OPPORTUNITY

2008
Annual Financial
Report

Emera

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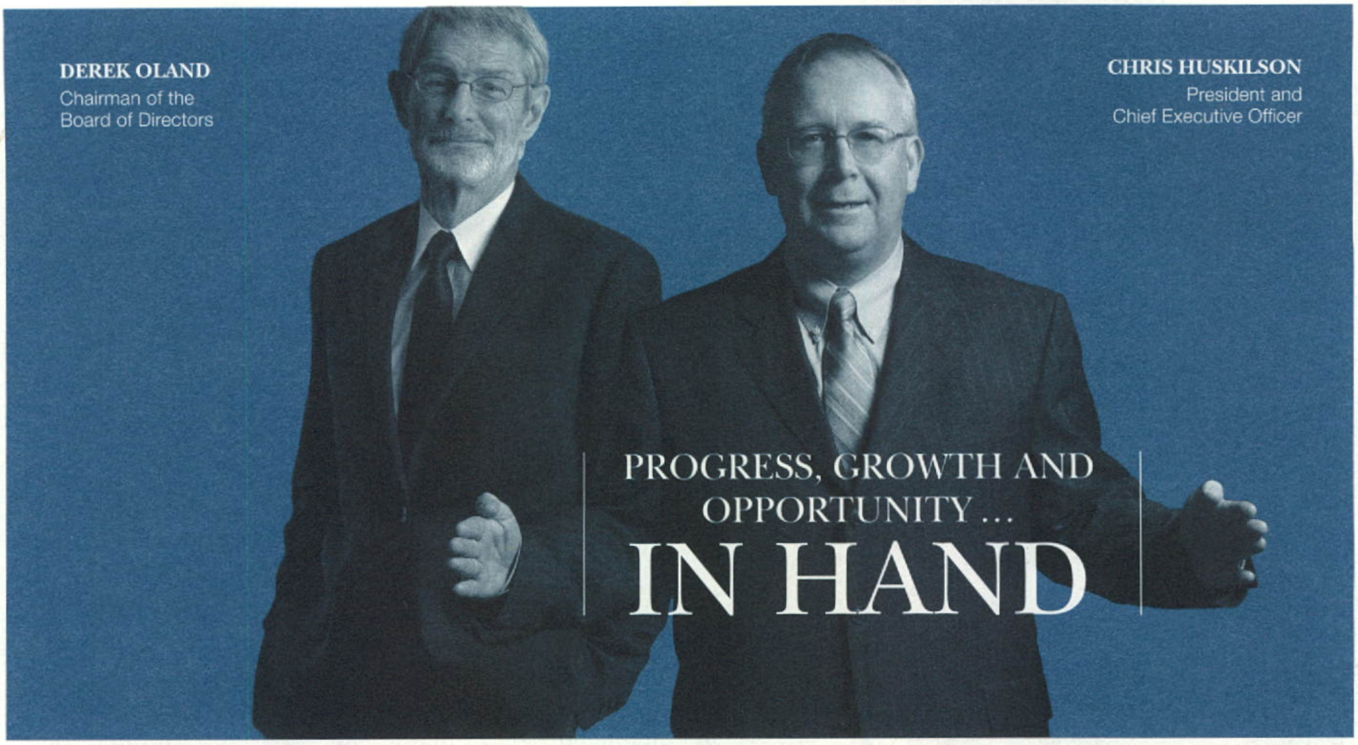


CHAIRMAN'S MESSAGE

Dear Fellow Shareholders,

On behalf of your Board of Directors, I am pleased to report that 2008 was another successful year for Emera. The company achieved strong earnings and a dividend increase during a very challenging year. Shareholders were comforted by Emera's disciplined approach to managing its business and measured growth strategy. This confidence resulted in a slightly higher year over year share price while most other companies saw a decline.

All of Emera's businesses worked hard in 2008 to strengthen current operations and capitalize on new opportunities. These achievements are mentioned throughout this report and our Annual Progress Report but I would like to comment on a few highlights from the year.

Brunswick Pipeline completed construction of its pipeline in January of this year. This project demonstrates Emera's ability to seize new opportunities and then see them through to completion. The pipeline is now ready to deliver gas to customers in Canada and New England from the new Canaport™ Liquefied Natural Gas import terminal in Saint John, New Brunswick.

Emera also made two exciting new investments in 2008. In February, the company invested in Irish tidal developer OpenHydro as part of its renewable energy strategy. This exciting new company is capturing the tremendous energy generation potential available in the world's tides. Some of the best tidal resources are located here in Nova Scotia's Bay of Fundy. OpenHydro's first deployed tidal turbine has been providing energy to homes in Scotland for about a year. The Company's innovative technology has been selected by Nova Scotia Power for a test turbine in the Bay of Fundy's Minas Basin which will be installed this fall. It is the same technology being used by the EDF Group for a tidal turbine farm in Brittany, off the coast of France.

In September, Emera purchased 25% of Grand Bahama Power Company (GBPC), through the acquisition of 50% of the shares of ICD Utilities Limited of the Bahamas. This second investment in the Caribbean provides the company with enhanced earnings and additional opportunities for growth in this region.

In addition to these operational achievements, Emera continues to make progress with its goal to have best in class corporate governance. I am proud to report

that Emera placed 13th out of 180 companies ranked by the Globe and Mail's 2008 Corporate Governance survey. This is an improvement from 23rd place in 2007 and 31st place in 2006. The Board continues to demand transparency, accountability and the highest level of ethical conduct from all operations and activities. I acknowledge the leadership role our Board of Directors plays in this achievement. The substantial industry knowledge and vast business experience of our Board members is a significant contributor to our success. I would especially like to thank our committee chairs for their leadership and guidance in these challenging times: Dr. Elizabeth Parr-Johnston chairs our Management Resources and Compensation Committee, Dr. Gail Cook-Bennett chairs our Nominating and Corporate Governance Committee and Ms. Andrea Rosen chairs our Audit Committee.

I would also like to welcome Mr. Donald Pether and Ms. Jackie Sheppard to the Emera Board of Directors. Mr. Pether is former Chair of the Board and President and CEO of Dofasco Inc. He is currently Chair of the Board of the Hamilton Health Sciences Foundation, Vice-Chair of the Board of Governors for McMaster University, and Chair of the Board of the McMaster Innovation Park. Ms. Sheppard is a former Executive Vice-President, Corporate & Legal of Talisman Energy Inc. She was also responsible for Legal Affairs, Business Development, Mergers and Acquisitions, Corporate Projects, Corporate Communications, Investor Relations, Corporate Responsibility and Government Affairs. We are very pleased that Mr. Pether and Ms. Sheppard joined the Emera Board. Their experience will be of great benefit to Emera's Board and leadership team.

After 10 years, I will be stepping down as Chair of the Board but will continue as a Director of both the Emera and NSPI Boards until my retirement next year. I have enjoyed my tenure as Chairman and thank the Board and shareholders for the trust and confidence placed in me. It gives me great satisfaction knowing Emera is not only well managed and profitable, but also well positioned for continued growth. Despite these uncertain times, I know the Company will maintain its successful track record, treating our three most important constituents – shareholders, customers, and employees – with the consideration each deserves.

In closing, I extend my sincere thanks to President and CEO Chris Huskilson, my fellow directors, as well as all the people of Emera and its subsidiaries for their contributions to the organization's achievements during my term as Chairman.

Yours truly,

Derek Oland
Chairman of the Board of Directors

PRESIDENT'S MESSAGE

Dear Fellow Shareholders,

The past year was a very successful year for Emera and for you, our shareholders. During one of the worst global financial crises in recent memory, we maintained strong earnings and increased our dividend. While Emera shares closed the year at \$22.20 – more than 2% higher than at the end of 2007 – the Utilities Index decreased approximately 25% and the TSX dropped more than 35%.

We thank you for your continued trust in Emera. Our strong management team, sustainable business model and shareholder confidence have contributed to this successful year. Our strong dividend yield and average 7% earnings per share growth rate over the last four years have provided shareholders with a strong total return on investment. I am confident in our ability to maintain this momentum and seize the opportunities that we see ahead of us.

Emera's businesses made significant progress this past year and we see many opportunities to continue this growth in the years to come. Our existing businesses are strong and stable; we see opportunities for transmission development and renewable generation in our core utilities and in new markets. Several of these opportunities are right in our backyard and all take advantage of the expertise already existing in our businesses.

Nova Scotia Power Inc. (NSPI)'s earnings increased to \$105.6 million in the year, compared to just over \$100 million in 2007. This increase relates primarily to the utility's strong results in the first half of the year.

NSPI saw success on many fronts in 2008. The utility achieved a rate settlement agreement with stakeholders in the fourth quarter of the year. This agreement allows for an average 9.3% rate increase and the implementation of a Fuel Adjustment Mechanism (FAM), which was effective January 1st of this year. Achievement of a FAM has been a long-standing goal of ours and we are very pleased with this outcome. The Utility and Review Board approved this agreement in its entirety and also brought closure to the outstanding issues of Operating, Maintenance and General spending and executive compensation. We are pleased with the improved working relationship with our stakeholders that led to this positive outcome.

While we appreciate that any increase in the price of electricity will be challenging for our customers, certainty around rates for 2009 allows NSPI to focus on reliability and customer service, as well as the addition of new sources of renewable energy which will help with price stability over the long term.

In June, we had and important management change at NSPI. Rob Bennett, former President and COO of Bangor Hydro, was appointed President and CEO of Nova Scotia Power. Rob has been with Emera companies for his entire career and his depth of knowledge about NSPI is a great asset as he leads the company in these exciting times. He has made a good start on NSPI's renewable focus and will continue to further this agenda in the days ahead.

NSPI once again received top marks for the superior performance at our generating units. In rankings released in 2008, two of our units made it onto the Canadian Electricity Association's top 10 in Canada, among the more than 850 generating units surveyed. This national recognition represents an outstanding achievement by our dedicated employees. One of our units was also recognized for its operating factor of more than 95%. This means that the unit ran at full capacity most of the year.

Safety is our top priority and we are proud to announce an unprecedented milestone: our Lingan Generating Station achieved 1,000,000 hours without a lost time injury. That's one million hours of being dedicated to the job at hand, looking out for colleagues and putting safety first. This demonstrates the importance our employees place on safety and we couldn't be more proud. Widely known as a leader in safety, NSPI was also presented with safety awards from the Canadian Society of Safety Engineers and the Nova Scotia Construction Safety Association.

NSPI made headway in its goal to improve environmental performance by increasing renewable generation and decreasing emissions from existing generating facilities. The Company signed contracts with independent power producers for 246 MW of wind energy - almost twice as much as is required to meet the 2010 provincial renewable generation standards. This will increase the wind generation on the ground in Nova Scotia by five times and produce enough energy to power approximately 80,000 homes. We are investing in a waste heat recovery unit at our Tufts Cove Generating Station which will add 50 MW of energy. We are also improving the operational and environmental performance of our Trenton Generating Station. New technology, commonly referred to as a baghouse, will result in greater fuel flexibility that will keep costs down for customers and also has the benefit of reducing fly ash emissions. We are also taking advantage of an exciting energy opportunity that we see right in our backyard. We are participating in a demonstration project to test an underwater tidal turbine in the Bay of Fundy. Our unit will be ready for seabed installation and in the water by the fall of 2009 and will provide valuable data about the environmental impacts of this exciting technology.

We are exploring the possibility of displacing a portion of the solid fuel currently used in several of our plants with renewable biomass. A new pilot project will see NSPI begin a test burn of biomass fuel. Although at a very early test phase at this time, this offers an enormous opportunity to increase the renewable generation at our plants, reduce our future use of imported solid fuel and reduce our carbon footprint, while also helping the Nova Scotia forestry industry.

We also want to thank our employees for their hard work and dedication through the month of December as they restored power in both Maine and Nova Scotia. Many employees travelled to Maine to assist with restoration after a significant ice storm in mid-December. We then experienced major winter storms over Christmas and New Year's which kept many employees hard at work instead of spending time with their families. We truly appreciate this commitment to our company.

Bangor Hydro-Electric Company (BHE) earned \$23.1 million in 2008, compared with 2007 earnings of \$27.5 million. This decrease was due mainly to the one-time benefits received in 2007 related to the construction of the Northeast Reliability Interconnect transmission line. BHE continues to work on transmission development in New England. We have more than \$100 million in new projects underway and are actively looking for additional investments. The increase in renewable generation in the region will create opportunities due to the requirement for additional transmission.

Our subsidiary, Brunswick Pipeline, completed construction of a 145-kilometre pipeline in January. It is now ready to deliver gas to customers in Canada and New England from the new Canaport™ Liquefied Natural Gas import terminal in Saint John. Gas is expected to flow later this year. The final cost of

the project is expected to be \$465 million plus any increased Allowance for Funds Used During Construction accrued due to the later than expected flow of gas and final construction-related settlements. Brunswick Pipeline has a take-or-pay contract with Repsol which will begin paying a fixed toll, independent of the volume of gas shipped, once gas begins to flow from the Canaport™ LNG Terminal.

We expect to earn an incremental $8-$10 million from the Brunswick Pipeline in 2009, reflecting the partial year of service.

Emera made two exciting investments in 2008. In February, we invested $15 million for a 7.4% interest in Irish tidal developer OpenHydro as part of Emera's renewable energy strategy. OpenHydro designs and manufactures marine turbines for harnessing energy from tidal currents in the world's oceans. They are the first company to deploy a tidal turbine directly on the seabed at the European Energy Marine Centre in Scotland and have been providing energy to homes from this facility for about a year. EDF Group, a world energy leader, has selected OpenHydro and its innovative technology to build a tidal turbine farm in Brittany, off the coast of France. OpenHydro was selected by EDF Group from among leading tidal technology developers according to robust technical, environmental and financial criteria. OpenHydro Open-Centre turbines have also been chosen as the preferred technology for a tidal array in the Channel Islands. Here in our region, OpenHydro is currently completing its turbine for deployment in the Bay of Fundy. This investment gives us a seat on the Board of Directors and influence over the company's direction.

In September, we purchased 25% of Grand Bahama Power Company (GBPC), through our acquisition of 50% of the shares of ICD Utilities Limited of the Bahamas. GBPC is located on Grand Bahama Island - the second most populous island in The Commonwealth of The Bahamas, less than 85 kilometres off the east coast of Florida. This acquisition is immediately accretive to Emera and we believe the utility has significant potential in a favorable regulatory environment. This investment, combined with our investment in Lucelec in St. Lucia, has given us a perspective on the region and its opportunities.

We will focus on key business segments where we have expertise and will only invest under specific criteria. We will continue to be selective when assessing opportunities. We will focus on producing greater results and value from existing assets by leveraging our current position. We will identify and pursue niche opportunities, where solid companies exist, which are under the radar of the big players. We will identify and capitalize on "broken" assets or companies where our intellectual capital will create value and we will evaluate opportunities with new and existing partners.

We have momentum and are ready, willing and able to capitalize on opportunities we see or create for ourselves. I would like to acknowledge the important role our Board of Directors plays in our operational success and strong corporate governance. Each director brings specific industry expertise and significant experience to our Board. I am pleased to welcome two new directors to our board. Don Pether and Jackie Sheppard are tremendous additions and will provide invaluable guidance through these challenging times. Derek Oland steps down as Chair of the Board this year. Mr. Oland, who has served as Chair since 1998, will continue as a Director of both the Emera and NSPI Boards until his retirement in 2010. I personally would like to thank Derek for his guidance and leadership on both Boards and look forward to continuing to work with him over the next year.

I would also like to thank Ralph Tedesco for his leadership of Nova Scotia Power. Ralph retired this past year after five years at NSPI. I look forward to working with him again on other projects.

Finally, I would like to thank our more than 2,500 employees for their continued commitment to our company. That commitment is a key reason for our continued success.

OPPORTUNITY AHEAD

We are optimistic about the array of opportunities for Emera and its subsidiaries this year and in the years ahead. We will focus on transmission development, renewable investment, emissions reduction and expansion in the Caribbean to build our business and increase the value we provide to you, our shareholders.

Respectfully yours,

Christopher Huskilson

Chris Huskilson
President and Chief Executive Officer

MANAGEMENT'S DISCUSSION AND ANALYSIS

AS AT FEBRUARY 13, 2009

Management's Discussion and Analysis ("MD&A") provides a review of the results of operations of Emera Inc. and its primary subsidiaries and investments during the fourth quarter of 2008 relative to 2007, and the full year 2008 relative to 2007 and to 2006; and its financial position at December 31, 2008 relative to 2007. Certain factors that may affect future operations are also discussed. Such comments will be affected by, and may involve, known and unknown risks and uncertainties that may cause the actual results of the company to be materially different from those expressed or implied. Those risks and uncertainties include, but are not limited to, weather, commodity prices, interest rates, foreign exchange, regulatory requirements and general economic conditions. To enhance shareholders' understanding, certain multi-year historical financial and statistical information is presented.

This discussion and analysis should be read in conjunction with the Emera Inc. annual audited consolidated financial statements and supporting notes. Emera follows Canadian Generally Accepted Accounting Principles ("GAAP"). Emera's wholly-owned subsidiary, Nova Scotia Power Inc.'s accounting policies are subject to examination and approval by the Nova Scotia Utility and Review Board ("UARB"). Emera's wholly-owned subsidiary, Bangor Hydro-Electric Company's accounting policies are subject to examination and approval by the Maine Public Utilities Commission ("MPUC") and the Federal Energy Regulatory Commission ("FERC"). The accounting policies of Nova Scotia Power Inc. and Bangor Hydro-Electric Company may differ from GAAP for non rate-regulated companies.

Throughout this discussion, "Emera Inc." and "Emera" refer to Emera Inc. and all of its consolidated subsidiaries and affiliates.

All amounts are in Canadian dollars ("CAD") except for the Bangor Hydro-Electric Company section of the MD&A, which is reported in US dollars ("USD") unless otherwise stated.

Additional information related to Emera, including the company's Annual Information Form, can be found on SEDAR at **www.sedar.com**.

Consolidated Financial Highlights

	THREE MONTHS ENDED DECEMBER 31		YEAR ENDED DECEMBER 31		
MILLIONS OF DOLLARS (EXCEPT EARNINGS PER COMMON SHARE)	**2008**	2007	**2008**	2007	2006
Revenues	**$ 337.3**	$ 343.9	**$ 1,331.9**	$ 1,339.5	$ 1,166.0
Consolidated net earnings	**25.3**	36.6	**144.1**	151.3	125.8
Earnings per common share – basic	**0.23**	0.33	**1.29**	1.36	1.14
Earnings per common share – fully diluted	**0.22**	0.32	**1.26**	1.32	1.12
Cash dividends declared per share	**0.2525**	0.2275	**0.97**	0.90	0.89

	THREE MONTHS ENDED DECEMBER 31		YEAR ENDED DECEMBER 31		
OPERATING UNIT CONTRIBUTIONS	**2008**	2007	**2008**	2007	2006
Nova Scotia Power	**$ 14.4**	$ 25.2	**$ 105.6**	$ 100.2	$ 104.3
Bangor Hydro Electric	**6.6**	6.7	**23.1**	27.5	16.8
Other	**4.3**	4.7	**15.4**	23.6	4.7
Consolidated net earnings	**$ 25.3**	$ 36.6	**$ 144.1**	$ 151.3	$ 125.8
Earnings per common share – basic	**$ 0.23**	$ 0.33	**$ 1.29**	$ 1.36	$ 1.14
Earnings per common share – basic, absent the Bear Swamp after-tax mark-to-market adjustment	**$ 0.26**	$ 0.30	**$ 1.33**	$ 1.28	$ 1.14

	AS AT DECEMBER 31		
	2008	2007	2006
Total assets	**$ 5,269.4**	$ 4,221.1	$ 4,049.0
Total long-term liabilities	**2,843.1**	2,354.7	2,149.9

INTRODUCTION AND STRATEGIC OVERVIEW

Emera is a Canadian energy holding company headquartered in Halifax, Nova Scotia. The company invests in electricity generation, transmission and distribution, as well as gas transmission and energy marketing.

Most of Emera's revenues are earned by its two wholly-owned regulated electric utilities which it owns and operates in Northeastern North America. Nova Scotia Power Inc. ("NSPI") is an electricity generation, transmission and distribution company with $3.5 billion of assets providing service to 482,000 customers in the province of Nova Scotia, and Bangor Hydro-Electric Company ("BHE") is an electricity transmission and distribution company with $783 million of assets serving 117,000 customers in eastern Maine. Both businesses operate as monopolies in their service territories, and together comprise approximately 90% of Emera's consolidated revenues. The success of Emera's electric utilities is integral to the creation of shareholder value, providing substantial earnings and cash flow to fund dividends and reinvestment. The essential nature of the services provided, the monopoly positions, and the regulated market structures mean that NSPI and BHE can generally be expected to produce stable earnings streams within regulated ranges. Nova Scotia and Maine are mature electricity markets, with annual demand growth of approximately 1%. Accordingly, Emera looks beyond its existing regulated electricity business to supplement organic growth.

Emera's goal is to deliver annual consolidated earnings growth of 4% – 6%, and build and diversify its earnings base. To accomplish this, Emera will continue to seek growth from its existing businesses and will leverage its core strength in the electricity business, as it pursues both acquisitions and greenfield development opportunities in regulated electricity transmission and distribution and low risk generation. Emera's growth strategy also includes serving the United States' market by capitalizing on opportunities in related energy infrastructure businesses appropriate to its risk profile, where its development, commercial and operational skills are needed.

Emera is growing its business through the following investments:

- Bear Swamp, a 50/50 joint venture in a 600 megawatt pumped storage hydro-electric facility in northern Massachusetts.
- Brunswick Pipeline, a 145 kilometre pipeline that delivers natural gas from the Canaport™ Liquefied Natural Gas import terminal near Saint John, New Brunswick, to markets in Canada and the northeastern United States. The pipeline was mechanically complete, and received National Energy Board approval for shipping gas in January 2009. This accommodates the needs and schedule of the customer, Repsol, and the timing of completing the Canaport™ LNG terminal, expected in Q2 2009.
- A 12.9% interest in the $2 billion, 1,400 kilometre Maritimes & Northeast Pipeline ("M&NP") that transports Nova Scotia's offshore natural gas to markets in Maritime Canada and the northeastern United States.
- Emera Energy Services, a physical energy business which purchases and sells natural gas and electricity and provides related energy asset management services.
- A 19% interest in St. Lucia Electricity Services Limited ("Lucelec"), a vertically integrated electric utility on the Caribbean Island of St. Lucia, which was acquired in January 2007.
- A 25% indirect interest in Grand Bahama Power Company Limited ("GBPC"), a vertically integrated electric utility on Grand Bahama Island, which was acquired in September 2008.
- A 7.35% interest in OpenHydro Group Limited ("OpenHydro"), an Irish renewable energy company, which was acquired in February 2008.

Investment in Grand Bahama Power Company Limited

In September 2008, Emera indirectly purchased 25% of GBPC for $42.3 million USD ($45.3 million CAD) through its acquisition of 50% of the shares of ICD Utilities Limited ("ICDU") of the Bahamas. ICDU owns 50% of the shares of GBPC.

GBPC has 137 megawatts of installed oil-fired generating capacity. The Grand Bahama Port Authority Limited regulates the utility and has granted GBPC a licensed, regulated and exclusive franchise to produce, transmit, and distribute electricity on the island until 2054. There is a fuel pass through mechanism and flexible tariff adjustment policies to ensure that costs are recovered and a reasonable return is earned.

Emera financed the acquisition with existing credit facilities. GBPC is expected to add $2.5 million USD to $5.0 million USD to Emera's annual consolidated net earnings.

Consolidated Net Earnings History

(MILLIONS OF DOLLARS)	*2008*	*2007*	*2006*	*2005*	*2004*	*2003*
Net earnings applicable to common shares	**$ 144.1**	$ 151.3	$ 125.8	$ 121.2	$ 129.8	$ 129.2
Net earnings applicable to common shares, absent the Bear Swamp after-tax mark-to-market adjustment	**$ 148.9**	$ 141.9	$ 125.8	$ 121.2	$ 129.8	$ 129.2

Earnings per Share History

(DOLLARS)	*2008*	*2007*	*2006*	*2005*	*2004*	*2003*
Earnings per share	**$ 1.29**	$ 1.36	$ 1.14	$ 1.11	$ 1.20	$ 1.20
Earnings per share, absent the Bear Swamp after-tax mark-to-market adjustment	**$ 1.33**	$ 1.28	$ 1.14	$ 1.11	$ 1.20	$ 1.20

STRUCTURE OF MD&A

This Management's Discussion and Analysis begins with an overview of consolidated results; then presents information on the company's two primary subsidiaries, NSPI and BHE. All other operations, including Bear Swamp, Brunswick Pipeline, M&NP, Emera Energy Services, Lucelec, GBPC, OpenHydro and corporate activities are grouped and discussed as "Other". Significant changes in the consolidated balance sheets, outstanding share data, liquidity and capital resources, financial and commodity instruments, transactions with related parties, disclosure and internal controls, critical accounting estimates, changes in accounting policies, dividend policy and payout ratios, business risks and enterprise risk management, and selected quarterly trend information are presented on a consolidated basis.

Consolidated Statements of Earnings

MILLIONS OF DOLLARS (EXCEPT EARNINGS PER COMMON SHARE)	THREE MONTHS ENDED DECEMBER 31 2008	2007	YEAR ENDED DECEMBER 31 2008	2007	2006
Electric revenue	**$ 330.6**	$ 322.0	**$ 1,280.8**	$ 1,269.5	$ 1,132.0
Other revenue	**6.7**	21.9	**51.1**	70.0	34.0
	337.3	343.9	**1,331.9**	1,339.5	1,166.0
Fuel for generation and purchased power	**154.0**	124.0	**525.1**	494.5	347.7
Operating, maintenance and general	**71.0**	71.5	**266.8**	264.8	255.6
Provincial, state, and municipal taxes	**12.2**	11.4	**49.4**	47.5	48.0
Depreciation	**39.0**	38.1	**151.3**	149.3	145.2
Regulatory amortization	**9.5**	7.8	**28.5**	31.4	22.8
	51.6	91.1	**310.8**	352.0	346.7
Financing charges	**24.8**	27.9	**123.2**	133.2	148.1
Equity earnings	**6.1**	3.5	**15.2**	12.8	4.9
Other income	**–**	–	**–**	–	8.9
Earnings before income taxes	**32.9**	66.7	**202.8**	231.6	212.4
Income taxes	**7.0**	30.1	**58.1**	80.3	86.6
Net earnings	**25.9**	36.6	**144.7**	151.3	125.8
Non-controlling interest	**0.6**	–	**0.6**	–	–
Net earnings applicable to common shares	**$ 25.3**	$ 36.6	**$ 144.1**	$ 151.3	$ 125.8
Earnings per common share – basic	**$ 0.23**	$ 0.33	**$ 1.29**	$ 1.36	$ 1.14
Earnings per common share – diluted	**$ 0.22**	$ 0.32	**$ 1.26**	$ 1.32	$ 1.12

REVIEW OF 2008

Emera Inc.'s consolidated earnings decreased $11.3 million to $25.3 million in Q4 2008 compared to $36.6 million for the same period in 2007. Emera's annual consolidated earnings decreased $7.2 million to $144.1 million in 2008 compared to $151.3 million in 2007, and were $125.8 million in 2006. Highlights of the changes are summarized in the following table:

MILLIONS OF DOLLARS	THREE MONTHS ENDED DECEMBER 31	YEAR ENDED DECEMBER 31
Consolidated net earnings – 2006		**$ 125.8**
Decreased net earnings in NSPI due to increased fuel expense, a new regulatory amortization and decreased other income; partially offset by increased revenue and an income tax refund and related interest recovery		(4.1)
Increased net earnings in Bangor Hydro due to increased revenue and capitalized costs associated with the NRI transmission project; partially offset by increased income taxes and the effect of the stronger Canadian dollar		10.7
Increased net earnings in Other due mainly to Bear Swamp's increased energy and capacity sales and a favourable price position; and M&NP's capitalization of prior years' expansion costs in Q1 2007 and increased equity earnings due to increased tolls and volume		18.9
Consolidated net earnings – 2007	**$ 36.6**	**151.3**
Q4 decreased net earnings in NSPI due to increased fuel expense partially offset by lower income taxes; year-to-date increase is due to an electricity price increase on April 1, 2007, decreased financing charges and accelerated income tax deductions, partially offset by increased fuel expense	(10.8)	5.4
Decreased net earnings in Bangor Hydro due mainly to the capitalization of costs associated with the NRI transmission line in 2007	(0.1)	(4.4)
Increased net earnings in Other due mainly to allowance for funds used during construction ("AFUDC") on construction of the Brunswick Pipeline, partially offset by increased interest on short-term debt used to finance the construction of the pipeline. Increased year-to-date earnings also reflect Bear Swamp's increased year-to-date energy and forward reserve sales	6.7	6.0
Decreased net earnings in Other related to the after-tax mark-to-market adjustment on the commodity price position in Bear Swamp as discussed in Significant Items	(7.1)	(14.2)
Consolidated net earnings – 2008	**$ 25.3**	**$ 144.1**

Q4 basic earnings per share were $0.23 in 2008 compared to $0.33 in 2007; and $1.29 for the full year 2008 compared to $1.36 in 2007 and $1.14 in 2006.

SIGNIFICANT ITEMS

BEAR SWAMP (2007 – 2008)

As part of its long-term energy and capacity supply agreement with the Long Island Power Authority ("LIPA"), Bear Swamp has contracted with its parents to provide the power necessary to produce the energy requirements of the LIPA contract. One of the contracts between Bear Swamp and Emera's joint venture partner is marked-to-market through earnings, as it does not meet the stringent accounting requirements of hedge accounting. As at December 31, 2008, the fair value of the net derivative asset was $4.9 million (December 31, 2007 – $10.5 million), which is subject to market volatility of power prices, and will reverse over the life of the agreement as it is realized. The agreement expires in 2021.

The mark-to-market adjustments relating to this position were as follows:

	THREE MONTHS ENDED DECEMBER 31		YEAR ENDED DECEMBER 31	
MILLIONS OF DOLLARS (EXCEPT EARNINGS PER COMMON SHARE)	*2008*	*2007*	*2008*	*2007*
Mark-to-market (loss) gain	**$ (6.0)**	$ 5.9	**$ (8.1)**	$ 15.7
After-tax mark-to-market (loss) gain	**$ (3.6)**	$ 3.5	**$ (4.8)**	$ 9.4
Earnings per common share – basic	**$ 0.23**	$ 0.33	**$ 1.29**	$ 1.36
Earnings per common share – basic, absent the after-tax mark-to-market adjustment	**$ 0.26**	$ 0.30	**$ 1.33**	$ 1.28

INCOME TAX RECOVERY (2007 – 2008)

During 2008, NSPI accelerated the deduction of capitalized expenses pertaining to the 2007 tax year. As a result, in 2008 NSPI recorded an income tax recovery of $6.5 million. NSPI will continue to use this methodology in current and future years.

During 2007, NSPI filed amended tax returns for 2000 to 2004 related to the deductibility of previously capitalized overhead expenses. Canada Revenue Agency ("CRA") audited and approved the amended filings for these years. In 2008, NSPI amended its 2005 and 2006 tax returns on the same basis as was used for the 2000 to 2004 years. The amendments have since been processed by CRA. All material amounts relating to these prior year adjustments were recorded in the 2007 financial statements of NSPI. This resulted in an income tax recovery of $25.4 million in Q3 2007, of which $14.6 million was recorded as a reduction of other assets and the remaining $10.8 million was recorded as a reduction of income tax expense. In addition, in Q4 2007, NSPI recorded a refund interest of $8.6 million, $1.8 million of which was recorded as a reduction of other assets and the remaining $6.8 million was recorded as a reduction of financing charges. NSPI used this methodology in filing its 2007 return and will continue to use this methodology when filing its 2008 and future income tax returns.

SETTLEMENT OF CLAIM (2006)

In late 2005, a number of NSPI's petroleum coke suppliers were unable to supply fuel due to hurricanes in the Gulf of Mexico, which seriously affected their operations. As a result, NSPI incurred additional costs for replacement fuel and other expenses, which were included in Q4 2005 fuel expense. NSPI filed a claim with its insurers to recover applicable costs. In Q4 2006, NSPI received $8.9 million ($5.5 million after-tax) in settlement of this claim.

NOVA SCOTIA POWER INC.

OVERVIEW

NSPI is the primary electricity supplier in Nova Scotia, providing over 95% of electricity generation, transmission and distribution in the province. The company owns 2,293 megawatts ("MW") of generating capacity. Approximately 53% is coal-fired; natural gas and/or oil together comprise another 29% of capacity; and hydro and wind production provide 18%. In addition, NSPI has 85 MW of renewable energy, substantially wind energy, under contracts with independent power producers. During 2008, NSPI signed power purchase agreements for 246 MW of new wind energy sources with seven independent power producers. NSPI also owns approximately 5,000 kilometres of transmission facilities, and 26,000 kilometres of distribution facilities. The company has a workforce of approximately 1,800 people.

