2007 **NSUARB-P-886**

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: The *Public Utilities Act,* R.S.N.S. 1989, c.380 as amended

IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for Approval of Certain Revisions to its Rates, Charges and Regulations

RESPONSE TO INFORMATION REQUEST

TO: NSPI

FROM: UARB

Question IR-76: **Please file the Emera 2005 Annual Report.**

Response IR-76: Please refer to Attachments 1 and 2.

2005 annual financial report



Emera

letter to shareholders



To My Fellow Shareholders

In my letter last year, I emphasized the importance of Emera increasing the predictability of its earnings as a critical step in delivering on our investment value proposition. We've made solid progress toward this goal, though the path has not been as direct as I would have liked. Let me tell you where we have been, and where we are going.

2005 was a challenging year for Emera due to rate issues at our largest subsidiary, Nova Scotia Power (NSPI). Prior to 2002, NSPI had managed six years without requesting an electricity rate increase. We asked for new rates for 2002 in the face of a sharp increase in coal prices, and again for 2005 primarily to include corporate taxes in the rate structure. In the March 2005 rate decision, the Nova Scotia Utility and Review Board (UARB) was critical of NSPI's past fuel procurement practices, and awarded the utility substantially less for fuel than it had requested. As a result, in July of last year, NSPI again filed for new rates, requesting an average 15% increase for 2006, due to increasing world fuel prices.

Fuel is the company's single largest expense, so anything less than full recovery of this cost in rates can have a material effect on the utility's ability to earn within its allowed earnings range. It is worth noting that prior to 2000, NSPI had purchased all of its fuel from local suppliers under long-term contracts. Since then, NSPI has been sourcing coal on world markets. Both natural gas and petroleum coke have been added to our fuel mix, and we have put in place a portfolio of contracts for fuel commodities, transportation and currency. To help prepare for the future, we embarked on a program of testing new coal blends, and have invested in a new marine terminal. These efforts will both reduce costs and provide the utility with access to competitive coal supply basins around the globe.

In response to our regulator's 2005 decision we have worked to demonstrate that we are listening and acting. We have made improvements in fuel procurement practices and are actively building a portfolio of contract durations, suppliers, and fuels. Our results were acknowledged in the hearings on our 2006 application by UARB consultants who were previously critical.

NSPI's rate challenges are reflected in its 2005 financial performance. NSPI's contribution to consolidated net earnings fell to $91.2 million, a 15% decline from 2004 levels. 2005 earnings were actually higher than anticipated, and were achieved because, in the fourth quarter of the year, NSPI managed a better-than-forecast renegotiation of its natural gas supply contract. The new contract added approximately $15 million to net earnings in 2005, and we expect it will continue to bring significant value to future years.

Our efforts to address regulatory concerns are being recognized. I am encouraged by the UARB's recent decision on 2006 rates. The new revenue the decision provides, combined with the expected benefits from the gas supply contract I noted previously, should enable Nova Scotia Power to earn within its allowed range of 9.3% to 9.8% on common equity in 2006.

The decision also brings closure to past fuel procurement process issues. Of course, maintaining productive regulatory relationships is an ongoing process, and NSPI will continue to work to understand regulatory expectations, and meet them.

These are encouraging developments. Emera had some momentum building successes in 2005. We completed our acquisition of the Bear Swamp hydro-electric generating facility in the spring, in a joint venture with Brookfield Power (formerly Brascan Power). That investment has met our expectations operationally and financially, adding $4 million of operating earnings in 2005.

Bangor Hydro Electric's (BHE) *Northeast Reliability Interconnect* international transmission project recently received its Presidential Permit from the United States Department of Energy, the last step in the regulatory approval process. This is testimony to hard work, perseverance and cooperation among many key stakeholders. Clearing has already begun along the route, and construction is expected to begin later this year. This project is an important addition to the region's electricity grid and will have reliability and efficiency benefits for customers. This new $100 million investment will replenish BHE's earnings power, which has been contracting as its regulatory assets are amortized.

And Emera's energy marketing business made another strong contribution in 2005, slightly exceeding its prior year's performance generating $24 million in margin. This business has added key skills and capabilities to our company.

With the core businesses on more solid ground, I will turn my attention to our growth agenda in 2006. Emera has outstanding operational expertise in all aspects of the electricity business. Again in 2005, our thermal plant operations were recognized for extraordinary achievement nationally. An impressive five of NSPI's generating units reached the ranks of Canada's top ten thermal units in performance. Trenton Unit 6 outperformed 87 other generating units in the country for the Number 1 ranking, with the capability of operating at greater than 98% of capacity for the previous year.

We will leverage all of our expertise and experience outside of our current service areas. We will work with existing and new partners to build our business in 2006 and beyond.

We will also have opportunities for investment close to home, in air emission reduction technology for existing assets, renewable energy sources, conservation, and transmission development.

The energy world is changing. Demand for the benefits of energy and electricity is increasing. Prices are volatile. At the same time, citizens and their governments are looking for ways to reduce the environmental costs of energy. Electric utilities are also changing. I spent much of 2005 meeting with customers, partners and employees in Nova Scotia and Maine – to better understand what is most important to them, and to share our knowledge and expertise so that, together, we can find ways of meeting the challenges that lie ahead. It was important to me to make this a personal effort, and I found the experience to be very rewarding. I wanted to hear first-hand what people had to say. And I wanted to demonstrate the commitment of our company to change how we approach issues and

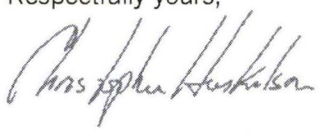
collaboratively solve problems. We are listening and acting. This work must and will continue.

Our operating companies, Nova Scotia Power and Bangor Hydro-Electric, will continue working hard to make their facilities cleaner, safer, and ready to meet the demands of a new era in energy generation, transmission and distribution.

Our Board of Directors continues to provide our company with keen strategic insight and strong governance. On behalf of our Management Team I thank them for their efforts.

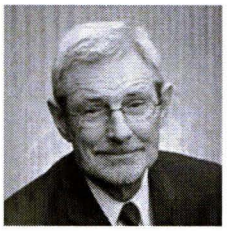
I am also profoundly grateful to our employees for their support and dedication to our company over the past year. I look forward to a successful and satisfying 2006.

Respectfully yours,



Christopher G. Huskilson
President and Chief Executive Officer

chairman's message



Fellow Shareholders

Emera's Board of Directors is currently focused on two critical tasks: providing strategic guidance to your Company, and ensuring that sound stewardship and governance is in place to meet the increasingly high standards demanded by shareholders.

Strategy is no longer a once-a-year agenda item, but a fundamental element of all Board discussions. This has resulted in greater collaboration between the Board and Management on matters of strategic importance to Emera. In 2005, much of that work focused on efforts to improve our relationship with our Nova Scotia regulator. This, of course, is vital to delivering appropriate and predictable returns to investors. We are encouraged that the 2006 rate decision is moving us in the right direction in this regard.

In the spirit of continuous improvement, key elements of the Board's governance process were reviewed and updated in 2005. For example, we implemented a new Board of Directors Charter which documents the responsibilities of the Board in a number of important areas including strategy development, selection and management of executive officers, financial performance, disclosure and internal control, risk management, independence, and environmental responsibility.

This new Charter specifically articulates the Board's leadership role in ensuring the integrity-based culture of the organization thrives. To that end, the Board has also recently approved new "Standards for Business Conduct" for Emera, to support and promote a business culture where ethical conduct is recognized, valued and exemplified.

Under the capable leadership of Dr. Gail Cook Bennett, of the Nominating and Corporate Governance Committee, we also recently began a review of our Director Evaluation processes.

The composition of our Board is changing as veteran Directors move on and new leaders step forward. In November 2005, Jim Gray retired after eight years of service. Jim is a leader of Canada's energy industry and he brought a wealth of knowledge and experience to Emera. Two more Directors will be retiring at our Annual Meeting in May, both of whom have served the Company since its privatization in 1992. Ken Rowe, one of Atlantic Canada's most successful business builders, has an entrepreneurial zeal that has been extremely valuable to Emera. Edward McNeil brought important perspectives gained through his labour-union leadership experience. These gentlemen will be missed. On behalf of the Directors, the management and the employees of Emera, I want to offer sincere thanks to them for their outstanding contributions.

We welcomed two new Directors to the Board in the past year. Like Jim Gray, Allan Edgeworth is an Albertan and an energy-industry veteran, having served as President and Chief Executive Officer of Alliance Pipeline, and also as President of Westcoast Energy's Pipeline Division. Wes Armour is the President and Chief Executive Officer of Moncton-based Armour Transportation Systems, which has been twice honoured as one of Canada's 50 Best Managed Companies. Allan and Wes are already making important contributions to our Board's deliberations, and I look forward to working with them.

We anticipate further changes to Emera's governance structure over the next year. Specifically, we will be establishing a separate Board of Directors for Nova Scotia Power Inc. This change will provide NSPI with distinct and independent governance from Emera. We believe this is important for a regulated utility. It will also bring Emera's governance structure in line with other investment-holding companies. We expect the new NSPI Board to be in place by the fall of this year.

In closing, I want to express my appreciation to Emera's employees who work hard every day serving our customers and building our company's success.

