartlett Enterprises Inc.
Grand Falls-Windsor,
Newfoundland & Labrador

Frank Davis
Corporate Director
St. John's,
Newfoundland & Labrador

Ed Drover
Financial Advisor & President
Ringwood Wealth
Management Inc.
St. John's,
Newfoundland & Labrador

Georgina Hedges
Owner/Operator
The Doctor's Inn
Eastport,
Newfoundland & Labrador

Earl Ludlow
President & Chief Executive Officer
Newfoundland Power Inc.
St. John's,
Newfoundland & Labrador

David Norris
Corporate Director
St. John's,
Newfoundland & Labrador

Fred O'Brien
President & Chief Executive Officer
Maritime Electric Company, Limited
Charlottetown,
Prince Edward Island

Barry Perry
Vice President, Finance &
Chief Financial Officer
Fortis Inc.
St. John's,
Newfoundland & Labrador

Bruce Simmons
President & Chief Executive Officer
Hammond Farm Ltd.
Corner Brook,
Newfoundland & Labrador

John Walker
President & Chief Executive Officer
FortisBC Inc.
Kelowna,
British Columbia

Jo Mark Zurel
President
Stonebridge Capital Inc.
St. John's,
Newfoundland & Labrador

# Investor Information

## Head Office

55 Kenmount Road, P.O. Box 8910
St. John's, NL A1B 3P6
Tel: (709) 737-2802
Fax: (709) 737-5300

## Share Transfer Agent and Registrar

Computershare Trust Company of Canada
1500 University Street, Suite 700
Montreal, QC H3A 3S8
Tel: (514) 982-7888
Fax: (514) 982-7635
computershare.com

## Annual General Meeting

Wednesday, May 5, 2010 at 8:00 a.m.
Main Boardroom, 3rd Floor
Newfoundland Power Inc.
55 Kenmount Road
St. John's, NL A1B 3P6

## Investor Information

Peter Alteen, Corporate Secretary
55 Kenmount Road, P.O. Box 8910
St. John's, NL A1B 3P6
Tel: (709) 737-5859
palteen@newfoundlandpower.com

## Website

newfoundlandpower.com

## Email

contactus@newfoundlandpower.com

## Fortis Websites

Fortis Inc.
fortisinc.com
FortisAlberta Inc.
fortisalberta.com
FortisBC Inc.
fortisbc.com
Terasen Gas
terasengas.com
FortisOntario Inc.
fortisontario.com
Maritime Electric Company, Limited
maritimeelectric.com
Belize Electricity Limited
bel.com.bz
Caribbean Utilities Company, Ltd.
cuc-cayman.com
Fortis Properties Corporation
fortisproperties.com
Fortis Turks and Caicos
provopowercompany.com

Special thanks to:
Inside front cover, Jeff Wareham; Page 4 (Back L-R), Dianne Drover, Keith Barrett, Bernice Whalen, Dave Lewis; (Front L-R), Glenn Fisher, Heather Carter, Lillian Decker; Page 6 (L-R), David Norris, Earl Ludlow; Page 10, Russ Kennedy; Page 12, Peter Upshall; Page 14, Tina Slade; Page 16 (L-R), Colleen Combden, Trina White, Blair Clarke, Rose Chafe, Edgar Lopez; Page 18, Alex Collins; Page 20 (L-R), Blake Shelley, Randy White.

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Corporate Communications, Newfoundland Power Inc.


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NEWFOUNDLAND
POWER
A FORTIS COMPANY

**IN THE MATTER OF**
the 2009 Annual Returns
of Newfoundland Power
Inc. filed pursuant to
Section 59(2) of the
*Public Utilities Act.*

## AFFIDAVIT

I, Jocelyn Perry, of the Town of Conception Bay South in the Province of Newfoundland and Labrador, Chartered Accountant, make oath and say as follows:

1. That I am Vice-President, Finance and Chief Financial Officer of Newfoundland Power Inc.

2. That to the best of my knowledge, information and belief, the information contained in the 2009 Annual Report and accompanying returns of Newfoundland Power Inc., filed with the Board of Commissioners of Public Utilities pursuant to section 59(2) of the *Public Utilities Act* is true and accurate.

**SWORN** to before me at St. John's
in the Province of Newfoundland and Labrador
this 1st day of April, 2010:

Barrister – Newfoundland & Labrador

Jocelyn Perry

# Newfoundland Power Inc.
## Names and Addresses of Officers and Directors
## as of December 31, 2009

| Name | Address | Position Held |
|---|---|---|
| **Peter Alteen** | 38 Mansfield Crescent<br>St. John's, NL A1E 5E3 | Vice President; Corporate Secretary |
| **Peggy Bartlett** | 173 Grenfell Heights<br>Grand Falls-Windsor, NL A2A 2J7 | Director |
| **Frank Davis** | 2 Crabapple Place<br>St. John's, NL A1A 5L7 | Director |
| **E.M. (Ed) Drover** | 44 Long Pond Road<br>St. John’s, NL A1B 1N7 | Director |
| **Georgina Hedges** | 5 Burden’s Road<br>Eastport, NL A0G 1Z0 | Director |
| **Lisa Hutchens**[1] | 88 Marine Drive<br>Logy Bay-Middle Cove-Outer Cove, NL A1K 3C7 | Vice President |
| **Earl Ludlow** | 33 Ortega Drive<br>Paradise, NL A1L 2L1 | President and Chief Executive Officer; Director |
| **David Norris** | 23 Mountbatten Drive<br>St. John's, NL A1A 3Y1 | Chair, Board of Directors |
| **Fred O'Brien** | 389 Church Street<br>Alberton, PEI C0B 1B0 | Director |
| **Barry Perry** | 14 Collingwood Crescent<br>Mount Pearl, NL A1N 5C6 | Director |

[1] Ms. Hutchens’ employment with the Company terminated effective January 12, 2010.

**Newfoundland Power Inc.**
**Names and Addresses of Officers and Directors**
**as of December 31, 2009**

| Name | Address | Position Held |
|---|---|---|
| **Jocelyn Perry** | 6 Maple Street<br>Conception Bay South, NL A1W 5M8 | Vice President and Chief Financial Officer |
| **Bruce Simmons** | 1 Hammond Drive<br>Little Rapids, NL A2H 2N2 | Director |
| **Gary Smith** | 89 Cheyne Drive<br>St. John's, NL A1A 5W5 | Vice President |
| **John Walker** | 617 Almandine Court<br>Kelowna, BC V1W 4Z5 | Director |
| **Jo Mark Zurel** | 16 Regent Street<br>St. John's, NL A1A 5A4 | Director |

**Newfoundland Power Inc.**
**Computation of Average Rate Base**
**For The Years Ended December 31**
**($000's)**

| | | 2009 | 2008 |
|---|---|---|---|
| 1 | **Net Plant Investment** | | |
| 2 | Plant Investment - Return 4 | 1,338,408 | 1,286,039 |
| 3 | Accumulated Amortization - Return 6 | (562,009) | (539,654) |
| 4 | Contributions in Aid of Construction - Return 7 | (29,017) | (25,884) |
| 5 | | 747,382 | 720,501 |
| 6 | | | |
| 7 | **Additions to Rate Base** | | |
| 8 | Deferred Charges - Return 8 | 103,761 | 100,321 |
| 9 | Deferred Energy Replacement Costs - Return 9 | 383 | 766 |
| 10 | Cost Recovery Deferral - Hearing Costs - Return 9 | 201 | 402 |
| 11 | Cost Recovery Deferral - Depreciation - Return 9 | 3,862 | 7,724 |
| 12 | Cost Recovery Deferral - Conservation - Return 9 | 948 | - |
| 13 | Customer Finance Programs - Return 10 | 1,679 | 1,776 |
| 14 | Weather Normalization Reserve - Return 17 | 3,919 | 5,910 |
| 15 | | 114,753 | 116,899 |
| 16 | | | |
| 17 | **Deductions from Rate Base** | | |
| 18 | Municipal Tax Liability - Return 9 | 1,363 | 2,727 |
| 19 | Unrecognized 2005 Unbilled Revenue - Return 9 | 4,618 | 9,236 |
| 20 | Customer Security Deposits - Return 10 | 581 | 785 |
| 21 | Accrued Pension Obligation - Return 10 | 3,379 | 3,142 |
| 22 | Future Income Taxes - Return 23 | 2,297 | 1,184 |
| 23 | Demand Management Incentive Account - Return 18 | - | 426 |
| 24 | Purchased Power Unit Cost Variance Reserve - Return 19 | 447 | 895 |
| 25 | | 12,685 | 18,395 |
| 26 | | | |
| 27 | **Year End Rate Base** | 849,450 | 819,005 |
| 28 | | | |
| 29 | **Average Rate Base Before Allowances** | 834,228 | 806,833 |
| 30 | | | |
| 31 | **Rate Base Allowances** | | |
| 32 | Materials and Supplies Allowance - Return 11 | 4,366 | 4,327 |
| 33 | Cash Working Capital Allowance - Return 12 | 9,899 | 9,716 |
| 34 | | | |
| 35 | **Average Rate Base at Year End** | 848,493 | 820,876 |

**Newfoundland Power Inc.**
**Plant Investment**
**For The Year Ended December 31, 2009**
**($000's)**

| | Opening Balance | Adjustments[1] | Additions | Retirements | Year End Balance |
|---|---|---|---|---|---|
| Power Generation | | | | | |
| Hydro | 138,593 | (4) | 9,240 | 818 | 147,011 |
| Diesel | 3,005 | 2 | 37 | 10 | 3,034 |
| Gas Turbine | 17,899 | 2 | 174 | 32 | 18,043 |
| | 159,497 | - | 9,451 | 860 | 168,088 |
| Substations | 133,469 | - | 9,579 | 1,319 | 141,729 |
| Transmission | 98,266 | - | 4,637 | 620 | 102,283 |
| Distribution | 737,931 | - | 38,556 | 5,738 | 770,749 |
| General Property | 50,636 | - | 657 | 348 | 50,945 |
| Transportation | 22,468 | - | 2,182 | 1,933 | 22,717 |
| Communications | 10,588 | - | 440 | 319 | 10,709 |
| Computer Software | 30,988 | - | 1,529 | 2,775 | 29,742 |
| Computer Hardware | 9,687 | - | 2,105 | 2,620 | 9,172 |
| Government Contributions | 23,109 | - | - | - | 23,109 |
| | 1,117,142 | - | 59,685 | 15,672 | 1,161,155 |
| Total Depreciable Plant | 1,276,639 | - | 69,136 | 16,532 | 1,329,243 |
| Non Depreciable Land | 9,400 | - | - | 235 | 9,165 |
| Plant Investment Included In Rate Base | 1,286,039 | - | 69,136 | 16,767 | 1,338,408 |
| Construction Work In Progress | | | | | 3,027 |
| Total Plant Investment[2] | | | | | 1,341,435 |

[1] Adjustments are due to asset reclassification and redistribution of original cost based on final project details.

[2] A reconciliation of the Total Plant Investment used in the calculation of average rate base for 2009 to the plant investment shown in Return 1 is as follows:

| | |
|---|---|
| 2009 Capital Assets shown in Return 1 (Note 7 to Financial Statements) | 1,230,371 |
| Add: Contributions in Aid of Construction - Return 7 | 78,039 |
| Add: Plant Investment classified as Intangibles (Note 9 to Financial Statements) | 37,287 |
| Deduct: Inventories included in Plant Investment for financial reporting purposes | (4,263) |
| Rounding | 1 |
| 2009 Total Plant Investment | 1,341,435 |

**Newfoundland Power Inc.**
**Capital Expenditure**
**For The Year Ended December 31, 2009**
**($000's)**

| | Approved By Board[1] | Actual | Variance[2] |
|---|---|---|---|
| Generation | | | |
| Hydro | 8,899 | 8,235 | (664) |
| Thermal | 100 | 202 | 102 |
| | 8,999 | 8,437 | (562) |
| Substations | 7,469 | 7,732 | 263 |
| Transmission | 4,507 | 4,520 | 13 |
| Distribution | 31,046 | 37,916 | 6,870 |
| General Property | 835 | 628 | (207) |
| Transportation | 2,255 | 2,087 | (168) |
| Telecommunications | 350 | 422 | 72 |
| Information Systems | 3,725 | 3,569 | (156) |
| Unforeseen | 1,835 | 1,049 | (786) |
| General Expenses Capital | 2,800 | 3,040 | 240 |
| | 63,821 | 69,400 | 5,579 |
| Projects carried forward from 2008[3] | | 934 | |

[1] Approved by Order Nos. P.U. 27 (2008), P.U. 29 (2009), P.U. 32 (2009) and P.U. 38 (2009).

[2] Variance explanations are provided in Newfoundland Power Inc.'s 2009 Capital Expenditure Report filed with the Board on February 26, 2010.

[3] The projects carried forward from 2008 include $81,000 from the wind turbine interconnection at Fermeuse Substation and $853,000 from the Water Street Underground project.

**Newfoundland Power Inc.**
**Accumulated Amortization**
**For The Year Ended December 31, 2009**
**($000's)**

| | |
|---|---|
| Opening Balance - January 1, 2009 | 539,654 |
| | |
| Add: | |
| Amortization of Fixed Assets[1] | 41,825 |
| Amortization of Contributions - Government - Return 7 | 45 |
| Amortization of Contributions - Customers - Return 7 | 1,393 |
| Salvage | 586 |
| | 43,849 |
| | |
| Deduct: | |
| Cost of Removal (Net of Income Tax) | 4,727 |
| Retirements | 16,767 |
| | 21,494 |
| | |
| Closing Balance - December 31, 2009[2] | 562,009 |

[1] The amortization rates for 2009 are from the 2006 Depreciation Study based on plant in service at December 31, 2005 and approved in Order No. P.U. 32 (2007).

| | |
|---|---|
| Hydro | 2.17% |
| Diesel | 4.28% |
| Gas Turbine | 4.81% |
| Substations | 2.63% |
| Transmission | 3.28% |
| Distribution | 3.14% |
| General Property | 2.94% |
| Transportation | 10.28% |
| Telecommunications | 6.18% |
| Computer Software | 10.00% |
| Computer Hardware | 20.00% |

[2] The accumulated amortization shown in Return 1 (Note 7 to the Financial Statements) is before adjustment for contributions in aid of construction, site restoration costs and intangibles.

| | |
|---|---|
| Accumulated Amortization shown in Return 1 (Note 7) | 443,153 |
| Add: Amortization of Contributions - Return 7 | 49,022 |
| Add: Site Restoration Costs - Return 1 (Note 4) | 48,660 |
| Add: Accumulated Depreciation classified as Intangibles (Note 9) | 21,174 |
| 2009 Accumulated Amortization for Average Rate Base | 562,009 |

**Newfoundland Power Inc.**
**Contributions in Aid of Construction**
**For The Year Ended December 31, 2009**
**($000's)**

| | | Customers | Government | Total |
|---|---|---|---|---|
| 1 | Gross Contributions to January 1, 2009 | 50,360 | 23,108 | 73,468 |
| 2 | | | | |
| 3 | Add: Contributions Received in 2009 | 4,571 | - | 4,571 |
| 4 | | | | |
| 5 | Gross Contributions to December 31, 2009 | 54,931 | 23,108 | 78,039 |
| 6 | | | | |
| 7 | | | | |
| 8 | Amortizations to January 1, 2009 | 25,101 | 22,483 | 47,584 |
| 9 | | | | |
| 10 | Add: Amortization in 2009 | 1,393 | 45 | 1,438 |
| 11 | | | | |
| 12 | Amortizations to December 31, 2009 | 26,494 | 22,528 | 49,022 |
| 13 | | | | |
| 14 | | | | |
| 15 | Unamortized Contributions to December 31, 2009 | 28,437 | 580 | 29,017 |

**Newfoundland Power Inc.**
**Deferred Charges**
**For The Year Ended December 31, 2009**
**($000's)**

| | Balance January 1 2009 | Additions During 2009 | Reductions During 2009 | Balance December 31 2009 |
|---|---|---|---|---|
| Deferred Pension Costs[1] | 100,196 | 4,866 | 1,339 | 103,723 |
| Capital Stock Issue Expenses | 75 | - | 37 | 38 |
| Deferred Credit Facility Issue Costs | 50 | - | 50 | - |
| Deferred Charges Included in Rate Base | 100,321 | 4,866 | 1,426 | 103,761 |

[1] The December 31, 2009 balance includes $5.9 million in pension costs associated with the 2005 Early Retirement Program. These pension costs were originally $11.3 million and are being amortized over ten years, beginning April 1, 2005.

**Newfoundland Power Inc.**
**Regulatory Deferrals**
**For The Year Ended December 31, 2009**
**($000's)**

| | Balance January 1 2009 | Additions During 2009 | Reductions During 2009 | Balance December 31 2009 |
|---|---|---|---|---|
| **Cost Recovery Deferrals** | | | | |
| Deferred Energy Replacement Costs[1] | 766 | - | 383 | 383 |
| Cost Recovery Deferral - Depreciation[1] | 7,724 | - | 3,862 | 3,862 |
| Deferred Hearing Costs[1] | 402 | - | 201 | 201 |
| Deferred Conservations Costs[2] | - | 948 | - | 948 |
| | | | | |
| **Revenue Deferrals[1]** | | | | |
| Municipal Tax Liability | 2,727 | - | 1,364 | 1,363 |
| Unrecognized 2005 Unbilled Revenue | 9,236 | - | 4,618 | 4,618 |

[1] In Order No. P.U. 32 (2007), the Board approved a 3-year amortization of these cost recovery and revenue deferrals.

[2] In Order No. P.U. 13 (2009), the Board approved the deferral of certain costs related to the implementation of the conservation plan in 2009.

**Newfoundland Power Inc.**
**Other Rate Base Assets and Liabilities**
**For The Year Ended December 31, 2009**
**($000's)**

| | Balance January 1 2009 | Change During 2009 | Balance December 31 2009 |
|---|---|---|---|
| **Assets** | | | |
| Customer Finance Programs[1] | 1,776 | (97) | 1,679 |
| **Liabilities** | | | |
| Accrued Pension Obligation[2] | 3,142 | 237 | 3,379 |
| Customer Security Deposits[3] | 785 | (204) | 581 |

[1] Comprised of loans provided to customers related to customer conservation programs and contributions in aid of construction.

[2] Executive and Senior Management supplemental pension benefits comprised of a defined benefit plan (PUP) and a defined contribution plan (SERP). The PUP was closed to new entrants in 1999.

[3] Security deposits received from customers for electrical service in accordance with the Board-approved Schedule of Rates, Rules and Regulations.

**Newfoundland Power Inc.**
**Materials and Supplies Allowance**
**For The Years Ended December 31**
**($000's)**

| | **2009**[1] | **2008**[1] |
|---|---|---|
| Opening - January 1 | 5,391 | 5,248 |
| January | 5,224 | 5,356 |
| February | 5,701 | 5,543 |
| March | 5,662 | 5,663 |
| April | 5,825 | 5,365 |
| May | 5,352 | 5,448 |
| June | 5,526 | 5,562 |
| July | 5,332 | 5,271 |
| August | 5,444 | 5,369 |
| September | 5,337 | 5,191 |
| October | 5,197 | 5,249 |
| November | 5,231 | 5,145 |
| December | 5,197 | 5,391 |
| Total | 70,419 | 69,801 |
| Average | 5,417 | 5,369 |
| Less: Expansion (19.4%)[2] | 1,051 | 1,042 |
| Materials and Supplies Allowance | 4,366 | 4,327 |

[1] The 2008 and 2009 materials and supplies allowance calculation reflects a 13-month average as approved by the Board in Order No. P.U. 32 (2007).

[2] The expansion factor of 19.4% is based on the 2008 cash working capital study approved by the Board in Order No. P.U. 32 (2007).

**Newfoundland Power Inc.**
**Cash Working Capital Allowance[1]**
**For The Years Ended December 31**
**($000's)**

| | 2009 | 2008 |
|---|---|---|
| Gross Operating Costs[2] | 395,731 | 382,799 |
| Current Income Taxes - Return 22 | 15,590 | 20,131 |
| Municipal Taxes Paid | 12,942 | 12,394 |
| Non-regulated Expenses (net of income taxes) | (1,203) | (995) |
| Total operating expenses | 423,060 | 414,329 |
| Cash Working Capital Factor | 2.1% | 2.1% |
| | 8,884 | 8,701 |
| HST Adjustment | 1,015 | 1,015 |
| Cash Working Capital Allowance | 9,899 | 9,716 |

[1] The cash working capital allowance for 2008 and 2009 is calculated based on the method used to calculate the 2008 Test Year average rate base approved by the Board in Order No. P.U. 32 (2007).

[2] In accordance with the methodology approved in Order No. P.U. 32 (2007), gross operating costs for 2009 used in the calculation of the 2009 cash working capital allowance are net of non-cash related amortizations.

**Newfoundland Power Inc.**
**Return on Average Rate Base[1]**
**For The Years Ended December 31**
**($000's)**

| | 2009 | 2008 |
|---|---|---|
| Net Earnings from Return 1 | 33,201 | 32,895 |
| Add: Non-regulated (net of income taxes) | 1,203 | 995 |
| | 34,404 | 33,890 |
| | | |
| Finance Costs | | |
| Interest on Long-term Debt | 34,547 | 32,334 |
| Other Interest | 402 | 1,456 |
| Amortization of Debt Issue Expenses | 235 | 235 |
| AFUDC | (675) | (618) |
| | 34,509 | 33,407 |
| | | |
| Regulated Earnings | 68,913 | 67,297 |
| | | |
| Average Rate Base from Return 3 | 848,493 | 820,876 |
| | | |
| Rate of Return on Average Rate Base | 8.12% | 8.20% |

| | 2009 | 2008 |
|---|---|---|
| Average Rate Base from Return 3 | 848,493 | 820,876 |
| | | |
| Upper Limit of the Allowed Range of Return on Average Rate Base[2] | 8.55% | 8.55% |
| | | |
| Upper Limit of Allowed Regulated Earnings | 72,546 | 70,185 |
| | | |
| Regulated Earnings | 68,913 | 67,297 |
| | | |
| Excess Revenue net of Income Taxes | - | - |
| | | |
| Income Taxes | - | - |
| | | |
| Excess Revenue | - | - |

[1] The return on average rate base is calculated in accordance with the methodology approved in Order No. P.U 32 (2007).

[2] Based on a return on rate base of 8.37% plus 18 basis points, as approved in Order No. P.U. 32 (2007) for 2008 and Order No. P.U. 35 (2008) for 2009.

**Newfoundland Power Inc.**
**Details of Normalized Sales and Revenue**
**For The Years Ended December 31**
**($000's)**

| | | 2009 | | | 2008 | | |
|---|---|---|---|---|---|---|---|
| | | Gigawatt Hours | Year End Customer Accounts | Revenue | Gigawatt Hours | Year End Customer Accounts | Revenue |
| **Revenue From Rates** | | | | | | | |
| Domestic | 1.1 | 3,203.3 | 207,335 | 309,360 | 3,130.3 | 204,204 | 302,916 |
| General Service: | | | | | | | |
| 0 - 10 kW | 2.1 | 89.8 | 12,036 | 11,840 | 88.8 | 11,920 | 11,742 |
| 10 - 100 kW | 2.2 | 640.9 | 8,770 | 63,318 | 641.8 | 8,626 | 63,129 |
| 110 - 1000 kVA | 2.3 | 890.5 | 1,088 | 74,182 | 878.5 | 1,061 | 72,997 |
| 1000 kVA and Over | 2.4 | 438.0 | 68 | 31,675 | 432.3 | 65 | 31,208 |
| Total General Service | | 2,059.2 | 21,962 | 181,015 | 2,041.4 | 21,672 | 179,076 |
| Street & Area Lighting | 4.1 | 36.5 | 10,010 | 12,862 | 36.5 | 9,902 | 12,722 |
| Forfeited Discounts | | - | - | 2,644 | - | - | 2,646 |
| Revenue From Rates | | 5,299.0 | 239,307 | 505,881 | 5,208.2 | 235,778 | 497,360 |
| **Adjustments and Transfers** | | | | | | | |
| Transfer From (To) RSA | | | | 2,878 [1] | | | (948) |
| 2005 Unbilled Revenue Accrual | | | | 4,618 [2] | | | 7,210 |
| Total Adjustments and Transfers | | | | 7,496 | | | 6,262 |
| **Other Revenue** | | | | | | | |
| Joint Use Revenue | | | | 9,219 | | | 8,861 |
| Wheeling Revenue | | | | 566 | | | 615 |
| Amortization of Municipal Tax Liability | | | | 1,364 [3] | | | 1,362 |
| Interest on Overdue Customer Accounts | | | | 818 | | | 1,155 |
| Other Non-Electrical Revenue | | | | 1,835 | | | 1,274 |
| Total Other Revenue | | | | 13,802 | | | 13,267 |
| **Total Revenue - Return 1** | | | | **527,179** | | | **516,889** |

[1] The transfer from the RSA in 2009 of $2,878,000 is related to the operation of the Energy Supply Cost Variance Adjustment.

[2] In Order No. P.U. 32 (2007), the Board approved a 3-year amortization of the 2005 Unbilled Revenue remaining balance.

[3] In Order No. P.U. 32 (2007), the Board approved a 3-year amortization of the municipal tax liability beginning in 2008.

**Newfoundland Power Inc.**
**Normalized Production and Sales Statistics**
**For The Years Ended December 31**
**($000's)**

| | 2009 | 2008 |
|---|---|---|
| Gigawatt Hours - Purchased | 5,187.9 | 5,088.0 |
| Gigawatt Hours - Produced | 425.9 | 425.8 |
| Total Purchased & Produced | 5,613.8 | 5,513.8 |
| Gigawatt Hours - Sold & Used | 5,310.6 | 5,219.9 |
| Gigawatt Hours - Losses | 303.2 | 293.9 |
| Losses Expressed as a Percentage of Total Purchased & Produced | 5.4% | 5.3% |
| Purchased Power Annual Billing Demand in kW | 1,119,136 | 1,074,714 |

**Newfoundland Power Inc.**
**Rate Stabilization Account**
**For The Year Ended December 31, 2009**
**($000's)**

| Month | Opening Balance | Adjustments | RSA Billed During Month | Municipal Taxes | Excess Fuel Costs | Secondary Energy Costs | Interest Costs | Transfer To (From) Nfld. Hydro | Closing Balance |
|---|---|---|---|---|---|---|---|---|---|
| January | 2,490.0 | - | (4,589.7) | - | 9.3 | - | 17.4 | 4,781.0 | 2,708.0 |
| February | 2,708.0 | - | (4,760.9) | - | 4.1 | (0.1) | 18.9 | 4,063.6 | 2,033.6 |
| March | 2,033.6 | (641.3) [1] | (4,378.2) | - | 11.0 | (0.1) | 14.2 | 4,151.5 | 1,190.7 |
| April | 1,190.7 | - | (3,836.3) | - | 7.3 | (1.1) | 8.3 | 3,171.9 | 540.8 |
| May | 540.8 | - | (3,122.1) | - | 16.2 | (119.5) | 3.8 | 2,631.3 | (49.5) |
| June | (49.5) | - | (2,560.1) | - | 7.2 | (242.3) | (0.3) | 2,287.6 | (557.4) |
| July | (557.4) | - | (1,194.6) | - | 29.3 | (39.4) | (3.9) | 128.8 | (1,637.2) |
| August | (1,637.2) | - | (187.7) | - | 88.8 | 39.4 | (11.6) | 124.7 | (1,583.6) |
| September | (1,583.6) | - | (191.0) | - | 28.6 | - | (11.0) | 130.8 | (1,626.2) |
| October | (1,626.2) | - | (217.5) | - | 4.6 | - | (11.3) | 182.5 | (1,667.9) |
| November | (1,667.9) | - | (297.4) | - | 2.8 | - | (11.6) | 198.1 | (1,776.0) |
| December | (1,776.0) | 2,877.6 [2] | (332.9) | 393.1 [3] | 18.0 | - | (12.4) | 250.9 | 1,418.3 |
| | | 2,236.3 | (25,668.4) | 393.1 | 227.2 | (363.1) | 0.5 | 22,102.7 | |

[1] This is the disposition of the 2008 year-end balance in the Demand Management Incentive Account, as well as the related income tax effects, approved in Order No. P.U. 21 (2009).

[2] This is the Energy Supply Cost Variance for 2009 approved in Order No. P.U. 32 (2007).

[3] This is the difference between total municipal taxes collected from customers through rates and the total taxes paid to municipalities for 2009.

**Newfoundland Power Inc.**
**Weather Normalization Reserve**
**For The Year Ended December 31, 2009**
**($000's)**

| | |
|---|---|
| **Degree Day Normalization Reserve Transfer** | |
| Revenue Adjustment | |
| Heating Degree Days | 7,241 |
| Cooling Degree Days | - |
| Wind Speed Adjustments | (1,483) |
| Total Revenue Adjustment | 5,758 |
| Less : Power Purchased Adjustment | |
| Heating Degree Days | 8,345 |
| Cooling Degree Days | - |
| Wind Speed Adjustments | (1,682) |
| Total Power Purchased Adjustment | 6,663 |
| Net Adjustment (Before Tax) | (905) |
| Less: Income Tax @ 33.0% | (299) |
| Net Adjustment (After Tax) | (606) |
| Amortization of Weather Normalization Reserve[1] | (1,366) |
| Net Transfer (To) From Degree Day Normalization Reserve | (1,972) |
| **Hydro Production Equalization Reserve Transfer** | |
| Transfer (To) From Reserve (Before Tax) | (29) |
| Less: Income Tax @ 33.0% | (10) |
| Net Transfer (To) From Hydro Production Equalization Reserve | (19) |
| **Net Transfer (To) From Weather Normalization Reserve** | **(1,991)** |

| | **Weather Normalization Account Balances** | | |
|---|---|---|---|
| | **Balance at January 1 2009** | **Net Transfers** | **Balance at December 31 2009[2]** |
| Degree Day Reserve | 4,567 | (1,972) | 2,595 |
| Hydro Equalization Reserve | 1,343 | (19) | 1,324 |
| | 5,910 | (1,991) | 3,919 |

[1] This is the amortization of a non-reversing balance in the degree day normalization reserve as approved by the Board in Order No. P.U. 32 (2007).

[2] A positive balance in the weather normalization reserve reflects amounts to be recovered from customers in future periods. A negative balance in the weather normalization reserve reflects amounts owed to customers.

**Newfoundland Power Inc.**
**Demand Management Incentive Account**
**For The Year Ended December 31, 2009**
**($000's)**

| | |
|---|---|
| **Demand Management Incentive Account Transfer** | |
| Demand Supply Cost Variance | (104) |
| Demand Management Incentive (+/-)[1] | 529 |
| Supply Cost Variance Outside Deadband | - |
| Less: Income Tax @ 33.0% | - |
| **Net Transfer (To) From Demand Management Incentive Account** | - |
| **Demand Management Incentive Account Balance** | |
| Balance at January 1, 2009 | (426) |
| Net Transfer (To) From Demand Management Incentive Account | 426 |
| Balance at December 31, 2009[2] | - |

[1] The demand management incentive of $529,000 is plus/minus 1% of test year wholesale demand charges. The Demand Management Incentive Account definition was approved by the Board in Order No. P.U. 32 (2007).

[2] In accordance with Order No. P.U. 32 (2007), Newfoundland Power filed a report with the Board on February 19, 2010 pertaining to the operation of the Demand Management Incentive Account for 2009.

# Newfoundland Power Inc.
## Purchased Power Unit Cost Variance Reserve
## For The Year Ended December 31, 2009
## ($000's)

**Purchased Power Unit Cost Variance Reserve Balance**

| | |
|---|---|
| Balance at January 1, 2009 | (895) |
| 2009 Amortization[1] | 448 |
| Balance at December 31, 2009 | (447) |

[1] In Order No. P.U. 32 (2007), the Board approved a 3-year amortization of the 2006 year end balance in the Purchased Power Unit Cost Variance Reserve of $1,342,000. The balance in the PPUCVR will be fully amortized at December 31, 2010. Beginning in 2008, the PPUCVR has been replaced by the Demand Management Incentive Account.

**Newfoundland Power Inc.**
**Statement of Operating & General Expenses**
**For The Year Ended December 31, 2009**
**($000's)**

| | 2009 | 2008 | Variances[1] |
|---|---|---|---|
| Operating Expenses | | | |
| Purchased Power | 345,656 | 336,658 | 8,998 |
| Power Produced | 2,527 | 2,552 | (25) |
| Administrative and Engineering Support | 6,120 | 5,604 | 516 |
| Environmental Policy | 385 | 398 | (13) |
| Substations | 2,300 | 2,123 | 177 |
| Transmission | 482 | 585 | (103) |
| Distribution | 7,172 | 6,592 | 580 |
| Communications | 1,381 | 1,394 | (13) |
| Fleet Operating and Maintenance Expense | 1,443 | 1,572 | (129) |
| | 367,466 | 357,478 | 9,988 |
| General Expenses | | | |
| Customer Service | 11,789 | 10,363 | 1,426 |
| Financial Services | 1,505 | 1,494 | 11 |
| Information Systems | 2,695 | 2,487 | 208 |
| Pension Costs | 2,673 | 3,040 | (367) |
| Retirement Allowances | 119 | 307 | (188) |
| Corporate and Employee Services | 14,589 | 13,458 | 1,131 |
| | 33,370 | 31,149 | 2,221 |
| Total Operating & General Expenses | 400,836 | 388,627 | 12,209 |
| Less: Transfers to General Expenses Capitalized | 1,836 | 1,797 | 39 |
| Transfers to Conservation Deferral | 1,356 | - | 1,356 |
| **Total Expenses[2]** | **397,644** | **386,830** | **10,814** |

[1] Variances are explained in Return 21.

[2] This is equal to the total of purchased power costs, operating expenses and pension costs shown in Return 1.

# Newfoundland Power Inc.
## Explanation of Expense Variances
## 2009 versus 2008
## ($000's)

| | 2009 | 2008 | Increase (Decrease) |
|---|---|---|---|
| **Total Expenses** | **397,644** | **386,830** | **10,814** |

Total expenses for 2009 increased by $10.8 million, or 2.8 per cent over 2008. This increase was due primarily to higher purchased power, customer service and corporate and employee service expenses.

The following is an explanation of significant variances for individual operating and general expense classes.

| | 2009 | 2008 | Increase (Decrease) |
|---|---|---|---|
| **Purchased Power** | **345,656** | **336,658** | **8,998** |

The increase in Purchased Power expense in 2009 was a result of higher energy sales as well as higher demand charges. This was partially offset by the 2008 leap year which amounted to one less day of purchases in 2009.

| | 2009 | 2008 | Increase (Decrease) |
|---|---|---|---|
| **Power Produced** | **2,527** | **2,552** | **(25)** |

The Power Produced costs for 2009 were in line with costs for 2008.

| | 2009 | 2008 | Increase (Decrease) |
|---|---|---|---|
| **Administrative and Engineering Support** | **6,120** | **5,604** | **516** |

The increase in Administrative and Engineering Support costs was primarily due to inflation impacts and higher employee benefits costs in 2009.

| | 2009 | 2008 | Increase (Decrease) |
|---|---|---|---|
| **Environmental Policy** | **385** | **398** | **(13)** |

The Environmental Policy costs for 2009 were in line with 2008. A decrease in labour costs which resulted from employee reassignments to Corporate and Employee Services in 2009 and lower environmental audit costs were offset by an increase in costs related to oil spills during 2009.

**Newfoundland Power Inc.**
**Explanation of Expense Variances**
**2009 versus 2008**
**($000's)**

| | 2009 | 2008 | Increase (Decrease) |
|---|---|---|---|
| **Substations** | **2,300** | **2,123** | **177** |

Substations operating costs were higher in 2009 compared to 2008. In 2008, labour costs were lower as a result of staff being reassigned to capital projects associated with the interconnection of two wind farms and the in-service failure of the Pierre's Brook transformer.

| | | | |
|---|---|---|---|
| **Transmission** | **482** | **585** | **(103)** |

Transmission operating costs were lower in 2009 primarily due to a reduction in vegetation management work performed on transmission lines. The decrease in Transmission related vegetation management was offset by an increase in Distribution related vegetation management work.

| | | | |
|---|---|---|---|
| **Distribution** | **7,172** | **6,592** | **580** |

Distribution operating costs were higher in 2009 for two reasons: (1) higher labour costs due to inflation and increased overtime associated with weather related repairs , and (2) a shift in vegetation management effort from transmission to distribution.

| | | | |
|---|---|---|---|
| **Communications** | **1,381** | **1,394** | **(13)** |

Communications operating costs for 2009 were in line with costs for 2008.

| | | | |
|---|---|---|---|
| **Fleet Operating and Maintenance Expense** | **1,443** | **1,572** | **(129)** |

The decrease in Fleet Operating and Maintenance Expense is primarily the result of lower fuel costs.

| | | | |
|---|---|---|---|
| **Customer Service** | **11,789** | **10,363** | **1,426** |

Customer Service operating costs were higher in 2009 as a result of higher conservation and demand management costs. In 2009, the Company launched four new conservation programs. The increase was partially offset by a decrease in labour costs that resulted from employee transfers and reassignments to Corporate and Employee Services.

# Newfoundland Power Inc.
## Explanation of Expense Variances
## 2009 versus 2008
## ($000's)

| | 2009 | 2008 | Increase (Decrease) |
|---|---|---|---|
| **Financial Services** | **1,505** | **1,494** | **11** |

Financial Services costs for 2009 were in line with costs for 2008.

| | 2009 | 2008 | Increase (Decrease) |
|---|---|---|---|
| **Information Systems** | **2,695** | **2,487** | **208** |

Information Systems operating costs were higher in 2009 as a result of changes in the payment schedule for software maintenance expenses in 2008. The increase was partially offset by lower corporate network improvements costs.

| | 2009 | 2008 | Increase (Decrease) |
|---|---|---|---|
| **Pension Costs** | **2,673** | **3,040** | **(367)** |

An increase in the discount rate used to determine the Company's accrued defined benefit pension obligation resulted in lower pension costs in 2009. This was partially offset by the effect of 2008 experience losses associated with pension plan assets and a lower assumed long-term rate of return on pension assets for 2009.

| | 2009 | 2008 | Increase (Decrease) |
|---|---|---|---|
| **Retirement Allowances** | **119** | **307** | **(188)** |

Retirement Allowance costs were lower in 2009 as a result of a lower number of severances compared to 2008.

| | 2009 | 2008 | Increase (Decrease) |
|---|---|---|---|
| **Corporate and Employee Services** | **14,589** | **13,458** | **1,131** |

Higher Corporate and Employee Services costs in 2009 were a result of costs associated with Company's 2010 general rate application, higher labour costs related to employee transfers and reassignments, and the timing of recognition of annual PUB assessment expenses in 2008. This was partially offset by lower insurance costs.

# Newfoundland Power Inc.
## Explanation of Expense Variances
## 2009 versus 2008
## ($000's)

| | 2009 | 2008 | Increase (Decrease) |
|---|---|---|---|
| **General Expenses Capitalized** | **1,836** | **1,797** | **39** |

The increase in General Expenses Capitalized (GEC) reflects increases in those expense groupings (mostly Administrative and Engineering Support costs, offset by reduced Pension costs) from which indirect allocations to GEC are derived.

| | 2009 | 2008 | Increase (Decrease) |
|---|---|---|---|
| **Conservation Deferral** | **1,356** | **-** | **1,356** |

The Conservation Cost Deferral Account reflects the Board's approval of the deferred recovery over 4 years of certain 2009 costs associated with the Company's energy conservation programs.

**Newfoundland Power Inc.**
**Calculation of Taxable Income and Income Tax Expense**
**For The Year Ended December 31, 2009**
**($000's)**

| | | |
|---|---|---|
| Net Earnings from Return 1 | | 33,201 |
| Add: Provision for current income tax | 16,208 | |
| Provision for prior years taxes | (618) | |
| Provision for future income taxes | 1,112 | |
| Provision for Conservation Cost Deferral | 409 | |
| Provision for Purchased Power Unit Cost Variance Reserve (PPUCVR) | 241 | |
| Provision for Replacement Energy Costs | (216) | |
| Provision for Weather Normalization | (1,044) | 16,092 |
| Net Income Before Income Taxes | | 49,293 |
| Add: Amortization of capital assets net of deferred expense | 41,825 | |
| Amortization of debt discount & expenses | 185 | |
| Amortization of capital stock issue expenses | 37 | |
| Amortization of credit facility costs | 50 | |
| Business meals & related expenses | 186 | |
| Special pension liability | 238 | |
| Replacement Energy Cost | 598 | |
| Stock option expense not deductible | 400 | |
| Taxable capital gains on sale of land | 129 | |
| Small tools in excess of $500 | 227 | |
| Deferred Depreciation Costs | 3,862 | |
| Deferred GRA Expenses | 201 | |
| Other non deductible costs | 17 | 47,955 |
| | | 97,248 |
| Less: | | |
| Capital cost allowance | 40,074 | |
| Cumulative eligible capital | 10 | |
| Revenue re: Agreement With CRA | 4,618 | |
| General expenses capitalized | 3,040 | |
| Interest charged to construction | 675 | |
| Bond issue expenses | 185 | |
| Deferred CDM | 1,357 | |
| Part VI.1 tax deduction | 41,767 | |
| Capital gains on sale of land included in income | 444 | |
| Difference in pension funding and accounting cost | 1,047 | 93,217 |
| Taxable Income | | 4,031 |
| Weather Normalization deducted as future tax | | 1,044 |
| Provision for PPUCVR | | (241) |
| Income Tax - Part 1 | | 1,330 |
| Income Tax - Part VI.1 | | 13,922 |
| Normalization adjustment | | 153 |
| Provision for prior years taxes | | (618) |
| Current Income Tax Expense | | 15,590 |
| Provision for CDM | | 409 |
| Provision for PPUCVR | | 241 |
| Provision for Replacement Energy Costs | | (216) |
| Provision for Weather Normalization | | (1,044) |
| Future income tax | | 1,112 |
| Future Income Tax Provision | | 502 |
| Total Tax Expense | | 16,092 |

**Newfoundland Power Inc.**
**Accumulated Future Income Taxes**
**For The Year Ended December 31, 2009**
**($000's)**

## Plant Investments

| | | |
|---|---|---|
| Balance on January 1, 2009 | | 575 |
| Add: CCA claimed on all property, plant and equipment - from Return 22 | 40,074 | |
| Less: Amortization expense on all property, plant and equipment (GEC excluded from post-1986 additions) | 38,229 | |
| Difference | 1,845 | |
| Future Income Tax Rate @ 29% | | 535 |
| Balance on December 31, 2009 (if negative enter 0) | | 1,110 |

## Pension and Early Retirement Costs

| | | |
|---|---|---|
| Balance on January 1, 2009 | | 609 |
| Add: Pension Funding | 3,784 | |
| Less: Pension Expense (including Special Pension Costs) | 1,792 | |
| Difference | 1,992 | |
| Future Income Tax Rate @ 29% | | 578 |
| Balance on December 31, 2009 | | 1,187 |
| **Total Accumulated Future Income Taxes** | | **2,297** |

**Newfoundland Power Inc.**
**Average Regulated Capital Structure**
**For The Year Ended December 31, 2009**
**($000's)**

## Average Book Capital Structure

| | Year-End December 31 2009 | Year-End December 31 2008 | Average | Percent |
|---|---|---|---|---|
| Total Debt | 479,250 | 438,154 | 458,702 | 54.26% |
| Preference Shares | 9,111 | 9,352 | 9,232 | 1.09% |
| Common Equity | 381,185 | 373,738 | 377,462 | 44.65% |
| | 869,546 | 821,244 | 845,396 | 100.00% |

## Average Regulated Capital Structure[1]

| | Average 2009 | Percent |
|---|---|---|
| Total Debt | 458,702 | 54.26% |
| Preference Shares | 9,232 | 1.09% |
| Common Equity | 377,462 | 44.65% |
| | 845,396 | 100.00% |

[1] In Order No. P.U. 19 (2003), the Board ordered that the proportion of regulated common equity in the capital structure shall not exceed 45%. In years where the average common equity percentage is below 45% of the average invested capital, the regulated average capital structure will equal the average book capital structure.

**Newfoundland Power Inc.**
**Cost of Embedded Debt**
**For The Years Ended December 31**
**($000's)**

| | | 2009 | 2008 |
|---|---|---|---|
| **Debt** | | | |
| Bonds | | 468,888 | 409,088 |
| Credit Facilities | | 13,500 | 32,000 |
| | | 482,388 | 441,088 |
| Debt Discount and Issue Expenses | | (3,138) | (2,934) |
| | | 479,250 | 438,154 |
| Average Debt | **A** | 458,702 | 440,841 |
| **Interest Expense**[1] | | | |
| Interest on Bonds | | 34,547 | 32,334 |
| Interest on Credit Facilities | | 396 | 1,445 |
| Interest on Bank Indebtedness | | 7 | 11 |
| Amortization of Debt Discount and Issue Costs | | 235 | 235 |
| | **B** | 35,185 | 34,025 |
| **Embedded Cost of Debt** | **B/A** | **7.67%** | **7.72%** |

[1] Total financing costs for 2009 and 2008 as reported in Return 1 are as follows:

| | 2009 | 2008 |
|---|---|---|
| Interest Expense (B) from above | 35,185 | 34,025 |
| Add: Amortization of Capital Stock Issue Expenses | 37 | 62 |
| Add: Interest on Security Deposits | 8 | 38 |
| Less: AFUDC | (675) | (618) |
| Interest Expense Reported in Return 1 | 34,555 | 33,507 |

**Newfoundland Power Inc.**
**Explanation of Variances in Cost of Debt**
**For The Year Ended December 31, 2009**
**($000's)**

| | Actual 2009 | Test Year 2008 | Variance |
|---|---|---|---|
| **Average Debt** | 458,702 | 440,691 | 18,011 |
| | | | |
| **Embedded Cost of Debt** | 7.67% | 7.93% | -0.26% |
| | | | |
| **Details of the Embedded Cost of Debt** | | | |
| Interest on Bonds | 34,547 | 32,334 | 2,213 [1] |
| Interest on Credit Facilities | 396 | 2,393 | (1,997) [2] |
| Interest on Bank Indebtedness | 7 | - | 7 |
| Amortization of Debt Discount and Issue Costs | 235 | 236 | (1) |
| | | | |
| | 35,185 | 34,963 | 222 |

**Explanation of Variances**

[1] A $65 million First Mortgage Sinking Fund Bond was issued on May 25, 2009 at an interest rate of 6.606%. This bond issuance was approved by the Board in Order No. P.U. 11 (2009).

[2] The reduction in interest costs on credit facilities was primarily due to lower borrowing and a decline in short term borrowing rates in 2008 and 2009 due to market conditions.

**Newfoundland Power Inc.**
**Regulated Return on Average Common Equity**
**For The Year Ended December 31**
**($000's)**

| | 2009 | 2008 |
|---|---|---|
| **Average Common Equity** | | |
| Common Equity at December 31, 2009 | 381,185 | |
| Common Equity at December 31, 2008 | 373,738 | 373,738 |
| Common Equity at December 31, 2007 | | 356,671 |
| Average Common Equity | 377,462 | 365,205 |
| **Regulated Return on Average Common Equity** | | |
| Earnings Applicable to Common Shares - Return 1 | 32,628 | 32,341 |
| Add: Non-Regulated Expenses (net of income taxes) | 1,203 | 995 |
| | 33,831 | 33,336 |
| **Regulated Return on Average Common Equity** | **8.96%** | **9.13%** |

**Newfoundland Power Inc.**
**Assessable Revenue**
**(s. 13 of the *Public Utilities Act* )**
**For The Year Ended December 31, 2009**
**($000's)**

| | | |
|---|---|---|
| Revenue From Rates from Return 14 | 505,881 | |
| Weather Normalization Revenue Adjustment from Return 17 | (5,758) | |
| | 500,123 | |
| Municipal Taxes Billed | 12,549 | |
| Billing per the Rate Stabilization Account from Return 16 | 25,668 | |
| Total Electrical Revenue Billed | | 538,340 |
| Other Revenue from Return 14 | | 13,802 |
| **Assessable Revenue** | | **552,142** |

NEWFOUNDLAND POWER
A FORTIS COMPANY

# 2010 Annual Report

In Good Hands.

# Corporate Profile

Newfoundland Power Inc. (“Newfoundland Power”) operates an integrated generation, transmission and distribution system throughout the island portion of Newfoundland and Labrador.

For over 125 years, we have provided customers with safe, reliable electricity in the most cost-efficient manner possible. Our Company serves over 243,000 customers, 86% of all electricity consumers in the province.

Our employees continue to provide our customers with the service they expect and deserve in an environmentally and socially responsible manner.

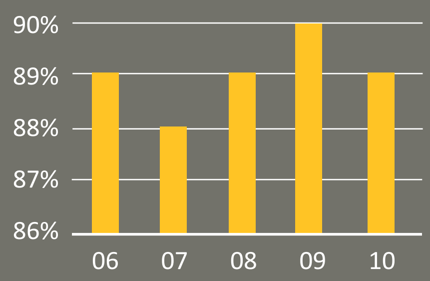
Our vision is to be a leader among North American electric utilities in terms of safety, customer service, reliability and efficiency.

All the common shares of Newfoundland Power are owned by Fortis Inc. (“Fortis”) (TSX:FTS), the largest investor-owned distribution utility in Canada, which serves approximately 2,100,000 gas and electricity customers, and has assets exceeding $12.5 billion.

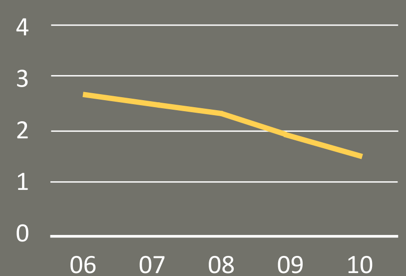
Rick Slade, Operations, Carbonear

# 2010 Highlights

**Customer Satisfaction Rating**




**Outages per Customer***




*Excluding major storm impacts.

| Financial | 2010 | 2009 |
|---|---|---|
| Revenue *($000s)* | 554,950 | 527,179 |
| Property, Plant and Equipment *($000s)*[1] | 1,212,810 | 1,230,371 |
| Long-term Debt *($000s)* | 478,688 | 482,388 |
| Common Shareholders' Equity *($000s)* | 400,502 | 381,185 |
| Earnings Applicable to Common Shares *($000s)* | 35,005 | 32,628 |
| Earnings per Common Share *($)* | 3.39 | 3.16 |
| **Operating** | | |
| Customers *(#)* | 243,426 | 239,307 |
| Customer Satisfaction Rating *(%)* | 89 | 90 |
| Generating Capacity *(MW)* | 140.4 | 140.1 |
| Transmission and Distribution Line *(km)* | 11,072 | 10,957 |
| Substations *(#)* | 130 | 130 |
| Peak Demand *(MW)* | 1,206 | 1,219 |
| Electricity Sales *(GWh)* | 5,419 | 5,299 |

[1] *Excluding accumulated amortization.*


Junior House, Operations, Stephenville

# Report to Shareholders

Delivery of quality customer service and efficient operations remain in good hands with our employees. The Company's annual customer satisfaction rating of 89% confirms that customers viewed our overall performance in 2010 positively, despite being impacted by two severe storms throughout the year. In March, we were impacted by one of the worst ice storms to hit the province in 25 years. It damaged 8 main transmission lines and left over 10,000 customers without power on the Northeast Avalon and Bonavista Peninsulas. In September, the effects of Hurricane Igor were more wide spread, leaving approximately 100 communities across the island isolated or in states of emergency. Approximately 77,000 customers were left without power as a result of downed power lines caused by high winds and severe flooding.

Our first priority was to restore power to our customers in the safest, most efficient manner possible. During both storms, we immediately mobilized crews from across the island and called in additional equipment and resources from our contractors, Newfoundland and Labrador Hydro ("Hydro") and other Fortis utilities. We spent over $6.0 million in capital expenditures to repair damage to our electricity system and over $1.5 million in additional operating costs as a result of storms.

We maintained close contact with affected customers through timely media updates and one on one conversations with customers. Particular attention was given to emergency service providers, such as fire departments, hospitals, the Red Cross and municipal leaders. Our employees' dedicated performance during the ice storm resulted in the Company receiving the 2010 Business of the Year Award from the Town of Bonavista.

In addition to overcoming the challenges brought by severe weather, we maintained our focus on safety; invested in the continued reliability of our electricity system; expanded our energy efficiency efforts; and, strengthened relationships with our environmental and community partners.

To improve the safety of our contractors, we introduced several new initiatives in 2010, including: electrical safety training for pole and vegetation contractors; quarterly meetings with contractor owners; and, increased safety inspections and work observations. As part of our pursuit to educate the public about electrical safety, we launched a new print advertising campaign in 2010, "The Power of…", which has been recognized with an Award of Merit by the provincial chapter of the International Association of Business Communicators ("IABC").

The investments we make in our electricity system each year serve to maintain our strong level of reliability. Capital investments totalling in excess of $300 million over the last 5 years, including $78.4 million in 2010, have not only helped to upgrade and reinforce our province's electricity system, but allowed us to maintain its integrity in one of the harshest electrical operating environments in the country. We invested approximately half of our capital expenditures to connecting a record 5,300 new customers and meeting their electricity requirements, and the other 50% to upgrading components of our electricity system.

Customer convenience has also been an ongoing focus for Newfoundland Power. Our corporate website has undergone substantial changes to increase self service options and enhance customer convenience. In 2010, we answered more than 285,000 calls at our Customer Contact Centre, and recorded approximately 2.6 million electronic interactions with our customers.

Our **takeCHARGE – Saving Energy Starts Here!** partnership with Hydro helped to exceed our 2010 energy savings goal of 4.4 gigawatt hours ("GWh") by 0.6 GWh. In excess of 3,600 customers benefited from the Energy Savers Rebate Programs, and more than 100 municipalities in the province signed up to participate in our **takeCHARGE of Your Town Challenge**, pledging to reduce their town's collective energy usage. Energy efficiency education and awareness also expanded to include the use of social media in 2010, adding Facebook and YouTube as new avenues of customer communication.

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NEWFOUNDLAND
POWER
A FORTIS COMPANY

A combined external audit of the Company's Health and Safety Management System and Environment Management System verified our continued compliance with the 18001 Occupational Health and Safety Assessment Series ("OHSAS") and the ISO 14001 international standard. The audit confirmed our facilities are well maintained and that employees continue to demonstrate a commitment to working in a safe and environmentally responsible manner.

Our earnings of $35.0 million in 2010 increased by $2.4 million over 2009. Higher electricity sales of 5,419 GWh in 2010, an increase of 2.3% over 2009, were due to customer growth combined with a higher than average use of electricity. Through operation of the Automatic Adjustment Formula, the Company's rate of return on common equity, for the purpose of setting electricity rates, will be reduced from 9.00% in 2010 to 8.38% in 2011. The Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB") also approved changes in accounting practices for future retiree benefits costs, effective January 1, 2011.

A new Support Structure Agreement ("Agreement") was signed with Bell Aliant regarding joint-use poles and related infrastructure. Bell Aliant will buy back approximately 40% of these poles, with the Company responsible for the construction and maintenance of Bell Aliant's support structure requirements throughout 2011. The Agreement is subject to approval by the PUB and is expected to close in 2011.

We wish to thank our employees for offering their talents, hard work and commitment throughout the year. Our ability to deliver safe, reliable electricity while providing our customers with a high standard of service is a credit to their valued contributions.

Newfoundland Power's Board of Directors provided another year of sound leadership in 2010. We express our sincerest appreciation for their continued support and direction. We thank Mr. David Norris, who retired from our Board after 7 years of service, 4 as Chair of the Board, Mr. Edward Drover, who retired after 6 years of service, and Mr. John Walker, who resigned after 5 years of service, for their unique perspective and guidance. We congratulate Ms. Peggy Bartlett, a Board member for the past 5 years, on her appointment as our new Chair, and welcome our newest members, Mr. Edward Murphy and Ms. Nora Duke.

Our employees' unrelenting dedication to putting safety first, developing relationships with our customers, preserving our environment and serving our communities, has shaped the way we do business in Newfoundland and Labrador. As a Company, we are committed to continuing this proud tradition.

Sincerely,

Earl Ludlow
President and Chief Executive Officer

Peggy Bartlett
Chair, Board of Directors

Ed Corrigan, Operations, St. John’s

# In Safe Hands.

Our focus on establishing a safety culture aimed at eliminating workplace accidents has yielded a significant reduction in the number of days our employees have been off the job because of work related injuries.

Our innovative use of technology allowed us to create an important connection between safety leaders and employees across the island in 2010. Using web based software we communicated annual safety objectives and targets to the entire Company and addressed safety related questions in real time. Working toward improving workplace safety, we provided safety training tailored to field supervisors and conducted workshops for Linecrew Lead Hands. Our concentration on Meter Reader safety resulted in this group achieving 2 consecutive years with no lost-time incidents.

We introduced several new safety initiatives as part of our goal to improve contractor safety, including: electrical safety training for pole and vegetation contractors; quarterly meetings with contractor owners; and, increasing the number of safety inspections and contractor work observations conducted each year. We also worked with the Workplace Health and Safety Compensation Commission and Hydro in response to the growing number of contacts third-party contractors have with the electricity system. This collaboration resulted in providing contractors and heavy equipment operators across the province with detailed information about how to identify, avoid and deal with the electrical hazards they could potentially encounter while on the job.

Throughout 2010, we reviewed electrical arc flash requirements for transmission and distribution operations, and completed training in the protection required to guard against arc flash hazards during the installation and removal of meters. We increased focus on public safety with the launch of our new marketing brand, “The Power Of…”, which features both safety and community focused messaging. This campaign was recognized with a Pinnacle Award of Merit by the provincial chapter of IABC.

Our history of educating our communities about electrical safety remains strong. In 2010, we provided electrical safety seminars to over 240 firefighters. With the help of our retirees and employee volunteers, we educated approximately 3,000 school children about electrical hazards. The Company also provided electrical safety training to the Newfoundland and Labrador Construction Association and municipalities across the province.

The completion of an external audit of our Health and Safety Management System in 2010 confirmed our continued compliance with the OHSAS 18001 Health and Safety Management System international standard.

**Our first priority is the safety of our employees, contractors and the public. We are committed to providing the education and training necessary to ensure the safety of our operations each and every day. Our goal is, and always will be, zero accidents!**


Danny Blanchard, Operations, Stephenville

# In Reliable Hands.

2010 was marked by two major storms. The worst ice storm to hit the province in 25 years caused extensive damage to 8 of our main transmission lines on the Northeast Avalon and Bonavista Peninsulas, leaving over 10,000 customers without power. High winds and severe flooding during Hurricane Igor left approximately 100 communities across the province isolated or in states of emergency and approximately 77,000 customers without power. In both instances, we immediately mobilized crews from across the island, and called in additional equipment and resources from our contractors, Hydro and other Fortis utilities. More than 400 people worked to restore power to our customers during Hurricane Igor, using ATVs, boats and helicopters to reach communities rendered otherwise inaccessible.

Capital investments totalling in excess of $300 million over the last 5 years have not only helped to upgrade and reinforce our electricity system, but have allowed us to maintain its integrity in one of the harshest electrical operating environments in the country. The average length of outages experienced by our customers, excluding severe storm impacts, remained consistent with last year's record reliability performance.

We invested approximately half of our $78.4 million in capital expenditures to connect a record 5,300 new customers to the province's electricity system and complete projects to accommodate increased electricity requirements. This included investing approximately $30.0 million to construct distribution lines to service new customers across the island and $7.7 million to accommodate increased electricity demand at our Deer Lake and Mobile substations.