NSPI is a public utility as defined in the Public Utilities Act (Nova Scotia) and is subject to regulation under the Act by the UARB. The Act gives the UARB supervisory powers over NSPI's operations and expenditures. Electricity rates for NSPI's customers are also subject to UARB approval. The company is not subject to an annual rate review process, but rather participates in hearings from time to time at the company's or the regulator's request.

NSPI is regulated under a cost of service model, with rates set to recover prudently incurred costs of providing electricity service to customers, and provide an appropriate return to investors. NSPI's return on equity ("ROE") range for 2008 was 9.3% – 9.8%, on a maximum allowed common equity component of 40% of total capitalization. Rates were set for 2009 using a 9.35% ROE, with a common equity component of 37.5%. The ROE range for 2009 is 9.1% – 9.6% on a maximum allowed common equity component of 45% of total capitalization.

Appointment

On December 1, 2008, NSPI announced plans that George Caines will become Chair of the Board of Directors of NSPI, effective May 6, 2009. Mr. Caines will take over from John McLennan, who will replace Derek Oland as Chair of the Board of Emera Inc.

2009 Rate Decision

In May 2008, NSPI filed a rate application with the UARB requesting an overall rate increase of 11.9% effective January 1, 2009. In September 2008, NSPI reached a settlement agreement with stakeholders regarding that rate application. The UARB approved that settlement agreement in November 2008 which includes an average rate increase of 9.4% for most customer segments effective January 1, 2009. The approved settlement agreement also includes a Fuel Adjustment Mechanism ("FAM") effective January 1, 2009 with the first rate adjustment under the FAM occurring on January 1, 2010. The UARB will oversee the FAM, including review of fuel costs, contracts and transactions. With the implementation of the FAM, NSPI's ROE range will be reduced to 9.1% – 9.6% with 9.35% used to set rates.

2007 Cash Flow Highlights

During Q4 2007, NSPI had two significant cash receipts. NSPI received $87.6 million USD for the November 2004 to October 2007 price adjustment rebate on an existing long-term natural gas purchase agreement. The final three-year settlement will be received in November 2010 for the November 2007 to October 2010 price adjustment rebate. In addition, NSPI received $34.0 million in cash related to the income tax recovery discussed in Significant Items.

2007 Rate Decision

In February 2007, the UARB approved an average increase in electricity rates of 3.8% effective April 1, 2007. The rate increase was part of a first-ever rate settlement agreement between NSPI and key stakeholders. NSPI's ROE range was unchanged at 9.3% to 9.8%.

2006 Rate Decision

The UARB granted NSPI an average rate increase of approximately 8.7% effective March 10, 2006. The UARB noted improvements NSPI had made in fuel procurement, but determined that a previous finding related to 2002 and 2003 fuel procurement carried over into 2006, resulting in a $15.7 million disallowance for 2006. The UARB noted that this would be the final disallowance related to this issue.

REVIEW OF 2008

NSPI Net Earnings

	THREE MONTHS ENDED DECEMBER 31		YEAR ENDED DECEMBER 31		
MILLIONS OF DOLLARS (EXCEPT EARNINGS PER COMMON SHARE)	*2008*	*2007*	*2008*	*2007*	*2006*
Electric revenue	**$ 280.7**	$ 283.1	**$ 1,111.1**	$ 1,102.0	$ 967.9
Fuel for generation and purchased power	**139.5**	110.3	**471.4**	433.7	292.8
Operating, maintenance and general	**52.3**	55.3	**203.7**	206.0	202.5
Provincial grants and taxes	**10.3**	10.1	**41.2**	40.4	40.3
Depreciation	**33.8**	33.1	**133.6**	131.1	127.8
Regulatory amortization	**6.4**	4.5	**17.7**	17.2	8.6
Other revenue	**(3.5)**	(3.7)	**(15.5)**	(11.7)	(9.6)
	41.9	73.5	**259.0**	285.3	305.5
Financing charges	**20.3**	24.7	**106.8**	123.0	130.6
Other income	**–**	–	**–**	–	(8.9)
Earnings before income taxes	**21.6**	48.8	**152.2**	162.3	183.8
Income taxes	**7.2**	23.6	**46.6**	62.1	79.5
Contribution to consolidated net earnings	**$ 14.4**	$ 25.2	**$ 105.6**	$ 100.2	$ 104.3
Contribution to consolidated earnings per common share	**$ 0.12**	$ 0.23	**$ 0.94**	$ 0.90	$ 0.94

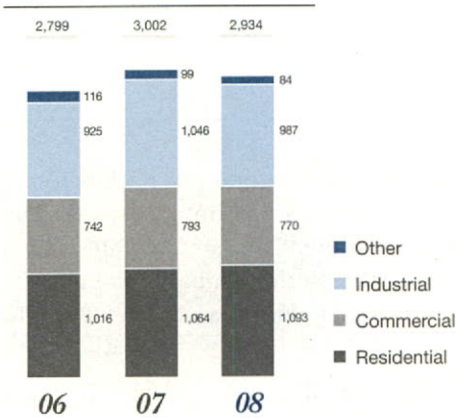
NSPI's contribution to consolidated net earnings decreased $10.8 million to $14.4 million in Q4 2008, compared to $25.2 million in Q4 2007. Annual contribution to consolidated net earnings increased $5.4 million to $105.6 million in 2008 compared to $100.2 million in 2007, and was $104.3 million in 2006. Highlights of the earnings changes are summarized in the following table:

MILLIONS OF DOLLARS	THREE MONTHS ENDED DECEMBER 31	YEAR ENDED DECEMBER 31
Contribution to consolidated net earnings – 2006		**$ 104.3**
Increased electric revenue due to electricity price increases on March 10, 2006 and April 1, 2007, higher industrial sales volume, and colder weather partially offset by lower export sales volume		134.1
Increased fuel expense		(140.9)
Increased operating expenses mainly due to increased storm related costs		(3.5)
Increased regulatory amortization due to the start of a new regulatory amortization on April 1, 2007		(8.6)
Decreased other income		(8.9)
Decreased financing charges mainly due to income tax recovery interest		7.6
Decreased income taxes due to an income tax recovery		10.8
Decreased income taxes due to lower taxable income		6.6
All other		(1.3)
Contribution to consolidated net earnings – 2007	**$ 25.2**	**100.2**
Decreased electric revenue in Q4 due to decreased commercial and industrial sales volume; year-to-date increased electric revenue due to an electricity price increase on April 1, 2007	(2.4)	9.1
Increased fuel expense	(29.2)	(37.7)
Decreased financing charges due to foreign exchange gains on USD denominated monetary net assets compared to foreign exchange losses in 2007; and lower interest costs	4.4	16.2
Decreased income taxes due to lower taxable income, accelerated deductions for capital items and a lower statutory rate	16.4	15.5
Other	–	2.3
Contribution to consolidated net earnings – 2008	**$ 14.4**	**$ 105.6**

ELECTRIC REVENUE

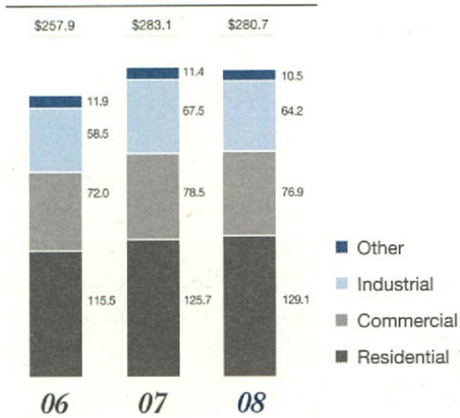
Q4 Electric Sales Volume

Gigawatt hours ("GWh")



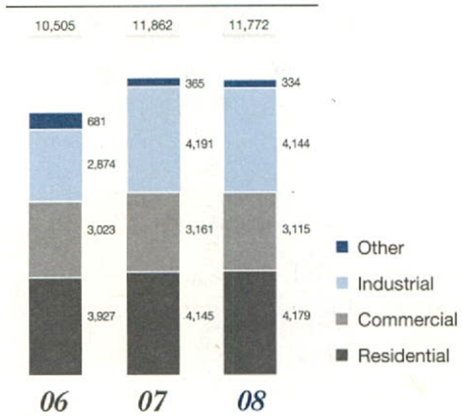
Q4 Electric Sales Revenues

MILLIONS OF DOLLARS



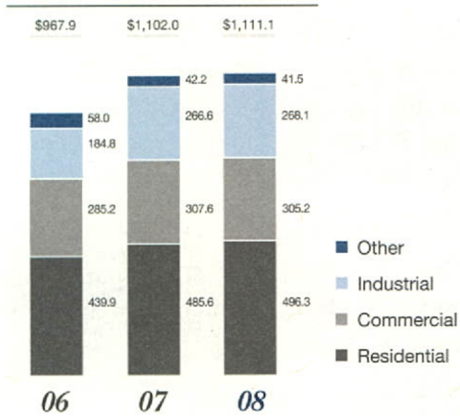
Year-to-Date ("YTD") Electric Sales Volume

GWh



YTD Electric Sales Revenues

MILLIONS OF DOLLARS



Q4 Average Revenue / Megawatt hour ("MWh")

	2008	*2007*	*2006*
Dollars per MWh	**$ 96**	$ 94	$ 92

YTD Average Revenue / MWh

	2008	*2007*	*2006*
Dollars per MWh	**$ 94**	$ 93	$ 92

Electric sales volume is primarily driven by general economic conditions, population and weather. Electricity pricing in Nova Scotia is regulated and therefore only changes when new regulatory decisions are implemented. The exceptions are annually adjusted rates, subscribed to by certain larger industrial customers, and export sales which in recent years comprised less than 1% of NSPI sales volume and are priced at market. Residential and commercial electricity sales are seasonal, with Q1 and Q4 the strongest periods, reflecting colder weather, and fewer daylight hours in the winter season.

NSPI's residential load generally comprises individual homes, apartments and condominiums. Commercial customers include small retail operations, large office and commercial complexes, and the province's universities and hospitals. Industrial customers include manufacturing facilities and other large volume operations. Other electric consists of export sales, sales to municipal electric utilities and revenues from street lighting.

Electric revenues decreased by $2.4 million to $280.7 million in Q4 2008 compared to $283.1 million in Q4 2007 due to decreased commercial and industrial sales volume.

For the year ended December 31, 2008 electric revenues increased $9.1 million to $1,111.1 million compared to $1,102.0 million in 2007. Revenue increases are substantially due to a 3.8% rate increase effective April 1, 2007.

For the year ended December 31, 2007 electric revenues increased by $134.1 million to $1,102.0 million, compared to $967.9 million in 2006. Revenue increases are substantially due to the 8.7% rate increase effective March 10, 2006 and a 3.8% rate increase effective April 1, 2007 and increased sales volume due to a large industrial customer returning to operations in late 2006, and colder weather, partially offset by lower export sales.

The increase in average revenue per MWh in 2008 compared to 2007 reflects the April 1, 2007 rate increase noted above.

The average revenue per MWh is higher in 2007 compared to 2006 reflecting the two rate increases noted above, offset by a change in sales mix, specifically the increase in lower priced industrial sales due to the return to operations of a large industrial customer.

FUEL FOR GENERATION AND PURCHASED POWER

Capacity

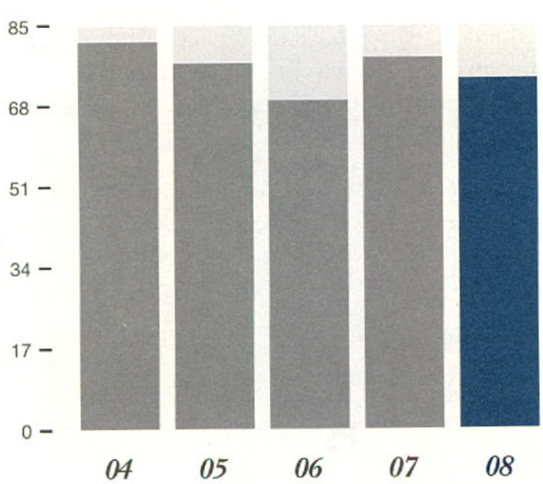
To ensure reliability of service, NSPI maintains a generating capacity greater than firm peak demand. The total company-owned generation capacity is 2,293 MW, which is supplemented by 85 MW contracted with independent power producers. NSPI meets the planning criteria for reserve capacity established by the Maritime Control Area, and the Northeast Power Coordinating Council.

Management of capacity and capacity utilization is a critical element of operating efficiency. The provision of sufficient generating capacity to meet peak demand inevitably results in excess capacity in non-peak periods, which allows for annual maintenance programs to be carried out without compromising reserve capacity requirements. NSPI's daily load is generally highest in the early evening; its seasonal load is highest through the winter months. Maximizing capacity utilization can have a positive effect on earnings, and helps defer significant investment in additional generation capacity. Maximizing capacity utilization primarily depends on:

- Ensuring generating plants are consistently available to service demand – NSPI conducts ongoing planned maintenance programs, and has sustained high availability over the past several years. NSPI maintains low forced and unplanned outage rates compared to North American averages.
- Moving demand from peak to non-peak periods – NSPI encourages customers to move some electricity demand from high cost to lower cost periods by offering customers various pricing alternatives. NSPI also controls over 400 MW of interruptible electric load; over 250 MW is supplied under real time or time of day rates.
- Export sales – Increasing export sales when margins are satisfactory allows energy from excess capacity to be sold when not required in the province. NSPI operates a 24-hour marketing desk to optimize commercial opportunities such as export sales.

NSPI Thermal Capacity Utilization

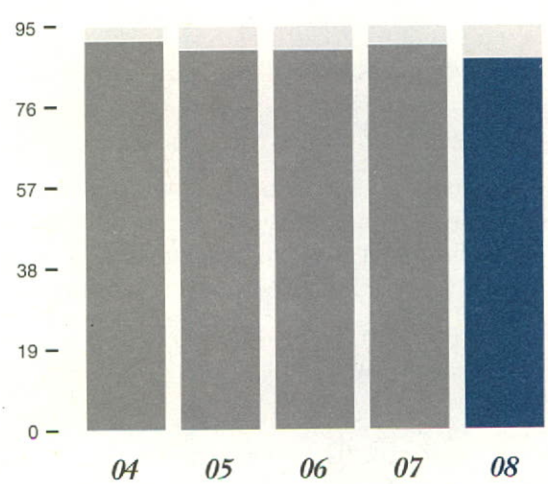
(PERCENT)



NSPI's thermal capacity utilization was 75% in 2008 compared to 79% in 2007. This was due to NSPI taking advantage of economic import energy as a result of lower marginal cost for energy in the northeastern United States during extended periods of warmer weather.

NSPI Thermal Capacity Availability

(PERCENT)

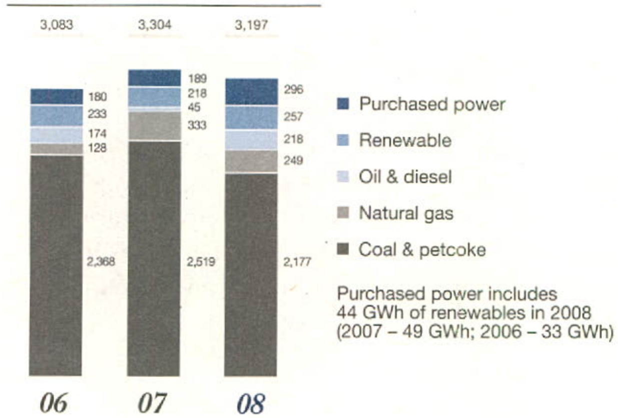


NSPI facilities continue to rank among the best in Canada on capacity related performance indicators. The high availability and capability of low cost thermal generating stations provide lower cost energy to customers. In 2008, coal plant availability was 88%. The decrease in availability from 2007 reflects extended maintenance periods. Sustained high availability and low forced outage rates on low cost facilities are good indicators of sound maintenance and investment practices.

FUEL EXPENSE

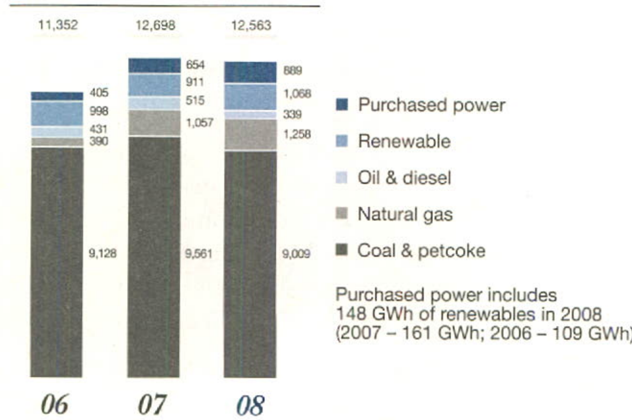
Q4 Production Volume

GWh



YTD Production Volume

GWh



Q4 Average Unit Fuel Costs

	2008	*2007*	*2006*
Dollars per MWh	**$ 44**	$ 33	$ 28

YTD Average Unit Fuel Costs

	2008	*2007*	*2006*
Dollars per MWh	**$ 38**	$ 34	$ 26

Solid fuel is NSPI's dominant fuel source, supplying approximately 72% of the company's annual energy. Solid fuels have the lowest per unit fuel cost, after hydro and NSPI owned wind production, which have no fuel cost component. Oil, natural gas, and purchased power are next, depending on the relative pricing of each. Economic dispatch of the generating fleet brings the lowest cost options on stream first, with the result that the incremental cost of production increases as sales volume increases.

The average unit fuel costs increased in 2008 compared to 2007 mainly due to the decreased value of the natural gas supply contract as reflected in the long-term receivable, and change in generation mix due to lower coal production due to an increase in coal plant maintenance. Increased coal prices were partially offset by the economic use of natural gas and favourable hedge positions as a result of this fuel switch.

The average unit fuel costs increased in 2007 compared to 2006 mainly due to the use of higher marginal cost production because of increased load.

A substantial amount of NSPI's fuel supply comes from international suppliers, and is subject to commodity price and foreign exchange risk. The company manages exposure to commodity price risk utilizing a portfolio strategy, combining physical fixed-price fuel contracts and financial instruments providing fixed or maximum prices. Foreign exchange risk is managed through forward and option contracts. Further details on the company's fuel cost risk management strategies are included in the Business Risks and Enterprise Risk Management section. Fuel contracts may be exposed to broader global conditions which may include impacts on delivery reliability and price, despite contracted terms.

For the three months ended December 31, 2008, fuel for generation and purchased power increased $29.2 million to

$139.5 million, compared to $110.3 million in Q4 2007. For the year ended December 31, 2008, fuel for generation and purchased power increased $37.7 million to $471.4 million compared to $433.7 million in 2007 and $292.8 million in 2006. Highlights of the changes are summarized in the following table:

MILLIONS OF DOLLARS	THREE MONTHS ENDED DECEMBER 31	YEAR ENDED DECEMBER 31
Fuel for generation and purchased power – 2006		**$ 292.8**
Increased sales volume due to the return to operation of a large industrial customer that had been shut-down for most of 2006, colder weather, and generation mix		103.6
Commodity price increases		6.6
Decreased net proceeds from the resale of natural gas due to the economic decision to use natural gas in the production process		48.6
Decreased export sales volume		(12.4)
All other		(5.5)
Fuel for generation and purchased power – 2007	**$ 110.3**	**433.7**
Increased commodity prices in Q4 primarily due to increased coal and natural gas prices; year-to-date the increase in coal prices was partially offset by the economic use of natural gas and favourable hedge positions as a result of this fuel switch	16.9	18.3
Decreased sales volume	(7.4)	(9.9)
Decreased net proceeds from the resale of natural gas due to the economic decision to use natural gas in the production process	6.6	8.8
Increased hydro production	(3.0)	(11.9)
Changes in generation mix due to increased coal plant maintenance	16.1	30.7
Other	–	1.7
Fuel for generation and purchased power – 2008	**$ 139.5**	**$ 471.4**

The valuation of the long-term receivable from a natural gas supplier requires NSPI to utilize a combination of historical and future natural gas prices. NSPI uses market-based forward indices when determining future prices. Future prices can change from period to period which will cause a corresponding change in the value of the long-term receivable.

Operating, Maintenance and General

Operating, maintenance and general expenses have remained relatively unchanged over the three year period.

Provincial Grants and Taxes

NSPI pays annual grants to the Province of Nova Scotia in lieu of municipal taxation other than deed transfer tax.

Depreciation

Depreciation expense increased slightly over the three-year period due to plant additions.

In its November 5, 2008 rate decision, the UARB approved a scheduled year-three phase-in of the previously approved increased depreciation rates commencing January 1, 2009.

Regulatory Amortization

Regulatory amortization increased $1.9 million to $6.4 million in Q4 2008 compared to $4.5 million in Q4 2007 due to additional amortization of the pre-2003 income taxes partially offset by the completion of Glace Bay generating station amortization in 2007.

For the year ended December 31, 2008 regulatory amortization increased $0.5 million to $17.7 million compared to $17.2 million in 2007 for the reasons noted above.

For the year ended December 31, 2007 regulatory amortization increased $8.6 million to $17.2 million compared to $8.6 million in 2006 due to the amortization of pre-2003 income taxes beginning in April 2007 partially offset by the completion of the Glace Bay generating station amortization in 2007.

Other Revenue

Other revenue has increased over the three year period due to settlements received and a reduction in the accounts receivable securitization program which resulted in lower fees.

Financing Charges

Financing charges decreased $4.4 million to $20.3 million in Q4 2008 compared to $24.7 million in Q4 2007, and decreased $16.2 million to $106.8 million for the year ended December 31, 2008 compared to $123.0 million in 2007 primarily due to foreign exchange gains in 2008 partially offset by income tax recovery interest in 2007.

Financing charges decreased $7.6 million to $123.0 million for the year ended December 31, 2007 compared to $130.6 million in 2006 primarily due to the income tax recovery interest as discussed below. As discussed in Significant Items, in Q4 2007 NSPI recorded income tax refund interest of $8.6 million, $1.8 million of which has been recorded as a reduction of other assets. The remaining $6.8 million has been recorded as a reduction of financing charges.

The company manages exposure to interest rate risk through a combination of fixed and floating borrowing, and hedging. Interest rate caps are the principal instrument used to hedge interest rate risk.

Other Income

In Q4 2006, Nova Scotia Power received an $8.9 million insurance settlement on a petcoke supply interruption claim.

Income Taxes

In accordance with ratemaking regulations established by the UARB, NSPI uses the taxes-payable method of accounting for income taxes.

In 2008, NSPI was subject to provincial capital tax (0.2125%), corporate income tax (35.5%) and Part VI.1 tax relating to preferred dividends (40%). NSPI also receives a reduction in its corporate income tax otherwise payable related to the Part VI.1 tax deduction (42.6% of preferred dividends).

As discussed in Significant Items, during 2008, NSPI accelerated the deduction of capitalized expenses pertaining to the 2007 tax year. As a result, in 2008 NSPI recorded an income tax recovery of $6.5 million. In Q3 2007 NSPI recorded an income tax recovery of $25.4 million, of which $14.6 million was recorded as a reduction of other assets. The remaining $10.8 million was recorded as a reduction of income tax expense.

Outlook

Based on the 2009 rate decision and the current economic forecast for Nova Scotia, NSPI expects to earn within its ROE range in 2009.

Debt Management

NSPI has established the following available credit facilities:

Short-term

MILLIONS OF DOLLARS	MATURITY	MAXIMUM AMOUNT
Operating credit facility	1 Year Revolving	$ 500.0

In July 2008, medium term note series "O", 5.65%, $115 million matured.

In December 2008, NSPI issued a $150 million medium term note. This note was issued under a reopening of Series "T", 5.75%, originally issued in September 2003. This $150 million issue yields 6.238% and will mature in October 2013. In January 2009, NSPI issued an additional $50 million medium term note under an additional reopening of Series "T", yielding 5.455%. This additional issue also matures in October 2013. The proceeds of both issues were used to pay down short-term borrowings, incurred for general corporate purposes.

There were no long-term debt issuances or maturities in 2007 and 2006.

The weighted average coupon rate on NSPI's outstanding medium-term and debenture notes at December 31, 2008, was 6.84% (2007 – 6.86%). Approximately 39% of the debt matures over the next ten years; 57% matures between 2018 and 2037; and $50 million, or 4%, matures in 2097. The quoted market weighted average interest rate for the same or similar issues of the same remaining maturities was 6.12% as of December 31, 2008 (2007 – 5.34%).

NSPI has the following credit ratings:

	DBRS	S&P	MOODY'S
Corporate	N/A	BBB	Baa1
Senior unsecured debt	A (low)	BBB	Baa1
Preferred stock	Pfd–2 (low)	P–3 (high)	N/A
Commercial paper	R–1 (low)	A–2 (Cdn)	P–2

In November 2008, Standard & Poor's ("S&P") Rating Services revised its rating outlook on Nova Scotia Power to Positive from Stable. At the same time, S&P confirmed NSPI's other ratings. The outlook revision reflects the recent regulatory approval of a FAM.

In August 2008, Moody's Investors Service ("Moody's") confirmed the credit ratings of Nova Scotia Power and revised the rating outlook from negative to stable. The revision reflects Moody's view that NSPI has been successful in improving its relationships with key stakeholders and the UARB. Moody's also expects that NSPI's exposure to regulatory risk will be reduced and that there is less likelihood of variability in NSPI's financial results following implementation of the FAM in January 2009.

BANGOR HYDRO-ELECTRIC COMPANY

ALL AMOUNTS IN THE BHE SECTION ARE REPORTED IN US DOLLARS UNLESS OTHERWISE STATED.

OVERVIEW

BHE's core business is the transmission and distribution ("T&D") of electricity. BHE is the second largest electric utility in Maine. Electricity generation is deregulated in Maine, and several suppliers compete to provide customers with the commodity that is delivered through the BHE T&D network. BHE owns and operates approximately 1,100 kilometres of transmission facilities, and 7,000 kilometres of distribution facilities. BHE has recently invested approximately $141 million in the Northeast Reliability Interconnect ("NRI"), an international electricity transmission line connecting New Brunswick to Maine which went into service in Q4 2007, and currently has approximately $100 million of additional transmission development in progress. BHE has a workforce of approximately 260 people.

In addition to T&D assets, BHE has net "regulatory" assets (stranded costs), which arose through the restructuring of the electricity industry in the state in the late 1990s; and as a result of rate and accounting orders issued by its regulator. BHE's net regulatory assets primarily include the costs associated with the restructuring of an above-market power purchase contract; and the unamortized portion on its loss on the sale of its investment in the Seabrook nuclear facility. Unlike T&D operational assets, which are generally sustained with new investment, the regulatory asset pool diminishes over time, as elements are amortized through charges to earnings, and recovered through rates. These regulatory assets total approximately $55.2 million at December 31, 2008, or 8% of BHE's net asset base.

Approximately 60% of BHE's electric rate represents distribution service, 20% relates to stranded cost recoveries, and 20% to transmission service. The rates for each element are established in distinct regulatory proceedings. BHE's distribution operations and stranded costs are regulated by the Maine Public Utilities Commission ("MPUC"). The transmission operations are regulated by the Federal Energy Regulatory Commission ("FERC").

BHE operates under a traditional cost-of-service regulatory structure. In December 2007, the MPUC approved an increase of approximately 2% in distribution rates effective January 1, 2008. The allowed ROE used in setting the new distribution rates is 10.2%, with a common equity component of 50%.

Until December 31, 2007, BHE's distribution service operated under an Alternate Rate Plan ("ARP"), which provided for an ROE range of 5% to 17% on distribution operations, with rates set at the midpoint of 11%. There was a 50/50 sharing mechanism between the company and customers outside of the earnings band. The ARP also included performance standards and provided for average annual reductions in distribution rates of approximately 2.5% for five years, to 2007. Beginning January 1, 2008, the earnings band and associated sharing mechanism, performance standard, and annual distribution rate reductions are no longer applicable.

BHE's stranded cost rates provide for an allowed ROE of 10% on the related asset base for the three-year period ending February 29, 2008. In December 2007 the MPUC issued an order approving an approximate 39% reduction in stranded cost rates for the three-year period beginning March 1, 2008. The allowed ROE used in setting the new stranded cost rates is 8.5%.

Transmission rates are set by the FERC annually on July 1, based on the prior year's revenue requirement. The allowed ROE for transmission operations ranges from 11.14% for low voltage transmission up to 12.64% for high voltage transmission developed as a result of the regional system plan, which includes the NRI transmission line.

REVIEW OF 2008

BHE Net Earnings

MILLIONS OF DOLLARS (EXCEPT EARNINGS PER COMMON SHARE)	THREE MONTHS ENDED DECEMBER 31		YEAR ENDED DECEMBER 31		
	2008	2007	**2008**	2007	2006
T&D revenues	**$ 25.9**	$ 25.9	**$ 97.6**	$ 101.7	$ 101.8
Resale of purchased power	**5.4**	3.7	**20.4**	14.6	15.2
Transmission pool revenue	**3.2**	4.5	**16.5**	12.7	–
Total revenue	**34.5**	34.1	**134.5**	129.0	117.0
Fuel for generation and purchased power	**8.1**	8.3	**32.2**	31.9	31.4
Operating, maintenance and general	**7.8**	8.0	**28.8**	26.3	27.1
Property taxes	**1.3**	0.8	**5.4**	4.8	5.0
Depreciation	**3.9**	3.2	**15.3**	13.0	12.9
Regulatory amortization	**2.6**	3.2	**10.1**	13.2	12.6
Other	**(0.7)**	(0.8)	**(3.8)**	(2.1)	(2.2)
Earnings before financing charges and income taxes	**11.5**	11.4	**46.5**	41.9	30.2
Financing charges	**2.6**	1.2	**11.1**	3.2	6.6
Earnings before income taxes	**8.9**	10.2	**35.4**	38.7	23.6
Income taxes	**3.6**	3.5	**13.9**	13.0	8.8
Contribution to consolidated net earnings – USD	**$ 5.3**	$ 6.7	**$ 21.5**	$ 25.7	$ 14.8
Contribution to consolidated net earnings – CAD	**$ 6.6**	$ 6.7	**$ 23.1**	$ 27.5	$ 16.8
Contribution to consolidated earnings per common share – CAD	**$ 0.07**	$ 0.06	**$ 0.21**	$ 0.25	$ 0.15
Net earnings weighted average foreign exchange rate – CAD/USD	**$ 1.23**	$ 0.99	**$ 1.07**	$ 1.07	$ 1.13

BHE's contribution to consolidated net earnings decreased $1.4 million to $5.3 million in Q4 2008 compared to $6.7 million in Q4 2007. Annual contribution to consolidated net earnings decreased $4.2 million to $21.5 million compared to $25.7 million in 2007, and was $14.8 million in 2006. Highlights of the earnings changes are summarized in the following table:

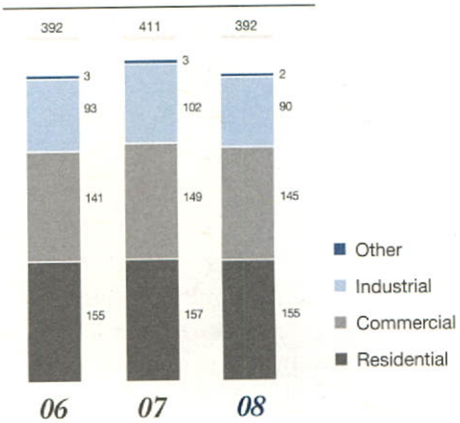
MILLIONS OF DOLLARS	THREE MONTHS ENDED DECEMBER 31	YEAR ENDED DECEMBER 31
Contribution to consolidated net earnings – 2006		**$ 14.8**
Increased transmission pool revenue associated with the recovery of the NRI transmission line from the New England Power Pool ("NEPOOL") beginning in June 2007		12.7
Increased overheads and AFUDC capitalized primarily as a result of capital expenditures on the NRI transmission line		4.0
Increased income taxes due to increased earnings		(4.2)
All other		(1.6)
Contribution to consolidated net earnings – 2007	**$ 6.7**	**$ 25.7**
Year-to-date increase primarily due to increased net transmission pool revenue and a decrease in miscellaneous transmission charges	(0.9)	5.0
Decreased overheads and AFUDC capitalized primarily as a result of completing the NRI transmission line in Q4 2007	(1.7)	(10.0)
Increased interest expense and depreciation primarily related to the NRI transmission line	(0.4)	(3.0)
Other	1.6	3.8
Contribution to consolidated net earnings – 2008	**$ 5.3**	**$ 21.5**

BHE's decreased contribution to consolidated net earnings in CAD in Q4 2008 compared to Q4 2007 was partially offset by the $1.3 million impact of the weaker Canadian dollar. BHE's increased contribution to consolidated net earnings in CAD in 2007 compared to 2006 was partially offset by the $1.5 million effect of the stronger Canadian dollar.