Sincerely,



Derek Oland
Chairman of the Board of Directors

management's discussion and analysis

as at February 17, 2006

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 2005 relative to 2004, and the full year 2005 relative to 2004 and to 2003, and its financial position at December 31, 2005 relative to 2004. 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 subsidiary, Nova Scotia Power Inc.'s accounting policies are subject to examination and approval by the Nova Scotia Utility and Review Board. Emera's subsidiary, Bangor Hydro-Electric Company's accounting policies are subject to examination and approval by the Maine Public Utilities Commission and the Federal Energy Regulatory Commission. The rate-regulated accounting policies of Nova Scotia Power and Bangor Hydro 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 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)	2005	2004	2005	2004	2003
Revenues	$ 297.1	$ 286.5	$ 1,168.0	$ 1,134.2	$ 1,146.8
Net earnings from continuing operations	37.7	30.7	122.1	127.6	128.2
Consolidated net earnings	37.7	31.4	121.2	129.8	129.2
Earnings per common share – basic	0.34	0.30	1.11	1.20	1.20
Net cash (used in) provided by operating activities	(36.3)	62.9	164.3	304.6	251.9
Cash dividends declared per share	0.2225	0.22	0.89	0.88	0.86

Introduction and Strategic Overview

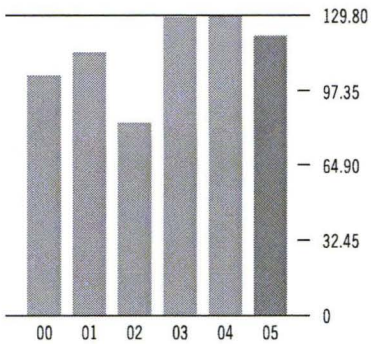
The core business of Emera is electricity. The company owns and operates two regulated electric utilities in northeastern North America. Both businesses operate as monopolies in their service territories, and together comprise approximately 95% of Emera's consolidated revenues:

- **Nova Scotia Power Inc. ("NSPI")** is an electricity generation, transmission and distribution company, providing service to the vast majority of the province of Nova Scotia. NSPI has $3 billion in assets, and 470,000 customers. NSPI is a cost of service utility. As such, regulated electricity rates are set to enable the company to recover all prudently incurred costs, with an opportunity to earn a prescribed return on equity. The company is regulated by the Nova Scotia Utility and Review Board ("UARB").
- **Bangor Hydro-Electric Company ("BHE")** is an electricity transmission and distribution company with $580 million of assets serving 110,000 customers in eastern Maine. BHE's transmission operations are regulated by the Federal Energy Regulatory Commission ("FERC"), and its distribution operations are regulated by the Maine Public Utilities Commission ("MPUC"). BHE is a cost of service utility, with an alternate rate plan ("ARP") for its distribution operations.

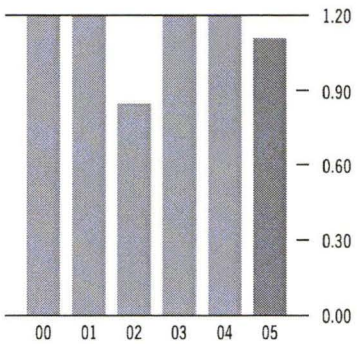
The success of Emera's electric utilities is integral to the creation of shareholder value, providing substantial earnings and cash flow to fund dividends and reinvestment. The essential nature of the services provided, the monopoly positions, and the regulated market structures means that NSPI and BHE can generally be expected to produce relatively stable earnings streams, within regulated ranges. Nova Scotia and Maine are mature electricity markets, with annual demand growth of approximately 2%. Accordingly, Emera must look beyond its existing regulated electricity business to supplement organic growth.

Emera's plan for growth seeks to add energy infrastructure assets to its portfolio. The company is focused on building on its core electricity business, specifically in regulated transmission and distribution operations, and low risk generation facilities. To this end, in 2005 Emera, in a 50/50 joint venture with Brookfield Power Corporation (formerly Brascan Power Corporation), completed the acquisition of Bear Swamp, a 600 megawatt ("MW") pumped storage hydro-electric generating facility in northern Massachusetts.

Consolidated Net Earnings History
(millions of dollars)



Earnings Per Share History
(dollars)



STRUCTURE OF MD&A

This MD&A has been prepared in accordance with the Canadian Securities Administrators National Instrument 51-102 Management's Discussion & Analysis.

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 the Maritimes & Northeast Pipeline, Emera Energy Services, Bear Swamp, 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, 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.

Emera Consolidated

SUMMARY CONSOLIDATED INCOME STATEMENT

	Three months ended December 31		Year ended December 31		
millions of dollars (except earnings per common share)	2005	2004	2005	2004	2003
Electric revenue	$ 287.3	$ 276.9	$ 1,125.9	$ 1,095.7	$ 1,104.1
Other	9.8	9.6	42.1	38.5	42.7
	297.1	286.5	1,168.0	1,134.2	1,146.8
Fuel for generation and purchased power	96.7	97.0	432.0	350.0	363.3
Operating, maintenance, and general	61.9	62.6	248.2	245.2	258.6
Provincial, state, and municipal taxes	11.8	11.4	48.4	46.3	40.8
Provincial tax deferral	0.4	–	(4.5)	–	–
Depreciation	34.2	32.3	136.1	131.2	126.9
Regulatory amortization	2.9	6.8	19.4	26.1	18.2
Other	(2.7)	(2.8)	(10.9)	(10.2)	(13.6)
Earnings before interest and income taxes	91.9	79.2	299.3	345.6	352.6
Interest	38.4	30.5	117.4	126.8	133.6
Amortization of defeasance costs	3.3	3.8	13.2	15.1	16.7
Other income	(8.0)	–	(8.0)	–	–
Earnings before income taxes	58.2	44.9	176.7	203.7	202.3
Income taxes	19.0	10.8	53.5	62.7	60.9
Income taxes deferral	(1.8)	–	(12.2)	–	–
Net earnings before non-controlling interest	41.0	34.1	135.4	141.0	141.4
Non-controlling interest	3.3	3.4	13.3	13.4	13.2
Net earnings from continuing operations	37.7	30.7	122.1	127.6	128.2
(Loss) earnings from discontinued operations, net of tax	–	0.7	(0.9)	2.2	1.0
Net earnings applicable to common shares	$ 37.7	$ 31.4	$ 121.2	$ 129.8	$ 129.2
Earnings per common share – basic					
Continuing operations	$ 0.34	$ 0.29	$ 1.12	$ 1.18	$ 1.19
Discontinued operations	–	0.01	(0.01)	0.02	0.01
	$ 0.34	$ 0.30	$ 1.11	$ 1.20	$ 1.20
Earnings per common share – diluted					
Continuing operations	$ 0.34	$ 0.27	$ 1.10	$ 1.14	$ 1.14
Discontinued operations	–	0.01	(0.01)	0.02	0.01
	$ 0.34	$ 0.28	$ 1.09	$ 1.16	$ 1.15

OPERATING UNIT CONTRIBUTIONS

millions of dollars (except earnings per common share)	Three months ended December 31 2005	2004	Year ended December 31 2005	2004	2003
Nova Scotia Power	$ 34.0	$ 25.0	$ 91.2	$ 107.3	$ 112.1
Bangor Hydro-Electric	4.0	4.4	14.9	18.5	18.8
Other	(0.3)	2.0	15.1	4.0	(1.7)
Consolidated net earnings	$ 37.7	$ 31.4	$ 121.2	$ 129.8	$ 129.2
Earnings per common share – basic	$ 0.34	$ 0.30	$ 1.11	$ 1.20	$ 1.20
Earnings per common share – diluted	$ 0.34	$ 0.28	$ 1.09	$ 1.16	$ 1.15

REVIEW OF 2005

Emera Inc.'s consolidated earnings increased $6.3 million to $37.7 million in Q4, 2005 compared to $31.4 million for the same period in 2004. The earnings increase was substantially due to the finalization of pricing terms of NSPI's natural gas supply contract in the quarter at better than previously estimated pricing. Also contributing to the quarter over quarter increase was a separate agreement with NSPI's gas supplier that resulted in a net payment of $8.0 million. Emera's annual consolidated earnings were $121.2 million in 2005 compared to $129.8 million in 2004 and $129.2 million in 2003. 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 – 2003		**$ 129.2**
Increased electric revenue in NSPI, reflecting volume growth		21.3
Increased fuel expense in NSPI due to reduced gas sales margin and higher coal costs in Q4		(25.3)
Increased provincial grants and taxes in NSPI		(6.1)
Increased depreciation in NSPI, reflecting updated rates and capital investment		(14.3)
Increased energy marketing margin		12.5
Decreased interest expense, reflecting lower debt levels and interest rates		6.8
Adjustment to NSPI's and BHE's unbilled revenue in 2003		13.2
Hurricane Juan operating expenses in 2003		6.0
Cessation of SOEP processing fees and depreciation expense on sale of asset in 2003		(5.7)
All other		(7.8)
Consolidated net earnings – 2004	**$ 31.4**	**$ 129.8**
Increased electric revenue in NSPI due to the 5.3% rate increase effective April 1, 2005, partially offset by a 36 GWh decrease in volume for the year	5.2	28.1
Increased fuel expense in NSPI due to higher commodity prices, changes in generation mix partially offset by increased hydro production	(20.8)	(84.3)
Decrease in fuel expense in NSPI due to finalization of pricing terms of NSPI's natural gas supply contract	23.8	–
Decrease in fuel expense in NSPI due to increased gas resale margin	4.3	13.6
Increased operating expenses in NSPI due to increased planned plant maintenance, storm-related costs, and regulatory costs	(2.4)	(11.3)
Net payment from a gas supplier in NSPI	8.0	8.0
(Increased) decreased income taxes in NSPI resulting from (higher) lower earnings	(7.8)	13.7
Deferral of Q1, 2005 taxes in NSPI	1.4	16.7
Addition of Bear Swamp hydro-electric facility earnings before interest & taxes	1.6	4.2
Reversal of foreign exchange gain, recognized earlier in the year, due to settlement of US denominated financial obligations	(5.9)	–
Increased foreign exchanges gains reflecting an adjustment to refine prior years' foreign exchange	–	5.2
All other	(1.1)	(2.5)
Consolidated net earnings – 2005	$ 37.7	$ 121.2

Q4 basic earnings per share were $0.34 in 2005 compared to $0.30 in 2004; and $1.11 for the full year 2005 compared to $1.20 in both 2004 and 2003.