50% of our 2010 capital spending also involved upgrading components of our electricity system. We invested approximately $15.0 million to upgrade customer distribution lines across the island and $5.5 million on increasing operating efficiencies at our Lookout Brook, Petty Harbour and Seal Cove hydroelectric plants. We invested approximately $6.0 million to repair damage resulting from storm impacts and dedicated another $5.2 million to ensure the reliability of our substations.

We continued our mobile technologies project, installing computers in additional trucks in our fleet. This increased the number of field employees with real time access to critical safety, operational and environmental information. The Company will incorporate mobile technology across its entire fleet by the end of 2011.

**To provide safe, reliable electricity to our customers we continue to make strategic capital investments in our electricity system every year. We plan to invest an additional $73.0 million in 2011.**


Paul Smith, Customer Relations, Stephenville

# In Friendly Hands.

In 2010, our island wide customer satisfaction survey showed that our connection to customers remains strong, with an average annual rating of 89%.

When severe weather conditions impacted our electricity system in 2010 we maintained close contact with our customers and communities while restoring power in the safest, most efficient manner possible. We worked with the media to give timely outage restoration updates to our customers and remained in direct contact with firefighters, police and critical public safety facilities. During Hurricane Igor, we extended the hours of our Customer Contact Centre to 24 hours and suspended normal business calls for the first time in our Company's history. Over approximately 6 days, we answered in excess of 30,000 weather related calls and 850 emails. We also launched our corporate Twitter account, providing online and mobile updates to customers. The Company's use of Twitter has since expanded to include messaging related to recruitment and daily operational functions, such as electrical safety, customer service and community related events.

Working toward enhancing customer convenience, we expanded the self service options available on our corporate website, newfoundlandpower.com. New improvements introduced in 2010 allow customers the ability to make web and phone based payment arrangements, submit their own meter readings online and interact with us 24 hours a day. An increased number of customers are using electronic means to communicate with us. Throughout the year, we recorded approximately 2.6 million electronic interactions with our customers. The number of email service requests received by our Customer Contact Centre has steadily increased from 24,000 in 2007 to approximately 40,000 in 2010.

Our advertising campaign to encourage customers to join our electronic billing ("ebills") program serves to enhance customer convenience and positively impact our environment. To date, more than 35,000 customers have signed up for ebills.

Automated Meter Reading ("AMR") technology is now the standard for all new meter installations across the province. This technology improves safety and accessibility, reduces the need for bill estimates and allows for the consolidation of meter reading routes. To date, more than 30,000 properties across the island have been equipped with AMR capabilities.

**Every one of our dedicated employees has a hand in providing service excellence to our customers.**

Theresa Critch, Customer Relations, Clarenville

# In Efficient Hands.

Our ongoing energy efficiency partnership with Hydro, **takeCHARGE – Saving Energy Starts Here!**, helped us to exceed our energy savings goal of 4.4 GWh by 0.6 GWh in 2010, resulting in overall savings of 5.0 GWh. This is equal to removing approximately 185 electrically heated homes from the province's electricity system for an entire year.

Residential customers who availed of our Energy Savers Rebate Programs received rebates on insulation, programmable and electronic thermostats, and ENERGY STAR® windows. Our commercial customers benefited from rebates on energy efficient lighting. In 2010, we provided rebates to over 3,600 customers and recorded more than 52,000 visits to the **takeCHARGE** website throughout the year, a 4.6% increase over 2009.

The **takeCHARGE** partnership received an Award of Excellence for Traditional Advertising and an Award of Merit for Energy Savers Marketing Communications from the provincial chapter of IABC. We also took a hands on approach to social media, reaching out to customers through Facebook and YouTube for the first time. Each of the sites offer our customers valuable information and tips on how to save energy in their homes and businesses. We used both traditional and social media to promote our first ever **takeCHARGE of Your Town Challenge**. Over 100 municipalities pledged to take action to reduce the energy they use.

**takeCHARGE** also focused on educating and interacting with customers one on one. To do this, we set up information booths at building supply stores, and presented at tradeshows and customer conferences. Each presentation was tailored to address the needs of specific audiences, including retailers and suppliers, senior citizens, and youth. We celebrated our second annual **takeCHARGE** Energy Efficiency Week in Newfoundland and Labrador, and talked with our customers about how to save energy and money. Other promotions featured the addition of new "how-to" videos to the **takeCHARGE** website and educational appearances on local television.

We completed several energy efficiency upgrades to our electricity system, plants and corporate buildings across the island. Such projects involved completing energy audits at a number of our facilities, improving operating efficiencies at our hydroelectric generating plants and installing energy efficient lighting in our office buildings.

**Our goal is to provide our customers with the knowledge and tools they need to make informed decisions about how to reduce their electricity usage, save money and positively impact our environment.**

Cathy Dormody, Human Resources, St. John’s

# In Caring Hands.

Our corporate success stems from the contributions our employees make, both individually and collectively, to our daily operations.

Early in the year, we conducted a survey to enhance employee communication and garner our employees' opinions about topics including safety, leadership, work environment and employee appreciation. Suggestions about what works well and what needs improvement initiated detailed action plans aimed at improving the efficiency of safety meetings, effective communication across all levels of the Company, and employee recognition and development.

As part of our workforce and succession planning we remain concentrated on the areas of recruitment, critical knowledge transfer and retirement. In 2010, we held a series of retirement planning presentations for employees across the island, and offered detailed information sessions around health coverage and retirement benefits. Employee development opportunities are made available through our newly revised mentoring program, lunch and learns, job shadowing and temporary work assignments. We also expanded our recruitment and awareness efforts to include high school students, remained active in career fairs at Memorial University of Newfoundland and College of the North Atlantic campuses and, continued our support of Engineering and Business Cooperative Programs, welcoming 17 work term students to our team.

We maintained our Power Line Technician Apprenticeship Program to facilitate the critical transfer of knowledge from senior employees to apprentices. During the year, 4 of our apprentices became Power Line Technicians, and we added additional recruits to the program, bringing our total complement of apprentices to 27.

We also focused on several employee enhancement opportunities throughout the year, including: development plans for new engineers; job specific safety training for employees in lead operational roles; and, training in critical skills for field supervisors.

As part of our corporate commitment to health and wellness, our employees benefit from several in-house services. These include in-house Employee Assistance Program services and a variety of health and wellness seminars. We also offered several programs through our Occupational Health Nurse in 2010, including: early and safe return to work seminars; flu vaccinations; blood pressure monitoring; fitness programs; weight loss clinics; and, healthy lifestyle advice.

**Investing in the well being and development of our employees is an investment in the future success of our Company.**


Brian Malone, Information Services, St. John's

# In Responsible Hands.

We take our pledge to operate in an environmentally responsible manner very seriously. In 2010, we completed several capital projects aimed at reducing the environmental risks associated with operating our electricity system. Projects included installing new, more environmentally friendly circuit breakers at our Mobile, Deer Lake and Kenmount substations, and modernizing equipment at our Lookout Brook hydroelectric plant to better manage water usage. We continued with the replacement of streetlights across the island with energy efficient High Pressure Sodium lights. The new lights provide the same quality lighting while consuming 35% less energy.

To reduce the risk of corrosion and potential oil leaks, we replaced over 500 deteriorated transformers with stainless steel units throughout our service territory. We continued removing and disposing of PCB oil-filled electrical equipment. Approximately 82% of our distribution feeders and 92% of our substations have now been completed under our PCB Phase-out Program.

To aid in managing potential environmental emergency situations, we completed 6 emergency preparedness and response tests throughout the year. These tests ensure our employees are aware of, and prepared for, what must be done in the event of an actual environmental emergency.

An external audit of our Environmental Management System in 2010 verified our continued compliance with the ISO 14001 international standard. This audit confirmed that our facilities are well maintained and our employees continue to demonstrate a commitment to working in an environmentally responsible manner.

We celebrated the 13th anniversary of our annual employee-driven *EnviroFest* events. During Environment Week, we hosted 8 events across the island attended by thousands of people, and over 300 community groups and organizations. Over the years, our employees and community volunteers have successfully completed more than 50 beautification projects throughout the province.

To reinforce the importance of being environmentally responsible in our daily operations, we provided environmental training to almost 420 employees and contractor employees in 2010.

**We pride ourselves on taking a leadership role in creating public awareness and stewardship aimed at preserving our environment for future generations.**

Dianna Ryan, Regional Operations, St. John’s

# In Helping Hands.

With employees living and working across the island we have a connection to hundreds of communities in the province. Our employees use their talents and skills to operate cohesively as a team, and go above and beyond as individuals to make a personal difference in their communities.

In 2010, we partnered with the Dr. H. Bliss Murphy Cancer Care Foundation to open the Newfoundland Power Four Dimensional CT Simulator Suite at the Cancer Centre in St. John's. The Suite is only the second of its kind in the province, and houses technology that enables cancer care teams to enhance the accuracy of radiation treatment planning.

Our corporate charity, *The Power of Life Project*, concluded the year on a high note with donations totalling over $200,000 to improve cancer care in Newfoundland and Labrador. The commitment of our employees and retirees to organizing and participating in annual fundraising activities, coupled with a corporate donation and monthly donations from our employees and customers, continue to benefit cancer patients and their families. *The Project* works closely with the Dr. H. Bliss Murphy Cancer Care Foundation and cancer centres across the island to identify and address area specific needs.

In 2010, *The Power of Life Project* furnished the atrium at the Grand Falls-Windsor Cancer Centre; donated an ice machine to the G. B. Cross Memorial Hospital in Clarenville; purchased chemotherapy recliners for the Sir Thomas Roddick Hospital in Stephenville and Burin Peninsula Health Care Centre; decorated the Newfoundland Power Suite with a visual art mural; increased support for children living with cancer attending Camp Delight; and, refurbished and restocked our toy chest for children undergoing radiation treatment. *The Power of Life Project* has donated in excess of $2.0 million toward equipment, patient and family support funds, research, and treatment and awareness initiatives in this province!

We augmented our commitment to improving cancer care through another successful collaboration with Motorcycle Ride for Dad. We assisted with education and awareness initiatives and hosted more than 600 bikes at our corporate headquarters on Ride Day, which raised over $150,000 for prostate cancer.

In doing our part to promote tourism in our province, we supported the newly expanded East West North Summer Expo and the province's Cupids 400 celebrations. We continued our commitment to the province's youth by once again working with community partners to present the Newfoundland and Labrador Winter Games, held this year in Grand Falls-Windsor.

Our employees also supported several other community initiatives in 2010, including: collecting money and food at Christmas parades for local charities and food banks; gathering warm winter clothing for the Coats for Kids campaign; volunteering to deliver food as part of the Meals on Wheels initiative; and, entering corporate teams in fundraising events like CIBC Run for the Cure and the Arthritis Jingle Bell Walk and Run.

Our employees' dedication to giving the gift of life once again resulted in exceeding our annual target of 300 blood donations. Since joining Canadian Blood Services' *Partners for Life* program in 2004, our employees and their families have made approximately 2,000 blood donations, helping to save up to 6,000 lives.

**Delivering safe, reliable electricity to our customers is what we do . . . giving back to our communities is who we are.**

# Management Discussion and Analysis

*Dated February 10, 2011*

*The following Management Discussion and Analysis ("MD&A") should be read in conjunction with Newfoundland Power Inc.'s (the "Company" or "Newfoundland Power") annual financial statements and notes thereto for the year ended December 31, 2010. The MD&A has been prepared in accordance with National Instrument 51-102 Continuous Disclosure Obligations. Financial information herein reflects Canadian dollars and Canadian generally accepted accounting principles ("Canadian GAAP"), including certain accounting practices unique to rate regulated entities. These accounting practices, which are disclosed in Notes 2 and 4 to the Company's 2010 annual audited financial statements, result in the recognition of revenues, expenses, regulatory assets and regulatory liabilities which would not occur in the absence of rate regulation and which affect the Company's reported earnings, cash flows and financial position.*

*Certain information herein is forward-looking within the meaning of applicable securities laws in Canada ("forward-looking information"). The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words.*

*The forward-looking information reflects management's current beliefs and is based on information currently available to the Company's management. The forward-looking information in this MD&A includes, but is not limited to, statements regarding: expectations to generate sufficient cash to complete required capital expenditures, and to service interest and sinking fund payments on debt; meeting pension funding requirements; no material adverse credit rating actions expected in the near-term; the Company's belief that it does not anticipate any difficulties in issuing bonds on reasonable market terms; and, the forecast gross capital expenditures for 2011.*

*The forecasts and projections that make up the forward-looking information are based on assumptions, which include, but are not limited to: receipt of applicable regulatory approvals; continued electricity demand; no significant operational disruptions or environmental liability due to severe weather or other acts of nature; no significant decline in capital spending in 2011; sufficient liquidity and capital resources; the continuation of regulator-approved mechanisms that permit recovery of costs; no significant variability in interest rates; no significant changes in government energy plans and environmental laws; the ability to obtain and maintain insurance coverage, licences and permits; the ability to maintain and renew collective bargaining agreements on acceptable terms; and, sufficient human resources to deliver service and execute the capital program.*

*The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. The factors which could cause results or events to differ from current expectations include, but are not limited to: regulation; operating and maintenance; economic conditions; defined benefit pension plan performance; capital resources and liquidity; interest rates; electricity prices; purchased power cost; health, safety and the environment; insurance; weather; changes in accounting standards; information technology infrastructure; labour relations; and, human resources. For additional information with respect to these risk factors, reference should be made to the section entitled "Business Risk Management" in this MD&A.*

*All forward-looking information in this MD&A is qualified in its entirety by this cautionary statement and, except as required by law, the Company undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise after the date hereof.*

*Additional information, including the Company's quarterly and annual financial statements and MD&A, annual information form and management information circular, is available on SEDAR at sedar.com.*

# OVERVIEW

## The Company

Newfoundland Power is a regulated electricity utility that owns and operates an integrated generation, transmission and distribution system throughout the island portion of the Province of Newfoundland and Labrador. All the Company's common shares are owned by Fortis Inc. ("Fortis"), which is principally a diversified, international holding company for electricity and gas distribution utilities.

Newfoundland Power's primary business is electricity distribution. It generates approximately 7% of its electricity needs and purchases the remainder from Newfoundland and Labrador Hydro ("Hydro"). Newfoundland Power serves over 243,000 customers, approximately 86% of all electricity consumers in the province.

Newfoundland Power's vision is to be a leader among North American electricity utilities in terms of safety, reliability, customer service and efficiency. The key goals of the Company are to operate sound electricity distribution systems, deliver safe, reliable electricity to customers at the lowest reasonable cost, and conduct business in an environmentally and socially responsible manner.

## Regulation

Newfoundland Power is regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB"). The Company operates under cost of service regulation whereby it is entitled the opportunity to recover, through customer rates, all reasonable and prudent costs incurred in providing electricity service to its customers, including a just and reasonable return on its rate base. The rate base is the value of the net assets required to provide electricity service.

Between general rate hearings, customer rates are established annually through an automatic adjustment formula (the "Formula"). The Formula sets an appropriate rate of return on common equity ("ROE") which is used to determine the rate of return on rate base. Pursuant to the 2010 General Rate Application ("2010 GRA"), the Company's rate of return on rate base for ratemaking purposes was set at 8.23%, with a range of 8.05% to 8.41%, for 2010. This reflects a regulated ROE of 9.00% for 2010 compared to 8.95% for 2009. Customer rates increased by an average of approximately 3.5% effective January 1, 2010.

The 2010 GRA provided for revenue and costs changes as well as the amortization of certain regulatory assets and liabilities, and the creation of a pension expense variance deferral account ("PEVDA"). The PEVDA deals with differences between defined benefit pension expense calculated in accordance with Canadian GAAP and pension expense approved by the PUB for rate setting purposes.

On March 12, 2010, the Company submitted an application to the PUB with proposed changes to the existing Formula. In this application, Newfoundland Power proposed use of the forecast long-term Canada Bond yields in determining the risk-free rate for calculating the forecast cost of equity to be used in the Formula for 2011 and 2012. The application received PUB approval on April 20, 2010. The previous approach used a 10-day observation of long-term Canada Bond yields as the forecast risk-free rate.

On June 30, 2010, the Company submitted an application to the PUB proposing, effective January 1, 2011: (i) the adoption of the accrual method of accounting for Other Post-Employment Benefits ("OPEBs"); (ii) the amortization of the regulatory asset composed of accumulated costs that were not recognized as an expense in previous years; and (iii) the creation of an OPEBs cost variance deferral account. This account will deal with the differences between annual OPEBs expense, calculated in accordance with Canadian GAAP, and OPEBs expense approved by the PUB for rate setting purposes. The application received PUB approval on December 10, 2010.

## Financial Highlights

| | 2010 | 2009 | Change |
|---|---|---|---|
| Electricity Sales *(gigawatt hours ("GWh"))*[1] | 5,419.0 | 5,299.0 | 120.0 |
| Earnings Applicable to Common Shares | | | |
| $ Millions | 35.0 | 32.6 | 2.4 |
| $ Per Share | 3.39 | 3.16 | 0.23 |
| ROE *(%)*[2] | 8.96 | 8.64 | 0.32 |
| Cash Flow from Operating Activities *($millions)* | 94.6 | 59.4 | 35.2 |
| Total Assets *($millions)*[3] | 1,191.1 | 1,165.2 | 25.9 |

1 *Reflects normalized electricity sales.*
2 *Earnings applicable to common shares, divided by the average of common shareholders' equity at the beginning and end of the year. This ratio is a non-GAAP financial measure, does not have any standardized meaning prescribed by GAAP and is unlikely to be comparable to similar ratios published by other companies. It is presented because it is commonly referred to by the users of the Company's financial statements in evaluating the results of operations and by the Company's regulator in the rate-setting process.*
3 *Certain comparative figures have been reclassified to comply with the current year's presentation.*

Electricity sales for the year ended December 31, 2010, increased by 120 GWh or 2.3% compared to 2009. The increase in electricity sales was composed of an increase of: (i) 1.7% due to customer growth; and (ii) 0.6% due to higher average consumption.

Earnings for the year ended December 31, 2010, increased $2.4 million from $32.6 million in 2009 to $35.0 million in 2010. Approximately half of the increase was the result of the 3.5% increase in customer rates which was effective January 1, 2010, reflecting rate base growth and a higher ROE embedded in customer rates. The remaining increase in earnings resulted from operational performance during 2010 which varied from the forecasts used to establish customer rates. The primary variances were: (i) higher than anticipated electricity sales; (ii) lower effective income tax rate; (iii) lower financing costs; (iv) higher operating costs, primarily related to Hurricane Igor; and (v) higher purchased power costs due to higher water inflows associated with the Company's hydroelectric generating facilities, partially offset by lower billing demand charges and lower electricity system losses.

The actual ROE in both 2010 and 2009 is broadly consistent with that reflected in customer rates.

The increase in cash flow from operating activities of $35.2 million primarily reflects the: (i) January 1, 2010, customer rate increase; (ii) higher electricity sales; (iii) lower income tax instalments, partially offset by; (iv) higher interest payments; and (v) timing of payments to vendors.

Total assets increased by $25.9 million at December 31, 2010, compared to December 31, 2009. The increase was predominantly due to continued investment in the electricity system, and is consistent with the Company's strategy to provide safe, reliable electricity service at the lowest reasonable cost.

## RESULTS OF OPERATIONS

### Revenue:

| *($millions)* | 2010 | 2009 | Change |
|---|---|---|---|
| Revenue from Rates | 537.6 | 508.8 | 28.8 |
| Amortization of Regulatory Liabilities and Deferrals | 5.3 | 6.0 | (0.7) |
| Other Revenue[1] | 12.1 | 12.4 | (0.3) |
| Total | 555.0 | 527.2 | 27.8 |

[1] *Other revenue is composed largely of pole attachment charges to various telecommunication companies.*

Revenue from rates increased by $28.8 million, from $508.8 million in 2009 to $537.6 million in 2010. The increase primarily resulted from the January 1, 2010, customer rate increase and electricity sales growth.

The amortization of regulatory liabilities relates to unbilled revenue, municipal tax and the pension expense variance deferral and is in accordance with PUB orders. These regulatory liabilities are described in Notes 2 and 4 to the Company's 2010 annual audited financial statements.

Other revenue decreased by $0.3 million, from $12.4 million in 2009 to $12.1 million in 2010. The decrease was primarily related to land sales in 2009.

**Purchased Power:** Purchased power expense increased by $12.7 million, from $345.7 million in 2009 to $358.4 million in 2010. The increase was primarily due to electricity sales growth and higher water inflows associated with the Company's hydroelectric generating facilities.

**Operating Expense:** Operating expense increased by $5.3 million, from $49.3 million in 2009 to $54.6 million in 2010. The increase was mainly a result of: (i) costs associated with Hurricane Igor; (ii) increased conservation costs; (iii) wage and inflationary increases; and (iv) higher retirement and severance expenses. This increase was partially offset by a reduction in costs associated with the 2010 GRA and an increase in general expenses capitalized ("GEC").

**Pension and Early Retirement Program Costs:** Pension and early retirement program costs increased by $4.9 million, from $2.7 million in 2009 to $7.6 million in 2010. The increase was primarily related to the amortization of 2008 experience losses associated with the pension plan assets and a lower discount rate at December 31, 2009, which was used to determine the Company's accrued benefit pension obligation associated with its defined benefit pension plan.

**Amortization:** Amortization of property, plant and equipment and intangible assets increased by $1.6 million, from $41.8 million in 2009 to $43.4 million in 2010. Higher amortization was associated with capital and intangible asset expenditures of $78.4 million in 2010.

**Amortization True-Up Deferral:** Amortization of property, plant and equipment and intangible assets is subject to periodic review by external experts via an amortization study. Based on a 2002 amortization study, the PUB ordered the deferred recovery of approximately $11.6 million, $5.8 million in each of 2006 and 2007, related to a variance in accumulated amortization. These deferrals were recorded as an increase in regulatory assets and a decrease in expenses in each year and were amortized evenly over 2008 through 2010.

**Finance Charges:** Finance charges increased by $1.0 million, from $34.6 million in 2009 to $35.6 million in 2010. The increase primarily related to higher interest costs associated with the May 2009 first mortgage sinking fund bond issue.

**Income Taxes:** Income tax expense decreased by $0.2 million, from $16.1 million in 2009 to $15.9 million in 2010. The decrease primarily reflects a lower effective income tax rate partially offset by higher pre-tax earnings. The lower effective income tax rate related primarily to a reduction in the: (i) statutory tax rate; (ii) timing of pension funding; and (iii) the allocation of the Part VI.1 tax liability and related Part I tax deduction from Fortis to Newfoundland Power in 2010. This was partially offset by the income tax treatment of regulatory amortizations and deferrals.

## FINANCIAL POSITION

Explanations of the primary causes of significant changes in the Company's balance sheets between December 31, 2009, and December 31, 2010, follow:

| *($millions)* | Increase (Decrease) | Explanation |
|---|---|---|
| Income Taxes Payable (Net) | 8.5 | Increase reflects current income tax expense in excess of income tax instalments paid. Lower instalments were required in 2010 based upon 2009 income taxes. |
| Assets Held for Sale | 44.7 | Represents reclassification of assets from *Property, Plant and Equipment* related to the new Support Structure Agreement which provides for Bell Aliant Regional Communications Inc. ("Bell Aliant") to purchase 40% of all the Company's joint-use poles. This transaction is subject to PUB approval and is expected to close in 2011. See "Outlook" section of this MD&A. |
| Property, Plant and Equipment | (10.8) | Decrease due to reclassification of assets to *Assets Held for Sale*; amortization; and, customer contributions in aid of construction, partially offset by investment in the electricity system, in accordance with 2010 capital expenditure program. |
| Other Post-Employment Benefits | 5.9 | Increase in post-employment benefits related to accrual of benefits earned during 2010. |
| Long-term Debt, including Current Portion | (3.8) | Decrease reflects less debt required due to higher operating cash flows, lower common share dividends payments and annual sinking fund redemption of outstanding first mortgage sinking fund bonds. |
| Retained Earnings | 19.3 | Earnings, in excess of dividends, retained to finance rate base growth. |

## LIQUIDITY AND CAPITAL RESOURCES

The primary sources of liquidity and capital resources are net funds generated from operations, debt capital markets and bank credit facilities. These sources are used primarily to satisfy capital and intangible asset expenditures, service and repay debt, and pay dividends. A summary of cash flows and cash position for 2010 and 2009 follows:

| *($millions)* | **2010** | **2009** | **Change** |
|---|---|---|---|
| Cash, Beginning of Year | 5.3 | 0.6 | 4.7 |
| Operating Activities | 94.6 | 59.4 | 35.2 |
| Investing Activities | (75.4) | (69.6) | (5.8) |
| Financing Activities | | | |
| Proceeds from Long-term Debt, Net of Issue Costs | - | 64.6 | (64.6) |
| Credit Facility Proceeds (Repayments) | 1.5 | (18.5) | 20.0 |
| Dividends on Common Shares | (15.7) | (25.2) | 9.5 |
| Repayment of Long-term Debt | (5.2) | (5.2) | - |
| Other | (0.9) | (0.8) | (0.1) |
| | (20.3) | 14.9 | (35.2) |
| Cash, End of Year | 4.2 | 5.3 | (1.1) |

## Operating Activities

Cash flow from operating activities totalled $94.6 million in 2010 compared to $59.4 million in 2009. The $35.2 million increase in cash flow from operating activities reflects: (i) the January 1, 2010, customer rate increase; (ii) higher electricity sales; and (iii) timing of income tax payments. This was partially offset by higher interest payments and timing of payments to vendors.

## Investing Activities

Cash flow used in investing activities totalled $75.4 million in 2010 compared to $69.6 million in 2009. The $5.8 million increase was due primarily to higher capital expenditures in 2010 compared to 2009.

A summary of 2010 and 2009 capital and intangible asset expenditures follows:

| *($millions)* | **2010** | **2009** |
|---|---|---|
| Electricity System | | |
| Generation | 5.6 | 8.8 |
| Transmission | 6.4 | 4.4 |
| Substations | 9.6 | 8.2 |
| Distribution | 41.3 | 38.8 |
| Other | 13.5 | 11.1 |
| Intangible Assets | 2.0 | 2.8 |
| Capital and Intangible Asset Expenditures | 78.4 | 74.1 |

The Company's business is capital intensive. Capital investment is required to ensure continued and enhanced performance, reliability and safety of the electricity system, and to meet customer growth. All costs considered to be repairs and maintenance are expensed as incurred. Capital investment also arises for information technology systems and for general facilities, equipment and vehicles. Capital expenditures, and property, plant and equipment repairs and maintenance expense, can vary from year-to-year depending upon both planned electricity system expenditures and unplanned expenditures arising from weather or other unforeseen events.

The Company's annual capital plan requires prior PUB approval. Variances between actual and planned expenditures are generally subject to PUB review prior to inclusion in the Company's rate base.

The PUB has approved the Company's 2011 capital plan which provides for capital expenditures of approximately $73.0 million, approximately half of which relate to construction and capital maintenance of the electricity distribution system.

## Financing Activities

Cash flow used in financing activities totalled $20.3 million in 2010 compared to cash from financing activities of $14.9 million in 2009. The $35.2 million decrease in cash required from financing activities was primarily the result of higher operating cash flows and lower dividends partially offset by higher capital expenditures. The Company's common share dividend policy is to maintain a capital structure composed of 55% debt and 45% common equity. The Company also issued $65 million 6.606%, first mortgage sinking fund bonds on May 25, 2009. The net proceeds from this issuance were used primarily to repay amounts outstanding under the Company's committed credit facility. These amounts were previously borrowed primarily in relation to the Company's capital expenditure program.

The Company has historically generated sufficient annual cash flows from operating activities to service annual interest and sinking fund payments on debt, to pay dividends and to finance a major portion of its annual capital program. Additional financing to fully fund the annual capital program is primarily obtained through the Company's bank credit facilities and these borrowings are periodically refinanced along with any maturing bonds through the issuance of long-term first mortgage sinking fund bonds. The Company currently does not expect any material changes in these basic cash flow and financing dynamics over the foreseeable future, with the exception of an increase in cash flow from the proceeds of the Bell Aliant joint-use pole sale which is expected to extend the timing of the next bond issue.

**Debt:** The Company's credit facilities are comprised of a $100.0 million committed revolving term credit facility ("Committed Facility") and a $20.0 million uncommitted demand facility. Details follow:

| *($millions)* | **2010** | **2009** |
|---|---|---|
| Total Credit Facilities | 120.0 | 120.0 |
| Borrowing, Committed Facility | (15.0) | (13.5) |
| Credit Facilities Available | 105.0 | 106.5 |

During the third quarter of 2010, the $100.0 million committed facility was renegotiated on similar terms as the previous facility, with an increase in pricing, and matures in August 2013.

**Pensions:** As at December 31, 2010, the fair value of the Company's primary defined benefit pension plan assets was $269.3 million compared to fair value of plan assets of $242.7 million as at December 31, 2009. The $26.6 million increase in fair value of plan assets was primarily due to improved market conditions. Details of the plan asset changes are included in Note 9 to the Company's 2010 annual audited financial statements.

In 2009, Newfoundland Power received the Actuarial Valuation Report for its defined benefit pension plan. This report included the funding status of the plan as at December 31, 2008, on a going concern and solvency basis.

The going concern and solvency valuation was based on an adjusted market related value method to determine the actuarial value of assets. Under this method, investment gains (losses) arising during a given year are spread on a straight-line basis over three years, within a 5% corridor of the fair value of the assets for the solvency valuation. The actuarial value of the assets, determined as at December 31, 2008, under the adjusted market related value method for the going concern and solvency valuation was $251.4 million and $222.7 million, respectively.

Based on the report, the solvency deficit as at December 31, 2008, was $6.9 million ($7.7 million inclusive of interest). The solvency deficit is being funded over a five-year period, which commenced in 2009. The Company fulfilled its 2010 annual solvency deficit funding requirement of $1.5 million during the second quarter of 2010.

Based on the December 2008 Actuarial Valuation Report, the defined benefit pension funding contributions, including current service and solvency deficit funding amounts, are expected to be $5.2 million in 2011, $1.6 million in 2012 and $1.5 million in 2013. Actual pension funding contributions may differ from estimated amounts, pending completion of the next actuarial valuation for funding purposes, which is expected to be as of December 31, 2011. The Company expects to be able to meet future pension funding requirements as it expects the amounts will be financed from a combination of cash generated from operations and amounts available for borrowing under existing credit facilities.

**Contractual Obligations:** Details, as at December 31, 2010, of all contractual obligations over the subsequent five years and thereafter, follow:

| *($millions)* | Total | Due Within 1 Year | Due in Years 2 & 3 | Due in Years 4 & 5 | Due After 5 Years |
|---|---|---|---|---|---|
| Credit Facilities (unsecured) | 15.0 | - | 15.0 | - | - |
| First Mortgage Sinking Fund Bonds[1] | 463.7 | 5.2 | 10.4 | 38.6 | 409.5 |
| Total | 478.7 | 5.2 | 25.4 | 38.6 | 409.5 |

[1] *First mortgage sinking fund bonds are secured by a first fixed and specific charge on property, plant and equipment owned or to be acquired by the Company, by a floating charge on all other assets and carry customary covenants.*

**Credit Ratings and Capital Structure:** To ensure continued access to capital at reasonable cost, the Company endeavours to maintain its investment grade credit ratings. Details of the Company's investment grade bond ratings as at December 31, 2010, and 2009 follow:

| | 2010 | | 2009 | |
|---|---|---|---|---|
| Rating Agency | Rating | Outlook | Rating | Outlook |
| Moody's Investors Service | A2 | Stable | A2 | Stable |
| DBRS | A | Stable | A | Stable |

During the first quarter of 2010 and the first quarter of 2011, Moody's and DBRS, respectively, issued updated credit rating reports confirming the Company's existing investment grade bond rating and ratings outlook.

Newfoundland Power manages common share dividends to maintain a capital structure composed of 55% debt and 45% common equity. This capital structure is reflected in customer rates and is consistent with the Company's current investment grade credit ratings. The Company's capital structure as at December 31, 2010, and 2009 follows:

| | 2010 | | 2009 | |
|---|---|---|---|---|
| | $millions | % | $millions | % |
| Total Debt[1] | 471.3 | 53.5 | 473.9 | 54.8 |
| Common Equity | 400.5 | 45.5 | 381.2 | 44.1 |
| Preference Equity | 9.1 | 1.0 | 9.1 | 1.1 |
| Total | 880.9 | 100.0 | 864.2 | 100.0 |

[1] *Includes bank indebtedness, or net of cash and debt issue costs, if applicable.*

The Company expects it will be able to maintain its current investment grade credit ratings in 2011.

**Capital Stock and Dividends:** For the years ended 2010 and 2009, the weighted average number of common shares outstanding was 10,320,270. Dividends on common shares for 2010 were $9.5 million lower than 2009. In 2010, quarterly common share dividends decreased to $0.38 per share from $0.61 per share in 2009. The decrease in common share dividends was to maintain an average capital structure that includes approximately 45% common equity.

There were no changes to the number of preference shares during 2010 compared to 2009.

## RELATED PARTY TRANSACTIONS

The Company provides services to, and receives services from, its parent company, Fortis and other subsidiaries of Fortis. The Company also incurs charges from Fortis for the recovery of general corporate expenses incurred by Fortis. These transactions are in the normal course of business and are recorded at their exchange amounts.

Related party transactions included in revenue and operating expenses for the year ended December 31, 2010, and 2009 follow:

| *($millions)* | 2010 | 2009 |
|---|---|---|
| Revenue[1] | 4.4 | 4.5 |
| Operating Expenses | 2.1 | 1.6 |

[1] *Includes charges for electricity consumed.*

Related party transactions included in accounts receivable at December 31, 2010, were $0.1 million, consistent with 2009.

## FINANCIAL INSTRUMENTS

The carrying values of financial instruments included in current assets, current liabilities, other financial assets, and other financial liabilities approximate their fair value, reflecting their nature, short-term maturity or normal trade credit terms. The fair value of long-term debt is calculated by discounting the future cash flows of each debt instrument at the estimated yield-to-maturity equivalent to benchmark government bonds, with similar terms to maturity, plus a market credit risk premium equal to that of issuers of similar credit quality. Since the Company does not intend to settle its debt instruments before maturity, the fair value estimate does not represent the actual liability, and therefore, does not include exchange or settlement costs.

The carrying and estimated fair values of the Company's long-term debt as at December 31, 2010, and 2009 follows:

| ($millions) | 2010 Carrying Value | 2010 Estimated Fair Value | 2009 Carrying Value | 2009 Estimated Fair Value |
|---|---|---|---|---|
| Long-term debt, including current portion and committed credit facility | 478.7 | 581.3 | 482.4 | 582.0 |

## BUSINESS RISK MANAGEMENT

The following is a summary of the Company's significant business risks.

**Regulation:** The Company's key business risk is regulation. The Company is subject to normal uncertainties facing entities that operate under cost of service regulation. It is dependent on PUB approval of customer rates that permit a reasonable opportunity to recover on a timely basis the estimated costs of providing electricity service, including a fair and reasonable return on rate base. The ability to recover the actual costs of providing service and to earn the approved rates of return depends on achieving the forecasts established in the rate setting process. There can be no assurance that rate orders issued by the PUB will permit the Company to recover the estimated costs of providing electricity service. A failure to obtain acceptable rate orders may adversely affect the operations of the Company, the timing of capital projects, and the Company's credit ratings assigned by rating agencies, which may in turn, negatively affect the results of operations and financial position of the Company.

Between general rate applications, the setting of customer rates through the Formula can cause earnings and cash flows to increase or decrease due to corresponding changes in bond yields which are beyond the Company's control.

**Operating and Maintenance:** The Company's electricity system requires ongoing maintenance and capital investment to ensure its continued performance, reliability and safety. The failure of the Company to properly execute its capital expenditure programs, maintenance programs or the occurrence of significant unforeseen equipment failures could have a material adverse effect on the Company's results of operations, cash flows and financial position. There can be no assurance that any additional maintenance and capital costs will receive regulatory approval for recovery in future customer rates.

**Economic Conditions:** Economic conditions primarily impact the Company's electricity sales, cost of capital and the performance of the defined benefit pension plan. The impact on pensions and cost of capital are discussed below. Electricity sales are influenced by economic factors such as changes in employment levels, personal disposable income and housing starts. Out-migration in rural areas, as well as declining birth rates and increasing death rates associated with an aging population also affect sales. An extended decline in economic conditions would be expected to have the effect of reducing demand for energy over time. In addition to the impact of reduced demand, an extended decline in economic conditions could also impair the ability of customers to pay for electricity consumed, thereby affecting the aging and collection of the Company's accounts receivable. Modest sales growth is currently expected for 2011; however, economic conditions may impact actual future sales.

**Defined Benefit Pension Plan Performance:** The defined benefit pension plan is subject to judgements utilized in the actuarial determination of the accrued pension benefit obligation and the related pension expense. The primary assumptions utilized by management are the expected long-term rate of return on pension plan assets and the discount rate used to value the accrued pension benefit obligation. A discussion of the critical accounting estimates associated with pensions is provided in the "Critical Accounting Estimates - Employee Future Benefits" section of this MD&A.

Pension benefit obligations and related pension expense can be affected by change in the global financial and capital markets. There is no assurance that the pension plan assets will earn the expected long-term rate of return in the future. Market driven changes impacting the performance of the pension plan assets may result in material variations in actual return on pension plan assets from the expected long-term return on the assets. This may cause material changes in future pension funding requirements from current estimates and material changes in future pension expense. Market-driven changes may also impact the discount rate resulting in material variations in future pension funding requirements from current estimates and material changes in future pension expense.

There is also risk associated with measurement uncertainty inherent in the actuarial valuation process as it affects the measurement of pension expense, future funding requirements, the accrued benefit asset and benefit obligation.

The pension risks are mitigated for 2010 and onwards, due to the PUB approved PEVDA to deal with the differences between defined benefit pension expense calculated in accordance with Canadian GAAP and pension expense approved by the PUB for rate setting purposes. Variations in pension expense from that approved by the PUB for rate setting purposes would be recovered from (returned to) customers through the Company's Rate Stabilization Account ("RSA"). The closure of the defined benefit pension plan in 2004 also mitigates the above risk.

**Capital Resources and Liquidity:** The Company's financial position could be adversely affected if it fails to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and the repayment of maturing debt. There can be no assurance that sufficient capital will continue to be available on acceptable terms to repay existing debt and to fund capital expenditures. The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the financial position of the Company, conditions in the capital and bank credit markets, ratings assigned by rating agencies and general economic conditions.

Credit ratings affect the level of credit risk spreads on new long-term bond issues and on the Company's credit facilities. A change in credit ratings could potentially affect access to various sources of capital and increase or decrease the Company's financing costs. During 2010, the Company's credit ratings remained unchanged from 2009. The Company does not anticipate any material adverse rating actions by the credit rating agencies in the near term. However, recent global financial market conditions have placed increased scrutiny on rating agencies and rating agency criteria, which may result in changes to credit rating practices and policies.

The Company has been successful at securing cost-effective capital and expects to have reasonable access to capital in the near to medium terms. In 2010, the Company renegotiated its committed credit facility on similar terms as the previous facility, with an increase in pricing. The increased pricing is not expected to materially impact the Company's financial results in 2011.

Further information on the Company's credit facilities, contractual obligations, including long-term debt maturities and repayments, and cash flow requirements is provided in the "Liquidity and Capital Resources" section of this MD&A and under "Liquidity Risk" in Note 18 to the Company's 2010 annual audited financial statements.

**Interest Rates:** Global financial market conditions could impact the Company's cost of capital as well as impact timing of future long-term bond issues. Market driven changes in interest rates could cause fluctuations in interest costs associated with the Company's bank credit facilities. The Company periodically refinances its credit facilities in the normal course with first mortgage sinking fund bonds, which compose most of its long-term debt, thereby significantly mitigating exposure to short-term interest rate changes.

**Electricity Prices:** Increases in electricity rates can cause changes in customer electricity consumption, which could negatively impact sales and therefore earnings and cash flows. Electricity prices have risen in recent years primarily due to the flow-through of the rising cost of oil used at Hydro's thermal generating station. Future changes or volatility in oil prices may affect electricity prices in a manner that affects sales.

**Purchased Power Cost:** The Company is dependent on Hydro for approximately 93% of its electricity requirements. Purchased power costs are based on a wholesale demand and energy rate structure. The demand and energy rate structure presents the risk of volatility in purchased power costs due to uncertainty in forecasting energy sales and peak billing demand.

Effective January 1, 2008, the PUB ordered the operation of the demand management incentive account (the "DMI"). The DMI limits variations in the unit cost of purchased power related to demand up to 1% of total demand costs reflected in customer rates, or approximately $0.5 million for 2010. The disposition of balances in this account, which would be determined by a further order of the PUB, will consider the merits of the Company's conservation and demand management activities.

With respect to energy charges, as a result of January 1, 2007, changes in Hydro's wholesale rates, the marginal cost of purchased power now exceeds the average cost of purchased power that is embedded in customer rates. To the extent actual electricity sales in any period exceed forecast electricity sales used to set customer rates, the marginal purchased power expense will exceed related revenue. These supply cost dynamics had no material effect on 2010 earnings because the PUB ordered, for 2008 to 2010, that variations in purchased power expense caused by differences between the actual unit cost of energy purchased and that reflected in customer rates be recovered from (returned to) customers through the Company's RSA. Pursuant to the Company's 2010 GRA, the PUB has ordered the continued use of the energy supply cost variance reserve.

**Health and Safety:** The Company is subject to numerous and increasing health and safety laws, regulations and guidelines. Damages and costs could potentially arise due to a variety of events, including human error or misconduct and equipment failure. There is no assurance that any costs which might arise would be recoverable through customer rates and, if substantial, unrecovered costs could have a material adverse effect on the results of operations, cash flows and financial position of the Company. A focus on safety is an integral and continuing component of the Company's core business strategy.

2010 was the Company's third full year under the internationally recognized Occupational Health and Safety Assessment Series 18001 Health and Safety Management System. Continuing to meet this standard improves the Company's ability to capture and track information related to safe work practices and hazard recognition, and enhanced safety management.

**Environment:** The Company is subject to numerous laws, regulations and guidelines governing the management, transportation and disposal of hazardous substances and other waste materials, and otherwise relating to the protection of the environment. Environmental damage and associated costs could potentially arise due to a variety of events, including the impact of severe weather and other natural disasters, human error or misconduct and equipment failure. Costs arising from environmental protection initiatives, compliance with environmental laws, regulations and guidelines or damages may become material to the Company. To identify, mitigate and monitor environmental performance the Company has established an environmental management system ("EMS"). The Company's EMS is compliant with the International Organization for Standardization 14001 standard. As at December 31, 2010, there were no environmental liabilities recorded in the Company's 2010 annual audited financial statements and there were no unrecorded environmental liabilities known to management.

The Company's key environmental hazard relates to risks of contamination of air, soil and water primarily relating to the storage and handling of fuel, the use and/or disposal of petroleum-based products, mainly transformer and lubricating oil containing polychlorinated biphenyls ("PCBs"), in the day-to-day operating and maintenance activities, and emissions from the combustion of fuel required in the generation of electricity.

The Company is also subject to inherent risks, including risk of fires. Electricity transmission and distribution facilities have the potential to cause fires as a result of equipment failure, trees falling on a transmission or distribution line or lightning strikes to wooden poles.

The environmental hazards related to hydroelectric generation operations include the creation of artificial water flows that may disrupt natural habitats and the storage of large volumes of water for the purpose of electricity generation.

**Insurance:** While the Company maintains a comprehensive insurance program, the Company's transmission and distribution assets (i.e. poles and wires) are not covered under insurance for physical damage. This is customary in North America as the cost of the coverage is not considered economical. Insurance is subject to coverage limits as well as time-sensitive claims discovery and reporting provisions, and there is no assurance that the types of liabilities that may be incurred by the Company, including those that may arise relating to environmental matters, will be covered by insurance.

For material uninsured losses, the Company expects that it would seek regulatory relief. However, there is no assurance that regulatory relief would be received. Any major damage to the physical assets of the Company could result in repair costs and customer claims that are substantial in amount and which could have a material adverse effect on the Company's results of operations, cash flows and financial position.

It is expected that existing insurance coverage will be maintained. However, there is no assurance that the Company will be able to obtain or maintain adequate insurance in the future at rates considered reasonable or that insurance will continue to be available on terms comparable to those now existing.

**Weather:** The physical assets of the Company are exposed to the effects of severe weather conditions and other acts of nature. Although the physical assets have been constructed, operated and maintained to withstand severe weather, there is no assurance that they will successfully do so in all circumstances. In the event of a material uninsured loss caused by severe weather conditions or other natural disasters, there is potential to make an application to the PUB for recovery of those costs. However, there can be no assurance that the PUB would approve any such application. Any major damage to the Company's facilities could result in lost revenues, repair costs and customer claims that are substantial in amount, and could result in a material adverse effect on the Company's results of operations, cash flows and financial position.

**Changes in Accounting Standards:** Effective January 1, 2011, Canadian publicly accountable enterprises are required to adopt International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). Due to an unresolved issue on whether or not regulatory assets and liabilities can be recognized based on the current IFRS - *Framework for the Preparation and Presentation of Financial Statements*, the Canadian Accounting Standards Board ("AcSB") offered an optional deferral of the mandatory IFRS changeover date for entities with rate-regulated activities for one year. The Company has elected to avail of the deferral and is currently evaluating the option of adopting United States Generally Accepted Accounting Principles ("US GAAP") effective January 1, 2012, as provided in the "Future Accounting Changes" section of this MD&A.

**Information Technology Infrastructure:** The ability of the Company to operate effectively is dependent upon developing and maintaining its information systems and infrastructure that support electricity operations, provide customers with billing information and support the financial and general operating aspects of the business. System failures could have a material adverse effect on the Company.

**Labour Relations:** Approximately 54% of the employees of the Company are members of the International Brotherhood of Electrical Workers labour union (the "IBEW") which had entered into two collective bargaining agreements with the Company. The two agreements expire on September 30, 2011. The inability to maintain or renew the collective bargaining agreements on acceptable terms could result in increased labour costs, or service interruptions arising from labour disputes that are not provided for in approved rates and that could have a material adverse effect on the results of operations, cash flows and financial position of the Company.

**Human Resources:** The ability of the Company to deliver service in a cost-effective manner is dependent on the ability of the Company to attract, develop and retain a skilled workforce. The Company is faced with demographic challenges relating to trades, technical staff and engineers. An increasing competitive job market may also present future recruitment challenges.

## FUTURE ACCOUNTING CHANGES

**Financial Reporting Standards:** The AcSB confirmed that Canadian GAAP for publicly accountable enterprises would be replaced by IFRS for fiscal years beginning on or after January 1, 2011.

The Company commenced its IFRS conversion project in 2007 when it established a formal project governance structure which included the Newfoundland Power Audit and Risk Committee and senior management. An external advisor was engaged to assist in the IFRS conversion project.

IFRS does not currently provide guidance with respect to accounting for rate-regulated activities. Over the past several years, the IASB discussed and deliberated accounting for rate-regulated activities, but failed to reach a conclusion on any of the associated technical issues. In September 2010, the IASB reconfirmed its earlier view that matters associated with rate-regulated accounting could not be resolved quickly. The IASB, therefore, decided to defer any further discussion on accounting for rate-regulated activities until public consultation on its future agenda is held, and views as to what form a future project might take, if at all, to address accounting for the effects of rate-regulated activities are obtained. Without specific guidance on accounting for rate-regulated activities by the IASB, a transition to IFRS would likely result in the derecognition of some, or perhaps all, of the Company's regulatory assets and liabilities, and net earnings would be expected to be subject to significant volatility under current application of IFRS.

The timing and uncertainty of the IASB's actions, as it relates to rate-regulated activities, has put Canadian rate-regulated entities at a significant disadvantage in terms of their ability to adopt IFRS as of January 1, 2011. Accordingly, the AcSB has provided qualifying entities with an option to defer its changeover to IFRS to January 1, 2012.

While the Company's IFRS Conversion Project has proceeded as planned in preparation for the adoption of IFRS, the Company has elected for the optional one year deferral to January 1, 2012, and therefore, will continue to prepare its financial statements in accordance with current Canadian GAAP for all interim and annual periods ending on or before December 31, 2011.

Due to the continued uncertainty around the timing and adoption of a rate-regulated accounting standard by the IASB, the Company is evaluating the option of adopting US GAAP effective January 1, 2012. Canadian rules allow a reporting issuer to prepare and file its financial statements in accordance with US GAAP by qualifying as a US Securities and Exchange Commission ("SEC") Issuer. The Company is considering becoming an SEC Issuer by December 31, 2011. Several other Canadian investor-owned, rate-regulated utilities are also expected to take a similar approach to possible adoption of US GAAP in 2012.

Based on preliminary analysis, the adoption of US GAAP in 2012 is expected to result in fewer significant changes in the Company's accounting policies as compared to those that may have resulted with the adoption of IFRS. Current Canadian GAAP relies on US GAAP for guidance on accounting for rate-regulated activities which allows the economic impact of rate-regulated activities to be properly recognized in the financial statements in a manner consistent with the timing by which amounts are reflected in customer rates. The Company believes that the continued application of rate-regulated accounting, and the associated recognition of regulatory assets and liabilities under US GAAP, more accurately reflects the impact that rate-regulation has on the Company's financial position and results of operations.

The Company plans to identify the high-level differences between US GAAP and Canadian GAAP by mid-year 2011. The detailed diagnostics and evaluation of both the financial and operational impacts of adopting US GAAP and identification and design of operational and financial business processes is expected to be completed by the third quarter of 2011.

Should the Company not adopt US GAAP, Newfoundland Power will be required to adopt IFRS effective January 1, 2012.

## CRITICAL ACCOUNTING ESTIMATES

Preparation of the Company's financial statements in accordance with Canadian GAAP requires management to make estimates and judgements that affect the reported amounts of assets and liabilities, and the disclosure of contingencies and commitments at the date of the financial statements and the reported amounts of revenue and expenses during the reporting periods. Estimates and judgements are based on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances. Due to changes in facts and circumstances and the inherent uncertainty involved in making estimates, actual results may differ from current estimates. Estimates and judgements are reviewed periodically and, as adjustments become necessary, are reported in earnings in the period they become known. The critical accounting estimates are discussed below.

**Property, Plant and Equipment and Intangible Assets Amortization:** Amortization, by its nature, is an estimate based primarily on the useful lives of assets. Estimated useful lives are based on current facts and historical information, and take into consideration the anticipated physical lives of the assets. Newfoundland Power's amortization methodology, including amortization rates, accumulated amortization and estimated remaining service lives, is subject to a periodic study by external experts. The difference between actual accumulated amortization and that indicated by the amortization study is amortized and included in customer rates in a manner prescribed by the PUB.

The most recently completed amortization study, based on property, plant and equipment and intangible assets in service as at December 31, 2005, indicated an accumulated amortization variance of approximately $0.7 million. The PUB ordered that this variance be amortized equally over 2008 - 2011 and that the revised amortization rates arising from the amortization study be implemented effective January 1, 2008. As a result, the total composite amortization rate declined from 3.5% to 3.4%. These changes did not have a significant impact on the Company's earnings, cash flow or financial position because the changes were reflected in customer rates effective January 1, 2008. As part of the 2010 GRA, the PUB ordered the next amortization study to be based on property, plant and equipment and intangible assets in service as at December 31, 2009. This study is ongoing and is expected to be completed in the first half of 2011.

The estimate of future removal and site restoration costs, net of salvage proceeds, is based on historical experience and future expected cost trends. The balance of this regulatory liability at December 31, 2010, was $49.5 million (December 31, 2009 - $48.7 million). The net amount of estimated future removal and site restoration costs provided for and reported in amortization expense during 2010 was $5.1 million (2009 - $4.8 million).

**Capitalized Overhead:** Newfoundland Power capitalizes overhead costs which are not directly attributable to specific capital assets, but which relate to the overall capital expenditure program. Capitalization reflects estimates of the portions of various general expenses that relate to the overall capital expenditures program in accordance with a methodology ordered by the PUB. GEC is allocated over constructed property, plant and equipment and amortized over their estimated service lives. In 2010, GEC totalled $3.3 million (2009 - $3.0 million). Changes to the methodology for calculating and allocating general overhead costs to property, plant and equipment could have a material impact on the amounts recorded as operating expenses versus property, plant and equipment. However, any change in the fundamental methodology for the calculation and allocation of GEC would require the approval of the PUB.

**Income Taxes:** Effective January 1, 2009, CICA Handbook Section 3465, *Income Taxes* was amended to require the recognition of future income tax assets and liabilities for rate-regulated utilities. Future income tax assets and liabilities are based upon temporary differences between the accounting and tax basis of existing assets and liabilities, the benefit of income tax reductions or tax losses available to be carried forward and the effects of changes in tax laws. The carrying amounts of assets and liabilities are based upon the amounts recorded in the financial statements and are therefore subject to accounting estimates that are inherent to those balances. The timing of the reversal of temporary differences is estimated based upon assumptions of expectations of future results of operations. The composition of future income tax assets and liabilities are likely to change from period to period because of changes in the estimation of these uncertainties.

**Employee Future Benefits:** The Company's primary defined benefit pension plan is subject to judgements utilized in the actuarial determination of the expense and related obligations. The primary assumptions utilized by management in determining the expense and the accrued benefit obligation are the discount rate and the expected long-term rate of return on plan assets. All assumptions are assessed and concluded in consultation with the Company's external actuarial advisor.

The discount rate as at December 31, 2010, which is utilized to determine the accrued pension benefit obligation and the 2011 pension expense, is 5.8% compared to the discount rate of 6.5% as at December 31, 2009. Discount rates reflect market interest rates on high quality bonds with cash flows that match the timing and amount of expected pension benefit payments. The methodology in determining the discount rate was consistent with that used to determine the discount rate in the previous year. The decrease in discount rates reflects lower credit spreads and cost of capital on investment grade corporate bonds.

The expected long-term rate of return on pension plan assets which is used to estimate the 2011 defined benefit pension expense is 7.0%, consistent with 2010. The actual rate of return on pension plan assets during 2010 was approximately 13.5%. As in previous years, an actuary provided the Company with a range of expected long-term pension asset returns based on their internal modelling. The expected long-term return on pension plan assets of 7.0% falls within the normal to optimistic range as indicated by the actuary.

In 2011, the Company expects the pension expense related to its primary defined benefit pension plan to increase by approximately $3.9 million compared to 2010. This is primarily driven by the amortization of net actuarial losses that arose in prior years, and a decrease in the discount rate used in the measurement of the accrued pension benefit obligation.

The following table provides sensitivity to the changes in the primary assumptions associated with the Company's defined benefit pension plan:

| *($millions)* | Pension Expense[1] | Net Accrued Benefit Asset[2] | Accrued Benefit Obligation[2] |
|---|---|---|---|
| Impact of increasing the rate of return on plan assets assumption used during 2010 by 1.0% | (2.4) | 2.4 | - |
| Impact of decreasing the rate of return on plan assets assumption used during 2010 by 1.0% | 2.4 | (2.4) | - |
| Impact of increasing the discount rate assumption used during 2010 by 1.0% | (2.8) | 2.8 | (31.1) |
| Impact of decreasing the discount rate assumption used during 2010 by 1.0% | 3.6 | (3.6) | 38.5 |

1 *For the year ended December 31, 2010. The volatility of future pension expense has been significantly mitigated with the PUB approved PEVDA in which pension expense calculated in accordance with Canadian GAAP and pension expense approved by the PUB for rate setting purposes would be recovered from (returned to) customers through the Company's RSA.*

2 *As at December 31, 2010.*

Other assumptions applied in measuring the defined benefit pension expense and/or the accrued pension benefit obligation were the average rate of compensation increase, average remaining service life of the active employee group, and employee and retiree mortality rates.

The Company's OPEBs are also subject to judgements utilized in the actuarial determination of the expense and related obligation. Assumptions utilized by management in determining OPEBs costs and obligations include the health care cost trend rate and the foregoing assumptions, excluding the expected long-term rate of return on plan assets and average rate of compensation increase.

For 2010 and prior, in accordance with PUB orders, Newfoundland Power expensed the cost of OPEBs on a cash basis, whereby the difference between the cash payments during the year and the expense incurred in the year is deferred as a regulatory asset. Therefore, changes in assumptions resulted in changes in the regulatory asset and did not impact earnings. OPEBs costs deferred as a regulatory asset in 2010 totalled $5.9 million (2009 - $5.6 million) and the regulatory asset at December 31, 2010, was $52.6 million (2009 - $46.7 million).

Effective January 1, 2011, the PUB ordered the adoption of the accrual method of accounting for OPEBs, the amortization on a straight-line basis over 15 years the $52.6 million regulatory asset and the creation of an OPEBs cost variance deferral account. The volatility of future OPEBs expense caused by the adoption of the accrual method has been significantly mitigated with the PUB approved OPEBs cost variance deferral account in which OPEBs expense calculated in accordance with Canadian GAAP and OPEBs expense approved by the PUB for rate setting purposes will be recovered from (returned to) customers through the Company's RSA.

**Asset Retirement Obligations:** The measurement of the fair value of asset retirement obligations ("AROs") requires the Company to make reasonable estimates about the method of settlement and settlement dates associated with legally obligated asset retirement costs. While the Company has AROs for its generation assets and certain distribution and transmission assets, there were no amounts recognized as at December 31, 2010, and December 31, 2009.

The nature, amount and timing of AROs for hydroelectric generation assets cannot be reasonably estimated at this time as these assets are expected to effectively operate in perpetuity given their nature. In the event that environmental issues are identified or hydroelectric generation assets are decommissioned, AROs will be recorded at that time provided the costs can be reasonably estimated. It is management's judgement that identified AROs for its remaining assets are immaterial.

**Revenue Recognition:** The Company recognizes electricity revenue on an accrual basis. Customer bills are issued throughout the month based on meter readings that establish electricity consumption by the customer since the last meter reading. The unbilled revenue accrual for each period is based on estimated electricity sales to customers for the period since the last meter reading at the rates approved by the PUB.

The development of the electricity sales estimates requires analysis of electricity consumption on a historical basis in relation to key inputs such as the current price of electricity, population growth, economic activity, weather conditions and electricity system losses. The estimation process for accrued unbilled electricity consumption will result in adjustments to electricity revenue in the period during which the difference between actual results and those estimated becomes known. As at December 31, 2010, the amount of accrued unbilled revenue recorded in accounts receivable was approximately $28.4 million (December 31, 2009 - $29.3 million).

**Contingencies:** The Company is subject to various legal proceedings and claims associated with the ordinary course of business operations. It is management's judgement that the amount of liability, if any, from these actions would not have a material adverse effect on the Company's financial position or results of operations.