ELECTRIC REVENUE

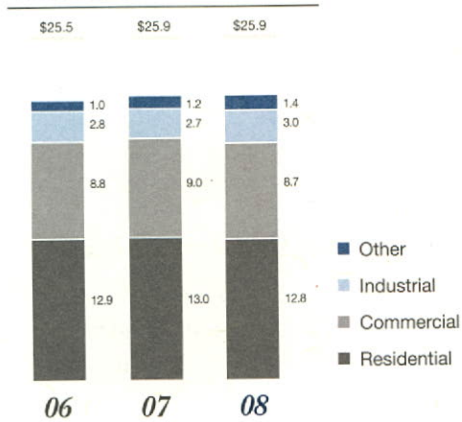
Q4 Electric Sales Volume

GWh



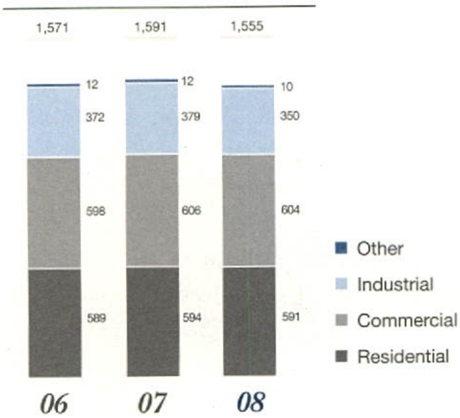
Q4 Electric Sales Revenues

MILLIONS OF DOLLARS



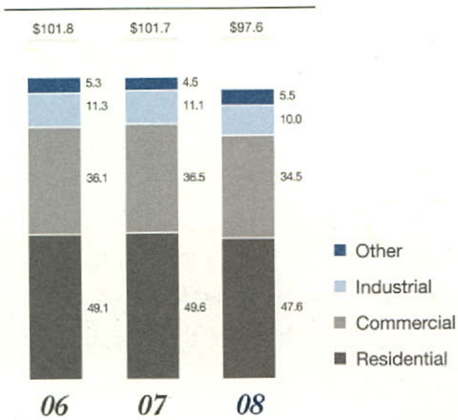
YTD Electric Sales Volume

GWh



YTD Electric Sales Revenues

MILLIONS OF DOLLARS



Q4 Average Revenue / MWh

	2008	*2007*	*2006*
Dollars per MWh	**$ 66**	$ 63	$ 65

YTD Average Revenue / MWh

	2008	*2007*	*2006*
Dollars per MWh	**$ 63**	$ 64	$ 65

Electric sales volume is primarily driven by general economic conditions, population and weather. Electric sales pricing in Maine is regulated, and therefore changes in accordance with regulatory decisions.

Electric revenues were flat at $25.9 million in Q4 2008 compared to Q4 2007. For the year ended December 31, 2008, electric revenues decreased $4.1 million to $97.6 million compared to $101.7 million for 2007 due to decreased sales volume and decreased stranded cost rates. For the year ended December 31, 2007, electric revenues were unchanged at $101.7 million compared to $101.8 million in 2006.

The changes in average revenue per MWh in 2008 compared to 2007 reflects the July 1, 2007 reduction in transmission rates and the March 1, 2008 reduction in stranded cost rates, offset by the January 1, 2008 increase in distribution rates and an increase in transmission rates on July 1, 2008.

Resale of Purchased Power, and Fuel for Generation and Purchased Power

BHE has several above-market purchase power contracts pre-dating the Maine market restructuring. Power purchased under these arrangements is resold to a third party at market rates as determined through a bid process administered and approved by the MPUC. The difference between the cost of the power purchased under these arrangements and the revenue collected from the third party is recovered through stranded cost rates.

Transmission Pool Revenue

Transmission pool revenue includes recovery of the NRI transmission line from NEPOOL, which began in June 2007, offset by NEPOOL transmission infrastructure investment charges. BHE recovers the cost of its regionally funded transmission infrastructure investment through the transmission pool revenue based on a regional formula that is updated on June 1st of each year.

Transmission pool revenue decreased by $1.3 million in Q4 2008 to $3.2 million compared to $4.5 million in Q4 2007 due to increased regional charges from increased transmission infrastructure investment. For the year ended December 31, 2008, transmission pool revenue increased $3.8 million to $16.5 million compared to $12.7 million for 2007. Much of the year over year increase is due to 12 months of pool revenue in 2008 from the NRI transmission line compared to seven months in 2007, partially offset by increased regional charges.

Depreciation

Depreciation expense increased $0.7 million to $3.9 million in Q4 2008 compared to $3.2 million in Q4 2007; and increased $2.3 million to $15.3 million in 2008 compared to $13.0 million in 2007; primarily due to depreciation on the NRI transmission line which went into service in Q4 2007.

Financing Charges

Financing charges increased $1.4 million to $2.6 million in Q4 2008 compared to $1.2 million in Q4 2007 and increased $7.9 million to $11.1 million for the year ended December 31, 2008, compared to $3.2 million in 2007 primarily due to increased debt used to finance the NRI transmission line and decreased AFUDC capitalized on the NRI transmission line which went into service in Q4 2007.

Financing charges decreased $3.4 million to $3.2 million for the year ended December 31, 2007, compared to $6.6 million in 2006 primarily due to increased capitalized AFUDC related to the NRI transmission line partially offset by increased debt used to finance the NRI transmission line.

Income Taxes

BHE uses the future income tax method of accounting for income taxes.

BHE is subject to corporate income tax at the statutory rate of 40.8% (combined federal and state income tax rate).

Outlook

BHE's net earnings for 2009 are expected to be slightly higher than 2008 primarily due to increased transmission investment recoveries.

Debt Management

BHE has established the following credit facilities:

Short-term

MILLIONS OF DOLLARS	MATURITY	MAXIMUM AMOUNT
Unsecured revolving facility	2 year revolving – matures in June 2010	$ 60.0

In September 2007, the company completed a private placement of $50 million in senior unsecured notes at an average interest rate of 5.74% of which $30 million will mature in September 2014 and $20 million will mature in September 2017. The primary use of these proceeds was to fund the NRI transmission line. Proceeds were used to pay down a $40 million interim bank credit line used as bridge financing, and short-term debt.

The weighted-average coupon rate on BHE's long-term debt outstanding at December 31, 2008 was 6.87% (2007 – 6.82%). Approximately 70% of the debt matures over the next 10 years; the remaining issues mature in 2020 and 2022. The quoted market weighted average interest rate for the same or similar issues of the same remaining maturities was 6.95% as of December 31, 2008 (2007 – 5.62%).

BHE has no public debt, and accordingly has no requirement for public credit ratings. BHE believes that its credit facility provides adequate access to capital to support current operations and a base level of capital expenditures. For additional capital needs, BHE expects to have sufficient access to competitively priced funds in the unsecured debt market.

OTHER, INCLUDING CORPORATE COSTS

All activities of Emera other than its two wholly-owned regulated electric utilities are incorporated into Other, including:

- Bear Swamp, a 50/50 joint venture in a 600 megawatt pumped storage hydro-electric facility in northern Massachusetts. Bear Swamp typically pumps water into its reservoir using lower priced off-peak power, and uses that hydro capacity to generate electricity during higher priced on-peak periods.
- Brunswick Pipeline, a 145 kilometre pipeline that delivers natural gas from the Canaport™ Liquefied Natural Gas import terminal near Saint John, New Brunswick, to markets in Canada and the northeastern United States. The pipeline was mechanically complete, and received National Energy Board approval for shipping gas, in January 2009. This accommodates the needs and schedule of the customer, Repsol, and the timing of completing the Canaport™ LNG terminal, expected in Q2 2009.
- A 12.9% interest in the $2 billion, 1,400 kilometre M&NP that transports Nova Scotia's offshore natural gas to markets in Maritime Canada and the northeastern United States.
- Emera Energy Services, a physical energy business which purchases and sells natural gas and electricity and provides related energy asset management services. Emera Energy Services operates with minimal day-to-day commodity risk exposure. Volatility in natural gas markets usually results in increased opportunities for Emera Energy Services.
- A 19% interest in Lucelec, a vertically integrated electric utility on the Caribbean Island of St. Lucia, which was acquired in January 2007.
- A 25% indirect interest in GBPC, a vertically integrated utility serving 19,000 customers on Grand Bahama Island, which was acquired in September 2008.
- A 7.35% interest in OpenHydro, an Irish renewable tidal energy company, which was acquired in February 2008.
- Certain corporate-wide functions such as executive management, strategic planning, treasury services, tax planning, business development, and corporate governance; and financing and income taxes associated with the corporation's business outside of its two wholly-owned regulated electric utilities.

REVIEW OF 2008

Bear Swamp, Brunswick Pipeline, and Emera Energy Services are reported on an earnings before interest and other income taxes basis ("EBIT"), and M&NP, Lucelec and GBPC are reported on an equity earnings basis.

Other Net Earnings

	THREE MONTHS ENDED DECEMBER 31		YEAR ENDED DECEMBER 31		
MILLIONS OF DOLLARS (EXCEPT EARNINGS PER COMMON SHARE)	2008	2007	2008	2007	2006
Bear Swamp – operational	**$ 2.4**	$ 3.6	**$ 15.8**	$ 8.9	$ 1.4
Bear Swamp – mark-to-market	**(6.0)**	5.9	**(8.1)**	15.7	–
Brunswick Pipeline	**7.0**	–	**15.6**	–	–
M&NP	**4.6**	2.6	**12.2**	10.6	4.9
Emera Energy Services	**1.8**	1.9	**7.3**	12.2	15.1
Lucelec	**0.3**	0.9	**1.8**	2.2	–
GBPC	**1.2**	–	**1.2**	–	–
Corporate costs & other	**(2.2)**	(4.8)	**(12.3)**	(14.4)	(9.6)
	9.1	10.1	**33.5**	35.2	11.8
Interest	**8.6**	2.4	**20.8**	7.4	10.0
	0.5	7.7	**12.7**	27.8	1.8
Income taxes	**(4.4)**	3.0	**(3.3)**	4.2	(2.9)
	4.9	4.7	**16.0**	23.6	4.7
Non-controlling interest	**(0.6)**	–	**(0.6)**	–	–
Contribution to consolidated net earnings	**$ 4.3**	$ 4.7	**$ 15.4**	$ 23.6	$ 4.7
Contribution to consolidated earnings per share	**$ 0.04**	$ 0.04	**$ 0.14**	$ 0.21	$ 0.05
Contribution to consolidated net earnings, absent the Bear Swamp after-tax mark-to-market adjustment	**$ 7.9**	$ 1.2	**$ 20.2**	$ 14.2	$ 4.7
Contribution to consolidated earnings per share, absent the Bear Swamp after-tax mark-to-market adjustment	**$ 0.07**	$ 0.01	**$ 0.18**	$ 0.13	$ 0.05

The total contribution of Other to consolidated net earnings decreased $0.4 million to $4.3 million in Q4 2008 compared to $4.7 million in Q4 2007. Annual contribution to consolidated net earnings decreased $8.2 million to $15.4 million in 2008 compared to $23.6 million in 2007, and was $4.7 million in 2006. Highlights of the earnings changes are summarized in the following table:

MILLIONS OF DOLLARS	THREE MONTHS ENDED DECEMBER 31	YEAR ENDED DECEMBER 31
Contribution to consolidated net earnings – 2006		**$ 4.7**
Increased Bear Swamp – operational due to increased energy and capacity sales		7.5
Increased Bear Swamp – mark-to-market due to a favourable commodity price position		15.7
Decreased Emera Energy Services as a result of changes in supply, market performance, and a stronger Canadian dollar		(2.9)
Increased M&NP due to expansion costs that were expensed throughout 2006 and then capitalized in Q1 2007 and increased equity earnings due to increased tolls and volume		5.7
Equity earnings from Lucelec which was purchased in Q1 2007		2.2
Increased corporate costs and other due to increased business development activity and depreciation		(4.8)
Increased income taxes related to increased earnings		(7.1)
All other		2.6
Contribution to consolidated net earnings – 2007	**$ 4.7**	**23.6**
Increased year-to-date Bear Swamp – operational due to increased energy and forward reserve sales	(1.2)	6.9
Decreased Bear Swamp – mark-to-market due to an unfavourable commodity price position	(11.9)	(23.8)
Increased Brunswick Pipeline due to AFUDC on construction of the pipeline	7.0	15.6
Decreased Emera Energy Services primarily due to reduced activity	(0.1)	(4.9)
Increased interest due to increased short-term debt used to finance the construction of Brunswick Pipeline and foreign exchange losses in 2008 compared to foreign exchange gains in 2007	(6.2)	(13.4)
Decreased income taxes due to decreased earnings	7.4	7.5
Equity earnings from GBPC which was purchased in Q3 2008	1.2	1.2
Other	3.4	2.7
Contribution to consolidated net earnings – 2008	**$ 4.3**	**$ 15.4**

Bear Swamp

Bear Swamp EBIT represents Emera's investment in the Bear Swamp joint venture.

Operational

Bear Swamp EBIT – operational decreased quarter over quarter to $2.4 million in Q4 2008 compared to $3.6 million in Q4 2007; and increased to $15.8 million in 2008 compared to $8.9 million in 2007 and $1.4 million in 2006. During 2006 a hedging program was implemented to provide more consistent margins and resulted in a mark-to-market loss in 2006, which reversed in 2007.

During Q1 2007, Bear Swamp finalized a long-term agreement with the Long Island Power Authority to provide LIPA with 345 MW of capacity to May 31, 2010 (approximately 55% of Bear Swamp's total capacity); and 100 MW thereafter, to April 30, 2021. In addition, Bear Swamp will provide LIPA with 12,200 MWh of super-peak and peak energy weekly, (approximately 35% of the plant's available energy) at a fixed price, with an annual increase, over the 15 year term of the agreement. Bear Swamp has contracted with its parent companies for the power supply necessary to produce the energy requirements of the LIPA agreement.

Mark-to-market

As mentioned above, Bear Swamp has contracted with its parents to provide the power necessary to produce the energy requirements of the LIPA contract. One of the contracts between Bear Swamp and Emera's joint venture partner is marked-to-market through earnings as it does not meet the stringent accounting requirements of hedge accounting. As at December 31, 2008, the fair value of the net derivative asset was $4.9 million (December 31, 2007 – $10.5 million), which is subject to market volatility of power prices, and will reverse over the life of the agreement as it is realized. The agreement expires in 2021.

Brunswick Pipeline

Brunswick Pipeline was mechanically complete, and received National Energy Board approval for shipping gas, in January 2009. This accommodates the needs of the customer, Repsol, and the timing of completing the Canaport™ LNG terminal, expected in Q2 2009. Capital costs of Brunswick Pipeline are expected to be $465 million plus additional AFUDC and operating expenses capitalized as a result of the delay in receiving gas from the Canaport™ LNG terminal. Revenue from the customer will begin when the terminal is operational, but no later than September 2009.

M&NP Equity Earnings

Equity earnings for M&NP were $4.6 million in Q4 2008 compared to $2.6 million in Q4 2007. The increase in earnings was a result of proceeds related to a settlement agreement between M&NP and EnCana Marketing (USA) Inc. ("EnCana"), a reduction in interest expense related to the US portion of the pipeline, and a weaker Canadian dollar. In late 2007, M&NP and EnCana entered into an agreement whereby M&NP would expand its facilities on the US portion of the pipeline and M&NP would provide firm transport service to EnCana. In 2008, EnCana terminated the agreement and a settlement agreement was reached in Q4 2008. A portion of the settlement proceeds has been recognized in Q4 2008 with the remaining portion deferred until 2009.

For the year ended December 31, 2008 M&NP equity earnings were $12.2 million compared to $10.6 million in 2007 due to the reasons noted above.

For the year ended December 31, 2007 M&NP equity earnings were $10.6 million compared to $4.9 million in 2006 primarily due to expansion costs that were expensed throughout 2006 and then capitalized in Q1 2007. During Q2 2006, M&NP filed an application with the FERC to expand its US pipeline system to carry volumes from the proposed Brunswick Pipeline to markets in the northeastern United States. Construction of the $307 million USD proposed expansion facilities began in June 2007, in conjunction with the building of Brunswick Pipeline. M&NP was expensing development costs associated with the expansion until FERC approval was obtained in Q1 2007 when these costs were capitalized as part of the US pipeline expansion. Emera's portion of the required capital contribution for the expansion facilities was $21 million USD.

During Q3 2008, M&NP repaid its outstanding debt related to the US portion of the pipeline through equity contributions from the partners, which M&NP will return to the partners once new financing is in place. The Company's portion of the equity contribution was $46.5 million USD ($47.0 million CAD). M&NP is expected to issue long-term debt in 2009, subject to capital market conditions.

Income Taxes

All businesses included in Other follow the future income taxes method of accounting for income taxes, excluding Brunswick Pipeline which uses the taxes-payable method as allowed for ratemaking purposes. Taxes are recognized on pre-tax income, excluding M&NP, Lucelec and GBPC equity earnings that are recorded net of tax. Variations in income tax expense are largely affected by earnings and foreign exchange fluctuations, along with changes in the statutory tax rate.

Outlook

Net earnings for 2009, after adjusting for the mark-to-market effect of the commodity price position in Bear Swamp, will increase over 2008 due to the Brunswick Pipeline being mechanically complete and ready for gas transportation in January 2009.

Debt Management

Emera has established the following credit facilities outside its regulated electric utilities:

Short-term

MILLIONS OF DOLLARS	MATURITY	MAXIMUM AMOUNT
Operating and acquisition credit facility	1 Year Revolving	$ 600.0
Bridge credit facility	June 20, 2009	$ 200.0

During Q4 2008, Emera entered into a $200 million non-revolving bridge credit facility ("bridge facility"), maturing June 30, 2009. The amount of the bridge facility is required to be reduced by the proceeds of any debt or equity issuance by Emera.

During Q2 2007, Bear Swamp completed a $125 million USD financing using a senior secured non-revolving credit facility. The five-year credit facility bears interest at a LIBOR-based facility rate, is secured by the assets of Bear Swamp, and is due in May 2012. Proceeds of the financing were distributed equally to Emera and its joint venture partner.

On a consolidated basis, Emera's target percentage of debt to total capitalization is 50% – 55%. The company manages long-term debt terms such that the average is not less than ten years.

The credit ratings issued by Dominion Bond Rating Service, Standard & Poor's, and Moody's Investors Service are unchanged from 2007, and are as follows:

	DBRS	S&P	MOODY'S
Long-term corporate	BBB (high)	BBB	Baa2

In November 2008, Standard & Poor's ("S&P") rating agency revised the corporate and senior unsecured debt rating outlook of Emera to Positive from Stable.

In August 2008, Moody's Investors Service confirmed the credit ratings of Emera and revised the rating outlook from negative to stable. The revision reflects Moody's view that NSPI has been successful in improving its relationships with key stakeholders and the UARB. Moody's also expects that NSPI's exposure to regulatory risk will be reduced and that there is less likelihood of variability in NSPI's financial results following implementation of the FAM.

CONSOLIDATED BALANCE SHEETS

Significant changes in the consolidated balance sheets between December 31, 2008 and December 31, 2007 include:

MILLIONS OF DOLLARS	INCREASE (DECREASE)	EXPLANATION
Assets		
Cash	$ (14.2)	See consolidated cash flow highlights section.
Accounts receivable	65.8	Lower accounts receivable securitized, increased posted margin to counterparties, and the effect of the weaker Canadian dollar.
Inventory	31.5	Increased coal volumes and commodity prices.
Derivatives in a valid hedging relationship (including long-term portion)	141.9	Favourable USD price positions partially offset by unfavourable commodity price positions. The effective portion of the change is recognized in accumulated other comprehensive income.
Long-term receivable	48.7	Increased receivable from a natural gas supplier.
Goodwill	19.2	Weaker Canadian dollar.
Investments subject to significant influence	193.1	Additional investment in MN&P, indirect investment in GBPC through the investment in ICDU, and equity earnings. The non-controlling interest in ICDU is reflected in non-controlling interest below.
Available-for-sale investments	14.4	Investment in OpenHydro.
Property, plant & equipment and construction work in progress	547.0	Capital spending in Brunswick Pipeline, NSPI and BHE, along with the effect of the weaker Canadian dollar.
Liabilities and Shareholders' Equity		
Accounts payable	24.4	Timing of payments.
Derivatives in a valid hedging relationship (including long-term portion)	92.6	Unfavourable commodity price positions partially offset by favourable USD price positions. The effective portion of the change is recognized in accumulated other comprehensive income.
Held-for-trading derivatives (including long-term portion)	23.0	Unfavourable commodity price positions. The portion related to NSPI's regulatory liabilities is recognized in other assets.
Future income tax liabilities	25.4	Increased timing differences relating to depreciable assets.
Other liabilities	25.9	Increased NSPI regulatory liability related to held-for-trading contracts, and the effect of the weaker Canadian dollar.
Short-term debt and long-term debt (including current portion)	622.7	Increased short-term debt to finance Brunswick Pipeline, increased posted margin and the effect of the weaker Canadian dollar.
Non-controlling interest	39.0	Investment in ICDU.
Common shares	15.2	Shares issued under purchase plans and stock options exercised.
Accumulated other comprehensive income	139.8	Primarily represents the favourable effect of the Canadian dollar on the company's investment in Bangor Hydro, and changes in USD and commodity price hedge positions.
Retained earnings	31.0	Net earnings in excess of dividends paid.

OUTSTANDING SHARE DATA

ISSUED AND OUTSTANDING:	MILLIONS OF SHARES	COMMON SHARE CAPITAL MILLIONS OF DOLLARS
December 31, 2006	110.93	$ 1,055.2
Issued for cash under purchase plans	0.45	9.0
Options exercised under senior management share option plan	0.09	1.7
Share-based compensation	–	0.3
December 31, 2007	111.47	$ 1,066.2
Issued for cash under purchase plans	0.39	8.0
Options exercised under senior management share option plan	0.35	6.4
Share-based compensation	–	0.8
December 31, 2008	112.21	$ 1,081.4

As at January 30, 2009 the number of issued and outstanding common shares was 112.25 million.

LIQUIDITY AND CAPITAL RESOURCES

The company generates cash primarily through its operations in regulated utilities involving the generation, transmission and distribution of electricity. NSPI's and BHE's customer bases are diversified by both sales volume and revenues among residential, commercial, industrial and other. Circumstances that could affect the company's ability to generate cash include fuel commodity price changes, general economic downturns in Nova Scotia and Maine, the loss of one or more large customers, and regulatory decisions affecting customer rates. The UARB approved a FAM that reduces NSPI's exposure to fuel price volatility effective January 1, 2009, providing a mechanism for NSPI to recover these fuel costs beginning in 2010.

In addition to internally generated funds, Emera Inc. and NSPI have in aggregate access to $1.1 billion committed syndicated revolving bank lines of credit, of which $375 million is undrawn and available as at December 31, 2008. Emera Inc. has access to $600 million of this facility and NSPI has access to $500 million. NSPI has an active commercial paper program for up to $400 million, of which outstanding amounts are 100% backed by the bank lines referred to above and this results in an equal amount of that credit being considered drawn.

Emera's and NSPI's revolving bank lines have a maturity date in June 2009 which can be extended annually for an additional 364 days with the approval of the syndicated banks. At each maturity date Emera and NSPI have the option to convert all amounts drawn on the bank credit line to a one year non-revolving term credit.

In October 2008, the company negotiated an additional $200 million in a committed non-revolving bank line of credit as a bridge facility for Brunswick Pipeline. As at December 31, 2008, $66 million is undrawn and available. This non-revolving bank line matures in June 2009. The company intends to finance Brunswick Pipeline with a longer term debt facility in 2009.

BHE has a $60 million USD revolving bank line of which $12 million USD was undrawn and available as at December 31, 2008. This facility matures in June 2010.

NSPI expects to have access to capital markets to enable it to refinance the $125 million Series C preferred shares and the $125 million long-term note maturing in June, while maintaining sufficient levels of operating liquidity in 2009.

In December 2008, NSPI completed a $150 million medium-term note issue, proceeds of which were used to pay down outstanding commercial paper debt. In January 2009, NSPI completed a $50 million medium-term note issue, which was also used to pay down outstanding short-term debt; these proceeds increased the $375 million in available credit referenced previously to $425 million. As at December 31, 2008, Emera and Nova Scotia Power had debt shelf prospectuses in the amounts of $400 million and $250 million respectively. Subsequent to the January 2009 $50 million medium-term note issue, the Nova Scotia Power debt shelf prospectus is now $200 million.

AS AT DECEMBER 31, 2008 MILLIONS OF DOLLARS	CREDIT LINE COMMITTED	UTILIZED	UNDRAWN AND AVAILABLE
Nova Scotia Power	$ 500	$ 171	$ 329
Emera	600	554	46
Emera bridge facility	200	134	66
Bangor Hydro – in USD	60	48	12

NSPI issues commercial paper, 100% backed by the syndicated bank line of credit, to finance short-term cash requirements and has accessed the market as required, despite liquidity and pricing pressures arising as a result of the disruption to capital markets. On a few occasions market demand for NSPI's commercial paper was less than required and the company accessed its bank credit line.

NSPI has an accounts receivable securitization program as described in the Off-Balance Sheet Arrangements section. NSPI temporarily suspended its accounts receivable securitization program in January 2008, due to a lack of investor interest. The program expires in May 2009 and NSPI's ability to sell its receivables is subject to acceptance by the sponsor bank to buy the receivables. The company does not expect to use this facility in 2009. The company refinanced this $25 million debt through its commercial paper program.

North American financial markets experienced significant volatility beginning in 2007 and continuing throughout 2008 due to concerns related to the state of both the global debt market and economy. In the past, the company has been able to access capital markets. Given the current state of North American financial markets, we expect that access to capital markets will continue to be available to the company although possibly at a higher cost. NSPI and BHE are each capable of paying dividends to Emera provided they do not breach their debt to capitalization ratios after giving effect to the dividend payment.

The pressure on global debt markets may affect the credit worthiness of certain counterparties of Emera and its subsidiaries. Emera continues to perform regular credit risk assessments on its counterparties and deposits are required on any high risk accounts. Further information on Emera's credit risk can be found in the Business Risks and Enterprise Risk Management section.

PENSION FUNDING

Emera has defined pension plans which, similar to most North American pension plans, had negative asset returns during 2008. Consistent with Canadian GAAP and Emera's accounting policy, the company amortizes the net actuarial gain or loss, which exceeds 10% of the greater of the accrued benefit obligation ("ABO") and the market-related value of assets, over active plan members' average remaining service period, which is currently 10 years. Any required amortization of 2008 investment losses in 2009 will be offset by Emera's use of smoothed asset values rather than market values for accounting purposes; and amortization of gains due to a lower ABO measured at December 31, 2008, as a result of a higher discount rate at year end. Emera's selection of the discount rate is in accordance with Canadian GAAP. The net result is that the 2009 pension cost is expected to be lower than the 2008 pension cost.

The 2008 asset loss will increase Emera's cash contribution to the pension plan. The increased cash requirements in 2009 will be approximately $14 million higher than 2008. This is projected to increase by another $15 million – $20 million in 2010. All pension plan contributions are tax deductible and will be funded with cash from operations.

Emera's pension plan is managed with a diversified portfolio of asset classes, investment managers and geographic investments. Emera does not expect to make any changes to the management of its plan as a result of the market performance in 2008.

Consolidated Cash Flow Highlights

Significant changes in the consolidated cash flow statements between December 31, 2008 and December 31, 2007 include:

MILLIONS OF DOLLARS	THREE MONTHS ENDED DECEMBER 31 2008	 2007	EXPLANATION
Cash and cash equivalents, beginning of period	**$ 28.5**	$ 8.6	
Provided by (used in):			
Operating activities	**(17.1)**	207.8	In 2008, increased non-cash working capital partially offset by cash earnings. In 2007, cash earnings and decreased non-cash working capital, due to settlement of a receivable from a natural gas supplier in NSPI.
Investing activities	**(146.7)**	(83.3)	In 2008, capital spending, including Brunswick Pipeline, and an additional investment in M&NP. In 2007, capital spending, including NRI project and Brunswick Pipeline projects.
Financing activities	**147.5**	(106.7)	In 2008, increased debt levels, partially offset by dividends on common shares. In 2007, reduced debt levels and dividends on common shares.
Cash and cash equivalents, end of year	**$ 12.2**	$ 26.4	

MILLIONS OF DOLLARS	YEAR ENDED DECEMBER 31 2008	 2007	EXPLANATION
Cash and cash equivalents, beginning of period	**$ 26.4**	$ 19.5	
Provided by (used in):			
Operating activities	**237.2**	351.4	In 2008, cash earnings partially offset by increased non-cash working capital. In 2007, cash earnings partially offset by increased non-cash working capital.
Investing activities	**(671.6)**	(288.9)	In 2008, capital spending in Brunswick Pipeline, NSPI, and BHE, and acquisition of a 7.35% interest in OpenHydro and a 50% interest in ICDU. In 2007, capital spending, including the NRI transmission line and Brunswick Pipeline projects, and the acquisition of a 19% interest in Lucelec.
Financing activities	**420.2**	(55.6)	In 2008, increased debt levels, partially offset by dividends on common shares and decreased accounts receivable securitized. In 2007, dividends on common shares and decreased accounts receivable securitized, partially offset by increased debt levels.
Cash and cash equivalents, end of year	**$ 12.2**	$ 26.4	

Contractual Obligations

The consolidated contractual obligations over the next five years and thereafter include:

MILLIONS OF DOLLARS — PAYMENTS DUE BY PERIOD

	TOTAL	2009	2010	2011	2012	2013	AFTER 2013
Long-term debt	**$ 2,304.6**	$ 774.7	$ 106.3	$ 6.0	$ 106.8	$ 255.5	$ 1,055.3
Preferred shares issued by subsidiary	**260.0**	125.0	–	–	–	–	135.0
Operating leases	**24.5**	10.0	10.0	1.5	0.4	0.4	2.2
Purchase obligations	**2,419.1**	317.8	243.9	207.5	154.1	106.3	1,389.5
Other long-term obligations	**321.0**	2.1	1.5	2.2	2.1	41.9	271.2
Total contractual obligations	**$ 5,329.2**	$ 1,229.6	$ 361.7	$ 217.2	$ 263.4	$ 404.1	$ 2,853.2

Operating lease obligations: Emera's operating lease obligations consist of operating lease agreements for office space, telecommunications services, and photocopiers.

Purchase obligations: Emera has purchasing commitments for electricity from independent power producers, transportation of coal, outsourced management of the company's computer infrastructure, natural gas, transportation capacity on the Maritimes & Northeast Pipeline, fuel, and construction costs on the Brunswick Pipeline.

Other long-term obligations: The company has asset retirement and other long-term obligations.

The company expects to be able to meet its obligations with cash flows generated from operations.

Capital Resources

Capital expenditures, including AFUDC, were approximately $590 million for 2008 and included:

- $167 million in Nova Scotia Power;
- $44 million in Bangor Hydro; and
- $375 million in Brunswick Pipeline.

Outlook

Emera's capital budget for 2009 includes approximately $220 million for NSPI, which is generally directed toward customer growth and system reliability, planned and preventative maintenance, productivity-related investments, air emissions upgrades and a new corporate office. BHE expects to invest approximately $54 million USD, including approximately $32 million USD for major transmission projects. Brunswick Pipeline expects to invest approximately $60 million plus additional AFUDC and operating expenses capitalized.

The company expects to finance its capital expenditures with funds from operations and debt.

Off-Balance Sheet Arrangements

Upon privatization of the former provincially owned Nova Scotia Power Corporation ("NSPC") in 1992, NSPI became responsible for managing a portfolio of defeasance securities, which as at December 31, 2008 totaled $1.1 billion, held in trust for Nova Scotia Power Finance Corporation ("NSPFC"), an affiliate of the Province of Nova Scotia. NSPI is responsible to ensure that the defeasance securities provide the principal and interest streams to match the related defeased NSPC debt. Approximately 73% of the defeasance portfolio consists of investments in the related debt, eliminating all risk associated with this portion of the portfolio; the remaining defeasance portfolio has a market value higher than the related debt, reducing the future risk of this portion of the portfolio.