SIGNIFICANT ITEMS

2005

Natural gas supply contract

In Q4, 2005, Nova Scotia Power reached an agreement with its supplier on pricing for natural gas under an existing long-term natural gas purchase agreement. The contract – which began in 2000 and runs until 2010 – calls for up to approximately 61,000 MMBtus of natural gas per day to be supplied to Nova Scotia Power, and was subject to a price re-determination as of November 1, 2004. With both parties unable to agree on terms, the matter was referred to arbitration. The two companies reached agreement prior to the rendering of a decision by the arbitration panel. Throughout most of 2005, while the initial contract discussions, and later, the arbitration hearing unfolded, NSPI recorded its gas purchases at its best estimate of the new contract price. The pricing ultimately agreed to was more favourable than NSPI's estimate. This resulted in a $23.8 million ($14.7 million after-tax) adjustment to fuel expense for the year, all of which was recorded in Q4. In addition, in a separate agreement, NSPI was provided a net payment of $8.0 million ($5.0 million after-tax) by its gas supplier, which has been recorded as other income in Q4.

Deferral of Q1 income and capital taxes

The UARB agreed to allow Nova Scotia Power 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.

2004

There were no significant items in 2004.

2003

Unbilled revenue adjustment

The company recognizes electric revenues on the accrual basis, which includes an estimate of electricity consumed by customers in the period but billed subsequently ("unbilled revenue"). In 2003, the Company improved its process for estimating its unbilled revenue. The change resulted in one-time reductions in unbilled revenue accruals with corresponding charges against revenues as follows:

- NSPI $10.0 million ($6.5 million after-tax) in Q2, 2003
- BHE $3.2 million ($1.9 million after-tax) in Q3, 2003

Hurricane Juan

In Q3, 2003 Nova Scotia was struck by Hurricane Juan, a Category Two hurricane causing extensive damage to Nova Scotia Power's transmission and distribution system. The total cost of the hurricane to the Company was $12.6 million, specifically $4.0 million of net after-tax operating costs that were recorded in Q3, 2003, and $8.6 million in capital costs.

Site restoration costs

Prior to 2003, Nova Scotia Power estimated and accrued site restoration costs for the Glace Bay generating station. The costs to complete the restoration were expected to be $3.8 million lower than estimated. Nova Scotia Power reduced its provision accordingly, with a corresponding reduction in depreciation expense in Q4, 2003.

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 55% is coal-fired; oil and natural gas together comprise another 30% of capacity; and hydro and wind production provide the remainder. NSPI has 122 MW of renewable energy, substantially wind energy, under contract with independent power producers, of which 57 MW are in service and the remainder expected to be in operation in the next 18 months. NSPI also owns approximately 5,000 kilometres of transmission facilities, and 25,000 kilometres of distribution facilities. The company has a workforce of approximately 1,600 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.

Nova Scotia Power 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 appropriate return to investors. NSPI's allowed regulated return on common equity ("ROE") range is 9.3% to 9.8%, with common equity allowed to grow to 40% of the capital structure. Rates were last set using 9.55% ROE with a common equity component of 37.5% of total capitalization.

2005 Electricity Rate Increase

On March 31, 2005, the UARB granted NSPI an average rate increase of approximately 5.3%, effective April 1, 2005. The rate decision increased NSPI's electric revenues by approximately $25 million in 2005 compared to 2004. The decision also provided for full recovery of NSPI's $146.7 million Section 21 income tax deposit over eight years, commencing in 2007. In the 2005 decision, the UARB expressed dissatisfaction with certain past fuel procurement practices, resulting in a disallowance of $18 million of NSPI's forecasted 2005 fuel costs. The UARB also rejected NSPI's settlement proposal to defer an additional $13 million of fuel costs to 2006.

The UARB made certain findings and directives concerning NSPI's fuel procurement in its decision. On September 30, 2005, Nova Scotia Power filed a report with the UARB outlining changes it has made to fuel procurement to comply with the UARB's findings.

2006 Rate Application

In July 2005, Nova Scotia Power filed a general rate application requesting an average 15% increase in electricity prices for 2006, primarily a result of rising fuel commodity prices. In November, as a result of benefits associated with the re-negotiated natural gas supply contract, NSPI reduced its rate request to an average 13%.

The rate application also proposes increases to operating costs of approximately $19 million to improve customer service, strengthen network reliability and to implement new conservation and energy efficiency measures.

Hearings concluded in early December with a decision anticipated in Q1, 2006.

REVIEW OF 2005

NSPI NET EARNINGS

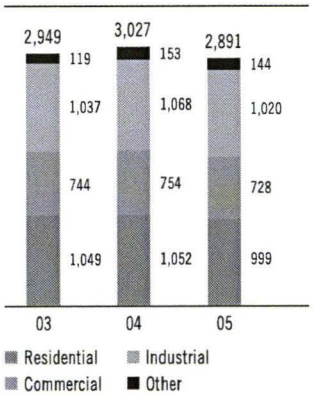
millions of dollars (except earnings per common share)	Three months ended December 31 2005	2004	Year ended December 31 2005	2004	2003
Electric revenue	$ 243.0	$ 237.8	$ 955.0	$ 926.9	$ 895.6
Fuel for generation and purchased power	79.5	86.9	373.8	303.1	277.8
Operating, maintenance and general	48.8	46.4	188.8	177.5	186.0
Provincial grants and taxes	10.2	9.9	40.4	39.5	33.4
Provincial grants and taxes deferral	0.4	–	(4.5)	–	–
Depreciation	30.1	28.2	119.5	116.0	101.7
Regulatory amortization	1.5	1.5	6.2	6.2	6.2
Other	(2.6)	(2.5)	(10.1)	(10.4)	(13.5)
Earnings before interest and income taxes	75.1	67.4	240.9	295.0	304.0
Interest	25.8	24.6	97.9	100.1	104.3
Amortization of defeasance costs	3.3	3.8	13.2	15.1	16.7
Other income	(8.0)	–	(8.0)	–	–
Earnings before income taxes	54.0	39.0	137.8	179.8	183.0
Income taxes	18.5	10.7	45.5	59.2	57.8
Income taxes deferral	(1.8)	–	(12.2)	–	–
Earnings before preferred dividends	37.3	28.3	104.5	120.6	125.2
Preferred dividends	3.3	3.3	13.3	13.3	13.1
Contribution to consolidated net earnings	$ 34.0	$ 25.0	$ 91.2	$ 107.3	$ 112.1
Contribution to consolidated earnings per common share	$ 0.30	$ 0.23	$ 0.83	$ 0.99	$ 1.04

NSPI's contribution to consolidated net earnings was $34.0 million in Q4, 2005, compared to $25.0 million in Q4, 2004. The earnings increase was substantially due to the finalization of pricing terms of NSPI's natural gas supply contract in the quarter at better than previously estimated pricing. Also contributing to the quarter over quarter increase was a separate agreement with NSPI's gas supplier that resulted in a net payment of $8.0 million. Annual contribution to consolidated net earnings was $91.2 million in 2005 compared to $107.3 million in 2004 and $112.1 million in 2003. Highlights of the earnings changes are summarized in the table on the following page:

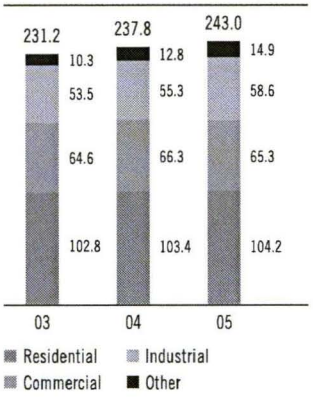
millions of dollars	Three months ended December 31	Year ended December 31
Contribution to consolidated net earnings – 2003		**$ 112.1**
Increased electric revenues, largely reflecting volume growth		21.3
Increased fuel expense due to reduced gas sales margin and higher coal costs in Q4		(25.3)
Increased provincial grants and taxes		(6.1)
Increased depreciation, reflecting updated rates, and capital investment		(14.3)
Adjustment to unbilled revenue in 2003		10.0
Hurricane Juan operating expenses in 2003		6.0
All other		3.6
Contribution to consolidated net earnings – 2004	**$ 25.0**	**$ 107.3**
Increased electric revenue due to the 5.3% rate increase effective April 1, 2005, partially offset by a 36 GWh decrease in sales volume for the year	5.2	28.1
Increased fuel expense due to higher commodity prices, and changes in generation mix partially offset by increased hydro production	(20.8)	(84.3)
Decrease in fuel expense due to finalization of pricing terms of NSPI's natural gas supply contract	23.8	–
Decrease in fuel expense due to increased gas resale margin	4.3	13.6
Increased operating expenses reflecting increased planned plant maintenance, storm-related costs, and regulatory costs	(2.4)	(11.3)
Increased depreciation due to capital investment	(1.9)	(3.5)
In Q4, increased interest due to foreign exchange losses; year ended December 31, decreased interest due to lower rates	(1.2)	2.2
Net payment from a gas supplier	8.0	8.0
(Increased) decreased income taxes resulting from (higher) lower earnings	(7.8)	13.7
Deferral of Q1, 2005 taxes	1.4	16.7
All other	0.4	0.7
Contribution to consolidated net earnings – 2005	**$ 34.0**	**$ 91.2**