## SELECTED ANNUAL INFORMATION

The following table sets forth the annual information for the years ended December 31, 2010, 2009 and 2008. The financial information has been prepared in accordance with Canadian GAAP for rate-regulated entities. The timing and recognition of certain assets, liabilities, revenue and expense, as a result of regulation, may differ from that otherwise expected using Canadian GAAP for non-regulated entities.

| ($millions, except per share amounts) | 2010 | 2009[1] | 2008 |
|---|---|---|---|
| Results of Operations | | | |
| Revenue | 555.0 | 527.2 | 516.9 |
| Net Earnings Applicable to Common Shares | 35.0 | 32.6 | 32.3 |
| Financial Position | | | |
| Total Assets | 1,191.1 | 1,165.2 | 1,001.9 |
| Total Long-term Liabilities | 704.5 | 695.8 | 534.6 |
| Shareholders' Equity | 409.6 | 390.3 | 383.1 |
| Per Share Data | | | |
| Earnings Applicable to Common Shares[2] | 3.39 | 3.16 | 3.13 |
| Common Dividends Declared[2] | 1.52 | 2.44 | 1.48 |
| Preference Dividends Declared[3] | 2.56 | 2.56 | 2.56 |

1 *Certain comparative figures have been reclassified to comply with the current year's presentation.*
2 *Basic and fully diluted. Based on the weighted average number of common shares outstanding, which was 10,320,270 common shares in each year.*
3 *Based on the aggregate weighted average number of preference shares outstanding in each year, which was 911,098 in both 2010 and 2009 and 935,223 in 2008. In 2010, no preference shares were repurchased (2009 - the Company repurchased 24,125 preference shares at $10 per share; no preference shares were repurchased in 2008).*

The changes from 2009 to 2010 have been discussed previously in this MD&A. The increase in revenue from 2008 to 2009 was primarily the result of electricity sales growth. The increase in total assets and long-term liabilities from 2008 to 2009 was due primarily to the adoption of CICA Handbook Section 3465, *Income Taxes*, along with continued investment in the electricity system and is consistent with the Company's strategy to provide safe, reliable electricity service at the lowest reasonable cost. The increase in common dividends from 2008 to 2009 was to maintain a capital structure composed of approximately 45% common equity and 55% debt.

## FOURTH QUARTER RESULTS

| | 2010 | 2009 | Change |
|---|---|---|---|
| Electricity Sales (*GWh*)[1] | 1,488.2 | 1,473.9 | 14.3 |
| Earnings Applicable to Common Shares | | | |
| $ Millions | 9.2 | 8.6 | 0.6 |
| $ Per Share | 0.89 | 0.84 | 0.05 |
| Cash Flow from Operating Activities *($millions)* | 25.0 | 13.9 | 11.1 |
| Cash Flow used in Investing Activities *($millions)* | (21.0) | (21.0) | - |
| Cash Flow (used in) from Financing Activities *($millions)* | (2.3) | 1.8 | (4.1) |

1 *Reflects normalized electricity sales.*

Electricity sales for the fourth quarter of 2010 increased by 14.3 GWh or 1.0% compared to 2009. The increase in electricity sales was composed of an increase of 1.7% due to customer growth partially offset by a reduction of 0.7% in average consumption.

Earnings for the fourth quarter of 2010 increased by $0.6 million compared to the fourth quarter of 2009. The increase in earnings was primarily the result of the customer rate increase effective January 1, 2010, reflecting rate base growth and a higher ROE embedded in customer rates, along with related timing differences in the rebasing of rates. The increase in earnings also related to higher than anticipated electricity sales and a lower effective income tax rate in the quarter. These increases were partially offset by an increase in operating expenses and higher purchased power costs due to higher water inflows associated with the Company's hydroelectric generating facilities.

Cash from operating activities for the fourth quarter of 2010 increased by $11.1 million compared to the fourth quarter of 2009. The increase in cash flow from operating activities primarily reflects: (i) lower income tax payments; (ii) lower purchased power costs; and (iii) timing of payments to vendors.

Cash from financing activities for the fourth quarter of 2010 decreased by $4.1 million compared to the fourth quarter of 2009. The decrease in cash required from financing activities was primarily the result of higher operating cash flows and lower dividends.

## QUARTERLY RESULTS

The following table sets forth unaudited quarterly information for each of the eight quarters ended March 31, 2009, through December 31, 2010. The quarterly information has been obtained from the Company's interim unaudited financial statements which, in the opinion of management, have been prepared in accordance with Canadian GAAP for rate-regulated entities. The timing and recognition of certain assets, liabilities, revenue and expense, as a result of regulation, may differ from that otherwise expected using Canadian GAAP for non-regulated entities. These financial results are not necessarily indicative of results for any future period and should not be relied upon to predict future performance.

| | First Quarter March 31 | | Second Quarter June 30 | | Third Quarter September 30 | | Fourth Quarter December 31 | |
|---|---|---|---|---|---|---|---|---|
| *(unaudited)* | 2010 | 2009 | 2010 | 2009 | 2010 | 2009 | 2010 | 2009 |
| Electricity Sales *(GWh)* | 1,795.2 | 1,762.9 | 1,220.2 | 1,177.2 | 915.4 | 885.0 | 1,488.2 | 1,473.9 |
| Revenue *($millions)* | 178.3 | 169.7 | 126.2 | 118.1 | 99.0 | 92.9 | 151.5 | 146.5 |
| Net Earnings Applicable to Common Shares *($millions)* | 7.2 | 6.2 | 11.0 | 10.7 | 7.6 | 7.1 | 9.2 | 8.6 |
| Earnings per Common Share *($)*[1] | 0.70 | 0.60 | 1.06 | 1.04 | 0.74 | 0.68 | 0.89 | 0.84 |

[1] *Basic and fully diluted.*

## Seasonality

**Sales and Revenue:** Sales and revenue are significantly higher in the first quarter and significantly lower in the third quarter compared to the remaining quarters. This reflects the seasonality of electricity consumption for heating.

**Earnings:** Beyond the seasonality of electricity consumption for heating, quarterly earnings are impacted by the purchased power rate structure. The Company pays more, on average, for each kilowatt hour ("kWh") of purchased power in the winter months and less, on average, for each kWh of purchased power in the summer months.

These sales, revenues and cost dynamics are expected to yield lower earnings in the first quarter compared to remaining quarters within any given year.

## Trending

**Sales and Revenue:** Year-over-year quarterly electricity sales increases primarily reflect modest customer growth.

**Earnings:** Beyond the impact of expected moderate sales growth, future quarterly earnings and earnings per share are expected to trend with the ROE reflected in customer rates and rate base growth.

## OUTLOOK

The Company's strategy will remain unchanged.

Newfoundland Power is regulated under a cost of service regime. Cost of service regulation entitles the Company to an opportunity to recover its reasonable cost of providing service, including its cost of capital, in each year. Newfoundland Power expects to maintain its investment grade credit ratings in 2011. The Company is currently assessing the requirement for it to file an application with the PUB to recover expected increased costs in 2012.

**The Formula:** In accordance with the operation of the Formula, the Company's rate of return on common equity, for purposes of setting rates, was reduced from 9.00% for 2010 to 8.38% for 2011. As a result, on December 10, 2010, the Company received an Order from the PUB reducing the Company's rate of return on rate base from 8.23%, with a range of 8.05% to 8.41% for 2010, to 7.96%, with a range of 7.78% to 8.14% for 2011.

**Other Post-Employment Benefits:** In 2010, the Company completed a review of its OPEBs provided to employees upon retirement. This review resulted in changes to the OPEBs plan relating to medical benefits and life insurance coverage, effective January 1, 2011. Changes to the plan reduced the Company's OPEBs obligation by approximately $15.0 million and annual OPEBs costs by approximately $2.0 million.

On June 30, 2010, the Company submitted a proposal to the PUB relating to the accounting for, and recovery of, OPEBs costs. The Company recommended that it: (i) adopt the accrual method of accounting for OPEBs costs effective January 1, 2011; (ii) recover the transitional balance or regulatory asset, associated with adoption of accrual accounting over a 15-year period; and (iii) adopt an OPEBs cost variance deferral account to capture differences between OPEBs expense calculated in accordance with Canadian GAAP and OPEBs expense approved by the PUB for rate setting purposes. The application received PUB approval on December 10, 2010.

**Customer Rates:** Effective January 1, 2011, there was an overall average increase in electricity rates charged to customers of approximately 0.8%. The increase is a result of the PUB's recent approval for the Company to change its accounting practices for its OPEBs costs partially offset by the operation of the Formula used annually to set electricity rates in between rate applications.

**Capital Plan:** On July 15, 2010, the Company filed an application with the PUB requesting approval for its 2011 capital expenditure plan totalling $73.0 million. The application was approved by the PUB on November 15, 2010.

**Cost Recovery Deferral Application:** On August 31, 2010, the Company filed an application with the PUB requesting the deferred recovery of expected increased costs in 2011 of $2.4 million due to expiring regulatory amortizations. The application was approved by the PUB on November 29, 2010.

**Support Structure Agreement:** On December 22, 2010, the Company signed a new Support Structure agreement (the "Agreement"), effective January 1, 2011, with Bell Aliant (formerly Aliant Telecom Inc.) where Bell Aliant will buy back 40% of all joint-use poles and related infrastructure at a price of approximately $45.7 million. This represents approximately 5% of Newfoundland Power's rate base. In 2001, Newfoundland Power purchased Bell Aliant's joint-use poles and related infrastructure under a 10-year Joint-Use Facilities Partnership Agreement (“JUFPA”) which expired December 31, 2010. Bell Aliant has rented space on these poles from Newfoundland Power since 2001 with the right to repurchase 40% of all joint-use poles at the end of the term. Bell Aliant exercised the option to buy back these poles from Newfoundland Power.

At December 31, 2010, the Company recorded assets held for sale in the amount of $44.7 million which represents the estimated purchase price less cost to sell. The estimated purchase price will be adjusted upon completion of a pole survey in 2011. Effective January 1, 2011, the Company will no longer be receiving pole rental revenue from Bell Aliant. However, Newfoundland Power will be responsible for the construction and maintenance of Bell Aliant’s support structure requirements throughout 2011. The Agreement with Bell Aliant is not expected to materially impact the Company’s ability to earn a reasonable return on its rate base in 2011. The Company is currently working with Bell Aliant regarding the future operational and financial aspects of this transaction beyond 2011. The Company anticipates the proceeds from this transaction will be used to pay down its short-term debt and maintain its capital structure of 45% common equity.

The Agreement is subject to certain conditions, including PUB approval of the sale of 40% of the Company’s joint-use poles, which must be met by June 30, 2011, or either party may choose to terminate. In the event of termination, the rights and recourses under the JUFPA will remain in effect for both parties. The Company filed an application with the PUB on February 4, 2011, and expects the transaction to close in 2011.

# Management Report

The accompanying 2010 Financial Statements of Newfoundland Power Inc. and all information in the 2010 Annual Report have been prepared by management, who are responsible for the integrity of the information presented, including the amounts that must, of necessity, be based on estimates and informed judgements. These Financial Statements were prepared in accordance with accounting principles generally accepted in Canada, including selected accounting treatments that differ from those used by entities not subject to rate regulation. Financial information contained elsewhere in the 2010 Annual Report is consistent with that in the annual audited Financial Statements.

In meeting its responsibility for the reliability and integrity of the Financial Statements, management has developed and maintains a system of accounting and reporting which provides for the necessary internal controls to ensure transactions are properly authorized and recorded, assets are safeguarded and liabilities are recognized. The systems of the Company focus on the need for training of qualified and professional staff and the effective communication of management guidelines and policies. The effectiveness of the internal controls of Newfoundland Power Inc. is evaluated on an ongoing basis.

The Board of Directors oversees management's responsibility for financial reporting through an Audit & Risk Committee which is composed entirely of external independent directors. The Audit & Risk Committee oversees the external audit of the Company's Annual Financial Statements and the accounting and financial reporting and disclosure processes and policies of the Company. The Audit & Risk Committee meets with management, the shareholders' auditors and the internal auditor to discuss the results of the audit, the adequacy of internal accounting controls and the quality and integrity of financial reporting. The Company's Annual Financial Statements are reviewed by the Audit & Risk Committee with each of management and the shareholders' auditors before the statements are recommended to the Board of Directors for approval. The shareholders' auditors have full and free access to the Audit & Risk Committee.

The Audit & Risk Committee has the duty to review the adoption of, and changes in, accounting principles and practices which have a material effect on the Company's financial statements and to review and report to the Board of Directors on policies relating to accounting and financial reporting and disclosure processes. The Audit & Risk Committee has the duty to review financial reports requiring the approval of the Board of Directors prior to submission to securities commissions or other regulatory authorities, to assess and review management's judgements that are material to reported financial information and to review shareholders' auditors' independence and auditors' fees.

The December 31, 2010, Financial Statements and Management Discussion and Analysis contained in the 2010 Annual Report were reviewed by the Audit & Risk Committee and, on their recommendation, were approved by the Board of Directors of Newfoundland Power Inc. Ernst & Young, LLP, independent auditors appointed by the shareholders of Newfoundland Power Inc. upon recommendation of the Audit & Risk Committee, have performed an audit of the 2010 Financial Statements and their report follows.

Earl Ludlow
President
and Chief Executive Officer

Jocelyn Perry
Vice President, Finance
and Chief Financial Officer

# Independent Auditors' Report

To the Shareholders,
Newfoundland Power Inc.

We have audited the accompanying financial statements of Newfoundland Power Inc., which comprise the balance sheets as at December 31, 2010, and 2009, and the statements of earnings, statements of retained earnings and statements of cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

**Management's Responsibility for the Financial Statements**

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

**Auditors' Responsibility**

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgement, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

**Opinion**

In our opinion, the financial statements present fairly, in all material respects, the financial position of Newfoundland Power Inc. as at December 31, 2010, and 2009 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Chartered Accountants
St. John's, Canada

February 4, 2011

## Statements of Earnings

**For the years ended December 31**

*(in thousands of Canadian dollars except per share amounts)*

| | 2010 | 2009 |
|---|---|---|
| Revenue | $ 554,950 | $ 527,179 |
| Purchased power | 358,443 | 345,656 |
| **Gross Margin** | 196,507 | 181,523 |
| Operating expenses | 54,623 | 49,315 |
| Pension and early retirement program costs | 7,588 | 2,673 |
| Amortization | 43,358 | 41,825 |
| Amortization true-up deferral *(Note 4)* | 3,862 | 3,862 |
| Finance charges *(Note 5)* | 35,633 | 34,555 |
| | 145,064 | 132,230 |
| **Earnings Before Income Taxes** | 51,443 | 49,293 |
| Income taxes *(Note 6)* | 15,870 | 16,092 |
| **Net Earnings** | 35,573 | 33,201 |
| Preference share dividends | 568 | 573 |
| **Net Earnings Applicable to Common Shares** | $ 35,005 | $ 32,628 |
| **Basic and Diluted Earnings per Common Share** | $ 3.39 | $ 3.16 |

## Statements of Retained Earnings

**For the years ended December 31**

*(in thousands of Canadian dollars)*

| | 2010 | 2009 |
|---|---|---|
| **Balance, Beginning of the Year** | $ 310,864 | $ 303,417 |
| Net earnings | 35,573 | 33,201 |
| Dividends | | |
| Preference shares | (568) | (573) |
| Common shares | (15,688) | (25,181) |
| **Balance, End of the Year** | $ 330,181 | $ 310,864 |

*See accompanying notes to financial statements.*

# Balance Sheets
## As at December 31
*(in thousands of Canadian dollars)*

| | 2010 | 2009 *(restated - see Note 20)* |
|---|---|---|
| **Assets** *(Note 13)* | | |
| **Current assets** | | |
| Cash | $ 4,182 | $ 5,308 |
| Accounts receivable | 61,654 | 64,553 |
| Regulatory assets *(Note 4)* | 11,536 | 8,736 |
| Materials and supplies | 992 | 934 |
| Prepaid expenses | 1,327 | 1,376 |
| Income taxes receivable | - | 4,194 |
| | 79,691 | 85,101 |
| **Property, plant and equipment** *(Note 8)* | 776,382 | 787,218 |
| **Regulatory assets** *(Note 4)* | 175,593 | 177,236 |
| **Accrued pension** *(Note 9)* | 97,755 | 97,802 |
| **Assets held for sale** *(Note 7)* | 44,698 | - |
| **Intangible assets** *(Note 10)* | 15,310 | 16,113 |
| **Other assets** *(Note 11)* | 1,647 | 1,717 |
| | $ 1,191,076 | $ 1,165,187 |
| **Liabilities and Shareholders' Equity** | | |
| **Current liabilities** | | |
| Accounts payable and accrued charges | $ 64,269 | $ 65,727 |
| Regulatory liabilities *(Note 4)* | - | 7,087 |
| Current instalments of long-term debt *(Note 13)* | 5,200 | 5,200 |
| Future income taxes *(Note 6)* | 3,211 | 1,068 |
| Income taxes payable | 4,302 | - |
| | 76,982 | 79,082 |
| **Regulatory liabilities** *(Note 4)* | 57,371 | 48,660 |
| **Other post-employment benefits** *(Note 9)* | 52,559 | 46,713 |
| **Other liabilities** *(Note 14)* | 4,253 | 3,960 |
| **Future income taxes** *(Note 6)* | 120,016 | 122,426 |
| **Long-term debt** *(Note 13)* | 470,282 | 474,050 |
| | 781,463 | 774,891 |
| **Shareholders' equity** | | |
| Common shares *(Note 15)* | 70,321 | 70,321 |
| Preference shares *(Note 15)* | 9,111 | 9,111 |
| Retained earnings | 330,181 | 310,864 |
| | 409,613 | 390,296 |
| | $ 1,191,076 | $ 1,165,187 |

Commitments *(Note 19)*

*See accompanying notes to financial statements.*

APPROVED ON BEHALF OF THE BOARD:

Jo Mark Zurel
Director

Peggy Bartlett
Director

# Statements of Cash Flows

**For the years ended December 31**

*(in thousands of Canadian dollars)*

| | 2010 | 2009 |
|---|---|---|
| **Cash From (Used In) Operating Activities** | | |
| Net earnings | $ 35,573 | $ 33,201 |
| **Items not affecting cash** | | |
| Amortization of property, plant and equipment | 40,521 | 38,935 |
| Amortization of intangible assets and other | 3,107 | 3,162 |
| Change in regulatory assets and liabilities | 7,124 | 691 |
| Future income taxes | (1,903) | 502 |
| Employee future benefits | 216 | (4,416) |
| | 84,638 | 72,075 |
| Change in non-cash working capital | 9,928 | (12,695) |
| | 94,566 | 59,380 |
| **Cash From (Used In) Investing Activities** | | |
| Capital expenditures | (76,347) | (71,267) |
| Intangible asset expenditures | (2,034) | (2,808) |
| Contributions from customers | 2,789 | 4,575 |
| Other | 156 | (107) |
| | (75,436) | (69,607) |
| **Cash From (Used In) Financing Activities** | | |
| Proceeds (Repayment) of committed credit facility | 1,500 | (18,500) |
| Proceeds from long-term debt | - | 65,000 |
| Repayment of long-term debt | (5,200) | (5,200) |
| Payment of debt financing costs | (300) | (389) |
| Redemption of preference shares | - | (241) |
| Dividends | | |
| Preference shares | (568) | (573) |
| Common shares | (15,688) | (25,181) |
| | (20,256) | 14,916 |
| **(Decrease) Increase in Cash** | (1,126) | 4,689 |
| Cash, Beginning of the Year | 5,308 | 619 |
| **Cash, End of the Year** | $ 4,182 | $ 5,308 |
| **Cash Flows Include the Following Elements** | | |
| Interest paid | $ 36,127 | $ 34,468 |
| Income taxes paid | $ 6,790 | $ 25,057 |

*See accompanying notes to financial statements.*

# Notes to Financial Statements

## December 31, 2010

Tabular amounts are in thousands of Canadian dollars unless otherwise noted.

## 1. Description of the Business

Newfoundland Power Inc. (the "Company" or "Newfoundland Power") is a regulated electricity utility that operates an integrated generation, transmission and distribution system throughout the island portion of Newfoundland and Labrador. The Company is regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities (the "PUB") and serves over 243,000 customers comprising approximately 86% of all electricity consumers in the Province. The Company is a wholly-owned subsidiary of Fortis Inc. ("Fortis"). Newfoundland Power has an installed generating capacity of 140 megawatts ("MW"), of which approximately 97 MW is hydroelectric generation. It generates approximately 7% of its energy needs and purchases the remainder from Newfoundland and Labrador Hydro ("Hydro").

## 2. Summary of Significant Accounting Policies

These financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). As a result of rate-regulation, the timing of the recognition of certain assets, liabilities, revenues and expenses may differ from that otherwise expected under Canadian GAAP for entities not subject to rate-regulation. These differences are disclosed below and in Note 4.

### Regulation

The Company operates under cost of service regulation as administered by the PUB under the *Public Utilities Act (Newfoundland and Labrador)* ("Public Utilities Act").

The Public Utilities Act provides for the PUB's general supervision of the Company's utility operations and requires the PUB to approve, among other things, customer rates, capital expenditures and the issuance of securities. The Public Utilities Act also entitles the Company an opportunity to recover all reasonable and prudent costs incurred in providing electricity service to its customers, including a just and reasonable return on its rate base. The rate base consists of the net assets required by the Company to provide service to customers.

The determination of the forecast return on rate base, together with the forecast of all reasonable and prudent costs, establishes the revenue requirement upon which the Company's customer rates are determined through a general rate hearing. Rates are bundled to include generation, transmission and distribution services.

Pursuant to the 2010 General Rate Application ("2010 GRA"), the Company's rate of return on rate base for ratemaking purposes was set at 8.23%, with a range of 8.05% to 8.41%, for 2010. This reflects a regulated rate of return on common equity ("ROE") of 9.00% for 2010 compared to 8.95% for 2009. Between general rate hearings, customer rates are established annually through the operation of an automatic adjustment formula (the "Formula"). The Formula sets a ROE which is used to determine the rate of return on rate base. In accordance with the operation of the Formula, as approved by the PUB in 2010, the Company's rate of return on rate base has been set at 7.96%, with a range of 7.78% to 8.14% for 2011.

## Revenue Recognition

Revenue is recognized under the accrual method when service is rendered. Revenue arising from the amortization of certain regulatory assets and liabilities is recognized in the manner prescribed by the PUB, as disclosed in Note 4.

## Property, Plant and Equipment

Property, plant and equipment are stated at values approved by the PUB as at June 30, 1966, with subsequent additions at cost.

Contributions in aid of construction represent the cost of utility property, plant and equipment contributed by customers and government. These contributions are recorded as a reduction in the cost of utility property, plant and equipment.

The Company capitalizes certain overhead costs not directly attributable to specific property, plant and equipment but which do relate to its overall capital expenditure program (general expenses capitalized or "GEC"). The methodology for calculating and allocating GEC among classes of property, plant and equipment is established by PUB order. In the absence of rate-regulation, only those overhead costs directly attributable to construction activity would be capitalized. In 2010, GEC totalled $3.3 million (2009 - $3.0 million).

The Company capitalizes an allowance for funds used during construction ("AFUDC"), which represents the cost of debt and equity financing incurred during construction of property, plant and equipment. AFUDC is calculated in a manner prescribed by the PUB based on a capitalization rate that is the Company's weighted average cost of capital. In 2010, the cost of equity financing capitalized as an AFUDC and deducted from financing charges was approximately $0.4 million (2009 - $0.3 million). In the absence of rate-regulation, this cost of equity financing would be expensed.

Property, plant and equipment are amortized using the straight-line method by applying the amortization rates approved by the PUB and disclosed below to the average original cost, including GEC and AFUDC, of the related assets.

The composite amortization rates for the Company's property, plant and equipment, as well as their service life ranges and average remaining service lives as at December 31, follow:

| | | | Service Life (Years) | | | |
|---|---|---|---|---|---|---|
| | Composite Amortization Rate | | Range | | Average Remaining | |
| | 2010 | 2009 | 2010 | 2009 | 2010 | 2009 |
| Distribution | 3.1% | 3.1% | 16-65 | 16-65 | 23 | 23 |
| Transmission and substations | 2.9 | 2.9 | 31-65 | 31-65 | 26 | 26 |
| Generation | 2.6 | 2.6 | 13-75 | 13-75 | 32 | 32 |
| Transportation and communications | 8.9 | 8.9 | 5-30 | 5-30 | 5 | 5 |
| Buildings | 2.3 | 2.3 | 35-70 | 35-70 | 27 | 27 |
| Equipment | 9.0 | 9.0 | 5-25 | 5-25 | 5 | 5 |
| | 3.4% | 3.4% | | | | |

## 2. Summary of Significant Accounting Policies (cont'd)

### Property, Plant and Equipment (cont'd)

The Company's amortization methodology, including amortization rates, accumulated amortization and estimated remaining service lives, is subject to periodic review by external experts (the "Amortization Study"). The differences between actual accumulated amortization and that indicated by the Amortization Study is treated as an amortization adjustment reserve (the "Amortization True-Up") which is used to increase or decrease amortization expense and is included in customer rates in a manner prescribed by the PUB.

The 2006 Amortization Study, based on property, plant and equipment in service as at December 31, 2005, indicated an Amortization True-Up of approximately $0.7 million. The PUB ordered that it be amortized as a decrease in amortization expense equally over 2008 - 2011.

Upon disposition, the original cost of property, plant and equipment is removed from the asset accounts. That amount, net of salvage proceeds, is also removed from accumulated amortization. As a result, any gain or loss is charged to accumulated amortization and is effectively included in the Amortization True-Up arising from the next Amortization Study. In 2010, approximately $7.7 million (2009 - $6.8 million) of losses were charged to accumulated amortization. In the absence of rate-regulation, these amounts would have been recognized as losses upon disposition.

### Materials and Supplies

Materials and supplies, representing fuel and materials required for maintenance activities, are carried at the lower of cost or net realizable value. Materials and supplies expensed in 2010 and 2009 were immaterial.

### Intangible Assets

Intangible assets are recorded at cost and amortized over their estimated useful lives on a straight-line basis. The weighted average amortization rates for intangible assets in 2010 were 10.0% for computer software (2009 - 10.0%) and 1.6% for land rights (2009 - 1.6%). There was no impact to the Company's financial statements as a result of intangible asset impairments for the years ended December 31, 2010, and 2009.

### Future Income Taxes

Effective January 1, 1981, as prescribed by the PUB, future income tax liabilities are recognized, and recovered in customer rates, on temporary timing differences associated with the cumulative excess of capital cost allowance over amortization of property, plant and equipment, excluding GEC. Effective January 1, 2008, as prescribed by the PUB, future income taxes are recognized and recovered in customer rates on temporary timing differences between pension expense and pension funding.

Future income tax expense (recovery) associated with the Company's regulatory reserves and certain regulatory deferrals is also recognized and included in the determination of customer rates. See Note 4.

Effective January 1, 2011, as prescribed by the PUB, future income taxes are to be recognized and recovered in customer rates on temporary timing differences between other post-employment benefits ("OPEBs") costs recovered using the accrual method and that using the cash method.

Future income tax assets and liabilities associated with other temporary timing differences between the tax basis of assets and liabilities and their carrying amount are not recognized or included in customer rates. Effective January 1, 2009, future income tax assets and liabilities, and related regulatory liabilities and assets are recognized for the amount of future income taxes expected to be refunded to, or recovered from, customers in future electricity rates.

### Employee Future Benefits

Newfoundland Power maintains defined contribution and defined benefit pension plans for its employees and also provides OPEBs. OPEBs are composed of retirement allowances for retiring employees as well as health, medical and life insurance for retirees and their dependants.

### Defined Contribution and Defined Benefit Pension Plans

Defined contribution pension plan costs are expensed as incurred.

The pension costs and accrued benefit obligations of the defined benefit pension plans are actuarially determined using the projected benefit method pro-rated on service and management's best estimate of expected plan investment performance, salary escalation and retirement ages of employees. Pension plan assets are valued using the market-related value where investment returns in excess of or below expected returns are recognized in asset value over a period of three years. The excess of the cumulative net actuarial gain or loss over 10% of the greater of the benefit obligation and the market-related value of plan assets is amortized over the estimated average remaining service period of active employees. The transitional obligation arising from the Company's January 1, 2000, adoption of Section 3461 of the CICA Handbook is being amortized on a straight-line basis over the 18 year expected average remaining service period of plan members at that time. Unamortized past service costs are amortized over a range of 5 - 15 years. See Notes 4 and 9.

Effective January 1, 2010, pursuant to the 2010 GRA, the PUB ordered the creation of a pension expense variance deferral account ("PEVDA"). This account will be charged or credited with the amount by which annual pension expense, recorded in accordance with Canadian GAAP, differs from amounts approved in rates by the PUB. Each year, at March 31, the balance in the PEVDA will be transferred to the Company's Rate Stabilization Account ("RSA") and disposed of in accordance with the operation of the RSA. See Note 4.

### Other Post-Employment Benefits ("OPEBs")

OPEBs costs and the accrued OPEBs obligation are actuarially determined using the projected benefits method prorated on service and best estimate assumptions. The excess of any cumulative net actuarial gain or loss over 10% of the benefit obligation, along with unamortized past service costs is amortized over the estimated average remaining service period of active employees. The transitional obligation arising from the Company's January 1, 2000, adoption of Section 3461 of the CICA Handbook is being amortized on a straight-line basis over the 18 year expected average remaining service period of plan members at that time. See Note 9.

Up to and including December 31, 2010, OPEBs costs were expensed when benefits were paid. In the absence of rate-regulation, OPEBs costs would have been expensed on an accrual basis as actuarially determined. The portion of the actuarially determined costs that has not been recognized as an expense has been deferred as a regulatory asset. See Note 4.

Effective January 1, 2011, the PUB ordered the adoption of the accrual method of accounting for OPEBs, the amortization on a straight-line basis over 15 years of the $52.6 million regulatory asset, and the creation of an OPEBs cost variance deferral account. This account will be charged or credited with the amount by which annual OPEBs expense, recorded in accordance with Canadian GAAP, differs from amounts approved in rates by the PUB. Each year, at March 31, the balance in the OPEBs cost variance deferral account will be transferred to the Company's RSA and disposed of in accordance with the operation of the RSA. See Note 4.

## 2. Summary of Significant Accounting Policies (cont'd)

### Financial Instruments

The Company has designated its financial instruments as follows:

(a) Cash is classified as "Held for Trading". After its initial fair value measurement, any change in fair value is recognized in earnings.
(b) Certain accounts receivable and loans under customer finance plans (Note 11) are classified as "Loans and Receivables".
(c) Short-term borrowings, bank indebtedness, accounts payable and accrued charges, security deposits (Note 14) and long-term debt (Note 13) are classified as "Other Financial Liabilities".

Initial measurement of Loans and Receivables and Other Financial Liabilities are at fair value and incorporates transaction costs, including debt issue costs. Subsequent measurement is at amortized cost using the effective interest method. For the Company, the measurement amount approximates cost.

### Asset Retirement Obligations

Under Canadian GAAP, the Company is required to record the fair value of future expenditures necessary to settle legal obligations associated with asset retirements even though the timing or method of settlement is conditional on future events. Newfoundland Power has determined that there are asset retirement obligations ("AROs") associated with its hydroelectric generation assets and some parts of its transmission and distribution system.

For hydroelectric generation assets, the legal obligation is the environmental remediation of the land and waterways to protect fish habitat. However, this obligation is conditional on the decision to decommission generation assets. The Company currently has no plans to decommission any of its hydroelectric generation assets as they are effectively operated in perpetuity. Therefore, the nature and fair value of any ARO is not currently determinable.

The legal obligations for the transmission and distribution system pertain to the proper disposal of used oil and polychlorinated biphenyls ("PCBs") contaminated assets and obligations related to other Company facilities consist of the removal of fuel storage tanks and asbestos. These obligations were determined to be immaterial and therefore no AROs have been recognized.

The Company will recognize AROs and offsetting property, plant and equipment if the nature and timing can reasonably be determined and the amount is material.

### Use of Accounting Estimates

The preparation of financial statements in accordance with Canadian GAAP requires management to make estimates and judgements that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting periods. Estimates and judgements are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances. Additionally, certain estimates are necessary since the regulatory environment in which the Company operates often require amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. Due to changes in facts and circumstances and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates are reviewed periodically and, as adjustments become necessary, are reported in earnings in the period in which they either, as appropriate, become known or included in customer rates.

## 3. Change in Accounting Policies

### Future Changes

The Canadian Accounting Standards Board ("AcSB") confirmed that Canadian GAAP for publicly accountable enterprises would be replaced by International Financial Reporting Standards ("IFRS") for fiscal years beginning on or after January 1, 2011.

The Company commenced its IFRS conversion project in 2007 when it established a formal project governance structure which included the Newfoundland Power Audit and Risk Committee and senior management. An external advisor was engaged to assist in the IFRS conversion project.

IFRS does not currently provide guidance with respect to accounting for rate-regulated activities. In September 2010, the IASB reconfirmed that matters associated with rate-regulated accounting would take time to be resolved. Without specific guidance on accounting for rate-regulated activities by the IASB, a transition to IFRS would likely result in the derecognition of some, or perhaps all, of the Company's regulatory assets and liabilities, and net earnings would be expected to be subject to significant volatility under current application of IFRS.

Given current uncertainty with rate-regulated activities under IFRS, the AcSB has provided qualifying entities with an option to defer their changeover to IFRS to January 1, 2012.

While the Company's IFRS Conversion Project proceeded as planned in preparation for the adoption of IFRS, the Company has elected for the optional one year deferral to January 1, 2012, and therefore, will continue to prepare its financial statements in accordance with current Canadian GAAP for all interim and annual periods ending on or before December 31, 2011.

Due to the continued uncertainty around the timing and adoption of a rate-regulated accounting standard by the IASB, the Company is evaluating the option of adopting United States Generally Accepted Accounting Principles ("US GAAP") effective January 1, 2012. Canadian rules allow a reporting issuer to prepare and file its financial statements in accordance with US GAAP by qualifying as a US Securities and Exchange Commission ("SEC") Issuer.

Current Canadian GAAP relies on US GAAP for guidance on accounting for rate-regulated activities which allows the economic impact of rate-regulated activities to be properly recognized in the financial statements in a manner consistent with the timing by which amounts are reflected in customer rates. The Company believes that the continued application of rate-regulated accounting, and the associated recognition of regulatory assets and liabilities under US GAAP, more accurately reflects the impact that rate-regulation has on the Company's financial position and results of operations.

The Company plans to identify the high-level differences between US GAAP and Canadian GAAP by mid-year 2011. The detailed diagnostics and evaluation of the financial impacts of adopting US GAAP, and identification and design of operational and financial business processes is expected to be completed by the third quarter of 2011.

Should the Company not adopt US GAAP, Newfoundland Power will be required to adopt IFRS effective January 1, 2012.

## 4. Regulatory Assets and Liabilities

Regulatory assets and liabilities arise as a result of the rate setting process. Regulatory assets represent future revenues associated with certain costs incurred in the current or prior periods that will be, or are expected to be, recovered from customers in future periods through the rate setting process. Regulatory liabilities represent future reductions or limitations of increases in revenues associated with amounts that will be, or are expected to be, refunded to customers through the rate setting process. The accounting methods underlying regulatory assets and liabilities, and their eventual settlement through the rate setting process, are prescribed by the PUB and impact the Company's cash flows.

## 4. Regulatory Assets and Liabilities (cont'd)

The Company's regulatory assets and liabilities which will be, or are expected to be, reflected in customer rates in future periods, follow:

| | 2010 | | 2009 | |
|---|---|---|---|---|
| | Current | Non-current | Current | Non-current |
| Regulatory Assets | | | | |
| Rate stabilization account *(i)* | $ 1,847 | $ 1,876 | $ - | $ 1,836 |
| OPEBs *(ii)* | 3,504 | 49,055 | - | 46,713 |
| Weather normalization account *(iii)* | 2,102 | 2,102 | 2,102 | 3,929 |
| Amortization true-up deferral *(iv)* | - | - | 3,862 | - |
| Pension deferral *(v)* | 1,128 | 3,665 | 1,128 | 4,793 |
| Replacement energy deferral *(vi)* | - | - | 600 | - |
| Deferred GRA costs *(vii)* | 253 | 253 | 451 | 500 |
| Conservation and demand management deferral *(viii)* | 339 | 678 | 339 | 1,018 |
| Future income taxes *(Note 2)* | 2,363 | 117,964 | 254 | 118,447 |
| | $ 11,536 | $ 175,593 | $ 8,736 | $ 177,236 |
| Regulatory Liabilities | | | | |
| Rate stabilization account *(i)* | $ - | $ - | $ 418 | $ - |
| Weather normalization account *(iii)* | - | 6,892 | - | - |
| Municipal tax liability *(ix)* | - | - | 1,363 | - |
| Unbilled revenue *(x)* | - | - | 4,618 | - |
| Purchased power unit cost variance reserve *(xi)* | - | - | 688 | - |
| Future removal and site restoration provision *(xii)* | - | 49,485 | - | 48,660 |
| Demand management incentive account *(xiii)* | - | 994 | - | - |
| | $ - | $ 57,371 | $ 7,087 | $ 48,660 |

**(i) Rate Stabilization Account**

On July 1 of each year, customer rates are recalculated in order to recover from or refund to customers, over the subsequent twelve months, the balance in the RSA as of March 31 of the current year. The amount and timing of the recovery or refund is subject to PUB approval.

The RSA passes through to the Company's customers amounts primarily related to changes in the cost and quantity of fuel used by Hydro to produce the electricity sold to the Company. In the absence of rate-regulation these transactions would be accounted for as incurred.

The RSA passes through, to the Company's customers, variations in purchased power expense caused by differences between the actual unit cost of energy and that reflected in customer rates ("energy supply cost variance"). The marginal cost of purchased power for the Company currently exceeds the average cost that is embedded in customer rates. To the extent actual electricity sales in any period exceed forecast electricity sales used to set customer rates, marginal purchased power expense will exceed related revenue. In the absence of rate-regulation, purchased power expense in 2010 would have been $2.2 million higher (2009 - $2.9 million higher). Pursuant to the 2010 GRA, the PUB ordered continued use of the energy supply cost variance until a further order of the PUB.

Effective January 1, 2010, the PUB approved the PEVDA as described in Note 2 to capture the difference between the annual pension expense approved for rate setting purposes and actual pension expense calculated in accordance with Canadian GAAP. The balance in this account will be transferred to the RSA on March 31 in the year in which the difference arises. The amount transferred to the RSA in 2010 was $0.6 million. In the absence of rate-regulation, revenue in 2010 would have been $0.6 million higher.

Effective January 1, 2011, the PUB approved the OPEBs cost variance deferral account as described in Note 2 to capture the difference between the annual OPEBs expense approved for rate setting purposes and actual OPEBs expense calculated in accordance with Canadian GAAP. The balance in this account will be transferred to the RSA on March 31 in the year in which the difference arises.

The RSA is also adjusted from time-to-time by other amounts as approved by the Board.

**(ii) OPEBs**

This regulatory asset represents the accumulated difference between OPEBs expense recognized on a cash basis for regulatory purposes and an accrual basis for financial reporting purposes since 2000. The accumulated difference arose from the Company's January 1, 2000, adoption of Section 3461 of the CICA Handbook that requires OPEBs expense to be recognized on an accrual basis. Effective January 1, 2011, the PUB ordered the adoption of the accrual method of accounting for OPEBs and the $52.6 million regulatory asset be amortized equally over 15 years. In the absence of rate-regulation, these costs would have been recorded as an operating expense as accrued.

In the absence of rate-regulation, OPEBs costs recognized in 2010 operating expenses would have been $5.8 million higher (2009 - $5.6 million higher).

**(iii) Weather Normalization Account**

The Weather Normalization Account reduces earnings volatility by adjusting purchased power expense and electricity sales revenue to eliminate variances in purchases and sales caused by the difference between normal weather conditions, based on long-term averages, and actual weather conditions. In the absence of rate-regulation these fluctuations would have been recognized in earnings in the period in which they occurred.

The balance in the Weather Normalization Account, because it is based on long-term averages for weather conditions, should tend to zero over time. However, the Company identified non-reversing balances in the account arising from changes in purchased power rates and income tax rates. In 2008, the PUB ordered that a non-reversing balance of approximately $6.8 million be amortized equally over 2008 - 2012 as an increase in purchased power expense of approximately $2.1 million and a decrease in future income tax expense of approximately $0.7 million in each year.

The recovery period for the remaining balance in the Weather Normalization Account is not determinable as it depends on future weather conditions. In the absence of rate-regulation, revenue in 2010 would have been $20.4 million lower (2009 - $5.8 million lower), purchased power expense in 2010 would have been $29.2 million lower (2009 - $8.8 million lower) and future income tax expense in 2010 would have been $2.9 million higher (2009 - $1.0 million higher).

**(iv) Amortization True-Up Deferral**

The PUB ordered the deferred recovery of approximately $5.8 million in each of 2006 and 2007, $11.6 million in aggregate, related to a variance in accumulated amortization identified in the 2002 Amortization Study. These deferrals were recorded as an increase in regulatory assets and a decrease in expenses of $5.8 million in each year. The resultant regulatory asset of approximately $11.6 million was amortized evenly over 2008 through 2010. In the absence of rate-regulation, $11.6 million would have been expensed in the original years incurred.

## 4. Regulatory Assets and Liabilities (cont'd)

**(v) Pension Deferral**

The PUB ordered that approximately $11.3 million of incremental pension costs arising from the Company's 2005 early retirement program be deferred and amortized to pension expense equally over a ten year period beginning April 1, 2005. In the absence of rate-regulation, these costs would have been expensed in 2005.

**(vi) Replacement Energy Deferral**

In 2008, the PUB ordered that a $1.1 million regulatory asset, related to the deferred recovery of the cost of replacement energy purchased during the refurbishment of the Company's Rattling Brook Hydroelectric Generating Plant, be amortized equally over 2008 - 2010. This increased purchased power expense by approximately $0.6 million and decreased future income tax expense by approximately $0.2 million in each year. In the absence of rate-regulation, these costs would have been expensed in 2007.

**(vii) Deferred GRA Costs**

In 2007, the PUB ordered that external costs related to the Company's 2008 GRA be deferred and amortized evenly over 2008 - 2010 as an increase to operating expense. In the absence of rate-regulation, these costs would have been expensed as incurred.

In 2009, the PUB ordered $0.8 million of external costs related to the Company's 2010 GRA be deferred and amortized equally over 2010 - 2012. The actual costs totalled $0.8 million as estimated. In the absence of rate-regulation, these costs would have been expensed in 2009.

**(viii) Conservation and Demand Management Deferral**

In 2009, the PUB ordered the deferral of $1.4 million of costs, associated with the implementation of conservation and demand management programs. In 2009, the PUB ordered that these costs be amortized evenly over 2010 - 2013 as an increase to operating expense. In the absence of rate-regulation, these costs would have been expensed in 2009.

**(ix) Municipal Tax Liability**

The municipal tax liability results from a timing difference related to the recovery and payment of municipal taxes. This arose as a result of the PUB approved municipal tax rate adjustment. The PUB ordered that this liability be amortized as other revenue equally over 2008 - 2010. In the absence of rate-regulation, these costs would have been recorded as revenue as incurred.

**(x) Unbilled Revenue**

Prior to January 1, 2006, revenue from electricity sales was recognized as bills were rendered to customers. Subsequent to this date, revenue is recognized on an accrual basis. The difference between revenue recognized on a billed basis and revenue recognized on an accrual basis as at December 31, 2005, was recorded on the balance sheet as a regulatory liability. As ordered by the PUB, the Company amortized as an increase to revenue approximately $4.6 million of this regulatory liability in 2010 (2009 - $4.6 million). In the absence of rate-regulation, all the unbilled revenue would have been recognized as revenue during 2005.

**(xi) Purchased Power Unit Cost Variance Reserve**

In 2007, the PUB ordered the discontinuance of the purchased power unit cost variance reserve and that the December 31, 2006, balance in the reserve of approximately $1.3 million be amortized over 2008 - 2010 as a decrease to purchased power. In 2008, the PUB ordered that the balance in the account related to 2007 be transferred to the RSA. In the absence of rate-regulation, the balance in the account would have been expensed as incurred.

**(xii) Future Removal and Site Restoration Provision**

This regulatory liability represents amounts collected in customer electricity rates over the life of certain property, plant and equipment which are attributable to removal and site restoration costs that are expected to be incurred in the future. Actual removal and site restoration costs, net of salvage proceeds, are recorded against the regulatory liability when incurred.

The regulatory liability represents the amount of expected future removal and site restoration costs associated with property, plant and equipment in service as at December 31, calculated using current amortization rates as approved by the PUB. In the absence of rate-regulation, removal and site restoration costs, net of salvage proceeds, would have been recognized as an operating expense when incurred.

**(xiii) Demand Management Incentive Account ("DMI")**

Through the DMI, variations in the unit cost of purchased power related to demand are limited, at the discretion of the PUB, to 1% of demand costs reflected in customer rates. The disposition of balances in this account, which would be determined by a further order of the PUB, will consider the merits of the Company's conservation and demand management activities. In the absence of rate-regulation, purchased power expense would have been $1.0 million lower in 2010 and would have had no impact in 2009.

## 5. Finance Charges

| | 2010 | 2009 |
|---|---|---|
| Interest - first mortgage sinking fund bonds | $ 35,850 | $ 34,547 |
| Interest - committed credit facility | 316 | 396 |
| Interest - other | 18 | 15 |
| Total interest expense | 36,184 | 34,958 |
| Amortization - debt issue costs | 190 | 185 |
| Amortization - committed credit facility costs | 42 | 50 |
| Amortization - capital stock issue costs | 37 | 37 |
| AFUDC *(Note 2)* | (820) | (675) |
| | $ 35,633 | $ 34,555 |

## 6. Income Taxes

Income taxes vary from the amount that would be determined by applying statutory income tax rates to pre-tax earnings. A reconciliation of the combined federal and provincial statutory income tax rate to the Company's effective income tax rate follows:

## 6. Income Taxes (cont'd)

| | 2010 | 2009 |
|---|---|---|
| Accounting income per financial statements | $ 51,443 | $ 49,293 |
| Statutory tax rate | 32.0% | 33.0% |
| Expected tax expense (statutory rate) | 16,462 | 16,267 |
| Items capitalized vs. expensed | (1,323) | (1,226) |
| Capital cost allowance vs. amortization | 1,009 | 1,113 |
| Pension funding vs. pension expense | (20) | 232 |
| Other timing differences | (341) | (53) |
| Unbilled revenue | (1,309) | (1,524) |
| Regulatory deferrals | 1,392 | 1,283 |
| Income tax expense | $ 15,870 | $ 16,092 |
| Effective income tax rate | 30.9% | 32.6% |

The composition of the Company's income tax expense follows:

| | 2010 | 2009 |
|---|---|---|
| Current income tax expense | $ 17,773 | $ 15,590 |
| Future income tax (recovery) expense | (267) | 3,382 |
| Regulatory adjustment | (1,636) | (2,880) |
| | $ 15,870 | $ 16,092 |

The composition of the Company's future income tax liability follows:

| | 2010 | 2009 |
|---|---|---|
| **Future income tax liability (asset)** | | |
| Property, plant and equipment/intangibles | $ 102,964 | $ 97,887 |
| Regulatory assets | 25,988 | 27,265 |
| Regulatory liabilities | (23,463) | (22,373) |
| Employee future benefits | 16,541 | 19,575 |
| Debt financing costs | 1,197 | 1,140 |
| **Net future income tax liability** | $ 123,227 | $ 123,494 |
| | | |
| Current future income tax liability | 3,211 | 1,068 |
| Long-term future income tax liability | 120,016 | 122,426 |
| **Net future income tax liability** | $ 123,227 | $ 123,494 |

As at December 31, 2010, the Company had no capital losses (2009 - Nil) carried forward.

## 7. Assets Held for Sale

On December 22, 2010, the Company signed a new Support Structure Agreement ("the Agreement"), effective January 1, 2011, with Bell Aliant (formerly Aliant Telecom Inc.) where Bell Aliant will buy back 40% of all joint-use poles and related infrastructure at a price of approximately $45.7 million. This represents approximately 5% of Newfoundland Power's rate base. In 2001, Newfoundland Power purchased Bell Aliant's joint-use poles and related infrastructure under a 10-year Joint-Use Facilities Partnership Agreement ("JUFPA") which expired December 31, 2010. Bell Aliant has rented space on these poles from Newfoundland Power since 2001 with the right to repurchase 40% of all joint-use poles at the end of the term. Bell Aliant exercised the option to buy back these poles from Newfoundland Power.

At December 31, 2010, the Company recorded assets held for sale in the amount of $44.7 million which represents the estimated purchase price less cost to sell. The estimated purchased price is expected to be adjusted upon completion of a pole survey in 2011. Effective January 1, 2011, as a result of the sale, the Company will no longer be receiving pole rental revenue from Bell Aliant. However, Newfoundland Power will be responsible for the construction and maintenance of Bell Aliant's support structure requirements throughout 2011.

The Agreement is subject to certain conditions, including PUB approval of the sale of 40% of the Company's joint-use poles, which must be met by June 30, 2011, or either party may choose to terminate. In the event of termination, the rights and recourses under the JUFPA will remain in effect for both parties. The Company filed an application with the PUB on February 4, 2011, and expects the transaction to close in 2011.

## 8. Property, Plant and Equipment

| | Cost | | Accumulated Amortization | | Net Book Value | |
|---|---|---|---|---|---|---|
| | 2010 | 2009 | 2010 | 2009 | 2010 | 2009 |
| Distribution | $ 752,901 | $ 718,921 | $ 274,142 | $ 261,404 | $ 478,759 | $ 457,517 |
| Transmission and substations | 246,762 | 234,154 | 90,812 | 88,199 | 155,950 | 145,955 |
| Generation | 173,314 | 168,087 | 53,259 | 49,478 | 120,055 | 118,609 |
| Transportation and communications | 34,716 | 33,426 | 18,138 | 16,710 | 16,578 | 16,716 |
| Land, buildings and equipment | 69,489 | 68,553 | 28,154 | 27,362 | 41,335 | 41,191 |
| Construction in progress | 3,584 | 2,967 | - | - | 3,584 | 2,967 |
| Construction materials | 4,819 | 4,263 | - | - | 4,819 | 4,263 |
| | 1,285,585 | 1,230,371 | 464,505 | 443,153 | 821,080 | 787,218 |
| Less assets held for sale *(Note 7)* | (72,775) | - | (28,077) | - | (44,698) | - |
| | $ 1,212,810 | $ 1,230,371 | $ 436,428 | $ 443,153 | $ 776,382 | $ 787,218 |

Distribution assets are used to distribute low voltage electricity to customers and include poles, towers and fixtures, low voltage wires, transformers, overhead and underground conductors, street lighting, metering equipment and other related equipment. Transmission and substations assets are used to transmit high voltage electricity to distribution assets and include poles, high voltage wires, switching equipment, transformers and other related equipment. Generation assets are used to generate electricity and include hydroelectric and thermal generating stations, gas and combustion turbines, dams, reservoirs and other related equipment. Transportation and communications assets include vehicles as well as telephone, radio and other communications equipment. Land, buildings and equipment are used generally in the provision of electricity service, but not specifically in the distribution, transmission or generation of electricity or specifically related to transportation and communication activities.

## 9. Employee Future Benefits

The Company's defined contribution plans are its individual and group registered retirement savings plans, and an unfunded supplementary employee retirement plan ("SERP"). Benefits are based upon employee earnings. The accrued benefit liability for the SERP is included in other liabilities on the Company's balance sheets (Note 14). During 2010, the Company expensed approximately $1.3 million (2009 - $1.2 million) related to these plans.

The Company's defined benefit plans are its funded defined benefit pension plan, an unfunded pension uniformity plan ("PUP") and OPEBs. Both pension plans are closed to new entrants and provide benefits based on a percentage of the highest 36 consecutive months average base earnings and the employee's years of service. The accrued benefit obligation for all of the Company's defined benefit plans, and the market-related value of plan assets for the Company's funded primary defined benefit pension plan, are measured for accounting purposes as at December 31 of each year. The most recent actuarial valuation of the Company's defined benefit pension plans for funding purposes was as of December 31, 2008, and the next valuation is expected to be as of December 31, 2011. The most recent actuarial valuation of the Company's OPEBs was December 1, 2008.

The accrued benefit asset for the Company's funded primary defined benefit pension plan is included in accrued pension on the Company's balance sheets. The accrued benefits liability for the PUP is included in other liabilities (Note 14).

Details of the Company's defined benefit plans follow:

| | 2010 | | | 2009 | | |
|---|---|---|---|---|---|---|
| | | Unfunded | | | Unfunded | |
| | Funded | PUP | OPEB | Funded | PUP | OPEB |
| **Change in accrued benefit obligation** | | | | | | |
| Balance, beginning of year | $ 221,936 | $ 2,318 | $ 69,667 | $ 190,391 | $ 2,169 | $ 59,636 |
| Current service costs | 4,194 | - | 1,032 | 3,420 | - | 1,008 |
| Interest cost | 14,172 | 144 | 4,673 | 13,923 | 154 | 4,485 |
| Benefits paid | (11,902) | (215) | (1,696) | (12,131) | (215) | (1,304) |
| Plan amendments[1] | - | - | (15,191) | - | - | 1,004 |
| Actuarial losses | 24,036 | 142 | 10,749 | 26,333 | 210 | 4,838 |
| Balance, end of year | $ 252,436 | $ 2,389 | $ 69,234 | $ 221,936 | $ 2,318 | $ 69,667 |
| **Change in fair value of plan assets** | | | | | | |
| Balance, beginning of year | $ 242,731 | $ - | $ - | $ 212,599 | $ - | $ - |
| Return on assets | 17,002 | - | - | 17,386 | - | - |
| Benefits paid | (11,902) | (215) | (1,696) | (12,131) | (215) | (1,304) |
| Actuarial gains | 15,221 | - | - | 18,725 | - | - |
| Employee contributions | 1,211 | - | - | 1,286 | - | - |
| Employer contributions | 4,999 | 215 | 1,696 | 4,866 | 215 | 1,304 |
| Balance, end of year | $ 269,262 | $ - | $ - | $ 242,731 | $ - | $ - |

| | 2010 | | | 2009 | | |
|---|---|---|---|---|---|---|
| | | Unfunded | | | Unfunded | |
| | Funded | PUP | OPEB | Funded | PUP | OPEB |
| **Funded status** | | | | | | |
| Surplus (deficit), end of year | $ 16,826 | $ (2,389) | $ (69,234) | $ 20,795 | $ (2,318) | $ (69,667) |
| Unamortized net actuarial loss | 69,798 | 594 | 21,547 | 64,376 | 474 | 11,093 |
| Unamortized transitional obligation *(Note 2)* | 9,010 | 326 | 9,429 | 10,297 | 373 | 10,857 |
| Unamortized past service costs *(Note 2)* | 2,121 | 1 | (14,301) | 2,334 | 1 | 1,004 |
| Accrued benefit asset (liability), end of year | $ 97,755 | $ (1,468) | $ (52,559) | $ 97,802 | $ (1,470) | $ (46,713) |
| **Effect of 1% increase in health care cost trends on:** | | | | | | |
| Accrued benefit obligation | - | - | $ 8,587 | - | - | $ 9,439 |
| Service costs and interest cost | - | - | $ 862 | - | - | $ 830 |
| **Effect of 1% decrease in health care cost trends on:** | | | | | | |
| Accrued benefit obligation | - | - | $ (7,033) | - | - | $ (7,606) |
| Service costs and interest cost | - | - | $ (679) | - | - | $ (655) |
| **Significant assumptions** | | | | | | |
| Discount rate during year | 6.50% | 6.50% | 6.70% | 7.50% | 7.50% | 7.50% |
| Discount rate as at December 31 | 5.75% | 5.75% | 5.75% | 6.50% | 6.50% | 6.70% |
| Expected long-term rate of return on plan assets | 7.00% | - | - | 7.00% | - | - |
| Rate of compensation increases | 4.00% | 4.00% | 4.00% | 4.00% | 4.00% | 4.00% |
| Health care cost trend increases as at December 31 | - | - | 4.55% | - | - | 4.50% |
| Expected average remaining service of active employees | 10 years | 10 years | 15.5 years | 11 years | 11 years | 14 years |
| **Net benefit expense** | | | | | | |
| Current service costs | $ 2,983 | $ - | $ 1,032 | $ 2,134 | $ - | $ 1,008 |
| Interest cost | 14,172 | 144 | 4,673 | 13,923 | 154 | 4,485 |
| Expected return on plan assets | (17,002) | - | - | (17,386) | - | - |
| Amortization of transitional obligation | 1,287 | 47 | 1,428 | 1,287 | 47 | 1,428 |
| Amortization of net actuarial loss | 3,393 | 22 | 295 | - | 5 | 22 |
| Amortization of past service costs | 212 | - | 114 | 253 | - | - |
| Regulatory adjustment *(Note 4)* | 1,128 | - | (5,846) | 1,128 | - | (5,639) |
| Net benefit expense | $ 6,173 | $ 213 | $ 1,696 | $ 1,339 | $ 206 | $ 1,304 |
| **Asset allocation** | | | | | | |
| Fixed income | 39% | - | - | 40% | - | - |
| Equities | 42% | - | - | 40% | - | - |
| Foreign equities | 19% | - | - | 20% | - | - |

[1] *The Company amended its OPEBs plan effective January 1, 2011. The key plan amendments include the introduction of a 50% member-paid cost sharing arrangement for retirees over the age of 65, the removal of the current $5,000 annual benefit cap, and the introduction of drug dispensing fees. The plan changes will not impact existing retirees. Employees who retire on or before December 31, 2012, or are eligible for full pension by December 31, 2012, can choose between either plan.*

*The impact of this amendment is being amortized evenly over the next 10 years which is the expected average remaining service period to qualify for a full pension.*

## 10. Intangible Assets

| | Cost | | Accumulated Amortization | | Net Book Value | |
|---|---|---|---|---|---|---|
| | 2010 | 2009 | 2010 | 2009 | 2010 | 2009 |
| Computer software | $ 29,223 | $ 30,533 | $ 16,339 | $ 16,892 | $ 12,884 | $ 13,641 |
| Land rights | 6,780 | 6,754 | 4,354 | 4,282 | 2,426 | 2,472 |
| | $ 36,003 | $ 37,287 | $ 20,693 | $ 21,174 | $ 15,310 | $ 16,113 |

## 11. Other Assets

| | 2010 | 2009 |
|---|---|---|
| Customer finance plans | $ 1,647 | $ 1,679 |
| Capital stock issue costs | - | 38 |
| | $ 1,647 | $ 1,717 |

Customer finance plans represent the non-current portion of loans to customers for certain new service requests and energy efficiency upgrades. The current portion of these loans is classified as accounts receivable. In the case of new service requests, and as prescribed by the PUB, interest is charged at a fixed rate of prime plus 3% for repayment periods up to 60 months and prime plus 4% for repayment periods of 61 months to 120 months. In the case of energy efficiency upgrades, interest is charged at a fixed rate of prime plus 4% for a maximum repayment period of 60 months. All loan instalments are made through the customers' monthly electricity bill payments. The balance of any loan may be repaid at any time without penalty.

## 12. Credit Facilities

Newfoundland Power has unsecured bank credit facilities of $120.0 million comprised of a syndicated $100.0 million committed revolving term credit facility which matures on August 27, 2013, and a $20.0 million demand facility. During the year, the $100.0 million committed credit facility was renegotiated on similar terms as the previous facility, with an increase in pricing.

Borrowings under the committed credit facility have been classified as long-term as the committed credit facility expires in 2013. Management intends to refinance these amounts in the future with the issuance of other long-term debt. These borrowings are in the form of bankers acceptances bearing interest based on the daily Canadian Deposit Offering Rate for the date of borrowing plus a stamping fee. Standby fees on the unutilized portion of the committed credit facility are payable quarterly in arrears at a fixed rate of 0.3125%. Borrowings under the demand facility are classified as current and interest is calculated at the daily prime rate and is payable monthly in arrears.