NSPI has an agreement with an independent trust administered by a Canadian chartered bank whereby it can sell accounts receivable to the trust at the sole discretion of the trust on a revolving non-recourse basis. As of December 31, 2008, there were no accounts receivable sold to the trust (2007 – $25.0 million). The agreement is in place until May 2009 and NSPI's ability to sell its receivables is subject to acceptance by the sponsor bank to buy the receivables. Securitization has provided NSPI with an alternative source of short-term funding. The securitization program was temporarily suspended in January 2008 due to a lack of investor interest. For the year ended December 31, 2007, the average all-in cost of this funding was 4.91%. In the event of termination of this arrangement, NSPI would utilize another credit facility to meet the ongoing operations of the business.

FINANCIAL AND COMMODITY INSTRUMENTS

The company manages its exposure to foreign exchange, interest rate, and commodity risks in accordance with established risk management policies and procedures. The company uses financial instruments consisting mainly of foreign exchange forward contracts, interest rate options and swaps, and coal, oil and gas options and swaps. In addition, the company has contracts for the physical purchase and sale of natural gas, and physical and financial contracts held-for-trading ("HFT"). Collectively these contracts are referred to as derivatives.

The company recognizes the fair value of all its derivatives on its balance sheet, except for non-financial derivatives that qualify and are designated as contracts held for normal purchase or sale.

Derivatives that meet stringent documentation requirements, and can be proven to be effective both at the inception and over the term of the instrument qualify for hedge accounting. Specifically, for cash flow hedges, the effective portion of the change in the fair value of derivatives is deferred to other comprehensive income and recognized in earnings in the same period the related hedged item is realized. Any ineffective portion of the change in the fair value of derivatives is recognized in net earnings in the reporting period. The total ineffectiveness recognized by the company was a $0.8 million gain in Q4 2008 and a $0.2 million gain for the year ended December 31, 2008.

Where the documentation or effectiveness requirements of hedge accounting are not met, the change in the fair value of the derivatives is recognized in earnings in the reporting period. The company also recognizes the change in the fair value of its HFT derivatives in earnings of the reporting period. The company has not designated any financial instruments to be included in the HFT category.

Nova Scotia Power has contracts for the purchase and sale of natural gas at its Tufts Cove generating station ("TUC") that are considered HFT derivatives and accordingly are recognized on the balance sheet at fair value. This reflects NSPI's history of buying and reselling any natural gas not used in the production of electricity at TUC. Changes in fair value of HFT derivatives are normally recognized in net earnings. In accordance with NSPI's accounting policy for financial instruments and hedges relating to TUC fuel, NSPI has deferred any changes in fair value to a regulatory asset or liability.

HEDGING ITEMS RECOGNIZED ON THE BALANCE SHEET

The company has the following categories on the balance sheet related to derivatives in valid hedging relationships:

MILLIONS OF DOLLARS	DECEMBER 31 2008	DECEMBER 31 2007
Inventory	**$ (7.1)**	$ 7.6
Derivatives in a valid hedging relationship	**(4.7)**	(54.0)
Long-term debt	**0.4**	0.6
	$ (11.4)	$ (45.8)

HEDGING IMPACT RECOGNIZED IN EARNINGS

For the three months and year ended December 31, the impacts of derivatives in valid hedging relationships recognized in earnings were recorded in the following categories:

MILLIONS OF DOLLARS	THREE MONTHS ENDED DECEMBER 31		YEAR ENDED DECEMBER 31	
	2008	*2007*	*2008*	*2007*
Financing charges decrease	**$ 1.5**	–	**$ 1.5**	–
Fuel and purchased power decrease (increase)	**10.9**	$ (4.3)	**26.5**	$ (14.7)
Hedging earnings impact	**$ 12.4**	$ (4.3)	**$ 28.0**	$ (14.7)

HELD-FOR-TRADING ITEMS RECOGNIZED ON THE BALANCE SHEET

The company has recognized a net held-for-trading derivatives asset of $85.7 million as at December 31, 2008 (2007 – $110.7 million) on the balance sheet.

HELD-FOR-TRADING DERIVATIVES GAINS (LOSSES) RECOGNIZED IN EARNINGS

The company has recognized the following realized and unrealized gains and losses with respect to held-for-trading derivatives in earnings:

MILLIONS OF DOLLARS	THREE MONTHS ENDED DECEMBER 31		YEAR ENDED DECEMBER 31	
	2008	*2007*	*2008*	*2007*
Electric revenue	**$ (2.2)**	$ (1.5)	**–**	$ (0.6)
Other revenue	**(5.0)**	6.2	**$ 3.6**	25.8
Fuel and purchased power	**(0.3)**	1.0	**(0.4)**	0.5
Financing charges	**(0.1)**	0.1	**(0.5)**	0.1
Held-for-trading derivatives (losses) gains	**$ (7.6)**	$ 5.8	**$ 2.7**	$ 25.8

In determining the fair value of derivative financial instruments, the company has relied on quoted market prices as at the reporting date.

Transactions With Related Parties

In the ordinary course of business, Emera purchased natural gas transportation capacity totaling $7.0 million (2007 – $5.1 million) during the three months ended December 31, 2008, and $29.4 million (2007 – $25.4 million) during the year ended December 31, 2008, from the Maritimes & Northeast Pipeline, an investment under significant influence of the company. The amount is recognized in fuel for generation and purchased power or netted against energy marketing margin in other revenue, and is measured at the exchange amount. At December 31, 2008 the amount payable to the related party is $4.1 million (2007 – $4.5 million), is non-interest bearing and is under normal credit terms.

Disclosure and Internal Controls

Emera's management is responsible for establishing and maintaining disclosure controls and procedures ("DC&P") and internal control over financial reporting ("ICFR"), as those terms are defined in National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings. The objective of this instrument is to improve the quality, reliability and transparency of information that is filed or submitted under securities legislation.

The President and Chief Executive Officer and the Chief Financial Officer have designed, with the assistance of company employees, DC&P and ICFR to provide reasonable assurance that material information is made known to them; is reported on a timely basis; financial reporting is reliable; and financial statements prepared for external purposes are in accordance with Canadian GAAP.

The President and Chief Executive Officer and the Chief Financial Officer have evaluated, with the assistance of company employees, the effectiveness of Emera and its consolidated subsidiaries' DC&P and ICFR and based on that evaluation have concluded DC&P and ICFR were effective at December 31, 2008.

There have been no changes in Emera or its consolidated subsidiaries' ICFR during the period beginning on January 1, 2008 and ending on December 31, 2008 that have materially affected, or are reasonably likely to materially affect ICFR.

Critical Accounting Estimates

The preparation of consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, related amounts of revenues and expenses, and disclosure of contingent assets and liabilities. Significant areas requiring the use of management estimates relate to rate regulation, the determination of post-retirement employee benefits, unbilled revenue, long-term receivable, asset retirement obligations, useful lives for depreciable assets, and goodwill impairment assessments. Actual results may differ from these estimates.

RATE REGULATION

NSPI, BHE, and Brunswick Pipeline accounting policies are subject to examination and approval by their respective regulators. As a result, their rate-regulated accounting policies may differ from accounting policies for non-rate-regulated companies. These differences occur when the regulators render their decisions on rate applications or other matters and generally involve the timing of revenue and expense recognition.

The accounting for these items is based on the expectation of the future actions of the regulators. For example, NSPI does not record future income taxes. The taxes payable method is prescribed by the regulator for rate-making purposes and there is reasonable expectation that the regulator will provide for all such future income taxes to be recovered in rates when they become payable. Similarly, the deferral of differences between the amounts included in rates and the incurrence of specified expenses is based on the expectation that the regulators will approve the refund to, or recovery from, ratepayers of the deferred balance.

Effective January 1, 2009 the Utility and Review Board has approved the implementation of a FAM. The difference between the costs included in rates and the actual costs of fuel will be deferred and refunded to or collected from customers in the subsequent year.

If the regulators' future actions are different from the regulators' previous rulings, the timing and amount of the recovery of liabilities and refund of assets, recorded or unrecorded, could be significantly different from that reflected in the financial statements.

PENSION AND OTHER POST-RETIREMENT EMPLOYEE BENEFITS

The company provides post-retirement benefits to employees, including a defined benefit pension plan. The cost of providing these benefits is dependent upon many factors that result from actual plan experience and assumptions of future experience.

The benefit cost and accrued benefit obligation for employee future benefits included in annual compensation expenses are affected by employee demographics, including age, compensation levels, employment periods, contribution levels and earnings on plan assets.

Changes to the provision of the plan may also affect current and future pension costs. Benefit costs may also be significantly affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets and discount rates used in determining the accrued benefit obligation and benefit costs.

The pension plan assets are comprised primarily of equity and fixed income investments. Fluctuations in actual equity market returns and changes in interest rates may result in increased or decreased pension costs in future periods.

The discount rate used to determine benefit costs is based on 'A' grade long-term Canadian corporate bonds for NSPI's pension plan and US corporate bonds for BHE's pension plan. The discount rate is determined with reference to bonds which have the same duration as the accrued benefit obligation as at January 1 of the fiscal year rounded to the nearest 25 basis points. For benefit cost purposes, NSPI's rate was 5.75% for 2008 (2007 – 5.25%) and BHE's rate was 6.75% for 2008 (2007 – 6.00%).

The expected return on plan assets is based on management's best estimate of future returns, considering economic and consensus forecasts. The benefit cost calculations assumed that plan assets would earn a rate of return of 7.5% for 2008 and 2007 for NSPI, and 8.0% for 2008 and 2007 for BHE.

The reported benefit cost for 2008, based on management's best estimate assumptions, is $34.5 million. While there are numerous assumptions which are used to determine the benefit cost, the discount rate and asset return assumptions have a significant impact on the calculations. The following shows the impact on 2008 benefit cost of a 25 basis point change (0.25%) in the discount rate and asset return assumptions:

MILLIONS OF DOLLARS	INCREASE 0.25%	DECREASE 0.25%
Discount rate assumption	$ (3.5)	$ 3.6
Asset return assumption	$ (1.7)	$ 1.7

UNBILLED REVENUE

Electric revenues are billed on a systematic basis over a one or two-month period for NSPI and a one-month period for BHE. At the end of each month, the company must make an estimate of energy delivered to customers since the date their meter was last read and of related revenues earned but not yet billed. The unbilled revenue is estimated based on several factors, including current month's generation, estimated customer usage by class, weather, line losses and applicable customer rates. Based on the extent of the estimates included in the determination of unbilled revenue, actual results may differ from the estimate. As of December 31, 2008, unbilled revenues amount to $89.7 million (2007 – $86.0 million) on a base of annual electric revenues of approximately $1.3 billion (2007 – $1.3 billion).

LONG-TERM RECEIVABLE

NSPI's existing long-term natural gas purchase agreement includes a price adjustment clause covering three years of natural gas purchases. The clause states that NSPI will pay for all gas purchases at the agreed contract price, but will be entitled to a price rebate on a portion of the volumes. The first settlement took place in November 2007 for purchases to the end of October 2007. The next settlement will be in November 2010. Management has made a best estimate of the price rebate based on the contract specifications using actual and forward market pricing and recorded it in long-term receivable.

ASSET RETIREMENT OBLIGATIONS

The Company recognizes asset retirement obligations for property, plant and equipment in the period in which they are incurred if a reasonable estimate of fair value can be determined. The fair value of the liability is described as the amount at which the liability could be settled in a current transaction between willing parties. Expected values are discounted at the risk-free interest rate adjusted to reflect the market's evaluation of the company's credit standing. Determining asset retirement obligations requires estimating the life of the related asset and the costs of activities such as demolition, restoration and remedial work based on present-day methods and technologies.

As part of the 2003 NSPI depreciation settlement, the UARB included the amount of future expenditures associated with the removal of generation facilities. NSPI believes that it will continue to be able to recover asset retirement obligations through rates. Accordingly, changes to the asset retirement obligations, or cost recognition attributable to changes in the factors discussed above, should not impact the results of operations of the company.

At December 31, 2008, the asset retirement obligations recorded on the balance sheet were $88.0 million (2007 – $83.8 million). The Company estimates the undiscounted amount of cash flow required to settle the obligations is approximately $314.2 million, which will be incurred between 2009 and 2061. The majority of these costs will be incurred between 2020 and 2039.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment represents 66% of total assets recognized on the company's balance sheet. Included in property, plant and equipment are the generation, transmission and distribution and other assets of the company. Due to the size of the company's property, plant and equipment, changes in estimated depreciation rates can have a significant impact on depreciation expense.

Depreciation is calculated on a straight-line basis over the estimated service life of the asset. The estimated useful lives of the assets are largely based on formal depreciation studies, which are conducted from time to time.

In 2002 NSPI commissioned a depreciation study by an external consultant. The study was filed with the UARB in 2003. A settlement agreement on the matter was reached with all intervenors, which recommended a four-year phase-in of new depreciation rates, which, based on assets in service in the study, would reach an overall increase in depreciation expense of $20 million by 2007. The UARB approved the settlement. NSPI began phasing the new rates in 2004. In its rate decision for 2005, the UARB deferred the scheduled phase-in for 2005. In the rate decision for 2006, the UARB included the phase-in of year-two in rates. In its February 5, 2007 decision, the UARB postponed the phase-in of year-three rates until the next rate application. In its November 5, 2008 decision, the UARB approved year-three phase-in effective January 1, 2009.

GOODWILL IMPAIRMENT ASSESSMENTS

Goodwill represents the excess of the acquisition purchase price for Bangor Hydro over the fair values assigned to individual assets acquired and liabilities assumed. Emera is required to perform an impairment assessment annually, or in the interim if an event occurs that indicates that the fair value of Bangor Hydro may be below its carrying value. Emera performs its annual impairment test as at March 31.

Impairment assessments are based on fair market value assessments. Fair market value is determined by use of net present value financial models that incorporate management's assumptions about future profitability. There was no impairment provision required in 2008 or 2007.

Changes in Accounting Policies

The Canadian Institute of Chartered Accountants ("CICA") has issued new accounting standards 1535 Capital Disclosures, 3031 Inventories, 3862 Financial Instruments – Disclosures, and 3863 Financial Instruments – Presentation which are applicable to Emera's 2008 fiscal year. The following provides more information on each new accounting standard.

Capital Disclosures: This new standard requires disclosure of the Company's objectives, policies, and processes for managing capital; quantitative data about what the Company regards as capital; whether the Company has complied with any externally imposed capital requirements; and, if the Company has not complied, the consequences of such non-compliance. The new accounting standard covers disclosure only and had no effect on the financial results of the company. Further information can be found in note 23 to the financial statements.

Financial Instruments – Disclosures, and Financial Instruments – Presentation: These new standards replace accounting standard 3861 Financial Instruments – Disclosure and Presentation. Presentation requirements have not changed. Enhanced disclosure is required to assist users of the financial statements in evaluating the significance of financial instruments on the Company's financial position and performance, including qualitative and quantitative information about the Company's exposure to risks arising from financial instruments. The new accounting standards cover disclosure only and had no effect on the financial results of the Company. Further information can be found in note 24 to the financial statements.

Inventories: The new standard provides more guidance on the measurement and disclosure requirements for inventories than the previous standard, 3030 Inventories. Specifically, the new standard requires that inventories be measured at the lower of cost and net realizable value, and provides more guidance on the determination of cost and its subsequent recognition as an expense, including any write-down to net realizable value. The Company previously measured inventories at the lower of cost and market. The Company uses the weighted average method to determine the cost of inventory.

The Company has applied the new standard retrospectively without restatement, which resulted in a decrease to inventory and retained earnings of $3.3 million as at January 1, 2008.

The change in inventory is due to the following:

	FUEL INVENTORY YEAR ENDED DECEMBER 31		MATERIALS INVENTORY YEAR ENDED DECEMBER 31	
MILLIONS OF DOLLARS	**2008**	2007	**2008**	2007
Inventory, beginning of period	**$ 67.7**	$ 81.2	**$ 32.1**	$ 32.4
Accounting policy change	**–**	–	**(3.3)**	–
Purchases	**359.7**	313.5	**38.7**	39.0
Write-down of inventory to net realizable value	**–**	–	**(1.1)**	(0.7)
Inventories expensed	**(325.7)**	(327.0)	**(16.3)**	(17.3)
Inventories capitalized	**–**	–	**(22.5)**	(23.0)
Other	**–**	–	**1.9**	1.6
Inventory, end of period	**$ 101.7**	$ 67.7	**$ 29.5**	$ 32.0

The company has not pledged inventory as security for liabilities.

Future Accounting Policy Changes

GOODWILL AND INTANGIBLE ASSETS

In February 2008, the CICA issued Section 3064 Goodwill and Intangible Assets ("3064") applicable to Emera's 2009 fiscal year, replacing Section 3062 Goodwill and Other Intangible Assets. The goodwill requirements have not changed. The requirements for intangible assets now clarify that costs may only be deferred when they relate to an item that meets the definition of an asset. An intangible asset must be identifiable; be a resource over which the company has control; probably generate future economic benefits; and have a reliably measurable cost. The Company is currently assessing the effect of 3064 on its financial statements but does not expect a material change.

RATE-REGULATED OPERATIONS

These new standards included removing the temporary exemption in Section 1100 Generally Accepted Accounting Principles pertaining to the application of the section to the recognition and measurement of assets and liabilities arising from rate regulation; and amending Section 3465 Income Taxes to require the recognition of future income tax assets and liabilities for the amount of future income taxes expected to be included in future rates and recovered from or paid to future customers. As a result of the new standard, Emera will recognize future income tax assets and liabilities of its wholly-owned regulated subsidiaries. In accordance with the company's regulated accounting policies covering income taxes, Emera will defer any future income taxes to a regulatory asset or liability where the future income taxes are expected to be included in future rates, with no resulting effect on net earnings. The Company is still assessing the effect on its balance sheet.

FINANCIAL INSTRUMENTS

In January 2009, the CICA issued Emerging Issue Committee Abstract of Issue Discussed 173 Credit Risk and the Fair Value of Financial Assets and Financial Liabilities ("EIC-173") applicable to Emera's 2009 fiscal year. EIC-173 recommends that a company take into account its own credit risk and the credit risk of the counterparty in determining the fair value of financial assets and financial liabilities. The Company is currently assessing the effect on its financial results.

CHANGEOVER TO INTERNATIONAL FINANCIAL REPORTING STANDARDS ("IFRS")

In April 2008, the CICA issued an IFRS Omnibus Exposure Draft which proposes that publicly accountable enterprises be required to apply IFRS effective for Emera's interim and annual periods beginning January 1, 2011 with consistent comparative information required for 2010. The Company is currently assessing the effect of IFRS on its accounting policies, information systems, internal controls, financial statements, and other business activities. Due to anticipated changes in IFRS during the transition period and up to January 1, 2011, and the uncertainty around the future of rate regulated accounting, the Company is not in a position to determine the impact on its financial results at this time.

In order to prepare for the transition, Emera has established a formal project and governance structure which includes a steering committee consisting of senior management from finance, information technology, and human resources. Quarterly updates are provided to the Audit Committee. Emera has engaged an external advisor to assist with the changeover to IFRS.

The project consists of four phases including the initial assessment, detailed assessment, design, and testing and implementation. Emera has completed the initial assessment phase which included a review of the major differences between Canadian GAAP and IFRS. Although IFRS has a conceptual framework similar to Canadian GAAP there are areas that have a high potential impact to Emera including rate regulated accounting, property, plant and equipment, income taxes, and employee future benefits. In addition, there is significantly more disclosure required under IFRS. Emera will also be affected by the provisions of IFRS 1 First-Time Adoption of IFRS.

Emera is now engaged in the detailed assessment phase. Working groups were formed by topical area and are focused on identifying accounting differences between Canadian GAAP and IFRS on a detailed basis. The detailed assessment phase and the design phase, which include designing business process changes and providing training to employees, are expected to be completed in 2009. The testing and implementation phase will take place during late 2009 to January 1, 2011. The rollout of IFRS and a parallel run of Canadian GAAP and IFRS will take place in 2010.

Dividends and Payout Ratios

The Board of Directors has approved two increases to the quarterly dividend in 2008. In January 2008, the Board of Directors approved a quarterly dividend increase to $0.2375 per common share, reflecting an increase on an annualized basis to $0.95 per common share. In October 2008, the Board of Directors approved a quarterly dividend increase to $0.2525 per common share, reflecting an increase on an annualized basis to $1.01 per common share.

Emera Inc.'s common dividend rate was $0.97 ($0.2375 per quarter in Q1, Q2 and Q3; and $0.2525 in Q4) per common share in 2008 and $0.90 ($0.2225 per quarter in Q1 and Q2; and $0.2275 in Q3 and Q4) for 2007, representing a payout ratio of approximately 76% for 2008 and 66% for 2007.

Business Risks and Enterprise Risk Management

RISK MANAGEMENT

Significant risk management activities for Emera are overseen by the Enterprise Risk Management Committee to ensure that risks are appropriately assessed, monitored and controlled within predetermined risk tolerances established through approved policies.

The company's risk management activities are focused on those areas that most significantly impact profitability and quality of earnings. These risks include, but are not limited to, exposure to commodity prices, foreign exchange, interest rates, credit risk, and regulatory risk.

In November 2008, the UARB approved the implementation of a FAM effective January 1, 2009. The FAM has been established to mitigate the effects of volatile fuel costs, including related foreign exchange risk, on the electricity rates paid by the customers of Nova Scotia Power. Customers will pay the actual fuel costs including foreign exchange gains and losses related to fuel, adjusted for the incentive mechanism in the FAM. The incentive is 10% of the first $50 million of fuel costs above or below the target, adjusted for load.

Commodity Prices

Substantially all of the Company's annual fuel requirement is subject to fluctuation in commodity market prices, prior to any commodity risk management activities. The Company utilizes a portfolio strategy for fuel procurement with a combination of long, medium, and short-term supply agreements. It also provides for supply and supplier diversification. The strategy is designed to reduce the effects from market volatility through agreements with staggered expiration dates, volume options, and varied pricing mechanisms.

Coal/Petroleum Coke

A substantial portion of NSPI's coal and petroleum coke supply comes from international suppliers, which was contracted at or near the market prices prevailing at the time of contract. The Company has entered into fixed-price and index price contractual arrangements with several suppliers as part of the fuel procurement portfolio strategy. All index priced contractual arrangements are matched with a corresponding financial instrument to fix the price. Physical contracts are used to hedge coal price risk, due to the lack of liquidity in the financial markets for coal. The approximate percentage of coal and petcoke requirements contracted at December 31, 2008 is as follows:

- *2009* – 91%
- *2010* – 29%
- *2011* – 19%
- *2012* – 7%

Heavy Fuel Oil

NSPI manages exposure to changes in the market price of heavy fuel oil through the use of swaps, options, and forward contracts. The approximate percentage of heavy fuel oil requirements hedged and contracted as at December 31, 2008, is as follows:

- *2009* – 100%
- *2010* – 58%

Natural Gas

NSPI has entered into multi-year contracts to purchase approximately 65,600 mmbtu of natural gas per day. Volumes exposed to market prices are managed using financial instruments where the fuel is required for NSPI's generation; and the balance is sold against market prices where available for resale. Fixed price gas volumes not required for generation will be resold into the gas market with the margin hedged using financial instruments. As at December 31, 2008, amounts of natural gas volumes that have been economically and/or financially hedged and contracted are approximately as follows:

- *2009* – 99%
- *2010* – 67%

Fuel Mix

The ability to switch fuel at NSPI's Tufts Cove generating station provides a dynamic and effective option in managing commodity price and supply risk. During 2007, NSPI began using a new domestic supplier in two of its coal plants, which provides additional pricing and geographical flexibility.

Purchased Power

Emera, along with its joint venture partner, has entered into a contract with Bear Swamp to provide the power necessary to produce the energy requirements of the LIPA contract. As at December 31, 2008, amounts of purchased power Emera has hedged are approximately as follows:

- *2009* – 97%
- *2010* – 100%
- *2011* – 60%
- *2012* – 10%
- *2013* – 10%

Foreign Exchange

The risk due to fluctuation of the Canadian dollar against the US dollar for the cost of fuel is measured and managed. In 2009, NSPI expects approximately 80% of its anticipated net fuel costs to be denominated in USD; USD from sales of surplus natural gas will provide a natural hedge against a portion of USD fuel costs.

Emera enters into foreign exchange forward and swap contracts to limit exposure on fuel purchases to currency rate fluctuations. Currency forwards are used to fix the Canadian dollar cost to acquire US dollars, reducing exposure to currency rate fluctuations. Forward contracts to buy USD $318.0 million are in place at a weighted average rate of $1.08, representing over 70% of 2009 anticipated USD requirements. Forward contracts to buy USD $602.5 million in 2010 through 2012 at a weighted average rate of $1.01 were in place at December 31, 2008 to manage exposure to 34% of anticipated USD requirements in these years.

Emera uses foreign exchange forward contracts to hedge the currency risk for capital projects and receivables denominated in foreign currencies. Forward contracts to buy USD $7.8 million are in place at a weighted average rate of $0.99 for capital projects in 2009. Forward contracts to sell USD $39.0 million are in place at a weighted average rate of $1.25 to hedge a portion of receivables in 2010.

Emera uses forward contracts to hedge the currency risk associated with revenue streams denominated in foreign currencies. Forward contracts to sell USD $46.0 million are in place in 2009 and 2010 at a weighted average rate of $1.25.

Option contracts, to eliminate exposure to currency rate fluctuations for 2009, of $0.5 million at a rate of $1.26 were outstanding on December 31, 2008.

INTEREST RATES

Emera manages interest rate risk through a combination of fixed and floating borrowing and a hedging program. Floating-rate debt is estimated to represent approximately 24% of total debt in 2009. The company has no interest rate hedging contracts outstanding as of December 31, 2008.

CREDIT RISK

Credit risk arising as a result of contractual obligations between the corporation and other counterparties is managed by assessing the counterparties' financial creditworthiness prior to assigning credit limits based on the Board of Directors' approved credit policies. The Company frequently uses collateral agreements within its negotiated master agreements to further mitigate credit exposure.

Regulatory Risk

NOVA SCOTIA POWER

NSPI faces risk with respect to the timeliness and certainty of full recovery of costs. A central outcome of the 2009 rate decision will help to reduce that risk. NSPI and formal Intervenors agreed that the UARB should implement a FAM for Nova Scotia Power effective January 1, 2009 to ensure fuel costs are recovered from customers. In November 2008 the UARB issued a decision that approves the implementation of the FAM, effective January 1, 2009 with the first rate adjustment under the FAM occurring on January 1, 2010. The UARB will oversee the FAM, including review of fuel costs, contracts and transactions. The decision supports NSPI's position that a FAM is the best way to ensure customer rates reflect the actual price of the fuel used to make electricity. With the proposed implementation of the FAM in 2009, NSPI's ROE range is reduced by 0.2%, changing its ROE range to 9.1% to 9.6%, with rates set at 9.35%.

BANGOR HYDRO

Bangor Hydro's business consists of three primary components which are each governed by their own regulatory structure. The components include distribution, transmission, and stranded costs.

BHE's distribution business operates under the regulation of the Maine Public Utilities Commission. BHE operates under a traditional cost-of-service regulatory structure. Until December 31, 2007, BHE operated under an Alternate Rate Plan which governed distribution rates. In late 2007 the MPUC approved a modest increase in distribution rates under the traditional cost-of-service regulatory structure. In the event that costs rise faster than revenues, BHE would have the ability to return to the MPUC at any time to request a further increase in rates.

The transmission business of BHE is primarily regulated by the FERC. The rates charged are determined by formula and are adjusted on an annual basis. Bangor Hydro is a participating transmission owner within the Regional Transmission Organization for New England, and its operations are therefore linked with the transmission operations of all of New England. BHE's return on equity on its transmission assets, and the extent to which BHE will receive added incentives on the ROE for its transmission assets is determined by FERC along with the regional transmission owners.

BHE also has the ability to recover stranded costs of both regulatory assets and purchasing power at above-market prices. This ability eliminates the commodity risk involved with fixed price purchase power contracts.

Metering, billing and settlement services for power suppliers are provided directly by BHE within its service territory, and BHE is permitted to recover all prudently incurred costs for these services.

LABOUR

Nova Scotia Power has a contract with its union which will expire in 2012 and Bangor Hydro has a contract with its union which will expire in 2010.

Corporate Environmental Governance

Emera is committed to operating in a manner that is respectful and protective of the environment, and in full compliance with legal requirements and company policy. Emera and its wholly-owned subsidiaries have implemented this policy through development and application of environmental management systems ("EMS").

Implementation of EMS has provided a systematic focus on environmental issues such that risks are identified and managed proactively. All areas of Emera undertook initiatives in 2008 to reduce potential environmental risks and associated costs. Activities included, but were not limited to, reducing air emissions, protecting water resources, and continued management of PCB contaminated electrical equipment.

Conformance with legislative and company requirements is verified through a comprehensive environmental audit program. There were no significant environmental or regulatory compliance issues identified during the 2008 audits. Plans are in place to promptly address any audit finding and continually improve the environmental management of the operations.

Oversight of environmental matters is carried out by the Board of Directors of all Emera operating companies or committees of the Board of Directors with specific environmental responsibilities. In addition, an Environmental Council, made up of senior Emera employees with working accountability for environment, continues to guide the implementation of programs that address key environmental issues. In addition to programs for employees, the EMS procedures of all wholly-owned subsidiaries include planning, implementing and monitoring of contractors' performance.

In 2007, NSPI was audited by the Canadian Electricity Association ("CEA") to verify the quality of its environmental reporting and management systems. The auditor from the CEA concluded that NSPI had "robust programs, environmental leadership and a strong, mature EMS."

Climate Change and Air Emissions

NSPI has stabilized greenhouse gas emissions. This has been achieved by energy efficiency and conservation programs, increased use of natural gas, improved efficiency of converting natural gas to electricity and adding and contracting for new renewable energy sources to the generation portfolio.

In January 2007, the Nova Scotia government announced the Renewable Energy Standards Regulations requiring NSPI to increase the supply of renewable energy by 5% by 2010 and 10% by 2013. In April 2007, the province enacted an Act Respecting Environmental Goals and Sustainable Prosperity. Within this act there is an objective to reduce provincial greenhouse gas emissions to 10 percent below 1990 levels by 2020. In January 2009, the province released their 2009 Energy Strategy and Climate Change Action Plan. These documents provide the elements of the plan to achieve this objective.

As described in the plan, greenhouse gas emissions from NSPI will be capped beginning in 2010 through to 2020. The province is developing regulations in line with the plan, which will provide details on the caps. It is anticipated that the 2010 cap will be achieved by continuing success of energy efficiency and conservation programs and the addition of renewable energy to meet the 2010 provincial renewable energy standards. In 2008, NSPI signed power purchase agreements for 246 MW of new wind energy sources with seven independent power producers. These power purchase agreements call for those facilities to reach commercial operation between 2009 and 2010.

Further it is anticipated that the 2013 – 2015 caps will be achieved by flattening load growth through aggressive energy efficiency and conservation programs and adding renewable energy to meet the provincial 2013 renewable energy standards. NSPI has also piloted co-firing of local biomass, which is a carbon neutral fuel, in the coal fired power plants.

Beyond 2015, reduced greenhouse gas emissions will be achieved through a combination of additional renewable energy, co-firing of biomass in existing coal power plants, import of non-emitting energy and energy efficiency and conservation.

The federal government has not formalized any greenhouse gas emission reduction regulations. NSPI continues to provide input to the federal government as they proceed with their consultations.

In 2008, NSPI carried out extensive testing on mercury abatement technology in the coal power plants. A capital program has been established to add sorbent injection to each of the seven pulverized fuel coal units in 2009. This will allow NSPI to meet the mercury emission cap of 65 kg established by the province for 2010.

NSPI has completed its capital program of retrofitting low nitrogen oxide combustion firing systems of six of its seven pulverized fuel coal units. NSPI now meets the nitrogen oxide emission cap of 21,365 tonnes per year established by the province for 2009.

NSPI continues to meet its emission cap on sulphur dioxide emissions by the use of compliant fuel.

Compared to historical levels, NSPI will have reduced sulphur dioxide by 50% for 2010, nitrogen oxide by 40% for 2009 and mercury emissions by 60% for 2010.

Summary of Quarterly Reports

FOR THE QUARTER ENDED
MILLIONS OF DOLLARS (EXCEPT EARNINGS PER COMMON SHARE)

	Q4 2008	Q3 2008	Q2 2008	Q1 2008	Q4 2007	Q3 2007	Q2 2007	Q1 2007
Total revenues	**$ 337.3**	$ 295.8	$ 317.6	$ 381.2	$ 343.9	$ 310.3	$ 325.4	$ 359.9
Net earnings applicable to common shares	**25.3**	6.5	42.9	69.4	36.6	40.9	34.1	39.7
Earnings per common share – basic	**0.23**	0.05	0.39	0.62	0.33	0.37	0.30	0.36
Earnings per common share – diluted	**0.22**	0.05	0.37	0.58	0.32	0.35	0.30	0.35

Quarterly total revenues and net earnings applicable to common shares are affected by seasonality, with Q1 and Q4 the strongest periods, reflecting colder weather and fewer daylight hours at those times of year.