ELECTRIC REVENUE

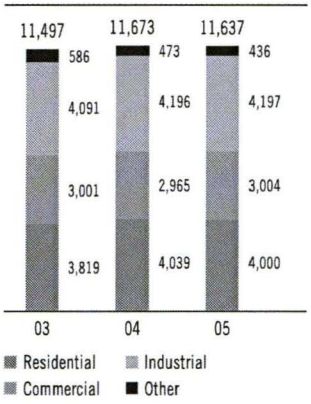
Q4 Electric Sales Volume
(GWh)



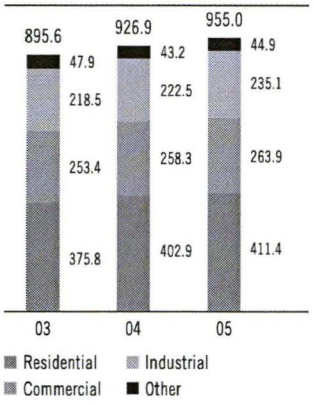
Q4 Electric Sales Revenues
(millions of dollars)



YTD Electric Sales Volume
(GWh)



YTD Electric Sales Revenues
(millions of dollars)



Q4 AVERAGE REVENUE PER MEGAWATT HOUR ("MWh")

	2005	2004	2003
Dollars per MWh	$ 84	$ 79	$ 78

YTD AVERAGE REVENUE PER MWh

	2005	2004	2003
Dollars per MWh	$ 82	$ 79	$ 78

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, which apply to approximately 20% of NSPI sales volume; and export sales, which in recent years comprised less than 2% of NSPI sales volume, and are priced at market. Residential and commercial electricity sales are seasonal in Nova Scotia, 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 everything from small retail operations to large office and commercial complexes, and the province's universities and hospitals. Industrial customers include manufacturing facilities and other large volume operations. Other consists of export sales, sales to municipal electric utilities and revenues from street lighting.

Electric revenues increased by $5.2 million to $243.0 million in Q4, 2005 from $237.8 million for the same period in 2004. Revenue increases are substantially due to the April 1, 2005 rate increase partially offset by reduced sales volume due to warmer weather in Q4, customer conservation efforts, and the temporary shut-down of a large industrial customer for a portion of December 2005.

For the year ended December 31, 2005, electric revenues increased $28.1 million to $955.0 million in comparison to $926.9 million in 2004. The revenue increase is due to the reasons noted above.

For the year ended December 31, 2004, electric revenues increased $31.3 million to $926.9 million from $895.6 million in 2003. Of the difference, $10.0 million relates to a charge against revenue in the 2003 comparative amounts, due to an adjustment to the company's unbilled revenue accrual. In addition to normal growth, a cold Q1, 2004 increased sales volumes. Export sales volumes were lower, as available capacity was used to service in-province load.

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 57 megawatts in service contracted with independent power producers. NSPI meets the planning criteria for reserve capacity established by the Maritime Control Area, and therefore meets the Northeast Power Coordinating Council criteria.

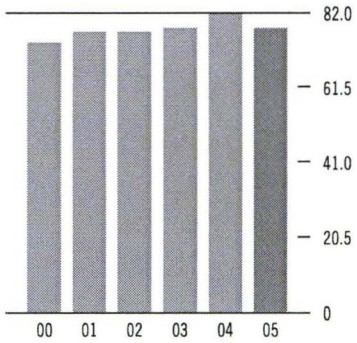
Management of capacity/capacity utilization is a critical element of operating efficiency. The provision of sufficient generating capacity to meet peak demand inevitably results in excess capacity in non-peak periods. NSPI's daily load is highest in the early evening; its seasonal load is highest through the winter months. Summer cooling load is not a significant factor. Maximizing capacity utilization has 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 continues to maintain unplanned outage rates below 3%.
- *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 controls over 300 MW of interruptible electric load, including 200 MW of which is economically interruptible.
- *Export sales* – Increasing export sales when margins are satisfactory allows excess capacity to be sold when not required in the province. NSPI operates a 24-hour marketing desk to optimize commercial opportunities.

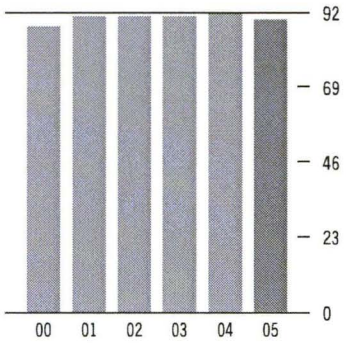
NSPI's generating capacity utilization was 78% in 2005 compared to 82% in 2004. The change is largely due to the completion of two planned turbine inspections as part of NSPI's maintenance and life cycle management program for generation assets.

NSPI facilities continue to perform highly among the top ten units in Canada for capacity related performance indicators. In the most recent Canadian Electrical Association rankings, NSPI units hold five of the top ten positions in Canada including Trenton 6 in first place in 2004. Point Tupper ranked Number 1 in the previous year.

NSPI Thermal Capacity Utilization
(percent)

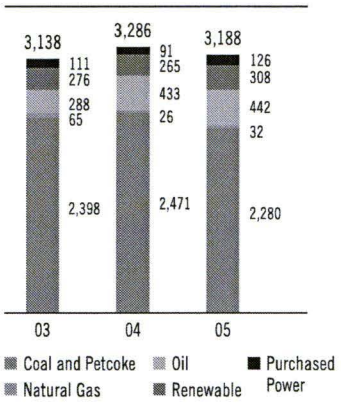


NSPI Generating Capacity Availability
(percent)

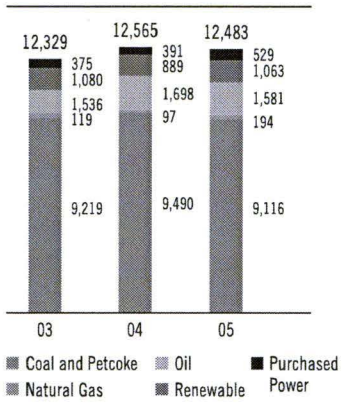


FUEL EXPENSE

Q4 Production Volume
(GWh)



YTD Production Volume
(GWh)



Q4 AVERAGE UNIT FUEL COSTS

	2005	2004	2003
Dollars per MWh	$ 25	$ 26	$ 20

YTD AVERAGE UNIT FUEL COSTS

	2005	2004	2003
Dollars per MWh	$ 30	$ 24	$ 23

Coal is NSPI's dominant fuel source, supplying approximately 50% of the company's annual generation. Petroleum coke ("petcoke") fuels approximately 25% of generation. These solid fuels have the lowest per unit fuel cost, after hydro and wind production, which have no fuel cost component. Oil and natural gas are next, depending on the relative pricing of each. Purchased power is generally the most expensive option. 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.

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 Risk and Enterprise Risk Management section.

For the three months ended December 31, 2005, fuel for generation and purchased power was $79.5 million, compared to $86.9 million in Q4, 2004. For the year ended December 31, 2005, fuel for generation and purchased power was $373.8 million compared to $303.1 million in 2004 and $277.8 million in 2003. 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 – 2003		**$ 277.8**
Lower net proceeds from resale of natural gas		32.0
Increased production		16.9
Decreased renewable production volumes		11.9
Commodity pricing, including favourable exchange rates		(16.7)
Decreased export volumes		(11.4)
All other		(7.4)
Fuel for generation and purchased power – 2004	**$ 86.9**	**$ 303.1**
Commodity pricing increase	29.5	91.1
Higher net proceeds from resale of natural gas	(4.3)	(13.6)
Finalization of pricing terms of NSPI's natural gas supply contract	(23.8)	–
Changes in generation mix	5.8	12.2
Increase in hydro production volumes	(2.2)	(11.7)
All other	(12.4)	(7.3)
Fuel for generation and purchased power – 2005	$ 79.5	$ 373.8

In Q4, 2005, Nova Scotia Power reached an agreement with its supplier on pricing for natural gas under an existing long-term natural gas purchase agreement. The contract – which began in 2000 and runs until 2010 – calls for up to approximately 61,000 MMBtus of natural gas per day to be supplied to Nova Scotia Power, and was subject to a price re-determination as of November 1, 2004. With both parties unable to agree on terms, the matter was referred to arbitration. The two companies reached agreement prior to the rendering of a decision by the arbitration panel. Throughout most of 2005, while the initial contract discussions and later, the arbitration hearing unfolded, NSPI recorded its gas purchases at its best estimate of the new contract price. The pricing ultimately agreed to was more favourable than NSPI's estimate. This resulted in a $23.8 million ($14.7 million after-tax) adjustment to fuel expense for the year, all of which was recorded in Q4. In addition, in a separate agreement, NSPI was provided a net payment of $8.0 million ($5.0 million after-tax) by its gas supplier, which has been recorded as other income in Q4.

OPERATING, MAINTENANCE AND GENERAL EXPENSES

NSPI's operating, maintenance and general expenditures ("OM&G") were $48.8 million in Q4, 2005 compared to $46.4 million in Q4, 2004. The increase of $2.4 million is primarily a result of adjustments to the allowance for doubtful accounts and increased regulatory costs.

For the year ended December 31, 2005, NSPI's OM&G expenditures were $188.8 million, compared to $177.5 million in 2004 and $186.0 million for 2003. OM&G expenditures increased $11.3 million in 2005 over 2004 due to increased planned plant maintenance, storm-related costs and higher regulatory costs. OM&G expenditures decreased $8.5 million in 2004 from 2003 levels primarily as a result of lower labour and materials costs.