The utilized and unutilized credit facilities as at December 31 follow:

| | 2010 | 2009 |
|---|---|---|
| Total credit facilities | $ 120,000 | $ 120,000 |
| Borrowings under committed credit facility *(Note 13)* | (15,000) | (13,500) |
| Credit facilities available | $ 105,000 | $ 106,500 |

## 13. Long-term Debt

| | Maturity Date | 2010 | 2009 |
|---|---|---|---|
| First mortgage sinking fund bonds | | | |
| 10.550% $40 million Series AD | 2014 | $ 30,153 | $ 30,553 |
| 10.900% $40 million Series AE | 2016 | 32,400 | 32,800 |
| 10.125% $40 million Series AF | 2022 | 32,800 | 33,200 |
| 9.000% $40 million Series AG | 2020 | 33,600 | 34,000 |
| 8.900% $40 million Series AH | 2026 | 34,435 | 34,835 |
| 6.800% $50 million Series AI | 2028 | 44,000 | 44,500 |
| 7.520% $75 million Series AJ | 2032 | 69,000 | 69,750 |
| 5.441% $60 million Series AK | 2035 | 56,400 | 57,000 |
| 5.901% $70 million Series AL | 2037 | 67,200 | 67,900 |
| 6.606% $65 million Series AM | 2039 | 63,700 | 64,350 |
| Committed credit facility *(Note 12)* | 2013 | 15,000 | 13,500 |
| | | 478,688 | 482,388 |
| Less: current instalments of long-term debt | | 5,200 | 5,200 |
| | | 473,488 | 477,188 |
| Less: debt issue costs | | 3,206 | 3,138 |
| | | $ 470,282 | $ 474,050 |

First mortgage sinking fund bonds are secured by a first fixed and specific charge on property, plant and equipment owned or to be acquired by the Company and by a floating charge on all other assets. They require an annual sinking fund payment of 1% of the original principal balance.

Future payments required to meet sinking fund instalments, maturities of long-term debt and long-term credit facilities follow:

| Year | $thousands |
|---|---|
| 2011 | 5,200 |
| 2012 | 5,200 |
| 2013 | 20,200 |
| 2014 | 33,753 |
| 2015 | 4,800 |
| Thereafter | 409,535 |

## 14. Other Liabilities

| | 2010 | 2009 |
|---|---|---|
| Defined benefit pension liability - unfunded *(Note 9)* | $ 1,468 | $ 1,470 |
| Security deposits | 705 | 581 |
| Defined contribution pension liability *(Note 9)* | 2,080 | 1,909 |
| | $ 4,253 | $ 3,960 |

## 14. Other Liabilities (cont'd)

Security deposits are advance cash collections from certain customers to guarantee the payment of electricity bills. The security deposit liability includes interest credited to customer deposits. The current portion of security deposits is reported in accounts payable and accrued charges.

## 15. Capital Stock

*Authorized*

(a) an unlimited number of Class A and Class B Common Shares without nominal or par value. The shares of each class are inter-convertible on a share-for-share basis and rank equally in all respects including dividends. The Board of Directors may provide for the payment, in whole or in part, of any dividends to Class B shareholders by way of a stock dividend;

(b) an unlimited number of First Preference Shares and Second Preference Shares without nominal or par value, except that each Series A, B, D and G First Preference Share has a par value of $10. The issued First Preference Shares are entitled to cumulative preferential dividends and are redeemable at the option of the Company at a premium not in excess of the annual dividend rate. Series D and G First Preference Shares are subject to the operation of purchase funds and the Company has the right to purchase limited amounts of these shares at or below par.

*Issued*

| | 2010 | | 2009 | |
|---|---|---|---|---|
| | Number of Shares | Amount | Number of Shares | Amount |
| Class A common shares | 10,320,270 | $ 70,321 | 10,320,270 | $ 70,321 |
| First preference shares | | | | |
| 5.50% Series A | 179,225 | 1,792 | 179,225 | 1,792 |
| 5.25% Series B | 337,983 | 3,380 | 337,983 | 3,380 |
| 7.25% Series D | 210,890 | 2,109 | 210,890 | 2,109 |
| 7.60% Series G | 183,000 | 1,830 | 183,000 | 1,830 |
| | 911,098 | $ 9,111 | 911,098 | $ 9,111 |

At December 31, 2010, Fortis held 232,194 or approximately 25.5% of the Company's issued and outstanding First Preference Shares.

## 16. Related Party Transactions

The Company provides services to, and receives services from, its parent company, Fortis, and other subsidiaries of Fortis. The Company also incurs charges from Fortis for the recovery of general corporate expenses incurred by Fortis. Related party revenue primarily relates to electricity sales. These transactions are in the normal course of business and are recorded at their exchange amounts.

Related party transactions included in revenue, operating expenses and finance charges in 2010 and 2009, and in accounts receivable at December 31 of these years, follow:

| | 2010 | | 2009 | |
|---|---|---|---|---|
| | Fortis | Other Affiliates | Fortis | Other Affiliates |
| Revenue | $ 189 | $ 4,255 | $ 181 | $ 4,313 |
| Operating expenses | 1,863 | 250 | 1,561 | 68 |
| Accounts receivable | $ 45 | $ 39 | $ 52 | $ 26 |

## 17. Capital Management

Newfoundland Power's primary objectives when managing capital are: (i) to ensure continued access to capital at reasonable cost; and (ii) to provide an adequate return to its common shareholder commensurate with the level of risk associated with the shareholder's investment in the Company.

The Company requires ongoing access to capital because its business is capital intensive. Capital investment is required to ensure continued and enhanced performance, reliability and safety of its electricity systems and to meet customer growth.

The Company operates under cost of service regulation. The cost of capital is ultimately borne by its customers. Access to capital at reasonable cost is a core aspect of the Company's business strategy, which is to operate a sound electricity system and to focus on the safe, reliable delivery of electricity service to its customers in the most cost-efficient manner possible.

The capital managed by the Company is composed of debt (first mortgage sinking fund bonds, bank credit facilities, short-term borrowings and cash/bank indebtedness), common equity (common shares and retained earnings) and preference equity.

The Company has historically generated sufficient annual cash flows from operating activities to service annual interest and sinking fund payments on debt, to pay dividends and to finance a major portion of its annual capital program. Additional financing to fully fund the annual capital program is primarily obtained through the Company's bank credit facilities and these borrowings are periodically refinanced along with any maturing bonds through the issuance of long-term first mortgage sinking fund bonds. The Company currently does not expect any material changes in these basic cash flow and financing dynamics over the foreseeable future, with the exception of an increase in cash flow from the Bell Aliant joint-use pole sale (Note 7) which is expected to extend the timing of the next bond issue.

Newfoundland Power endeavours to maintain a capital structure comprised of approximately 55% debt and 45% common equity. This capital structure is reflected in customer rates. It is also consistent with the Company's current investment grade credit ratings, thereby ensuring continued access to capital at reasonable cost. The Company maintains this capital structure primarily by managing its common share dividends.

A summary of the Company's capital structure as at December 31 follows:

| | 2010 | | 2009 | |
|---|---|---|---|---|
| | $ | % | $ | % |
| Debt[1] | 471,300 | 53.5 | 473,942 | 54.8 |
| Common equity | 400,502 | 45.5 | 381,185 | 44.1 |
| Preference equity | 9,111 | 1.0 | 9,111 | 1.1 |
| | 880,913 | 100.0 | 864,238 | 100.0 |

[1] *Includes bank indebtedness or net of cash, if applicable.*

## 17. Capital Management (cont'd)

The issuance of debt with a maturity that exceeds one year requires the prior approval of the PUB. The issuance of first mortgage sinking fund bonds is subject to an earnings covenant whereby the ratio of: (i) annual earnings applicable to common shares, before bond interest and tax; to (ii) annual bond interest incurred plus annual bond interest to be incurred on the contemplated bond issue, must be two times or higher. Under its committed credit facility, the Company must also ensure that its Debt to Capitalization ratio does not exceed 0.65:1.00 at any time. During the year, and as at December 31, 2010, the Company was in compliance with all of its debt covenants.

## 18. Financial Instruments

The Company has designated its financial instruments as at December 31 as follows:

| | 2010 | | 2009 | |
|---|---|---|---|---|
| | Carrying Value | Estimated Fair Value | Carrying Value | Estimated Fair Value |
| **Held for trading** | | | | |
| Cash | $ 4,182 | $ 4,182 | $ 5,308 | $ 5,308 |
| **Loans and receivables** | | | | |
| Accounts receivable | 61,654 | 61,654 | 64,553 | 64,553 |
| Customer finance plans[1] | 1,647 | 1,647 | 1,679 | 1,679 |
| **Other financial liabilities** | | | | |
| Accounts payable and accrued charges | 64,269 | 64,269 | 65,727 | 65,727 |
| Security deposits[2] | 705 | 705 | 581 | 581 |
| Long-term debt, including current portion and committed credit facility | $ 478,688 | $ 581,275 | $ 482,388 | $ 581,989 |

[1] *Included in other assets on the balance sheet.*
[2] *Included in other liabilities on the balance sheet.*

Fair Values: The fair value of long-term debt, including current portion and committed credit facility, is calculated by discounting the future cash flows of each debt instrument at the estimated yield-to-maturity equivalent to benchmark government bonds, with similar terms to maturity, plus a market credit risk premium equal to that of issuers of similar credit quality. Since the Company does not intend to settle its debt instruments before maturity, the fair value estimate does not represent an actual liability and, therefore, does not include exchange or settlement costs.

The fair value of the Company's remaining financial instruments approximates their carrying value, reflecting their nature, short-term maturity or normal trade credit terms.

The fair value of the Company's financial instruments reflects a point-in-time estimate based on current and relevant market information about the instruments as at the balance sheet date. The estimates cannot be determined with precision as they involve uncertainties and matters of judgement, and therefore, may not be relevant in predicting the Company's future earnings or cash flows.

Credit Risk: There is risk that Newfoundland Power may not be able to collect all of its accounts receivable and amounts owing under its customer finance plans.

These financial instruments, which arise in the normal course of business, do not represent a significant concentration of credit risk as amounts are owed by a large number of customers on normal credit terms. The requirement for security deposits for certain customers, which are advance cash collections from customers to guarantee payment of electricity billings, further reduces the exposure to credit risk. The maximum exposure to credit risk is the net carrying value of these financial instruments.

Newfoundland Power manages credit risk primarily by executing its credit and collection policy, including the requirement for security deposits, through the resources of its Customer Relations Department.

The aging of accounts receivable and amounts owing under customer finance plans, past due but not impaired, as at December 31 follow:

| | 2010 | 2009 |
|---|---|---|
| Not past due | $ 31,947 | $ 33,077 |
| Past due 1-30 days | 24,654 | 26,809 |
| Past due 31-60 days | 5,351 | 4,942 |
| Past due 61-90 days | 1,148 | 1,156 |
| Past due over 90 days | 201 | 248 |
| | $ 63,301 | $ 66,232 |

Liquidity Risk: The Company's financial position could be adversely affected if it failed to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and repayment of maturing debt.

The ability to arrange such financing is subject to numerous factors, including the results of operations and financial position of the Company, conditions in the capital and bank credit markets, ratings assigned by ratings agencies and general economic conditions. These factors are mitigated by the legal requirement as outlined in the *Electrical Power Control Act* which requires rates be set to enable the Company to achieve and maintain a sound credit rating in the financial markets of the world.

Newfoundland Power manages short-term liquidity risk primarily by maintaining bank credit facilities. The Company has unsecured facilities of $120.0 million, comprised of a syndicated $100.0 million committed credit facility and a $20.0 million demand facility.

Newfoundland Power manages long-term liquidity risk primarily by maintaining its investment grade credit ratings.

As at December 31, 2010, the fair value of the Company's primary defined benefit pension plan assets was $269.3 million compared to the fair value of plan assets of $242.7 million as at December 31, 2009.

Based on the Actuarial Valuation Report as at December 31, 2008, the solvency deficit was $6.9 million ($7.7 million inclusive of interest). The solvency deficit is required to be funded over a 5-year period, which commenced in 2009. See Note 19. The Company has fulfilled its 2010 annual solvency deficit funding requirement of $1.5 million. The Company does not expect any difficulty in its ability to meet future pension funding requirements as it expects the amounts will be financed from a combination of cash generated from operations and amounts available for borrowing under existing credit facilities.

## 18. Financial Instruments (cont'd)

The contractual maturities of the Company's financial liabilities at December 31, 2010, follow:

| *($millions)* | **Total** | **Due Within 1 Year** | **Due in Years 2 & 3** | **Due in Years 4 & 5** | **Due After 5 Years** |
|---|---|---|---|---|---|
| Accounts payable and accrued charges | 63.8 | 63.8 | - | - | - |
| Security deposits[1] | 1.2 | 0.5 | 0.7 | - | - |
| Credit facilities (unsecured) | 15.0 | - | 15.0 | - | - |
| Interest on first mortgage sinking fund bonds and committed credit facility | 544.0 | 35.7 | 69.7 | 63.8 | 374.8 |
| First mortgage sinking fund bonds[2] | 463.7 | 5.2 | 10.4 | 38.6 | 409.5 |
| Total | 1,087.7 | 105.2 | 95.8 | 102.4 | 784.3 |

[1] *Included in accounts payable and accrued charges and other liabilities.*
[2] *First mortgage sinking fund bonds are secured by a first fixed and specific charge on property, plant and equipment owned or to be acquired by the Company and by a floating charge on all other assets.*

Market Risk: Exposure to foreign exchange rate fluctuations is immaterial.

Market driven changes in interest rates and changes in the Company's credit ratings can cause fluctuations in interest costs associated with the Company's bank credit facilities. For the year ended December 31, 2010, each 25 basis points change in interest rates on the Company's credit facilities would have caused a $34,000 change in credit facility interest costs and a $23,000 change in earnings (2009 - $43,000 and $29,000, respectively).

The Company periodically refinances its credit facilities in the normal course with fixed-rate first mortgage sinking fund bonds thereby significantly mitigating exposure to interest rate changes.

Changes in interest rates and/or changes in the Company's credit ratings can affect the interest rate on first mortgage sinking fund bonds at the time of issue.

The Company's defined benefit pension plan is impacted by economic conditions. There is no assurance that the pension plan assets will earn the expected long-term rate of return in the future. Market driven changes impacting the performance of the pension plan assets may result in material variations from the expected long-term return on the assets. This may cause material changes in future pension liabilities and pension expense. Market driven changes impacting the discount rate may also result in material variations in future pension liabilities and pension expense. Effective January 1, 2010, pursuant to the 2010 GRA, the operation of the PEVDA is expected to significantly mitigate the impact on the Company's pension expense as described in Note 2.

## 19. Commitments

The Company is obligated to provide service to customers, resulting in ongoing capital expenditure commitments. Capital expenditures are subject to PUB approval. The Company's 2011 capital plan provides for capital expenditures of approximately $73.0 million and was approved by the PUB in November 2010.

The Company's defined benefit pension funding contributions, including current service and solvency deficit funding amounts, are based on estimates provided by the December 31, 2008, Actuarial Valuation Report as follows:

| *($millions)* | 2011 | 2012[1] | 2013[1] | Total |
|---|---|---|---|---|
| Current service costs | 3.6 | - | - | 3.6 |
| Solvency deficit funding | 1.6 | 1.6 | 1.5 | 4.7 |
| Total | 5.2 | 1.6 | 1.5 | 8.3 |

[1] *The next actuarial valuation at December 31, 2011, will determine the current service funding as well as the solvency deficit funding, if any.*

## 20. Comparative Figures

The comparative financial statements have been reclassified from statements previously presented to conform to the presentation of the current year financial statements.

# 10 Year Summary

| | 2010 | 2009[1] | 2008 | 2007 | 2006 | 2005 | 2004 | 2003 | 2002 | 2001 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Income Statement Items *($thousands)*** | | | | | | | | | | |
| Revenue | 554,950 | 527,179 | 516,889 | 491,709 | 422,405 | 419,963 | 404,447 | 384,150 | 369,627 | 359,305 |
| Purchased power | 358,443 | 345,656 | 336,658 | 326,778 | 257,157 | 255,954 | 244,012 | 227,964 | 210,764 | 202,479 |
| Operating, pension and ERP costs | 62,211 | 51,988 | 50,172 | 53,202 | 53,996 | 53,812 | 51,755 | 51,799 | 50,767 | 52,908 |
| Amortization[2] | 47,220 | 45,687 | 44,511 | 34,162 | 33,129 | 32,143 | 30,987 | 29,372 | 35,442 | 34,003 |
| Finance charges | 35,633 | 34,555 | 33,507 | 34,939 | 33,819 | 31,369 | 30,393 | 30,009 | 26,853 | 26,700 |
| Income taxes | 15,870 | 16,092 | 19,146 | 12,176 | 13,639 | 15,368 | 15,586 | 14,945 | 16,381 | 13,730 |
| Net earnings applicable to common shares | 35,005 | 32,628 | 32,341 | 29,866 | 30,078 | 30,729 | 31,122 | 29,460 | 28,807 | 28,862 |
| **Balance Sheet Items *($thousands)*** | | | | | | | | | | |
| Property, plant and equipment | 1,212,810 | 1,230,371 | 1,181,433 | 1,173,642 | 1,119,820 | 1,085,106 | 1,050,913 | 1,009,448 | 949,478 | 914,735 |
| Assets held for sale | 44,698 | - | - | - | - | - | - | - | - | - |
| Intangible assets[3] | 36,003 | 37,287 | 37,633 | - | - | - | - | - | - | - |
| Accumulated amortization | 457,121 | 464,327 | 444,109 | 422,848 | 402,683 | 387,815 | 420,836 | 407,319 | 381,003 | 369,659 |
| Net capital assets | 836,390 | 803,331 | 774,957 | 750,794 | 717,137 | 697,291 | 630,077 | 602,129 | 568,475 | 545,076 |
| Total assets | 1,191,076 | 1,165,187 | 1,001,855 | 985,930 | 929,158 | 889,013 | 825,310 | 744,375 | 704,598 | 667,289 |
| Long-term debt (including current instalments) | 475,482 | 479,250 | 438,154 | 443,527 | 414,489 | 395,298 | 328,558 | 332,208 | 335,858 | 263,758 |
| Preference shares | 9,111 | 9,111 | 9,352 | 9,352 | 9,353 | 9,410 | 9,417 | 9,429 | 9,709 | 9,709 |
| Common equity | 400,502 | 381,185 | 373,738 | 356,671 | 335,887 | 323,972 | 316,360 | 299,480 | 279,515 | 260,203 |
| Total capital | 885,095 | 869,546 | 821,244 | 809,550 | 759,729 | 728,680 | 654,335 | 641,117 | 625,082 | 533,670 |
| **Operating Statistics *(GWh)*** | | | | | | | | | | |
| Sources of Electricity (normalized) | | | | | | | | | | |
| Purchased | 5,308 | 5,188 | 5,088 | 5,013 | 4,876 | 4,873 | 4,841 | 4,725 | 4,604 | 4,495 |
| Generated | 425 | 426 | 426 | 381 | 417 | 426 | 424 | 425 | 424 | 416 |
| Total | 5,733 | 5,614 | 5,514 | 5,394 | 5,293 | 5,299 | 5,265 | 5,150 | 5,028 | 4,911 |
| Electricity sales (normalized) | | | | | | | | | | |
| Residential | 3,311 | 3,203 | 3,130 | 3,044 | 2,981 | 2,987 | 2,972 | 2,909 | 2,843 | 2,775 |
| Commercial and street lighting | 2,108 | 2,096 | 2,078 | 2,049 | 2,014 | 2,017 | 2,007 | 1,973 | 1,922 | 1,892 |
| Total | 5,419 | 5,299 | 5,208 | 5,093 | 4,995 | 5,004 | 4,979 | 4,882 | 4,765 | 4,667 |
| Electricity sales per employee | 9.5 | 9.3 | 9.5 | 9.2 | 9.0 | 9.0 | 8.3 | 8.1 | 7.8 | 7.5 |
| **Customers *(year-end)*** | | | | | | | | | | |
| Residential | 211,091 | 207,335 | 204,204 | 201,045 | 198,568 | 196,412 | 193,912 | 191,314 | 188,925 | 186,828 |
| Commercial and street lighting | 32,335 | 31,972 | 31,574 | 31,217 | 30,932 | 30,889 | 30,552 | 30,339 | 30,147 | 30,051 |
| Total | 243,426 | 239,307 | 235,778 | 232,262 | 229,500 | 227,301 | 224,464 | 221,653 | 219,072 | 216,879 |
| Operating cost per customer *($)*[4] | 234 | 214 | 208 | 213 | 212 | 218 | 220 | 225 | 223 | 231 |
| Number of regular full-time employees | 572 | 572 | 551 | 555 | 552 | 556 | 599 | 606 | 610 | 626 |

1 *Certain comparative figures have been reclassified to conform with current year presentation.*
2 *Amount for 2007 and 2006 is net of a regulatory deferral of $5.8 million, as approved by the PUB.*
3 *Beginning in 2008, intangible assets were reported separately on the Balance Sheet.*
4 *Operating cost per customer is calculated excluding pension and early retirement program costs. In 2010, operating costs were inclusive of conservation programming costs and the effects of Hurricane Igor.*

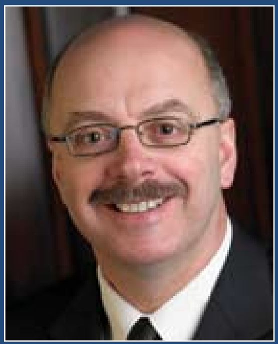
# Board of Directors

**Peggy Bartlett*•**
Chair, Board of Directors
President
Bartlett Enterprises Inc.
Grand Falls-Windsor,
Newfoundland & Labrador

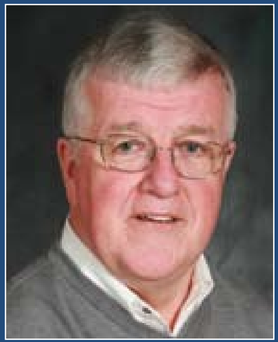
**Frank Davis•**
Chair, Governance & Human Resources Committee
Corporate Director
St. John's,
Newfoundland & Labrador

**Nora Duke**
President & Chief Executive Officer
Fortis Properties Corp.
St. John's,
Newfoundland & Labrador

**Georgina Hedges•**
Owner/Operator
The Doctor's Inn
Eastport,
Newfoundland & Labrador



**Earl Ludlow**
President & Chief Executive Officer
Newfoundland Power Inc.
St. John's,
Newfoundland & Labrador



**Edward Murphy***
Senior Vice President of Finance
Pennecon Limited
St. John's,
Newfoundland & Labrador

**Fred O'Brien**
President & Chief Executive Officer
Maritime Electric Company, Ltd.
Charlottetown,
Prince Edward Island

**Barry Perry•**
Vice President,
Finance & Chief Financial Officer
Fortis Inc.
St. John's,
Newfoundland & Labrador

**Bruce Simmons***
President & Chief Executive Officer
Hammond Farm Ltd.
Corner Brook,
Newfoundland & Labrador

**Jo Mark Zurel***
Chair, Audit & Risk Committee
President
Stonebridge Capital Inc.
St. John's,
Newfoundland & Labrador

* Audit & Risk Committee • Governance & Human Resources Committee


**Jocelyn Perry,** Vice President, Finance and Chief Financial Officer
**Peter Alteen,** Vice President, Regulation and Planning
**Earl Ludlow,** President and Chief Executive Officer
**Gary Smith,** Vice President, Customer Operations and Engineering

# Community Partners

We are proud that community groups throughout the province can count on us for support. We were pleased to provide financial, in-kind and hands on assistance to the following organizations and many more in 2010:

## Health

The Dr. H. Bliss Murphy Cancer Care Foundation, PRIORITY: The Campaign for Cancer Care, The Burin Peninsula Health Care Foundation, The Western Memorial Health Care Foundation, The Children's Wish Foundation, The Newfoundland & Labrador Down Syndrome Society, Juvenile Diabetes Research Foundation, The Arthritis Society (Newfoundland & Labrador Division), Alzheimer Society of Newfoundland & Labrador, Trinity Conception Placentia Health Care Foundation, Janeway Children's Hospital Foundation, Learning Disabilities Association of Newfoundland & Labrador, Heart and Stroke Foundation of Newfoundland & Labrador, Canadian Blood Services, Canadian Mental Health Association, The Health Care Foundation

## Safety

Newfoundland & Labrador Association of Fire Services, Firefighter Electricity Safety Training, Learn Not to Burn Program, Child Find Newfoundland & Labrador, School Electricity Safety Program, Safety Services Newfoundland Labrador, Newfoundland & Labrador Crime Stoppers, Newfoundland & Labrador Snowmobile Federation, Triple Bay Eagles Ground Search and Rescue

## Environment

Atlantic Salmon Federation, Tree Canada, Newfoundland & Labrador Home Builders' Association, Thomas Howe Demonstration Forest, Trans Canada Trail Foundation, Marystown Community Pride, Rennies River Development Foundation, Corner Brook Stream Development Corporation

## Education & Youth

Junior Achievement of Newfoundland & Labrador, Memorial University of Newfoundland, College of the North Atlantic, Sport Newfoundland & Labrador, Scouts Canada, Church Lads' Brigade, Special Olympics, 2010 Newfoundland & Labrador Winter Games

## Community

Newfoundland & Labrador Region of the Canadian Red Cross, Community Food Sharing Association, Coats for Kids, Habitat for Humanity, Community Sector Council Newfoundland & Labrador

## Arts & Culture

Newfoundland Symphony Orchestra, Kiwanis Music Festival Association, Resource Centre for the Arts

# Investor Information

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St. John's, NL A1B 3P6
Tel: (709) 737-2802
Fax: (709) 737-5300

Share Transfer Agent and Registrar
Computershare Trust Company of Canada
1500 University Street, Suite 700
Montreal, QC H3A 3S8
Tel: (514) 982-7888
Fax: (514) 982-7635
computershare.com

Annual General Meeting
Tuesday, May 10, 2011 at 8:00 a.m.
Main Boardroom, 3rd Floor
Newfoundland Power Inc.
55 Kenmount Road
St. John's, NL A1B 3P6

Investor Information
Peter Alteen, Corporate Secretary
55 Kenmount Road, P.O. Box 8910
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Fortis Websites
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FortisAlberta Inc.
fortisalberta.com
FortisBC Inc.
fortisbc.com
FortisOntario Inc.
fortisontario.com
Maritime Electric Company, Limited
maritimeelectric.com
Belize Electricity Limited
bel.com.bz
Caribbean Utilities Company, Ltd.
cuc-cayman.com
Fortis Properties Corporation
fortisproperties.com
Fortis Turks and Caicos
provopowercompany.com

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Kristine Hamlyn, Oscar Kaus and Eric Stephenson

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P.O. Box 8910
St. John's, NL   A1B 3P6

newfoundlandpower.com

**IN THE MATTER OF**
the 2010 Annual Returns
of Newfoundland Power
Inc. filed pursuant to
Section 59(2) of the
*Public Utilities Act.*

## AFFIDAVIT

I, Jocelyn Perry, of the Town of Conception Bay South in the Province of Newfoundland and Labrador, Chartered Accountant, make oath and say as follows:

1. That I am Vice-President, Finance and Chief Financial Officer of Newfoundland Power Inc.

2. That to the best of my knowledge, information and belief, the information contained in the 2010 Annual Report and accompanying returns of Newfoundland Power Inc., filed with the Board of Commissioners of Public Utilities pursuant to section 59(2) of the *Public Utilities Act* is true and accurate.

**SWORN** to before me at St. John's
in the Province of Newfoundland and Labrador
this 1st day of April, 2011:

Barrister – Newfoundland & Labrador

Jocelyn Perry

# Newfoundland Power Inc.
# Names and Addresses of Officers and Directors
# as of December 31, 2010

| Name | Address | Position Held |
|---|---|---|
| **Peter Alteen** | 38 Mansfield Crescent<br>St. John's, NL A1E 5E3 | Vice President; Corporate Secretary |
| **Peggy Bartlett** | 173 Grenfell Heights<br>Grand Falls-Windsor, NL A2A 2J7 | Chair, Board of Directors |
| **Frank Davis** | 2 Crabapple Place<br>St. John's, NL A1A 5L7 | Director |
| **Nora Duke** | 18 Jacaranda Place<br>St. John’s, NL A1H 1A2 | Director |
| **Georgina Hedges** | 5 Burden’s Road<br>Eastport, NL A0G 1Z0 | Director |
| **Earl Ludlow** | 33 Ortega Drive<br>Paradise, NL A1L 2L1 | President and Chief Executive Officer;<br>Director |
| **Edward Murphy** | 5 Lambert Place<br>St. John's, NL A1A 3X4 | Director |
| **Fred O'Brien** | 389 Church Street<br>Alberton, PEI C0B 1B0 | Director |
| **Barry Perry** | 14 Collingwood Crescent<br>Mount Pearl, NL A1N 5C6 | Director |
| **Jocelyn Perry** | 6 Maple Street<br>Conception Bay South, NL A1W 5M8 | Vice President and Chief Financial Officer |
| **Bruce Simmons** | 1 Hammond Drive<br>Little Rapids, NL A2H 2N2 | Director |

# Newfoundland Power Inc.
## Names and Addresses of Officers and Directors
## as of December 31, 2010

| Name | Address | Position Held |
| --- | --- | --- |
| **Gary Smith** | 89 Cheyne Drive<br>St. John's, NL A1A 5W5 | Vice President |
| **Jo Mark Zurel** | 16 Regent Street<br>St. John's, NL A1A 5A4 | Director |

**Newfoundland Power Inc.**
**Computation of Average Rate Base**
**For The Years Ended December 31**
**($000s)**

| | 2010 | 2009 |
|---|---|---|
| **Net Plant Investment** | | |
| Plant Investment - Return 4 | 1,393,801 | 1,338,408 |
| Accumulated Amortization - Return 6 | (585,245) | (562,009) |
| Contributions in Aid of Construction - Return 7 | (30,266) | (29,017) |
| | 778,290 | 747,382 |
| **Additions to Rate Base** | | |
| Deferred Charges - Return 8 | 102,807 | 103,761 |
| Deferred Energy Replacement Costs - Return 9 | - | 383 |
| Cost Recovery Deferral - Hearing Costs - Return 9 | 507 | 201 |
| Cost Recovery Deferral - Depreciation - Return 9 | - | 3,862 |
| Cost Recovery Deferral - Conservation - Return 9 | 682 | 948 |
| Customer Finance Programs - Return 10 | 1,647 | 1,679 |
| Weather Normalization Reserve - Return 17 | (1,954) | 3,919 |
| | 103,689 | 114,753 |
| **Deductions from Rate Base** | | |
| Municipal Tax Liability - Return 9 | - | 1,363 |
| Unrecognized 2005 Unbilled Revenue - Return 9 | - | 4,618 |
| Customer Security Deposits - Return 10 | 705 | 581 |
| Accrued Pension Obligation - Return 10 | 3,548 | 3,379 |
| Future Income Taxes - Return 23 | 3,617 | 2,297 |
| Demand Management Incentive Account - Return 18 | 676 | - |
| Purchased Power Unit Cost Variance Reserve - Return 19 | - | 447 |
| | 8,546 | 12,685 |
| **Year End Rate Base** | 873,433 | 849,450 |
| **Average Rate Base Before Allowances** | 861,442 | 834,228 |
| **Rate Base Allowances** | | |
| Materials and Supplies Allowance - Return 11 | 4,476 | 4,366 |
| Cash Working Capital Allowance - Return 12 | 9,292 | 9,899 |
| **Average Rate Base at Year End** | 875,210 | 848,493 |

**Newfoundland Power Inc.**
**Plant Investment**
**For The Year Ended December 31, 2010**
**($000s)**

| | Opening Balance | Adjustments[1] | Additions | Retirements | Year End Balance |
|---|---|---|---|---|---|
| Power Generation | | | | | |
| Hydro | 147,011 | - | 5,643 | 618 | 152,036 |
| Diesel | 3,034 | - | 3 | 2 | 3,035 |
| Gas Turbine | 18,043 | - | 202 | 2 | 18,243 |
| | 168,088 | - | 5,848 | 622 | 173,314 |
| Substations | 141,729 | - | 10,335 | 1,974 | 150,090 |
| Transmission | 102,283 | - | 5,916 | 1,273 | 106,926 |
| Distribution | 770,749 | - | 43,171 | 6,767 | 807,153 |
| General Property | 50,945 | - | 1,377 | 365 | 51,957 |
| Transportation | 22,717 | - | 2,394 | 1,035 | 24,076 |
| Communications | 10,709 | - | 340 | 408 | 10,641 |
| Computer Software | 29,742 | 731 | 1,870 | 3,341 | 29,002 |
| Computer Hardware | 9,172 | (731) | 1,550 | 1,623 | 8,368 |
| Government Contributions | 23,109 | - | - | - | 23,109 |
| | 1,161,155 | - | 66,953 | 16,786 | 1,211,322 |
| Total Depreciable Plant | 1,329,243 | - | 72,801 | 17,408 | 1,384,636 |
| Non Depreciable Land | 9,165 | - | - | - | 9,165 |
| Plant Investment Included In Rate Base | 1,338,408 | - | 72,801 | 17,408 | 1,393,801 |
| Construction Work In Progress | | | | | 3,804 |
| Total Plant Investment[2] | | | | | 1,397,605 |

[1] Adjustments are due to asset reclassification and redistribution of original cost based on final project details.

[2] A reconciliation of the Total Plant Investment used in the calculation of average rate base for 2010 to the plant investment shown in Return 1 is as follows:

| | (000s) |
|---|---|
| 2010 Capital Assets shown in Return 1 (Note 8 to Financial Statements) | 1,212,810 |
| Add: Contributions in Aid of Construction - Return 7 | 80,828 |
| Add: Assets held for sale (Note 8 to Financial Statements) | 72,775 |
| Add: Plant Investment classified as Intangibles (Note 10 to Financial Statements) | 36,003 |
| Deduct: Inventories included in Plant Investment for financial reporting purposes | (4,811) |
| 2010 Total Plant Investment | 1,397,605 |

**Newfoundland Power Inc.**
**Capital Expenditure**
**For The Year Ended December 31, 2010**
**($000s)**

| | Approved By Board[1] | Actual | Variance[2] |
|---|---|---|---|
| Generation | | | |
| Hydro | 5,279 | 4,973 | (306) |
| Thermal | 150 | 189 | 39 |
| | 5,429 | 5,162 | (267) |
| Substations | 10,218 | 9,341 | (877) |
| Transmission | 5,915 | 2,931 | (2,984) |
| Distribution | 31,965 | 38,765 | 6,800 |
| General Property | 1,381 | 1,320 | (61) |
| Transportation | 2,352 | 2,287 | (65) |
| Telecommunications | 379 | 324 | (55) |
| Information Systems | 3,490 | 3,393 | (97) |
| Unforeseen | 6,850 | 6,133 | (717) |
| General Expenses Capital | 2,800 | 3,316 | 516 |
| | 70,779 | 72,972 | 2,193 |
| Projects carried forward from 2008 and 2009[3] | | 607 | |

[1] Approved by Order Nos. P.U. 41 (2009), P.U. 17 (2010), and P.U. 35 (2010).

[2] Variance explanations are provided in Newfoundland Power Inc.'s 2010 Capital Expenditure Report filed with the Board on March 1, 2011.

[3] The projects carried forward from 2008 and 2009 include $384,000 from the Water Street Underground project and $223,000 from the Vale Inco line extension project.

**Newfoundland Power Inc.**
**Accumulated Amortization**
**For The Year Ended December 31, 2010**
**($000s)**

| | |
|---|---|
| Opening Balance - January 1, 2010 | 562,009 |
| | |
| Add: | |
| Amortization of Fixed Assets[1] | 43,358 |
| Amortization of Contributions - Government - Return 7 | 57 |
| Amortization of Contributions - Customers - Return 7 | 1,483 |
| Salvage | 998 |
| | 45,896 |
| | |
| Deduct: | |
| Cost of Removal (Net of Income Tax) | 5,252 |
| Retirements | 17,408 |
| | 22,660 |
| | |
| Closing Balance - December 31, 2010[2] | 585,245 |

[1] The amortization rates for 2010 are from the 2006 Depreciation Study based on plant in service at December 31, 2005 and approved in Order No. P.U. 32 (2007).

| | |
|---|---|
| Hydro | 2.17% |
| Diesel | 4.28% |
| Gas Turbine | 4.81% |
| Substations | 2.63% |
| Transmission | 3.28% |
| Distribution | 3.14% |
| General Property | 2.94% |
| Transportation | 10.28% |
| Telecommunications | 6.18% |
| Computer Software | 10.00% |
| Computer Hardware | 20.00% |

[2] The accumulated amortization shown in Return 1 (Note 8 to the Financial Statements) is before adjustment for contributions in aid of construction, site restoration costs and intangibles.

| | (000s) |
|---|---|
| Accumulated Amortization shown in Return 1 (Note 8) | 436,428 |
| Add: Amortization of Contributions - Return 7 | 50,562 |
| Add: Site Restoration Costs - Return 1 (Note 4) | 49,485 |
| Add: Accumulated Amortization of Assets Held for Sale - Return 1 (Note 8) | 28,077 |
| Add: Accumulated Amortization classified as Intangibles - Return 1 (Note 10) | 20,693 |
| 2010 Accumulated Amortization for Average Rate Base | 585,245 |

**Newfoundland Power Inc.**
**Contributions in Aid of Construction**
**For The Year Ended December 31, 2010**
**($000s)**

| | Customers | Government | Total |
|---|---|---|---|
| Gross Contributions to January 1, 2010 | 54,931 | 23,108 | 78,039 |
| Add: Contributions Received in 2010 | 2,789 | - | 2,789 |
| Gross Contributions to December 31, 2010 | 57,720 | 23,108 | 80,828 |
| Amortizations to January 1, 2010 | 26,494 | 22,528 | 49,022 |
| Add: Amortization in 2010 | 1,483 | 57 | 1,540 |
| Amortizations to December 31, 2010 | 27,977 | 22,585 | 50,562 |
| Unamortized Contributions to December 31, 2010 | 29,743 | 523 | 30,266 |

**Newfoundland Power Inc.**
**Deferred Charges**
**For The Year Ended December 31, 2010**
**($000s)**

| | Balance January 1 2010 | Additions During 2010 | Reductions During 2010 | Balance December 31 2010 |
|---|---|---|---|---|
| Deferred Pension Costs[1] | 103,723 | 4,999 | 6,173 | 102,549 |
| Capital Stock Issue Expenses | 38 | - | 38 | - |
| Deferred Credit Facility Issue Costs | - | 300 | 42 | 258 |
| Deferred Charges Included in Rate Base | 103,761 | 5,299 | 6,253 | 102,807 |

[1] The December 31, 2010 balance includes $4.8 million in pension costs associated with the 2005 Early Retirement Program. These pension costs were originally $11.3 million and are being amortized over ten years, beginning April 1, 2005.

**Newfoundland Power Inc.**
**Regulatory Deferrals**
**For The Year Ended December 31, 2010**
**($000s)**

| | Balance January 1 2010 | Additions During 2010 | Reductions During 2010 | Balance December 31 2010 |
|---|---|---|---|---|
| **Cost Recovery Deferrals** | | | | |
| Deferred Energy Replacement Costs[1] | 383 | - | 383 | - |
| Cost Recovery Deferral - Depreciation[1] | 3,862 | - | 3,862 | - |
| Deferred Hearing Costs - 2008 GRA[1] | 201 | - | 201 | - |
| Deferred Hearing Costs - 2010 GRA[2] | - | 760 | 253 | 507 |
| Deferred Conservation Costs[3] | 948 | - | 266 | 682 |
| | | | | |
| **Revenue Deferrals[1]** | | | | |
| Municipal Tax Liability | 1,363 | - | 1,363 | - |
| Unrecognized 2005 Unbilled Revenue | 4,618 | - | 4,618 | - |

[1] In Order No. P.U. 32 (2007), the Board approved a 3-year amortization of these cost recovery and revenue deferrals.

[2] In Order No. P.U. 43 (2009), the Board approved a 3-year amortization of this cost recovery.

[3] In Order No. P.U. 43 (2009), the Board approved the 4-year amortization of certain costs related to the implementation of the conservation plan in 2009.

**Newfoundland Power Inc.**
**Other Rate Base Assets and Liabilities**
**For The Year Ended December 31, 2010**
**($000s)**

| | Balance January 1 2010 | Change During 2010 | Balance December 31 2010 |
|---|---|---|---|
| **Assets** | | | |
| Customer Finance Programs[1] | 1,679 | (32) | 1,647 |
| **Liabilities** | | | |
| Accrued Pension Obligation[2] | 3,379 | 169 | 3,548 |
| Customer Security Deposits[3] | 581 | 124 | 705 |

[1] Comprised of loans provided to customers related to customer conservation programs and contributions in aid of construction.

[2] Executive and Senior Management supplemental pension benefits comprised of a defined benefit plan (PUP) and a defined contribution plan (SERP). The PUP was closed to new entrants in 1999.

[3] Security deposits received from customers for electrical service in accordance with the Board-approved Schedule of Rates, Rules and Regulations.

**Newfoundland Power Inc.**
**Materials and Supplies Allowance**
**For The Years Ended December 31**
**($000s)**

| | 2010[1] | 2009[1] |
|---|---|---|
| Opening - January 1 | 5,197 | 5,391 |
| January | 5,246 | 5,224 |
| February | 5,360 | 5,701 |
| March | 5,400 | 5,662 |
| April | 5,605 | 5,825 |
| May | 5,568 | 5,352 |
| June | 6,061 | 5,526 |
| July | 5,601 | 5,332 |
| August | 5,728 | 5,444 |
| September | 5,546 | 5,337 |
| October | 5,788 | 5,197 |
| November | 6,002 | 5,231 |
| December | 5,811 | 5,197 |
| Total | 72,913 | 70,419 |
| Average | 5,609 | 5,417 |
| Less: Expansion (20.2% and 19.4%)[2] | 1,133 | 1,051 |
| Materials and Supplies Allowance | 4,476 | 4,366 |

[1] The 2009 and 2010 materials and supplies allowance calculation reflects a 13-month average as approved by the Board in Order No. P.U. 32 (2007).

[2] The expansion factor of 20.2% is based on the 2010 cash working capital study approved by the Board in Order No. P.U. 43 (2009). The expansion factor of 19.4% is based on the 2008 cash working capital study approved by the Board in Order No. P.U. 32 (2007).

**Newfoundland Power Inc.**
**Cash Working Capital Allowance[1]**
**For The Years Ended December 31**
**($000s)**

| | 2010 | 2009 |
|---|---|---|
| Gross Operating Costs[2] | 415,097 | 395,731 |
| Current Income Taxes - Return 22 | 17,773 | 15,590 |
| Municipal Taxes Paid | 13,421 | 12,942 |
| Non-regulated Expenses (net of income taxes) | (979) | (1,203) |
| Total operating expenses | 445,312 | 423,060 |
| Cash Working Capital Factor | 2.0% | 2.1% |
| | 8,906 | 8,884 |
| HST Adjustment | 386 | 1,015 |
| Cash Working Capital Allowance | 9,292 | 9,899 |

[1] The cash working capital allowance for 2010 is calculated based on the method used to calculate the 2010 Test Year average rate base approved by the Board in Order No. P.U. 46 (2009).

[2] In accordance with the methodology approved in Order No. P.U. 43 (2009), gross operating costs for 2010 used in the calculation of the 2010 cash working capital allowance are net of non-cash related amortizations.

**Newfoundland Power Inc.**
**Return on Average Rate Base[1]**
**For The Years Ended December 31**
**($000s)**

| | 2010 | 2009 |
|---|---|---|
| Net Earnings from Return 1 | 35,573 | 33,201 |
| Add: Non-regulated (net of income taxes) | 979 | 1,203 |
| | 36,552 | 34,404 |
| | | |
| Finance Costs | | |
| Interest on Long-term Debt | 35,850 | 34,547 |
| Other Interest | 329 | 402 |
| Amortization of Debt Issue Expenses | 232 | 235 |
| AFUDC | (820) | (675) |
| | 35,591 | 34,509 |
| | | |
| Regulated Earnings | 72,143 | 68,913 |
| | | |
| Average Rate Base from Return 3 | 875,210 | 848,493 |
| | | |
| Rate of Return on Average Rate Base | 8.24% | 8.12% |
| | | |
| Average Rate Base from Return 3 | 875,210 | 848,493 |
| | | |
| Upper Limit of the Allowed Range of Return on Average Rate Base[2] | 8.41% | 8.55% |
| | | |
| Upper Limit of Allowed Regulated Earnings | 73,605 | 72,546 |
| | | |
| Regulated Earnings | 72,143 | 68,913 |
| | | |
| Excess Revenue net of Income Taxes | - | - |
| | | |
| Income Taxes | - | - |
| | | |
| Excess Revenue | - | - |

[1] The return on average rate base is calculated in accordance with the methodology approved in Order No. P.U 32 (2007).

[2] Based on a return on rate base of 8.23% plus 18 basis points, as approved in Order No. P.U. 46 (2009) for 2010 and a return on rate base of 8.37% plus 18 basis points, as approved in Order No. P.U. 35 (2008) for 2009.

**Newfoundland Power Inc.**
**Details of Normalized Sales and Revenue**
**For The Years Ended December 31**
**($000s)**

| | | 2010 | | | 2009 | | |
|---|---|---|---|---|---|---|---|
| | | Gigawatt Hours | Year End Customer Accounts | Revenue | Gigawatt Hours | Year End Customer Accounts | Revenue |
| **Revenue From Rates** | | | | | | | |
| Domestic | 1.1 | 3,311.2 | 211,091 | 332,664 | 3,203.3 | 207,335 | 309,360 |
| General Service: | | | | | | | |
| 0 - 10 kW | 2.1 | 92.5 | 12,116 | 12,331 | 89.8 | 12,036 | 11,840 |
| 10 - 100 kW | 2.2 | 649.3 | 8,909 | 65,291 | 640.9 | 8,770 | 63,318 |
| 110 - 1000 kVA | 2.3 | 910.6 | 1,101 | 77,976 | 890.5 | 1,088 | 74,182 |
| 1000 kVA and Over | 2.4 | 419.2 | 59 | 31,037 | 438.0 | 68 | 31,675 |
| Total General Service | | 2,071.6 | 22,185 | 186,635 | 2,059.2 | 21,962 | 181,015 |
| Street & Area Lighting | 4.1 | 36.2 | 10,150 | 13,540 | 36.5 | 10,010 | 12,862 |
| Forfeited Discounts | | - | - | 2,494 | - | - | 2,644 |
| Revenue From Rates | | 5,419.0 | 243,426 | 535,333 | 5,299.0 | 239,307 | 505,881 |
| **Adjustments and Transfers** | | | | | | | |
| Transfer From (To) RSA | | | | 2,213 [1] | | | 2,878 |
| 2010 Pension Expense Variance Deferral | | | | (640) | | | |
| 2005 Unbilled Revenue Accrual | | | | 4,618 [2] | | | 4,618 |
| Total Adjustments and Transfers | | | | 6,191 | | | 7,496 |
| **Other Revenue** | | | | | | | |
| Joint Use Revenue | | | | 9,360 | | | 9,219 |
| Wheeling Revenue | | | | 591 | | | 566 |
| Amortization of Municipal Tax Liability | | | | 1,363 [3] | | | 1,364 |
| Interest on Overdue Customer Accounts | | | | 801 | | | 818 |
| Other Non-Electrical Revenue | | | | 1,311 | | | 1,835 |
| Total Other Revenue | | | | 13,426 | | | 13,802 |
| **Total Revenue - Return 1** | | | | **554,950** | | | **527,179** |

[1] The transfer from the RSA is related to the operation of the Energy Supply Cost Variance Adjustment.

[2] In Order No. P.U. 32 (2007), the Board approved a 3-year amortization of the 2005 Unbilled Revenue remaining balance beginning in 2008.

[3] In Order No. P.U. 32 (2007), the Board approved a 3-year amortization of the municipal tax liability beginning in 2008.

**Newfoundland Power Inc.**
**Normalized Production and Sales Statistics**
**For The Years Ended December 31**
**($000s)**

| | 2010 | 2009 |
|---|---|---|
| Gigawatt Hours - Purchased | 5,308.3 | 5,187.9 |
| Gigawatt Hours - Produced | 424.6 | 425.9 |
| Total Purchased & Produced | 5,732.9 | 5,613.8 |
| Gigawatt Hours - Sold & Used | 5,430.2 | 5,310.6 |
| Gigawatt Hours - Losses | 302.7 | 303.2 |
| Losses Expressed as a Percentage of Total Purchased & Produced | 5.3% | 5.4% |
| Purchased Power Annual Billing Demand in kW | 1,119,636 | 1,119,136 |

**Newfoundland Power Inc.**
**Rate Stabilization Account**
**For The Year Ended December 31, 2010**
**($000s)**

| Month | Opening Balance | Adjustments | RSA Billed During Month | Municipal Taxes | Excess Fuel Costs | Secondary Energy Costs | Interest Costs | Transfer To (From) Nfld. Hydro | Closing Balance |
|---|---|---|---|---|---|---|---|---|---|
| January | 1,418.3 | - | (409.3) | - | 3.7 | - | 9.7 | 265.6 | 1,288.0 |
| February | 1,288.0 | - | (376.7) | - | 1.7 | - | 8.8 | 234.2 | 1,156.0 |
| March | 1,156.0 | (639.2) [1] | (364.2) | - | 364.8 [2] | - | 7.9 | 235.5 | 760.8 |
| April | 760.8 | - | (329.0) | - | 24.7 | - | 5.2 | 187.9 | 649.6 |
| May | 649.6 | - | (281.4) | - | 7.3 | - | 4.4 | 174.5 | 554.4 |
| June | 554.4 | - | (255.6) | - | 7.2 | - | 3.8 | 137.4 | 447.2 |
| July | 447.2 | - | (453.8) | - | 31.0 | - | 3.1 | 628.8 | 656.3 |
| August | 656.3 | - | (673.7) | - | 0.6 | - | 4.5 | 636.9 | 624.6 |
| September | 624.6 | - | (651.6) | - | 9.1 | - | 4.3 | 652.9 | 639.3 |
| October | 639.3 | - | (786.2) | - | 7.5 | - | 4.4 | 809.7 | 674.7 |
| November | 674.7 | - | (973.2) | - | 4.8 | - | 4.6 | 1,022.5 | 733.4 |
| December | 733.4 | 2,213.1 [3] | (1,117.0) | 633.3 [4] | 18.0 | 130.5 | 5.0 | 1,106.8 | 3,723.1 |
| | | 1,573.9 | (6,671.7) | 633.3 | 480.4 | 130.5 | 65.7 | 6,092.7 | |

[1] This is the disposition of the difference in forecasted vs. test year defined benefit pension plan expense for 2010, approved in Order No. P.U. 43 (2009).

[2] Increased generation required from Greenhill and Mobile gas turbines because of transmission line problems encountered as a result of the March Ice Storm.

[3] This is the Energy Supply Cost Variance for 2010, as approved in Order No. P.U. 32 (2007).

[4] This is the difference between total municipal taxes collected from customers through rates and the total taxes paid to municipalities for 2010.

**Newfoundland Power Inc.**
**Weather Normalization Reserve**
**For The Year Ended December 31, 2010**
**($000s)**

| | |
|---|---|
| **Degree Day Normalization Reserve Transfer** | |
| Revenue Adjustment | |
| Heating Degree Days | 19,564 |
| Cooling Degree Days | - |
| Wind Speed Adjustments | 881 |
| Total Revenue Adjustment | 20,445 |
| Less : Power Purchased Adjustment | |
| Heating Degree Days | 21,616 |
| Cooling Degree Days | - |
| Wind Speed Adjustments | 951 |
| Total Power Purchased Adjustment | 22,567 |
| Net Adjustment (Before Tax) | (2,122) |
| Less: Income Tax @ 32.0% | (679) |
| Net Adjustment (After Tax) | (1,443) |
| Amortization of Weather Normalization Reserve[1] | (1,366) |
| Net Transfer (To) From Degree Day Normalization Reserve | (2,809) |
| **Hydro Production Equalization Reserve Transfer** | |
| Transfer (To) From Reserve (Before Tax) | (4,506) |
| Less: Income Tax @ 32.0% | (1,442) |
| Net Transfer (To) From Hydro Production Equalization Reserve | (3,064) |
| **Net Transfer (To) From Weather Normalization Reserve** | **(5,873)** |

**Weather Normalization Account Balances**

| | **Balance at January 1 2010** | **Net Transfers** | **Balance at December 31 2010[2]** |
|---|---|---|---|
| Degree Day Reserve | 2,595 | (2,809) | (214) |
| Hydro Equalization Reserve | 1,324 | (3,064) | (1,740) |
| | 3,919 | (5,873) | (1,954) |

[1] This is the amortization of a non-reversing balance in the degree day normalization reserve as approved by the Board in Order No. P.U. 32 (2007).

[2] A positive balance in the weather normalization reserve reflects amounts to be recovered from customers in future periods. A negative balance in the weather normalization reserve reflects amounts owed to customers.

**Newfoundland Power Inc.**
**Demand Management Incentive Account**
**For The Year Ended December 31, 2010**
**($000s)**

**Demand Management Incentive Account Transfer**

| | |
|---|---|
| Demand Supply Cost Variance | (1,539) |
| Demand Management Incentive (+/-)[1] | 545 |
| Supply Cost Variance Outside Deadband | (994) |
| Less: Income Tax @ 32.0% | (318) |
| **Net Transfer (To) From Demand Management Incentive Account** | **(676)** |

**Demand Management Incentive Account Balance**

| | |
|---|---|
| Balance at January 1, 2010 | - |
| Net Transfer (To) From Demand Management Incentive Account | (676) |
| Balance at December 31, 2010[2] | (676) |

[1] The demand management incentive of $545,000 is plus/minus 1% of test year wholesale demand charges. The Demand Management Incentive Account definition was approved by the Board in Order No. P.U. 32 (2007).

[2] In accordance with Order No. P.U. 32 (2007), Newfoundland Power filed a report with the Board on February 28, 2011 pertaining to the operation of the Demand Management Incentive Account for 2010.

**Newfoundland Power Inc.**
**Purchased Power Unit Cost Variance Reserve**
**For The Year Ended December 31, 2010**
**($000s)**

**Purchased Power Unit Cost Variance Reserve Balance**

| | |
|---|---|
| Balance at January 1, 2010 | (447) |
| 2010 Amortization[1] | 447 |
| Balance at December 31, 2010 | - |

[1] In Order No. P.U. 32 (2007), the Board approved a 3-year amortization of the 2006 year end balance in the Purchased Power Unit Cost Variance Reserve of $1,342,000. The balance in the PPUCVR is fully amortized at December 31, 2010. Beginning in 2008, the PPUCVR has been replaced by the Demand Management Incentive Account.

**Newfoundland Power Inc.**
**Statement of Operating & General Expenses**
**For The Years Ended December 31**
**($000s)**

| | 2010 | 2009 | Variances[1] |
|---|---|---|---|
| Operating Expenses | | | |
| Purchased Power | 358,443 | 345,656 | 12,787 |
| Power Produced | 2,675 | 2,527 | 148 |
| Administrative and Engineering Support | 6,046 | 6,120 | (74) |
| Environmental Policy | 315 | 385 | (70) |
| Substations | 2,340 | 2,300 | 40 |
| Transmission | 830 | 482 | 348 |
| Distribution | 8,728 | 7,172 | 1,556 |
| Communications | 1,508 | 1,381 | 127 |
| Fleet Operating and Maintenance Expense | 1,504 | 1,443 | 61 |
| | 382,389 | 367,466 | 14,923 |
| General Expenses | | | |
| Customer Service | 12,872 | 11,789 | 1,083 |
| Financial Services | 1,715 | 1,505 | 210 |
| Information Systems | 2,856 | 2,695 | 161 |
| Pension Costs | 7,588 | 2,673 | 4,915 |
| Retirement Allowances | 712 | 119 | 593 |
| Corporate and Employee Services | 14,612 | 14,589 | 23 |
| | 40,355 | 33,370 | 6,985 |
| Total Operating & General Expenses | 422,744 | 400,836 | 21,908 |
| Transfers to General Expenses Capitalized | (2,429) | (1,836) | (593) |
| Amortization of Deferred CDM Costs | 339 | (1,356) | 1,695 |
| **Total Expenses[2]** | **420,654** | **397,644** | **23,010** |

[1] Variances are explained in Return 21.

[2] This is equal to the total of purchased power costs, operating expenses and pension costs shown in Return 1.

# Newfoundland Power Inc.
## Explanation of Expense Variances
## 2010 versus 2009
## ($000s)

| | 2010 | 2009 | Increase (Decrease) |
|---|---|---|---|
| **Total Expenses** | **420,654** | **397,644** | **23,010** |

Total expenses for 2010 increased by $23.0 million, or 5.8 per cent over 2009. This increase was due primarily to higher purchased power costs, higher distribution costs due to restoration efforts following Hurricane Igor, an increase in conservation costs and higher pension expense.

The following is an explanation of significant variances for individual operating and general expense classes.

| | 2010 | 2009 | Increase (Decrease) |
|---|---|---|---|
| **Purchased Power** | **358,443** | **345,656** | **12,787** |

Purchased Power costs were higher in 2010 as a result of electricity sales growth and higher water inflows associated with the Company's hydroelectric generating facilities.

| | 2010 | 2009 | Increase (Decrease) |
|---|---|---|---|
| **Power Produced** | **2,675** | **2,527** | **148** |

Power Produced costs were higher in 2010 as a result of increased fuel costs for the Wesleyville gas turbine operations, principally during the March ice storm, and higher generation taxes paid to the provincial government, offset by reduced snowclearing costs.

| | 2010 | 2009 | Increase (Decrease) |
|---|---|---|---|
| **Administrative and Engineering Support** | **6,046** | **6,120** | **(74)** |

Administrative and Engineering Support costs for 2010 were in line with costs for 2009.

| | 2010 | 2009 | Increase (Decrease) |
|---|---|---|---|
| **Environmental Policy** | **315** | **385** | **(70)** |

Environmental Policy costs for 2010 were in line with costs for 2009.

| | 2010 | 2009 | Increase (Decrease) |
|---|---|---|---|
| **Substations** | **2,340** | **2,300** | **40** |

Substations operating costs for 2010 were in line with costs for 2009.

**Newfoundland Power Inc.**
**Explanation of Expense Variances**
**2010 versus 2009**
**($000s)**

| | 2010 | 2009 | Increase (Decrease) |
|---|---|---|---|
| **Transmission** | **830** | **482** | **348** |

Transmission operating costs were higher in 2010 as a result of increased vegetation management costs and an increase in operating labour costs related to restoration efforts following the March ice storm and Hurricane Igor.

| | 2010 | 2009 | Increase (Decrease) |
|---|---|---|---|
| **Distribution** | **8,728** | **7,172** | **1,556** |

Distribution operating costs were higher in 2010 mainly because of expenses related to the restoration effort following Hurricane Igor.

| | 2010 | 2009 | Increase (Decrease) |
|---|---|---|---|
| **Communications** | **1,508** | **1,381** | **127** |

Communications operating costs were higher in 2010 as a result of an increase in usage costs for landline and wireless devices.

| | 2010 | 2009 | Increase (Decrease) |
|---|---|---|---|
| **Fleet Operating and Maintenance Expense** | **1,504** | **1,443** | **61** |

Fleet Operating and Maintenance costs for 2010 were in line with costs for 2009.

| | 2010 | 2009 | Increase (Decrease) |
|---|---|---|---|
| **Customer Service** | **12,872** | **11,789** | **1,083** |

Customer Service operating costs were higher in 2010 primarily as a result of higher costs related to conservation and demand management (CDM). In addition, overtime costs in 2010 were higher due to restoration efforts associated with Hurricane Igor.

| | 2010 | 2009 | Increase (Decrease) |
|---|---|---|---|
| **Financial Services** | **1,715** | **1,505** | **210** |

Financial Services costs were higher in 2010 due to normal salary increases and the transfer of an employee into the Finance and Regulatory group.