MANAGEMENT REPORT

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

The accompanying consolidated financial statements of Emera Inc. ("Emera"or "the Company") and the information in this annual report are the responsibility of management and have been approved by the Board of Directors ("Board").

The consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Nova Scotia Power Inc. ("NSPI"), one of Emera's wholly-owned electric utilities and principal subsidiary, is regulated by the Nova Scotia Utility and Review Board, which also examines and approves NSPI's accounting policies and practices. Emera's other wholly-owned electric utility and subsidiary, Bangor Hydro-Electric Company ("Bangor Hydro"), is regulated by the Federal Energy Regulatory Commission and the Maine Public Utilities Commission, which also examine and approve Bangor Hydro's accounting policies and practices. In preparation of these consolidated financial statements, estimates are sometimes necessary when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Management believes that such estimates, which have been properly reflected in the accompanying consolidated financial statements, are based on careful judgements and are within reasonable limits of materiality. Management has determined such amounts on a reasonable basis in order to ensure that the consolidated financial statements are presented fairly in all material respects. Management has prepared the financial information presented elsewhere in the annual report and has ensured that it is consistent with that in the consolidated financial statements.

Emera maintains effective systems of internal accounting and administrative controls, consistent with reasonable cost. Such systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that Emera's assets are appropriately accounted for and adequately safeguarded.

The Board is responsible for ensuring that management fulfills its responsibilities for financial reporting and is ultimately responsible for reviewing and approving the consolidated financial statements. The Board carries out this responsibility principally through its Audit Committee.

The Audit Committee is appointed by the Board, and its members are directors who are not officers or employees of Emera. The Audit Committee meets periodically with management, as well as with the internal auditors and with the external auditors, to discuss internal controls over the financial reporting process, auditing matters and financial reporting issues, to satisfy itself that each party is properly discharging its responsibilities, and to review the annual report, the consolidated financial statements and the external auditors' report. The Audit Committee reports its findings to the Board for consideration when approving the consolidated financial statements for issuance to the shareholders. The Audit Committee also considers, for review by the Board and approval by the shareholders, the appointment of the external auditors.

The consolidated financial statements have been audited by Ernst & Young LLP, the external auditors, in accordance with Canadian generally accepted auditing standards. Ernst & Young LLP has full and free access to the Audit Committee.

February 13, 2009

"Christopher Huskilson"
President and Chief Executive Officer

"Nancy Tower, FCA"
Chief Financial Officer

AUDITORS' REPORT

To the Shareholders of Emera Inc.

We have audited the consolidated balance sheets of Emera Inc. as at December 31, 2008 and 2007, and the consolidated statements of earnings, cash flows, and changes in shareholders' equity 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 mistatement. 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 consolidated 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 its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Halifax, Canada
February 12, 2009

Ernst + Young LLP

"Ernst & Young, LLP"
Chartered Accountants

Emera Inc.
CONSOLIDATED STATEMENTS OF EARNINGS

YEAR ENDED DECEMBER 31 MILLIONS OF DOLLARS (EXCEPT EARNINGS PER COMMON SHARE)	*2008*	*2007*
Revenue		
Electric	**$ 1,280.8**	$ 1,269.5
Other	**51.1**	70.0
	1,331.9	1,339.5
Cost of operations		
Fuel for generation and purchased power	**525.1**	494.5
Operating, maintenance and general	**266.8**	264.8
Provincial, state, and municipal taxes	**49.4**	47.5
Depreciation	**151.3**	149.3
Regulatory amortization	**28.5**	31.4
	1,021.1	987.5
	310.8	352.0
Equity earnings (note 6)	**15.2**	12.8
Financing charges (note 7)	**123.2**	133.2
Earnings before income taxes	**202.8**	231.6
Income taxes (note 8)	**58.1**	80.3
Net earnings	**144.7**	151.3
Non-controlling interest (note 14)	**0.6**	–
Net earnings applicable to common shares	**$ 144.1**	$ 151.3
Earnings per common share – basic (note 10)	**$ 1.29**	$ 1.36
Earnings per common share – diluted (note 10)	**$ 1.26**	$ 1.32

See accompanying notes to the consolidated financial statements.

Emera Inc.
CONSOLIDATED BALANCE SHEETS

AS AT DECEMBER 31 MILLIONS OF DOLLARS	*2008*	*2007*
Assets		
Current assets		
Cash and cash equivalents	**$ 12.2**	$ 26.4
Restricted cash	**0.8**	1.0
Accounts receivable (note 11)	**385.1**	319.3
Income tax receivable	**15.7**	13.7
Inventory (note 2)	**131.2**	99.7
Prepaid expenses	**8.3**	11.8
Future income tax assets (note 8)	**7.1**	6.7
Derivatives in a valid hedging relationship	**48.4**	12.2
Held-for-trading derivatives	**73.0**	76.2
	681.8	567.0
Long-term receivable (note 11)	**56.4**	7.7
Derivatives in a valid hedging relationship	**116.7**	11.0
Held-for-trading derivatives	**64.8**	63.6
Other assets (note 12)	**420.1**	417.3
Future income tax assets (note 8)	**17.6**	16.2
Goodwill (note 16)	**102.0**	82.8
Investments subject to significant influence (note 6)	**317.6**	124.5
Available for sale investments	**16.2**	1.8
Property, plant and equipment (note 13)	**2,961.9**	2,820.0
Construction work in progress	**514.3**	109.2
	3,476.2	2,929.2
	$ 5,269.4	$ 4,221.1

Emera Inc.
CONSOLIDATED BALANCE SHEETS (CONTINUED)

AS AT DECEMBER 31 MILLIONS OF DOLLARS	2008	2007
Liabilities and Shareholders' Equity		
Current liabilities		
Current portion of long-term debt (note 19)	$ 131.4	$ 121.0
Current portion of preferred shares issued by subsidiary (note 9)	125.0	–
Short-term debt (note 18)	157.9	28.4
Accounts payable and accrued charges	307.1	282.7
Income tax payable	7.9	3.2
Dividends payable	3.2	3.2
Future income tax liabilities (note 8)	–	2.0
Derivatives in a valid hedging relationship	109.8	44.1
Held-for-trading derivatives	37.8	22.0
	880.1	506.6
Derivatives in a valid hedging relationship	60.0	33.1
Held-for-trading derivatives	14.3	7.1
Future income tax liabilities (note 8)	110.3	82.9
Asset retirement obligations (note 17)	88.0	83.8
Other liabilities (note 12)	236.7	210.8
Long-term debt (note 19)	2,159.2	1,676.4
Preferred shares issued by subsidiary (note 9)	135.0	260.0
Non-controlling interest (note 14)	39.6	0.6
Shareholders' equity		
Common shares (note 20)	1,081.4	1,066.2
Contributed surplus	3.4	3.0
Accumulated other comprehensive income	(69.2)	(209.0)
Retained earnings (note 2)	530.6	499.6
	1,546.2	1,359.8
	$ 5,269.4	$ 4,221.1

Contingencies (note 25), Commitments (notes 5, 23 and 26), Guarantees (note 27), Subsequent Event (note 28)
See accompanying notes to the consolidated financial statements.

Approved on behalf of the Board of Directors

"Derek Oland"
Chairman

"Christopher Huskilson"
President and Chief Executive Officer

Emera Inc.
CONSOLIDATED STATEMENTS OF CASH FLOWS

YEAR ENDED DECEMBER 31 MILLIONS OF DOLLARS	2008	2007
Operating activities		
Net earnings applicable to common shares	**$ 144.1**	$ 151.3
Non-cash items:		
Depreciation	**151.3**	149.3
Amortization of other assets	**13.7**	14.1
Equity earnings	**(15.2)**	(12.8)
Regulatory amortization	**28.5**	31.4
Allowance for funds used during construction	**(21.7)**	(12.3)
Future income taxes	**4.3**	13.2
Post-retirement benefits	**12.5**	15.2
Non-controlling interest	**0.6**	–
Reduction in regulatory asset (note 8)	**–**	16.4
Other non-cash operating items	**(7.1)**	(0.1)
Other cash operating items	**6.5**	4.6
	317.5	358.7
Change in non-cash operating working capital (note 21)	**(80.3)**	(7.3)
Net cash provided by operating activities	**237.2**	351.4
Investing activities		
Property, plant and equipment	**(545.8)**	(251.6)
Decrease (increase) in restricted cash	**0.2**	(1.0)
Retirement spending net of salvage	**(5.7)**	(5.0)
Acquisitions (note 14)	**(60.7)**	(25.7)
Investments	**(59.6)**	(5.6)
Net cash used in investing activities	**(671.6)**	(288.9)
Financing activities		
Retirements of long-term debt	**(120.8)**	(2.8)
Issuance of long-term debt	**150.0**	117.1
Increase (decrease) in short-term debt	**519.5**	(22.2)
Issuance of common shares	**14.4**	10.7
Dividends on common shares	**(107.9)**	(99.9)
Dividends paid by subsidiaries to non-controlling interest	**(1.9)**	–
Accounts receivable securitization	**(25.0)**	(55.0)
Other financing activities	**(8.1)**	(3.5)
Net cash provided by (used in) financing activities	**420.2**	(55.6)
(Decrease) increase in cash and cash equivalents	**(14.2)**	6.9
Cash and cash equivalents, beginning of year	**26.4**	19.5
Cash and cash equivalents, end of year	**$ 12.2**	$ 26.4

Cash and cash equivalents consists of:		
Cash	**$ 5.0**	$ 5.4
Short-term investments	**7.2**	21.0
Cash and cash equivalents, end of year	**$ 12.2**	$ 26.4

Supplemental disclosure of cash paid:		
Interest	**$ 131.5**	$ 119.1
Income and capital taxes	**$ 62.1**	$ 108.2

See accompanying notes to the consolidated financial statements.

Emera Inc.
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

FOR THE YEAR ENDED DECEMBER 31, 2008 MILLIONS OF DOLLARS	COMMON SHARES	CONTRIBUTED SURPLUS	ACCUMULATED OTHER COMPREHENSIVE INCOME ("AOCI")	RETAINED EARNINGS	TOTAL AOCI AND RETAINED EARNINGS
Balance, December 31, 2007	$ 1,066.2	$ 3.0	$ (209.0)	$ 499.6	$ 290.6
Accounting policy change (note 2)	–	–	–	(3.3)	(3.3)
Comprehensive Income:					
Net earnings applicable to common shares	–	–	–	144.1	144.1
Net gain on derivatives in a valid hedging relationship	–	–	83.1	–	83.1
Reclassification of hedging gains included in income	–	–	(28.9)	–	(28.9)
Reclassification of hedging gains included in inventory	–	–	(14.7)	–	(14.7)
Reclassification of hedging gains included in construction work in progress	–	–	(0.5)	–	(0.5)
Unrealized gain on translation of self-sustaining foreign operations	–	–	102.1	–	102.1
Other	–	–	(1.3)	–	(1.3)
Total comprehensive income	–	–	139.8	144.1	283.9
Dividends declared on common shares	–	–	–	(107.9)	(107.9)
Dividends paid by subsidiaries to non-controlling interest	–	–	–	(1.9)	(1.9)
Common shares issued under purchase plans	8.0	–	–	–	–
Senior management stock options exercised	6.4	(0.5)	–	–	–
Stock option expense	–	0.9	–	–	–
Other share-based compensation	0.8	–	–	–	–
Balance, December 31, 2008	$ 1,081.4	$ 3.4	$ (69.2)	$ 530.6	$ 461.4

FOR THE YEAR ENDED DECEMBER 31, 2008 MILLIONS OF DOLLARS	COMMON SHARES	CONTRIBUTED SURPLUS	AOCI	RETAINED EARNINGS	TOTAL AOCI AND RETAINED EARNINGS
Balance, December 31, 2006	$ 1,055.2	$ 2.2	$ (100.2)	$ 450.9	$ 350.7
Accounting policy change	–	–	(5.3)	(2.7)	(8.0)
Comprehensive Income:					
Net earnings applicable to common shares	–	–	–	151.3	151.3
Net loss on derivatives in a valid hedging relationship	–	–	(58.2)	–	(58.2)
Reclassification of hedging losses included in income	–	–	14.6	–	14.6
Reclassification of hedging losses included in inventory	–	–	2.4	–	2.4
Unrealized loss on translation of self-sustaining foreign operations	–	–	(62.1)	–	(62.1)
Other	–	–	(0.2)	–	(0.2)
Total comprehensive income	–	–	(103.5)	151.3	47.8
Dividends declared on common shares	–	–	–	(99.9)	(99.9)
Common shares issued under purchase plans	9.0	–	–	–	–
Senior management stock options exercised	1.7	–	–	–	–
Stock option expense	–	0.8	–	–	–
Other share-based compensation	0.3	–	–	–	–
Balance, December 31, 2007	$ 1,066.2	$ 3.0	$ (209.0)	$ 499.6	$ 290.6

See accompanying notes to the consolidated financial statements.

EMERA INC.
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2008 AND 2007

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Emera Inc., incorporated in the Province of Nova Scotia, through its principal subsidiaries, Nova Scotia Power Inc. ("Nova Scotia Power" or "NSPI") and Bangor Hydro-Electric Company ("Bangor Hydro" or "BHE"), is engaged in the production and sale of electric energy.

Nova Scotia Power is the primary electricity supplier in Nova Scotia providing over 95% of electricity generation, transmission and distribution in the province. NSPI is a public utility as defined under the Public Utilities Act of Nova Scotia ("Act") and is subject to regulation under the Act by the Utility and Review Board ("UARB"). The Act gives the UARB authority over NSPI's operations and expenditures. Electricity rates for NSPI's customers are subject to UARB approval. NSPI is not subject to an annual rate review process, but rather participates in hearings from time to time at NSPI's or the regulator's request.

NSPI is regulated under a cost of service model, with rates set to cover prudently incurred costs of providing electricity service to customers, and provide an opportunity to earn an appropriate return to investors. NSPI's return on equity ("ROE") range for 2008 is 9.3% to 9.8%, on a maximum allowed common equity component of 40% of the total capitalization. Rates were set for 2009 using 9.35% ROE with a common equity component of 37.5%.

NSPI's accounting policies are subject to examination and approval by the UARB.

Bangor Hydro's core business is the transmission and distribution ("T&D") of electricity. Electricity is deregulated in Maine, and several suppliers compete to provide customers with the commodity that is delivered through the BHE T&D network. In addition to the T&D network, BHE has net regulatory assets (stranded costs), which arose through the electricity industry restructuring, and as a result of rate and accounting orders issued by its regulators. Approximately 60% of BHE's electric rates represent distribution services, 20% relate to stranded costs recoveries, and 20% to transmission service. The rates for each element are established in distinct regulatory proceedings. The transmission operations are regulated by the Federal Energy Regulatory Commission ("FERC"), and the distribution operations and stranded costs are regulated by the Maine Public Utilities Commission ("MPUC").

BHE operates under a traditional cost-of-service regulatory structure. In December 2007, the MPUC approved an increase of approximately 2% in distribution rates effective January 1, 2008. The allowed ROE used in setting the new distribution rates is 10.2%, with a common equity component of 50%.

Until December 31, 2007, BHE's distribution services operated under an Alternate Rate Plan ("ARP"), which provided for an ROE of 5% to 17% on distribution operations, with rates set at the midpoint of 11%. There was a 50/50 sharing mechanism between BHE and customers outside of the earnings band. The ARP also included performance standards and provided for average annual reductions in distribution rates of approximately 2.5% for five years, to 2007. Beginning January 1, 2008, the earnings band and associated sharing mechanism, performance standard, and annual distribution rate reductions were no longer applicable.

BHE's stranded cost rates provide for an allowed ROE of 10% on the related asset base for the three-year period ending February 29, 2008. In December 2007 the MPUC issued an order approving an approximately 39% reduction in stranded cost rates for the three-year period beginning March 1, 2008. The allowed ROE used in setting the new stranded cost rates is 8.5%.

Transmission rates are set by the FERC annually on July 1, based on the prior year's revenue requirement. The allowed ROE for transmission operations ranges from 11.14% for low voltage transmission up to 12.64% for high voltage transmission developed as a result of the regional system plan, which includes the NRI transmission line.

Bangor Hydro's accounting policies are subject to examination and approval by FERC and the MPUC.

Brunswick Pipeline is a pipeline which will deliver natural gas from the Canaport™ Liquefied Natural Gas ("LNG") import terminal, currently under construction, near Saint John, New Brunswick to markets in Canada and the northeastern United States. The pipeline was mechanically complete and received National Energy Board approval for shipping gas, in January 2009. The 145 kilometre Brunswick Pipeline will travel through southwest New Brunswick and connect with the Maritimes and Northeast Pipeline ("M&NP") at the Canada/US border near Baileyville, Maine.

Canaport™ LNG is a partnership of Repsol YPF, S.A. ("Repsol") and Irving Oil Limited. Emera has negotiated a 25 year send or pay toll agreement with Repsol to transport natural gas through the Brunswick Pipeline. Toll rates were set using a return on project equity of 11% – 14% and have been approved by the National Energy Board which regulates Brunswick Pipeline.

Emera follows Canadian generally accepted accounting principles ("GAAP"). The accounting policies approved by the regulators of NSPI, Bangor Hydro, and Brunswick Pipeline may differ from GAAP for non rate-regulated companies in that the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under GAAP. Where the differences between GAAP and GAAP for rate-regulated companies are considered significant, disclosure of the policy has been made in these notes to the consolidated financial statements.

a. Consolidation

The consolidated financial statements include the accounts of Emera Inc. and its subsidiaries. Intercompany transactions and accounts have been eliminated.

b. Measurement Uncertainty

The preparation of financial statements in accordance with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods.

At the end of each month, amounts of energy delivered to customers since the date of their last meter reading are estimated along with the associated unbilled revenues. This estimate is based on several different factors including generation, estimated usage by customer class, weather and line losses.

Actual results may differ from these estimates.

c. Revenue Recognition

The Company's revenue recognition policy is as follows:

- Electric: Revenues are recognized on the accrual basis, which includes an estimate of electricity consumed by customers in the year but billed subsequent to year-end.
- Energy Marketing: Derivatives that are not entered into for hedging purposes are recognized at fair market value at year-end.
- Other: Revenues are recognized on the accrual basis, which includes an estimate for services performed and goods delivered during the year but billed subsequent to year-end.
- Unearned revenue is recorded as an other liability.

Electric revenues generated by NSPI and Bangor Hydro are recognized at rates set by their respective regulators. The Company is unable to determine the effect the absence of rate regulation would have on electric revenue.

d. Allowance for Funds Used during Construction

Accounting for the impact of rate regulation:

In accordance with accounting policies determined by their respective regulators, NSPI, Bangor Hydro, and Brunswick Pipeline provide for the cost of financing construction work in progress by including an allowance for funds used during construction ("AFUDC") as an addition to the cost of property constructed, using a weighted average cost-of-capital. AFUDC is included in property, plant and equipment and construction work in progress for financial reporting purposes and is charged to operations through depreciation over the service life of the related assets and recovered through future revenues. Since AFUDC includes not only an interest component, but also an equity component, it exceeds the amount that could be capitalized in the absence of regulated accounting policies.

e. Regulatory Amortization

Accounting for the impact of rate regulation:

In accordance with the regulations of the UARB, significant assets of Nova Scotia Power, which are not currently being used and are not expected to provide service to customers in the foreseeable future, are amortized over five years. In 2000 the UARB approved NSPI's request to amortize the Glace Bay generating station over five years. The UARB had allowed Nova Scotia Power flexibility in determining the annual amount to be written off in order to support rate stability. On July 28, 2003, the UARB approved the Company's request to extend the write-off period through 2008, if necessary, with an annual minimum amortization of $6.2 million. Prior to 2007 the unamortized portion of the generation station was included in property, plant and equipment, however, amortization was completed in Q4 2007. In the absence of the UARB's approved accounting policies, the generation station would have been written off in the year when NSPI determined that the unamortized cost of the generating station would not be recoverable.

NSPI has a regulatory asset related to pre-2003 income taxes that have been paid, but not yet recovered from customers. This circumstance arose when NSPI claimed capital cost allowance ("CCA") deductions in its income tax returns that were ultimately disallowed by a decision of the Supreme Court of Canada. NSPI applied to the regulator to include recovery of these costs in customer rates. The UARB approved recovery of this regulatory asset over eight years, commencing April 1, 2007. In the absence of UARB approved recovery, the liability would have been expensed when incurred. More details are provided in note 12.

The UARB agreed to allow NSPI to defer taxes not reflected in rates for the period January 1, 2005 until April 1, 2005, the date when new rates became effective. The UARB approved recovery of this regulatory asset over eight years, commencing April 1, 2007. In the absence of UARB approved deferral, the taxes would have been expensed in 2005. More details are provided in note 12.

The UARB agreed to allow NSPI to defer demand side management program expenses for the period January 1, 2008 until December 31, 2009. The UARB approved recovery of this regulatory asset over six years commencing January 1, 2009. In the absence of UARB approved deferral, 2008 expenses incurred would have been expensed in 2008. More details are provided in note 12.

In accordance with rate and accounting orders issued by the MPUC, Bangor Hydro has recorded regulatory assets and liabilities on its balance sheet. These regulatory assets and liabilities are being amortized over varying lives expiring through to 2018 through charges to earnings. These regulatory assets and liabilities are included in other assets and other liabilities and include costs related to restructuring of purchased power contracts, the Seabrook nuclear project, decommissioning costs for Maine Yankee, obligations to Hydro-Québec, and the stranded cost revenue requirement levelizer, and are described in more detail in note 12.

f. Property, Plant and Equipment

Property, plant and equipment are recorded at original cost, net of contributions in aid of construction. When property, plant and equipment are replaced or retired, any remaining net book value is charged to net earnings.

Depreciation is determined by the straight-line method, based on the estimated remaining service lives of the depreciable assets in each category. The estimated average service life for the Company's unregulated general assets is 5 years (2007 – 8 years). Unregulated generation assets have an estimated average service life of 38 years (2007 – 51 years).

When indicators of impairment exist, the Company determines whether the net carrying amount of property, plant and equipment is recoverable from future undiscounted cash flows. Factors, which could indicate impairment exists, include significant changes in regulation, a change in the Company's strategy or underperformance relative to projected future operating results.

Accounting for the impact of rate regulation:

During 2003, following completion of a depreciation study, and a negotiated agreement with stakeholders, NSPI's regulator approved new depreciation rates which were to be phased in over four years beginning in 2004. In the decision on NSPI's 2005 rate application, the UARB delayed the phase-in of year-two rates for one year. In the decision on NSPI's 2006 rate application, the UARB approved restarting of the phase-in including year-two in 2006 rates. In its February 5, 2007 decision, the UARB postponed the scheduled year-three phase-in of increased depreciation rates until the next rate application. In its November 5, 2008 decision, the UARB approved the year-three phase-in effective January 1, 2009. Absent consideration of growth in plant-in-service, the phase-in of new depreciation rates will increase depreciation expense by a cumulative increase of $20 million over the phase-in period. In the absence of the UARB's approval of depreciation rates, NSPI would be required to set rates based on management's best estimates of useful lives. The average rates for the major categories of plant in service are summarized as follows:

FUNCTION	*2008*	*2007*
Generation		
Thermal	**2.44%**	2.44%
Gas turbines	**2.32%**	2.32%
Combustion turbines	**3.33%**	3.33%
Hydroelectric	**1.39%**	1.39%
Wind turbines	**5.00%**	5.00%
Transmission	**2.65%**	2.65%
Distribution	**4.04%**	4.04%
General plant	**7.12%**	7.12%
General plant under capital lease	**10.95%**	–
Weighted average depreciation rate	**3.05%**	3.07%

Bangor Hydro's depreciation is determined by the straight-line method, based on the estimated service lives of the depreciable assets in each category. In 2004 BHE implemented the results of a depreciation study that was completed in 2004 and approved by its regulators. The estimated average service lives in years for the major categories of plant in service are summarized as follows:

FUNCTION	*2008*	*2007*
Transmission	**50**	46
Distribution	**36**	36
Other	**15**	15
Weighted average service life	**38**	36

In accordance with regulator approved accounting policies, when depreciable property, plant and equipment of NSPI and Bangor Hydro are replaced or retired, the original cost plus any removal costs incurred (net of salvage) are charged to accumulated depreciation with no gain or loss reflected in results of operations. Gains and losses will be charged to results of operation in the future through adjustments to depreciation expense. In the absence of regulator approved accounting policies gains and losses on the disposition of property, plant and equipment are charged to net earnings as incurred.

g. Capitalization Policy

Capital assets of the Company include labour, materials, and other non-labour costs directly attributable to the capital activity. In addition, overhead costs that contribute to the capital program are allocated to capital projects. These costs include corporate costs such as finance, information technology, executive and other support functions, employee benefits, insurance, inventory costs, and fleet operating and maintenance costs. The Company calculates an application rate and only eligible operating expenditures are used in the calculation. The Company applies overhead costs based on direct labour costs. The application rate varies depending on the type of capital expenditure. In addition, BHE applies inventory overhead based on inventory issued to the project, and applies general and administrative overhead based upon non-labour charges.

h. Leases

Leases that substantially transfer all the benefits and risks of ownership of property, plant and equipment to the Company, or otherwise meet the criteria for capitalizing a lease under GAAP, are accounted for as capital leases. An asset is recognized at the time a capital lease is entered into together with its related long-term obligation. Property, plant and equipment recognized under capital leases are depreciated on the same basis as described in note 1(f). Payments on operating leases are expensed as incurred.

i. Income Taxes and Investment Tax Credits

Emera follows the future income tax method of accounting for income taxes.

Investment tax credits arise as a result of incurring qualifying scientific research and development expenditures and are recorded in the year as a reduction from the related expenditures where there is reasonable assurance of collection.

Accounting for the impact of rate regulation:

In accordance with ratemaking regulations established by the UARB, NSPI uses the taxes-payable method of accounting for income taxes. Bangor Hydro uses the future income tax method where allowed for ratemaking purposes. Brunswick Pipeline uses the taxes-payable method as allowed for ratemaking purposes. NSPI, Bangor Hydro, and Brunswick Pipeline would be required to recognize all future income tax assets and liabilities in the absence of their regulator approved accounting policies. More details are provided in note 8.

j. Employee Future Benefits

Pension obligations, and obligations associated with non-pension post-retirement benefits such as health benefits to retirees and retirement awards, are actuarially determined using the projected benefit method prorated on services and management's best estimate assumptions. The accrued benefit obligation is valued based on market interest rates at the valuation date.

Pension fund asset values are calculated using market values at year-end. The expected return on pension assets is determined based on market-related values. The market-related values are determined in a rational and systematic manner so as to recognize investment gains and losses, relative to the assumed rate of return, over a five-year period.

Adjustments to the accrued benefit obligation arising from plan amendments are amortized on a straight-line basis over the expected years of future service to the full eligibility date for active employees.

For any given year, when the net actuarial gain (loss), less the actuarial gain (loss) not yet included in the market-related value of plan assets, exceeds 10% of the greater of the accrued benefit obligation and the market-related value of the plan assets, an amount equal to the excess divided by the average remaining service period ("ARSP") is amortized on a straight-line basis. For NSPI, the ARSP of the active employees is 9 years as at December 31, 2008 (2007 – 10 years). For Bangor Hydro this excess is amortized on a straight-line basis over the expected ARSP, in accordance with ratemaking purposes, which is 11 years as at December 31, 2008 (2007 – 12 years). For Emera Inc., the ARSP of the active employees is 12 years as at December 31, 2008 (2007 – 12 years).

On January 1, 2000, Emera adopted the new accounting standard on employee future benefits using the prospective application method. The transitional obligation (asset) resulting from the initial application is amortized linearly over 13 years, which was the expected ARSP of active employees at the transition date.

The difference between benefit cost and pension funding is recorded as an other asset or liability on the balance sheet.

k. Share-Based Compensation

The Company has several share-based compensation plans, which are a common share option plan for senior management, an employee common share purchase plan, a deferred share unit plan, and a restricted share unit plan. The Company accounts for its plans in accordance with the fair value based method of accounting for share-based compensation.

l. Cash and Cash Equivalents

Short-term investments, which consist of money market instruments with maturities of three months or less, are considered to be cash equivalents and are recorded at cost, which approximates current market value. The short-term investments have an effective interest rate of 0.32% at December 31, 2008 (2007 – 3.73%).

m. Inventory

Inventories are measured at the lower of cost and net realizable value. The Company uses the weighted average method to determine the cost of inventory.

n. Debt Financing Costs

Financing costs pertaining to debt issues are amortized over the life of the related debt using the effective interest method.

o. Derivative Financial and Commodity Instruments

The Company uses various financial instruments to hedge its exposure to foreign exchange, interest rate, and commodity price risks. In addition, the Company has contracts for the physical purchase and sale of natural gas, and physical and financial contracts that are held-for-trading ("HFT"). Collectively, these contracts are referred to as derivatives.

The Company recognizes the fair value of all its derivatives that are not designated as contracts held for normal purchase or sale on its balance sheet.

Hedging relationships that meet stringent documentation requirements, and can be proven to be effective both at the inception and over the term of the relationship qualify for hedge accounting. Specifically, in a cash flow hedge, the effective portion of the change in the fair value of hedging derivatives is recorded in other comprehensive income and reclassified to earnings in the same period the related hedged item is realized. Any ineffective portion of the change in fair value of hedging derivatives is recognized in net earnings in the reporting period.

For fair value hedges, the change in fair value of the hedging derivatives and the hedged item are recorded in net earnings. Any ineffective portion of the change in fair value is recognized in net earnings in the reporting period.

Where documentation and effectiveness requirements are not met, the change in fair value of the derivative is recognized in earnings in the reporting period. The Company also recognizes the change in fair value of its HFT derivatives in earnings of the reporting period.

If a cash flow hedge is terminated, the effective portion of the change in fair value of the hedging derivative up until the date of termination remains in accumulated other comprehensive income and is recognized in earnings in the same period the related hedged risk is realized. The change in fair value of the derivative, if retained, would then be recognized in earnings from the termination date on.

Amounts received or paid related to derivatives used to hedge foreign exchange and commodity price risks are recognized in the cost of fuel purchases. Amounts received or paid related to derivatives used to hedge interest rate risks are recognized over the term of the hedged item in interest expense. Amounts received or paid related to HFT derivatives are reflected in other revenue, unless alternative treatment is available as approved by the UARB.

Cash flows related to derivatives are reflected in operating activities on the statement of cash flows.

Accounting for the impact of rate regulation:

In accordance with Handbook Section 3865 Hedges, NSPI determined that it cannot meet the probability requirement of the standard for its derivatives in place to hedge natural gas and heavy fuel oil for its Tufts Cove generating station ("TUC"). This is due to the generating station's ability to fuel switch and NSPI's economic dispatch based on the cost of these two fuels. The UARB has allowed NSPI to apply hedge accounting to these derivatives as long as the other requirements of the handbook are met. Absent UARB approval, NSPI would be required to recognize the fair value of these derivatives in earnings.

Nova Scotia Power has contracts for the purchase and sale of natural gas at TUC that are considered HFT derivatives and accordingly are recognized on the balance sheet at fair value. This reflects NSPI's history of buying and reselling any natural gas not used in the production of electricity at TUC. Changes in fair value of HFT derivatives are normally recognized in net earnings. In accordance with NSPI's accounting policy for financial instruments and hedges relating to TUC fuel, NSPI has deferred any changes in fair value to a regulatory asset or liability.

Further details on the regulatory assets and liabilities recognized as a result of the above can be found in note 12.

p. Goodwill

Goodwill represents the excess of the purchase price of an acquired business over the net amount of the fair values assigned to its assets and liabilities and is not subject to amortization. The Company evaluates the carrying value of goodwill for potential impairment through an annual review and analysis of fair market value. Goodwill is also evaluated for potential impairment between annual tests if an event or circumstances occur that more likely than not reduces the fair value of a business below its carrying value. Fair market value is determined by use of net present value financial models, which incorporate management's assumptions of future profitability.

q. Long-Term Investments

The Company accounts for certain investments, over which it shares control, using the proportionate consolidation method, whereby the Company recognizes its pro-rata share of the jointly controlled assets and the liabilities jointly incurred in the Company's balance sheet, recognizes its pro-rata share of any revenue and expenses in the Company's statement of earnings, and recognizes its pro-rata share of cash flows on the Company's statement of cash flows. Emera accounts for its investment in Bear Swamp using proportionate consolidation.