PROVINCIAL GRANTS AND TAXES

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

Provincial grants and taxes increased $0.3 million in Q4, 2005, and $0.9 million for the year ended December 31, 2005 reflecting inflationary adjustments. For the year ended December 31, 2004, the provincial grants and taxes increased $6.1 million over 2003, reflecting a $4.6 million increase in NSPI's annual provincial grants, and an increase in the provincial capital tax rate from 0.25% to 0.3%, effective April 1, 2004.

In Q1, 2005 the UARB agreed to allow NSPI to defer these and other taxes not reflected in rates for the period from January 1, 2005 until April 1, 2005, the date when new rates became effective. As a result, NSPI deferred $4.5 million of provincial grants and taxes to March 31, 2005. The amortization period is pending approval by the UARB.

DEPRECIATION

NSPI's depreciation expense increased $1.9 million in Q4, 2005 to $30.1 million compared to $28.2 million in Q4, 2005, primarily due to increased plant-in-service.

For the year ended December 31, 2005 depreciation expense increased $3.5 million to $119.5 million compared to $116.0 million in 2004, for the reason noted above. The 2004 amount is $14.3 million higher than 2003, reflecting the change in depreciation rates approved by the UARB in its 2003 depreciation order, and increased plant-in-service.

REGULATORY AMORTIZATION

The Glace Bay generating station has been demolished and returned to an industrial Greenfield site, and is being amortized at a minimum annual rate of $6.2 million. The amount remaining to be written off is $12.9 million.

INTEREST

Interest expense increased $1.2 million to $25.8 million in Q4, 2005, compared to $24.6 million in Q4, 2004 due to foreign exchange losses on US dollar denominated working capital, offset by a gain on an interest rate derivative.

For the year ended December 31, 2005, interest expense decreased $2.2 million to $97.9 million from $100.1 million for 2004 largely due to the refinancing in May 2005 of a $100 million 8.38% medium-term note with a $100 million 4.22% medium-term note.

For the year ended December 31, 2004, interest expense decreased $4.2 million to $100.1 million compared to $104.3 million in 2003. This decrease is due to the refinancing of a $140 million mid-term note with short-term debt in 2004.

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

OTHER INCOME

During 2005, Nova Scotia Power received a payment of $10.5 million, less $2.5 million of associated costs, from a gas supplier as part of renegotiation of certain contractual matters.

INCOME TAXES

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

NSPI is subject to provincial capital tax (0.288%), large corporations tax (0.175%), corporate income tax (38.12%) and Part VI.1 tax relating to preferred dividends (40%).

NSPI has a $146.7 million regulatory asset related to pre-2003 income taxes that have been paid, but not yet recovered from customers. This circumstance arose when NSPI claimed deductions that were ultimately disallowed by a decision of

the Supreme Court of Canada. The UARB has approved the amortization and recovery of this regulatory asset over eight years, commencing in 2007.

In Q1, 2005 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. As a result, NSPI deferred $12.2 million of federal capital taxes and income taxes reflecting increases in these taxes since rates were last set in 2002. The amortization period is pending approval by the UARB.

OUTLOOK

NSPI's earnings outlook for 2006 is substantially dependent on the outcome of the 2006 rate decision, expected in Q1, 2006. The magnitude of any approved increase, as well as timing of the implementation will affect revenues and could have a material impact on earnings.

Electricity sales volume (load) is expected to be lower in 2006 than in 2005, due to warmer weather in Q1, the temporary shut-down of a large industrial customer and customer conservation effects.

Fuel costs are expected to increase primarily due to higher commodity prices and an increase in the amount of higher cost, lower sulphur coal in the fuel mix to meet provincial environmental regulations. These higher costs will be partially offset by the expected reduction in load noted above.

Other costs of NSPI are generally expected to remain consistent with normalized 2005 levels, with additional investments expected to be made in vegetation management, storm response initiatives and energy conservation management. NSPI has also requested an increase in depreciation expense in its 2006 rate application, to implement approved increases flowing from its recent depreciation study.

DEBT MANAGEMENT

In Q4, 2005, NSPI issued a $150 million medium-term note at a coupon rate of 5.67% maturing November 14, 2035. Proceeds were used to pay down short-term debt.

Earlier in 2005, NSPI issued a $100 million medium-term note at a coupon rate of 4.22% maturing May 17, 2010. The proceeds were used to refinance $100 million 8.38% medium-term notes that matured on that date.

In 2004, a $140 million 7.3% mid-term note matured and was refinanced with short-term debt.

The weighted average coupon rate on NSPI's outstanding medium-term and debenture notes at December 31, 2005, was 6.83% (2004 – 7.32%). Approximately 41% of the debt matures over the next ten years; 55% matures between 2016 and 2036; and $50.0 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 4.96% as of December 31, 2005 (2004 – 5.14%).

NSPI has established the following available credit facilities:

millions of dollars	Maturity	Maximum amount
Short-term		
Commercial paper, with 100% backup line of credit	1 Year Revolving	$ 400.0
Operating credit facility	3 Year Revolving	$ 100.0

NSPI has the following available credit ratings:

	DBRS		S&P		Moody's	
	2005	2004	2005	2004	2005	2004
Long-term corporate	A (low)	A (low)	BBB+	BBB+	na	na
Senior unsecured debt	A (low)	A (low)	BBB+	BBB+	Baa1	Baa1
Preferred stock	Pfd-2 (low)	Pfd-2 (low)	P-2 (Low)	P-2 (Low)	na	na
Commercial paper	R-1 (low)	R-1 (low)	A-1 (Low)	A-1 (Low)	P-2 (Baa)	P-2 (Baa)

On July 5, 2005, Standard & Poor's Rating Services revised its outlook on Nova Scotia Power to negative from stable, citing fuel cost recovery concerns. On July 6, 2005, the Dominion Bond Rating Service confirmed NSPI's ratings as A (low) and the commercial paper rating as R-1 (low). On October 11, 2005, Moody's Investor Services revised its outlook on Nova Scotia Power from stable to negative citing fuel cost recovery and regulatory uncertainty.

OUTLOOK

An NSPI medium-term note ("MTN") of $40 million bearing interest of 5.20%, maturing in 2029 is redeemable at the option of the holder in April 2006. If not redeemed, the interest rate on the MTN increases to 6.28% until maturity.

Based on the company's available credit and credit ratings, and past experience in public financing since privatization, NSPI expects to have access to capital when needed.

Bangor Hydro-Electric Company

All amounts in the Bangor Hydro section are reported in US dollars unless otherwise stated.

OVERVIEW

Bangor Hydro is the second largest electric utility in Maine.

BHE's core business is the transmission and distribution ("T&D") of electricity. 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 900 kilometres of transmission facilities, and 7,000 kilometres of distribution facilities. BHE has a workforce of approximately 230 people.

In addition to T&D assets, BHE has substantial 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 unamortized portion on its loss on the sale of its investment in the Seabrook nuclear facility, and the costs associated with the buy-out/restructure of above-market power purchase contracts. 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 $80 million at December 31, 2005, or 15% of BHE's net asset base.

Approximately 55% of BHE's electric rate represents distribution service, 30% relates to stranded cost recoveries, and 15% 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's distribution service operates under an Alternate Rate Plan, or ARP, which provides for an earnings band of 5% to 17% return on equity on distribution operations, with rates set at the midpoint of 11%. There is a 50/50 sharing mechanism between the company and customers outside of the earnings band. The ARP also includes performance standards and provides for average annual reductions in distribution rates of approximately 2.5% for five years, to 2007.

On February 25, 2005, the Maine Public Utilities Commission approved BHE's stranded cost rates for the three-year period March 1, 2005 to February 29, 2008, providing an allowed return on equity of 10% on BHE's stranded assets. The stranded cost rates were reduced to reflect the completion of a major regulatory amortization, and increases in the rate at which BHE's power purchases under long-term power supply agreements will be resold to a third party. Accordingly, the impact on net earnings is expected to be minimal.

Transmission rates are set by the FERC annually on July 1, based on the prior year's revenue requirement. The current allowed ROE for transmission operations is 11.25%.