**Newfoundland Power Inc.**
**Explanation of Expense Variances**
**2010 versus 2009**
**($000s)**

| | 2010 | 2009 | Increase (Decrease) |
|---|---|---|---|
| **Information Systems** | **2,856** | **2,695** | **161** |

Information Systems operating costs were higher in 2010 due to normal salary increases and the transfer of an employee from Customer Service.

| | 2010 | 2009 | Increase (Decrease) |
|---|---|---|---|
| **Pension Costs** | **7,588** | **2,673** | **4,915** |

Pension costs were higher in 2010 as a result of the amortization of 2008 experience losses associated with the pension plan assets and a lower discount rate at December 31, 2009 which was used to determine the Company's accrued benefit pension obligation associated with its defined benefit pension plan.

| | 2010 | 2009 | Increase (Decrease) |
|---|---|---|---|
| **Retirement Allowances** | **712** | **119** | **593** |

Retirement Allowance costs were higher in 2010 as a result of a higher number of severances and retirements.

| | 2010 | 2009 | Increase (Decrease) |
|---|---|---|---|
| **Corporate and Employee Services** | **14,612** | **14,589** | **23** |

Corporate and Employee Services costs were in line with 2009.

| | 2010 | 2009 | Increase (Decrease) |
|---|---|---|---|
| **General Expenses Capitalized** | **(2,429)** | **(1,836)** | **(593)** |

The increase in General Expenses Capitalized (GEC) is primarily related to higher pension costs in 2010.

| | 2010 | 2009 | Increase (Decrease) |
|---|---|---|---|
| **Conservation Deferral** | **339** | **(1,356)** | **1,695** |

The Conservation Cost Deferral Account reflects the Board's approval of the deferred recovery over 4 years of certain 2009 costs associated with the Company's energy conservation programs.

**Newfoundland Power Inc.**
**Calculation of Taxable Income and Income Tax Expense**
**For The Year Ended December 31, 2010**
**($000s)**

| | | |
|---|---|---|
| Net Earnings from Return 1 | | 35,573 |
| Add: Provision for current income tax | 19,109 | |
| Provision for prior years taxes | (1,336) | |
| Provision for future income taxes | 1,320 | |
| Provision for Conservation Cost Deferral | (73) | |
| Provision for Demand Management Incentive (DMI) | (318) | |
| Provision for Purchased Power Unit Cost Variance Reserve (PPUCVR) | 241 | |
| Provision for Replacement Energy Costs | (216) | |
| Provision for Weather Normalization | (2,857) | 15,870 |
| Net Income Before Income Taxes | | 51,443 |
| Add: Amortization of capital assets net of deferred expense | 43,358 | |
| Amortization of debt discount & expenses | 191 | |
| Amortization of capital stock issue expenses | 38 | |
| Amortization of credit facility costs | 42 | |
| Business meals & related expenses | 231 | |
| Special pension liability | 242 | |
| Difference in pension funding and accounting cost | 2,300 | |
| Replacement Energy Cost | 598 | |
| Stock option expense not deductible | 404 | |
| Unbilled Revenue Reserve | 526 | |
| Small tools in excess of $500 | 88 | |
| Deferred Depreciation Costs | 3,862 | |
| Deferred GRA Expenses | 454 | |
| Deferred Conservation Costs | 339 | |
| Other non deductible costs | 17 | 52,690 |
| | | 104,133 |
| Less: | | |
| Capital cost allowance | 43,361 | |
| Cumulative eligible capital | 10 | |
| Revenue re: Agreement With CRA | 4,618 | |
| General expenses capitalized | 3,316 | |
| Interest charged to construction | 820 | |
| Bond issue expenses | 132 | |
| Deferred credit facility costs | 300 | |
| Part VI.1 tax deduction | 43,860 | 96,417 |
| Taxable Income | | 7,716 |
| Weather Normalization deducted as future tax | | 2,857 |
| Provision for PPUCVR | | (241) |
| Provision for DMI | | 318 |
| Income Tax - Part 1 | | 2,469 |
| Income Tax - Part VI.1 | | 13,706 |
| Provision for prior years taxes | | (1,336) |
| Current Income Tax Expense | | 17,773 |
| Provision for CDM | | (73) |
| Provision for PPUCVR | | 241 |
| Provision for DMI | | (318) |
| Provision for Replacement Energy Costs | | (216) |
| Provision for Weather Normalization | | (2,857) |
| Future income tax | | 1,320 |
| Future Income Tax Provision | | (1,903) |
| Total Tax Expense | | 15,870 |

**Newfoundland Power Inc.**
**Accumulated Future Income Taxes**
**For The Year Ended December 31, 2010**
**($000s)**

| | | |
|---|---|---|
| **Plant Investments** | | |
| Balance on January 1, 2010 | | 1,110 |
| Add: CCA claimed on all property, plant and equipment - from Return 22[1] | 44,417 | |
| Less: Amortization expense on all property, plant and equipment (GEC excluded from post-1986 additions) | 39,732 | |
| Difference | 4,685 | |
| Future Income Tax Rate @ 29% | | 1,359 |
| Balance on December 31, 2010 (if negative enter 0) | | 2,469 |

| | | |
|---|---|---|
| **Pension and Early Retirement Costs** | | |
| Balance on January 1, 2010 | | 1,187 |
| Add: Pension Funding | 6,498 | |
| Less: Pension Expense (including Special Pension Costs) | 6,631 | |
| Difference | (133) | |
| Future Income Tax Rate @ 29% | | (39) |
| Balance on December 31, 2010 | | 1,148 |
| **Total Accumulated Future Income Taxes** | | **3,617** |

[1] Equals CCA $43,361,000 (Return 22, line 32) + provision for prior year CCA, $1,056,000.

**Newfoundland Power Inc.**
**Average Regulated Capital Structure**
**For The Year Ended December 31, 2010**
**($000s)**

## Average Book Capital Structure

| | Year-End December 31 2010 | Year-End December 31 2009 | Average | Percent |
|---|---|---|---|---|
| Total Debt | 475,482 | 479,250 | 477,366 | 54.41% |
| Preference Shares | 9,111 | 9,111 | 9,111 | 1.04% |
| Common Equity | 400,502 | 381,185 | 390,844 | 44.55% |
| | 885,095 | 869,546 | 877,321 | 100.00% |

## Average Regulated Capital Structure[1]

| | Average 2010 | Percent |
|---|---|---|
| Total Debt | 477,366 | 54.41% |
| Preference Shares | 9,111 | 1.04% |
| Common Equity | 390,844 | 44.55% |
| | 877,321 | 100.00% |

[1] In Order No. P.U. 19 (2003), the Board ordered that the proportion of regulated common equity in the capital structure shall not exceed 45%. In years where the average common equity percentage is below 45% of the average invested capital, the average regulated capital structure will equal the average book capital structure.

**Newfoundland Power Inc.**
**Cost of Embedded Debt**
**For The Years Ended December 31**
**($000s)**

| | | 2010 | 2009 |
|---|---|---|---|
| **Debt** | | | |
| Bonds | | 463,688 | 468,888 |
| Credit Facilities | | 15,000 | 13,500 |
| | | 478,688 | 482,388 |
| Debt Discount and Issue Expenses | | (3,206) | (3,138) |
| | | 475,482 | 479,250 |
| Average Debt | **A** | 477,366 | 458,702 |
| **Interest Expense**[1] | | | |
| Interest on Bonds | | 35,850 | 34,547 |
| Interest on Credit Facilities | | 316 | 396 |
| Interest on Bank Indebtedness | | 13 | 7 |
| Amortization of Debt Discount and Issue Costs | | 232 | 235 |
| | **B** | 36,411 | 35,185 |
| **Embedded Cost of Debt** | **B/A** | **7.63%** | **7.67%** |

[1] Total financing costs for 2010 and 2009 as reported in Return 1 are as follows:

| | (000s) 2010 | 2009 |
|---|---|---|
| Interest Expense (B) from above | 36,411 | 35,185 |
| Add: Amortization of Capital Stock Issue Expenses | 38 | 38 |
| Add: Interest on Security Deposits | 4 | 7 |
| Less: AFUDC | (820) | (675) |
| Interest Expense Reported in Return 1 | 35,633 | 34,555 |

**Newfoundland Power Inc.**
**Explanation of Variances in Cost of Debt**
**For The Year Ended December 31, 2010**
**($000s)**

| | Actual 2010 | Test Year 2010 | Variance |
|---|---|---|---|
| **Average Debt** | 477,366 | 475,448 | 1,918 |
| | | | |
| **Embedded Cost of Debt** | 7.63% | 7.64% | -0.01% |
| | | | |
| **Details of the Embedded Cost of Debt** | | | |
| Interest on Bonds | 35,850 | 35,849 | 1 |
| Interest on Credit Facilities | 316 | 270 | 46 [1] |
| Interest on Bank Indebtedness | 13 | - | 13 |
| Amortization of Debt Discount and Issue Costs | 232 | 185 | 47 [2] |
| | | | |
| | 36,411 | 36,304 | 107 |

**Explanation of Variances**

[1] Interest on credit facilities was higher than the 2010 Test Year due to higher than expected capital expenditures related to customer growth.

[2] The increase in debt amortization costs is due to legal/accounting costs related to the Amended Committed Credit Facility Agreement dated August 27, 2010.

**Newfoundland Power Inc.**
**Regulated Return on Average Common Equity**
**For The Years Ended December 31**
**($000s)**

| | 2010 | 2009 |
|---|---|---|
| **Average Common Equity** | | |
| Common Equity at December 31, 2010 | 400,502 | |
| Common Equity at December 31, 2009 | 381,185 | 381,185 |
| Common Equity at December 31, 2008 | | 373,738 |
| Average Common Equity | 390,844 | 377,462 |
| **Regulated Return on Average Common Equity** | | |
| Earnings Applicable to Common Shares - Return 1 | 35,005 | 32,628 |
| Add: Non-Regulated Expenses (net of income taxes) | 979 | 1,203 |
| | 35,984 | 33,831 |
| **Regulated Return on Average Common Equity** | **9.21%** | **8.96%** |

**Newfoundland Power Inc.**
**Assessable Revenue**
**(s. 13 of the *Public Utilities Act* )**
**For The Year Ended December 31, 2010**
**($000s)**

| | | |
|---|---|---|
| Revenue From Rates from Return 14 | 535,333 | |
| Weather Normalization Revenue Adjustment from Return 17 | (20,445) | |
| | 514,888 | |
| Municipal Taxes Billed | 12,788 | |
| Billing per the Rate Stabilization Account from Return 16 | 6,672 | |
| Total Electrical Revenue Billed | | 534,348 |
| Other Revenue from Return 14 | | 13,426 |
| **Assessable Revenue** | | **547,774** |

# 2011 Annual Report

NEWFOUNDLAND POWER
A FORTIS COMPANY

# About Us

Newfoundland Power Inc. ("Newfoundland Power") operates an integrated generation, transmission and distribution system throughout the island portion of Newfoundland and Labrador.

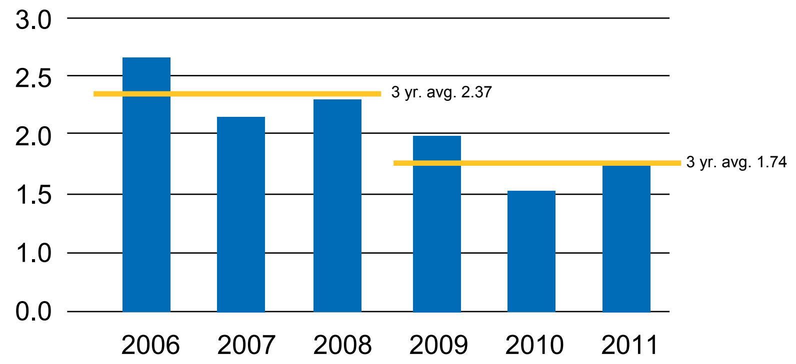
For over 125 years, we have provided customers with safe, reliable electricity in the most cost-efficient manner possible. Our Company serves over 247,000 customers, 87% of all electricity consumers in the province.

Our employees continue to provide our customers with the service they expect and deserve in an environmentally and socially responsible manner.

Our vision is to be a leader among North American electric utilities in terms of safety, reliability, customer service and efficiency.

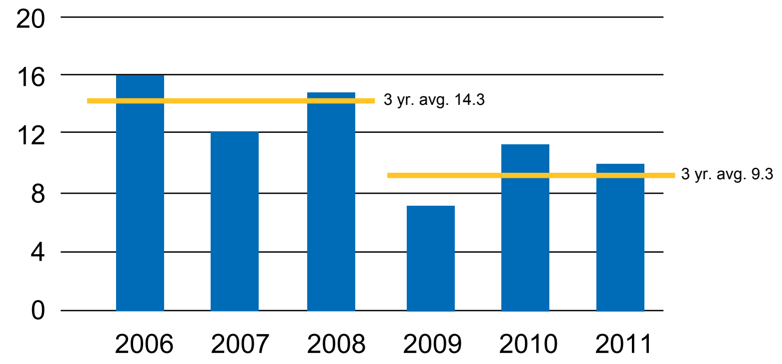
All the common shares of Newfoundland Power are owned by Fortis Inc. ("Fortis") (TSX:FTS), the largest investor-owned distribution utility in Canada, which serves approximately 2,000,000 gas and electricity customers, and has assets exceeding $13 billion.

**RELIABILITY**
**Outages per Customer (#)**

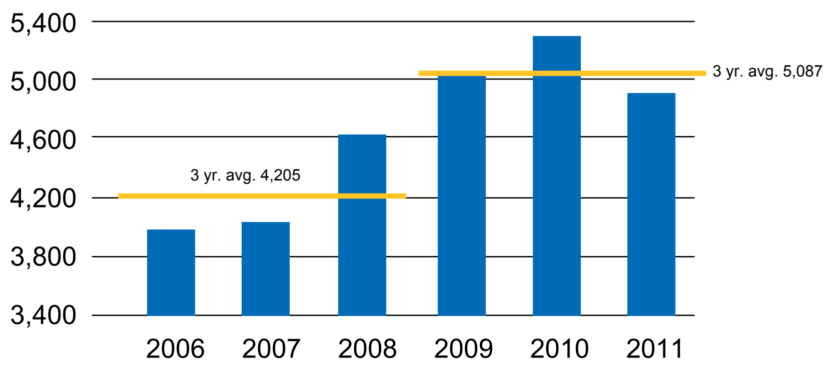



* Excluding major storms and PCB legislative requirements.

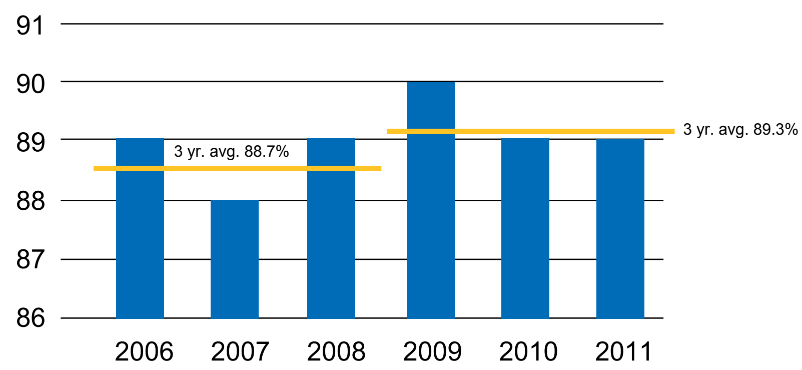
**SAFETY**
**Lost Time/Medical Aid Injuries (#)**




**GROWTH**
**Gross Customer Connections (#)**




**CUSTOMER SERVICE**
**Customer Satisfaction Rating (%)**

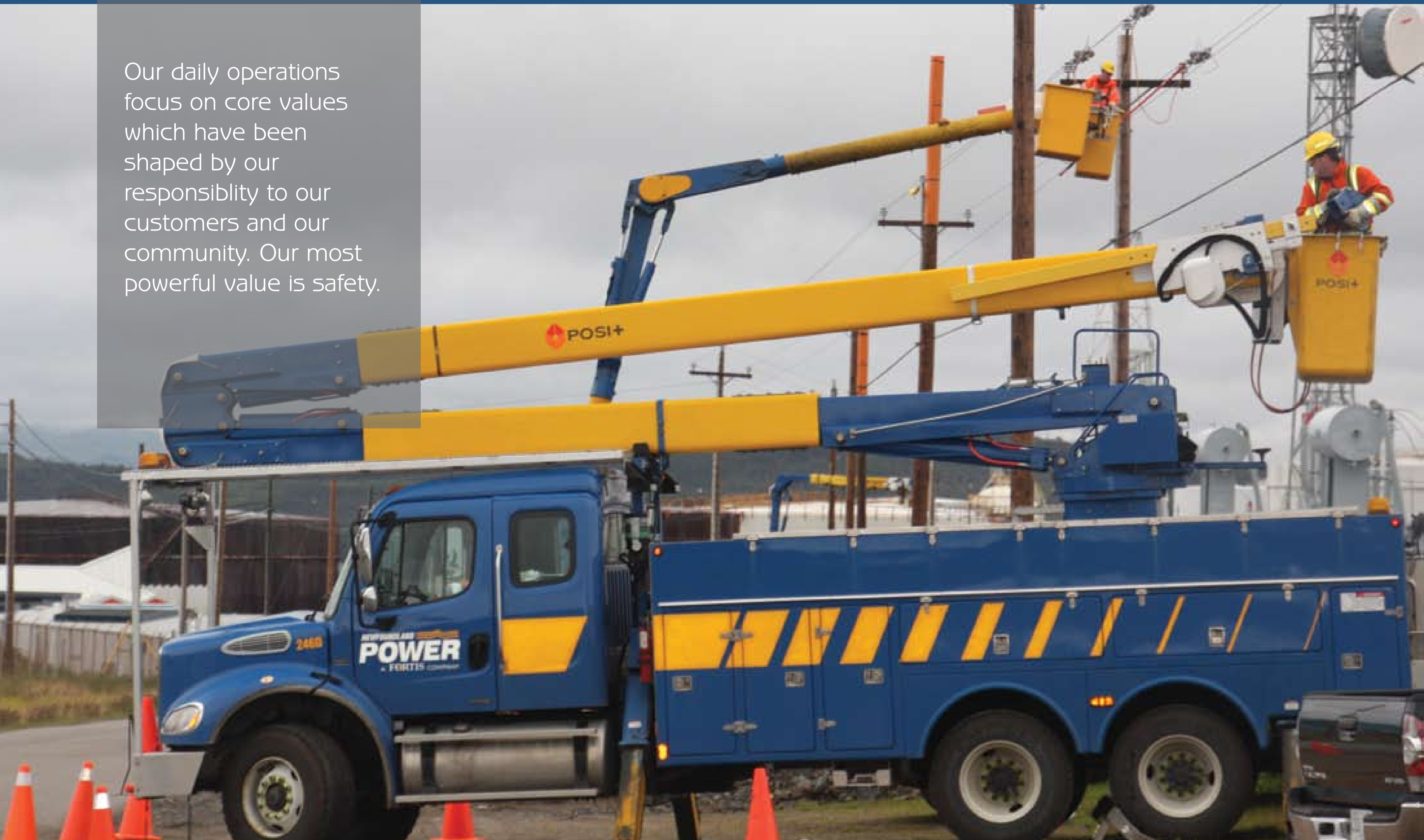


# Highlights

| Financial | 2011 | 2010 |
|---|---|---|
| Revenue *($000s)* | 573,072 | 555,355 |
| Property, Plant and Equipment *($000s)* | 1,268,305 | 1,212,810 |
| Long-term Debt *($000s)* | 478,488 | 478,688 |
| Common Shareholders' Equity *($000s)* | 384,030 | 400,502 |
| Earnings Applicable to Common Shares *($000s)* | 33,685 | 35,005 |
| Earnings per Common Share *($)* | 3.26 | 3.39 |

| Operating | | |
|---|---|---|
| Customers *(#)* | 247,163 | 243,426 |
| Customer Satisfaction Rating *(%)* | 89 | 89 |
| Generating Capacity *(MW)* | 140.4 | 140.4 |
| Transmission and Distribution Lines *(km)* | 11,235 | 11,072 |
| Substations *(#)* | 130 | 130 |
| Peak Demand *(MW)* | 1,166 | 1,206 |
| Electricity Sales *(GWh)* | 5,553 | 5,419 |

Our daily operations focus on core values which have been shaped by our responsiblity to our customers and our community. Our most powerful value is safety.



# Report to Shareholders

Our employees are dedicated to incorporating the Company's corporate values into their daily operations. We take our commitment to safety, reliability, customer service, our environment and community outreach very seriously. Our 89% annual customer satisfaction rating indicates our customers are supportive of the job we do.

Reminding the public to be safe around electricity and warning of potential electrical hazards were among our top priorities in 2011. We introduced a new television campaign featuring scenarios involving operating heavy equipment and managing vegetation growth near power lines.

We introduced a new recognition program for employees who have demonstrated a commitment to safety. Throughout the year, twelve employees were recognized for their outstanding safety contributions. To improve safety performance in field operations, we dedicated health and safety personnel to complete a series of assessments and action plans at our locations across the island.

Contractor safety also continues to be a focus for the Company. We worked on strengthening our relationship with contractor owners, as well as increasing the effectiveness of job planning meetings and completing a higher number of personal worksite inspections and observations. An external audit of our Health and Safety Management System in 2011 confirmed our continued compliance with the OHSAS 18001 Health and Safety Management System international standard.

We sustained damage to our electricity system in December as a result of a major wind storm. High winds left approximately 41,000 customers without power across the island, with the majority of customers affected in the Corner Brook, Grand Falls-Windsor and Bonavista Peninsula areas. Crews from across the island worked to restore power in the safest, most efficient way possible.

We invested approximately $76.2 million in capital expenditures, excluding retirements, throughout the year. This included 40% to connect approximately 5,000 new customers to the electricity system and accommodate growth; and, 60% to maintain our system's reliability.

Over the past five years, we have invested more than $350 million toward improving reliability across the province. These investments have benefitted our customers through an approximate 30% decrease in the number of outages per customer over the same period. The average length of outages experienced by our customers in 2011 remained consistent with our reliability performance in 2010.

New technologies have resulted in several efficiencies in the delivery of customer service excellence. Implementation of mobile computing devices provides field employees with real time access to operational procedures, and optimizes the way we do planned work and respond to outages.

We also introduced a new mobile website for smart phone users and several new online self service options for customers. Our continued advancement of electronic communications has resulted in more than 2.8 million electronic interactions with our customers in 2011.

Our residential customers now have options when it comes to electricity rates. Our new Seasonal Rate offers residential customers the option to pay less for the electricity used in summer than winter months. We also began a two-year pilot project to investigate offering a Time of Day electricity rate which could result in savings for customers who alter their electricity usage patterns.

Our energy efficiency efforts through takeCHARGE have helped to achieve overall savings of 12.1 GWh for 2011. An external audit of the Company's Environmental Management System verified our continued compliance with the ISO 14001 international standard. The audit confirmed our facilities are well-maintained and that employees continue to demonstrate a commitment to working in an environmentally responsible manner.

We unveiled a new logo for our corporate charity, *The Power of Life Project*. Thanks to the support of our customers and employees, we are making a difference in cancer care here at home. From cancer treatment equipment to family and patient support, *The Project* is dedicated to contributing to the areas where it is needed most.

Our earnings of $33.7 million in 2011 decreased by $1.3 million as compared to 2010. Through operation of the Automatic Adjustment Formula ("Formula"), the Company's regulated rate of return on common equity, for the purpose of setting electricity rates, was reduced to 8.38% in 2011 from 9.00% in 2010.

On December 13, 2011, the Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB") approved the Company's application to suspend operation of the Formula for 2012. As a result, the Company's regulated rate of return on common equity will remain at 8.38% and current customer electricity rates will continue in effect for 2012, on an interim basis. A full cost of capital review is expected to be held by the PUB in 2012.

We completed the sale of certain utility poles to Bell Aliant Regional Communications Inc. ("Bell Aliant"). The Company continues to provide for the construction of Bell Aliant's support structures.

We wish to thank our employees for their hard work and commitment in 2011. Our ability to deliver safe, reliable electricity, while providing our customers with a high standard of customer service is a direct result of their dedication to the Company, our customers and communities across the province.

Newfoundland Power's Board of Directors provided another year of sound leadership in 2011. We express our sincerest appreciation for their continued support and direction. We thank Mr. Barry Perry, who retired from our Board after 3 years service, and welcome our newest member, Mr. Richard Hew.

Sincerely,

Earl Ludlow

Earl Ludlow
President and Chief Executive Officer

Peggy Bartlett

Peggy Bartlett
Chair, Board of Directors


Prior to starting any job, our crews identify hazards and ensure the proper safety precautions are in place. Clayton Peach signs off on worksite details after completing the safety meeting with members of his crew.

# Safety

The safety of our employees, contractors and the general public is at the forefront of everything we do. In 2011, we implemented several initiatives to strengthen our internal safety culture, improve upon our safety procedures in the field and educate the public about electrical safety.

To promote a vibrant internal safety culture, we introduced a new safety recognition program for employees in 2011. Under this program, employees who have demonstrated a commitment to safety, on the job or in their communities, are nominated by their peers for awards of recognition. Twelve employees held the title Safety Leader Among Us in 2011.

Currently, more than 20% of our workforce has been employed with the Company for 5 years or less. As new employees enter the workforce, our job shadowing and mentorship programs allow for the critical transfer of knowledge between junior and senior counterparts. During 2011, we completed a series of assessments and action plans tailored to improve field safety performance in each of our service areas. As part of this initiative, employees have received coaching through worksite assessments, job specific training and participation in safety meetings. It has also helped to identify a number of improvement opportunities in areas such as supervisor training, job safety planning, grounding practices and competency assessment for newly hired Power Line Technicians.

We took a concentrated approach to safety training in 2011, paying particular attention to high risk work such as grounding and bonding and worker protection procedures. The majority of the training planned for the year was completed by the end of the first quarter.

Our dedication to contractor safety remains unwavering. In 2011, we strengthened our relationship with contractor owners and focused on worksite visits. Throughout the year, health and safety personnel as well as field staff completed in excess of 300 worksite inspections and observations with our contractors. Contractors are an extension of our workforce and, as work volume continues to increase, their safety will continue to be a primary focus.

Once again, the majority of our corporate advertising was focused on keeping electrical safety top-of-mind with the general public. In addition to our radio and print campaigns, we launched new television ads during the month of September. The new ads highlight the potential danger and consequences involved with using heavy construction equipment and tree trimming near energized power lines. We continue to use Twitter to communicate real time safety information to the public and warn of potential weather related concerns.

Our employees and retirees carried on our Company's proud tradition of teaching members of the community about electrical safety. We demonstrated potential hazards in and around the home to more than 2,600 children in approximately 40 schools across the island.

The completion of an external audit of our Health and Safety Management System in 2011 confirmed our continued compliance with the OHSAS 18001 Health and Safety Management System international standard.

Whether on-the-job, at home or in the community, we are committed to putting safety first in everything we do.

As part of our commitment to reliability, we continue to invest in strengthening and rebuilding our electricity system. Power Line Technician, Chris Vivian, helps to rebuild a structure during a job in Come By Chance, NL.

# Reliability

Over the past five years, we have invested more than $350 million to enhance our province's electricity system. These investments have served to improve reliability, reducing the number of outages experienced by our customers by approximately 30%.

In December 2011 we sustained damage to our electricity system across the island as a result of a major wind storm. Wind speeds in excess of 120 km/h left approximately 41,000 customers without power in the Corner Brook, Grand Falls-Windsor and Bonavista Peninsula areas. Crews from across the island mobilized immediately, restoring power to our customers in the safest, most efficient way possible.

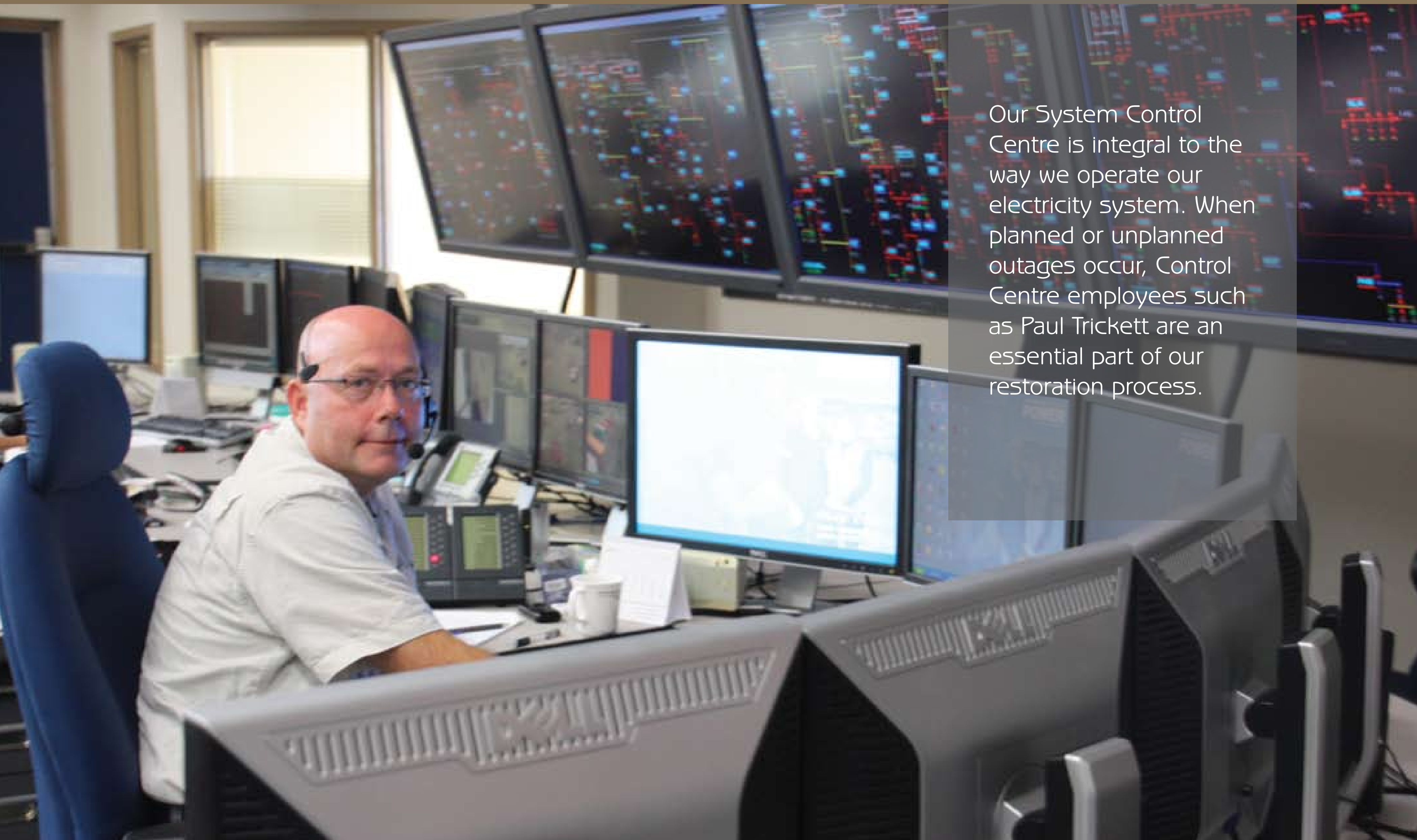
For the third consecutive year, we connected approximately 5,000 new customers to our electricity system. This increased volume of new customers required capital expenditures to increase our system's capacity. In 2011, we spent approximately 40% of our $76.2 million capital expenditures, excluding retirements, to expand and upgrade the electricity system in areas experiencing economic and customer growth. Specific projects involved spending approximately $4.9 million to upgrade power transformers at Kelligrews and Pulpit Rock substations on the Northeast Avalon, another $12.0 million to construct both primary and secondary power lines to connect new customers to our electricity system, as well as $6.7 million to refurbish substations across the island.

Our approach to asset management involves identifying deficiencies in our system through inspections and repairing them before they yield negative results. Last year, we dedicated approximately 60% of our capital expenditures to strengthen aging components of our electricity system. This included $5.5 million to upgrade transmission lines, including two in the St. John's area and one on the Southern Shore of the Avalon Peninsula, and $5.0 million to refurbish our Horse Chops, Rattling Brook and Sandy Brook hydroelectric generating facilities which provide low cost, clean energy. We invested $3.9 million to upgrade and add new technology to manage our electricity system more efficiently. We spent approximately $1.7 million to repair the dam at our hydroelectric plant in Lawn and rebuild our Port Union hydroelectric plant as a result of damage sustained during Hurricane Igor.

We completed the successful installation of mobile computing equipment in vehicles across our entire fleet in 2011. This ensures our field employees have real time access to the most up-to-date operational safety and environmental procedures. In 2011, we also began the implementation of new work scheduling software in select vehicles to optimize the way we deploy service and line crews. This technology allows for better scheduling of planned and unplanned work. Crews can share information, update project status directly from their vehicles, and access GPS navigation software to get information about, and directions to, jobsites.

To continue providing safe, reliable electricity to our customers we plan to invest an additional $77.3 million in 2012. Planned areas of focus include: purchasing a new mobile transformer for use during emergency and maintenance work; strengthening several of our transmission lines; constructing distribution lines to connect new customers; and, improving the overall operating efficiency of the electricity system.

Excluding storm related outages, our reliability remains among the best in the Country compared with utilities who serve both rural and urban customers.



Our System Control Centre is integral to the way we operate our electricity system. When planned or unplanned outages occur, Control Centre employees such as Paul Trickett are an essential part of our restoration process.

# Service

We worked hard to maintain our customers' confidence in our service abilities throughout the year. This involved streamlining our approach to dispatching crews in the field, introducing new mobile technologies for smart phones, improving the functionality of our corporate website and offering new online self service options. Once again, our commitment to continually improving service is showing tangible benefits. In 2011, our customers gave us an annual customer satisfaction rating of 89%.

Customers are interacting with us electronically on a much larger scale. The Company recorded more than 2.8 million electronic interactions with customers in 2011, an increase of almost 30% over the last 5 years. In addition to viewing personal account and payment information online, customers can now access outage information and report street light outages on their smart phones via our mobile website 24 hours a day, 7 days a week.

We processed more than 46,000 email customer service requests and inquires, up almost 17% over 2010, and recorded over 540,000 visits to our corporate website, an increase of 17% over the previous year. Throughout the year, we tweeted about topics related to safety, outages, new service offerings, job opportunities and community events.

In 2011, more than 45,000 customers participated in our ebills program, up by almost 30% over 2010. Electronic billing reduces our environmental footprint and enhances convenience for our customers. It was particularly valued during the Canada Post strike.

The introduction of our new contractor website has also helped to streamline several of our contracted work processes. Our contractors login to directly access information about ongoing work such as street light repairs and pole installations. This allows contractors to manage project deadlines and workload requirements, and ensures better service for our customers.

We've begun to install Electronic Scheduling Software across our fleet of vehicles. This is serving to make work scheduling more efficient for processes such as new customer connections and system maintenance. Through this software crews in the field are able to access and work from project documents anywhere, anytime. This reduces inefficiencies in pre-job planning and communications in the field, resulting in improved service for our customers.

We implemented Click Scheduling Software to organize and schedule work for crews in the St. John's area. This software assigns work based on location and skill set, serving to optimize field work and reduce the time associated with manual processes.

Automated Meter Reading ("AMR") technology is now the standard for new meter installations in the province. The number of properties now equipped with AMR capabilities has risen 50% from approximately 30,000 in 2010 to approximately 45,000 by the end of 2011. The technology improves safety for our meter readers, reduces the need for electrical billing estimates and allows for the consolidation of some meter reading routes.

We introduced a new electricity rate option for residential customers. Since being introduced nearly 1,700 customers have opted for the new Seasonal Rate, where the cost of electricity in the summer months is lower than the winter. We also began a two-year pilot project to investigate offering a Time of Day electricity rate. Customers willing to alter their electricity usage patterns could benefit from this new structure.

We strive to deliver the best service possible for our customers, and the positive feedback we receive motivates us to carry on.

Employees with differing levels of experience, such as Trina Troke, Jia Ma and Tony Hancock with our Engineering Department, work closely on projects as part of our succession planning process.

# Employees

Our employees are the key to who we are and what we do. We continue our focus on furthering our position as an employer of choice. This involves enhancing our work environment to maximize employee satisfaction and maintaining our current knowledge base through succession planning.

Early in 2011, the Company conducted an in-depth workforce assessment in which we projected retirements for the next five years, reviewed workload plans and identified human resource strategies to guide the Company in the future. We implemented a plan to ensure knowledge transfer between senior Engineers and Engineering Technologists and their junior counterparts in 2011.

As our Company's retirement rate continues to rise, we added 65 new employees to our team in 2011, the largest number hired in at least 20 years. We continue to support and participate in career fairs and co-op programs with Memorial University of Newfoundland and College of the North Atlantic campuses. In 2011, we worked closely with a local private educational institute to develop a certified training program for Power Line Technicians. We also enhanced our in-house Power Line Technician Apprentice Program with the addition of new apprentices, bringing our current complement to 25.

Our new corporate website dedicated to attracting new employees has made relevant information more accessible to those seeking careers. Online recruitment features now include a career alert option and first-hand employee testimonials.

Our focus on learning and development continued to be strong in 2011. Our mentoring program was very active and we made enhancements to our orientation program for employees and students. We also enhanced the tools and services available to employees to assist them with pre-retirement planning and offered a number of financial and retirement planning sessions.

We took an inventory of critical skills among technical staff in the Company to identify areas of expertise. This resulted in a risk analysis which involves matching skills sets by department and location.

We renewed our commitment to employee health and well being through updating our Respectful Workplace Policy and the formalizing of an Early and Safe Return to Work Program. Our employees continue to benefit from several in-house Employee Assistance Program services, and a variety of health and wellness initiatives. We were also proud to offer programs through our Occupational Health Nurse in 2011, including: flu vaccinations; blood pressure monitoring; fitness programs; weight loss clinics; and, healthy lifestyle advice.

Employees are the driving force behind our commitment to safety, service excellence and our community.


Corinne Roberts and Kristy Woodford with our takeCHARGE Energy Conservation Team reveal our new Smart House – an interactive way to teach kids and the public about the many ways to save energy and money in your home.

# Environment

Our commitment to operating in an environmentally responsible manner is part of our daily responsibilities. In 2011, we educated our customers about how to use energy more efficiently through our takeCHARGE partnership, completed capital projects which improved the condition and operation of our electricity system, and completed beautification projects within our communities.

Our customers' energy efficiency efforts through takeCHARGE have resulted in the conservation of 12.1 GWh of energy for 2011. This was more than double our goal of 5.1 GWh. Over 6,500 customers took advantage of our ENERGY SAVERS Rebate Programs. Residential customers benefitted from rebates on insulation, ENERGY STAR® windows, and programmable and electronic thermostats, and commercial customers received rebates on high performance lighting.

Visits to the takeCHARGE website increased by more than 40% over 2010, and our level of interaction with customers continues to grow through social media channels such as facebook and YouTube. More than 6,000 users have indicated they "like" our takeCHARGE facebook fan page and our YouTube viewers are continuing to rise.

2011 was also a busy year for capital projects aimed at improving the operating efficiency of our electricity system. We allocated $1.6 million to increase the annual energy production at our Sandy Brook Hydroelectric Plant. We invested $2.6 million to install a spillway and rehabilitate the dams at our Rattling Brook Hydroelectric Plant to improve water management through reduced spillage.

To lower the risk of oil spills through corrosion of electrical equipment, we are continuing to replace mild steel transformers with stainless steel units throughout the province. Approximately 85% of our distribution feeders and 92% of our substations have been completed under the PCB Phase Out Program to date. By the end of 2011, we replaced several circuit breakers in our service territory with more environmentally friendly breakers.

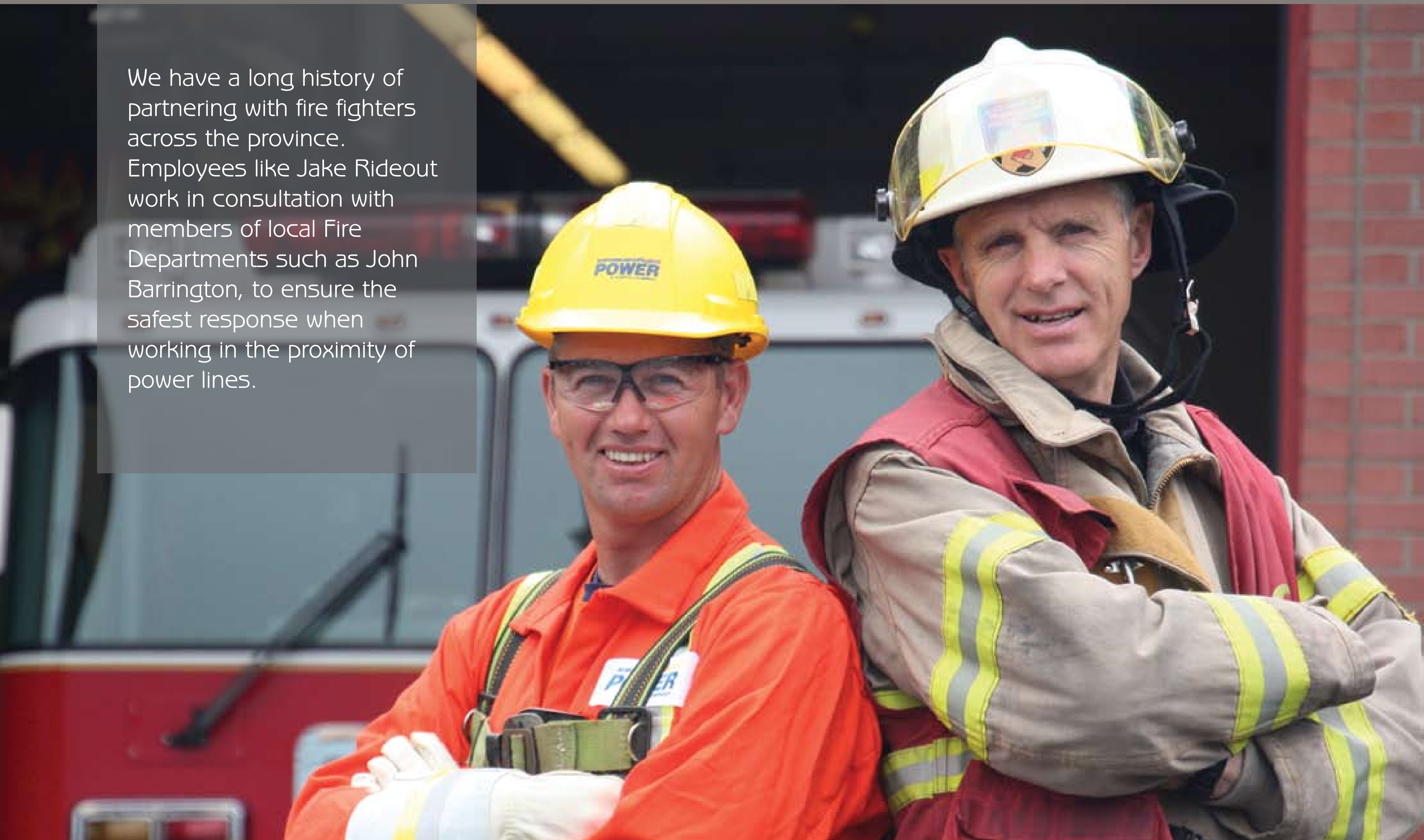
We held our 14th annual *EnviroFest* celebrations at 8 of our area locations during Environment Week. Through events tailored for each area, we educated thousands of participants about how to take better care of our environment, and completed tree planting and beautification projects throughout the province.

We celebrated our 14th year as a corporate sponsor of the Atlantic Salmon Federation's *Fish Friends* program. Since its inception we have invested approximately $80,000 to help students in schools across the island raise and release thousands of Atlantic salmon fry into our streams and waterways. We partnered with the City of St. John's and Tree Canada to kick off the first National Tree Day at Bowring Park in St. John's. During the event, school children and other participants planted trees, took part in safety demonstrations and learned lessons in tree care.

Throughout the year, we provided environmental training to 150 employees and almost 350 contractor employees. This reinforced the importance of performing duties in an environmentally responsible manner. We completed 6 emergency preparedness and response drills in 2011 to ensure that we are ready to respond in the event of any spills or emergency situations.

We demonstrate our commitment to the environment through our daily operations and community involvement.

We have a long history of partnering with fire fighters across the province. Employees like Jake Rideout work in consultation with members of local Fire Departments such as John Barrington, to ensure the safest response when working in the proximity of power lines.



# Community

We are proud to partner with other community minded organizations for the betterment of our communities. In addition to providing in-kind support, corporate donations and sponsorships, our employees took a hands on approach to community involvement in 2011.

We donated $150,000 through our corporate charity, *The Power of Life Project*, which raises funds for cancer treatment equipment, support programs, and education and awareness. The commitment of our employees and retirees to organizing annual fundraising events, combined with a corporate donation and monthly donations from our employees and customers is making a difference in the lives of cancer patients and their families throughout the province.

*The Project* works closely with the Dr. H. Bliss Murphy Cancer Care Foundation and cancer centres across the island to identify and address area specific needs. In 2011, some of the initiatives included: helping almost 500 families through the Foundation's Patient and Family Support Fund; supporting children living with cancer attending Camp Delight; upgrading the waiting room at the Cancer Centre Western Region in Corner Brook; donating a blanket warmer to the Cancer Centre in Carbonear; and, providing 12 automated blood pressure monitors to a variety of cancer centres across the island.

We unveiled a new logo for *The Power of Life Project* in November, with the goal of increasing awareness for *The Project*. Since it began in 2002, *The Power of Life Project* has donated in excess of $2.0 million to support cancer care.

We successfully collaborated with the Newfoundland and Labrador Chapter of Motorcycle Ride for Dad in the fight against prostate cancer. Along with assisting with promotional and awareness initiatives, we hosted almost 600 bikes at our corporate headquarters on Ride Day, helping to raise over $160,000 toward prostate cancer research and education.

As part of our commitment to give back to our communities, we donated $50,000 to the Red Cross's Prepared campaign to help increase its disaster response capacity. We provided $15,000 to support the Newfoundland and Labrador Association of Fire Services' Learn Not to Burn Program for schools across the province. We partnered with Municipalities Newfoundland and Labrador on conferences and trade shows, and renewed our commitment to the youth of our province through our active involvement with Junior Achievement Newfoundland and Labrador.

We also continued our more than 30 year history of educating firefighters about the safest ways to fight fires in the proximity of high voltage power lines and equipment. We completed this training with 120 firefighters in 2011, bringing the total number of firefighters to receive the training to date to approximately 8,500.

Throughout 2011, employee groups and associations collected money and food at local Christmas parades for charities and food banks; gathered warm winter clothing for the Coats for Kids Campaign; delivered food as part of the Meals on Wheels initiative; and, entered corporate teams in fundraising events, such as CIBC Run for the Cure.

Our employees' commitment to giving the gift of life remains strong. In 2011, we exceeded our target of 300 blood donations in support of the Canadian Blood Services' Partners for Life program. Since 2004, our employees and their families have made approximately 2,300 blood donations, helping to save up to 6,900 lives.

Our employees, retirees and family members give freely of their time and money to make a difference to those in need.

# Management Discussion and Analysis

*Dated February 9, 2012*

*The following Management Discussion and Analysis ("MD&A") should be read in conjunction with Newfoundland Power Inc.'s (the "Company" or "Newfoundland Power") annual financial statements and notes thereto for the year ended December 31, 2011. The MD&A has been prepared in accordance with National Instrument 51-102 - Continuous Disclosure Obligations. Financial information herein reflects Canadian dollars and Canadian generally accepted accounting principles ("Canadian GAAP"), including certain accounting practices unique to rate regulated entities. These accounting practices, which are disclosed in Notes 2 and 6 to the Company's 2011 annual audited financial statements, result in the recognition of revenues, expenses, regulatory assets and regulatory liabilities which would not occur in the absence of rate regulation and which affect the Company's reported earnings, cash flows and financial position.*

*Certain information herein is forward-looking within the meaning of applicable securities laws in Canada ("forward-looking information"). The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words.*

*The forward-looking information reflects management's current beliefs and is based on information currently available to the Company's management. The forward-looking information in this MD&A includes, but is not limited to, statements regarding: expectations to generate sufficient cash to complete required capital expenditures, and to service interest and sinking fund payments on debt; meeting pension funding requirements; no material adverse credit rating actions expected in the near term; the Company's belief that it does not anticipate any difficulties in issuing bonds on reasonable market terms; and, the forecast gross capital expenditures for 2012.*

*The forecasts and projections that make up the forward-looking information are based on assumptions, which include, but are not limited to: receipt of applicable regulatory approvals; continued electricity demand; no significant operational disruptions or environmental liability due to severe weather or other acts of nature; no significant decline in capital spending in 2012; sufficient liquidity and capital resources; the continuation of regulator-approved mechanisms that permit recovery of costs; no significant variability in interest rates; no significant changes in government energy plans and environmental laws; the ability to obtain and maintain insurance coverage, licences and permits; the ability to maintain and renew collective bargaining agreements on acceptable terms; and, sufficient human resources to deliver service and execute the capital program.*

*The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. The factors which could cause results or events to differ from current expectations include, but are not limited to: regulation; operating and maintenance investment requirements; economic conditions; defined benefit pension plan performance; capital resources and liquidity; interest rates; electricity prices; purchased power cost; health, safety and environmental regulations; insurance; weather; information technology infrastructure; labour relations; and, human resources. For additional information with respect to these risk factors, reference should be made to the section entitled "Business Risk Management" in this MD&A.*

*All forward-looking information in this MD&A is qualified in its entirety by this cautionary statement and, except as required by law, the Company undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise after the date hereof.*

*Additional information, including the Company's quarterly and annual financial statements and MD&A, annual information form and management information circular, is available on SEDAR at sedar.com.*

## OVERVIEW

### The Company

Newfoundland Power is a regulated electricity utility that owns and operates an integrated generation, transmission and distribution system throughout the island portion of the Province of Newfoundland and Labrador. All the Company's common shares are owned by Fortis Inc. ("Fortis"), which is principally a diversified, international holding company for electricity and gas distribution utilities.

Newfoundland Power's primary business is electricity distribution. It generates approximately 7% of its electricity needs and purchases the remainder from Newfoundland and Labrador Hydro ("Hydro"). Newfoundland Power serves over 247,000 customers, approximately 87% of all electricity consumers in the Province.

Newfoundland Power's vision is to be a leader among North American electricity utilities in terms of safety, reliability, customer service and efficiency. The key goals of the Company are to operate sound electricity distribution systems, deliver safe, reliable electricity to customers at the lowest reasonable cost, and conduct business in an environmentally and socially responsible manner.

### Regulation

Newfoundland Power is regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB"). The Company operates under cost of service regulation whereby it is entitled the opportunity to recover, through customer rates, all reasonable and prudent costs incurred in providing electricity service to its customers, including a just and reasonable return on its rate base. The rate base is the value of the net assets required to provide electricity service.

Employees like Christine Rumsey of our Finance Department are committed to ensuring the financial integrity of our daily operations.

Between general rate hearings, customer rates are established annually through an automatic adjustment formula (the "Formula"). The Formula sets an appropriate rate of return on common equity ("ROE") which is used to determine the rate of return on rate base. In accordance with the operation of the Formula, the Company's rate of return on common equity, for purposes of setting rates, was reduced to 8.38% for 2011 from 9.00% in 2010. The Company's rate of return on rate base was reduced to 7.96%, with a range of 7.78% to 8.14% for 2011, from 8.23%, with a range of 8.05% to 8.41% in 2010.

Effective January 1, 2011, customer electricity rates increased by an average of 0.8%. This reflects the net impact of the increase in revenue requirement due to the adoption of accrual accounting for other post employment benefits ("OPEBs") effective January 2011, partially offset by operation of the Formula which reduced the Company's allowed return on rate base for 2011.

On December 13, 2011, the PUB approved the Company's application to suspend operation of the Formula and review cost of capital for 2012. See the Outlook section of this MD&A.

## Financial Highlights

| | 2011 | 2010 | Change |
|---|---|---|---|
| Electricity Sales *(gigawatt hours ("GWh"))*[1] | 5,552.8 | 5,419.0 | 133.8 |
| Earnings Applicable to Common Shares | | | |
| $ Millions | 33.7 | 35.0 | (1.3) |
| $ Per Share | 3.26 | 3.39 | (0.13) |
| ROE *(%)*[2] | 8.59 | 8.96 | (0.37) |
| Cash Flow from Operating Activities *($millions)* | 80.0 | 94.2 | (14.2) |
| Total Assets *($millions)* | 1,202.4 | 1,196.9 | 5.5 |

[1] *Reflects normalized electricity sales.*
[2] *Earnings applicable to common shares, divided by the average of common shareholders' equity at the beginning and end of the year. This ratio is a non-GAAP financial measure, does not have any standardized meaning prescribed by GAAP and is unlikely to be comparable to similar ratios published by other companies. It is presented because it is commonly referred to by the users of the Company's financial statements in evaluating the results of operations and by the Company's regulator in the rate setting process.*

Electricity sales for the year ended December 31, 2011, increased by 133.8 GWh, or approximately 2.5% compared to 2010. The increase was composed of (i) an increase of 1.6% in customer growth; and, (ii) an increase of 0.9% in average consumption reflecting higher concentration of electric heat in new home construction as well as strong economic growth.

Earnings for the year ended December 31, 2011, decreased by $1.3 million from $35.0 million in 2010 to $33.7 million in 2011. The decrease in earnings was primarily the result of: (i) a lower ROE embedded in customer rates effective January 1, 2011; (ii) a decrease in other revenue related to the new support structure arrangements with Bell Aliant Regional Communications Inc. ("Bell Aliant"); (iii) a higher effective tax rate; and, (iv) an increase in operating expenses. This decrease was partially offset by higher electricity sales, a reduction to purchased power costs due to higher generation associated with the Company's hydroelectric generating facilities, and decreased amortization expense.

The actual ROE in both 2011 and 2010 is broadly consistent with that reflected in customer rates.

Cash from operating activities decreased by $14.2 million compared to 2010. This decrease was mainly a result of: (i) higher income tax instalments; (ii) timing of payments to vendors, partially offset by; (iii) the January 1, 2011, customer rate increase; and, (iv) higher electricity sales.

Total assets increased by $5.5 million at December 31, 2011, compared to December 31, 2010. The increase was due to: (i) continued investment in the electricity system, consistent with the Company's strategy to provide safe, reliable electricity service at the lowest reasonable cost; (ii) an increase in accounts receivable primarily due to higher electricity sales and customer rates; and, (iii) an increase in regulatory assets, due to the normal operation of various regulatory mechanisms. This increase was substantially offset by the disposal of 40% of all joint-use poles and related infrastructure to Bell Aliant as described in Note 9 of the Company's 2011 annual audited financial statements.

## RESULTS OF OPERATIONS

### Revenue:

| *($millions)* | 2011 | 2010 | Change |
|---|---|---|---|
| Revenue from Rates | 559.5 | 537.6 | 21.9 |
| Amortization of Regulatory Liabilities and Deferrals | 3.1 | 5.3 | (2.2) |
| Other Revenue[1] | 10.5 | 12.5 | (2.0) |
| Total | 573.1 | 555.4 | 17.7 |

[1] *Other revenue is composed largely of maintenance, construction and related charges associated with the new support structure arrangements with Bell Aliant effective January 2011, as well as pole attachment charges to various telecommunication companies.*

Revenue from rates increased by $21.9 million, from $537.6 million in 2010 to $559.5 million in 2011. The increase primarily reflects the electricity sales growth and the January 1, 2011, customer rate increase.

The amortization of regulatory liabilities and deferrals in 2011 include the pension expense variance deferral ("PEVDA") and the OPEBs cost variance deferral. These regulatory liabilities and deferrals are described in Notes 2 and 6 to the Company's 2011 annual audited financial statements. The amortization of the unbilled revenue and municipal tax regulatory liability expired in December 2010, as described in Notes 2 and 4 to the Company's 2010 annual audited financial statements. The amounts recorded are in accordance with PUB orders.

Other revenue decreased by $2.0 million, from $12.5 million in 2010 to $10.5 million in 2011. The decrease was primarily related to the new support structure arrangements with Bell Aliant effective January 1, 2011. See the Outlook section of this MD&A.

**Purchased Power:** Purchased power expense increased by $11.1 million, from $358.4 million in 2010 to $369.5 million in 2011. The increase was primarily due to electricity sales growth. The increase was partially offset by a reduction in purchased power costs as a result of higher generation associated with the Company's hydroelectric generating facilities.

**Operating Expenses:** Operating expenses increased by $2.8 million, from $53.8 million in 2010 to $56.6 million in 2011. The increase was mainly a result of: (i) wage and inflationary increases; (ii) higher costs associated with training and illness; (iii) increased conservation costs associated with rebate programs offered to customers; (iv) higher distribution maintenance costs; and, (v) higher professional fees associated with the Company's adoption of new accounting standards in 2012. This increase was partially offset by a reduction in retirement and severance expenses, storm related costs and an increase in general expenses capitalized ("GEC").

**Employee Future Benefits:** Employee future benefits increased by $12.2 million, from $8.4 million in 2010 to $20.6 million in 2011. Approximately $4.0 million of the increase related to the amortization of experience losses from prior years associated with the pension plan assets and a lower discount rate at December 31, 2010, which is used to determine the Company's accrued benefit pension obligation associated with its defined benefit pension plan. The remaining increase of $8.2 million relates to higher OPEBs costs. Effective January 1, 2011, pursuant to a PUB order: (i) the Company recognized OPEBs based on the accrual method of accounting; and, (ii) commenced amortization of the OPEBs regulatory asset of $52.6 million over 15 years.

**Amortization:** Amortization expense decreased by $0.7 million, from $43.4 million in 2010 to $42.7 million in 2011. The decrease was primarily due to lower depreciable assets resulting from the new support structure arrangements with Bell Aliant effective January 1, 2011. See Note 9 of the Company's 2011 annual audited financial statements. This was partially offset by increased amortization relating to the Company's capital expenditure program.

Amortization of property, plant and equipment is subject to periodic review by external experts via an amortization study. The most recent amortization study, based on capital assets in service as at December 31, 2010, indicates an accumulated amortization variance of approximately $17.7 million. Subject to PUB approval, this variance is expected to increase the amortization of capital assets in future years which will be recovered in future customer rates.

**Amortization True-Up Deferral:** Based on a 2002 amortization study, the PUB ordered the deferred recovery of approximately $11.6 million, $5.8 million in each of 2006 and 2007, related to a variance in accumulated amortization. These deferrals were amortized evenly over 2008 through 2010.

**Cost Recovery Deferral:** The PUB approved the deferred recovery of $2.4 million of costs in 2011 due to increased costs associated with expiring regulatory amortizations related to unbilled revenue, municipal tax liability, amortization true-up deferral, replacement energy deferral, purchased power unit cost variance deferral and deferred General Rate Application ("GRA") costs. The deferral was recorded as an increase in regulatory assets and a decrease in expense.