The Company accounts for certain investments, over which it maintains significant influence, but not control, using the equity method, whereby the amount of the investment is adjusted annually for the Company's pro-rata share of the income or loss of investment and reduced by the amount of any dividends received. Emera accounts for its investments in Maritimes & Northeast Pipeline, St. Lucia Electricity Services, Grand Bahama Power Corporation, Maine Yankee Atomic Power Company, and Maine Electric Power Company Inc. using the equity method.

r. Foreign Currency Translation

Monetary assets and liabilities denominated in foreign currencies are converted to Canadian dollars at rates of exchange prevailing at the balance sheet date. The resulting differences between the translation at the original transaction date and the balance sheet date are charged to earnings.

Assets and liabilities of self-sustaining foreign operations are translated using the exchange rates in effect at the balance sheet date and the results of operations at the average rates for the period. The resulting exchange gains and losses on the assets and liabilities are deferred and included in other comprehensive income.

s. Research and Development Costs

All research and development costs are expensed in the year incurred, unless they qualify for deferral as a part of capital assets.

2. CHANGE IN ACCOUNTING POLICIES

The Canadian Institute of Chartered Accountants ("CICA") has issued new accounting standards 1535 Capital Disclosures, 3031 Inventories, 3862 Financial Instruments – Disclosures, and 3863 Financial Instruments – Presentation, which are applicable to Emera's 2008 fiscal year. The following provides more information on each new accounting standard.

CAPITAL DISCLOSURES

This new standard requires disclosure of the Company's objectives, policies, and processes for managing capital; quantitative data about what the Company regards as capital; whether the Company has complied with any externally imposed capital requirements; and, if the Company has not complied, the consequences of such non-compliance. The new accounting standard covers disclosure only and had no effect on the financial results of the Company. Further information can be found in note 22.

FINANCIAL INSTRUMENTS – DISCLOSURES, AND FINANCIAL INSTRUMENTS – PRESENTATION

These new standards replace accounting standard 3861 Financial Instruments – Disclosure and Presentation. Presentation requirements have not changed. Enhanced disclosure is required to assist users of the financial statements in evaluating the significance of financial instruments on the Company's financial position and performance, including qualitative and quantitative information about the Company's exposure to risks arising from financial instruments. The new accounting standards cover disclosure only and had no effect on the financial results of the Company. Further information can be found in note 23.

INVENTORIES

The new standard provides more guidance on the measurement and disclosure requirements for inventories than the previous standard, 3030 Inventories. Specifically, the new standard requires that inventories be measured at the lower of cost and net realizable value, and provides more guidance on the determination of cost and its subsequent recognition as an expense, including any write-down to net realizable value. The Company previously measured inventories at the lower of cost and market. The Company uses the weighted-average method to determine the cost of inventory.

The Company has applied the new standard retrospectively without restatement, which resulted in a decrease to inventory and retained earnings of $3.3 million as at January 1, 2008.

The change in inventory is due to the following:

FOR THE	FUEL INVENTORY YEAR ENDED DECEMBER 31		MATERIALS INVENTORY YEAR ENDED DECEMBER 31	
MILLIONS OF DOLLARS	**2008**	*2007*	**2008**	*2007*
Inventory, beginning of period	**$ 67.7**	$ 81.2	**$ 32.1**	$ 32.4
Accounting policy change	**–**	–	**(3.3)**	–
Purchases	**359.7**	313.5	**38.7**	39.0
Write-down of inventory to net realizable value	**–**	–	**(1.1)**	(0.7)
Inventories expensed	**(325.7)**	(327.0)	**(16.3)**	(17.3)
Inventories capitalized	**–**	–	**(22.5)**	(23.0)
Other	**–**	–	**1.9**	1.6
Inventory, end of period	**$ 101.7**	$ 67.7	**$ 29.5**	$ 32.0

The Company has not pledged inventory as security for liabilities.

Future Accounting Policy Changes

Changeover to International Financial Reporting Standards ("IFRS"): In April 2008, the CICA issued an IFRS Omnibus Exposure Draft which proposes that publicly accountable enterprises be required to apply IFRS effective for Emera's 2011 fiscal year with consistent comparative information required for 2010. The Company is currently assessing the effect of IFRS on its financial statements and developing its changeover plan.

Goodwill and Intangible Assets: In February 2008, the CICA issued Section 3064 Goodwill and Intangible Assets ("3064") applicable to Emera's 2009 fiscal year, replacing Section 3062 Goodwill and Other Intangible Assets. The goodwill requirements have not changed. The requirements for intangible assets now clarify that costs may only be deferred when they relate to an item that meets the definition of an asset. An intangible asset must be identifiable; be a resource over which the Company has control; probably generate future economic benefits; and have a reliably measurable cost. The Company is currently assessing the effect of 3064 on its financial statements but does not expect a material change.

Rate-Regulated Operations: These new standards included removing the temporary exemption in Section 1100 Generally Accepted Accounting Principles pertaining to the application of the section to the recognition and measurement of assets and liabilities arising from rate regulation; and amending Section 3465 Income Taxes to require the recognition of future income tax assets and liabilities for the amount of future income taxes expected to be included in future rates and recovered from or paid to future customers. As a result of the new standard, Emera will recognize future income tax assets and liabilities of its wholly-owned regulated subsidiaries. In accordance with the Company's regulated accounting policies covering income taxes, Emera will defer any future income taxes to a regulatory asset or liability where the future income taxes are expected to be included in future rates, with no resulting effect on net earnings. The Company is currently assessing the effect on its balance sheet.

Financial Instruments: In January 2009, the CICA issued Emerging Issue Committee Abstract of Issue Discussed 173 Credit Risk and the Fair Value of Financial Assets and Financial Liabilities ("EIC-173") applicable to Emera's 2009 fiscal year. EIC-173 recommends that a company take into account its own credit risk and the credit risk of the counterparty in determining the fair value of financial assets and financial liabilities. The Company is currently assessing the effect on its financial results.

3. SEGMENT INFORMATION

The Company has two reportable segments: Nova Scotia Power and Bangor Hydro. The Company evaluates performance based on contribution to consolidated net earnings applicable to common shareholders. The accounting policies of the reported segments are the same as those described in the summary of significant accounting policies.

Reported segments are determined based on Emera's operating activities. NSPI is engaged in the production and sale of electric energy in Nova Scotia; and Bangor Hydro is engaged in the transmission and distribution of electric energy in central Maine. Other revenue is largely generated from the energy marketing margin and electric revenue from the Company's investment in Bear Swamp.

MILLIONS OF DOLLARS	NOVA SCOTIA POWER	BANGOR HYDRO	OTHER*	TOTAL
Year ended December 31, 2008				
Revenues from external customers	$ 1,126.5	$ 147.7	$ 57.7	$ 1,331.9
Depreciation	133.6	16.3	1.4	151.3
Cost of operations, including depreciation	867.6	97.9	55.6	1,021.1
Equity earnings	–	–	15.2	15.2
Interest expense	99.1	13.3	19.3	131.7
Income taxes	46.6	14.8	(3.3)	58.1
Net earnings applicable to common shareholders	105.6	23.1	15.4	144.1
Net inter-segment revenues (expenses)	93.5	(0.9)	(92.6)	–
Capital expenditures	158.0	41.3	346.5	545.8
As at December 31, 2008				
Total assets	3,490.7	783.0	995.7	5,269.4
Investments subject to significant influence	–	2.2	315.4	317.6
Goodwill	–	101.1	0.9	102.0
Year ended December 31, 2007				
Revenues from external customers	$ 1,113.5	$ 140.4	$ 85.6	$ 1,339.5
Depreciation	131.1	13.9	4.3	149.3
Cost of operations, including depreciation	828.4	95.6	63.5	987.5
Equity earnings	–	–	12.8	12.8
Interest expense	95.8	13.7	12.4	121.9
Income taxes	62.1	14.0	4.2	80.3
Net earnings applicable to common shareholders	100.2	27.5	23.6	151.3
Net inter-segment revenues (expenses)	87.3	(2.1)	(85.2)	–
Capital expenditures	119.4	98.6	33.6	251.6
As at December 31, 2007				
Total assets	3,182.5	609.9	428.7	4,221.1
Investments subject to significant influence	–	1.9	122.6	124.5
Goodwill	–	82.5	0.3	82.8

*Other includes corporate activities and adjustments to reconcile to consolidated balances.

4. EMPLOYEE FUTURE BENEFITS

Nova Scotia Power Plans

NSPI maintains contributory defined-benefit and defined-contribution pension plans, which cover substantially all of its employees, and plans providing non-pension benefits for its retirees. Certain of Emera's corporate employees participate in these plans and Emera Inc. is charged accordingly.

Defined benefit pension plans are based on the years of service and average salary at the time the employee terminates employment, and provide annual post-retirement indexing equal to the change in the Consumer Price Index, up to a maximum increase of 6% per year.

Other retirement benefit plans include: unfunded pension arrangements (with the same indexing formula as the funded pension arrangements), unfunded long service award (which is impacted by expected future salary levels) and contributory health care plan. The unfunded long service award was closed to new entrants, effective August 1, 2007.

The measurement date for the assets and obligations of each benefit plan is December 31, 2008.

VALUATION DATE FOR DEFINED-BENEFIT PLANS

NSPI has a December 31 valuation date for accounting purposes. The most recent and the next required actuarial valuation dates for funding purposes are as follows:

	MOST RECENT ACTUARIAL VALUATION	NEXT REQUIRED ACTUARIAL VALUATION
Employee pension plan	December 31, 2008	December 31, 2009
Acquired companies pension plan	December 31, 2008	December 31, 2009

TOTAL CASH AMOUNT

Total cash amount for 2008, made up of contributions to its funded defined-benefit pension plans, contributions to its defined-contribution pension plan, employer paid premiums for its post-retirement health care plan, and amounts paid directly to retirees and beneficiaries in other plans, was $16.9 million (2007 – $18.2 million) for NSPI and Emera.

Accrued pension and non-pension benefit asset (liability)

	2008		2007	
MILLIONS OF DOLLARS	DEFINED BENEFIT PENSION PLANS	NON-PENSION BENEFITS PLANS	DEFINED BENEFIT PENSION PLANS	NON-PENSION BENEFITS PLANS
Assumptions (weighted average)				
Accrued benefit obligation – December 31:				
Discount rate	**7.50%**	**7.50%**	5.75%	5.75%
Rate of compensation increase	**3% to 5.5%**	**3% to 5.5%**	3% to 5.5%	3% to 5.5%
Health care trend – initial (next year)	**–**	**6.00%**	–	7.00%
– ultimate	**–**	**4.00%**	–	4.00%
– year ultimate reached	**–**	**2010**	–	2010
Benefit cost for year ending December 31:				
Discount rate	**5.75%**	**5.75%**	5.25%	5.25%
Expected long-term return on plan assets	**7.50%**	**–**	7.50%	–
Rate of compensation increase	**3% to 5.5%**	**3% to 5.5%**	3% to 5.5%	3% to 5.5%
Health care trend – initial (current year)	**–**	**7.00%**	–	8.00%
– ultimate	**–**	**4.00%**	–	4.00%
– year ultimate reached	**–**	**2010**	–	2010
Accrued benefit obligations				
Balance, January 1	**$ 780.0**	**$ 40.9**	$ 802.7	$ 39.6
Employer current service cost	**10.8**	**1.6**	12.7	1.5
Employee contributions	**5.1**	**–**	5.0	–
Interest cost	**44.4**	**2.3**	41.6	2.0
Actuarial (gains) losses	**(134.8)**	**(4.7)**	(46.1)	1.5
Benefits paid	**(36.0)**	**(4.0)**	(35.9)	(3.7)
Balance, December 31	**669.5**	**36.1**	780.0	40.9
Fair value of plan assets				
Balance, January 1	**640.9**	**–**	656.5	–
Employer contributions	**12.0**	**4.0**	13.8	3.7
Employee contributions	**5.1**	**–**	5.0	–
Actual return on plan assets	**(112.8)**	**–**	1.5	–
Benefits paid	**(36.0)**	**(4.0)**	(35.9)	(3.7)
Balance, December 31	**509.2**	**–**	640.9	–
Reconciliation of financial status to accrued benefit asset, December 31				
Fair value of plan assets	**509.2**	**–**	640.9	–
Accrued benefit obligations	**669.5**	**36.1**	780.0	40.9
Plan deficit	**(160.3)**	**(36.1)**	(139.1)	(40.9)
Unamortized past service (gains) costs	**(0.4)**	**1.8**	(0.5)	2.1
Unamortized actuarial losses (gains)	**204.2**	**(3.0)**	191.5	1.7
Unamortized transitional obligation	**0.1**	**9.0**	0.1	11.2
Accrued benefit asset (liability)	**$ 43.6**	**$ (28.3)**	$ 52.0	$ (25.9)

The amounts to be recognized in other assets and other liabilities are as follows:

MILLIONS OF DOLLARS	2008 DEFINED BENEFIT PENSION PLANS	2008 NON-PENSION BENEFITS PLANS	2007 DEFINED BENEFIT PENSION PLANS	2007 NON-PENSION BENEFITS PLANS
Prepaid benefit cost	**$ 74.8**	**–**	$ 81.6	–
Accrued benefit liability	**(31.2)**	**$ (28.3)**	(29.6)	$ (25.9)
Net accrued benefit asset (liability)	**$ 43.6**	**$ (28.3)**	$ 52.0	$ (25.9)

Defined benefit plans asset allocation (% of plan assets)

	2008 EMPLOYEE PENSION PLAN	2008 ACQUIRED COMPANIES PENSION PLAN	2007 EMPLOYEE PENSION PLAN	2007 ACQUIRED COMPANIES PENSION PLAN
Equity securities	**56%**	**50%**	66%	60%
Debt securities	**41%**	**47%**	31%	38%
Cash	**3%**	**3%**	3%	2%
Total	**100%**	**100%**	100%	100%

As at December 31, 2008, the pension funds do not hold any material investments in Emera Inc. or Nova Scotia Power Inc. securities.

PLANS WITH ACCRUED BENEFIT OBLIGATIONS IN EXCESS OF ASSETS

As at December 31, 2008, all post-retirement benefit plans have accrued benefit obligations in excess of assets.

Benefits cost components

MILLIONS OF DOLLARS	2008 DEFINED BENEFIT PENSION PLANS	2008 NON-PENSION BENEFITS PLANS	2007 DEFINED BENEFIT PENSION PLANS	2007 NON-PENSION BENEFITS PLANS
Defined benefit plan				
Costs arising from events during the year:				
Current service costs	**$ 10.8**	**$ 1.6**	$ 12.7	$ 1.6
Interest on accrued benefits	**44.4**	**2.3**	41.6	2.0
Less: actual return on plan assets	**112.8**	**–**	(1.5)	–
Actuarial (gains) losses on accrued benefit obligation	**(134.8)**	**(4.7)**	(46.1)	1.5
Future benefit costs before adjustments	**33.2**	**(0.8)**	6.7	5.1
Adjustments to recognize long-term nature of costs:				
Difference between expected return on assets and actual return	**(159.6)**	**–**	(43.1)	–
Amortization of transitional obligation	**–**	**2.2**	–	2.2
Difference between amortization of actuarial losses (gains) and actual actuarial losses (gains) on accrued benefit obligations	**146.8**	**4.8**	64.8	(1.3)
Difference between amortization of past service costs and past service costs for the year	**–**	**0.2**	–	0.2
Total cost recognized	**$ 20.4**	**$ 6.4**	$ 28.4	$ 6.2
Defined contribution plan				
Employer cost	**$ 0.8**	**–**	$ 0.8	–

The expected return on plan assets is determined based on the market-related value of plan assets of $633.5 million at January 1, 2008 (2007 – $601.7 million), adjusted for interest on certain cash flows during the year.

SENSITIVITY ANALYSIS FOR NON-PENSION BENEFITS PLANS

The health care cost trend significantly influences the amounts presented for health care plans. An increase or decrease of one percentage point of the assumed health care cost trend would have had the following impact in 2008:

MILLIONS OF DOLLARS	INCREASE	DECREASE
Current service cost and interest cost	$ 0.2	$ (0.1)
Accrued benefit obligation, December 31	$ 1.3	$ (1.1)

Bangor Hydro Plans

BHE maintains a non-contributory defined-benefit and a contributory defined-contribution pension plan, which cover substantially all of its employees, and a health care plan for its retirees. The defined benefit pension is based on the years of service and average salary at the time the employee terminates employment and provides no post-employment indexing. The defined benefit pension plan was closed to new entrants, effective February 2006. Employees hired after January 1, 2006 are not eligible for the retiree health care plan.

Other retirement benefit plans include an unfunded pension arrangement and a retiree life insurance plan.

The measurement date for the assets and obligations of each benefit plan is December 31, 2008.

VALUATION DATE FOR DEFINED-BENEFIT PLANS

BHE has a December 31 valuation date for accounting purposes. The most recent and the next required actuarial valuation dates for funding purposes are the following:

	MOST RECENT ACTUARIAL VALUATION	NEXT REQUIRED ACTUARIAL VALUATION
Employee pension plan	December 31, 2007	December 31, 2008

TOTAL CASH AMOUNT

Total cash amount for 2008, made up of BHE contributions to its funded defined-benefit pension plan, contributions to its defined contribution pension plan, employer paid premiums for its post-retirement health care plan, and amounts paid directly to retirees and beneficiaries in other plans, was $4.8 million (2007 – $8.9 million).

Accrued pension and non-pension benefit liability

MILLIONS OF DOLLARS	2008 DEFINED BENEFIT PENSION PLANS	2008 NON-PENSION BENEFIT PLANS	2007 DEFINED BENEFIT PENSION PLANS	2007 NON-PENSION BENEFIT PLANS
Assumptions (weighted average)				
Accrued benefit obligation – December 31:				
Discount rate	6.75%	6.75%	6.75%	6.75%
Rate of compensation increase	3.75%	3.75%	4.00%	–
Health care trend – initial (next year)	–	7.60%	–	9.20%
– ultimate	–	5.00%	–	5.00%
– year ultimate reached	–	2015	–	2013
Benefit cost for year ending December 31:				
Discount rate	6.75%	6.75%	6.00%	6.00%
Expected long-term return on plan assets	8.00%	5.00%	8.00%	5.00%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%
Health care trend – initial (current year)	–	9.20%	–	8.40%
– ultimate	–	5.00%	–	5.00%
– year ultimate reached	–	2013	–	2011
Accrued benefit obligations				
Balance, January 1	$ 65.5	$ 38.0	$ 84.0	$ 37.8
Employer current service cost	1.2	0.9	1.3	0.8
Interest cost	4.7	2.8	4.5	2.1
Actuarial losses (gains)	1.0	4.1	(7.9)	5.9
Benefits paid	(3.9)	(2.0)	(4.1)	(2.3)
Foreign currency translation adjustment	16.1	9.8	(12.3)	(6.3)
Balance, December 31	84.6	53.6	65.5	38.0
Fair value of plan assets				
Balance, January 1	55.0	1.0	59.9	1.2
Employer contributions	2.6	2.0	6.3	2.3
Actual return on plan assets	(16.4)	–	2.4	0.1
Benefits paid	(3.9)	(2.0)	(4.1)	(2.3)
Foreign currency translation adjustment	10.6	0.2	(9.5)	(0.3)
Balance, December 31	47.9	1.2	55.0	1.0
Reconciliation of financial status to accrued benefit asset, December 31				
Fair value of plan assets	47.9	1.2	55.0	1.0
Accrued benefit obligations	84.6	53.6	65.5	38.0
Plan deficit	(36.7)	(52.4)	(10.5)	(37.0)
Unamortized past service costs (gains)	1.1	(3.7)	1.1	(3.4)
Unamortized actuarial losses	36.4	20.5	9.3	13.8
Unamortized transitional obligation	–	2.4	–	2.5
Accrued benefit asset (liability)	$ 0.8	$ (33.2)	$ (0.1)	$ (24.1)

Defined benefit plans asset allocation (% of plan assets)

	2008	2007
	EMPLOYEE PENSION PLAN	EMPLOYEE PENSION PLAN
Equity securities	56%	64%
Debt securities	43%	35%
Other	1%	1%
Total	100%	100%

As at December 31, 2008, the pension fund does not directly hold any investments in Emera or Bangor Hydro securities. However, as a significant portion of assets for the benefit plans are held in mutual funds, there may be indirect investments in these securities.

Plans with accrued benefit obligation in excess of assets

As at December 31, 2008, all post-retirement benefit plans have accrued pension obligations in excess of assets.

Benefits cost components

	2008		2007	
MILLIONS OF DOLLARS	DEFINED BENEFIT PENSION PLANS	NON-PENSION BENEFIT PLANS	DEFINED BENEFIT PENSION PLANS	NON-PENSION BENEFIT PLANS
Defined benefit plan				
Costs arising from events during the year:				
Current service costs	$ 1.2	$ 0.9	$ 1.3	$ 0.8
Interest on accrued benefits	4.7	2.8	4.5	2.1
Less: actual return on plan assets	16.4	–	(2.4)	(0.1)
Actuarial losses (gains) on accrued benefit obligation	1.0	4.1	(7.9)	5.9
Future benefit costs before adjustments	23.3	7.8	(4.5)	8.7
Adjustments to recognize long-term nature of costs:				
Difference between expected return on assets and actual return	(21.3)	(0.1)	(2.1)	0.1
Amortization of transitional obligation	–	0.5	–	0.5
Difference between amortization of actuarial losses (gains) and actual actuarial losses (gains) on accrued benefit obligations	(0.3)	(3.0)	9.0	(4.9)
Difference between amortization of past service costs and past service costs for the year	0.2	(0.4)	0.2	(0.4)
Total cost recognized	$ 1.9	$ 4.8	$ 2.6	$ 4.0
Defined contribution plan				
Employer cost	$ 0.3	–	$ 0.3	–

For the defined benefit pension plan, the expected return on plan assets is determined on the market-related value of plan assets of $70.2 million at January 1, 2008 (2007 – $50.1 million), adjusted for interest on certain cash flows during the year.

Sensitivity analysis for non-pension plans

The health care cost trend significantly influences the amounts presented for health care plans. An increase or decrease of one percentage point of the assumed health care cost trend would have had the following impact in 2008:

	INCREASE	DECREASE
Current service cost and interest cost	$ 0.6	$ (0.5)
Accrued benefit obligation, December 31	$ 8.2	$ (6.5)

Accounting for the impact of rate regulation:

When Bangor Hydro was purchased by Emera, BHE received regulatory approval to continue amortizing certain existing balances over a period of 10 years. Under GAAP, as a result of the purchase, these unamortized balances would have been recognized immediately in the year BHE was purchased. In the absence of the regulatory policy, BHE's total accrued benefit liability would be $45.1 million (2007 – $36.3 million) and the total defined benefits expense for 2008 would be $4.6 million (2007 – $4.5 million).

5. OPERATING LEASES

The Company has entered into operating lease agreements for office space, telecommunication services, and certain other equipment, which expire in 2009 to 2020. Future minimum annual lease payments under the leases are as follows:

MILLIONS OF DOLLARS	
2009	$ 10.0
2010	10.0
2011	1.5
2012	0.4
2013	0.4
Thereafter	2.2
	$ 24.5

For the year ended December 31, 2008, the Company recognized $10.5 million (2007 – $12.3 million) of operating leases in operating, maintenance and general expense.

6. INVESTMENTS SUBJECT TO SIGNIFICANT INFLUENCE AND EQUITY EARNINGS

Investments subject to significant influence are comprised of the following:

	2008		*2007*	
MILLIONS OF DOLLARS	CARRYING VALUE	EQUITY EARNINGS	CARRYING VALUE	EQUITY EARNINGS
Maritimes & Northeast Pipeline	**$ 198.5**	**$ 12.2**	$ 99.8	$ 10.6
Grand Bahama Power Company Limited	**87.8**	**1.2**	–	–
St. Lucia Electricity Services Ltd.	**29.1**	**1.8**	22.8	2.2
Maine Electric Power Company Inc.	**2.0**	**–**	1.4	–
Maine Yankee Atomic Power Company	**0.2**	**–**	0.5	–
	$ 317.6	**$ 15.2**	$ 124.5	$ 12.8

Equity investments include a $26.3 million difference between the cost and the underlying net book value of the investees' assets as at the date of acquisition. The excess is attributable to goodwill and is therefore not subject to amortization.

7. FINANCING CHARGES

Financing charges consists of the following:

MILLIONS OF DOLLARS	2008	2007
Interest – long-term debt	$ 104.7	$ 105.3
– short-term debt	25.4	21.6
Preferred share dividends paid by subsidiary (note 9)	14.1	14.1
Amortization of defeasance cost (note 12)	12.4	12.7
Amortization of debt financing costs	1.6	1.8
Allowance for funds used during construction	(21.7)	(12.3)
Refund interest on income tax recovery (note 8)	–	(6.8)
Foreign exchange gains	(13.3)	(3.2)
	$ 123.2	$ 133.2

8. INCOME TAXES

The income tax provision differs from that computed using the statutory rates for the following reasons:

MILLIONS OF DOLLARS		2008		2007
Earnings before income taxes	$ 202.8		$ 231.6	
Income taxes, at statutory rates	72.0	35.5%	88.2	38.1%
Unrecorded future income taxes on regulated earnings	(12.0)	(5.9)	–	–
Income tax recovery	(6.5)	(3.3)	(10.8)	(4.7)
Equity earnings not subject to tax	(4.9)	(2.3)	(4.9)	(2.1)
Change in future income tax asset resulting from rate change	–	–	0.9	0.4
Other	9.5	4.7	6.9	3.0
	58.1	28.7%	80.3	34.7%
Income taxes – current	53.8		67.1	
Income taxes – future	$ 4.3		$ 13.2	

The future income tax assets and liabilities comprise the following:

MILLIONS OF DOLLARS	CURRENT PORTION 2008	CURRENT PORTION 2007	LONG-TERM PORTION 2008	LONG-TERM PORTION 2007
Future income tax assets:				
Tax loss carry forwards	**$ 1.9**	$ 6.2	**$ 13.2**	$ 11.7
Property, plant and equipment	**–**	–	**1.4**	1.7
Other	**5.2**	0.5	**3.0**	2.8
	$ 7.1	$ 6.7	**$ 17.6**	$ 16.2
Future income tax liabilities:				
Property, plant and equipment	**–**	–	**$ 116.1**	$ 81.7
Other assets	**–**	–	**7.1**	6.8
Other liabilities	**–**	–	**(10.6)**	(6.1)
Tax loss carry forwards	**–**	–	**(5.4)**	–
Other	**–**	$ 2.0	**3.1**	0.5
	–	$ 2.0	**$ 110.3**	$ 82.9

As at December 31, 2008, the Company has tax losses of $59.4 million, which are reflected in future income tax assets or netted against future income liabilities as appropriate, and begin to expire in 2014.

Accounting for the impact of rate regulation:

At December 31, 2008, the unrecorded future income tax liability of Emera's wholly-owned regulated subsidiaries is approximately $2.2 million (2007 – future income tax asset of $40.7 million), of which a future income tax asset of $2.7 million (2007 – $16.3 million) is related to AOCI. The unrecorded future income tax liability consists of taxable temporary differences of $45.6 million (2007 – deductible temporary differences of $122.4 million) and unused non-capital losses of $30.0 million (2007 – $0.4 million) which begin to expire in 2027.

In the absence of regulatory approval of the taxes payable accounting policies, Emera would have had a future income tax expense of $29.3 million in 2008 (2007 – $9.6 million).

During 2008, NSPI accelerated the deduction of capitalized expenses pertaining to the 2007 tax year. As a result, in 2008 NSPI recorded an income tax recovery of $6.5 million.

During 2007, NSPI prepared and filed with Canada Revenue Agency ("CRA") amended tax returns for the years 2000 to 2004 inclusive. CRA reviewed and approved the amended filings, which has resulted in accelerated deductions of certain capitalized expenses. In 2008, NSPI amended its 2005 and 2006 tax returns on the same basis as was used for the years 2000 to 2004 inclusive. The amendments have been processed by CRA. All material amounts relating to these prior year adjustments were recorded in the 2007 financial statements of NSPI. As a result, in Q3 2007, NSPI recorded an income tax recovery of $25.4 million, of which $14.6 million was recorded as a reduction of other assets, specifically the regulatory asset related to its pre-2003 income tax liability. The remaining $10.8 million was recorded as a reduction of current income tax expense. In addition, NSPI received a refund interest of $8.6 million for the years 2000 to 2004, $1.8 million of which has been recorded as a reduction of other assets. The remaining $6.8 million has been recorded as a reduction of financing charges. NSPI will continue to use this methodology when filing its future tax returns.

Absent NSPI's regulator approved taxes payable accounting policy, the recoveries would have no effect on the total current and future income tax expense and net earnings would have been $6.5 million lower (2007 – $10.8 million) for year ended December 31, 2008.

9. PREFERRED SHARES ISSUED BY SUBSIDIARY

Preferred shares issued by subsidiary consist of the preferred shares of Nova Scotia Power Inc. and are classified as a financial liability on the balance sheet.

AUTHORIZED:

Unlimited number of First Preferred Shares, issuable in series.

Unlimited number of Second Preferred Shares, issuable in series.

ISSUED AND OUTSTANDING:	MILLIONS OF SHARES	PREFERRED SHARE CAPITAL MILLIONS OF DOLLARS
January 1, 2007	10.4	$ 260.0
December 31, 2007	10.4	260.0
December 31, 2008	**10.4**	**$ 260.0**

As at December 31, 2008 and December 31, 2007, the Company had outstanding 5.0 million 4.9% Series C preferred shares, and 5.4 million 5.9% Series D preferred shares with the following redemption features:

Series C First Preferred Shares:

Each Series C First Preferred Share is entitled to a $1.225 per share per annum fixed cumulative preferential dividend, as and when declared by the Board of Directors, accruing from the date of issue and payable quarterly on the first day of January, April, July and October of each year.

On and after April 1, 2009, Series C First Preferred Shares are redeemable by NSPI, in whole at any time or in part from time to time at $25 per share plus accrued and unpaid dividends. NSPI also has the option, commencing April 1, 2009, to exchange the Series C First Preferred Shares into Emera Inc. common shares, determined by dividing $25 by the greater of $2 and the market price of the Emera Inc. common share.

Commencing on and after July 1, 2009, with prior notice and prior to any dividend payment date, each Series C First Preferred Share will be exchangeable at the option of the holder into fully paid and freely tradable Emera Inc. common shares determined by dividing $25 by the greater of $2 and the market price of the Emera Inc. common shares, subject to the right of NSPI to redeem such shares for cash or to cause the holders of such shares to sell on the exchange date all or any part of such shares. NSPI will pay all accrued and unpaid dividends to the exchange date.

These shares are classified as short-term on the balance sheet.

Series D First Preferred Shares:

Each Series D First Preferred Share is entitled to a $1.475 per share per annum fixed cumulative preferential dividend, as and when declared by the Board of Directors, accruing from the date of issue and payable quarterly on the fifteenth day of January, April, July and October of each year.

On and after October 15, 2015, Series D First Preferred Shares are redeemable by NSPI, in whole at any time or in part from time to time at $25 per share plus accrued and unpaid dividends. NSPI also has the option, commencing October 15, 2015, to exchange the Series D First Preferred Shares into Emera Inc. common shares determined by dividing $25 by the greater of $2 and the market price of the Emera Inc. common shares.

Commencing on and after January 15, 2016, with prior notice and prior to any dividend payment date, each Series D First Preferred Share will be exchangeable at the option of the holder into fully paid and freely tradable Emera Inc. common shares determined by dividing $25 by the greater of $2 and the market price of the Emera Inc. common shares, subject to the right of NSPI to redeem such shares for cash or to cause the holders of such shares to sell on the exchange date all or any part of such shares to substitute purchasers found by NSPI. NSPI will pay all accrued and unpaid dividends to the exchange date.

10. EARNINGS PER SHARE

Earnings per share for 2008 are as follows:

	2008		
	NET EARNINGS (MILLIONS OF DOLLARS)	WEIGHTED AVERAGE COMMON SHARES (MILLIONS)	EPS ($)
Basic EPS	$ 144.1	111.9	$ 1.29
Series C preferred shares of NSPI	6.0	5.8	(0.01)
Series D preferred shares of NSPI	7.8	6.2	–
Restricted share units and deferred share units	–	0.7	(0.01)
Other share-based compensation	–	0.3	(0.01)
Diluted EPS	$ 157.9	124.9	$ 1.26

Earnings per share for 2007 are as follows:

	2007		
	NET EARNINGS (MILLIONS OF DOLLARS)	WEIGHTED AVERAGE COMMON SHARES (MILLIONS)	EPS ($)
Basic EPS	$ 151.3	111.2	$ 1.36
Series C preferred shares of NSPI	5.8	6.0	(0.02)
Series D preferred shares of NSPI	7.5	6.5	(0.01)
Restricted share units and deferred share units	–	0.6	(0.01)
Other share-based compensation	–	0.3	–
Diluted EPS	$ 164.6	124.6	$ 1.32

Senior management share options were excluded from the above calculation because they did not dilute earnings per share where the exercise price exceeded the average price for the period.