REVIEW OF 2005

BHE NET EARNINGS

millions of dollars (except earnings per common share)	Three months ended December 31 2005	2004	Year ended December 31 2005	2004	2003
T&D revenues	$ 25.9	$ 29.7	$ 105.5	$ 116.4	$ 115.1
Resale of purchased power	4.0	1.9	13.6	10.6	26.0
Total electric revenue	29.9	31.6	119.1	127.0	141.1
Fuel for generation and purchased power	9.7	8.4	33.6	35.0	54.4
Operating, maintenance and general	7.7	8.7	31.2	31.7	33.1
Property taxes	0.8	1.1	4.9	4.8	5.0
Depreciation	3.2	3.1	12.4	10.9	9.6
Regulatory amortization	1.1	4.3	10.8	15.2	10.4
Other	(0.8)	(1.1)	(3.9)	(3.3)	(3.8)
Earnings before interest and income taxes	8.2	7.1	30.1	32.7	32.4
Interest	2.6	2.5	10.0	10.3	10.2
Earnings before income taxes	5.6	4.6	20.1	22.4	22.2
Income taxes	2.2	0.8	7.8	8.0	8.9
Contribution to consolidated net earnings – US $	$ 3.4	$ 3.8	$ 12.3	$ 14.4	$ 13.3
Contribution to consolidated net earnings – Canadian $	$ 4.0	$ 4.4	$ 14.9	$ 18.5	$ 18.8
Contribution to consolidated earnings per common share – Canadian $	$ 0.04	$ 0.04	$ 0.14	$ 0.17	$ 0.17
Net earnings weighted average foreign exchange rate – Canadian/US $	1.17	1.22	1.21	1.30	1.42

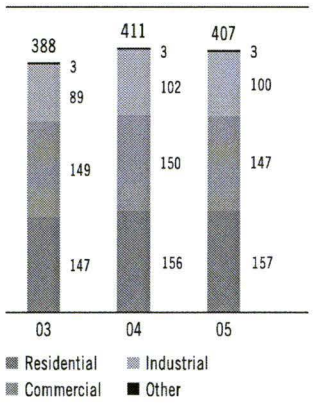
Bangor Hydro's contribution to consolidated net earnings was $3.4 million in Q4, 2005 compared to $3.8 million in Q4, 2004. For the year ended December 31, 2005, Bangor Hydro's contribution to consolidated net earnings was $12.3 million, compared to $14.4 million in 2004 and $13.3 million in 2003. Highlights 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 – 2003		**$ 13.3**
Adjustment to the company's unbilled revenue in 2003		2.7
Increased revenues due to higher energy sales volume		1.8
Decrease in labour costs		1.5
Increased depreciation expense due to depreciation study impacts		(1.2)
Write-off in Q2, 2004 of deferred costs disallowed in rates		(1.1)
All other		(2.6)
Contribution to consolidated net earnings – 2004	**$ 3.8**	**$ 14.4**
(Decreased) increased energy sales volume	(0.3)	1.8
Increased depreciation expense, reflecting new depreciation study	(0.1)	(1.6)
2004 stranded cost purchased power expense less than amount used in setting rates	(0.2)	(1.1)
Decreased (increased) NEPOOL related transmission expenses	0.3	(0.9)
Write-off in Q2, 2004 of deferred costs disallowed in rates	–	1.1
All other	(0.1)	(1.4)
Contribution to consolidated net earnings – 2005	$ 3.4	$ 12.3

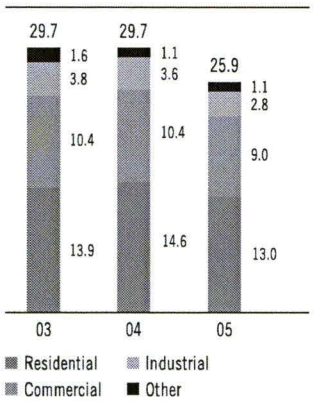
Bangor Hydro's contribution to consolidated net earnings was $4.0 million CAD in Q4, 2005 compared to $4.4 million CAD in Q4, 2004, due to the Canadian dollar equivalent of the variances discussed above and the $0.2 million impact of the stronger Canadian dollar. For the year ended December 31, 2005, net earnings contributed by Bangor Hydro was $14.9 million CAD compared to $18.5 million CAD for 2004 and $18.8 million CAD for 2003, due to the Canadian dollar equivalent of the variances discussed above and the $1.0 million impact of the stronger Canadian dollar in 2005 and the $1.8 million impact of the stronger Canadian dollar in 2004.

ELECTRIC REVENUE

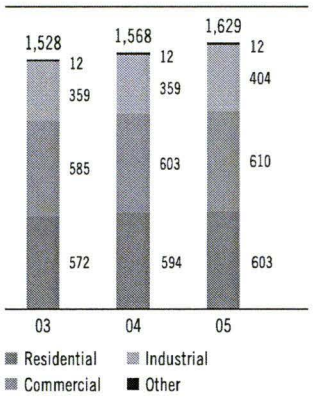
Q4 Electric Sales Volume
(GWh)



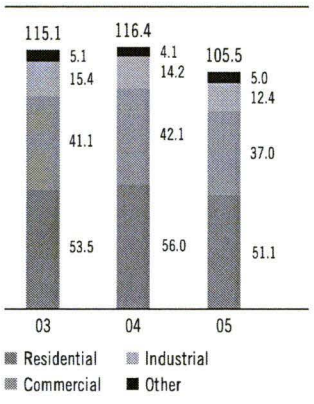
Q4 Electric Sales Revenues
(millions of US dollars)



YTD Electric Sales Volume
(GWh)



YTD Electric Sales Revenues
(millions of US dollars)



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 decreased by $3.8 million in Q4, 2005 to $25.9 million compared to $29.7 million in Q4, 2004. For the year ended December 31, 2005, T&D electric revenues were $105.5 million compared to $116.4 million for 2004 and $115.1 million in 2003. Highlights of the changes are summarized in the following table:

millions of dollars	Three months ended December 31	Year ended December 31
T&D revenues – 2003		**$ 115.1**
Increased energy sales volume		1.8
Unbilled revenue adjustment in Q3, 2003		2.7
Lower special contract rate for large customer		(1.1)
All other		(2.1)
T&D revenues – 2004	**$ 29.7**	**$ 116.4**
Stranded cost rate reduction on March 1, 2005	(3.5)	(13.0)
(Decreased) increased energy sales volume	(0.3)	1.8
All other	–	0.3
T&D revenues – 2005	$ 25.9	$ 105.5

Increases to industrial volumes year to date had a minimal impact on sales revenues due to lower unit pricing.

RESALE OF PURCHASED POWER, AND FUEL FOR GENERATION AND PURCHASED POWER

The company has several above-market purchase power contracts pre-dating the Maine market restructuring including a large contract that ended in February 2004. Power purchased under these arrangements is resold to a third party at market rates. The cessation of the contract in February 2004 was the primary reason for the decrease in resale of purchased power and fuel for generation and purchased power in 2004. Resale of purchased power increased in 2005 due to an increase in the rate at which BHE's power purchases are resold to a third party. Also affecting purchased power expense in 2005 was a $0.9 million increase in NEPOOL related transmission costs.

OPERATING, MAINTENANCE AND GENERAL EXPENSES

Operating expenses were $7.7 million in Q4, 2005 compared to $8.7 million in 2004. For the year ended December 31, 2005, BHE's operating expenses were $31.2 million compared to $31.7 million in 2004 and $33.1 million in 2003. The changes are primarily due to reduced labour costs.

DEPRECIATION

Depreciation expense increased by $0.1 million in Q4, 2005 compared to Q4, 2005; increased $1.5 million in 2005 relative to 2004; and increased $1.3 million in 2004 relative to 2003, due principally to the effect of plant additions. The results of BHE's depreciation study, completed in 2004, are also included in the results.

REGULATORY AMORTIZATION

Amortization expense was $3.2 million lower in Q4, 2005 at $1.1 million, compared to $4.3 million in Q4, 2004 reflecting new stranded cost amortization, which started March 1, 2005.

For the year ended December 31, 2005 amortization expense was $10.8 million, compared to $15.2 million in 2004 and $10.4 million in 2003. The decrease in 2005 reflects the new stranded cost amortization, while the increase in 2004 reflects the completion of the amortization of several regulatory liabilities in Q1, 2004, offset somewhat by reduced stranded cost amortization.

INTEREST

BHE's interest expense increased to $2.6 million in Q4, 2005 from $2.5 million in Q4, 2004, and decreased to $10.0 million in 2005 from $10.3 million in 2004 and $10.2 million in 2003. The decrease in annual interest expense is due primarily to lower rates on debt refinanced, offset by the impact of increased short-term borrowings and higher interest rates on short-term borrowings.

Bangor Hydro manages exposure through a combination of fixed and floating rate borrowings.

INCOME TAXES

Bangor Hydro uses the future income tax method of accounting for income taxes.

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

DEBT MANAGEMENT

The weighted-average coupon rate on Bangor Hydro's long-term debt outstanding at December 31, 2005 was 7.18% (2004 – 7.13%). Approximately 57% of the debt matures over the next 13 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 5.55% as of December 31, 2005 (2004 – 4.94%).

Bangor Hydro has established the following credit facilities:

millions of US dollars	Maximum amount
Short-term	
Unsecured revolving facility	$ 60.0
Operating line of credit	$ 10.0

During 2003, Bangor Hydro refinanced all of its public debt privately, and accordingly has no requirement for public credit ratings. Bangor Hydro 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.

REGULATORY MATTERS

When Emera acquired Bangor Hydro in 2001, it became a registered public utility holding company under the Public Utility Holding Company Act of 1935 ("PUHCA"). PUHCA is administered by the US Securities and Exchange Commission ("SEC"). In the normal course of regulating registered public utility holding companies, the SEC audits and/or reviews each registrant's compliance with PUHCA approximately once every five years. The SEC's review of Emera began in the fall of 2004. By letter dated September 25, 2005 the staff of the SEC indicates that Emera is in compliance with PUHCA, pending reallocation of certain costs among companies in the Emera group. The proposed reallocations are not material to Emera or any individual Emera subsidiary.

PUHCA has been repealed, effective February 8, 2006, under the Domenici-Barton Energy Policy Act of 2005. As of that date, Emera will cease to be regulated as a registered holding company under PUHCA. The Energy Policy Act lodged certain new powers over companies that own electric and gas public utility companies with the US FERC.

OUTLOOK

Bangor Hydro net earnings for 2006 are expected to be marginally higher than 2005.

The Northeast Reliability Interconnect, Bangor Hydro's proposed new transmission line linking New Brunswick and Maine, achieved a significant milestone in 2005, with the receipt of its Certificate of Public Convenience and Necessity from the Maine Public Utilities Commission. In January 2006, BHE received the outstanding environmental permits from the State and Federal Governments. Management continues to expect to have the line in service in late 2007.