**Finance Charges:** Finance charges for 2011 were comparable to 2010. Additional borrowings under the Company's credit facility and higher short-term interest rates were offset by a reduction in interest on long-term debt after the annual sinking fund payment. The higher short term interest rates are reflective of current market conditions.

**Income Taxes:** Income tax expense for 2011 was comparable to 2010. In 2011 lower pre-tax earnings was offset by a higher effective income tax rate. The higher effective income tax rate related primarily to recognition of a tax reserve for unpaid compensation and the allocation of the Part VI.1 tax deduction from Fortis to Newfoundland Power. This was partially offset by a reduction in the statutory tax rate and the recognition of tax deductions associated with regulatory costs.

## FINANCIAL POSITION

Explanations of the primary causes of significant changes in the Company's balance sheets between December 31, 2010, and December 31, 2011, follow:

| *($millions)* | Increase (Decrease) | Explanation |
|---|---|---|
| Accounts Receivable | 15.4 | Increase is attributable to: (i) higher electricity sales; (ii) the January 1 and July 1, 2011, customer rate increases; and, (iii) amounts receivable from Bell Aliant as part of the support structure arrangements effective January 1, 2011. |
| Regulatory Assets | 6.9 | Increase due to normal operation of various regulatory mechanisms. See Note 6 of the Company's 2011 annual audited financial statements. |
| Assets Held for Sale | (44.7) | Decrease is due to the sale of 40% of all joint-use poles and related infrastructure to Bell Aliant as described in Note 9 of the Company's 2011 annual audited financial statements. |
| Property, Plant and Equipment | 36.4 | Investment in electricity system, in accordance with the 2011 capital expenditure program offset partially by amortization and customer contributions in aid of construction. |
| Accrued Pension | (3.8) | Pension expense exceeded contributions made to the plan in 2011. |
| Accounts Payable and Accrued Charges | 15.8 | Increase is primarily due to payable for purchased power related to higher energy consumption in December 2011 compared to December 2010. |
| Regulatory Liabilities | 3.3 | Increase primarily due to normal operation of the weather normalization account and the demand management incentive account. See Note 6 of the Company's 2011 annual audited financial statements. |
| Other Post-Employment Benefits | 3.7 | Increase is related to accrual of benefits earned during 2011. |
| Retained Earnings | (16.5) | Payment of dividends, in excess of earnings, in order to maintain an average capital structure that includes approximately 45% common equity. The Company utilized a portion of the proceeds from the transaction with Bell Aliant to pay a special common dividend of $29.9 million to Fortis on October 7, 2011. |

## LIQUIDITY AND CAPITAL RESOURCES

The primary sources of liquidity and capital resources are net funds generated from operations, debt capital markets and bank credit facilities. These sources are used primarily to satisfy capital and intangible expenditures, service and repay debt, and pay dividends. A summary of cash flows and cash position for 2011 and 2010 follows:

| *($millions)* | **2011** | **2010** | **Change** |
|---|---|---|---|
| Cash, Beginning of Year | 4.2 | 5.3 | (1.1) |
| Operating Activities | 80.0 | 94.2 | (14.2) |
| Investing Activities | (32.8) | (75.0) | 42.2 |
| Financing Activities | | | |
| Net Credit Facility Proceeds | 5.0 | 1.5 | 3.5 |
| Dividends on Common Shares | (50.2) | (15.7) | (34.5) |
| Repayment of Long-term Debt | (5.2) | (5.2) | - |
| Other | (0.7) | (0.9) | 0.2 |
| | (51.1) | (20.3) | (30.8) |
| Cash, End of Year | 0.3 | 4.2 | (3.9) |

### Operating Activities

Cash flow from operating activities totalled $80.0 million in 2011 compared to $94.2 million in 2010. The $14.2 million decrease in cash flow from operating activities reflects timing of income tax instalments and payments to vendors. This was partially offset by the January 1, 2011, customer rate increase and higher electricity sales.

### Investing Activities

Cash flow used in investing activities totalled $32.8 million in 2011 compared to $75.0 million in 2010. The $42.2 million decrease was due primarily to the proceeds received from Bell Aliant related to the sale of 40% of all joint-use poles and related infrastructure. The decrease was partially offset by higher capital expenditures in 2011 compared to 2010. A summary of 2011 and 2010 capital and intangible asset expenditures follows:

| *($millions)* | **2011** | **2010** |
|---|---|---|
| Electricity System | | |
| Generation | 8.8 | 5.6 |
| Transmission | 5.2 | 6.4 |
| Substations | 11.9 | 9.6 |
| Distribution | 38.5 | 40.9 |
| Other | 14.1 | 13.5 |
| Intangible Assets | 2.0 | 2.0 |
| Capital and Intangible Asset Expenditures | 80.5 | 78.0 |

The Company's business is capital intensive. Capital investment is required to ensure continued and enhanced performance, reliability and safety of the electricity system, and to meet customer growth. All costs considered to be repairs and maintenance are expensed as incurred. Capital investment also arises for information technology systems and for general facilities, equipment and vehicles. Capital expenditures, and property, plant and equipment repairs and maintenance expense, can vary from year-to-year depending upon both planned electricity system expenditures and unplanned expenditures arising from weather or other unforeseen events.

The Company's annual capital plan requires prior PUB approval. Variances between actual and planned expenditures are generally subject to PUB review prior to inclusion in the Company's rate base.

The PUB has approved the Company's 2012 capital plan which provides for capital expenditures of approximately $77.3 million, approximately half of which relate to construction and capital maintenance of the electricity distribution system.

## Financing Activities

Cash flow used in financing activities totalled $51.1 million in 2011 compared to $20.3 million in 2010. The $30.8 million increase in cash used in financing activities was primarily the result of higher dividends. Upon receipt of the proceeds from Bell Aliant regarding the sale of 40% of all joint-use poles and related infrastructure, a special dividend of $29.9 million was paid to Fortis to maintain the Company's capital structure composed of 55% debt and preference equity and 45% common equity.

The Company has historically generated sufficient annual cash flows from operating activities to service annual interest and sinking fund payments on debt, to pay dividends and to finance a major portion of its annual capital program. Additional financing to fully fund the annual capital program is primarily obtained through the Company's bank credit facilities and these borrowings are periodically refinanced along with any maturing bonds through the issuance of long-term first mortgage sinking fund bonds. The Company currently does not expect any material changes in these annual cash flow and financing dynamics over the foreseeable future.

**Debt:** The Company's credit facilities are comprised of a $100.0 million committed revolving term credit facility ("Committed Facility") and a $20.0 million demand facility as detailed below:

| *($millions)* | **2011** | **2010** |
|---|---|---|
| Total Credit Facilities | 120.0 | 120.0 |
| Borrowing, Committed Facility | (20.0) | (15.0) |
| Credit Facilities Available | 100.0 | 105.0 |

During the second quarter of 2011, the Committed Facility was renegotiated on similar terms as the previous facility, with a decrease in pricing, and an extension to a four-year term maturing in August 2015.

**Pensions:** As at December 31, 2011, the fair value of the Company's primary defined benefit pension plan assets was $276.3 million compared to fair value of plan assets of $269.3 million as at December 31, 2010. Details of the plan asset changes are included in Note 12 to the Company's 2011 annual audited financial statements.

In 2009, Newfoundland Power received the Actuarial Valuation Report for its defined benefit pension plan. This report included the funding status of the plan as at December 31, 2008, on a going concern and solvency basis. Based on the report, the solvency deficit as at December 31, 2008, was $6.9 million ($7.7 million inclusive of interest). The solvency deficit is being funded over a five-year period, which commenced in 2009. The Company fulfilled its 2011 annual solvency deficit funding requirement of $1.5 million during the second quarter of 2011.

Based on the December 2008 Actuarial Valuation Report, the solvency deficit funding amounts are expected to be $1.6 million in 2012 and $1.5 million in 2013. Actual pension funding contributions will be based on the next actuarial valuation as of December 31, 2011. This valuation is expected to be completed in the first quarter of 2012. The Company expects to be able to meet future pension funding requirements as it expects the amounts will be financed from a combination of cash generated from operations and amounts available for borrowing under existing credit facilities.

**Contractual Obligations:** Details, as at December 31, 2011, of all contractual obligations over the subsequent five years and thereafter, follow:

| *($millions)* | Total | Due Within 1 Year | Due in Years 2 & 3 | Due in Years 4 & 5 | Due After 5 Years |
|---|---|---|---|---|---|
| Credit Facilities (unsecured) | 20.0 | - | - | 20.0 | - |
| First Mortgage Sinking Fund Bonds[1] | 458.5 | 5.2 | 39.0 | 39.6 | 374.7 |
| Total | 478.5 | 5.2 | 39.0 | 59.6 | 374.7 |

[1] *First mortgage sinking fund bonds are secured by a first fixed and specific charge on property, plant and equipment owned or to be acquired by the Company, by a floating charge on all other assets and carry customary covenants.*

**Credit Ratings and Capital Structure:** To ensure continued access to capital at reasonable cost, the Company endeavours to maintain its investment grade credit ratings. Details of the Company's investment grade bond ratings as at December 31, 2011, and 2010 follow:

| | 2011 | | 2010 | |
|---|---|---|---|---|
| **Rating Agency** | **Rating** | **Outlook** | **Rating** | **Outlook** |
| Moody's Investors Service ("Moody's") | A2 | Stable | A2 | Stable |
| DBRS | A | Stable | A | Stable |

Both Moody's and DBRS issued updated credit rating reports confirming the Company's existing investment grade bond rating and rating outlook. The Company's investment grade bond rating and rating outlook remain unchanged from 2010.

Newfoundland Power manages common share dividends to maintain a capital structure composed of 55% debt and preference equity and 45% common equity. This capital structure is reflected in customer rates and is consistent with the Company's current investment grade credit ratings. The Company's capital structure as at December 31, 2011, and 2010 follows:

| | 2011 | | 2010 | |
|---|---|---|---|---|
| | **$millions** | **%** | **$millions** | **%** |
| Total Debt[1] | 475.1 | 54.7 | 471.3 | 53.5 |
| Common Equity | 384.0 | 44.3 | 400.5 | 45.5 |
| Preference Equity | 9.1 | 1.0 | 9.1 | 1.0 |
| Total | 868.2 | 100.0 | 880.9 | 100.0 |

[1] *Includes bank indebtedness, or net of cash and debt issue costs, if applicable.*

The Company expects it will be able to maintain its current investment grade credit ratings in 2012.

**Capital Stock and Dividends:** For the years ended 2011 and 2010, the weighted average number of common shares outstanding was 10,320,270. Dividends on common shares, for 2011 were $34.5 million higher than 2010. In 2011, quarterly common share dividends increased to $0.49 per share from $0.38 per share in 2010. As well, the Company utilized a portion of the proceeds from the transaction with Bell Aliant to pay a special common share dividend of $29.9 million ($2.90 per share) to Fortis on October 7, 2011. The increase in common share dividends was to maintain an average capital structure that includes approximately 45% common equity.

The Company redeemed 3,000 Series D Preference shares outstanding for $30,000 in 2011.

## RELATED PARTY TRANSACTIONS

The Company provides services to, and receives services from, its parent company, Fortis and other subsidiaries of Fortis. The Company also incurs charges from Fortis for the recovery of general corporate expenses incurred by Fortis. These transactions are in the normal course of business and are recorded at their exchange amounts.

Related party transactions included in revenue and operating expenses for the years ended December 31, 2011, and 2010 follow:

| *($millions)* | 2011 | 2010 |
|---|---|---|
| Revenue[1] | 4.6 | 4.4 |
| Operating Expenses | 2.1 | 2.1 |

[1] *Includes charges for electricity consumed.*

Related party transactions included in accounts receivable at December 31, 2011, were $0.2 million, compared to $0.1 million at December 31, 2010.

In July 2011, the Company borrowed $25.0 million from Fortis as a short-term demand loan at an interest rate of 1.68% per annum. The full amount was repaid to Fortis in August 2011.

## FINANCIAL INSTRUMENTS

The carrying values of financial instruments included in current assets, current liabilities, other financial assets, and other financial liabilities approximate their fair value, reflecting their nature, short-term maturity or normal trade credit terms. The fair value of long-term debt is determined by discounting the future cash flows of each debt instrument at the estimated yield-to-maturity equivalent to benchmark government bonds, with similar terms to maturity, plus a market credit risk premium equal to that of issuers of similar credit quality. Since the Company does not intend to settle its debt instruments before maturity, the fair value estimate does not represent an actual liability, and therefore, does not include exchange or settlement costs.

The carrying and estimated fair values of the Company's long-term debt as at December 31, 2011, and 2010 follows:

| ($millions) | 2011 Carrying Value | 2011 Estimated Fair Value | 2010 Carrying Value | 2010 Estimated Fair Value |
|---|---|---|---|---|
| Long-term debt, including current portion and committed credit facility | 478.5 | 626.3 | 478.7 | 581.3 |

## BUSINESS RISK MANAGEMENT

The following is a summary of the Company's significant business risks.

**Regulation:** The Company's key business risk is regulation. The Company is subject to normal uncertainties facing entities that operate under cost of service regulation. It is dependent on PUB approval of customer rates that permit a reasonable opportunity to recover on a timely basis the estimated costs of providing electricity service, including a fair and reasonable return on rate base. The ability to recover the actual costs of providing service and to earn the approved rates of return depends on achieving the forecasts established in the rate setting process. There can be no assurance that rate orders issued by the PUB will permit the Company to recover the estimated costs of providing electricity service. A failure to obtain acceptable rate orders may adversely affect the operations of the Company, the timing of capital projects, and the Company's credit ratings assigned by rating agencies, which may in turn, negatively affect the results of operations and financial position of the Company.

Between general rate applications, the setting of customer rates through the Formula can cause earnings and cash flows to increase or decrease due to corresponding changes in bond yields which are beyond the Company's control.

**Operating and Maintenance:** The Company's electricity system requires ongoing maintenance and capital investment to ensure its continued performance, reliability and safety. The failure of the Company to properly execute its capital expenditure programs, maintenance programs or the occurrence of significant unforeseen equipment failures could have a material adverse effect on the Company's results of operations, cash flows and financial position. There can be no assurance that any additional maintenance and capital costs will receive regulatory approval for recovery in future customer rates.

**Economic Conditions:** Economic conditions primarily impact the performance of the Company's electricity sales, cost of capital and the performance of the defined benefit pension plan. The impact on pensions and cost of capital are discussed below. Electricity sales are influenced by economic factors such as changes in employment levels, personal disposable income and housing starts. Out-migration in rural areas, as well as declining birth rates and increasing death rates associated with an aging population, also affect sales. An extended decline in economic conditions would be expected to have the effect of reducing demand for energy over time. In addition to the impact of reduced demand, an extended decline in economic conditions could also impair the ability of customers to pay for electricity consumed, thereby affecting the aging and collection of the Company's accounts receivable. Modest sales growth is currently expected for 2012; however, economic conditions may impact actual future sales.

**Defined Benefit Pension Plan Performance:** The defined benefit pension plan is subject to judgements utilized in the actuarial determination of the accrued pension benefit obligation and the related pension expense. The primary assumptions utilized by management are the expected long-term rate of return on pension plan assets and the discount rate used to value the accrued pension benefit obligation. A discussion of the critical accounting estimates associated with pensions is provided in the "Critical Accounting Estimates – Employee Future Benefits" section of this MD&A.

Pension benefit obligations and related pension expense can be affected by change in the global financial and capital markets. There is no assurance that the pension plan assets will earn the expected long-term rate of return in the future. Market driven changes impacting the performance of the pension plan assets may result in material variations in actual return on pension plan assets from the expected long-term return on the assets. This may cause material changes in future pension funding requirements from current estimates and material changes in future pension expense. Market-driven changes may also impact the discount rate resulting in material variations in future pension funding requirements from current estimates and material changes in future pension expense.

There is also risk associated with measurement uncertainty inherent in the actuarial valuation process as it affects the measurement of pension expense, future funding requirements, the accrued benefit asset and benefit obligation.

The pension risks are mitigated due to the PUB approved PEVDA to deal with the differences between actual defined benefit pension expense and pension expense approved by the PUB for rate setting purposes. Variations in pension expense from that approved by the PUB for rate setting purposes would be recovered from (returned to) customers through the Company's Rate Stabilization Account ("RSA"). The closure of the defined benefit pension plan in 2004 also mitigates the above risk.

**Capital Resources and Liquidity:** The Company's financial position could be adversely affected if it fails to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and the repayment of maturing debt. There can be no assurance that sufficient capital will continue to be available on acceptable terms to repay existing debt and to fund capital expenditures. The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the financial position of the Company, conditions in the capital and bank credit markets, ratings assigned by rating agencies and general economic conditions.

Credit ratings affect the level of credit risk spreads on new long-term bond issues and on the Company's credit facilities. A change in credit ratings could potentially affect access to various sources of capital and increase or decrease the Company's financing costs. During 2011, the Company's credit ratings remained unchanged from 2010. The Company does not anticipate any material adverse rating actions by the credit rating agencies in the near term. However, global financial market conditions have placed increased scrutiny on rating agencies and rating agency criteria, which may result in changes to credit rating practices and policies.

The Company has been successful at securing cost effective capital and expects to have reasonable access to capital in the near to medium terms. In 2011, the Company renegotiated its committed credit facility on similar terms as the previous facility, with a decrease in pricing. The decreased pricing is not expected to materially impact the Company's financial results in 2012.

Further information on the Company's credit facilities, contractual obligations, including long-term debt maturities and repayments, and cash flow requirements is provided in the "Liquidity and Capital Resources" section of this MD&A and under "Liquidity Risk" in Note 20 to the Company's 2011 annual audited financial statements.

**Interest Rates:** Global financial market conditions could impact the Company's cost of capital as well as impact timing of future long-term bond issues. Market driven changes in interest rates could cause fluctuations in interest costs associated with the Company's bank credit facilities. The Company periodically refinances its credit facilities in the normal course with fixed-rate first mortgage sinking fund bonds, which compose most of its long-term debt, thereby significantly mitigating exposure to short-term interest rate changes.

**Electricity Prices:** Increases in electricity rates can cause changes in customer electricity consumption, which could negatively impact sales and therefore earnings and cash flows. Electricity prices have risen in recent years primarily due to the flow-through of the rising cost of oil used at Hydro's Holyrood thermal generating station. Future changes or volatility in oil prices may affect electricity prices in a manner that affects sales.

**Purchased Power Cost:** The Company is dependent on Hydro for approximately 93% of its electricity requirements. Purchased power costs are based on a wholesale demand and energy rate structure. The demand and energy rate structure presents the risk of volatility in purchased power costs due to uncertainty in forecasting energy sales and peak billing demand.

Effective January 1, 2008, the PUB ordered the operation of the demand management incentive account (the "DMI"). The DMI limits variations in the unit cost of purchased power related to demand up to 1% of total demand costs reflected in customer rates, or approximately $0.5 million for 2011. The disposition of balances in this account, which would be determined by a further order of the PUB, will consider the merits of the Company's conservation and demand management activities.

With respect to energy charges, as a result of January 1, 2007, changes in Hydro's wholesale rates, the marginal cost of purchased power now exceeds the average cost of purchased power that is embedded in customer rates. To the extent actual electricity sales in any period exceed forecast electricity sales used to set customer rates, the marginal purchased power expense will exceed related revenue. These supply cost dynamics had no material effect on earnings because the PUB ordered, for 2008 to 2010, that variations in purchased power expense caused by differences between the actual unit cost of energy purchased and that reflected in customer rates be recovered from (returned to) customers through the Company's RSA. Pursuant to the Company's 2010 GRA, the PUB ordered the continued use of the energy supply cost variance reserve until a further order from the PUB.

**Health and Safety:** The Company is subject to numerous and increasing health and safety laws, regulations and guidelines. Damages and costs could potentially arise due to a variety of events, including human error or misconduct and equipment failure. There is no assurance that any costs which might arise would be recoverable through customer rates and, if substantial, unrecovered costs could have a material adverse effect on the results of operations, cash flows and financial position of the Company. A focus on safety is an integral and continuing component of the Company's core business strategy.

2011 was the Company's fourth full year under the internationally recognized Occupational Health and Safety Assessment Series 18001 Health and Safety Management System. Continuing to meet this standard improves the Company's ability to capture and track information related to safe work practices and hazard recognition, and enhanced safety management.

**Environment:** The Company is subject to numerous laws, regulations and guidelines governing the management, transportation and disposal of hazardous substances and other waste materials and otherwise relating to the protection of the environment. Environmental damage and associated costs could potentially arise due to a variety of events, including the impact of severe weather and other natural disasters, human error or misconduct and equipment failure. Costs arising from environmental protection initiatives, compliance with environmental laws, regulations and guidelines or damages may become material to the Company. To identify, mitigate and monitor environmental performance the Company has established an environmental management system ("EMS"). The Company's EMS is compliant with the International Organization for Standardization 14001 standard. As at December 31, 2011, there were no environmental liabilities recorded in the Company's 2011 annual audited financial statements and there were no unrecorded environmental liabilities known to management.

The Company's key environmental hazard relates to risks of contamination of air, soil and water primarily relating to the storage and handling of fuel, the use and/or disposal of petroleum-based products, mainly transformer and lubricating oil containing polychlorinated biphenyls ("PCBs"), in the day-to-day operating and maintenance activities, and emissions from the combustion of fuel required in the generation of electricity.

The Company is also subject to inherent risks, including risk of fires. Electricity transmission and distribution facilities have the potential to cause fires as a result of equipment failure, trees falling on a transmission or distribution line or lightning strikes to wooden poles.

The environmental hazards related to hydroelectric generation operations include the creation of artificial water flows that may disrupt natural habitats and the storage of large volumes of water for the purpose of electricity generation.

**Insurance:** While the Company maintains a comprehensive insurance program, the Company's transmission and distribution assets (i.e. poles and wires) are not covered under insurance for physical damage. This is customary in North America as the cost of the coverage is not considered economical. Insurance is subject to coverage limits as well as time-sensitive claims discovery and reporting provisions and there is no assurance that the types of liabilities that may be incurred by the Company, including those that may arise relating to environmental matters, will be covered by insurance.

For material uninsured losses, the Company expects that it could seek regulatory relief. However, there is no assurance that regulatory relief would be received. Any major damage to the physical assets of the Company could result in repair costs and customer claims that are substantial in amount and which could have a material adverse effect on the Company's results of operations, cash flows and financial position.

It is expected that existing insurance coverage will be maintained. However, there is no assurance that the Company will be able to obtain or maintain adequate insurance in the future at rates considered reasonable or that insurance will continue to be available on terms comparable to those now existing.

**Weather:** The physical assets of the Company are exposed to the effects of severe weather conditions and other acts of nature. Although the physical assets have been constructed, operated and maintained to withstand severe weather, there is no assurance that they will successfully do so in all circumstances. In the event of a material uninsured loss caused by severe weather conditions or other natural disasters, there is potential to make an application to the PUB for recovery of those costs. However, there can be no assurance that the PUB would approve any such application. Any major damage to the Company's facilities could result in lost revenues, repair costs and customer claims that are substantial in amount and could result in a material adverse effect on the Company's results of operations, cash flows and financial position.

**Information Technology Infrastructure:** The ability of the Company to operate effectively is dependent upon developing and maintaining its information systems and infrastructure that support electricity operations, provide customers with billing information and support the financial and general operating aspects of the business. System failures could have a material adverse effect on the Company.

**Labour Relations:** Approximately 54% of the employees of the Company are members of the International Brotherhood of Electrical Workers labour union (the "IBEW") which had entered into two collective bargaining agreements with the Company. The two agreements expired on September 30, 2011.

The Company and the IBEW reached a tentative agreement in January 2012; however, the tentative agreement is subject to ratification by the members. The inability to maintain or renew the collective bargaining agreements on acceptable terms could result in increased labour costs, or service interruptions arising from labour disputes that are not provided for in approved rates and that could have a material adverse effect on the results of operations, cash flows and financial position of the Company.

**Human Resources:** The ability of the Company to deliver service in a cost-effective manner is dependent on the ability of the Company to attract, develop and retain a skilled workforce. The Company is faced with demographic challenges relating to trades, technical staff and engineers. An increasing competitive job market may also present future recruitment challenges.

## FUTURE ACCOUNTING CHANGES

**Adoption of New Accounting Standards:** Due to continued uncertainty around the adoption of a rate-regulated accounting standard by the International Accounting Standards Board, the Company has evaluated the option of adopting United States generally accepted accounting principles ("U.S. GAAP"), as opposed to International Financial Reporting Standards ("IFRS"), and has decided to adopt U.S. GAAP effective January 1, 2012.

Canadian securities rules allow a reporting issuer to prepare and file its financial statements in accordance with U.S. GAAP by qualifying as a U.S. Securities and Exchange Commission ("SEC") Issuer. On June 6, 2011, an application was filed with the Ontario Securities Commission (the "OSC") seeking relief, pursuant to National Policy 11-203 – *Process for Exemptive Relief Applications in Multiple Jurisdictions*, to permit Fortis and its reporting issuer subsidiaries, including Newfoundland Power, to prepare their financial statements in accordance with U.S. GAAP without qualifying as SEC Issuers (the "Exemption"). On June 9, 2011, the OSC granted the Exemption for financial years commencing on or after January 1, 2012, but before January 1, 2015, and interim periods therein. The Exemption will terminate in respect of financial statements for annual and interim periods commencing on or after the earlier of: (i) January 1, 2015; or, (ii) the date on which the Company ceases to have activities subject to rate regulation.

The Company also required an amendment to regulations made under the *Corporations Act* (Newfoundland and Labrador) in order to prepare its financial statements in accordance with U.S. GAAP. The amendment was enacted in the third quarter of 2011.

The Company's application of Canadian GAAP currently references U.S. GAAP for guidance on accounting for rate-regulated activities. The adoption of U.S. GAAP in 2012 is, therefore, expected to result in fewer significant changes in the Company's accounting policies as compared to accounting policy changes that may have resulted with the adoption of IFRS. U.S. GAAP guidance on accounting for rate-regulated activities allows the economic impact of rate-regulated activities to be recognized in the financial statements in a manner consistent with the timing by which amounts are reflected in customer rates. The Company believes that the continued application of rate-regulated accounting, and the associated recognition of regulatory assets and liabilities under U.S. GAAP, accurately reflects the impact that rate regulation has on the Company's financial position and results of operations.

Several other Canadian investor-owned, rate-regulated utilities are also expected to take a similar approach to adoption of U.S. GAAP in 2012. The Company's voluntary filing of audited U.S. GAAP financial statements for the year ending December 31, 2011, and the comparative period, subsequent to the filing of its audited Canadian GAAP financial statements for the year ending December 31, 2011, has been approved by the OSC. The voluntary filing is expected to be completed prior to March 31, 2012.

The Company has substantially completed its analysis of differences between U.S. GAAP and Canadian GAAP. The areas identified to date where differences between U.S. GAAP and Canadian GAAP are expected to have the most significant financial statement impacts are as follows:

**Employee Future Benefits:** Under Canadian GAAP, the accrued benefit asset or liability associated with defined benefit pension plans and OPEBs is recognized on the balance sheet with a reconciliation of the recognized asset or liability to the funded or unfunded status being disclosed in the notes to the financial statements. The accrued benefit asset or liability excludes unamortized balances related to past service costs, actuarial gains or losses and transitional obligations which have not yet been expensed.

U.S. GAAP requires recognition of the funded or unfunded status of defined benefit pension plans and OPEBs on the balance sheet. This is expected to result in several one-time adjustments upon adoption of U.S. GAAP.

The opening unamortized balances for transitional obligations associated with defined benefit pension plans, and the majority of the opening unamortized transitional obligation for OPEBs are required to be recorded as a reduction to retained earnings and the amortization of these opening transitional balances would no longer be included in the calculation of employee future benefit expense. Newfoundland Power expects to record these balances as a regulatory asset.

Opening unamortized balances related to past service costs, actuarial gains or losses and the remaining portion of the OPEBs transitional obligation are required to be recorded as a reduction to equity and classified as accumulated other comprehensive income on the balance sheet. The amortization of these balances will be included in the calculation of employee future benefit expense. Newfoundland Power expects to reclassify these balances as a regulatory asset on the balance sheet.

An additional difference between Canadian GAAP and U.S. GAAP relates to the period over which pension expense is recognized. Canadian GAAP allows a period that extends beyond the date when the credited service period ends. U.S. GAAP limits the period up to the date when the credited service period ends. Newfoundland Power expects to recognize the cumulative difference up to the transition to U.S. GAAP as a regulatory asset to be recovered from customers in future rates, and the disposition of this regulatory asset would depend on a future PUB order. The shorter period over which pension expense is recognized is expected to result in an increase to future pension expense, although the difference is expected to be immaterial.

U.S. GAAP also requires that OPEBs costs be recorded on an accrual basis, and prohibits the recognition of regulatory assets or liabilities associated with OPEBs costs that are recovered on a cash basis. The Company had historically recovered its OPEBs costs on a cash basis and as a result the Company was not permitted under U.S. GAAP to record its OPEBs regulatory asset. However, in December 2010 the PUB approved Newfoundland Power's application to adopt the accrual method of accounting for OPEBs costs, effective January 1, 2011. Based on the PUB's approval of the Company's application to adopt the accrual method of accounting for OPEBs, the regulatory asset can be recognized through earnings in accordance with U.S. GAAP in 2010.

The impact of adopting U.S. GAAP with respect to accounting for employee future benefits is not expected to have a material impact on the Company's earnings with the exception of the one-time adjustment in 2010 related to the Company's recognition of the OPEBs regulatory asset.

**Corporate Income Taxes:** Under Canadian GAAP, the Company has recognized corporate income taxes using substantially enacted corporate income tax rates. Under U.S. GAAP, the Company is required to record corporate income taxes based on enacted corporate income tax rates. Therefore, upon adoption of U.S. GAAP, the Company will be required to recognize the impact of the difference between enacted tax rates and substantially enacted tax rates related to the allocation of the Part VI.1 tax deduction from Fortis to Newfoundland Power. The retroactive adjustment to recognize the Part VI.1 tax deduction based on enacted corporate income tax rates under U.S. GAAP will result in a reduction in opening retained earnings. Annual earnings thereafter will also be impacted by the Part VI.1 tax deduction, should this deduction be allocated to the Company in future periods. However, the amount of the adjustments is expected to reverse as corporate taxation years become statute barred or once pending Canadian federal legislation is passed resulting in the enactment of the proposed corporate income tax rate changes. This difference in income tax rates applies to the Company's non-regulated activities, and as such would not qualify as a regulatory asset.

Adjustments to retained earnings based on the application of U.S. GAAP are not expected to affect Newfoundland Power's credit ratings or debt covenants.

The above items do not represent a complete list of expected differences between U.S. GAAP and Canadian GAAP, and are subject to change. Other less significant differences have also been identified. Analysis remains ongoing and additional areas where the Company's financial statements may be materially impacted may be identified prior to the Company's voluntary preparation and filing of its audited U.S. GAAP financial statements for the year ending December 31, 2011. A detailed reconciliation between the Company's audited Canadian GAAP and U.S. GAAP financial statements for 2011, including 2010 comparatives, will be disclosed as part of that voluntary filing.

The unaudited, estimated quantification and reconciliation of the Company's balance sheet as of December 31, 2010, prepared in accordance with U.S. GAAP versus Canadian GAAP has been completed based on the differences identified to date, and is summarized as follows:

Total assets as of December 31, 2010, are estimated to increase by approximately $20.8 million. The increase relates to the recognition of unamortized transitional obligations for OPEBs as a regulatory asset.

Total liabilities as of December 31, 2010, are estimated to increase by approximately $34.3 million. The increase is due to the recognition of the OPEBs unamortized transitional obligation, as discussed above, and an increase in income taxes payable in accordance with U.S. GAAP.

Shareholders' equity as of December 31, 2010, is estimated to decrease by approximately $13.5 million. The decrease is due to corporate income taxes based on enacted rates in accordance with U.S. GAAP. This decrease is expected to reverse in future years.

The unaudited, estimated quantification and reconciliation of the Company's statement of earnings for the year ended December 31, 2010, prepared in accordance with U.S. GAAP versus Canadian GAAP is summarized as follows:

> Net earnings to be reported in accordance with U.S. GAAP for the year ended December 31, 2010, is estimated to decrease by approximately $4.2 million reflecting corporate income taxes calculated using enacted tax rates.
>
> As well, net earnings for 2010 will reflect the one-time positive adjustment of approximately $46.7 million to recognize the OPEBs regulatory asset upon regulatory approval for the accrual method of accounting for OPEBs. This adjustment has no impact on retained earnings as of December 31, 2010, as it reverses a previous U.S. GAAP versus Canadian GAAP difference.

The quantification and reconciliation of the Company's financial statements from Canadian GAAP to U.S. GAAP for 2011 interim and annual reporting periods is expected to be completed by March 31, 2012.

## CRITICAL ACCOUNTING ESTIMATES

Preparation of the Company's financial statements in accordance with Canadian GAAP requires management to make estimates and judgements that affect the reported amounts of assets and liabilities, and the disclosure of contingencies and commitments at the date of the financial statements and the reported amounts of revenue and expenses during the reporting periods. Estimates and judgements are based on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances. Due to changes in facts and circumstances and the inherent uncertainty involved in making estimates, actual results may differ from current estimates. Estimates and judgements are reviewed periodically and, as adjustments become necessary, are reported in earnings in the period they become known. The critical accounting estimates are discussed below.

**Property, Plant and Equipment, and Intangible Assets Amortization:** Amortization, by its nature, is an estimate based primarily on the useful lives of assets. Estimated useful lives are based on current facts and historical information, and take into consideration the anticipated physical lives of the assets. Newfoundland Power's amortization methodology, including amortization rates, accumulated amortization and estimated remaining service lives, is subject to a periodic study by external experts. The difference between actual accumulated amortization and that indicated by the amortization study is amortized and included in customer rates in a manner prescribed by the PUB.

The most recently completed amortization study, based on property, plant and equipment, and intangible assets in service as at December 31, 2010, indicated an accumulated amortization variance of approximately $17.7 million. Subject to PUB approval, this variance is expected to increase amortization of property, plant and equipment, and intangible assets in future years which will be recovered in future customer rates.

The estimate of future removal and site restoration costs, net of salvage proceeds, is based on historical experience and future expected cost trends. The balance of this regulatory liability at December 31, 2011, was $49.8 million (December 31, 2010 - $49.5 million). The net amount of estimated future removal and site restoration costs provided for and reported in amortization expense during 2011 was $5.0 million (2010 - $5.1 million).

**Capitalized Overhead:** Newfoundland Power capitalizes overhead costs which are not directly attributable to specific capital assets, but which relate to the overall capital expenditure program. Capitalization reflects estimates of the portions of various general expenses that relate to the overall capital expenditure program in accordance with a methodology ordered by the PUB. GEC is allocated over constructed property, plant and equipment, and amortized over their estimated service lives. In 2011, GEC totalled $3.7 million (2010 - $3.3 million). Changes to the methodology for calculating and allocating general overhead costs to property, plant and equipment could have a material impact on the amounts recorded as operating expenses versus property, plant and equipment. However, any change in the fundamental methodology for the calculation and allocation of GEC would require the approval of the PUB.

**Income Taxes:** Future income tax assets and liabilities are based upon temporary differences between the accounting and tax basis of existing assets and liabilities, the benefit of income tax reductions or tax losses available to be carried forward and the effects of changes in tax laws. The carrying amounts of assets and liabilities are based upon the amounts recorded in the financial statements and are therefore subject to accounting estimates that are inherent to those balances. The timing of the reversal of temporary differences is estimated based upon assumptions of expectations of future results of operations. The composition of future income tax assets and liabilities are reasonably likely to change from period to period because of changes in the estimation of these uncertainties.

**Employee Future Benefits:** The Company's primary defined benefit pension plan is subject to judgements utilized in the actuarial determination of the expense and related obligations. The primary assumptions utilized by management in determining the expense and the accrued benefit obligation are the discount rate and the expected long-term rate of return on plan assets. All assumptions are assessed and concluded in consultation with the Company's external actuarial advisor.

The discount rate as at December 31, 2011, which is utilized to determine the accrued pension benefit obligation and the 2012 pension expense, is 5.3% compared to the discount rate of 5.8% as at December 31, 2010. Discount rates reflect market interest rates on high quality bonds with cash flows that match the timing and amount of expected pension benefit payments. The methodology in determining the discount rate was consistent with that used to determine the discount rate in the previous year. The decrease in discount rates reflects lower yields on investment grade corporate bonds.

The expected long-term rate of return on pension plan assets which is used to estimate the 2012 defined benefit pension expense is 6.5%, compared to the expected long-term rate of return on plan assets of 7.0% used for the 2011 defined benefit pension expense. The actual rate of return on pension plan assets during 2011 was approximately 4.3%. As in previous years, an actuary provided the Company with a range of expected long-term pension asset returns based on their internal modelling. The expected long-term return on pension plan assets of 6.5% falls within the normal to optimistic range as indicated by the actuary.

The following table provides sensitivity to the changes in the primary assumptions associated with the Company's defined benefit pension plan:

| *($millions)* | Pension Expense[1] | Net Accrued Benefit Asset | Accrued Benefit Obligation[2] |
|---|---|---|---|
| Impact of increasing the rate of return on plan assets assumption used during 2011 by 1.0% | (2.5) | 2.5 | - |
| Impact of decreasing the rate of return on plan assets assumption used during 2011 by 1.0% | 2.5 | (2.5) | - |
| Impact of increasing the discount rate assumption used during 2011 by 1.0% | (3.5) | 3.5 | (35.1) |
| Impact of decreasing the discount rate assumption used during 2011 by 1.0% | 4.4 | (4.4) | 43.7 |

[1] *For the year ended December 31, 2011. The volatility of future pension expense has been significantly mitigated with the PUB approved PEVDA in which the difference between actual pension expense and pension expense approved by the PUB for rate setting purposes would be recovered from (returned to) customers through the Company's RSA.*
[2] *As at December 31, 2011.*

Other assumptions applied in measuring the defined benefit pension expense and/or the accrued pension benefit obligation were the average rate of compensation increase, average remaining service life of the active employee group, and employee and retiree mortality rates.

The Company's OPEBs are also subject to judgements utilized in the actuarial determination of the expense and related obligation. Assumptions utilized by management in determining OPEBs costs and obligations include the health care cost trend rate and the foregoing assumptions, excluding the expected long-term rate of return on plan assets and average rate of compensation increase.

For 2010 and prior, in accordance with PUB orders, Newfoundland Power expensed the cost of OPEBs on a cash basis, whereby the difference between the cash payments during the year and the expense incurred in the year is deferred as a regulatory asset. Therefore, changes in assumptions resulted in changes in the regulatory asset and did not impact earnings. Effective January 1, 2011, the PUB ordered the adoption of the accrual method of accounting for OPEBs, the amortization on a straight line basis over 15 years of the $52.6 million regulatory asset, and the creation of an OPEBs cost variance deferral account. The volatility of future OPEBs expense caused by the adoption of the accrual method has been significantly mitigated with the PUB approved OPEBs cost variance deferral account in which the difference between actual OPEBs expense and OPEBs expense approved by the PUB for rate setting purposes will be recovered from (returned to) customers through the Company's RSA.

**Asset Retirement Obligations:** The measurement of the fair value of asset retirement obligations ("AROs") requires the Company to make reasonable estimates about the method of settlement and settlement dates associated with legally obligated asset retirement costs. While the Company has AROs for its generation assets and certain distribution and transmission assets, there were no amounts recognized as at December 31, 2011, and December 31, 2010.

The nature, amount and timing of AROs for hydroelectric generation assets cannot be reasonably estimated at this time as these assets are expected to effectively operate in perpetuity given their nature. In the event that environmental issues are identified or hydroelectric generation assets are decommissioned, AROs will be recorded at that time provided the costs can be reasonably estimated. It is management's judgement that identified AROs for its remaining assets are immaterial.

**Revenue Recognition:** The Company recognizes electricity revenue on an accrual basis. Electricity is metered upon delivery to customers and recognized as revenue using approved rates when consumed. Meters are read periodically and bills are issued to customers based on those readings. At the end of each period, an estimate of electricity consumed but not yet billed is accrued as revenue. The unbilled revenue accrual for each period is based on estimated electricity sales to customers for the period since the last meter reading at the rates approved by the PUB.

The development of the electricity sales estimates requires analysis of electricity consumption on a historical basis in relation to key inputs such as the current price of electricity, population growth, economic activity, weather conditions and electricity system losses. The estimation process for accrued unbilled electricity consumption will result in adjustments to electricity revenue in the period during which the difference between actual results and those estimated becomes known. As at December 31, 2011, the amount of accrued unbilled revenue recorded in accounts receivable was approximately $32.7 million (December 31, 2010 - $28.4 million).

**Contingencies:** The Company is subject to various legal proceedings and claims associated with the ordinary course of business operations. It is management's judgement that the amount of liability, if any, from these actions would not have a material adverse effect on the Company's financial position or results of operations.

## SELECTED ANNUAL INFORMATION

The following table sets forth the annual information for the years ended December 31, 2011, 2010 and 2009. The financial information has been prepared in accordance with Canadian GAAP for rate-regulated entities. The timing and recognition of certain assets, liabilities, revenue and expense, as a result of regulation, may differ from that otherwise expected using Canadian GAAP for non-regulated entities.

| ($millions, except per share amounts) | 2011 | 2010[1] | 2009[1] |
|---|---|---|---|
| Results of Operations | | | |
| Revenue | 573.1 | 555.4 | 527.5 |
| Net Earnings Applicable to Common Shares | 33.7 | 35.0 | 32.6 |
| Financial Position | | | |
| Total Assets | 1,202.4 | 1,196.9 | 1,171.0 |
| Total Long-term Liabilities | 717.1 | 710.3 | 701.6 |
| Shareholders' Equity | 393.1 | 409.6 | 390.3 |
| Per Share Data | | | |
| Earnings Applicable to Common Shares[2] | 3.26 | 3.39 | 3.16 |
| Common Dividends Declared[2] | 4.86 | 1.52 | 2.44 |
| Preference Dividends Declared[3] | 2.56 | 2.56 | 2.56 |

[1] *Certain comparative figures have been reclassified to comply with the current year's presentation.*
[2] *Basic and fully diluted. Based on the weighted average number of common shares outstanding, which was 10,320,270 common shares in each year.*
[3] *Based on the aggregate weighted average number of preference shares outstanding in each year, which was 908,098 in 2011 and 911,098 in both 2010 and 2009. In 2011, 3,000 preference shares were repurchased at $10 per share (2010 no preference shares were repurchased; 2009 - the Company repurchased 24,125 preference shares at $10 per share).*

The changes from 2010 to 2011 have been discussed previously in this MD&A. The increase in revenue from 2009 to 2010 was primarily the result of the January 1, 2010, customer rate increase of 3.5% and electricity sales growth. The increase in net earnings applicable to common shares was the result of the increase in customer rates effective January 1, 2010, reflecting rate base growth and a higher ROE embedded in customer rates as compared to 2009, and operational performance during 2010 which varied from the forecasts used to establish customer rates. The increase in total assets from 2009 to 2010 was due primarily to continued investment in the electricity system, and is consistent with the Company's strategy to provide safe, reliable electricity service at the lowest reasonable cost. The increase in long-term liabilities from 2009 to 2010 was primarily related to the normal operation of the weather normalization regulatory account. The decrease in common share dividends from 2009 to 2010 was to maintain an average capital structure that includes approximately 45% common equity.

## FOURTH QUARTER RESULTS

| | 2011 | 2010 | Change |
|---|---|---|---|
| Electricity Sales (*GWh*)[1] | 1,526.6 | 1,488.2 | 38.4 |
| Earnings Applicable to Common Shares | | | |
| $ Millions | 8.0 | 9.2 | (1.2) |
| $ Per Share | 0.77 | 0.89 | (0.12) |
| Cash Flow from Operating Activities *($millions)* | 21.6 | 24.8 | (3.2) |
| Cash Flow from (used in) Investing Activities *($millions)* | 19.9 | (20.8) | 40.7 |
| Cash Flow used in Financing Activities *($millions)* | (45.3) | (2.3) | (43.0) |

[1] *Reflects normalized electricity sales.*

Electricity sales for the fourth quarter of 2011 increased by 38.4 GWh or 2.6% compared to 2010. This increase was composed of: (i) an increase of 1.6% due to customer growth; and, (ii) an increase of 1.0% in average consumption reflecting higher concentration of electric heat in new home construction as well as strong economic growth.

Earnings for the fourth quarter of 2011 decreased by $1.2 million compared to the fourth quarter of 2010. The decrease in earnings was primarily the result of: (i) a lower ROE embedded in customer rates effective January 1, 2011; (ii) a decrease in other revenue related to the new support structure arrangements with Bell Aliant; (iii) a higher effective tax rate; and, (iv) an increase in operating expenses. The increase in operating expenses primarily related to increased conservation costs related to rebate programs offered to customers, higher labour costs reflecting wage and inflationary increases, and higher distribution maintenance costs. This decrease was partially offset by higher electricity sales and a reduction in purchased power costs due to higher generation associated with the Company's hydroelectric generating facilities.

Cash flow from operating activities for the fourth quarter of 2011 decreased by $3.2 million compared to the fourth quarter of 2010. The decrease was mainly the result of increased purchased power and higher income tax instalments. This was partially offset by payment received for the first eight months of joint-use pole services as a result of the new support structure arrangements with Bell Aliant effective January 2011.

Cash flow from investing activities for the fourth quarter of 2011 increased by $40.7 million compared to the fourth quarter of 2010. The increase was the result of the proceeds from Bell Aliant related to the sale of 40% of all joint-use poles and related infrastructure. The increase was partially offset by higher capital expenditures in 2011 compared to 2010.

Cash flow used in financing activities for the fourth quarter of 2011 increased by $43.0 million compared to the fourth quarter of 2010. The increase was primarily the result of higher dividends. Upon receipt of the proceeds from Bell Aliant regarding the sale of 40% of all joint-use poles and related infrastructure, a special dividend of $29.9 million was paid to Fortis to maintain the Company's capital structure composed of 55% debt and preference equity and 45% common equity.

## QUARTERLY RESULTS

The following table sets forth unaudited quarterly information for each of the eight quarters ended March 31, 2010, through December 31, 2011. The quarterly information has been obtained from the Company's interim unaudited financial statements which, in the opinion of management, have been prepared in accordance with Canadian GAAP for rate-regulated entities. The timing and recognition of certain assets, liabilities, revenue and expense, as a result of regulation, may differ from that otherwise expected using Canadian GAAP for non-regulated entities. These financial results are not necessarily indicative of results for any future period and should not be relied upon to predict future performance.

| | First Quarter March 31 | | Second Quarter June 30 | | Third Quarter September 30 | | Fourth Quarter December 31 | |
|---|---|---|---|---|---|---|---|---|
| *(unaudited)* | 2011 | 2010 | 2011 | 2010 | 2011 | 2010 | 2011 | 2010 |
| Electricity Sales *(GWh)* | 1,833.8 | 1,795.2 | 1,268.7 | 1,220.2 | 923.7 | 915.4 | 1,526.6 | 1,488.2 |
| Revenue *($millions)* | 183.0 | 178.3 | 132.6 | 126.3 | 101.4 | 99.1 | 156.1 | 151.7 |
| Net Earnings Applicable to Common Shares *($millions)* | 7.0 | 7.2 | 10.7 | 11.0 | 8.0 | 7.6 | 8.0 | 9.2 |
| Earnings per Common Share *($)*[1] | 0.68 | 0.70 | 1.03 | 1.06 | 0.78 | 0.74 | 0.77 | 0.89 |

[1] *Basic and fully diluted.*

## Seasonality

**Sales and Revenue:** Sales and revenue are significantly higher in the first quarter and significantly lower in the third quarter compared to the remaining quarters. This reflects the seasonality of electricity consumption for heating.

**Earnings:** Beyond the seasonality of electricity consumption for heating, quarterly earnings are impacted by the purchased power rate structure. The Company pays more, on average, for each kilowatt hour ("kWh") of purchased power in the winter months and less, on average, for each kWh of purchased power in the summer months.

These sales, revenues and cost dynamics are expected to yield lower earnings in the first quarter compared to remaining quarters within any given year.

## Trending

**Sales and Revenue:** Year-over-year quarterly electricity sales increases primarily reflect modest customer growth.

**Earnings:** Beyond the impact of expected moderate sales growth, future quarterly earnings and earnings per share are expected to trend with the ROE reflected in customer rates and rate base growth.

## OUTLOOK

The Company's strategy will remain unchanged.

Newfoundland Power is regulated under a cost of service regime. Cost of service regulation entitles the Company to an opportunity to recover its reasonable cost of providing service, including its cost of capital, in each year. Newfoundland Power expects to maintain its investment grade credit ratings in 2012.

**The Formula and Customer Rates:** On November 23, 2011, the Company submitted an application to the PUB to suspend operation of the Formula and review Cost of Capital for 2012. On December 13, 2011, the PUB approved the suspension of the Formula and deferred a full cost of capital review until a later date. As a result of the suspension of the operation of the Formula for 2012, the Company's regulated return on common equity will remain at 8.38% and current customer electricity rates will continue in effect for 2012, both on an interim basis. A full cost of capital review is expected to be held by the PUB in 2012. The Company is currently assessing the requirement for it to file a rate case application with the PUB to recover increased costs in 2013.

**Capital Plan:** On July 8, 2011, the Company filed an application with the PUB requesting approval for its 2012 capital expenditure plan totalling $77.3 million. The application was approved by the PUB on December 13, 2011.

**U.S. GAAP:** On November 10, 2011, the Company filed an application with the PUB requesting the adoption of U.S. GAAP for regulatory purposes effective January 1, 2012. The application was approved by the PUB on December 15, 2011.

**Support Structure Arrangements:** On January 1, 2011, the new support structure arrangements with Bell Aliant went into effect, including Bell Aliant repurchasing 40% of all joint-use poles and related infrastructure from Newfoundland Power. This represents approximately 5% of Newfoundland Power's rate base. In 2001, Newfoundland Power purchased Bell Aliant's (formerly Aliant Telecom Inc.) joint-use poles and related infrastructure under a 10-year Joint Use Facilities Partnership Agreement ("JUFPA") which expired December 31, 2010. Bell Aliant had rented space on these poles from Newfoundland Power since 2001 with the right to repurchase 40% of all joint-use poles at the end of the term. Bell Aliant exercised the option to buy back these poles from Newfoundland Power in 2010.

The new support structure arrangements were subject to certain conditions, including PUB approval of the sale of 40% of the Company's joint-use poles. On September 28, 2011, the PUB issued an Order that approved the sale of the joint-use poles.

On October 5, 2011, proceeds in the amount of $45.7 million were received from Bell Aliant reflecting the estimated purchase price for 40% of all joint-use poles and related infrastructure. The Company also recovered its financing costs on the assets held for sale of approximately $3.3 million up to October 5, 2011. The Company utilized the proceeds from this transaction to pay down its short-term debt, and on October 7, 2011, paid a special dividend to Fortis of $29.9 million in order to maintain its capital structure of 45% common equity. On January 16, 2012, the transaction with Bell Aliant closed and a purchase price adjustment of $0.9 million was paid to Bell Aliant from the Company. The purchase price adjustment was based on the results of the pole survey completed in the fourth quarter of 2011.

Effective January 1, 2011, the Company no longer received pole rental revenue from Bell Aliant. Newfoundland Power was responsible for the construction and maintenance of Bell Aliant's support structure requirements throughout 2011. The new support structure arrangements had no material impact on the Company's ability to earn a reasonable return on its rate base in 2011.

**Cost Recovery Deferral:** On September 16, 2011, the Company filed an application with the PUB requesting the deferred recovery of expected increased costs in 2012 of $2.4 million due to expired regulation amortizations. The application was approved by the PUB on October 27, 2011.

# Management Report

The accompanying 2011 financial statements of Newfoundland Power Inc. and all information in the 2011 Annual Report have been prepared by management, who are responsible for the integrity of the information presented, including the amounts that must, of necessity, be based on estimates and informed judgements. These financial statements were prepared in accordance with accounting principles generally accepted in Canada, including selected accounting treatments that differ from those used by entities not subject to rate regulation. Financial information contained elsewhere in the 2011 Annual Report is consistent with that in the annual audited financial statements.

In meeting its responsibility for the reliability and integrity of the financial statements, management has developed and maintains a system of accounting and reporting which provides for the necessary internal controls to ensure transactions are properly authorized and recorded, assets are safeguarded and liabilities are recognized. The systems of the Company focus on the need for training of qualified and professional staff, and the effective communication of management guidelines and policies. The effectiveness of the internal controls of Newfoundland Power Inc. is evaluated on an ongoing basis.

The Board of Directors oversees management's responsibility for financial reporting through an Audit & Risk Committee which is composed entirely of external independent directors. The Audit & Risk Committee oversees the external audit of the Company's annual financial statements, and the accounting and financial reporting and disclosure processes and policies of the Company. The Audit & Risk Committee meets with management, the shareholders' auditors and the internal auditor to discuss the results of the audit, the adequacy of internal accounting controls, and the quality and integrity of financial reporting. The Company's annual financial statements are reviewed by the Audit & Risk Committee with each of management and the shareholders' auditors before the statements are recommended to the Board of Directors for approval. The shareholders' auditors have full and free access to the Audit & Risk Committee.

The Audit & Risk Committee has the duty to review the adoption of, and changes in, accounting principles and practices which have a material effect on the Company's financial statements, and to review and report to the Board of Directors on policies relating to accounting and financial reporting and disclosure processes. The Audit & Risk Committee has the duty to review financial reports requiring the approval of the Board of Directors prior to submission to securities commissions or other regulatory authorities, to assess and review management's judgements that are material to reported financial information and to review shareholders' auditors' independence and auditors' fees.

The December 31, 2011, financial statements and Management Discussion and Analysis contained in the 2011 Annual Report were reviewed by the Audit & Risk Committee and, on their recommendation, were approved by the Board of Directors of Newfoundland Power Inc. Ernst & Young, LLP, independent auditors appointed by the shareholders of Newfoundland Power Inc. upon recommendation of the Audit & Risk Committee, have performed an audit of the 2011 financial statements and their report follows.

Earl Ludlow
President
and Chief Executive Officer

Jocelyn Perry
Vice President, Finance
and Chief Financial Officer

# Independent Auditors' Report

To the Shareholders,
Newfoundland Power Inc.

We have audited the accompanying financial statements of Newfoundland Power Inc., which comprise the balance sheets as at December 31, 2011, and 2010, and the statements of earnings, statements of retained earnings and statements of cash flows for the years then ended, and a summary of significant accounting policies and other explanatory information.

**Management's Responsibility for the Financial Statements**

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

**Auditors' Responsibility**

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgement, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

**Opinion**

In our opinion, the financial statements present fairly, in all material respects, the financial position of Newfoundland Power Inc. as at December 31, 2011, and 2010 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Ernst + Young LLP

Chartered Accountants
St. John's, Canada

February 7, 2012

## Statements of Earnings

**For the years ended December 31**

*(in thousands of Canadian dollars except per share amounts)*

| | 2011 | 2010 |
|---|---|---|
| Revenue | $ 573,072 | $ 555,355 |
| Purchased power | 369,484 | 358,443 |
| **Gross Margin** | 203,588 | 196,912 |
| Operating expenses | 56,615 | 53,830 |
| Employee future benefits | 20,569 | 8,381 |
| Amortization | 42,695 | 43,358 |
| Amortization true-up deferral *(Note 2)* | - | 3,862 |
| Cost recovery deferral *(Note 6)* | (2,363) | - |
| Finance charges *(Note 7)* | 35,944 | 36,038 |
| | 153,460 | 145,469 |
| **Earnings Before Income Taxes** | 50,128 | 51,443 |
| Income taxes *(Note 8)* | 15,876 | 15,870 |
| **Net Earnings** | 34,252 | 35,573 |
| Preference share dividends | 567 | 568 |
| **Net Earnings Applicable to Common Shares** | $ 33,685 | $ 35,005 |
| **Basic and Diluted Earnings per Common Share** | $ 3.26 | $ 3.39 |

## Statements of Retained Earnings

**For the years ended December 31**

*(in thousands of Canadian dollars)*

| | 2011 | 2010 |
|---|---|---|
| **Balance, Beginning of the Year** | $ 330,181 | $ 310,864 |
| Net earnings | 34,252 | 35,573 |
| Dividends | | |
| Preference shares | (567) | (568) |
| Common shares | (50,157) | (15,688) |
| **Balance, End of the Year** | $ 313,709 | $ 330,181 |

*See accompanying notes to financial statements.*

## Balance Sheets
### As at December 31
*(in thousands of Canadian dollars)*

| | 2011 | 2010 |
|---|---|---|
| **Assets** *(Note 15)* | | |
| **Current assets** | | |
| Cash | $ 330 | $ 4,182 |
| Accounts receivable *(Note 4)* | 77,091 | 61,654 |
| Materials and supplies *(Note 5)* | 1,140 | 992 |
| Prepaid expenses | 1,084 | 1,327 |
| Regulatory assets *(Note 6)* | 18,041 | 11,536 |
| | 97,686 | 79,691 |
| **Assets held for sale** *(Note 9)* | - | 44,698 |
| **Property, plant and equipment** *(Note 10)* | 812,766 | 776,382 |
| **Intangible assets** *(Note 11)* | 14,582 | 15,310 |
| **Regulatory assets** *(Note 6)* | 181,859 | 181,454 |
| **Accrued pension** *(Note 12)* | 93,963 | 97,755 |
| **Other assets** *(Note 13)* | 1,527 | 1,647 |
| | $ 1,202,383 | $ 1,196,937 |
| **Liabilities and Shareholders' Equity** | | |
| **Current liabilities** | | |
| Accounts payable and accrued charges | $ 72,514 | $ 56,712 |
| Interest payable | 7,470 | 7,557 |
| Income taxes payable | 4,043 | 4,302 |
| Current instalments of long-term debt *(Note 15)* | 5,200 | 5,200 |
| Future income taxes *(Note 8)* | 2,992 | 3,211 |
| | 92,219 | 76,982 |
| **Regulatory liabilities** *(Note 6)* | 60,663 | 57,371 |
| **Other post-employment benefits** *(Note 12)* | 56,255 | 52,559 |
| **Other liabilities** *(Note 16)* | 4,473 | 4,253 |
| **Future income taxes** *(Note 8)* | 125,402 | 125,877 |
| **Long-term debt** *(Note 15)* | 470,260 | 470,282 |
| | 809,272 | 787,324 |
| **Shareholders' equity** | | |
| Common shares *(Note 17)* | 70,321 | 70,321 |
| Preference shares *(Note 17)* | 9,081 | 9,111 |
| Retained earnings | 313,709 | 330,181 |
| | 393,111 | 409,613 |
| | $ 1,202,383 | $ 1,196,937 |

Commitments *(Note 21)*

*See accompanying notes to financial statements.*

APPROVED ON BEHALF OF THE BOARD:

Jo Mark Zurel
Director

Peggy Bartlett
Director

# Statements of Cash Flows

**For the years ended December 31**

*(in thousands of Canadian dollars)*

| | 2011 | 2010 |
|---|---|---|
| **Cash From (Used In) Operating Activities** | | |
| Net earnings | $ 34,252 | $ 35,573 |
| **Items not affecting cash** | | |
| Amortization of property, plant and equipment | 39,896 | 40,521 |
| Amortization of intangible assets and other | 3,107 | 3,107 |
| Change in long-term regulatory assets and liabilities | 5,898 | 11,364 |
| Future income taxes | (3,755) | (1,903) |
| Employee future benefits | 7,717 | 216 |
| Equity portion of allowance for funds used during construction *(Note 2)* | (460) | (405) |
| | 86,655 | 88,473 |
| Change in non-cash working capital | (6,610) | 5,688 |
| | 80,045 | 94,161 |
| **Cash From (Used In) Investing Activities** | | |
| Net proceeds from sale to Bell Aliant *(Note 9)* | 44,735 | - |
| Capital expenditures | (78,436) | (75,942) |
| Intangible asset expenditures | (2,071) | (2,034) |
| Contributions from customers | 2,848 | 2,789 |
| Other | 111 | 156 |
| | (32,813) | (75,031) |
| **Cash From (Used In) Financing Activities** | | |
| Proceeds of committed credit facility | 5,000 | 1,500 |
| Repayment of long-term debt | (5,200) | (5,200) |
| Proceeds from related party loan *(Note 18)* | 25,000 | - |
| Repayment of related party loan *(Note 18)* | (25,000) | - |
| Payment of debt financing costs | (130) | (300) |
| Redemption of preference shares *(Note 17)* | (30) | - |
| Dividends | | |
| Preference shares | (567) | (568) |
| Common shares | (50,157) | (15,688) |
| | (51,084) | (20,256) |
| **Decrease in Cash** | (3,852) | (1,126) |
| Cash, Beginning of the Year | 4,182 | 5,308 |
| **Cash, End of the Year** | $ 330 | $ 4,182 |
| **Cash Flows Include the Following Elements** | | |
| Interest paid | $ 35,990 | $ 36,127 |
| Income taxes paid | $ 17,836 | $ 6,790 |

*See accompanying notes to financial statements.*

# Notes to Financial Statements

## December 31, 2011

Tabular amounts are in thousands of Canadian dollars unless otherwise noted.