11. ACCOUNTS RECEIVABLE AND LONG-TERM RECEIVABLE

NSPI has a revolving non-recourse securitization agreement with an independent trust administered by a major Canadian bank. Under the securitization agreement NSPI sells an undivided co-ownership interest in certain current and future accounts receivable generated in the normal course of business. The amount of the accounts receivables sold is removed from the balance sheet with each revolving securitization. NSPI also retains an undivided co-ownership of approximately 10% in the receivables sold to the trust. The retained interest is recognized at amortized cost in other assets. Fees related to securitization are expensed as incurred. At December 31, 2008, no accounts receivables were sold (2007 – $25 million). The agreement is in place until May 2009 and NSPI's ability to sell its receivables is subject to acceptance by the sponsor bank. The securitization program was suspended in January 2008, due to a lack of investor interest.

At December 31, 2008, the Company had unbilled revenue included in accounts receivable in the amount of $89.7 million (2007 – $86.0 million). The unbilled revenue is an estimate of the amount of revenue related to energy delivered to customers since the date their meter was last read. Actual results may differ from this estimate.

NSPI's existing long-term natural gas purchase agreement includes a price adjustment clause covering three years of natural gas purchases. The clause states that NSPI will pay for all gas purchases at the agreed contract price, but will be entitled to a price rebate on a portion of the volumes, settled in November 2007 and November 2010. In November 2007, NSPI received the first settlement of the pricing rebate. Management's best estimate of the price rebate, based on the contract specifications using actual and forward market pricing of $56.4 million (2007 – $7.7 million) is reflected in long-term receivable.

12. OTHER ASSETS AND LIABILITIES

Other assets and liabilities, including the impact of rate-regulated accounting policies, include the following:

MILLIONS OF DOLLARS	*2008*	*2007*
Other assets:		
Regulatory assets:		
Unamortized defeasance costs	**$ 118.8**	$ 131.1
Pre-2003 income tax liability and related interest	**105.3**	119.9
Deferral of fuel switching derivatives	**36.3**	5.6
Costs to restructure purchased power contracts	**20.1**	17.9
Seabrook nuclear project	**14.3**	13.2
Deferral of income and capital taxes not included in Q1 2005 rates	**13.8**	15.5
Hydro-Québec obligation	**5.9**	4.0
Maine Yankee decommissioning costs	**5.8**	6.9
Deferred restructuring costs	**4.7**	4.8
Stranded cost revenue requirement levelizers	**4.3**	3.0
Held-for-trading natural gas contracts	**1.7**	1.5
Other	**7.0**	6.6
	338.0	330.0
Non-regulatory assets:		
Accrued pension asset – Nova Scotia Power (note 4)	**74.8**	81.6
Accrued pension asset – Bangor Hydro (note 4)	**0.8**	–
Retained interest in accounts receivable securitized (note 11)	**–**	2.5
Other	**6.5**	3.2
	82.1	87.3
	$ 420.1	$ 417.3
Other liabilities:		
Regulatory liabilities:		
Held-for-trading natural gas contracts	**$ 67.5**	$ 75.3
Deferral of fuel switching derivatives	**49.6**	29.9
Other	**3.1**	0.2
	120.2	105.4
Non-regulatory liabilities:		
Accrued pension and non-pension benefit liability – Nova Scotia Power (note 4)	**59.5**	55.5
Accrued non-pension benefit liability – Bangor Hydro (note 4)	**33.2**	24.2
Hydro-Québec obligation	**5.9**	4.0
Maine Yankee decommissioning liability	**5.8**	6.9
Unearned revenue	**2.2**	2.8
Other	**9.9**	12.0
	116.5	105.4
	$ 236.7	$ 210.8

Based on the terms and conditions of NSPI's defined-benefit pension plans and non-pension benefit plans, the Company is required under the accounting standards to disclose the accrued benefit assets and accrued benefit liabilities separately rather than the net amount as previously disclosed. As a result, other assets and liabilities as at December 31, 2007 have been increased by $55.5 million respectively. The change had no impact on the measurement of cash flows, shareholders' equity, net earnings applicable to common shares, and basic and diluted earnings per share. Further information can be found in note 4.

Regulatory assets consist of:

Unamortized Defeasance Costs

Upon privatization in 1992, NSPI became responsible for managing a portfolio of defeasance securities held in trust, which as at December 31, 2008 totalled $1.1 billion. The excess of the cost of defeasance investments over the face value of the related debt is deferred on the balance sheet and amortized over the life of the defeased debt as permitted by the UARB. In the absence of UARB approval, the losses would have been expensed as incurred and net earnings would be $12.3 million higher in 2008 (2007 – $12.7 million).

Pre-2003 Income Tax Liability and Related Interest

NSPI has a regulatory asset related to pre-2003 income taxes that have been paid, but not yet recovered from customers. This circumstance arose when NSPI claimed capital cost allowance ("CCA") deductions in its income tax returns that were ultimately disallowed by a decision of the Supreme Court of Canada. NSPI applied to the regulator to include recovery of these costs in customer rates. In its February 5, 2007 decision, the UARB approved recovery of this regulatory asset over eight years, commencing April 1, 2007. In addition, in 2007 NSPI has recorded an income tax recovery of $14.6 million relating to accelerated deductibility of certain capitalized expenses and associated interest of $1.8 million relating to its pre-2003 income tax liability, which reduced this regulatory asset. In the absence of UARB approved recovery, the liability would have been expensed when incurred and the interest reflected in earnings when receivable, therefore net earnings would be $14.6 million higher in 2008 (2007 – $12.6 million).

Deferral of Fuel Switching Derivatives

In accordance with Handbook Section 3865 Hedges, NSPI determined that it could not meet the probability requirement of the standard for its derivatives in place to hedge natural gas and heavy fuel oil for its Tufts Cove generating station. This is due to the generating station's ability to fuel switch and NSPI's economic dispatch based on the relative cost of these two fuels. The UARB has allowed NSPI to apply hedge accounting to these derivatives as long as the other requirements of the handbook are met. This accounting policy permits NSPI to defer the fair value of hedges that are no longer required because of fuel switching. Absent UARB approval, NSPI would be required to recognize the changes in fair value of these derivatives in earnings, and net earnings for 2008 would be $30.7 million ($19.8 million after-tax) lower (2007 – $5.6 million or $3.5 million after-tax).

Costs to Restructure Purchased Power Contracts

Bangor Hydro has power purchase contracts, which it was required to negotiate when oil prices were high, with several independent power producers known as small power production facilities. The cost of power from these facilities is more than Bangor Hydro would incur from other sources if it were not obligated under these contracts. Bangor Hydro attempted to alleviate the adverse impact of these high-cost contracts and in doing so incurred costs to restructure certain of the contracts. The MPUC has allowed Bangor Hydro to defer these costs and recover them in stranded cost rates. The contract restructuring costs are being recovered over a 20-year period, ending in June 2018. The annual amortization is approximately $1.8 million. In the absence of the MPUC's approval, these costs would have been expensed as incurred and earnings would have been $1.8 million ($1.1 million after-tax) higher in 2008 (2007 – $1.8 million or $1.1 million after-tax).

Seabrook Nuclear Project

Bangor Hydro was a participant in the Seabrook nuclear project in Seabrook, New Hampshire. On December 31, 1984, Bangor Hydro had almost $87 million invested in Seabrook, but because the uncertainties arising out of the Seabrook Project were having an adverse impact on Bangor Hydro's financial condition, an agreement for the sale of Seabrook was reached in mid-1985 and was consummated in November 1986. In 1985, the MPUC issued an order disallowing recovery of certain Seabrook costs, but provided for the recovery through customer rates of 70% of Bangor Hydro's year-end 1984 investment in Seabrook Unit 1 over 30 years, ending in October 2015. In the absence of MPUC approval, the loss on sale would have been recognized when incurred and earnings for 2008 and 2007 would each be $1.8 million ($1.1 million after-tax) higher.

Deferral of Income and Capital Taxes Not Included in Q1 2005 Rates

The UARB agreed to allow NSPI to defer taxes not reflected in rates for the period January 1, 2005 until April 1, 2005, the date when new rates became effective. In 2005, NSPI deferred $16.7 million consisting of $4.5 million of provincial and federal grants and $12.2 million in income taxes reflecting increases in these taxes since rates were last set in 2002. In its February 5, 2007 decision, the UARB approved recovery of this regulatory asset over eight years, commencing April 1, 2007. In the absence of the UARB's approval, these taxes would not have been deferred and net earnings for 2008 would be $1.7 million (2007 – $1.2 million) higher.

Hydro-Québec Obligation

The obligation associated with Hydro-Québec represents the estimated present value of Bangor Hydro's estimated future payments for net costs associated with ownership and operation of the Hydro-Québec intertie between the New England utilities and Hydro-Québec. The obligation has been recognized as a long-term other liability, and the MPUC has permitted recovery of this obligation. The regulatory asset and obligation are being reduced as expenses are incurred with the reduction of the regulatory asset amortized to purchase power expense. In the absence of regulator approval, 2008 earnings would be $0.3 million ($0.2 million after-tax) higher (2007 – $0.4 million or $0.2 million after-tax).

Maine Yankee Decommissioning Costs

Bangor Hydro owns 7% of the common stock of Maine Yankee, which in 1997 permanently shutdown its nuclear generating plant. Pursuant to a contract with Maine Yankee, BHE is required to pay its pro-rata share of Maine Yankee's decommissioning costs. BHE's share of the estimated decommissioning costs were approximately $5.0 million in 2008 (2007 – $4.4 million). Maine Yankee expense recovery is included in BHE's stranded cost revenues, and along with all stranded cost revenues, purchased power, and Hydro-Québec costs, are fully recoverable. For any variance between the actual amount of these items and the amounts used in setting rates, a regulatory deferral is recorded with a credit or charge to regulatory amortizations. Any over or under-recovery will be reviewed at future rate proceedings with the MPUC. In the absence of regulator approval, the Maine Yankee decommissioning costs would have been expensed when incurred and earnings would have been $3.3 million ($1.9 million after-tax) higher in 2008 (2007 – $4.4 million or $2.6 million after-tax).

Deferred Restructuring Costs

In conjunction with Bangor Hydro's Alternative Rate Plan, BHE was provided with accounting orders from the MPUC to defer and amortize over ten years certain employee transition costs. Eligible for deferral were the 2002 and 2003 employee transition costs related to reductions in the cost of operations and employee transition costs associated with Bangor Hydro's automated meter reading project, and the outsourcing of information technology support in 2004 and 2005. In the absence of regulator approval, these costs would have been expensed as incurred and 2008 earnings would be $1.1 million ($0.6 million after-tax) higher (2007 – $1.2 million or $0.7 million after-tax).

Stranded Cost Revenue Requirement Levelizer

Bangor Hydro's stranded cost rates are reset every three years and are designed to recover BHE's cumulative stranded cost revenue requirements over the three-year period. The most recently approved stranded cost rates are in effect from March 2008 to February 2011. While the stranded cost revenue requirements differ throughout the period due to changes in stranded cost revenues and expenses, the annual stranded cost revenues are the same during the period. To levelize the impact of the varying revenue requirements, cost or revenue deferrals are recognized. This levelizer is recognized only as result of regulatory accounting and the stranded cost ratemaking process. Absent regulatory accounting, the levelizer mechanism would not exist, and the methodology for determining BHE's rates associated with stranded costs is not known. In the absence of regulator approval, earnings for 2008 would be $0.9 million ($0.5 million after-tax) higher (2007 – $6.3 million or $3.7 million after-tax).

Held-for-trading Natural Gas Contracts

In accordance with implementing 3855 Financial Instruments – Recognition and Measurement, Nova Scotia Power has contracts for the purchase and sale of natural gas at its Tufts Cove generating station that are considered HFT derivatives, and accordingly are recognized on the balance sheet at fair value. This reflects NSPI's history of buying and reselling any natural gas not used in the production of electricity at TUC. Changes in fair value of HFT derivatives are normally recognized in net earnings. In accordance with NSPI's regulated accounting policy for financial instruments and hedges relating to TUC fuel, NSPI has deferred any changes in fair value to a regulatory asset or liability. Absent this accounting policy, NSPI's 2008 net earnings would be $0.2 million ($0.1 million after-tax) lower (2007 – $0.1 million or $0.1 million after-tax).

Other

The UARB approved NSPI's deferral of $2.0 million of vegetation management spending in 2008 to be recovered in rates in a future period. The UARB also agreed to allow NSPI to defer up to $12.8 million of demand side management expenditures for the period January 1, 2008 through December 31, 2009, to be recovered in rates over six years commencing January 1, 2009. In the absence of the UARB's approval, these costs would not have been deferred and net earnings for 2008 would be $2.3 million lower.

Bangor Hydro has other regulatory assets, which are being amortized to net earnings over varying lives. These deferred costs would have been expensed as incurred in the absence of approval from one of its regulators, and earnings would have been $4.9 million ($2.9 million after-tax) higher in 2008 (2007 – $3.5 million or $2.0 million after-tax).

Regulatory liabilities include:

Held-for-trading Natural Gas Contracts

As discussed above, in accordance with NSPI's accounting policy for financial instruments and hedges relating to TUC fuel, NSPI has deferred any changes in fair value of its natural gas contracts to a regulatory asset or liability. Absent this accounting policy, NSPI's 2008 net earnings would be $7.8 million ($5.0 million after-tax) lower (2007 – $98.0 million or $60.6 million after-tax).

Deferral of Fuel Switching Derivatives

As discussed above, NSPI has an accounting policy that permits NSPI to defer the fair value of any hedges that are no longer required because of fuel switching. Absent UARB approval, NSPI would be required to recognize the changes in fair value of these derivatives in earnings and net earnings for 2008 would be $19.7 million ($12.7 million after-tax) higher (2007 – $29.9 million or $18.5 million after-tax).

Other

Bangor Hydro has other regulatory liabilities, which are being amortized to net earnings over varying lives. These deferred gains would have been expensed as incurred in the absence of approval from one of its regulators, and earnings would have been $2.7 million ($1.6 million after-tax) lower in 2008 (2007 – $1.3 million or $0.7 million after-tax).

13. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is comprised of the following:

			2008
MILLIONS OF DOLLARS	COST	ACCUMULATED DEPRECIATION	NET BOOK VALUE
Generation			
Thermal	**$ 1,809.0**	**$ 752.1**	**$ 1,056.9**
Gas Turbines	**38.5**	**29.3**	**9.2**
Combustion Turbines	**73.8**	**12.6**	**61.2**
Hydroelectric	**450.7**	**142.3**	**308.4**
Wind Turbines	**2.1**	**0.6**	**1.5**
Transmission	**906.4**	**351.2**	**555.2**
Distribution	**1,433.7**	**699.4**	**734.3**
Other	**417.1**	**184.9**	**232.2**
Other, under capital lease	**3.7**	**0.7**	**3.0**
	$ 5,135.0	**$ 2,173.1**	**$ 2,961.9**

			2007
MILLIONS OF DOLLARS	COST	ACCUMULATED DEPRECIATION	NET BOOK VALUE
Generation			
Thermal	$ 1,768.9	$ 712.7	$ 1,056.2
Gas Turbines	32.5	22.4	10.1
Combustion Turbines	76.3	14.9	61.4
Hydroelectric	431.3	135.0	296.3
Wind Turbines	2.1	0.5	1.6
Transmission	809.1	326.0	483.1
Distribution	1,325.5	639.2	686.3
Other	384.7	161.8	222.9
Other, under capital lease	2.5	0.4	2.1
	$ 4,832.9	$ 2,012.9	$ 2,820.0

Accounting for the impact of rate regulation:

During 2007, NSPI completed the amortization of the Glace Bay generating station by expensing $5.2 million related to the plant. In the absence of the UARB approved accounting policy, the generating station would have been written off in the year when NSPI determined that the unamortized cost of the generating station would not be recoverable and net earnings for 2007 would be $5.2 million higher.

14. ACQUISITIONS

ICD Utilities Limited ("ICDU")

In September 2008, Emera purchased 50% of the shares of ICDU of the Bahamas for $42.3 million USD ($45.3 million CAD). ICDU owns 50% of Grand Bahama Power Company Limited ("GBPC"), which is a vertically integrated utility serving 19,000 customers on Grand Bahama Island.

GBPC has 137 megawatts of installed oil-fired generating capacity. The Grand Bahama Port Authority Limited regulates the utility and has granted GBPC a licensed, regulated and exclusive franchise to produce, transmit, and distribute electricity on the island until 2054. There is a fuel pass-through mechanism and flexible tariff adjustment policies to ensure that costs are recovered and a reasonable return is earned.

The acquisition has been accounted for under the purchase method of accounting as Emera has determined it has control of ICDU, and accordingly, the results of operations since the date of acquisition have been included in the consolidated statements of earnings. ICDU is included in the segment "Other" in note 3 Segment Information. The following summarizes the transaction:

NET ASSETS ACQUIRED	MILLIONS OF DOLLARS
Long-term investment	$ 78.8
Non-controlling interest	(33.5)
Cash paid	$ 45.3

The purchase price allocation has not yet been finalized as the Company has not completed the valuation of the long-term investment in GBPC.

OpenHydro Group Limited ("OpenHydro")

In February 2008 Emera acquired a 7.35% interest in OpenHydro, an Irish renewable tidal energy company for €10.2 million ($15.4 million CAD). OpenHydro designs and manufactures marine turbines for harnessing energy from tidal currents in the world's oceans.

The acquisition has been accounted for as an available-for-sale investment as Emera has determined it does not have significant influence over the investment, and accordingly, the investment was initially recorded at cost. Any dividends received or receivable since acquisition will be recognized as dividend income. OpenHydro is included in the segment "Other" in note 3 Segment Information.

15. INTEREST IN JOINT VENTURES

The following amounts represent the Company's proportionate interest in its joint ventures' financial position, operating results, and cash flows included in the consolidated financial statements:

MILLIONS OF DOLLARS	2008	2007
Current assets	$ 8.3	$ 7.8
Non-current assets	71.5	61.6
	$ 79.8	$ 69.4
Current liabilities	$ 13.2	$ 7.9
Non-current liabilities	95.7	67.7
	$ 108.9	$ 75.6
Revenues	$ 34.3	$ 55.4
Expenses	(31.7)	(42.2)
Net earnings	$ 2.6	$ 13.2
Cash provided by operations	$ 18.4	$ 8.8
Cash used in investing activities	(1.5)	(2.0)
Cash used in financing activities	(19.1)	(4.7)
(Decrease) increase in cash	$ (2.2)	$ 2.1

16. GOODWILL

The change in goodwill is due to the following:

MILLIONS OF DOLLARS	2008	2007
Balance, beginning of year	$ 82.8	$ 97.1
Change in foreign exchange rate	19.2	(14.3)
Balance, end of year	$ 102.0	$ 82.8

17. ASSET RETIREMENT OBLIGATIONS

Asset retirement obligations are recognized when incurred and represent the fair value, using the Company's credit-adjusted risk-free rate, of the Company's estimated future cash flows necessary to discharge legal obligations related to reclamation of land at the Company's thermal, hydro and combustion turbine sites, and disposal of polychlorinated biphenyls ("PCBs") in its transmission and distribution equipment. Estimated future cash flows are based on the Company's completed depreciation studies, prior experience, estimated useful lives, and governmental regulatory requirements. Actual results may differ from these estimates.

The change in asset retirement obligations is due to the following:

MILLIONS OF DOLLARS	2008	2007
Balance, beginning of year	$ 83.8	$ 78.1
Accretion included in depreciation expense	2.2	2.0
Accretion deferred to regulatory asset	2.3	2.0
Liabilities settled	(0.3)	(0.2)
Other	-	1.9
Balance, end of year	$ 88.0	$ 83.8

The key assumptions used to determine the asset retirement obligations are as follows:

ASSET	CREDIT-ADJUSTED RISK-FREE RATE	ESTIMATED UNDISCOUNTED FUTURE OBLIGATION (MILLIONS OF DOLLARS)	EXPECTED SETTLEMENT DATE
Thermal	5.3%	$ 242.3	12–31 years
Hydro	5.3%	60.8	23–53 years
Combustion Turbines	5.3%	5.1	1–15 years
Transmission & Distribution	5.8%	5.5	1–17 years
Other	7.4% – 8.6%	0.5	3–8 years
		$ 314.2	

Some of the Company's hydro, transmission and distribution assets may have additional asset retirement obligations. As the Company expects to use the majority of its installed assets for an indefinite period, no removal date can be determined and consequently a reasonable estimate of the fair value of any related asset retirement obligation cannot be made at this time. Additionally, some of the Company's transmission and distribution assets may have conditional asset retirement obligations, the fair value of which cannot be reasonably estimated as sufficient information does not exist to estimate the obligation. A liability will be recognized in the period in which sufficient information becomes available.

Accounting for the impact of rate regulation:

Any difference between the amount approved by the regulator of Nova Scotia Power as depreciation expense and the amount that would have been calculated under the accounting standard for asset retirement obligations is recognized as a regulatory asset in property, plant and equipment. In the absence of this deferral, net earnings for 2008 would be $2.3 million lower (2007 – $2.0 million).

18. SHORT-TERM DEBT

For the year ended December 31, 2008, short-term debt consists of:

- Short-term discount notes of $129.9 million issued against lines of credit, which bear interest at prevailing market rates, which on December 31, 2008, averaged 2.36%.
- LIBOR loans of $24.9 million issued against lines of credit, which bear interest at prevailing market rates, which on December 31, 2008, averaged 1.50%.
- Advances of $3.1 million, which when drawn upon against operating lines of credit, bear interest at the prime rate, which on December 31, 2008, was 3.50% in Canada and 3.25% in the US.

For the year ended December 31, 2007, short-term debt consists of:

- Short-term discount notes of $22.9 million. Short-term discount notes bear interest at prevailing market rates, which on December 31, 2007, averaged 4.69%.
- Advances of $5.5 million, which when drawn upon against operating lines of credit, bear interest at the prime rate, which on December 31, 2007, was 6.00% in Canada and 7.25% in the US.

This short-term debt is unsecured.

19. LONG-TERM DEBT

Long-term debt includes the issues detailed below. Medium term notes and debentures are issued under trust indentures at fixed interest rates, and are unsecured unless noted below. Also included are certain banker's acceptances and commercial paper where the Company has the intention and the unencumbered ability to refinance the obligations for a period greater than one year.

	EFFECTIVE AVERAGE INTEREST RATE %			AMOUNT OUTSTANDING	
MILLIONS OF DOLLARS	*2008*	*2007*	YEARS OF MATURITY	*2008*	*2007*
Emera					
Bankers acceptances, LIBOR loans and advances	**2.23**	5.31	1 year renewal	**$ 535.6**	$ 107.4
Capital lease obligations	**5.09**	5.15	Various	**1.8**	1.5
NSPI					
Medium term notes	**6.63**	6.64	2009 – 2097	**1,285.0**	1,250.0
Debentures	**9.75**	9.75	2019	**95.0**	95.0
Short-term discount notes	**2.13**	4.69	1 year renewal	**53.0**	94.0
Capital lease obligations	**6.30**	–	–	**0.4**	–
Bangor Hydro (issued and payable in USD)					
LIBOR loans & demand loans	**2.14**	5.62	1 year renewal	**54.7**	30.7
General & refunding mortgage bonds – secured by property, plant and equipment	**9.74**	9.74	2020 – 2022	**61.2**	49.4
Municipal review committee	**–**	5.00	–	**–**	0.9
Senior unsecured note	**5.63**	5.63	2009 – 2017	**141.4**	118.6
Bear Swamp (issued and payable in USD)					
Senior non-revolving credit facility secured by the assets of Bear Swamp	**4.81**	5.63	2012	**76.5**	61.7
				2,304.6	1,809.2
Amount due within one year				**(131.4)**	(121.0)
Unamortized debt financing costs				**(14.0)**	(11.8)
				$ 2,159.2	$ 1,676.4

An NSPI medium term note ("MTN") of $40.0 million bearing interest at 8.50%, maturing in 2026, is extendable until 2056 at the option of the holders.

As at December 31, 2008 long-term debt and obligations under a capital lease are due as follows:

MILLIONS OF DOLLARS	
Year of Maturity	
One year renewable	$ 643.3
2009	131.4
2010	106.3
2011	6.0
2012	106.8
2013	255.5
Greater than 5 years	1,055.3
	$ 2,304.6

20. COMMON SHARES

Authorized: Unlimited number of non-par value common shares.

ISSUED AND OUTSTANDING:	MILLIONS OF SHARES
January 1, 2007	110.93
Issued for cash under purchase plans	0.45
Options exercised under senior management share option plan	0.09
December 31, 2007	111.47
Issued for cash under purchase plans	0.39
Options exercised under senior management share option plan	0.35
December 31, 2008	112.21

As at December 31, 2008, there were 4.5 million (2007 – 4.8 million) common shares reserved for issuance under the senior management common share option plan, and 0.8 million (2007 – 1.0 million) common shares reserved for issuance under the employee common share purchase plan.

Dividend Reinvestment And Employee Common Share Purchase Plans

The Company has a Common Shareholder Dividend Reinvestment Plan, which provides an opportunity for shareholders to reinvest dividends and to make cash contributions for the purpose of purchasing common shares. The Company also has an Employee Common Share Purchase Plan to which the Company and employees make cash contributions for the purpose of purchasing common shares and which allows reinvestment of dividends.

Share-Based Compensation Plan

COMMON SHARE OPTION PLAN

The Company has a common share option plan that grants options to senior management of the Company for a maximum term of ten years. The option price for these shares is the closing market price of the shares on the day before the option is granted.

All options granted to date are exercisable on a graduated basis with up to 25 percent of options exercisable on the first anniversary date and in further 25 percent increments on each of the second, third and fourth anniversaries of the grant. If an option is not exercised within ten years, it expires and the optionee loses all rights thereunder. The holder of the option has no rights as a shareholder until the option is exercised and shares have been issued. The total number of shares to be optioned to any optionee shall not exceed five percent of the issued and outstanding common shares on the date the option is granted.

If, before the expiry of an option in accordance with its terms, the optionee ceases to be an eligible person due to retirement or termination for other than just cause, such option may, subject to the terms thereof and any other terms of the plan, be exercised at any time within the 24 months following the date the optionee retires, but in any case prior to the expiry of the option in accordance with its terms.

If, before the expiry of an option in accordance with its terms, the optionee ceases to be an eligible person due to employment termination for just cause, resignation or death, such option may, subject to the terms thereof and any other terms of the plan, be exercised at any time within the six months following the date the optionee is terminated, resigns, or dies, as applicable, but in any case prior to the expiry of the option in accordance with its terms.

	2008		2007	
	SHARES UNDER OPTION	WEIGHTED AVERAGE EXERCISE PRICE	SHARES UNDER OPTION	WEIGHTED AVERAGE EXERCISE PRICE
Outstanding, beginning of year	**2,343,450**	**$ 18.98**	1,892,425	$ 18.54
Granted	**289,500**	**$ 21.51**	542,600	$ 20.43
Exercised	**(351,625)**	**$ 18.27**	(91,575)	$ 18.18
Expired	**(83,600)**	**$ 20.14**	–	–
Outstanding, end of year	**2,197,725**	**$ 19.39**	2,343,450	$ 18.98
Exercisable, end of year	**1,176,300**	**$ 18.43**	1,058,150	$ 17.86

The weighted average contractual life of options outstanding at December 31, 2008 is 6.9 years (2007 – 7.3 years). The range of exercise prices for the options outstanding at December 31, 2008 is $13.70 to $22.59 (2007 – $13.70 to $20.52).

The fair value of each option is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions used for the grants:

	2008	2007
Expected dividend yield	**5.00%**	5.04%
Expected volatility	**13.96%**	14.00%
Risk-free interest rate	**4.18%**	4.24%
Expected life	**7 years**	7 years

DEFERRED SHARE UNIT PLAN AND RESTRICTED SHARE UNIT PLAN

The Company has deferred share unit ("DSU") and restricted share unit ("RSU") plans.

Under the Directors' DSU plan, Directors of the Company may elect to receive all or any portion of their compensation in DSUs in lieu of cash compensation. Directors' fees are paid on a quarterly basis and at the time of each payment of fees, the applicable amount is converted to DSUs. A DSU has a value equal to one Emera common share. When a dividend is paid on Emera's common shares, the Director's DSU account is credited with additional DSUs. DSUs cannot be redeemed for cash until the Director retires, resigns, or otherwise leaves the Board. The cash redemption value of a DSU equals the market value of a common share at the time of redemption, pursuant to the plan.

Under the executive and senior management DSU plan, each participant may elect to defer all or a percentage of their annual incentive award in the form of DSUs with the proviso that for participants who are subject to executive share ownership guidelines, a minimum of 50% of the value of their actual annual incentive award (25% in the first year of the program) will be payable in DSUs until the applicable guidelines are met.

When incentive awards are determined, the amount elected is converted to DSUs, which have a value equal to the market price of a Company common share. When a dividend is paid on Emera's common shares, each participant's DSU account is allocated additional DSUs equal in value to the dividends paid on an equivalent number of Emera common shares. Following termination of employment or retirement, and by December 15 of the calendar year after termination or retirement, the value of the DSUs credited to the participant's account is calculated by multiplying the number of DSUs in the participant's account by the then market value of an Emera common share. Payments are usually made in cash. At the sole discretion of the Management Resources and Compensation Committee ("MRCC"), payments may be made in the form of actual shares. Any participant who is a United States taxpayer shall receive payment on the first business day following the six month anniversary of their termination.

In addition, special DSU awards may be made from time to time by the MRCC to selected executives and senior management to recognize singular achievements or to achieve certain corporate objectives.

RSUs are granted annually for three-year overlapping performance cycles. RSUs are granted based on the average of Emera's stock closing price for the fifty trading days prior to a given calculation date and multiplied by a ratio factor of 1.11. Dividend equivalents are awarded and are used to purchase additional RSUs. The RSU value varies according to the Company's common share market price and corporate performance.

RSUs vest at the end of the three-year cycle and will be calculated and approved by the MRCC early in the following year. The value of the payout considers actual service over the performance cycle and will be pro-rated in the case of retirement, disability or death.

	EMPLOYEE DSUs OUTSTANDING	EMPLOYEE RSUs OUTSTANDING	DIRECTOR DSUs OUTSTANDING
January 1, 2006	152,486	295,085	62,783
Granted	96,371	90,548	23,886
Retirement, termination, disability and death	(6,729)	(3,360)	(11,019)
Payout	–	(115,055)	–
December 31, 2007	242,128	267,218	75,650
Granted	70,680	137,816	27,838
Retirement, termination, disability and death	(32,559)	(16,432)	(16,286)
Payout	–	(105,255)	–
December 31, 2008	**280,249**	**283,347**	**87,202**

The Company is using the fair value based method to measure the compensation expense related to its share-based compensation and employee purchase plan and recognizes the expense over the vesting period on a straight-line basis. The DSU and RSU liabilities are mark-to-market at the end of each period based on the common share price at the end of the period. For the year ended December 31, 2008, $4.7 million (2007 – $4.0 million) of compensation expense related to options granted, units issued, and shares purchased by employees was recognized in operating, maintenance and general expense.

21. SUPPLEMENTAL CASH FLOW INFORMATION

The change in non-cash operating working capital consists of the following:

MILLIONS OF DOLLARS	*2008*	*2007*
Decrease (increase) in accounts receivable	**$ 37.6**	$ (43.5)
(Increase) decrease in inventory	**(34.1)**	15.2
Decrease (increase) in prepaid expenses	**14.7**	(10.5)
(Increase) decrease in long-term receivables	**(48.6)**	61.2
Change in posted margin included in accounts receivable or accounts payable and accrued charges	**(70.5)**	(0.9)
Increase in other accounts payable and accrued charges	**18.6**	15.6
Increase (decrease) in income tax payable	**2.0**	(44.4)
	$ (80.3)	$ (7.3)

22. CAPITAL MANAGEMENT

The Company includes shareholders' equity (excluding AOCI), short-term and long-term debt, preferred shares issued by subsidiary, non-controlling interest related to BHE, securitized receivables, and cash and cash equivalents in the definition of capital as follows:

MILLIONS OF DOLLARS	2008	2007
Shareholders' equity, excluding AOCI	**$ 1,615.4**	$ 1,568.8
Debt	**2,448.5**	1,825.8
Preferred shares issued by subsidiary	**260.0**	260.0
Non-controlling interest related to BHE	**0.5**	0.6
Securitized accounts receivable	**–**	25.0
Cash and cash equivalents	**(12.2)**	(26.4)
	$ 4,312.2	$ 3,653.8

The Company's objectives when managing capital are to ensure sufficient liquidity and ongoing access to capital in order to allow the Company to acquire, build and maintain its regulated electric utilities, low risk unregulated generation and energy infrastructure businesses. The Company has a strategy of managing its capital structure through its various wholly-owned subsidiaries, while ensuring it is in compliance with its debt covenants. This strategy is managed by the Company through the issuance from time to time of shares, bonds, medium-term notes, preferred shares, or other indebtedness, and sales of receivables through the Company's securitization program. The securitization program was suspended in January 2008 due to increased pricing and limitations of supply in the market and expires in May 2009.