Other

All activities of Emera other than its two regulated electric utilities are incorporated in Other, including:

- Emera Energy Services, which manages energy assets on behalf of third parties and provides related energy management services. Emera Energy Services operates with minimal day-to-day commodity risk exposure.
- A 12.9% interest in the $2 billion, 1,300 kilometre Maritimes & Northeast Pipeline ("M&NP") that transports Nova Scotia's offshore natural gas to markets in Maritime Canada and the northeastern United States.
- Bear Swamp, a 50/50 joint venture in a 600 megawatt pumped storage hydro-electric facility in northern Massachusetts, which was acquired on May 24, 2005, as discussed below.
- Certain corporate-wide functions such as executive management, strategic planning, treasury services, tax planning, business development, and corporate governance; and financing for the corporation's business outside of its regulated electric utilities.

SALE OF ASSETS OF EMERA FUELS

Effective September 30, 2005 Emera sold its heating oil distribution business for proceeds of $18.6 million, which were used to pay down debt. A loss on disposition of $1.6 million after-tax was recognized in Q3, 2005. The transaction reduced Emera's total assets by approximately $25 million (net assets approximately $20 million). The reduction in annual after-tax net earnings and cash provided by operating activities is expected to be immaterial.

ACQUISITION

On May 24, 2005 Emera and Brookfield Power Corporation (formerly Brascan Power Corporation), in a 50/50 joint venture, completed the acquisition of Bear Swamp, a 600 MW pumped storage hydro-electric facility in northern Massachusetts. Emera's share of the purchase price was $61.2 million including acquisition costs. The facility sells energy, capacity and ancillary products to the New England Power Pool. Also included in the acquisition is the nearby 10 MW Fife Brook run-of-river hydro-electric facility.

The acquisition has been accounted for under the purchase method of accounting using proportionate consolidation, and accordingly, Emera's pro-rata share of the results of operations since the date of acquisition have been included in the consolidated statement of earnings and the summary statement of earnings below.

A second proposed joint venture acquisition, the 49 MW Bellows Falls hydro-electric facility, did not receive the required regulatory approval. Emera's escrow deposit was returned in Q4, 2005.

REVIEW OF 2005

OTHER NET EARNINGS

millions of dollars (except earnings per common share)	Three months ended December 31 2005	2004	Year ended December 31 2005	2004	2003
Energy marketing margin	$ 5.5	$ 6.7	$ 24.7	$ 24.2	$ 11.7
Electric revenue	9.2	–	26.5	–	–
M&NP equity earnings	1.7	1.2	6.5	6.2	9.6
SOEP processing fees	–	–	–	–	16.3
Total revenue	16.4	7.9	57.7	30.4	37.6
Purchased power	5.9	–	17.7	–	–
Operating maintenance and general	5.4	5.1	21.7	20.8	19.1
Business development	(1.3)	0.5	(0.2)	5.7	8.2
Depreciation	0.4	0.4	1.7	1.2	11.7
Other	(1.1)	(1.6)	(5.2)	(5.6)	(4.2)
Earnings before interest and income taxes	7.1	3.5	22.0	8.3	2.8
Interest	9.5	2.9	7.4	13.2	14.9
Earnings before income taxes	(2.4)	0.6	14.6	(4.9)	(12.1)
Income taxes	(2.1)	(0.7)	(1.4)	(6.7)	(9.4)
Net earnings from continuing operations	(0.3)	1.3	16.0	1.8	(2.7)
(Loss) earnings from discontinued operations, net of tax	–	0.7	(0.9)	2.2	1.0
Contribution to consolidated net earnings	$ (0.3)	$ 2.0	$ 15.1	$ 4.0	$ (1.7)
Contribution to consolidated earnings per share	$ –	$ 0.02	$ 0.14	$ 0.04	$ (0.01)

The contribution of Other operations to consolidated net earnings decreased $2.3 million quarter over quarter. For the year ended December 31, 2005 Other operations contributed $15.1 million to consolidated net earnings compared to $4.0 million in 2004 and a loss of $1.7 million in 2003. Highlights of the changes are summarized in the following table:

millions of dollars	Three months ended December 31	Year ended December 31
Contribution to consolidated net earnings – 2003		**$ (1.7)**
Cessation of SOEP processing fees on sale of asset		(16.3)
Increase in energy marketing margin		12.5
Cessation of SOEP depreciation expense on sale of asset		10.6
All other		(1.1)
Contribution to consolidated net earnings – 2004	**$ 2.0**	**$ 4.0**
(Decreased) increased energy marketing margin as a result of (decreased) increased marketing opportunities and mark-to-market gains on longer term contracts	(1.2)	0.5
Addition of Bear Swamp hydro-electric facility earnings before interest & taxes	1.6	4.2
Reversal of foreign exchange gain, recognized earlier in the year, due to settlement of US denominated financial obligations	(5.9)	–
Increased foreign exchange gains reflecting an adjustment to refine prior years' foreign exchange	–	5.2
Lower (higher) income taxes due to lower (higher) earnings	1.4	(5.3)
Capitalization of previously expensed business development costs to the Bear Swamp cost of net assets purchased	2.5	2.5
Loss on disposition of Emera Fuels, net of tax	–	(1.6)
Write-off of Greyhawk Gas Storage joint venture in Q1, 2004	–	1.9
All other	(0.7)	3.7
Contribution to consolidated net earnings – 2005	$ (0.3)	$ 15.1

ENERGY MARKETING MARGIN

Emera Energy Services net margin decreased quarter over quarter to $5.5 million in Q4, 2005 from $6.7 million in Q4, 2004 as a result of decreased marketing opportunities.

For the year ended December 31, 2005 net margin was $24.7 million compared to $24.2 million in 2005 and $11.7 million in 2004 due to increased marketing opportunities and mark-to-market gains on longer term contracts in 2005.

ELECTRIC REVENUE AND PURCHASED POWER

Electric revenue and purchased power represent Emera's pro-rata share of electric revenue and purchased power from Bear Swamp since the date of acquisition on May 24, 2005.

EQUITY EARNINGS

Equity earnings from the Maritimes & Northeast Pipeline were $1.7 million in Q4, 2005 compared to $1.2 million for the same period in 2004. The increase is primarily due to increases in tolls collected for the US operations.

M&NP applied for new rates in 2004 and a decision is expected in Q1, 2006. In the interim, since January 1, 2005, M&NP was permitted to collect proposed rates from customers. In the event approved rates are lower than proposed, any excess will be returned to customers. On June 28, 2005 M&NP submitted an offer of settlement to the FERC. The company has recognized its best estimate of equity earnings based on the terms of the proposed settlement. The rate decision will also impact energy marketing margin in Emera Energy Services. The decision from the FERC is expected in Q1, 2006.

For the year ended December 31, 2005 M&NP equity earnings were $6.5 million compared to $6.2 million in 2004. Increases in the tolls collected for the US operations have been offset by the write-off of previously deferred costs for pipeline expansion on the US pipeline, and the $0.1 million impact of the stronger Canadian dollar on the US portion of the pipeline.

For the year ended December 31, 2004, equity earnings decreased $3.4 million to $6.2 million compared to $9.6 million in 2003, reflecting performance on the US component of the pipeline due to lower volumes, higher operating costs associated with the Phase III expansion (not reflected in rates at that time) and the $0.1 million impact of a stronger Canadian dollar.

BUSINESS DEVELOPMENT

Business development recognized a $1.3 million cost recovery in Q4, 2005, compared to a $0.5 million expense in Q4, 2004 due primarily to the capitalization in Q4, 2005 of $2.5 million of previously expensed business development costs to the Bear Swamp cost of net assets purchased.

For the year ended December 31, 2005, business development recognized a $0.2 million cost recovery compared to a $5.7 million expense for the same period in 2004, reflecting the capitalization referred to above; and the write-off in Q1, 2004 of Emera's $1.9 million investment in the Greyhawk Gas Storage joint venture, a portion of which was subsequently recovered in Q1, 2005. Business development expenses for 2004 were down $2.5 million from $8.2 million in 2003 reflecting the streamlining of business development activities.

INTEREST

Interest expense was $9.5 million in Q4, 2005 compared to $2.9 million in Q4, 2004 largely as a result of the reversal of foreign exchange gains recognized earlier in the year on the settlement of USD financial obligations, as expected.

For the year ended December 31, 2005 interest was $7.4 million compared to $13.2 million in 2004. The difference was substantially due to an accounting adjustment required to refine prior years' foreign exchange recognized on US denominated obligations. Interest expense was $1.7 million lower in 2004 than in 2003, reflecting lower rates on short-term debt refinanced.

INCOME TAXES

All businesses included in Other follow the future income taxes method of accounting for income taxes. Taxes are recognized on pre-tax income, excluding M&NP equity earnings that are recorded net of tax. Variations in income tax expense are largely impacted by withholding taxes paid on cross-border dividends and interest, completion of prior years' tax returns, and corporate tax sharing agreements.

DEBT MANAGEMENT

In Q4 2005, Emera amended its operating and acquisition credit facilities. The operating facility increased from $150 million to $200 million and US subsidiaries were added as US borrowers.

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

millions of dollars	Maturity	Maximum amount
Short-term		
Operating credit facility	1 Year Revolving	$ 200.0
Acquisition credit facility	1 Year Revolving	$ 400.0

Emera has the following available credit ratings:

	DBRS		S&P		Moody's	
	2005	2004	2005	2004	2005	2004
Long-term corporate	BBB (high)	BBB (high)	BBB+	BBB+	na	na
Senior unsecured debt	BBB (high)	BBB (high)	BBB	BBB	Baa2	Baa2

In 2005, S&P and Moody's revised their outlook for Emera from stable to negative citing Nova Scotia Power fuel cost recovery concerns and regulatory uncertainty.