### 1. Description of the Business

Newfoundland Power Inc. (the "Company" or "Newfoundland Power") is a regulated electricity utility that operates an integrated generation, transmission and distribution system throughout the island portion of Newfoundland and Labrador. The Company is regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities (the "PUB") and serves over 247,000 customers comprising approximately 87% of all electricity consumers in the Province. All the common shares of the Company are owned by Fortis Inc. ("Fortis"). Newfoundland Power has an installed generating capacity of 140 megawatts ("MW"), of which approximately 97 MW is hydroelectric generation. It generates approximately 7% of its energy needs and purchases the remainder from Newfoundland and Labrador Hydro ("Hydro").

The Company operates under cost of service regulation as administered by the PUB under the *Public Utilities Act (Newfoundland and Labrador)* ("Public Utilities Act").

The Public Utilities Act provides for the PUB's general supervision of the Company's utility operations and requires the PUB to approve, among other things, customer rates, capital expenditures and the issuance of securities. The Public Utilities Act also entitles the Company an opportunity to recover all reasonable and prudent costs incurred in providing electricity service to its customers, including a just and reasonable return on its rate base. The rate base consists of the net assets required by the Company to provide service to customers.

The determination of the forecast return on rate base, together with the forecast of all reasonable and prudent costs, establishes the revenue requirement upon which the Company's customer rates are determined through a general rate hearing. Rates are bundled to include generation, transmission and distribution services.

Between general rate hearings, customer rates are established annually through an automatic adjustment formula (the "Formula"). The Formula sets the rate of return on common equity ("ROE") which is used to determine the rate of return on rate base. In accordance with the operation of the Formula, the Company's rate of return on common equity, for purposes of setting rates, was reduced to 8.38% for 2011 from 9.00% in 2010. The Company's rate of return on rate base was reduced to 7.96%, with a range of 7.78% to 8.14% for 2011, from 8.23%, with a range of 8.05% to 8.41% in 2010.

On December 13, 2011, the PUB approved the Company's application to suspend operation of the Formula for 2012. As a result, the Company's regulated return on common equity will remain at 8.38%, the rate of return on rate base will continue at 7.96%, and current customer electricity rates will continue in effect for 2012, all on an interim basis. A full cost of capital review is expected to be held by the PUB in 2012.

### 2. Summary of Significant Accounting Policies

These financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). As a result of rate-regulation, the timing of the recognition of certain assets, liabilities, revenues and expenses may differ from that otherwise expected under Canadian GAAP for entities not subject to rate-regulation. These differences are disclosed below and in Note 6.

## Revenue Recognition

Revenue is recognized under the accrual method when service is rendered. Electricity is metered upon delivery to customers and recognized as revenue using approved rates when consumed. Meters are read periodically and bills are issued to customers based on these readings. At the end of each period, an estimate of electricity consumed but not yet billed is accrued as revenue. The unbilled revenue accrual for each period is based on estimated electricity sales to customers for the period since the last meter reading at the rates approved by the PUB. The development of the electricity sales estimates requires analysis of electricity consumption on a historical basis in relation to key inputs such as the current price of electricity, population growth, economic activity, weather conditions and electricity system losses.

Revenue arising from the amortization of certain regulatory assets and liabilities is recognized in the manner prescribed by the PUB, as disclosed in Note 6.

## Materials and Supplies

Materials and supplies, representing fuel and materials required for maintenance activities, are carried at the lower of cost or net realizable value. Materials and supplies expensed in 2011 and 2010 were immaterial.

## Regulatory Assets and Liabilities

Regulatory assets and liabilities arise as a result of the rate setting process. Regulatory assets represent future revenues associated with certain costs incurred in the current or prior periods that will be, or are expected to be, recovered from customers in future periods through the rate setting process. Regulatory liabilities represent future reductions or limitations of increases in revenues associated with amounts that will be, or are expected to be, refunded to customers through the rate setting process. The accounting methods underlying regulatory assets and liabilities, and their eventual settlement through the rate setting process, are approved by the PUB and impact the Company's cash flows.

## Property, Plant and Equipment

Property, plant and equipment are stated at values approved by the PUB as at June 30, 1966, with subsequent additions at cost.

Contributions in aid of construction represent the cost of utility property, plant and equipment contributed by customers and government. These contributions are recorded as a reduction in the cost of utility property, plant and equipment.

The Company capitalizes certain overhead costs not directly attributable to specific property, plant and equipment but which do relate to its overall capital expenditure program (general expenses capitalized or "GEC"). The methodology for calculating and allocating GEC among classes of property, plant and equipment is established by PUB order. In the absence of rate-regulation, only those overhead costs directly attributable to construction activity would be capitalized. In 2011, GEC totalled $3.7 million (2010 - $3.3 million).

The Company capitalizes an allowance for funds used during construction ("AFUDC"), which represents the cost of debt and equity financing incurred during construction of property, plant and equipment. AFUDC is calculated in a manner prescribed by the PUB based on a capitalization rate that is the Company's weighted average cost of capital. In 2011, the cost of equity financing capitalized as an AFUDC and recorded in revenue was approximately $0.5 million (2010 - $0.4 million). The interest component of AFUDC is recorded as a deduction from financing charges.

Property, plant and equipment are amortized using the straight-line method by applying the amortization rates approved by the PUB and disclosed below to the average original cost, including GEC and AFUDC, of the related assets.

## 2. Summary of Significant Accounting Policies (cont'd)

### Property, Plant and Equipment (cont'd)

The composite amortization rates for the Company's property, plant and equipment, as well as their service life ranges and average remaining service lives as at December 31, follow:

| | Composite Amortization Rate | | Service Life (Years) Range | | Service Life (Years) Average Remaining | |
|---|---|---|---|---|---|---|
| | 2011 | 2010 | 2011 | 2010 | 2011 | 2010 |
| Distribution | 3.1% | 3.1% | 16-65 | 16-65 | 23 | 23 |
| Transmission and substations | 2.9 | 2.9 | 31-65 | 31-65 | 26 | 26 |
| Generation | 2.6 | 2.6 | 13-75 | 13-75 | 32 | 32 |
| Transportation and communications | 8.9 | 8.9 | 5-30 | 5-30 | 5 | 5 |
| Buildings | 2.3 | 2.3 | 35-70 | 35-70 | 27 | 27 |
| Equipment | 9.0 | 9.0 | 5-25 | 5-25 | 5 | 5 |
| | 3.4% | 3.4% | | | | |

The Company's amortization methodology, including amortization rates, accumulated amortization and estimated remaining service lives, is subject to periodic review by external experts (the "Amortization Study"). The difference between actual accumulated amortization and that indicated by the Amortization Study is treated as an amortization reserve ("Amortization True-Up") which is used to increase or decrease amortization expense and is included in customer rates in a manner prescribed by the PUB. The most recent Amortization Study, based on capital assets in service as at December 31, 2010, indicated an accumulated Amortization True-Up of $17.7 million. Subject to PUB approval, this Amortization True-Up is expected to increase the amortization of capital assets in future years which will be recovered in future customer rates.

The 2006 Amortization Study, based on property, plant and equipment in service as at December 31, 2005, indicated an accumulated amortization variance of $0.7 million. The PUB ordered that it be amortized as a decrease in amortization expense equally over 2008 - 2011.

Based on a 2002 Amortization Study, the PUB ordered the deferred recovery of approximately $11.6 million, $5.8 million in each of 2006 and 2007, related to a variance in accumulated amortization. The PUB ordered that it be amortized as an increase in the Amortization True-Up deferral expense evenly through 2008 – 2010.

Upon disposition, the original cost of property, plant and equipment is removed from the asset accounts. That amount, net of salvage proceeds, is also removed from accumulated amortization. As a result, any gain or loss is charged to accumulated amortization and is effectively included in the Amortization True-Up arising from the next Amortization Study. In 2011, approximately $8.4 million (2010 - $7.7 million) of losses were charged to accumulated amortization. In the absence of rate-regulation, these amounts would have been recognized as losses upon disposition.

## Intangible Assets

Intangible assets are recorded at cost and amortized over their estimated useful lives on a straight-line basis by applying the amortization rates approved by the PUB. The weighted average amortization rates for intangible assets in 2011 were 10% for computer software (2010 – 10.0%) and 1.6% for land rights (2010 – 1.6%).

Upon disposition, the original cost of the intangible asset is removed from the asset accounts. That amount, net of salvage proceeds, is also removed from accumulated amortization. As a result, any gain or loss is charged to accumulated amortization and is effectively included in the accumulated amortization variance arising from the next Amortization Study.

## Impairment of Long-Lived Assets

The Company reviews the valuation of property, plant and equipment, intangible assets and other long-term assets when events or changes in circumstances indicate that the assets' carrying value exceeds the total undiscounted cash flows expected from their use and eventual disposition. An impairment loss, calculated as the difference between the assets' carrying value and their fair value, which is determined using present value techniques, is recognized in earnings in the period in which it is identified. There was no impact on the financial statements as a result of asset impairments for the years ended December 31, 2011, and 2010.

## Income Taxes

The Company follows the asset and liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are recognized for temporary differences between the tax and accounting basis of assets and liabilities. The future income tax assets and liabilities are measured using substantively enacted income tax rates and laws that will be in effect when the differences are expected to be recovered or settled. The effect of a change in income tax rates on future income tax assets and liabilities is recognized in earnings in the period that the change occurs. Current income tax expense is recognized for the estimated income taxes payable or receivable in the current year.

As approved by the PUB, Newfoundland Power recovers current income tax expense in customer rates. The Company is permitted to recover future income tax expense by the PUB as follows:

> Effective January 1, 1981, future income tax liabilities are recognized, and recovered in customer rates, on temporary timing differences associated with the cumulative excess of capital cost allowance over amortization of property, plant and equipment, excluding GEC.
>
> Effective January 1, 2008, future income taxes are recognized and recovered in customer rates on temporary timing differences between pension expense and pension funding.
>
> Future income tax expense (recovery) associated with the Company's regulatory reserves and certain regulatory deferrals is also recognized and included in the determination of customer rates. See Note 6.
>
> Effective January 1, 2011, future income taxes are to be recognized and recovered in customer rates on temporary timing differences between other post-employment benefits ("OPEBs") costs recovered using the accrual method and that using the cash method.

Future income tax assets and liabilities associated with other temporary timing differences between the tax basis of assets and liabilities and their carrying amount are not included in customer rates. These amounts are expected to be recovered from (refunded to) customers through rates when the income taxes actually become payable (recoverable). The Company has recognized this future income tax liability with an offsetting increase in regulated assets. The Company's net regulatory asset for future income taxes at December 31, 2011, was $129.0 million (2010 - $126.2 million). See Note 6.

## 2. Summary of Significant Accounting Policies (cont'd)

### Employee Future Benefits

Newfoundland Power maintains defined contribution and defined benefit pension plans for its employees and also provides OPEBs. OPEBs are composed of retirement allowances for retiring employees as well as health, medical and life insurance for retirees and their dependants.

### Defined Contribution and Defined Benefit Pension Plans

Defined contribution pension plan costs are expensed as incurred.

The pension costs and accrued benefit obligations of the defined benefit pension plans are actuarially determined using the projected benefit method pro-rated on service and management's best estimate of expected plan investment performance, salary escalation and retirement ages of employees. Pension plan assets are valued using the market-related value where investment returns in excess of or below expected returns are recognized in asset value over a period of three years. The excess of the cumulative net actuarial gain or loss over 10% of the greater of the benefit obligation and the market-related value of plan assets is amortized over the estimated average remaining service period of active employees. The transitional obligation arising from the Company's January 1, 2000, adoption of Section 3461 of the Canadian Institute of Chartered Accountants ("CICA") Handbook is being amortized on a straight-line basis over the 18 year expected average remaining service period of plan members at that time. Unamortized past service costs are amortized over a range of 5 - 15 years. See Notes 6 and 12.

Effective January 1, 2010, the PUB ordered the creation of a pension expense variance deferral account ("PEVDA"). This account will be charged or credited with the amount by which actual pension expense differs from amounts approved in rates by the PUB. Each year, at March 31, the balance in the PEVDA will be transferred to the Company's Rate Stabilization Account ("RSA") and disposed of in accordance with the operation of the RSA. See Note 6.

### Other Post-Employment Benefits

OPEBs costs and the accrued OPEBs obligation are actuarially determined using the projected benefits method prorated on service and best estimate assumptions. The excess of any cumulative net actuarial gain or loss over 10% of the benefit obligation, along with unamortized past service costs is amortized over the estimated average remaining service period of active employees. The transitional obligation arising from the Company's January 1, 2000, adoption of Section 3461 of the CICA Handbook is being amortized on a straight line basis over the 18 year expected average remaining service period of plan members at that time. See Note 12.

Up to and including December 31, 2010, OPEBs costs were expensed when benefits are paid. In the absence of rate-regulation, OPEBs costs would have been expensed on an accrual basis as actuarially determined. The portion of the actuarially determined costs that has not been recognized as an expense has been deferred as a regulatory asset. See Note 6.

Effective January 1, 2011, the PUB ordered the adoption of the accrual method of accounting for OPEBs, the amortization on a straight line basis over 15 years of the $52.6 million regulatory asset, and the creation of an OPEBs cost variance deferral account. This account will be charged or credited with the amount by which actual OPEBs expense differs from amounts approved in rates by the PUB. Each year, at March 31, the balance in the OPEBs cost variance deferral account will be transferred to the Company's RSA and disposed of in accordance with the operation of the RSA. See Note 6.

## Financial Instruments

The Company has designated its financial instruments as follows:

(a) Cash is classified as "Held for Trading". After its initial fair value measurement, any change in fair value is recognized in earnings.
(b) Certain accounts receivable and loans under customer finance plans (Note 13) are classified as "Loans and Receivables".
(c) Short-term borrowings, bank indebtedness, accounts payable and accrued charges, security deposits (Note 16) and long-term debt (Note 15) are classified as "Other Financial Liabilities".

Initial measurement of Loans and Receivables and Other Financial Liabilities are at fair value and incorporates transaction costs, including debt issue costs. Subsequent measurement is at amortized cost using the effective interest method. For the Company, the measurement amount approximates cost.

## Asset Retirement Obligations

Under Canadian GAAP, the Company is required to record the fair value of future expenditures necessary to settle legal obligations associated with asset retirements even though the timing or method of settlement is conditional on future events. Newfoundland Power has determined that there are asset retirement obligations ("AROs") associated with its hydroelectric generation assets, and some parts of its transmission and distribution system.

For hydroelectric generation assets, the legal obligation is the environmental remediation of the land and waterways to protect fish habitat. However, this obligation is conditional on the decision to decommission generation assets. The Company currently has no plans to decommission any of its hydroelectric generation assets as they are effectively operated in perpetuity. Therefore, the nature and fair value of any ARO is not currently determinable.

The legal obligations for the transmission and distribution system pertain to the proper disposal of used oil and polychlorinated biphenyls ("PCBs") contaminated assets and obligations related to other Company facilities consist of the removal of fuel storage tanks and asbestos. These obligations were determined to be immaterial and therefore no AROs have been recognized.

The Company will recognize AROs and offsetting property, plant and equipment if the nature and timing can reasonably be determined and the amount is material.

## Use of Accounting Estimates

The preparation of financial statements in accordance with Canadian GAAP requires management to make estimates and judgements that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting periods. Estimates and judgements are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances. Additionally, certain estimates are necessary since the regulatory environment in which the Company operates often require amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. Due to changes in facts and circumstances and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates are reviewed periodically and, as adjustments become necessary, are reported in earnings in the period in which they either, as appropriate, become known or included in customer rates.

## 3. Change in Accounting Policies

### Future Changes

Effective January 1, 2012, the Company will be required to adopt a new set of accounting standards. Publicly accountable enterprises in Canada were required to adopt International Financial Reporting Standards ("IFRS") effective January 1, 2011; however, qualifying entities with rate-regulated activities were granted an optional one-year deferral for the adoption of IFRS, due to continued uncertainty around the adoption of a rate-regulated accounting standard by the International Accounting Standards Board ("IASB"). As a qualifying entity with rate-regulated activities, the Company elected to opt for the one-year deferral and, therefore, has continued to prepare its financial statements in accordance with Part V of the CICA Handbook for all interim and annual periods ending on or before December 31, 2011.

Due to continued uncertainty around the adoption of a rate-regulated accounting standard by the IASB, the Company has evaluated the option of adopting United States generally accepted accounting principles ("U.S. GAAP"), as opposed to IFRS, and has decided to adopt U.S. GAAP effective January 1, 2012.

Canadian securities rules allow a reporting issuer to prepare and file its financial statements in accordance with U.S. GAAP by qualifying as a U.S. Securities and Exchange Commission ("SEC") Issuer. On June 6, 2011, an application was filed with the Ontario Securities Commission (the "OSC") seeking relief, pursuant to National Policy 11-203 – *Process for Exemptive Relief Applications in Multiple Jurisdictions*, to permit Fortis and its reporting issuer subsidiaries, including Newfoundland Power, to prepare their financial statements in accordance with U.S. GAAP without qualifying as SEC Issuers (the "Exemption"). On June 9, 2011, the OSC granted the Exemption for financial years commencing on or after January 1, 2012, but before January 1, 2015, and interim periods therein. The Exemption will terminate in respect of financial statements for annual and interim periods commencing on or after the earlier of: (i) January 1, 2015; or, (ii) the date on which the Company ceases to have activities subject to rate-regulation.

The Company also required an amendment to regulations made under the *Corporations Act (Newfoundland and Labrador)* in order to prepare its financial statements in accordance with U.S. GAAP. The amendment was enacted in the third quarter of 2011.

The Company's application of Canadian GAAP currently references U.S. GAAP for guidance on accounting for rate-regulated activities. The adoption of U.S. GAAP in 2012 is, therefore, expected to result in fewer significant changes to the Company's accounting policies as compared to accounting policy changes that may have resulted from the adoption of IFRS. U.S. GAAP guidance on accounting for rate-regulated activities allows the economic impact of rate-regulated activities to be recognized in the financial statements in a manner consistent with the timing by which amounts are reflected in customer rates.

## 4. Accounts Receivable

| | 2011 | 2010 |
|---|---|---|
| Trade accounts receivable | $ 78,159 | $ 62,448 |
| Other | 615 | 584 |
| Allowance for doubtful accounts | (1,683) | (1,378) |
| | $ 77,091 | $ 61,654 |

## 5. Materials and Supplies

| | 2011 | 2010 |
|---|---|---|
| Materials and supplies | $ 910 | $ 809 |
| Fuel in storage | 230 | 183 |
| | $ 1,140 | $ 992 |

## 6. Regulatory Assets and Liabilities

The Company's regulatory assets and liabilities which will be, or are expected to be, reflected in customer rates in future periods, follow:

| | 2011 | | 2010 | |
|---|---|---|---|---|
| | Current | Non-current | Current | Non-current |
| Regulatory Assets | | | | |
| Rate stabilization account *(i)* | $ 8,571 | $ 3,863 | $ 1,847 | $ 1,876 |
| OPEBs *(ii)* | 3,504 | 45,552 | 3,504 | 49,055 |
| Weather normalization account *(iii)* | 2,102 | - | 2,102 | 2,102 |
| Pension deferral *(iv)* | 1,128 | 2,537 | 1,128 | 3,665 |
| Cost recovery deferral *(v)* | - | 2,363 | - | - |
| Deferred GRA costs *(vi)* | 253 | - | 253 | 253 |
| Conservation and demand management deferral *(vii)* | 339 | 339 | 339 | 678 |
| Optional seasonal rate revenue and cost recovery account *(viii)* | - | 328 | - | - |
| Future income taxes *(Note 2)* | 2,144 | 126,877 | 2,363 | 123,825 |
| | $ 18,041 | $ 181,859 | $ 11,536 | $ 181,454 |
| Regulatory Liabilities | | | | |
| Weather normalization account *(iii)* | $ - | $ 9,108 | $ - | $ 6,892 |
| Future removal and site restoration provision *(ix)* | - | 49,754 | - | 49,485 |
| Demand management incentive account *(x)* | - | 1,801 | - | 994 |
| | $ - | $ 60,663 | $ - | $ 57,371 |

**(i) Rate Stabilization Account ("RSA")**

On July 1 of each year, customer rates are recalculated in order to recover from or refund to customers, over the subsequent twelve months, the balance in the RSA as of March 31 of the current year. The amount and timing of the recovery or refund is subject to PUB approval.

The RSA passes through, to the Company's customers, amounts primarily related to changes in the cost and quantity of fuel used by Hydro to produce the electricity sold to the Company. In the absence of rate-regulation these transactions would be accounted for as incurred.

## 6. Regulatory Assets and Liabilities (cont'd)

### (i) Rate Stabilization Account (cont'd)

The RSA also passes through, to the Company's customers, variations in purchased power expense caused by differences between the actual unit cost of energy and that reflected in customer rates ("energy supply cost variance"). The marginal cost of purchased power for the Company currently exceeds the average cost that is embedded in customer rates. To the extent actual electricity sales in any period exceed forecast electricity sales used to set customer rates, marginal purchased power expense will exceed related revenue. In the absence of rate-regulation, purchased power expense in 2011 would have been $6.9 million higher (2010 - $2.2 million higher).

Effective January 1, 2010, the PUB approved the PEVDA as described in Note 2 to capture the difference between the annual pension expense approved for rate setting purposes and actual pension expense. The balance in this account will be transferred to the RSA on March 31 in the year in which the difference arises. The amount transferred to the RSA in 2011 was $2.9 million (2010 – ($0.6 million)). In the absence of rate-regulation, revenue in 2011 would have been $2.9 million lower (2010 - $0.6 million higher).

Effective January 1, 2011, the PUB approved the OPEBs cost variance deferral account as described in Note 2 to capture the difference between the annual OPEBs expense approved for rate setting purposes and actual OPEBs expense. The balance in this account will be transferred to the RSA on March 31 in the year in which the difference arises. The amount transferred to the RSA in 2011 was $0.2 million. In the absence of rate-regulation, revenue in 2011 would have been $0.2 million lower.

The RSA is also adjusted from time-to-time by other amounts as approved by the PUB.

### (ii) OPEBs

This regulatory asset represents the accumulated difference between OPEBs expense recognized on a cash basis for regulatory purposes and an accrual basis for financial reporting purposes since 2000. The accumulated difference arose from the Company's January 1, 2000, adoption of Section 3461 of the CICA Handbook that requires OPEBs expense to be recognized on an accrual basis. Effective January 1, 2011, the PUB ordered the adoption of the accrual method of accounting for OPEBs and the $52.6 million regulatory asset be amortized equally over 15 years. In the absence of rate-regulation, these costs would have been recorded as an operating expense as accrued.

In the absence of rate-regulation, OPEBs costs recognized in 2011 employee future benefits would have been $3.5 million lower (2010 - $5.8 million higher).

### (iii) Weather Normalization Account

The Weather Normalization Account reduces earnings volatility by adjusting purchased power expense and electricity sales revenue to eliminate variances in purchases and sales caused by the difference between normal weather conditions, based on long-term averages, and actual weather conditions. In the absence of rate-regulation these fluctuations would have been recognized in earnings in the period in which they occurred.

The balance in the Weather Normalization Account, because it is based on long-term averages for weather conditions, should tend to zero over time. However, the Company identified non-reversing balances in the account arising from changes in purchased power rates and income tax rates. In 2008, the PUB ordered that a non-reversing balance of approximately $6.8 million be amortized equally over 2008 - 2012 as an increase in purchased power expense of approximately $2.1 million and a decrease in future income tax expense of approximately $0.7 million in each year.

The recovery period for the remaining balance in the Weather Normalization Account is not determinable as it depends on future weather conditions. In the absence of rate-regulation, revenue in 2011 would have been $7.2 million lower (2010 - $20.4 million lower), purchased power expense in 2011 would have been $11.8 million lower (2010 - $29.2 million lower) and future income tax expense in 2011 would have been $1.5 million higher (2010 - $2.9 million higher).

**(iv) Pension Deferral**

The PUB ordered that approximately $11.3 million of incremental pension costs arising from the Company's 2005 early retirement program be deferred and amortized to pension expense equally over a ten year period beginning April 1, 2005. In the absence of rate-regulation, these costs would have been expensed in 2005.

**(v) Cost Recovery Deferral**

Effective January 1, 2011, the PUB ordered the deferred recovery of $2.4 million due to the conclusion of various regulatory amortizations. The disposition of balances in this account will be determined by a further order of the PUB. In the absence of rate-regulation, these costs would have been expensed in 2011.

**(vi) Deferred GRA Costs**

In 2007, the PUB ordered that external costs related to the Company's 2008 rate case be deferred and amortized evenly over 2008 – 2010 as an increase to operating expense. In the absence of rate-regulation, these costs would have been expensed as incurred.

In 2009, the PUB ordered $0.8 million of external costs related to the Company's 2010 rate case be deferred and amortized equally over 2010 – 2012. In the absence of rate-regulation, these costs would have been expensed in 2009.

**(vii) Conservation and Demand Management Deferral**

In 2009, the PUB ordered the deferral of $1.4 million of costs, associated with the implementation of conservation and demand management programs. In 2009, the PUB ordered that these costs be amortized evenly over 2010 – 2013 as an increase to operating expense. In the absence of rate-regulation, these costs would have been expensed in 2009.

**(viii) Optional Seasonal Rate Revenue and Cost Recovery Account**

Effective July 1, 2011, an optional seasonal rate for Domestic Customers was introduced. This optional seasonal rate charges a higher price for electricity during the months of December to April and a lower rate for May to November. The Company also initiated a study to evaluate time of day rates over a two-year period. On April 13, 2011, the PUB approved the creation of an Optional Seasonal Rate Revenue and Cost Recovery Account that provides for the deferral of annual costs and revenue effects associated with implementing optional rates and conducting the time of day study. The balance in this account will be transferred to the RSA on March 31 in the year in which the difference arises. In the absence of rate-regulation, revenue in 2011 would have been $0.1 million lower, operating expenses in 2011 would have been $0.3 million higher and future income tax expense in 2011 would have been $0.1 million lower.

**(ix) Future Removal and Site Restoration Provision**

This regulatory liability represents amounts collected in customer electricity rates over the life of certain property, plant and equipment which are attributable to removal and site restoration costs that are expected to be incurred in the future. Actual removal and site restoration costs, net of salvage proceeds, are recorded against the regulatory liability when incurred. The regulatory liability represents the amount of expected future removal and site restoration costs associated with property, plant and equipment in service as at December 31, calculated using current amortization rates as approved by the PUB. In the absence of rate-regulation, removal and site restoration costs, net of salvage proceeds, would have been recognized as an operating expense when incurred.

## 6. Regulatory Assets and Liabilities (cont'd)

**(x) Demand Management Incentive Account ("DMI")**

Through the DMI, variations in the unit cost of purchased power related to demand are limited, at the discretion of the PUB, to 1% of demand costs reflected in customer rates. The disposition of balances in this account are determined by orders of the PUB following consideration of the Company's conservation and demand management activities. In the absence of rate-regulation, purchased power expense would have been $1.8 million lower in 2011 (2010 - $1.0 million lower).

## 7. Finance Charges

| | 2011 | 2010 |
|---|---|---|
| Interest - first mortgage sinking fund bonds | $ 35,444 | $ 35,850 |
| Interest - committed credit facility | 672 | 316 |
| Interest - other | 30 | 18 |
| Total interest expense | 36,146 | 36,184 |
| Amortization - debt issue costs | 190 | 190 |
| Amortization - committed credit facility costs | 118 | 42 |
| Amortization - capital stock issue costs | - | 37 |
| Interest portion of AFUDC *(Note 2)* | (510) | (415) |
| | $ 35,944 | $ 36,038 |

## 8. Income Taxes

The composition of the Company's income tax expense follows:

| | 2011 | 2010 |
|---|---|---|
| Current income tax expense | $ 19,631 | $ 17,773 |
| Future income tax recovery | (694) | (267) |
| Less: regulatory adjustment | (3,061) | (1,636) |
| | $ 15,876 | $ 15,870 |

Income taxes differ from the amount that would be determined by applying the enacted combined Canadian federal and provincial statutory income tax rate to earnings before income taxes. A reconciliation of the combined statutory income tax rate to the Company's effective income tax rate follows:

| | 2011 | 2010 |
|---|---|---|
| Earnings before income taxes per financial statements | $ 50,128 | $ 51,443 |
| Statutory tax rate | 30.5% | 32.0% |
| Income taxes, at statutory rate | 15,289 | 16,462 |
| Items capitalized for accounting purposes but expensed for income tax purposes | (1,439) | (1,323) |
| Difference between capital cost allowance and amortization claimed for accounting purposes | 1,123 | 1,009 |
| Difference between pension funding and pension expense for accounting purposes | 60 | (20) |
| Difference between OPEBs premiums and retirement allowances paid and OPEBs expense for accounting purposes | 100 | - |
| Change in tax reserve for unpaid compensation | 681 | - |
| Allocation of Part VI.I tax | 221 | (329) |
| Other | (159) | 71 |
| Income tax expense | $ 15,876 | $ 15,870 |
| Effective income tax rate | 31.7% | 30.9% |

**Future Income Taxes**

The composition of the Company's future income tax liability follows:

| | 2011 | 2010 |
|---|---|---|
| Future income tax liabilities | | |
| Property, plant and equipment | $ 101,974 | $ 97,073 |
| Intangible assets | 5,509 | 5,891 |
| Regulatory assets | 23,871 | 25,988 |
| Defined benefit pension plan | 39,326 | 39,459 |
| Debt financing costs | 1,119 | 1,197 |
| Total future income tax liabilities | 171,799 | 169,608 |
| Future income tax assets | | |
| Regulatory liabilities | (18,885) | (17,602) |
| Other post-employment benefits | (22,977) | (21,468) |
| Defined benefit pension plan | (599) | (600) |
| Defined contribution pension liability | (944) | (850) |
| Total future income tax assets | (43,405) | (40,520) |
| **Net future income tax liability** | $ 128,394 | $ 129,088 |
| | | |
| Current future income tax liability | $ 2,992 | $ 3,211 |
| Long-term future income tax liability | 125,402 | 125,877 |
| **Net future income tax liability** | $ 128,394 | $ 129,088 |

The net future income tax liability includes a gross up to reflect the income tax associated with future revenue required to fund the net future income tax liability.

## 8. Income Taxes (cont'd)

As at December 31, 2011, the Company had no capital losses (2010 - nil) carried forward.

As at December 31, 2011, the Company's tax years still open to examination by taxing authorities include 2007 and subsequent years. With few exceptions, the Company is no longer subject to examination for years prior to 2007.

## 9. Assets Held for Sale

On December 22, 2010, the Company signed new support structure arrangements, effective January 1, 2011, with Bell Aliant (formerly Aliant Telecom Inc.) where Bell Aliant would repurchase 40% of all joint-use poles and related infrastructure at a price of approximately $45.7 million. This represented approximately 5% of Newfoundland Power's rate base. In 2001, Newfoundland Power purchased the joint-use poles and related infrastructure under a 10-year Joint Use Facilities Partnership Agreement ("JUFPA") which expired December 31, 2010. Bell Aliant had rented space on these poles from Newfoundland Power since 2001 with the right to repurchase 40% of all joint-use poles at the end of the term. Bell Aliant exercised the option to repurchase these poles from Newfoundland Power.

Effective January 1, 2011, the Company no longer received pole rental revenue from Bell Aliant. However, Newfoundland Power was responsible for the construction and maintenance of Bell Aliant's support structures throughout 2011.

The new support structure arrangements were subject to certain conditions, including PUB approval of the sale of 40% of the Company's joint-use poles. On September 28, 2011, the PUB issued an order that approved of the sale of the joint-use poles. On October 5, 2011, the transaction substantially closed and proceeds in the amount of $45.7 million were received from Bell Aliant. The estimated purchase price is subject to adjustment based upon the results of a pole survey completed in 2011 (Note 23).

## 10. Property, Plant and Equipment

| | Cost | | Accumulated Amortization | | Net Book Value | |
|---|---|---|---|---|---|---|
| | **2011** | **2010** | **2011** | **2010** | **2011** | **2010** |
| Distribution | $ 710,648 | $ 752,901 | $ 258,857 | $ 274,142 | $ 451,791 | $ 478,759 |
| Transmission and substations | 260,398 | 246,762 | 92,513 | 90,812 | 167,885 | 155,950 |
| Generation | 180,679 | 173,314 | 56,798 | 53,259 | 123,881 | 120,055 |
| Transportation and communications | 34,305 | 34,716 | 18,204 | 18,138 | 16,101 | 16,578 |
| Land, buildings and equipment | 71,660 | 69,489 | 29,167 | 28,154 | 42,493 | 41,335 |
| Construction in progress | 5,190 | 3,584 | - | - | 5,190 | 3,584 |
| Construction materials | 5,425 | 4,819 | - | - | 5,425 | 4,819 |
| | 1,268,305 | 1,285,585 | 455,539 | 464,505 | 812,766 | 821,080 |
| Less assets held for sale *(Note 9)* | - | (72,775) | - | (28,077) | - | (44,698) |
| | $ 1,268,305 | $ 1,212,810 | $ 455,539 | $ 436,428 | $ 812,766 | $ 776,382 |

Distribution assets are used to distribute low voltage electricity to customers and include poles, towers and fixtures, low voltage wires, transformers, overhead and underground conductors, street lighting, metering equipment and other related equipment. Transmission and substations assets are used to transmit high voltage electricity to distribution assets and include poles, high voltage wires, switching equipment, transformers and other related equipment. Generation assets are used to generate electricity and include hydroelectric and thermal generating stations, gas and combustion turbines, dams, reservoirs and other related equipment. Transportation and communications assets include vehicles as well as telephone, radio and other communications equipment. Land, buildings and equipment are used generally in the provision of electricity service, but not specifically in the distribution, transmission or generation of electricity or specifically related to transportation and communication activities.

## 11. Intangible Assets

| | Cost | | Accumulated Amortization | | Net Book Value | |
|---|---|---|---|---|---|---|
| | 2011 | 2010 | 2011 | 2010 | 2011 | 2010 |
| Computer software | $ 28,932 | $ 29,223 | $ 16,679 | $ 16,339 | $ 12,253 | $ 12,884 |
| Land rights | 6,780 | 6,780 | 4,451 | 4,354 | 2,329 | 2,426 |
| | $ 35,712 | $ 36,003 | $ 21,130 | $ 20,693 | $ 14,582 | $ 15,310 |

Amortization expense related to intangibles was $2.8 million for 2011 and 2010.

## 12. Employee Future Benefits

The Company's defined contribution plans are its individual and group registered retirement savings plans, and an unfunded supplementary employee retirement plan ("SERP"). Benefits under the SERP are based upon employee earnings and years of service. The accrued benefit liability for the SERP is included in other liabilities on the Company's balance sheets (Note 16). During 2011, the Company expensed approximately $1.3 million (2010 - $1.3 million) related to these plans.

The Company's defined benefit plans are its funded defined benefit pension plan, an unfunded pension uniformity plan ("PUP") and OPEBs. Both pension plans are closed to new entrants and provide benefits based on a percentage of the highest 36 consecutive months average base earnings and the employee's years of service. The accrued benefit obligation for all of the Company's defined benefit plans, and the market-related value of plan assets for the Company's funded primary defined benefit pension plan, are measured for accounting purposes as at December 31 of each year. The most recent actuarial valuation of the Company's primary defined benefit pension plan for funding purposes was as of December 31, 2008. The most recent actuarial valuation of the Company's OPEBs was December 1, 2008. Valuations as of December 31, 2011, for both the defined benefit pension plan and OPEBs are currently ongoing.

The accrued benefit asset for the Company's funded primary defined benefit pension plan is included in accrued pension on the Company's balance sheets. The accrued benefits liability for the PUP is included in other liabilities (Note 16).

## 12. Employee Future Benefits (cont'd)

Details of the Company's defined benefit plans follow:

| | 2011 | | | 2010 | | |
|---|---|---|---|---|---|---|
| | | Unfunded | | | Unfunded | |
| | Funded | PUP | OPEB | Funded | PUP | OPEB |
| **Change in accrued benefit obligation** | | | | | | |
| Balance, beginning of year | $ 252,436 | $ 2,389 | $ 69,234 | $ 221,936 | $ 2,318 | $ 69,667 |
| Current service costs | 3,845 | - | 889 | 2,983 | - | 1,032 |
| Employee contributions | 1,132 | - | - | 1,211 | - | - |
| Interest cost | 14,320 | 131 | 3,997 | 14,172 | 144 | 4,673 |
| Benefits paid | (12,350) | (215) | (2,200) | (11,902) | (215) | (1,696) |
| Plan amendments[1] | - | - | 464 | - | - | (15,191) |
| Actuarial loss | 18,764 | 98 | 4,987 | 24,036 | 142 | 10,749 |
| Balance, end of year | $ 278,147 | $ 2,403 | $ 77,371 | $ 252,436 | $ 2,389 | $ 69,234 |
| **Change in fair value of plan assets** | | | | | | |
| Balance, beginning of year | $ 269,262 | $ - | $ - | $ 242,731 | $ - | $ - |
| Actual return on assets | 13,083 | - | - | 32,223 | - | - |
| Benefits paid | (12,350) | (215) | (2,200) | (11,902) | (215) | (1,696) |
| Employee contributions | 1,132 | - | - | 1,211 | - | - |
| Employer contributions | 5,137 | 215 | 2,200 | 4,999 | 215 | 1,696 |
| Balance, end of year | $ 276,264 | $ - | $ - | $ 269,262 | $ - | $ - |
| **Funded status** | | | | | | |
| Surplus (deficit), end of year | $ (1,883) | $ (2,403) | $ (77,371) | $ 16,826 | $ (2,389) | $ (69,234) |
| Unamortized net actuarial loss | 86,214 | 656 | 25,594 | 69,798 | 594 | 21,547 |
| Unamortized transitional obligation *(Note 2)* | 7,723 | 279 | 8,001 | 9,010 | 326 | 9,429 |
| Unamortized past service costs *(Note 2)* | 1,909 | 1 | (12,479) | 2,121 | 1 | (14,301) |
| Accrued benefit asset (liability), end of year | $ 93,963 | $ (1,467) | $ (56,255) | $ 97,755 | $ (1,468) | $ (52,559) |
| **Effect of 1% increase in health care cost trends on:** | | | | | | |
| Accrued benefit obligation | - | - | $ 10,232 | - | - | $ 8,587 |
| Service costs and interest cost | - | - | $ 572 | - | - | $ 862 |
| **Effect of 1% decrease in health care cost trends on:** | | | | | | |
| Accrued benefit obligation | - | - | $ (8,277) | - | - | $ (7,033) |
| Service costs and interest cost | - | - | $ (583) | - | - | $ (679) |
| **Significant assumptions** | | | | | | |
| Discount rate during year | 5.75% | 5.75% | 5.75% | 6.50% | 6.50% | 6.70% |
| Discount rate as at December 31 | 5.25% | 5.25% | 5.25% | 5.75% | 5.75% | 5.75% |
| Expected long-term rate of return on plan assets | 7.00% | - | - | 7.00% | - | - |
| Rate of compensation increases | 4.00% | 4.00% | 4.00% | 4.00% | 4.00% | 4.00% |
| Health care cost trend increases as at December 31 | - | - | 4.55% | - | - | 4.55% |

| | 2011 | | | 2010 | | |
|---|---|---|---|---|---|---|
| | | Unfunded | | | Unfunded | |
| | Funded | PUP | OPEB | Funded | PUP | OPEB |
| **Net benefit expense** | | | | | | |
| Current service costs | $ 3,845 | $ - | $ 889 | $ 2,983 | $ - | $ 1,032 |
| Interest cost | 14,320 | 131 | 3,997 | 14,172 | 144 | 4,673 |
| Actual return on assets | (13,083) | - | - | (32,223) | - | - |
| Actuarial loss | 18,764 | 98 | 4,987 | 24,036 | 142 | 10,749 |
| Plan amendments | - | - | 464 | - | - | (15,191) |
| Cost arising in the year | $ 23,846 | $ 229 | $ 10,337 | $ 8,968 | $ 286 | $ 1,263 |
| Difference between costs arising and costs recognized in the year in respect of: | | | | | | |
| Return on plan assets | (4,191) | - | - | 15,221 | - | - |
| Actuarial loss | (12,225) | (62) | (4,047) | (20,643) | (120) | (10,454) |
| Past service costs | 212 | - | (1,359) | 212 | - | 114 |
| Transitional obligation | 1,287 | 47 | 1,428 | 1,287 | 47 | 1,428 |
| Plan amendments | - | - | (464) | - | - | 15,191 |
| Regulatory adjustment *(Note 4)* | 1,128 | - | 3,504 | 1,128 | - | (5,846) |
| Net benefit expense | $ 10,057 | $ 214 | $ 9,399 | $ 6,173 | $ 213 | $ 1,696 |
| **Asset allocation** | | | | | | |
| Fixed income | 42% | - | - | 39% | - | - |
| Equities | 38% | - | - | 42% | - | - |
| Foreign equities | 20% | - | - | 19% | - | - |

[1] *The Company amended its OPEBs plan effective January 1, 2011. The key plan amendments include the introduction of a 50% member-paid cost sharing arrangement for retirees over the age of 65, the removal of the current $5,000 annual benefit cap, and the introduction of drug dispensing fees. The plan changes will not impact existing retirees. Employees who retire on or before December 31, 2012, or are eligible for full pension by December 31, 2012, can choose between either plan.*

*The impact of this amendment is being amortized evenly over 10 years, starting in 2011, which reflects the expected average remaining service period to qualify for a full pension.*

## 13. Other Assets

| | 2011 | 2010 |
|---|---|---|
| Customer finance plans | $ 1,527 | $ 1,647 |

Customer finance plans represent the non-current portion of loans to customers for certain new service requests and energy efficiency upgrades. The current portion of these loans is classified as accounts receivable. In the case of new service requests, and as prescribed by the PUB, interest is charged at a fixed rate of prime plus 3% for repayment periods up to 60 months and prime plus 4% for repayment periods of 61 months to 120 months. In the case of energy efficiency upgrades, interest is charged at a fixed rate of prime plus 4% for a maximum repayment period of 60 months. All loan instalments are made through the customers' monthly electricity bill payments. The balance of any loan may be repaid at any time without penalty.

## 14. Credit Facilities

Newfoundland Power has unsecured bank credit facilities of $120.0 million comprised of a syndicated $100.0 million committed revolving term credit facility ("Committed Facility") which matures on August 27, 2015, and a $20.0 million demand facility. During the year, the $100.0 million Committed Facility was renegotiated on similar terms as the previous facility, with a decrease in pricing, and an extension to a four-year term maturing in August 2015.

Borrowings under the Committed Facility have been classified as long-term as the Committed Facility expires in 2015. Management intends to refinance these amounts in the future with the issuance of other long-term debt. These borrowings are in the form of bankers acceptances bearing interest based on the daily Canadian Deposit Offering Rate for the date of borrowing plus a stamping fee. Standby fees on the unutilized portion of the Committed Facility are payable quarterly in arrears at a fixed rate of 0.24%. Borrowings under the demand facility are classified as current and interest is calculated at the daily prime rate and is payable monthly in arrears.

The utilized and unutilized credit facilities as at December 31 follow:

| | 2011 | 2010 |
|---|---|---|
| Total credit facilities | $ 120,000 | $ 120,000 |
| Borrowings under Committed Facility *(Note 15)* | (20,000) | (15,000) |
| Credit facilities available | $ 100,000 | $ 105,000 |

## 15. Long-term Debt

| | Maturity Date | 2011 | 2010 |
|---|---|---|---|
| First mortgage sinking fund bonds | | | |
| 10.550% $40 million Series AD | 2014 | $ 29,753 | $ 30,153 |
| 10.900% $40 million Series AE | 2016 | 32,000 | 32,400 |
| 10.125% $40 million Series AF | 2022 | 32,400 | 32,800 |
| 9.000% $40 million Series AG | 2020 | 33,200 | 33,600 |
| 8.900% $40 million Series AH | 2026 | 34,035 | 34,435 |
| 6.800% $50 million Series AI | 2028 | 43,500 | 44,000 |
| 7.520% $75 million Series AJ | 2032 | 68,250 | 69,000 |
| 5.441% $60 million Series AK | 2035 | 55,800 | 56,400 |
| 5.901% $70 million Series AL | 2037 | 66,500 | 67,200 |
| 6.606% $65 million Series AM | 2039 | 63,050 | 63,700 |
| Committed credit facility *(Note 14)* | 2015 | 20,000 | 15,000 |
| | | 478,488 | 478,688 |
| Less: current instalments of long-term debt | | 5,200 | 5,200 |
| | | 473,288 | 473,488 |
| Less: debt issue costs | | 3,028 | 3,206 |
| | | $ 470,260 | $ 470,282 |

First mortgage sinking fund bonds are secured by a first fixed and specific charge on property, plant and equipment owned or to be acquired by the Company and by a floating charge on all other assets. They require an annual sinking fund payment of 1% of the original principal balance.

Future payments required to meet sinking fund instalments, maturities of long-term debt and long-term credit facilities follow:

| Year | $thousands |
|---|---|
| 2012 | 5,200 |
| 2013 | 5,200 |
| 2014 | 33,753 |
| 2015 | 24,800 |
| 2016 | 34,800 |
| Thereafter | 374,735 |

## 16. Other Liabilities

| | 2011 | 2010 |
|---|---|---|
| Defined benefit pension liability - unfunded *(Note 12)* | $ 1,467 | $ 1,468 |
| Security deposits | 695 | 705 |
| Defined contribution pension liability *(Note 12)* | 2,311 | 2,080 |
| | $ 4,473 | $ 4,253 |

Security deposits are advance cash collections from certain customers to guarantee the payment of electricity bills. The security deposit liability includes interest credited to customer deposits. The current portion of security deposits is reported in accounts payable and accrued charges.

## 17. Capital Stock

*Authorized*

(a) an unlimited number of Class A and Class B Common Shares without nominal or par value. The shares of each class are inter-convertible on a share-for-share basis and rank equally in all respects including dividends. The Board of Directors may provide for the payment, in whole or in part, of any dividends to Class B shareholders by way of a stock dividend;

(b) an unlimited number of First Preference Shares and Second Preference Shares without nominal or par value, except that each Series A, B, D and G First Preference Share has a par value of $10. The issued First Preference Shares are entitled to cumulative preferential dividends and are redeemable at the option of the Company at a premium not in excess of the annual dividend rate. Series D and G First Preference Shares are subject to the operation of purchase funds and the Company has the right to purchase limited amounts of these shares at or below par.

## 17. Capital Stock (cont'd)

*Issued*

| | 2011 | | 2010 | |
|---|---|---|---|---|
| | Number of Shares | Amount | Number of Shares | Amount |
| Class A common shares | 10,320,270 | $ 70,321 | 10,320,270 | $ 70,321 |
| First preference shares | | | | |
| 5.50% Series A | 179,225 | 1,792 | 179,225 | 1,792 |
| 5.25% Series B | 337,983 | 3,380 | 337,983 | 3,380 |
| 7.25% Series D | 207,890 | 2,079 | 210,890 | 2,109 |
| 7.60% Series G | 183,000 | 1,830 | 183,000 | 1,830 |
| | 908,098 | $ 9,081 | 911,098 | $ 9,111 |

The Company redeemed 3,000 Series D preference shares outstanding for $30,000 during the year.

At December 31, 2011, Fortis held 233,744 or approximately 25.7% of the Company's issued and outstanding First Preference Shares.

## 18. Related Party Transactions

The Company provides services to, and receives services from, its parent company, Fortis, and other subsidiaries of Fortis. The Company also incurs charges from Fortis for the recovery of general corporate expenses incurred by Fortis. Related party revenue primarily relates to electricity sales. These transactions are in the normal course of business and are recorded at their exchange amounts.

Related party transactions included in revenue and operating expenses in 2011 and 2010, and in accounts receivable at December 31 of these years, follow:

| | 2011 | | 2010 | |
|---|---|---|---|---|
| | Fortis | Other Affiliates | Fortis | Other Affiliates |
| Revenue | $ 155 | $ 4,419 | $ 189 | $ 4,255 |
| Operating expenses | 2,037 | 60 | 1,863 | 250 |
| Accounts receivable | 142 | 96 | 45 | 39 |

In July 2011, the Company borrowed $25.0 million from Fortis as a short-term demand loan, at an interest rate of 1.68% per annum. The full amount was repaid to Fortis in August 2011.

## 19. Capital Management

Newfoundland Power's primary objectives when managing capital are: (i) to ensure continued access to capital at reasonable cost; and, (ii) to provide an adequate return to its common shareholder commensurate with the level of risk associated with the shareholder's investment in the Company.

The Company requires ongoing access to capital because its business is capital intensive. Capital investment is required to ensure continued and enhanced performance, reliability and safety of its electricity systems and to meet customer growth.

The Company operates under cost of service regulation. The cost of capital is ultimately borne by its customers. Access to capital at reasonable cost is a core aspect of the Company's business strategy, which is to operate a sound electricity system and to focus on the safe and reliable delivery of electricity service to its customers in the most cost-efficient manner possible.

The capital managed by the Company is composed of debt (first mortgage sinking fund bonds, bank credit facilities, short-term borrowings and cash/bank indebtedness), common equity (common shares and retained earnings) and preference equity.

The Company has historically generated sufficient annual cash flows from operating activities to service annual interest and sinking fund payments on debt, to pay dividends and to finance a major portion of its annual capital program. Additional financing to fully fund the annual capital program is primarily obtained through the Company's bank credit facilities and these borrowings are periodically refinanced along with any maturing bonds through the issuance of long-term first mortgage sinking fund bonds. The Company currently does not expect any material changes in these basic cash flow and financing dynamics over the foreseeable future, with the exception of the increase in cash flow from the Bell Aliant joint-use pole sale (Note 9) which will extend the timing of the next bond issue.

Newfoundland Power endeavours to maintain a capital structure comprised of approximately 55% debt and preference equity, and 45% common equity. This capital structure is reflected in customer rates. It is also consistent with the Company's current investment grade credit ratings, thereby ensuring continued access to capital at reasonable cost. The Company maintains this capital structure primarily by managing its common share dividends.

A summary of the Company's capital structure as at December 31 follows:

| | 2011 | | 2010 | |
|---|---|---|---|---|
| | $ | % | $ | % |
| Debt[1] | 475,130 | 54.7 | 471,300 | 53.5 |
| Common equity | 384,030 | 44.3 | 400,502 | 45.5 |
| Preference equity | 9,081 | 1.0 | 9,111 | 1.0 |
| | 868,241 | 100.0 | 880,913 | 100.0 |

[1] *Includes bank indebtedness or net of cash, if applicable.*

The issuance of debt with a maturity that exceeds one year requires the prior approval of the PUB. The issuance of first mortgage sinking fund bonds is subject to an earnings covenant whereby the ratio of (i) annual earnings applicable to common shares, before bond interest and tax, to (ii) annual bond interest incurred plus annual bond interest to be incurred on the contemplated bond issue, must be two times or higher. Under its committed credit facility, the Company must also ensure that its Debt to Capitalization ratio does not exceed 0.65:1.00 at any time. During the year, and as at December 31, 2011, the Company was in compliance with all of its debt covenants.

## 20. Financial Instruments

The Company has designated its financial instruments as at December 31 as follows:

| | 2011 | | 2010 | |
|---|---|---|---|---|
| | Carrying Value | Estimated Fair Value | Carrying Value | Estimated Fair Value |
| **Held for trading** | | | | |
| Cash | $ 330 | $ 330 | $ 4,182 | $ 4,182 |
| **Loans and receivables** | | | | |
| Accounts receivable | 77,091 | 77,091 | 61,654 | 61,654 |
| Customer finance plans[1] | 1,527 | 1,527 | 1,647 | 1,647 |
| **Other financial liabilities** | | | | |
| Accounts payable and accrued charges | 72,514 | 72,514 | 56,712 | 56,712 |
| Interest payable | 7,470 | 7,470 | 7,557 | 7,557 |
| Security deposits[2] | 696 | 696 | 705 | 705 |
| Long-term debt, including current portion and committed credit facility | 478,488 | 626,256 | 478,688 | 581,275 |

[1] *Included in other assets on the balance sheet.*
[2] *Included in other liabilities on the balance sheet.*

**Fair Values:** The fair value of long-term debt, including current portion and committed credit facility, is calculated by discounting the future cash flows of each debt instrument at the estimated yield-to-maturity equivalent to benchmark government bonds, with similar terms to maturity, plus a market credit risk premium equal to that of issuers of similar credit quality. Since the Company does not intend to settle its debt instruments before maturity, the fair value estimate does not represent an actual liability and, therefore, does not include exchange or settlement costs.

The fair value of the Company's remaining financial instruments approximates their carrying value, reflecting their nature, short-term maturity or normal trade credit terms.

The fair value of the Company's financial instruments reflects a point-in-time estimate based on current and relevant market information about the instruments as at the balance sheet date. The estimates cannot be determined with precision as they involve uncertainties and matters of judgement, and therefore, may not be relevant in predicting the Company's future earnings or cash flows.

The Company is primarily exposed to credit risk, liquidity risk and market risk as a result of holding financial instruments in the normal course of business.

**Credit Risk:** There is risk that Newfoundland Power may not be able to collect all of its accounts receivable and amounts owing under its customer finance plans. These financial instruments, which arise in the normal course of business, do not represent a significant concentration of credit risk as amounts are owed by a large number of customers on normal credit terms. The requirement for security deposits for certain customers, which are advance cash collections from customers to guarantee payment of electricity billings, further reduces the exposure to credit risk. The maximum exposure to credit risk is the net carrying value of these financial instruments.

Newfoundland Power manages credit risk primarily by executing its credit and collection policy, including the requirement for security deposits, through the resources of its Customer Relations Department.

The aging of accounts receivable and amounts owing under customer finance plans, past due but not impaired, as at December 31 follow:

| | 2011 | 2010 |
|---|---|---|
| Not past due | $ 39,800 | $ 31,947 |
| Past due 1-30 days | 30,638 | 24,654 |
| Past due 31-60 days | 6,189 | 5,351 |
| Past due 61-90 days | 1,904 | 1,148 |
| Past due over 90 days | 87 | 201 |
| | $ 78,618 | $ 63,301 |

**Liquidity Risk:** The Company's financial position could be adversely affected if it failed to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and repayment of maturing debt.

The ability to arrange such financing is subject to numerous factors, including the results of operations and financial position of the Company, conditions in the capital and bank credit markets, ratings assigned by ratings agencies and general economic conditions. These factors are mitigated by the legal requirement as outlined in the *Electrical Power Control Act*, 1994 (Newfoundland and Labrador) which requires rates be set to enable the Company to achieve and maintain a sound credit rating in the financial markets of the world.

Newfoundland Power manages short-term liquidity risk primarily by maintaining bank credit facilities. The Company has unsecured facilities of $120.0 million, comprised of a syndicated $100.0 million committed credit facility and a $20.0 million demand facility.

Newfoundland Power manages long-term liquidity risk primarily by maintaining its investment grade credit ratings.

The contractual maturities of the Company's financial liabilities at December 31, 2011, follow:

| *($millions)* | Total | Due Within 1 Year | Due in Years 2 & 3 | Due in Years 4 & 5 | Due After 5 Years |
|---|---|---|---|---|---|
| Accounts payable and accrued charges | $ 72.1 | $ 72.1 | - | - | - |
| Interest payable | 7.5 | 7.5 | - | - | - |
| Security deposits[1] | 1.1 | 0.4 | 0.7 | - | - |
| Credit facilities (unsecured) | 20.0 | - | - | 20.0 | - |
| Interest on first mortgage sinking fund bonds and committed credit facility | 510.0 | 35.5 | 68.5 | 59.4 | 346.6 |
| First mortgage sinking fund bonds[2] | 458.5 | 5.2 | 39.0 | 39.6 | 374.7 |
| Total | $ 1,069.2 | $ 120.7 | $ 108.2 | $ 119.0 | $ 721.3 |

[1] *Included in accounts payable and accrued charges and other liabilities.*
[2] *First mortgage sinking fund bonds are secured by a first fixed and specific charge on property, plant and equipment owned or to be acquired by the Company and by a floating charge on all other assets.*

## 20. Financial Instruments (cont'd)

**Market Risk:** Exposure to foreign exchange rate fluctuations is immaterial.

Market driven changes in interest rates and changes in the Company's credit ratings can cause fluctuations in interest costs associated with the Company's bank credit facilities. For the year ended December 31, 2011, each 25 basis points change in interest rates on the Company's credit facilities would have caused a $62,000 change in credit facility interest costs and a $43,000 change in earnings (2010 - $34,000 and $23,000, respectively).

The Company periodically refinances its credit facilities in the normal course with fixed-rate first mortgage sinking fund bonds thereby significantly mitigating exposure to interest rate changes. Changes in interest rates and/or changes in the Company's credit ratings can affect the interest rate on first mortgage sinking fund bonds at the time of issue.

The Company's defined benefit pension plan is impacted by economic conditions. There is no assurance that the pension plan assets will earn the expected long-term rate of return in the future. Market driven changes impacting the performance of the pension plan assets may result in material variations from the expected long-term return on the assets. This may cause material changes in future pension liabilities and pension expense. Market driven changes impacting the discount rate may also result in material variations in future pension liabilities and pension expense. The operation of the PEVDA is expected to significantly mitigate the impact on the Company's pension expense as described in Note 2.

## 21. Commitments

The Company is obligated to provide service to customers, resulting in ongoing capital expenditure commitments. Capital expenditures are subject to PUB approval. The Company's 2012 capital plan provides for capital expenditures of approximately $77.3 million and was approved by the PUB in December 2011.

The Company's defined benefit pension funding contributions, including current service and solvency deficit funding amounts, are based on estimates provided by the Company actuary. Based on the December 31, 2008, Actuarial Valuation Report, the Company's commitments for 2012 and 2013 for its solvency deficit are $1.6 million and $1.5 million, respectively. The funding required for current service, as well as revised solvency deficit funding, if any, will be determined in the Company's next actuarial valuation as at December 31, 2011.