NSPI is subject to regulation by the Utility and Review Board with an allowed maximum common equity component for 2008 of 40%. The UARB has approved this component to increase to 45% in 2009. BHE is subject to regulation by the Maine Public Utilities Commission with an allowed maximum common equity component of 50% for rate-making purposes. The Federal Energy Regulatory Commission does not specify an allowed common equity component for BHE. The Company is in compliance with these requirements.

Emera Inc.'s syndicated bank credit agreement provides that the Company's debt cannot exceed 70% of the Company's capitalization. NSPI's trust indentures, applicable to the senior unsecured debenture and senior unsecured medium-term notes, provide that NSPI's funded debt cannot exceed 75% of total capitalization as defined in the credit agreements. NSPI's syndicated bank credit facility limits its debt to capitalization ratio to no greater than 0.65:1. BHE has short-term and long-term financing agreements that limit the amount of debt to less than 55% of capitalization, limit priority debt to 15% of net worth, limit earnings before interest, taxes, depreciation and amortization to interest to 2:1, and requires net worth of at least $150 million. The Company is in compliance with all of its financial debt covenants.

23. FINANCIAL INSTRUMENTS

The Company manages its exposure to foreign exchange, interest rate, and commodity risks in accordance with established risk management policies and procedures. Derivative financial instruments, consisting mainly of foreign exchange forward contracts, interest caps and collars, and oil and gas options and swaps, are used to hedge cash flows. Derivative financial instruments, consisting of foreign exchange forward contracts, are also used to hedge fair values.

Derivative financial instruments involve credit and market risks. Credit risks arise from the possibility that a counterparty will default on its contractual obligations and is limited to those contracts where the Company would incur a loss in replacing the instrument.

Financial instruments include the following:

	2008		2007	
MILLIONS OF DOLLARS	CARRYING AMOUNT	FAIR VALUE	CARRYING AMOUNT	FAIR VALUE
Cash and cash equivalents	$ 12.2	$ 12.2	$ 26.4	$ 26.4
Restricted cash	0.8	0.8	1.0	1.0
Accounts receivable	385.1	385.1	319.3	319.3
Long-term receivable	56.4	56.4	7.7	7.7
Derivatives held in a valid hedging relationship (current and long-term portion)	165.1	165.1	23.2	23.2
Held-for-trading derivatives (current and long-term portion)	137.8	137.8	139.8	139.8
Total financial assets	$ 757.4	$ 757.4	$ 517.4	$ 517.4
Accounts payable and accrued charges	$ 307.1	$ 307.1	$ 282.7	$ 282.7
Short-term debt	157.9	158.0	28.4	28.5
Long-term debt (including current portion)	2,290.6	2,330.8	1,797.4	2,030.4
Preferred shares issued by a subsidiary	260.0	258.9	260.0	275.7
Derivatives held in a valid hedging relationship (current and long-term portion)	169.8	169.8	77.2	77.2
Held-for-trading derivatives (current and long-term portion)	52.1	52.1	29.1	29.1
Total financial liabilities	$ 3,237.5	$ 3,276.7	$ 2,474.8	$ 2,723.6

Accounts Receivable, Long-Term Receivable And Accounts Payable And Accrued Charges

The Company's accounts receivable, long-term receivable and accounts payable and accrued charges are recognized at amortized cost. The carrying value of accounts receivable, long-term receivable and accounts payable and accrued charges is a reasonable approximation of fair value. Losses included in earnings and recorded in operating, maintenance and general expenses are $5.1 million (2007 – $6.9 million).

The allowance for doubtful accounts was $4.8 million as at January 1, 2008 (2007 – $2.6 million) and $4.5 million as at December 31, 2008 (2007 – $4.8 million). Changes in the allowance were due to changes in mix and volume of accounts receivable and changes in the provision related to specific customers.

Preferred Shares Issued By A Subsidiary, Long-Term Debt And Short-Term Debt

The Company's preferred shares issued by a subsidiary, long-term debt and short-term debt are measured at amortized cost. Preferred share dividends paid by a subsidiary are recognized using the effective interest method and are disclosed in note 7. Interest expense and debt financing expenses related to the Company's long-term debt and short-term debt are recognized using the effective interest method and are included in note 7.

The fair value of preferred shares issued by a subsidiary is based on market rates.

The fair value of the Company's long-term and short-term debt is estimated based on the quoted market prices for the same or similar issues, or on the current rates offered to the Company, for debt of the same remaining maturities.

Derivatives In Valid Hedging Relationships

The fair value of derivative financial instruments is estimated by obtaining prevailing market rates from investment dealers.

Gains and losses included in net earnings with respect to derivatives in valid hedging relationships include the following:

MILLIONS OF DOLLARS	2008	2007
Financing charges decrease	$ 1.5	–
Fuel and purchased power decrease (increase)	26.5	$ (14.7)
Total gains (losses)	$ 28.0	$ (14.7)

The Company recognized total ineffectiveness in net earnings related to cash flow hedges as follows:

MILLIONS OF DOLLARS	2008	2007
Fuel and purchased power increase	$ (0.5)	$ (0.2)
Total losses	$ (0.5)	$ (0.2)

The Company recognized total ineffectiveness in net earnings related to fair value hedges as follows:

MILLIONS OF DOLLARS	2008	2007
Financing charges decrease	$ 0.7	–
Total gains	$ 0.7	–

The Company expects to reclassify $61.4 million of losses currently included in AOCI to net earnings over the next 12 months related to hedged items realized in net earnings.

INTEREST RATES

The Company makes use of various financial instruments to hedge against interest rate risk. Additionally, the Company uses diversification as a risk management strategy. It maintains a portfolio of debt instruments which includes short-term instruments and long-term instruments with staggered maturities. The Company also deals with several counterparties so as to mitigate concentration risk.

The Company may enter into interest rate hedging contracts to limit exposure to fluctuations in floating and fixed interest rates on its short-term and long-term debt.

The Company has no interest rate hedging contracts outstanding as of December 31, 2008.

COMMODITY PRICES

A substantial amount of NSPI's fuel supply comes from international suppliers and is subject to commodity price risk. As part of its fuel management strategy, NSPI manages exposure to commodity price risk utilizing financial instruments providing fixed or maximum prices.

The Company enters into natural gas swap contracts to limit exposure to fluctuations in natural gas prices. As at December 31, 2008, the Company had hedged approximately 99% of all natural gas purchases and sales associated with its forecasted natural gas burn and resale for 2009, and 67% for 2010.

The Company enters into oil swap contracts to limit exposure to fluctuations in world prices of heavy fuel oil. As at December 31, 2008, the Company has hedged approximately 100% of 2009 requirements and 58% for 2010.

The Company enters into solid fuel swap contracts to limit exposure to fluctuations in world prices of solid fuel. As at December 31, 2008, the Company had hedged approximately 91% of all solid fuel purchases for 2009, 29% for 2010, 19% for 2011 and 7% for 2012.

The Company enters into power swaps to limit exposure to fluctuations in power prices. At December 31, 2008, the Company has hedged 97% of 2009 requirements, 100% of 2010 requirements, 60% of 2011 requirements and approximately 10% of the requirements for 2012 and 2013.

FOREIGN EXCHANGE

The risk due to fluctuation of the Canadian dollar against the US dollar for the cost of fuel is measured and managed. In 2009, NSPI expects approximately 80% of its anticipated net fuel costs to be denominated in USD; USD from sales of surplus natural gas will provide a natural hedge against a portion of USD fuel costs.

Emera enters into foreign exchange forward and swap contracts to limit exposure on fuel purchases to currency rate fluctuations. Currency forwards are used to fix the Canadian dollar cost to acquire US dollars, reducing exposure to currency rate fluctuations. Forward contracts to buy USD $318.0 million are in place at a weighted average rate of $1.08, representing over 70% of 2009 anticipated USD requirements. Forward contracts to buy USD $602.5 million in 2010 through 2012 at a weighted average rate of $1.01 were outstanding at December 31, 2008 to manage exposure to 34% of anticipated USD requirements in these years. As of December 31, 2008 there were no fuel related swaps outstanding. Emera uses foreign exchange forward contracts to hedge the currency risk for capital projects and receivables denominated in foreign currencies. Forward contracts to buy USD $7.8 million are in place at a weighted average rate of $0.99 for capital projects in 2009. Forward contracts to sell USD $39.0 million are in place at a weighted average rate of $1.25 to hedge a portion of receivables in 2010.

Emera uses forward contracts to hedge the currency risk associated with revenue streams denominated in foreign currencies. Forward contracts to sell USD $46.0 million are in place in 2009 and 2010 at a weighted average rate of $1.25.

Option contracts, to eliminate exposure to currency rate fluctuations for 2009, of $0.5 million at a rate of $1.26 were outstanding on December 31, 2008.

Held-For-Trading Derivatives

Derivatives included in held-for-trading assets and liabilities are required to be included in this classification in accordance with Canadian GAAP. The Company has not designated any financial instruments to be included in the held-for-trading category.

The fair value of derivatives is estimated by obtaining prevailing market rates from investment dealers. The Company has a derivative, a power swap, where no observable market exists, therefore modelling techniques are employed using assumptions reflective of current market rates, yield curves and forward prices as applicable, to interpolate certain prices.

Total gains and losses included in net earnings with respect to held-for-trading derivatives include the following:

MILLIONS OF DOLLARS	*2008*	*2007*
Electric revenue	–	$ (0.6)
Other revenue	$ 3.6	25.8
Fuel and purchased power	(0.4)	0.5
Financing charges	(0.5)	0.1
Total gains	$ 2.7	$ 25.8

Changes in the fair value of the derivative asset, where no observable market exists, includes the following:

MILLIONS OF DOLLARS	*2008*	*2007*
Balance, beginning of year	$ 10.5	–
(Loss) gain recognized in other revenue	(8.1)	$ 15.7
Foreign exchange included in AOCI	2.5	(5.2)
Balance, end of year	$ 4.9	$ 10.5

ENERGY MARKETING ASSETS AND LIABILITIES

On December 31, 2008, the Company held derivative financial and commodity instruments within its trading group.

NATURAL GAS CONTRACTS

Nova Scotia Power has contracts for the purchase and sale of natural gas at its Tufts Cove generating station that are considered HFT derivatives and accordingly are recognized on the balance sheet at fair value. This reflects NSPI's history of buying and reselling any natural gas not used in the production of electricity at TUC.

DERIVATIVES NOT IN VALID HEDGING RELATIONSHIPS

On December 31, 2008, the Company held natural gas, power and oil derivatives, which were not in valid hedging relationships. This includes a certain swap in place to economically hedge the power necessary to produce the energy requirements of the long-term power supply agreement with the Long Island Power Authority, which is marked-to-market through earnings as it does not meet the stringent accounting requirements of hedge accounting.

Risk Management

MARKET RISK

The Company uses value-at-risk limits to manage its exposure to energy commodities from commercial activities on behalf of third parties such as the purchase and sale of natural gas and electricity, and related energy management services. These commercial activities are monitored on a daily basis by the Company's risk management group such that the value-at-risk is not material.

Market risks associated with derivatives, which include the Company's hedges and HFT derivatives, are related to movement in commodity prices and foreign exchange rates. Market risk associated with short-term debt is related to movement in interest rates. Market risk associated with the long-term receivable is related to movements in commodity prices and foreign exchange rates.

As at December 31, 2008 the Company determined that market risk exposure associated with its financial instruments would affect the Company's financial results as follows:

MILLIONS OF DOLLARS	AFTER-TAX NET EARNINGS INCREASE (DECREASE)	AFTER-TAX AOCI INCREASE (DECREASE)
$1 per one million British Thermal Unit increase in the price of natural gas	$ 2.3	$ 8.7
$5 per barrel increase in the price of heavy fuel oil	0.8	10.0
$15 per metric tonne increase in the price of coal	–	38.6
$0.01 decrease in the strength of the Canadian relative to the US dollar	(0.3)	8.1
100 basis point increase in the central bank interest rates	0.2	–
$1 per megawatt hour increase in the price of power	0.6	–

The above table illustrates the effect on the Company's financial results due to a certain fixed price change on the entire portfolio of financial instruments as at the end of the quarter. The results disclosed in the above table cannot be extrapolated linearly to determine the effect on the Company's financial results due to varying price changes.

CREDIT RISK

The Company is exposed to credit risk with respect to amounts receivable from customers. Credit assessments are conducted on all new customers and deposits are requested on any high risk accounts. The Company also maintains provisions for potential credit losses, which are assessed on a regular basis. With respect to customers other than electric customers, counterparty creditworthiness is assessed through reports of credit rating agencies or other available financial information.

As at December 31, 2008, the maximum exposure the Company has to credit risk is $606.8 million, which includes accounts receivable, long-term receivable, and the assets related to derivatives in a valid hedging relationship, and held-for-trading derivatives, excluding NSPI's natural gas contracts.

The Company transacts with counterparties as part of its risk management strategy for managing commodity price, foreign exchange and interest rate risk. Counterparties that exceed established credit limits can provide a cash deposit or letter of credit to the Company for the value in excess of the credit limit where contractually required. The Company also obtains cash deposits from electric customers. The total cash deposits and letters of credit on hand as at December 31, 2008 was $47.6 million, which mitigates the Company's maximum credit risk exposure. The Company uses the cash as payment for the amount receivable or returns the cash deposit to the counterparty where the credit limit is no longer exceeded or where the customer is no longer considered a high risk account.

The Company generally considers the credit quality of financial assets that are neither past due nor impaired to be good. The Company monitors collection performance to ensure payments are received on a timely basis.

The Company does not have any financial assets that would be considered to be impaired.

As at December 31, 2008, the Company had $31.3 million in financial assets considered to be past due, which have been outstanding for an average of 69 days. The fair value of these financial assets is $28.5 million, the difference of which is included in the allowance for doubtful accounts. These assets primarily relate to accounts receivable from electric revenue.

CONCENTRATION RISK

The Company's concentration of risk as at December 31, 2008 is as follows:

	2008 MILLIONS OF DOLLARS	% OF TOTAL EXPOSURE
Accounts receivable		
Regulated utilities		
Residential	$115.6	16%
Commercial	62.0	8%
Industrial	31.2	4%
Other	15.1	2%
Posted margin with other counterparties	25.1	3%
	249.0	33%
Trading group		
Credit rating of A- or above	44.1	6%
Credit rating of BBB- to BBB+	21.5	3%
Not rated	46.1	6%
Fully collateralized	12.3	2%
	124.0	17%
Other accounts receivable	12.1	2%
	385.1	52%
Long-term receivable	56.4	7%
Derivatives (in a valid hedging relationship and held-for-trading; current and long-term portions)		
Credit rating of A- or above	216.4	29%
Credit rating of BBB- to BBB+	15.5	2%
Not rated	71.0	10%
	302.9	41%
	$744.4	100%

LIQUIDITY RISK

Liquidity risk encompasses the risk that the Company cannot meet its financial obligations.

Emera's main sources of liquidity are its cash flows from operations, short-term and long-term debt, and the securitization of accounts receivable. Funds are primarily used to finance capital transactions. Some of these instruments are subject to market risks that the Company typically hedges with interest rate swaps, caps, floors, futures and options.

Emera manages its liquidity by holding adequate volumes of liquid assets and maintaining credit facilities in addition to the cash flow generated by its operating businesses. The liquid assets consist of cash and cash equivalents.

The Company's financial instrument liabilities mature as follows:

	2009	*2010*	*2011*	*2012*	*> 2012*
Accounts payable and accrued charges	$ 307.1	–	–	–	–
Short-term debt	157.9	–	–	–	–
Long-term debt	774.7	$ 106.3	$ 6.0	$ 106.8	$ 1,310.8
Preferred shares issued by subsidiary	125.0	–	–	–	135.0
Derivatives held in a valid hedging relationship	110.2	36.0	18.8	4.6	0.2
Held-for-trading derivatives	40.4	11.4	0.3	–	–
Total financial liabilities	$ 1,515.3	$ 153.7	$ 25.1	$ 111.4	$ 1,446.0

The Company has available the following credit facilities as at December 31, 2008 for the management of liquidity risk:

MILLIONS OF DOLLARS	AVAILABLE	USED	UNUSED
Bank operating and commercial paper	$ 1,373.5	$ 917.9	$ 455.6

Available-For-Sale Investments

Available-for-sale investments includes the Company's investment in OpenHydro Group Limited ("OpenHydro"). The investment is recognized at its cost of $15.4 million. The fair value of OpenHydro has not been recognized or disclosed because its shares are not actively traded in an open market. The Company does not intend to dispose of the investment in the near term. The market for any disposition of OpenHydro shares would be with an existing shareholder or a new private investor.

24. RELATED PARTY TRANSACTIONS

In the ordinary course of business, Emera purchased natural gas transportation capacity totalling $29.4 million (2007 – $25.4 million) during the year ended December 31, 2008, from the Maritimes & Northeast Pipeline, an investment under significant influence of the Company. The amount is recognized in fuel for generation and purchased power or netted against energy marketing margin in other revenue, and is measured at the exchange amount. At December 31, 2008 the amount payable to the related party is $4.1 million (2007 – $4.5 million), is non-interest bearing and is under normal credit terms.

25. CONTINGENCIES

A number of individuals who live in proximity to NSPI's Trenton generating station have filed a statement of claim against Nova Scotia Power in respect of emissions from the operation of the plant for the period 2001 forward. The plaintiffs proposed to amend the statement of claim to reference emissions from the operation of the plant commencing in the early 1970's, though the amendment has not at this time been consented to nor granted by the court. The Company has filed a defence to the claim. The plaintiffs claim unspecified damages as a result of interference with enjoyment of, or damage to, their property and adverse health effects they allege were caused by such emissions. The outcome, and therefore an estimate of any contingent loss, of this litigation are not determinable.

Bangor Hydro Electric has a potential liability to Great Lake Hydro America LLC, for headwater benefits on the Penobscot River in connection with hydro assets sold to PPL Generation, LLC in 1999. The matter is currently before the Federal Energy Regulatory Commission for determination. The outcome, and therefore an estimate of any contingent loss, of this litigation, are not determinable.

In addition, the Company may, from time to time, be involved in legal proceedings, claims and litigations that arise in the ordinary course of business which the Company believes would not reasonably be expected to have a material adverse affect on the financial condition of the Company.

26. COMMITMENTS

In addition to commitments outlined elsewhere in these notes, Emera had the following significant commitments at December 31, 2008:

- The Company has a commitment to purchase approximately 43,000 mmbtu per day of transportation capacity on the US portion of the Maritimes & Northeast Pipeline, a related party, for the next five years, at an approximate average cost of $10 million per year.
- NSPI has an annual requirement to purchase approximately 952 GWh of electricity from independent power producers over varying contract lengths ranging from five to 25 years.
- NSPI is required to purchase approximately 61,600 mmbtu of natural gas per day for the next two years (subject to offshore gas production), and an additional 4,000 mmbtu per day for three years.
- NSPI has a commitment to purchase approximately 61,600 mmbtu per day of transportation capacity on the Maritimes & Northeast Pipeline, a related party, for the next two years. The approximate cost of the commitment is $18 million per year.
- NSPI has a commitment to purchase an additional 4,000 mmbtu per day of transportation capacity on the Maritimes & Northeast Pipeline, a related party, for three years. The commitment includes renewal rights at the supplier's option for two additional five year terms, at an approximate cost of $1 million per year.
- NSPI is responsible for managing a portfolio of approximately $1.1 billion of defeasance securities held in trust. The defeasance securities must provide the principal and interest payment streams of the related defeased debt. Approximately 73%, or $774 million, of the defeasance portfolio consists of investments in the related debt, eliminating all risk associated with this portion of the portfolio.
- NSPI has a commitment to a third party for the unloading and transportation of coal for ten years beginning in late 2002 at an approximate cost of $16 million per year.
- NSPI has commitments to third parties for 2009 to 2012, to purchase and transport 3.5 million metric tonnes ("mts") of import coal, 335,800 mts of petroleum coke, 720,000 mts of domestic coal and 2.4 million mts of marine freight.
- Bangor Hydro has various contracts committing it to purchase annually, net of resale revenues, approximately $7 million to $11 million of electricity for the period from 2009 to 2019 from independent power producers. These commitments are reduced to less than $2 million each year from 2018 to 2026.

27. GUARANTEES

Emera had the following guarantees at December 31, 2008:

- The Company has letters of credit issued totalling $133.1 million. Emera's outstanding letters of credit are to secure payment to various vendors that expire in 2009 and/or are renewed annually. Nova Scotia Power's letters of credit extend to 2009 and/or are renewed annually and secure payments to various vendors, including counterparties, and to secure obligations under an unfunded pension plan. Bangor Hydro's letters of credit extend to 2009 and/or are renewed annually to secure payments to a vendor and for obligations under an unfunded pension plan.

28. SUBSEQUENT EVENT

In January 2009, Nova Scotia Power issued $50 million in medium term notes, at a yield of 5.455%. The notes are due in full in October 2013. Proceeds were used to pay down short-term debt.

29. COMPARATIVE INFORMATION

Certain of the comparative figures have been reclassified to conform to the financial statement presentation adopted for 2008.

Operating Statistics
Five-Year Summary

YEAR ENDED DECEMBER 31	*2008*	*2007*	*2006*	*2005*	*2004*
Electric energy sales (GWh)					
Residential	**4,769.6**	4,738.5	4,516.0	4,602.7	4,632.4
Commercial	**3,721.1**	3,768.5	3,621.1	3,614.1	3,567.4
Industrial	**4,491.5**	4,568.4	3,246.7	4,600.3	4,556.1
Other	**1,115.2**	1,320.4	1,550.8	902.7	819.1
Total electric energy sales	**14,097.4**	14,395.8	12,934.6	13,719.8	13,575.0
Sources of energy (GWh)					
Thermal – coal	**9,008.9**	9,561.4	9,128.1	9,116.3	9,490.2
– oil	**340.7**	516.6	431.9	1,581.3	1,699.3
– natural gas	**1,257.9**	1,057.1	390.3	194.3	97.0
Hydro	**1,102.3**	936.8	1,034.7	1,092.6	983.5
Wind	**2.4**	2.4	2.4	1.8	2.4
Purchases	**3,493.2**	3,534.7	3,144.7	2,961.6	2,339.9
Total generation and purchases	**15,205.4**	15,609.0	14,132.1	14,947.9	14,612.3
Losses and internal use	**1,076.3**	1,213.2	1,197.5	1,228.1	1,037.3
Total electric energy sold	**14,129.1**	14,395.8	12,934.6	13,719.8	13,575.0
Electric customers					
Residential	**535,494**	530,955	526,014	520,671	515,726
Commercial	**54,461**	51,083	50,780	50,321	49,353
Industrial	**2,541**	2,543	2,526	2,515	2,455
Other	**9,064**	9,574	9,378	9,094	8,684
Total electric customers	**601,560**	594,155	588,698	582,601	576,218
Capacity					
Generating nameplate capacity (MW)					
Coal fired	**1,243**	1,243	1,243	1,243	1,243
Dual fired	**365**	350	350	350	350
Gas turbines	**304**	319	323	323	319
Hydroelectric	**1,005**	1,005	1,005	1,005	395
Wind turbines	**1**	1	1	1	1
Independent power producers	**120**	120	120	74	66
	3,038	3,038	3,042	2,996	2,374
Total number of employees	**2,215**	2,194	2,149	2,075	2,249
km of transmission lines	**6,400**	6,200	6,100	6,100	6,100
km of distribution lines	**32,600**	32,000	32,000	32,000	32,000

Five-Year Summary

YEAR ENDED DECEMBER 31 (MILLIONS OF DOLLARS)	*2008*	*2007*	*2006*	*2005*	*2004*
Statements of Earnings Information					
Revenue	**$ 1,331.9**	$ 1,339.5	$ 1,166.0	$ 1,168.0	$ 1,134.2
Cost of operations					
Fuel for generation and power purchased	**525.1**	494.5	347.7	432.0	350.0
Operating, maintenance and general	**266.8**	264.8	255.6	248.2	245.2
Provincial, state and municipal taxes	**49.4**	47.5	48.0	48.4	46.3
Provincial tax deferral	**–**	–	–	(4.5)	–
Depreciation	**151.3**	149.3	145.2	136.1	131.2
Regulatory amortization	**28.5**	31.4	22.8	19.4	26.1
	1,021.1	987.5	819.3	879.6	798.8
	310.8	352.0	346.7	288.4	335.4
Equity earnings	**15.2**	12.8	4.9	6.5	6.2
Other income	**–**	–	8.9	8.0	–
Financing charges	**123.2**	133.2	148.1	140.3	152.1
Earnings before income taxes	**202.8**	231.6	212.4	162.6	189.5
Income taxes	**58.1**	80.3	86.6	52.7	61.9
Income taxes deferral	**–**	–	–	(12.2)	–
Net earnings from continuing operations	**144.7**	151.3	125.8	122.1	127.6
(Loss) earnings from discontinued operations	**–**	–	–	(0.9)	2.2
Net earnings	**144.7**	151.3	125.8	121.2	129.8
Non-controlling interest	**0.6**	–	–	–	–
Net earnings applicable to common shares	**144.1**	151.3	125.8	121.2	129.8
Common dividends	**107.9**	99.9	98.3	97.4	95.5
Dividends paid by subsidiaries to non-controlling interest	**1.9**	–	–	–	–
Earnings retained for use in Company	**$ 34.3**	$ 51.4	$ 27.5	$ 23.8	$ 34.3
Cost of fuel for generation – coal	**$ 282.1**	$ 276.0	$ 266.2	$ 260.9	$ 209.1
– oil	**17.7**	49.7	34.3	100.2	91.1
– natural gas	**92.5**	52.0	(41.6)	(35.4)	(30.6)
Power purchased	**132.8**	116.8	88.8	106.3	80.4
Total cost of fuel for generation and power purchased	**$ 525.1**	$ 494.5	$ 347.7	$ 432.0	$ 350.0
Balance Sheets Information					
Current assets	**$ 681.8**	$ 567.0	$ 491.3	$ 391.5	$ 332.1
Other assets	**793.0**	600.4	577.3	678.8	742.0
Investments subject to significant influence	**317.6**	124.5	98.5	99.1	96.8
Property, plant and equipment	**3,476.2**	2,929.2	2,881.9	2,829.2	2,778.3
Total assets	**$ 5,268.6**	$ 4,221.1	$ 4,049.0	$ 3,998.6	$ 3,949.2
Current liabilities	**$ 880.1**	$ 506.6	$ 491.0	$ 506.4	$ 493.6
Other liabilities	**508.5**	417.7	231.8	233.4	231.5
Long-term debt	**2,159.2**	1,676.4	1,657.4	1,631.8	1,626.5
Preferred shares issued by subsidiary	**135.0**	260.0	260.0	260.0	260.0
Non-controlling interest	**39.6**	0.6	0.7	0.8	0.8
Common shares	**1,081.4**	1,066.2	1,055.2	1,039.2	1,017.3
Contributed surplus	**3.4**	3.0	2.2	1.8	1.9
Accumulated other comprehensive income	**(69.2)**	(209.0)	(100.2)	(98.2)	(82.0)
Retained earnings	**530.6**	499.6	450.9	423.4	399.6
Total equity and liabilities	**$ 5,268.6**	$ 4,221.1	$ 4,049.0	$ 3,998.6	$ 3,949.2
Statements of Cash Flow Information					
Cash provided by operating activities	**$ 237.2**	$ 351.4	$ 332.5	$ 151.0	$ 291.2
Cash used in investing activities	**$ 671.6**	$ 288.9	$ 196.9	$ 117.2	$ 214.5
Cash provide by (used in) financing activities	**$ 419.7**	$ (55.6)	$ (143.4)	$ (55.0)	$ (44.0)
Financial ratios ($ per common share)					
Earnings per common share	**$ 1.29**	$ 1.36	$ 1.14	$ 1.11	$ 1.20

* Other assets and liabilities restated to December 31, 2007 only

BOARD OF DIRECTORS

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New River Beach, New Brunswick

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Company Director
Former President and
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Carrabassett Valley, Maine

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TD Canada Trust
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Corporate and Legal
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Calgary, Alberta

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(Committee Chair)

ROBERT S. BRIGGS

ALLAN L. EDGEWORTH

Emera Inc. Management Resources and Compensation Committee:

DR. ELIZABETH PARR-JOHNSTON
(Committee Chair)

ALLAN L. EDGEWORTH

JOHN T. MCLENNAN

Emera Inc. Nominating and Corporate Governance Committee:

DR. GAIL COOK-BENNETT
(Committee Chair)

JOHN T. MCLENNAN

DR. ELIZABETH PARR-JOHNSTON

DIVIDEND PAYMENTS IN 2009

Subject to approval by the Board of Directors, common share dividends for Emera Inc. are payable on or about the 15th of February, May, August and November. A first quarter dividend of $0.2525 has been declared payable February 16, 2009. A quarterly dividend of $0.30625 is payable on the 1st of January and April. Nova Scotia Power Inc.'s Series C First Preferred Shares are being redeemed on April 1, 2009. A quarterly dividend of $0.36875 is payable on the 15th of January, April, July and October for Nova Scotia Power Inc.'s Series D First Preferred Shares.

DIVIDEND REINVESTMENT AND SHARE PURCHASE PLAN

Emera's Dividend Reinvestment and Share Purchase Plan is available to shareholders resident in Canada. The plan provides shareholders with a convenient and economical means of acquiring additional common shares through the reinvestment of dividends. Plan participants may also contribute cash payments of up to $5,000 per quarter. Participants of the plan pay no commissions, service charges or brokerage fees for shares purchased under the Plan. Please contact Investor Services if you have questions or wish to receive a copy of the plan brochure and enrollment form.

DIRECT DEPOSIT SERVICE

Shareholders may have dividends deposited directly into accounts held at financial institutions that are members of the Canadian Payments Association. To arrange this service, please contact Investor Services.

QUARTERLY EARNINGS

Quarterly earnings are expected to be announced May 5, August 7 and November 6, 2009. Year-end results for 2008 were released in February 2009.

ANNUAL GENERAL MEETING

The Annual General Meeting is scheduled to be held May 6, 2009 at 2:00 p.m. (Atlantic Time) at the Cunard Centre in Halifax, Nova Scotia.

Environmental Savings

Paper quantity used for this resource: 8,910 lbs. / 4,041.51 kg

Printed on a Cascades Rolland Opaque30 – manufactured with 30% post-consumer recycled waste fibre.

Savings:

Wood Use	**32 trees**
Total Energy	**22 million BTUs**
Greenhouse Gases	**1,277.77 kg of CO_2 equivalent**
Waste Water	**5,685.71 litres**
Solid Waste	**681.3 kg**

Environmental impact estimates were made using the Environmental Defense Fund Paper Calculator. For more information visit http://www.papercalculator.org.

This resource is printed on uncoated paper that is manufactured in Canada with 30% post-consumer recycled waste fiber; is Elemental Chlorine Free (ECF); ensures the responsible use of forest resources by being Forest Stewardship Council (FSC) certified; is Eco Logo certified and uses Biogas Energy in its production (an alternative green energy source produced from decomposing waste collected from landfill sites) to help reduce greenhouse gas emissions. It is also archival and recyclable.

Printed by Colour Innovations, an FSC-certified and Eco-Logo certified printer.

Carbon Neutral Made

FSC Mixed Sources
Product group from well-managed forests and recycled wood or fiber
www.fsc.org Cert no. SW-COC-001731
© 1996 Forest Stewardship Council

SHAREHOLDER INFORMATION

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Information regarding company news and initiatives, including our 2008 Financial Report, is also available at our website: **www.emera.com**

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SHARE LISTINGS
Toronto Stock Exchange (TSX)
Common Shares: EMA
Preferred Shares:
NSI.PR.C, NSI.PR.D
(Series C Preferred Shares are being redeemed on April 1, 2009)

SHARES OUTSTANDING
Common Shares:
112,206,608
(as of December 31, 2008)

DIVIDENDS PAID IN 2008
Emera Inc. paid Common Share dividends of $0.2375 per Common Share in Q1, Q2 and Q3, and $0.2525 per Common Share in Q4, for an effective annual Common Share dividend rate of $0.97 per Common Share.

Emera

WWW.EMERA.COM