## 22. Economic Dependence

The Company is dependent on Hydro for approximately 93% of its electricity requirements. The principal terms of the supply arrangements with Hydro are regulated by the PUB on a basis similar to that upon which the Company's service to its customers is regulated.

## 23. Subsequent Event

On January 16, 2012, the transaction with Bell Aliant closed (Note 9) and a purchase price adjustment of $0.9 million was paid to Bell Aliant from the Company. The purchase price adjustment was based on the results of the pole survey completed in the fourth quarter of 2011. The adjustment will be reflected as an increase to property, plant and equipment in 2012.

## 24. Comparative Figures

The comparative financial statements have been reclassified from statements previously presented to conform to the current year financial statements.

# Ten Year Summary

| | 2011 | 2010[1] | 2009 | 2008 | 2007 | 2006 | 2005 | 2004 | 2003 | 2002 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Income Statement Items *($thousands)*** | | | | | | | | | | |
| Revenue | 573,072 | 555,355 | 527,503 | 516,889 | 491,709 | 422,405 | 419,963 | 404,447 | 384,150 | 369,627 |
| Purchased power | 369,484 | 358,443 | 345,656 | 336,658 | 326,778 | 257,157 | 255,954 | 244,012 | 227,964 | 210,764 |
| Operating and employee future benefit cost | 77,184 | 62,211 | 51,988 | 50,172 | 53,202 | 53,996 | 53,812 | 51,755 | 51,799 | 50,767 |
| Amortization[2] | 42,695 | 47,220 | 45,687 | 44,511 | 34,162 | 33,129 | 32,143 | 30,987 | 29,372 | 35,442 |
| Finance charges | 35,944 | 36,038 | 34,879 | 33,507 | 34,939 | 33,819 | 31,369 | 30,393 | 30,009 | 26,853 |
| Income taxes | 15,876 | 15,870 | 16,092 | 19,146 | 12,176 | 13,639 | 15,368 | 15,586 | 14,945 | 16,381 |
| Net earnings applicable to common shares | 33,685 | 35,005 | 32,628 | 32,341 | 29,866 | 30,078 | 30,729 | 31,122 | 29,460 | 28,807 |
| **Balance Sheet Items *($thousands)*** | | | | | | | | | | |
| Property, plant and equipment | 1,268,305 | 1,212,810 | 1,230,371 | 1,181,433 | 1,173,642 | 1,119,820 | 1,085,106 | 1,050,913 | 1,009,448 | 949,478 |
| Assets held for sale | - | 44,698 | - | - | - | - | - | - | - | - |
| Intangible assets[3] | 35,712 | 36,003 | 37,287 | 37,633 | - | - | - | - | - | - |
| Accumulated amortization | 476,669 | 457,121 | 464,327 | 444,109 | 422,848 | 402,683 | 387,815 | 420,836 | 407,319 | 381,003 |
| Net capital assets | 827,348 | 836,390 | 803,331 | 774,957 | 750,794 | 717,137 | 697,291 | 630,077 | 602,129 | 568,475 |
| Total assets | 1,202,383 | 1,196,937 | 1,170,950 | 1,001,855 | 985,930 | 929,158 | 889,013 | 825,310 | 744,375 | 704,598 |
| Long-term debt (including current instalments) | 475,460 | 475,482 | 479,250 | 438,154 | 443,527 | 414,489 | 395,298 | 328,558 | 332,208 | 335,858 |
| Preference shares | 9,081 | 9,111 | 9,111 | 9,352 | 9,352 | 9,353 | 9,410 | 9,417 | 9,429 | 9,709 |
| Common equity | 384,030 | 400,502 | 381,185 | 373,738 | 356,671 | 335,887 | 323,972 | 316,360 | 299,480 | 279,515 |
| Total capital | 868,571 | 885,095 | 869,546 | 821,244 | 809,550 | 759,729 | 728,680 | 654,335 | 641,117 | 625,082 |
| **Operating Statistics *(GWh)*** | | | | | | | | | | |
| Sources of Electricity (normalized) | | | | | | | | | | |
| Purchased | 5,456 | 5,308 | 5,188 | 5,088 | 5,013 | 4,876 | 4,873 | 4,841 | 4,725 | 4,604 |
| Generated | 422 | 425 | 426 | 426 | 381 | 417 | 426 | 424 | 425 | 424 |
| Total | 5,878 | 5,733 | 5,614 | 5,514 | 5,394 | 5,293 | 5,299 | 5,265 | 5,150 | 5,028 |
| Electricity sales (normalized) | | | | | | | | | | |
| Residential | 3,407 | 3,311 | 3,203 | 3,130 | 3,044 | 2,981 | 2,987 | 2,972 | 2,909 | 2,843 |
| Commercial and street lighting | 2,146 | 2,108 | 2,096 | 2,078 | 2,049 | 2,014 | 2,017 | 2,007 | 1,973 | 1,922 |
| Total | 5,553 | 5,419 | 5,299 | 5,208 | 5,093 | 4,995 | 5,004 | 4,979 | 4,882 | 4,765 |
| Electricity sales per employee | 8.7 | 8.5 | 8.2 | 8.3 | 8.1 | 8.0 | 8.1 | 7.5 | 7.3 | 7.2 |
| **Customers *(year-end)*** | | | | | | | | | | |
| Residential | 214,515 | 211,091 | 207,335 | 204,204 | 201,045 | 198,568 | 196,412 | 193,912 | 191,314 | 188,925 |
| Commercial and street lighting | 32,648 | 32,335 | 31,972 | 31,574 | 31,217 | 30,932 | 30,889 | 30,552 | 30,339 | 30,147 |
| Total | 247,163 | 243,426 | 239,307 | 235,778 | 232,262 | 229,500 | 227,301 | 224,464 | 221,653 | 219,072 |
| Operating cost per customer *($)*[4] | 241 | 234 | 214 | 208 | 213 | 212 | 218 | 220 | 225 | 223 |
| Number of full-time equivalent employees | 640 | 641 | 644 | 628 | 627 | 623 | 621 | 661 | 667 | 666 |

1 *Certain comparative figures have been reclassified to conform with current year presentation.*
2 *Amount for 2007 and 2006 is net of a regulatory deferral of $5.8 million, as approved by the PUB.*
3 *Beginning in 2008, intangible assets were reported separately on the Balance Sheet.*
4 *Operating cost per customer is calculated excluding pension, OPEBs and early retirement program costs.*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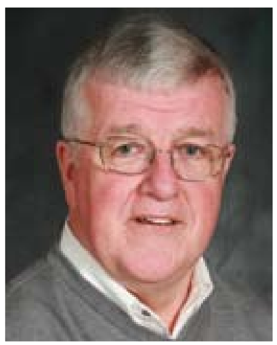

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**Bruce Simmons***
President & Chief Executive Officer
Hammond Farm Ltd.
Corner Brook,
Newfoundland & Labrador

**Jo Mark Zurel***
Chair, Audit & Risk Committee
President
Stonebridge Capital Inc.
St. John's,
Newfoundland & Labrador

* Audit & Risk Committee • Governance & Human Resources Committee

# Community Partners

We are proud that community groups throughout the province can count on us for support. We were pleased to provide financial, in-kind and hands on assistance to the following organizations and many more in 2011:

**Health**
The Dr. H. Bliss Murphy Cancer Care Foundation, PRIORITY: The Campaign for Cancer Care, The Health Care Foundation, The Burin Peninsula Health Care Foundation, The Western Memorial Health Care Foundation, The Children's Wish Foundation, The Newfoundland & Labrador Down Syndrome Society, Juvenile Diabetes Research Foundation, The Arthritis Society (Newfoundland & Labrador Division), Alzheimer Society of Newfoundland & Labrador, Trinity Conception Placentia Health Care Foundation, Janeway Children's Hospital Foundation, Learning Disabilities Association of Newfoundland & Labrador, Heart and Stroke Foundation of Newfoundland & Labrador, Canadian Blood Services, Canadian Mental Health Association

**Safety**
Newfoundland & Labrador Association of Fire Services, Firefighter Electricity Safety Training, Learn Not to Burn Program, Child Find Newfoundland & Labrador, School Electricity Safety Program, Safety Services Newfoundland Labrador, Newfoundland & Labrador Crime Stoppers, Triple Bay Eagles Ground Search and Rescue

**Environment**
Atlantic Salmon Federation, Tree Canada, Newfoundland & Labrador Home Builders' Association, Trans Canada Trail Foundation, Marystown Community Pride, Rennies River Development Foundation, Corner Brook Stream Development Corporation

**Education & Youth**
Junior Achievement of Newfoundland & Labrador, Memorial University of Newfoundland, College of the North Atlantic, Sport Newfoundland & Labrador, Scouts Canada, Church Lads' Brigade, Special Olympics

**Community**
Newfoundland & Labrador Region of the Canadian Red Cross, Community Food Sharing Association, Coats for Kids, Habitat for Humanity, Community Sector Council Newfoundland & Labrador

**Arts & Culture**
Newfoundland Symphony Orchestra, Kiwanis Music Festival Association, Resource Centre for the Arts

# Investor Information

Head Office
55 Kenmount Road, P.O. Box 8910
St. John's, NL A1B 3P6
Tel: (709) 737-2802
Fax: (709) 737-5300

Share Transfer Agent and Registrar
Computershare Trust Company of Canada
1500 University Street, Suite 700
Montreal, QC H3A 3S8
Tel: (514) 982-7888
Fax: (514) 982-7635
computershare.com

Annual General Meeting
Friday, April 27, 2012 at 8:00 a.m.
Main Boardroom, 3rd Floor
Newfoundland Power Inc.
55 Kenmount Road
St. John's, NL A1B 3P6

Investor Information
Peter Alteen, Corporate Secretary
55 Kenmount Road, P.O. Box 8910
St. John's, NL A1B 3P6
Tel: (709) 737-5859
palteen@newfoundlandpower.com

Website
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Email
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Fortis Websites
Fortis Inc.
fortisinc.com
FortisAlberta Inc.
fortisalberta.com
FortisBC Inc.
fortisbc.com
FortisOntario Inc.
fortisontario.com
Maritime Electric Company, Limited
maritimeelectric.com
Caribbean Utilities Company, Ltd.
cuc-cayman.com
Fortis Properties Corporation
fortisproperties.com
Fortis Turks and Caicos
provopowercompany.com

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Corporate Communications, Newfoundland Power Inc.
Front Cover (Pictured): Gary Hillier

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**Newfoundland Power Inc.**
**P.O. Box 8910**
**St. John's, NL A1B 3P6**
**newfoundlandpower.com**

**IN THE MATTER OF**
the 2011 Annual Returns
of Newfoundland Power
Inc. filed pursuant to
Section 59(2) of the
*Public Utilities Act.*

## AFFIDAVIT

I, Jocelyn Perry, of the Town of Conception Bay South in the Province of Newfoundland and Labrador, Chartered Accountant, make oath and say as follows:

1. That I am Vice-President, Finance and Chief Financial Officer of Newfoundland Power Inc.

2. That to the best of my knowledge, information and belief, the information contained in the 2011 Annual Report and accompanying returns of Newfoundland Power Inc., filed with the Board of Commissioners of Public Utilities pursuant to section 59(2) of the *Public Utilities Act* is true and accurate.

**SWORN** to before me at St. John's
in the Province of Newfoundland and Labrador
this 26th day of March, 2012:

Barrister – Newfoundland & Labrador

Jocelyn Perry

**Newfoundland Power Inc.**
**Names and Addresses of Officers and Directors**
**as of December 31, 2011**

| Name | Address | Position Held |
|---|---|---|
| **Peter Alteen** | 38 Mansfield Crescent<br>St. John's, NL A1E 5E3 | Vice President; Corporate Secretary |
| **Peggy Bartlett** | 173 Grenfell Heights<br>Grand Falls-Windsor, NL A2A 2J7 | Chair, Board of Directors |
| **Frank Davis** | 2 Crabapple Place<br>St. John's, NL A1A 5L7 | Director |
| **Nora Duke** | 18 Jacaranda Place<br>St. John’s, NL A1H 1A2 | Director |
| **Georgina Hedges** | 15 Crescent Heights<br>Grand Falls-Windsor, NL A2A 1K6 | Director |
| **Earl Ludlow** | 33 Ortega Drive<br>Paradise, NL A1L 2L1 | President and Chief Executive Officer;<br>Director |
| **Edward Murphy** | 5 Lambert Place<br>St. John's, NL A1A 3X4 | Director |
| **Fred O'Brien** | 389 Church Street<br>Alberton, PEI C0B 1B0 | Director |
| **Richard Hew** | 33 Destiny Avenue, P.O. Box 30521<br>Grand Cayman, KY1-1203, Cayman Islands | Director |
| **Jocelyn Perry** | 6 Maple Street<br>Conception Bay South, NL A1W 5M8 | Vice President and Chief Financial Officer |
| **Bruce Simmons** | PO Box 2198, RR1<br>Corner Brook, NL A2H 2N2 | Director |
| **Gary Smith** | 89 Cheyne Drive | Vice President |

**Newfoundland Power Inc.**
**Names and Addresses of Officers and Directors**
**as of December 31, 2011**

| Name | Address | Position Held |
|---|---|---|
| | St. John's, NL A1A 5W5 | |
| **Jo Mark Zurel** | 16 Regent Street<br>St. John's, NL A1A 5A4 | Director |

# Newfoundland Power Inc.
## Computation of Average Rate Base
## For The Years Ended December 31
## ($000s)

| | | 2011 | 2010 |
|---|---|---|---|
| 1 | **Net Plant Investment** | | |
| 2 | Plant Investment - Return 4 | 1,371,762 | 1,393,801 |
| 3 | Accumulated Amortization - Return 6 | (575,926) | (585,245) |
| 4 | Contributions in Aid of Construction - Return 7 | (29,013) | (30,266) |
| 5 | | 766,823 | 778,290 |
| 6 | | | |
| 7 | **Additions to Rate Base** | | |
| 8 | Deferred Pension Costs - Return 8 | 97,628 | 102,549 |
| 9 | Credit Facility Costs - Return 8 | 270 | 258 |
| 10 | Cost Recovery Deferral - Seasonal/TOD Rates - Return 9 | 228 | - |
| 11 | Cost Recovery Deferral - Hearing Costs - Return 9 | 253 | 507 |
| 12 | Cost Recovery Deferral - Regulatory Amortizations - Return 9 | 1,642 | - |
| 13 | Cost Recovery Deferral - Conservation - Return 9 | 454 | 682 |
| 14 | Customer Finance Programs - Return 10 | 1,527 | 1,647 |
| 15 | | 102,002 | 105,643 |
| 16 | | | |
| 17 | **Deductions from Rate Base** | | |
| 18 | Weather Normalization Reserve - Return 17 | 5,020 | 1,954 |
| 19 | Adjustment - 2010 Hearing Costs - Return 9 | 6 | - |
| 20 | Other Post Employment Benefits - Return 10 | 7,199 | - |
| 21 | Customer Security Deposits - Return 10 | 695 | 705 |
| 22 | Accrued Pension Obligation - Return 10 | 3,778 | 3,548 |
| 23 | Future Income Taxes - Return 23 | 862 | 3,617 |
| 24 | Demand Management Incentive Account - Return 18 | 1,252 | 676 |
| 25 | | 18,812 | 10,500 |
| 26 | | | |
| 27 | **Year End Rate Base** | 850,013 | 873,433 |
| 28 | | | |
| 29 | **Average Rate Base Before Allowances** | 861,723 | 861,442 |
| 30 | | | |
| 31 | **Rate Base Allowances** | | |
| 32 | Materials and Supplies Allowance - Return 11 | 5,012 | 4,476 |
| 33 | Cash Working Capital Allowance - Return 12 | 9,663 | 9,292 |
| 34 | | | |
| 35 | **Average Rate Base at Year End** | 876,398 | 875,210 |

**Newfoundland Power Inc.**
**Plant Investment**
**For The Year Ended December 31, 2011**
**($000s)**

| | Opening Balance | Adjustments[1] | Additions | Retirements | Year End Balance |
|---|---|---|---|---|---|
| Power Generation | | | | | |
| Hydro | 152,036 | (67) | 8,115 | 967 | 159,117 |
| Diesel | 3,035 | 29 | 75 | 10 | 3,129 |
| Gas Turbine | 18,243 | 26 | 170 | 6 | 18,433 |
| | 173,314 | (12) | 8,360 | 983 | 180,679 |
| Substations | 150,090 | (5) | 12,457 | 1,813 | 160,729 |
| Transmission | 106,926 | (215) | 6,025 | 2,419 | 110,317 |
| Distribution | 807,153 | (77,117) | 39,508 | 7,078 | 762,466 |
| General Property | 51,957 | (424) | 1,823 | 477 | 52,879 |
| Transportation | 24,076 | - | 2,389 | 2,711 | 23,754 |
| Communications | 10,641 | (13) | 65 | 143 | 10,550 |
| Computer Software | 29,002 | - | 2,308 | 2,378 | 28,932 |
| Computer Hardware | 8,368 | - | 1,750 | 1,371 | 8,747 |
| Government Contributions | 23,109 | - | - | - | 23,109 |
| | 1,211,322 | (77,774) | 66,325 | 18,390 | 1,181,483 |
| Total Depreciable Plant | 1,384,636 | (77,786) | 74,685 | 19,373 | 1,362,162 |
| Non Depreciable Land | 9,165 | 429 | 6 | - | 9,600 |
| Plant Investment Included In Rate Base | 1,393,801 | (77,357)[2] | 74,691 | 19,373 | 1,371,762 |
| Construction Work In Progress | | | | | 5,190 |
| Total Plant Investment[3] | | | | | 1,376,952 |

[1] Adjustments are due to asset reclassification and redistribution of original cost based on final project details.

[2] Gross book value of poles sold to Bell Aliant Regional Communication Inc. ("Bell"). The pole sale was approved in Order No. P.U. 21 (2011).

[3] A reconciliation of the Total Plant Investment used in the calculation of average rate base for 2011 to the plant investment shown in Return 1 is as follows:

| | ($000s) |
|---|---|
| 2011 Capital Assets shown in Return 1 (Note 10 to Financial Statements) | 1,268,305 |
| Add: Contributions in Aid of Construction - Return 7 | 78,360 |
| Add: Plant Investment classified as Intangibles (Note 11 to Financial Statements) | 35,712 |
| Deduct: Inventories included in Plant Investment for financial reporting purposes | (5,425) |
| 2011 Total Plant Investment for Average Rate Base | 1,376,952 |

**Newfoundland Power Inc.**
**Capital Expenditure**
**For The Year Ended December 31, 2011**
**($000s)**

| | Approved By Board[1] | Actual | Variance[2] |
|---|---|---|---|
| Generation | | | |
| Hydro | 9,496 | 8,576 | (920) |
| Thermal | 268 | 252 | (16) |
| | 9,764 | 8,828 | (936) |
| Substations | 11,647 | 10,527 | (1,120) |
| Transmission | 4,745 | 3,389 | (1,356) |
| Distribution | 36,842 | 38,210 | 1,368 |
| General Property | 1,792 | 1,757 | (35) |
| Transportation | 2,254 | 2,272 | 18 |
| Telecommunications | 572 | 109 | (463) |
| Information Systems | 3,728 | 3,699 | (29) |
| Unforeseen | 750 | 305 | (445) |
| General Expenses Capital | 2,800 | 3,750 | 950 |
| | 74,894 | 72,846 | (2,048) |
| Projects carried forward from 2010[3] | | 3,325 | |

[1] Approved by Order Nos. P.U. 28 (2010), P.U. 8 (2011), and P.U. 11 (2011).

[2] Variance explanations are provided in Newfoundland Power Inc.'s 2011 Capital Expenditure Report filed with the Board on February 29, 2012.

[3] The projects carried forward from 2010 include $1,872,000 from the rebuild of transmission lines 23L and 24L; $1,326,000 from work relating to the old Grand Falls substation and $127,000 miscellaneous.

**Newfoundland Power Inc.**
**Accumulated Amortization**
**For The Year Ended December 31, 2011**
**($000s)**

| | |
|---|---|
| Opening Balance - January 1, 2011 | 585,245 |
| | |
| Add: | |
| Amortization of Fixed Assets[1] | 42,695 |
| Amortization of Contributions - Government - Return 7 | 67 |
| Amortization of Contributions - Customers - Return 7 | 1,476 |
| Salvage[2] | 48,273 |
| | 92,511 |
| | |
| Deduct: | |
| Gross Book Value of Poles Sold to Bell | 77,357 |
| Cost of Removal (Net of Income Tax) | 5,099 |
| Retirements | 19,374 |
| | 101,830 |
| | |
| Closing Balance - December 31, 2011[3] | 575,926 |

[1] The amortization rates for 2011 are from the 2006 Depreciation Study based on plant in service at December 31, 2005 and approved in Order No. P.U. 32 (2007).

| | |
|---|---|
| Hydro | 2.17% |
| Diesel | 4.28% |
| Gas Turbine | 4.81% |
| Substations | 2.63% |
| Transmission | 3.28% |
| Distribution | 3.14% |
| General Property | 2.94% |
| Transportation | 10.28% |
| Telecommunications | 6.18% |
| Computer Software | 10.00% |
| Computer Hardware | 20.00% |

[2] Includes proceeds from the sale of support structures to Bell.

[3] The accumulated amortization shown in Return 1 (Note 10 to the Financial Statements) is before adjustment for contributions in aid of construction, site restoration costs and intangibles.

| | ($000s) |
|---|---|
| Accumulated Amortization shown in Return 1 (Note 10 to Financial Statements) | 455,539 |
| Add: Amortization of Contributions - Return 7 | 49,347 |
| Add: Site Restoration Costs | 49,910 |
| Add: Accumulated Amortization classified as Intangibles - (Note 11 to Financial Statements) | 21,130 |
| 2011 Accumulated Amortization for Average Rate Base | 575,926 |

**Newfoundland Power Inc.**
**Contributions in Aid of Construction**
**For The Year Ended December 31, 2011**
**($000s)**

| | | Customers | Government | Total |
|---|---|---|---|---|
| 1 | Gross Contributions to January 1, 2011 | 57,720 | 23,108 | 80,828 |
| 2 | | | | |
| 3 | Add: Contributions Received in 2011 | 2,764 | - | 2,764 |
| 4 | Less: Contributions Relating to Bell Pole Sale | (5,232) | - | (5,232) |
| 5 | | | | |
| 6 | Gross Contributions to December 31, 2011 | 55,252 | 23,108 | 78,360 |
| 7 | | | | |
| 8 | | | | |
| 9 | Amortizations to January 1, 2011 | 27,977 | 22,585 | 50,562 |
| 10 | | | | |
| 11 | Add: Amortization in 2011 | 1,476 | 67 | 1,543 |
| 12 | Less: Amortizations Relating to Bell Pole Sale | (2,758) | - | (2,758) |
| 13 | | | | |
| 14 | Amortizations to December 31, 2011 | 26,695 | 22,652 | 49,347 |
| 15 | | | | |
| 16 | | | | |
| 17 | Unamortized Contributions to December 31, 2011 | 28,557 | 456 | 29,013 |

**Newfoundland Power Inc.**
**Deferred Charges**
**For The Year Ended December 31, 2011**
**($000s)**

| | Balance January 1 2011 | Additions During 2011 | Reductions During 2011 | Balance December 31 2011 |
|---|---|---|---|---|
| Deferred Pension Costs[1] | 102,549 | 5,137 | 10,058 | 97,628 |
| Deferred Credit Facility Issue Costs | 258 | 130 | 118 | 270 |
| Deferred Charges Included in Rate Base | 102,807 | 5,267 | 10,176 | 97,898 |

[1] The December 31, 2011 balance includes $3.7 million in pension costs associated with the 2005 Early Retirement Program. These pension costs were originally $11.3 million and are being amortized over ten years, beginning April 1, 2005.

# Newfoundland Power Inc.
## Regulatory Deferrals
## For The Year Ended December 31, 2011
## ($000s)

| | Balance January 1 2011 | Additions During 2011 | Reductions During 2011 | Balance December 31 2011 |
|---|---|---|---|---|
| **Cost Recovery Deferrals** | | | | |
| Deferred Costs - Seasonal/TOD Rates[1] | - | 228 | - | 228 |
| Deferred Costs - 2010 Regulatory Amortizations[2] | - | 1,642 | - | 1,642 |
| Deferred Costs - Conservation Program[3] | 682 | - | 228 | 454 |
| Deferred Costs - 2010 Hearing Costs[4] | 507 | - | 254 | 253 |
| | 1,189 | 1,870 | 482 | 2,577 |
| | | | | |
| **Other Regulatory Adjustments** | | | | |
| 2010 Hearing Costs[5] | - | 6 | - | 6 |

[1] In Order No. P.U. 8 (2011), the Board approved the deferred recovery of revenues and costs related to the implementation of the optional seasonal rates and TOD pilot study.

[2] In Order No. P.U. 30 (2010), the Board approved the deferred recovery of $2,363,000 in costs ($1,642,000 on an after-tax basis) related to the conclusion in 2010 of a number of regulatory amortizations.

[3] In Order No. P.U. 43 (2009), the Board approved the 4-year amortization of certain costs related to the implementation of the conservation plan in 2009.

[4] In Order No. P.U. 43 (2009), the Board approved the 3-year amortization of hearing costs related to the 2010 General Rate Application.

[5] In Order No. P.U. 26 (2011), the Board ordered Newfoundland Power to adjust the recovery of its 2010 Hearing Costs to reflect total costs of $750,000.

**Newfoundland Power Inc.**
**Other Rate Base Assets and Liabilities**
**For The Year Ended December 31, 2011**
**($000s)**

| | Balance January 1 2011 | Change During 2011 | Balance December 31 2011 |
|---|---|---|---|
| **Assets** | | | |
| Customer Finance Programs[1] | 1,647 | (120) | 1,527 |
| | | | |
| **Liabilities** | | | |
| Accrued Pension Obligation[2] | 3,548 | 230 | 3,778 |
| | | | |
| Customer Security Deposits[3] | 705 | (10) | 695 |
| | | | |
| Net OPEBs Liability[4] | - | 7,199 | 7,199 |

[1] Comprised of loans provided to customers related to customer conservation programs and contributions in aid of construction.

[2] Executive and Senior Management supplemental pension benefits comprised of a defined benefit plan (PUP) and a defined contribution plan (SERP). The PUP was closed to new entrants in 1999.

[3] Security deposits received from customers for electrical service in accordance with the Board-approved Schedule of Rates, Rules and Regulations.

[4] Equal to the difference, at December 31, 2011, between the OPEBs liability of $56,255,000 and the OPEBs asset of $49,056,000.

**Newfoundland Power Inc.**
**Materials and Supplies Allowance**
**For The Years Ended December 31**
**($000s)**

| | **2011[1]** | **2010[1]** |
|---|---|---|
| Opening - January 1 | 5,811 | 5,197 |
| January | 6,095 | 5,246 |
| February | 6,075 | 5,360 |
| March | 6,259 | 5,400 |
| April | 6,232 | 5,605 |
| May | 5,926 | 5,568 |
| June | 6,100 | 6,061 |
| July | 6,354 | 5,601 |
| August | 6,398 | 5,728 |
| September | 6,500 | 5,546 |
| October | 6,707 | 5,788 |
| November | 6,627 | 6,002 |
| December | 6,565 | 5,811 |
| Total | 81,649 | 72,913 |
| Average | 6,281 | 5,609 |
| Less: Expansion (20.2%)[2] | 1,269 | 1,133 |
| Materials and Supplies Allowance | 5,012 | 4,476 |

[1] The 2010 and 2011 materials and supplies allowance calculation reflects a 13-month average approved in Order No. P.U. 32 (2007).

[2] The expansion factor of 20.2% is based on the 2010 cash working capital study approved in Order No. P.U. 43 (2009).

**Newfoundland Power Inc.**
**Cash Working Capital Allowance[1]**
**For The Years Ended December 31**
**($000s)**

| | 2011 | 2010 |
|---|---|---|
| Gross Operating Costs[2] | 432,485 | 415,097 |
| Current Income Taxes - Return 22 | 19,631 | 17,773 |
| Municipal Taxes Paid | 13,348 | 13,421 |
| Non-regulated Expenses (net of income taxes) | (1,604) | (979) |
| Total operating expenses | 463,860 | 445,312 |
| Cash Working Capital Factor | 2.0% | 2.0% |
| | 9,277 | 8,906 |
| HST Adjustment | 386 | 386 |
| Cash Working Capital Allowance | 9,663 | 9,292 |

[1] The cash working capital allowance for 2010 is calculated based on the method used to calculate the 2010 Test Year average rate base approved in Order No. P.U. 46 (2009).

[2] In accordance with the method used to calculate the 2010 Test Year average rate base approved in Order No. P.U. 46 (2009), gross operating costs used in the calculation of the cash working capital allowance are net of non-cash related amortizations.

**Newfoundland Power Inc.**
**Return on Average Rate Base[1]**
**For The Years Ended December 31**
**($000s)**

| | 2011 | 2010 |
|---|---|---|
| Net Earnings from Return 1 | 34,252 | 35,573 |
| Add: Non-regulated (net of income taxes) | 1,604 | 979 |
| | 35,856 | 36,552 |
| Finance Costs | | |
| Interest on Long-term Debt | 35,444 | 35,850 |
| Other Interest | 687 | 329 |
| Amortization of Debt Issue Expenses | 308 | 232 |
| AFUDC[2] | (970) | (820) |
| | 35,469 | 35,591 |
| Regulated Earnings | 71,325 | 72,143 |
| Average Rate Base from Return 3 | 876,398 | 875,210 |
| Rate of Return on Average Rate Base | 8.14% | 8.24% |

| | 2011 | 2010 |
|---|---|---|
| Average Rate Base from Return 3 | 876,398 | 875,210 |
| Upper Limit of the Allowed Range of Return on Average Rate Base[3] | 8.14% | 8.41% |
| Upper Limit of Allowed Regulated Earnings | 71,339 | 73,605 |
| Regulated Earnings | 71,325 | 72,143 |
| Excess Revenue net of Income Taxes | - | - |
| Income Taxes | - | - |
| Excess Revenue | - | - |

[1] The return on average rate base is calculated in accordance with the methodology approved in Order No. P.U 32 (2007).

[2] For financial reporting purposes, the equity component of the 2011 AFUDC is reported as other income in Return 1.

[3] Based on a return on rate base of 7.96% plus 18 basis points, approved in Order No. P.U. 32 (2010) for 2011 and a return on rate base of 8.23% plus 18 basis points, approved in Order No. P.U. 46 (2009) for 2010.

**Newfoundland Power Inc.**
**Details of Normalized Sales and Revenue**
**For The Years Ended December 31**
**($000s)**

| | | 2011 | | | 2010 | | |
|---|---|---|---|---|---|---|---|
| | | Gigawatt Hours | Year End Customer Accounts | Revenue | Gigawatt Hours | Year End Customer Accounts | Revenue |
| **Revenue From Rates** | | | | | | | |
| Domestic | | | | | | | |
| Domestic | 1.1 | 3,398.7 | 212,843 | 343,775 | 3,311.2 | 211,091 | 332,664 |
| Domestic - Seasonal | 1.1S | 8.3 | 1,672 | 834.0 | - | - | - |
| Total Domestic | | 3,407.0 | 214,515 | 344,609 | 3,311.2 | 211,091 | 332,664 |
| | | | | | | | |
| General Service: | | | | | | | |
| 0 - 10 kW | 2.1 | 93.7 | 12,152 | 12,568 | 92.5 | 12,116 | 12,331 |
| 10 - 100 kW | 2.2 | 665.5 | 9,030 | 67,341 | 649.3 | 8,909 | 65,291 |
| 110 - 1000 kVA | 2.3 | 927.7 | 1,126 | 79,954 | 910.6 | 1,101 | 77,976 |
| 1000 kVA and Over | 2.4 | 422.4 | 64 | 31,500 | 419.2 | 59 | 31,037 |
| Total General Service | | 2,109.3 | 22,372 | 191,363 | 2,071.6 | 22,185 | 186,635 |
| | | | | | | | |
| Street & Area Lighting | 4.1 | 36.5 | 10,276 | 13,867 | 36.2 | 10,150 | 13,540 |
| Forfeited Discounts | | - | - | 2,719 | - | - | 2,494 |
| | | | | | | | |
| Revenue From Rates | | 5,552.8 | 247,163 | 552,558 | 5,419.0 | 243,426 | 535,333 |
| | | | | | | | |
| **Adjustments and Transfers** | | | | | | | |
| Energy Supply Cost Variance Deferral | | | | 6,896 [1] | | | 2,213 |
| Seasonal Rate Revenue Deferral | | | | 70 [2] | | | - |
| 2011 Pension Expense Variance Deferral | | | | 2,888 [3] | | | (640) |
| 2011 OPEBs Variance Deferral | | | | 195 [4] | | | - |
| 2005 Unbilled Revenue Accrual | | | | - | | | 4,618 |
| Total Adjustments and Transfers | | | | 10,049 | | | 6,191 |
| | | | | | | | |
| **Other Revenue** | | | | | | | |
| Joint Use Revenue | | | | 927 | | | 9,360 |
| Cost of Capital - Bell Pole Sale | | | | 3,328 | | | - |
| Pole Installation Revenues - Bell | | | | 1,046 | | | - |
| Pole Maintenance Agreement - Bell | | | | 1,375 | | | - |
| Wheeling Revenue | | | | 596 | | | 591 |
| Amortization of Municipal Tax Liability | | | | - | | | 1,363 |
| Interest on Overdue Customer Accounts | | | | 942 | | | 801 |
| Other Non-Electrical Revenue | | | | 2,251 | | | 1,311 |
| Total Other Revenue | | | | 10,465 | | | 13,426 |
| | | | | | | | |
| **Total Revenue - Return 1** | | | | **573,072** | | | **554,950** |

[1] The Energy Supply Cost Variance Deferral Account was approved in Order No. P.U. 32 (2007).

[2] The Seasonal Rate Revenue Deferral was approved in Order No. P.U. 8 (2011).

[3] The Pension Expense Variance Deferral Account was approved in Order No. P.U. 43 (2009).

[4] The OPEBs Variance Deferral Account was approved in Order No. P.U. 31 (2010).

**Newfoundland Power Inc.**
**Normalized Production and Sales Statistics**
**For The Years Ended December 31**
**($000s)**

| | 2011 | 2010 |
|---|---|---|
| Gigawatt Hours - Purchased | 5,455.4 | 5,308.3 |
| Gigawatt Hours - Produced | 422.4 | 424.6 |
| Total Purchased & Produced | 5,877.8 | 5,732.9 |
| Gigawatt Hours - Sold & Used | 5,564.4 | 5,430.2 |
| Gigawatt Hours - Losses | 313.4 | 302.7 |
| Losses Expressed as a Percentage of Total Purchased & Produced | 5.3% | 5.3% |
| Purchased Power Annual Billing Demand in kW | 1,134,566 | 1,119,636 |

**Newfoundland Power Inc.**
**Rate Stabilization Account**
**For The Year Ended December 31, 2011**
**($000s)**

| Month | Opening Balance | Adjustments | RSA Billed During Month | Municipal Taxes | Excess Fuel Costs | Secondary Energy Costs | Interest Costs | Transfer To (From) Nfld. Hydro | Closing Balance |
|---|---|---|---|---|---|---|---|---|---|
| January | 3,723.1 | - | (1,305.8) | - | 3.1 | - | 24.7 | 1,271.6 | 3,716.7 |
| February | 3,716.7 | - | (1,399.6) | - | 0.8 | - | 24.7 | 1,284.4 | 3,627.0 |
| March | 3,627.0 | 2,088.2 [1] | (1,378.9) | - | 6.1 | - | 24.1 | 1,281.0 | 5,647.5 |
| April | 5,647.5 | - | (1,240.0) | - | 2.6 | - | 37.5 | 1,038.8 | 5,486.4 |
| May | 5,486.4 | - | (1,070.8) | - | 112.6 [2] | - | 36.4 | 865.1 | 5,429.7 |
| June | 5,429.7 | - | (888.6) | - | 2.7 | - | 36.0 | 744.5 | 5,324.3 |
| July | 5,324.3 | - | (2,083.8) | - | 5.8 | - | 35.3 | 2,708.1 | 5,989.7 |
| August | 5,989.7 | - | (3,185.6) | - | 0.9 | - | 39.7 | 2,818.2 | 5,662.9 |
| September | 5,662.9 | - | (2,893.1) | - | 3.2 | - | 37.5 | 2,868.8 | 5,679.3 |
| October | 5,679.3 | - | (3,362.2) | - | - | - | 37.7 | 3,682.4 | 6,037.2 |
| November | 6,037.2 | - | (4,537.3) | - | 3.0 | - | 40.0 | 4,530.1 | 6,073.0 |
| December | 6,073.0 | 6,895.4 [3] | (5,223.6) | (938.1) [4] | 9.8 | - | 40.3 | 5,577.6 | 12,434.4 |
| | | 8,983.6 | (28,569.3) | (938.1) | 150.6 | - | 413.9 | 28,670.6 | |

[1] Adjustments in March include (i) $2.9 million for the disposition of the difference in forecasted vs. test year defined benefit pension plan expense for 2011, approved in Order No. P.U. 43 (2009); (ii) $194,900 for the disposition of the difference in forecasted vs. test year OPEBs expense for 2011, approved in Order No. P.U. 31 (2010); and ($994,200) for the disposition of the 2010 balance in the Demand Management Incentive Account and related income tax effects, approved in Order No. P. U. 7 (2011).

[2] Excess fuel costs due to generation required from Wesleyville gas turbine May 24th to 29th for rebuild on 116L.

[3] This is the amount related to the operation of the Energy Supply Cost Variance for 2011, approved in Order No. P.U. 32 (2007).

[4] This is the difference between total municipal taxes collected from customers through rates and the total taxes paid to municipalities for 2011.

# Newfoundland Power Inc.
# Weather Normalization Reserve
# For The Year Ended December 31, 2011
# ($000s)

| | |
|---|---|
| **Degree Day Normalization Reserve Transfer** | |
| Revenue Adjustment | |
| Heating Degree Days | 8,166 |
| Cooling Degree Days | - |
| Wind Speed Adjustments | (923) |
| Total Revenue Adjustment | 7,243 |
| Less : Power Purchased Adjustment | |
| Heating Degree Days | 9,025 |
| Cooling Degree Days | - |
| Wind Speed Adjustments | (1,017) |
| Total Power Purchased Adjustment | 8,008 |
| Net Adjustment (Before Tax) | (765) |
| Less: Income Tax @ 30.5% | (233) |
| Net Adjustment (After Tax) | (532) |
| Amortization of Weather Normalization Reserve[1] | (1,366) |
| Net Transfer (To) From Degree Day Normalization Reserve | (1,898) |
| **Hydro Production Equalization Reserve Transfer** | |
| Transfer (To) From Reserve (Before Tax) | (1,679) |
| Less: Income Tax @ 30.5% | (512) |
| Net Transfer (To) From Hydro Production Equalization Reserve | (1,167) |
| **Net Transfer (To) From Weather Normalization Reserve** | **(3,065)** |

**Weather Normalization Account Balances**

| | **Balance at January 1 2011** | **Net Transfers** | **Balance at December 31 2011[2]** |
|---|---|---|---|
| Degree Day Reserve | (215) | (1,898) | (2,113) |
| Hydro Equalization Reserve | (1,740) | (1,167) | (2,907) |
| | (1,955) | (3,065) | (5,020) |

[1] This is the amortization of the Degree Day Normalization Reserve approved by the Board in Order No. P.U. 32 (2007).

[2] A positive balance in the Weather Normalization Reserve reflects amounts to be recovered from customers in future periods. A negative balance in the Weather Normalization Reserve reflects amounts owed to customers.

# Newfoundland Power Inc.
## Demand Management Incentive Account
## For The Year Ended December 31, 2011
## ($000s)

| | |
|---|---|
| **Demand Management Incentive Account Transfer** | |
| Demand Supply Cost Variance | (2,346) |
| Demand Management Incentive (+/-)[1] | 545 |
| Supply Cost Variance Outside Deadband | (1,801) |
| Less: Income Tax @ 30.5.% | (549) |
| **Net Transfer (To) From Demand Management Incentive Account** | **(1,252)** |
| **Demand Management Incentive Account Balance** | |
| Balance at January 1, 2011 | (676) |
| Transfers to the RSA[2] | 676 |
| Net Transfer (To) From Demand Management Incentive Account | (1,252) |
| Balance at December 31, 2011[3] | (1,252) |

[1] The demand management incentive of $545,000 is plus/minus 1% of test year wholesale demand charges. The Demand Management Incentive Account definition was approved in Order No. P.U. 32 (2007).

[2] The transfer to the RSA of the DMI account balance at March 31, 2011 was approved in Order No. P.U. 7 (2011).

[3] In accordance with Order No. P.U. 32 (2007), Newfoundland Power filed a report with the Board on February 10, 2012 pertaining to the operation of the Demand Management Incentive Account for 2011.

**Newfoundland Power Inc.**
**Pension Expense Variance Deferral Account**
**OPEBs Cost Variance Deferral Account**
**For The Year Ended December 31, 2011**
**($000s)**

| | |
|---|---|
| **Pension Expense Variance Deferral Account ("PEVDA")**[1] | |
| 2011 Actual Pension Expense[2] | 9,075 |
| 2010 Test Year Forecast Pension Expense | 6,188 |
| Variance | 2,887 |
| **OPEBs Cost Variance Deferral Account ("OPEVDA")**[3] | |
| 2011 Actual OPEBs Expense[2] | 9,026 |
| 2010 Test Year Forecast OPEBs Expense[4] | 8,831 |
| Variance | 195 |
| **Amount Transferred to the RSA in 2012**[5] | 3,082 |

[1] In Order No. P.U. 43 (2009), the Board approved a Pension Expense Variance Deferral Account, which is charged or credited with the amount by which the annual pension expense computed in accordance with generally accepted accounting principles differs from the annual pension expense approved most recently for the establishment of revenue requirement from rates for a test year.

[2] The Pension expense and OPEBs expense are net of capitalization.

[3] In Order No. P.U. 31 (2010), the Board approved an OPEBs Cost Variance Deferral Account, which is charged or credited with the amount by which the OPEBs expense differs from that approved for the establishment of revenue requirement from rates for a test year.

[4] Revised 2010 Test Year as approved in Order No. P.U. 36 (2010).

[5] In Order No. P.U. 43 (2009) and in Order No. P.U. 31 (2010), the Board ordered that Newfoundland Power shall charge or credit any amounts in the PEVDA and the OPEVDA to the Rate Stabilization Account as of the 31st day of March in the year the difference arises.

**Newfoundland Power Inc.**
**Statement of Operating & General Expenses**
**For The Years Ended December 31**
**($000s)**

| | 2011 | 2010 | 2011/2010 Variances[1] |
|---|---|---|---|
| Operating Expenses | | | |
| Purchased Power | 369,484 | 358,443 | 11,041 |
| Power Produced | 2,604 | 2,675 | (71) |
| Administrative and Engineering Support | 7,132 | 6,046 | 1,086 |
| Environmental Policy | 269 | 315 | (46) |
| Substations | 2,271 | 2,340 | (69) |
| Transmission | 701 | 830 | (129) |
| Distribution | 8,769 | 8,728 | 41 |
| Communications | 1,472 | 1,508 | (36) |
| Fleet Operating and Maintenance Expense | 1,791 | 1,504 | 287 |
| | 394,493 | 382,389 | 12,104 |
| General Expenses | | | |
| Customer Service | 14,253 | 12,872 | 1,381 |
| Financial Services | 1,840 | 1,715 | 125 |
| Information Systems | 2,965 | 2,856 | 109 |
| Pension Costs | 11,566 | 7,588 | 3,978 |
| Other Post Employment Benefits | 9,003 | 712 | 8,291 |
| Corporate and Employee Services | 15,381 | 14,612 | 769 |
| | 55,008 | 40,355 | 14,653 |
| Total Operating & General Expenses | 449,501 | 422,744 | 26,757 |
| Transfers to General Expenses Capitalized | (2,914) | (2,429) | (485) |
| Amortization of Deferred CDM Costs | 339 | 339 | - |
| Deferred Seasonal Rates/Time of Day | (258) | - | (258) |
| **Total Expenses[2]** | **446,668** | **420,654** | **26,014** |

[1] Variances are explained in Return 21.

[2] This is equal to the total of purchased power costs, operating expenses and employee future benefit costs shown in Return 1.

# Newfoundland Power Inc.
## Explanation of Expense Variances
## 2011 versus 2010
## ($000s)

| | 2011 | 2010 | Increase (Decrease) |
|---|---|---|---|
| **Total Expenses** | **446,668** | **420,654** | **26,014** |

The increase in total expenses for 2011 was primarily the result of higher purchased power costs and increases in employee future benefits costs.

The following is an explanation of significant variances for individual operating and general expense classes.

| | | | |
|---|---|---|---|
| **Purchased Power** | **369,484** | **358,443** | **11,041** |

Purchased Power costs were higher in 2011 primarily due to electricity sales growth. The increase was partially offset by higher generation from the Company's hydroelectric generating facilities.

| | | | |
|---|---|---|---|
| **Power Produced** | **2,604** | **2,675** | **(71)** |

Power Produced costs for 2011 were broadly consistent with 2010.

| | | | |
|---|---|---|---|
| **Administrative and Engineering Support** | **7,132** | **6,046** | **1,086** |

Administrative and Engineering Support costs were higher in 2011 due to normal wage increases, higher employee vacation costs, employee relocation costs and the reassignment of a manager from corporate to regional operations.

| | | | |
|---|---|---|---|
| **Environmental Policy** | **269** | **315** | **(46)** |

Environmental Policy costs for 2011 were broadly consistent with 2010.

| | | | |
|---|---|---|---|
| **Substations** | **2,271** | **2,340** | **(69)** |

Substation costs for 2011 were broadly consistent with 2010.

| | | | |
|---|---|---|---|
| **Transmission** | **701** | **830** | **(129)** |

Transmission operating costs were lower in 2011 as 2010 included costs related to restoration efforts following the March ice storm and Hurricane Igor.

# Newfoundland Power Inc.
## Explanation of Expense Variances
## 2011 versus 2010
## ($000s)

| | 2011 | 2010 | Increase (Decrease) |
|---|---|---|---|
| **Distribution** | **8,769** | **8,728** | **41** |

Distribution costs in 2010 were higher than average due to Hurricane Igor. 2011 costs are consistent with 2010 primarily due to increased maintenance and repair costs in the first quarter of 2011, recovery work following a December 2011 wind storm, normal salary increases and higher costs related to employee training and illness.

| | 2011 | 2010 | Increase (Decrease) |
|---|---|---|---|
| **Communications** | **1,472** | **1,508** | **(36)** |

Communications operating costs were broadly consistent with 2010.

| | 2011 | 2010 | Increase (Decrease) |
|---|---|---|---|
| **Fleet Operating and Maintenance Expense** | **1,791** | **1,504** | **287** |

Fleet Operating and Maintenance costs were higher in 2011 due to increased fuel costs.

| | 2011 | 2010 | Increase (Decrease) |
|---|---|---|---|
| **Customer Service** | **14,253** | **12,872** | **1,381** |

Customer Service costs were higher in 2011 primarily as a result of higher costs related to conservation and demand management. Specifically, increased customer participation in energy programs resulted in higher customer program rebates. In addition, an increase in the allowance for doubtful accounts also contributed to higher costs in 2011. These increases were partially offset by Board approval in 2011 of the deferred recovery of costs related to the implementation of the Seasonal/Time of Day Rate Study.

| | 2011 | 2010 | Increase (Decrease) |
|---|---|---|---|
| **Financial Services** | **1,840** | **1,715** | **125** |

Financial Services costs were higher in 2011 due to normal salary increases.

| | 2011 | 2010 | Increase (Decrease) |
|---|---|---|---|
| **Information Systems** | **2,965** | **2,856** | **109** |

Information Systems operating costs were higher in 2011 due to normal salary increases.

| | 2011 | 2010 | Increase (Decrease) |
|---|---|---|---|
| **Pension Costs** | **11,566** | **7,588** | **3,978** |

Pension Costs were higher in 2011 due to the amortization of 2008 losses on pension plan assets and a reduction in the pension plan discount rate used to determine the Company's accrued benefit pension obligation for 2011.

**Newfoundland Power Inc.**
**Explanation of Expense Variances**
**2011 versus 2010**
**($000s)**

| | 2011 | 2010 | Increase (Decrease) |
|---|---|---|---|
| **Other Post Employment Benefits ("OPEBs")** | **9,003** | **712** | **8,291** |
| Effective January 1, 2011, the Company began recognizing OPEBs costs based on the accrual method of accounting. Prior to 2011, OPEBs were accounted for on the cash basis. In addition, 2011 OPEBs costs reflects the Board's approved amortization, over a 15-year period, of an OPEBs transitional asset arising out of the adoption of accrual accounting. | | | |
| **Corporate and Employee Services** | **15,381** | **14,612** | **769** |
| Corporate and Employee Services costs were higher in 2011 due to costs related to U.S. GAAP implementation, increases in the annual PUB assessment, normal salary increases and higher non-regulated inter-corporate charges. These increases were partially offset by the reassignment of a manager to regional operations. | | | |
| **General Expenses Capitalized** | **(2,914)** | **(2,429)** | **(485)** |
| The increase in General Expenses Capitalized (GEC) was primarily related to higher pension costs. | | | |
| **Amortization of Conservation Cost Deferral** | **339** | **339** | **-** |
| The Conservation Cost Deferral amortization reflects the Board's approval of deferred recovery, over a 4-year period, of certain 2009 costs associated with the Company's energy conservation programs. | | | |
| **Deferred Cost Seasonal Rates/Time of Day** | **(258)** | **-** | **(258)** |
| In 2011, the Board approved the deferred recovery of costs and revenues associated with implementing the Optional Seasonal/Time of Day Rate Study. | | | |

**Newfoundland Power Inc.**
**Calculation of Taxable Income and Income Tax Expense**
**For The Year Ended December 31, 2011**
**($000s)**

| | | | |
|---|---|---|---|
| 1 | Net Earnings from Return 1 | | 34,252 |
| 2 | | | |
| 3 | Add: Provision for current income tax | 20,498 | |
| 4 | Provision for prior years taxes | (867) | |
| 5 | Provision for future income taxes | (2,754) | |
| 6 | Provision for Conservation Cost Deferral | (112) | |
| 7 | Provision for Demand Management Incentive (DMI) | (230) | |
| 8 | Provision for Cost Recovery Deferral | 721 | |
| 9 | Provision for Optional Seasonal/TOD Rate Cost Recovery | 100 | |
| 10 | Provision for Weather Normalization | (1,480) | 15,876 |
| 11 | | | |
| 12 | Net Income Before Income Taxes | | 50,128 |
| 13 | | | |
| 14 | Add: Amortization of capital assets net of deferred expense | 42,695 | |
| 15 | Amortization of debt discount & expenses | 190 | |
| 16 | Amortization of credit facility costs | 118 | |
| 17 | Difference in overtime payments and accounting cost | 2,233 | |
| 18 | Difference in OPEBs payments and accounting cost | 6,802 | |
| 19 | Business meals & related expenses | 214 | |
| 20 | Special pension liability | 229 | |
| 21 | Difference in pension funding and accounting cost | 6,081 | |
| 22 | Stock option expense not deductible | 376 | |
| 23 | Small tools in excess of $500 | 217 | |
| 24 | Deferred Hearing Expenses | 253 | |
| 25 | Deferred Conservation Costs | 339 | |
| 26 | Other non deductible costs | 22 | 59,769 |
| 27 | | | |
| 28 | | | 109,897 |
| 29 | Less: | | |
| 30 | Capital cost allowance | 41,340 | |
| 31 | Cumulative eligible capital | 9 | |
| 32 | General expenses capitalized | 3,749 | |
| 33 | Interest charged to construction | 970 | |
| 34 | Bond issue expenses | 132 | |
| 35 | Deferred credit facility costs | 130 | |
| 36 | Optional Seasonal/TOD Rate Cost Recovery | 328 | |
| 37 | Cost Recovery Deferral | 2,363 | |
| 38 | Part VI.1 tax deduction | 29,511 | 78,532 |
| 39 | | | |
| 40 | Taxable Income | | 31,365 |
| 41 | | | |
| 42 | Weather Normalization deducted as future tax | | 1,480 |
| 43 | Provision for DMI | | 230 |
| 44 | Income Tax - Part 1 | | 9,566 |
| 45 | Income Tax - Part VI.1 | | 9,222 |
| 46 | Provision for prior years taxes | | (867) |
| 47 | | | |
| 48 | Current Income Tax Expense | | 19,631 |
| 49 | | | |
| 50 | Provision for CDM | | (112) |
| 51 | Provision for DMI | | (230) |
| 52 | Provision for Weather Normalization | | (1,480) |
| 53 | Provision for Cost Recovery Deferral | | 721 |
| 54 | Provision for Optional Seasonal/TOD Rate Cost Recovery | | 100 |
| 55 | Future income tax | | (2,754) |
| 56 | | | |
| 57 | Future Income Tax Provision | | (3,755) |
| 58 | | | |
| 59 | Total Tax Expense | | 15,876 |

**Newfoundland Power Inc.**
**Accumulated Future Income Taxes**
**For The Year Ended December 31, 2011**
**($000s)**

| | | |
|---|---|---|
| **Plant Investments** | | |
| Balance on January 1, 2011 | | 2,469 |
| Add: CCA claimed on all property, plant and equipment - from Return 22 | 41,340 | |
| Less: Amortization expense on all property, plant and equipment (GEC excluded from post-1986 additions) | 38,888 | |
| Difference | 2,452 | |
| Future Income Tax Rate @ 29% | | 711 |
| Balance on December 31, 2011(if negative enter 0) | | 3,180 |
| **Pension and Early Retirement Costs** | | |
| Balance on January 1, 2011 | | 1,148 |
| Add: Pension Funding | 5,352 | |
| Less: Pension Expense (including Special Pension Costs) | 10,501 | |
| Difference | (5,149) | |
| Future Income Tax Rate @ 29% | | (1,493) |
| Balance on December 31, 2011 | | (345) |
| **Other Post Employment Benefits ("OPEBs")** | | |
| Balance on January 1, 2011 | | - |
| Add: OPEBs Payments | 2,200 | |
| Less: OPEBs Expense | 9,002 | |
| Difference | (6,802) | |
| Future Income Tax Rate @ 29% | | (1,973) |
| Balance on December 31, 2011 | | (1,973) |
| **Total Accumulated Future Income Taxes** | | **862** |

**Newfoundland Power Inc.**
**Average Regulated Capital Structure**
**For The Year Ended December 31, 2011**
**($000s)**

## Average Book Capital Structure

| | Year-End December 31 2011 | Year-End December 31 2010 | Average | Percent |
|---|---|---|---|---|
| Total Debt | 475,460 | 475,482 | 475,471 | 54.22% |
| Preference Shares | 9,081 | 9,111 | 9,096 | 1.04% |
| Common Equity | 384,030 | 400,502 | 392,266 | 44.74% |
| | 868,571 | 885,095 | 876,833 | 100.00% |

## Average Regulated Capital Structure[1]

| | Average 2011 | Percent |
|---|---|---|
| Total Debt | 475,471 | 54.22% |
| Preference Shares | 9,096 | 1.04% |
| Common Equity | 392,266 | 44.74% |
| | 876,833 | 100.00% |

[1] In Order No. P.U. 19 (2003), the Board ordered that the proportion of regulated common equity in the capital structure shall not exceed 45%. In years where the average common equity percentage is below 45% of the average invested capital, the average regulated capital structure will equal the average book capital structure.

**Newfoundland Power Inc.**
**Cost of Embedded Debt**
**For The Years Ended December 31**
**($000s)**

| | | 2011 | 2010 |
|---|---|---|---|
| **Debt** | | | |
| Bonds | | 458,488 | 463,688 |
| Credit Facilities | | 20,000 | 15,000 |
| | | 478,488 | 478,688 |
| Debt Discount and Issue Expenses | | (3,028) | (3,206) |
| | | 475,460 | 475,482 |
| Average Debt | **A** | 475,471 | 477,366 |
| **Interest Expense**[1] | | | |
| Interest on Bonds | | 35,444 | 35,850 |
| Interest on Credit Facilities | | 673 | 316 |
| Interest on Bank Indebtedness | | 14 | 13 |
| Amortization of Debt Discount and Issue Costs | | 308 | 232 |
| | **B** | 36,439 | 36,411 |
| **Embedded Cost of Debt** | **B/A** | **7.66%** | **7.63%** |

[1] Total financing costs for 2011 and 2010 reported in Return 1 are as follows:

| | ($000's) | |
|---|---|---|
| | 2011 | 2010 |
| Interest Expense (B) from above | 36,439 | 36,411 |
| Add: Interest on Tax | 5 | 38 |
| Add: Interest on Security Deposits | 10 | 4 |
| Less: AFUDC (Debt portion only for 2011) | (510) | (820) |
| Interest Expense Reported in Return 1 | 35,944 | 35,633 |

**Newfoundland Power Inc.**
**Explanation of Variances in Cost of Debt**
**For The Year Ended December 31, 2011**
**($000s)**

| | Actual 2011 | Test Year 2010 | Variance |
|---|---|---|---|
| **Average Debt** | 475,471 | 475,448 | 23 |
| **Embedded Cost of Debt** | 7.66% | 7.64% | 0.02% |
| **Details of the Embedded Cost of Debt** | | | |
| Interest on Bonds | 35,444 | 35,849 | (405) |
| Interest on Credit Facilities | 673 | 270 | 403 [1] |
| Interest on Bank Indebtedness | 14 | - | 14 |
| Amortization of Debt Discount and Issue Costs | 308 | 185 | 123 [2] |
| | 36,439 | 36,304 | 135 |

**Explanation of Variances**

[1] Interest on credit facilities was higher than the 2010 Test Year due to continued capital expenditures related to customer growth. This was partially offset by proceeds of $45.7 million related to the 2011 Bell Pole Sale.

[2] The increase in debt amortization costs is due to legal/accounting costs related to the Amended Committed Credit Facility Agreement dated June 10, 2011.

**Newfoundland Power Inc.**
**Regulated Return on Average Common Equity**
**For The Years Ended December 31**
**($000s)**

| | **2011** | **2010** |
|---|---|---|
| **Average Common Equity** | | |
| Common Equity at December 31, 2011 | 384,030 | |
| Common Equity at December 31, 2010 | 400,502 | 400,502 |
| Common Equity at December 31, 2009 | | 381,185 |
| Average Common Equity | 392,266 | 390,844 |
| **Regulated Return on Average Common Equity** | | |
| Earnings Applicable to Common Shares - Return 1 | 33,685 | 35,005 |
| Add: Non-Regulated Expenses (net of income taxes) | 1,604 | 979 |
| | 35,289 | 35,984 |
| **Regulated Return on Average Common Equity** | **9.00%** | **9.21%** |

**Newfoundland Power Inc.**
**Assessable Revenue**
**(s. 13 of the *Public Utilities Act*)**
**For The Year Ended December 31, 2011**
**($000s)**

| | | |
|---|---|---|
| Revenue From Rates from Return 14 | 552,558 | |
| Weather Normalization Revenue Adjustment from Return 17 | (7,243) | |
| | 545,315 | |
| Municipal Taxes Billed | 14,286 | |
| Billing per the Rate Stabilization Account from Return 16 | 28,569 | |
| Total Electrical Revenue Billed | | 588,170 |
| Other Revenue from Return 14 | | 10,465 |
| **Assessable Revenue** | | **598,635** |