On a consolidated basis, Emera's target percentage of debt to total capitalization is 50%–55%, of which 10%–15% would be exposed to short-term rates. The company manages long-term debt terms such that the average is not less than ten years.

Consolidated Balance Sheets

As at December 31
millions of dollars

	2005	2004	2003
Total assets	$ 3,996.2	$ 3,949.2	$ 3,890.9
Total long-term liabilities	$ 2,123.6	$ 2,118.8	$ 1,797.3

Significant changes in the consolidated balance sheets between December 31, 2005 and December 31, 2004 include:

- $12.4 million decrease in restricted cash reflecting lower posted margin in Emera Energy Services.
- $55.7 million increase in accounts receivable, reflecting higher pricing for trading activity in Emera Energy Services, and increased electricity prices in Nova Scotia Power.
- $12.7 million increase in income tax receivable, reflecting Nova Scotia Power's installments in excess of earnings, which are lower year over year, and future income taxes in Emera Energy Services that became a current receivable in 2005.
- $10.5 million increase in prepaid expenses, reflecting increased posted margin paid to counterparties by Emera Energy Services.
- $23.5 million increase in long-term receivables, reflecting the increased estimated natural gas price adjustment in NSPI, offset partially by the reclassification of the Pengrowth receivable to current accounts receivable.

- $67.0 million decrease in deferred charges, reflecting a refund of the escrow deposit made in anticipation of the Bellows Falls acquisition, which did not proceed due to lack of regulatory approval, and normal amortization.
- $10.6 million decrease in goodwill, largely reflecting the disposition of the company's heating oil distribution business.
- $48.5 million increase in capital assets, primarily reflecting the acquisition of the Bear Swamp hydro-electric facility in northern Massachusetts.
- $15.2 million increase in accounts payable and accrued charges, reflecting higher pricing for trading activity offset by lower posted margin in Emera Energy Services.

Significant changes in the consolidated balance sheets between December 31, 2004 and December 31, 2003 include:

- $16.4 million decrease in inventory, primarily reflecting lower coal inventory in NSPI.
- $10.0 million decrease in the total receivable from Pengrowth Corporation in connection with the sale of the SOEP offshore assets reflecting the receipt of the 2004 payment.
- $46.1 million increase in deferred assets comprised of deposits related to Bellows Falls and Bear Swamp acquisitions, the implementation of Section 1100 Generally Accepted Accounting Principles, and amortization of regulatory and other deferred assets.
- $25.7 million increase in deferred credits reflecting the implementation of the provisions of Section 1100 Generally Accepted Accounting Principles.

Outstanding Share Data

Issued and Outstanding: millions of dollars	Millions of Shares	Common Share Capital
January 1, 2004	108.26	$1,008.4
Issued for cash under purchase plans	0.41	7.0
Options exercised under senior management share option plan	0.20	2.8
Share-based compensation	–	1.0
December 31, 2004	108.87	$1,019.2
Issued for cash under purchase plans	0.43	7.9
Options exercised under senior management share option plan	0.80	13.0
Share-based compensation	–	0.9
December 31, 2005	110.10	$1,041.0

As at January 31, 2006 the number of issued and outstanding common shares was 110,171,914.

Liquidity and Capital Resources

The company generates funds primarily through its operations in regulated utilities involving the generation, transmission and distribution of electricity. Circumstances that could affect the company's ability to generate funds include fuel commodity price changes, general economic downturns in Nova Scotia and Maine, and regulatory decisions affecting customer rates. In addition to internally generated funds, the company has access to debt capital markets, through operating lines of credit, an accounts receivable securitization program and a commercial paper program. The company's financing facilities are expected to provide sufficient access to money markets and capital markets necessary to maintain acceptable levels of liquidity relative to current cash forecasts. In Q1, 2005 Emera and Nova Scotia Power established debt shelf prospectuses in the amounts of $300 million and $400 million respectively that provide the companies with access to long-term debt. The prospectuses expire in April 2007. The company also has access to equity capital markets for both common and preferred shares.

In July 2005 NSPI's Board of Directors approved an increase to the size of its commercial paper program from $350 million to $400 million. The company's banking syndicate provides 100% backup facility for this program.

CONSOLIDATED CASH FLOW HIGHLIGHTS

millions of dollars	Three months ended December 31 2005	2004	Year ended December 31 2005	2004
Net cash (used in) provided by operating activities	$ (36.3)	$ 62.9	$ 164.3	$ 304.6
Net cash (used in) provided by financing activities	(19.9)	60.7	(68.3)	(57.4)
Net cash provided by (used in) investing activities	58.5	(105.5)	(117.2)	(214.5)
Increase (decrease) in cash and cash equivalents	$ 2.3	$ 18.1	$ (21.2)	$ 32.7

Consolidated net cash used in operating activities was $36.3 million in Q4, 2005 compared to $62.9 million of net cash provided by operating activities in Q4, 2004. Consolidated net cash provided by operating activities was $164.3 million in 2005 compared to $304.6 million in 2004. Highlights of the changes are summarized in the following table:

millions of dollars	Three months ended December 31	Year ended December 31
Net cash provided by operating activities – 2004	**$ 62.9**	**$ 304.6**
Increase (decrease) in cash flow from earnings	5.1	(19.8)
Decrease due to higher gas price adjustment receivable in NSPI as a result of price changes	(16.8)	(38.6)
Increase (decrease) due to timing of coal and heavy fuel oil shipments and commodity price changes in NSPI	13.8	(21.3)
Decrease due to higher prepaid expenses primarily due to increased posted margin Emera Energy Services has paid to counterparties	(11.0)	(11.3)
Increase (decrease) due to lower (higher) trade receivables	25.6	(35.6)
Decreased posted margin (offset by decreased restricted cash included in investing activities)	(50.1)	(23.2)
Decrease due to lower trade payables in NSPI with the Q4 decrease due to timing of payment to a large fuel contractor	(70.8)	(6.3)
All other	5.0	15.8
Net cash (used in) provided by operating activities – 2005	$ (36.3)	$ 164.3

Consolidated net cash used in financing activities was $19.9 million in Q4, 2005, compared to $60.7 million of net cash provided by financing activities in Q4, 2004. Net cash used in financing activities was $68.3 million in 2005 compared to $57.4 million in 2004. Highlights of the changes are summarized in the following table:

millions of dollars	Three months ended December 31	Year ended December 31
Net cash provided by (used in) financing activities – 2004	**$ 60.7**	**$ (57.4)**
Higher long-term debt levels	151.5	314.5
Reduction of short-term debt	(238.9)	(309.3)
Accounts receivable securitization	–	(30.0)
Issuance of common shares	2.0	11.1
All other	4.8	2.8
Net cash used in financing activities – 2005	$ (19.9)	$ (68.3)

Consolidated net cash provided by investing activities was $58.5 million in Q4, 2005, compared to $105.5 million of net cash used in investing activities in Q4, 2004. Net cash used in investing activities was $117.2 million in 2005 compared to $214.5 million in 2004. Highlights of the changes are summarized in the following table:

millions of dollars	Three months ended December 31	Year ended December 31
Net cash used in investing activities – 2004	**$ (105.5)**	**$ (214.5)**
Decreased restricted cash related to posted margin	50.1	23.2
Acquisition of Bear Swamp hydro-electric facility	3.4	(49.2)
Reduced capital spending	8.2	22.3
Proceeds on disposition of Emera Fuels' heating oil distribution business	18.3	18.4
Change in investments reflecting the 2004 deposit related to Bellows Falls and the subsequent return of the deposit in 2005	85.8	84.3
All other	(1.8)	(1.7)
Net cash provided by (used in) investing activities – 2005	$ 58.5	$ (117.2)

CONTRACTUAL OBLIGATIONS

millions of dollars	Payments Due by Period				
	Total	2006	2007–2008	2009–2010	After 2010
Long-term debt	$ 1,784.7	$ 334.9	$ 124.8	$ 235.7	$ 1,089.3
Operating leases	32.7	6.3	12.4	9.8	4.2
Purchase obligations	2,800.0	918.0	826.7	584.2	471.1
Other long-term obligations	309.2	–	0.5	–	308.7
Total contractual obligations	$ 4,926.6	$ 1,259.2	$ 964.4	$ 829.7	$ 1,873.3

Operating lease obligations consist of the company's operating lease agreements for office space, telecommunications services, vehicles, and photo copiers.

Purchase obligations include the company's purchasing commitments for electricity from independent power producers, transportation of coal, outsource management of the company's computer infrastructure, natural gas, transportation capacity on the Maritimes & Northeast Pipeline, purchasing commitments for fuel, and physical trading commitments.

Other long-term obligations represent the company's asset retirement obligations.

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

CAPITAL RESOURCES

Capital expenditures for 2005 were approximately $129 million, including:

- $20 million related to the installation of environmental technology (electrostatic precipitators) at NSPI's Tuft's Cove generating station;
- $7 million related to two large transmission upgrades in BHE; and
- $6 million related to Northeast Reliability Interconnect project in BHE.

Emera's capital budget for 2006 includes approximately $133 million for NSPI, which is generally directed to planned and preventative maintenance productivity-related investments, and air emissions upgrades. BHE expects to invest approximately $70 million CAD, including approximately $55 million CAD for several major transmission projects.

The company expects to finance its capital expenditures with funds from operations and short-term debt. Bangor Hydro may finance a portion of the Northeast Reliability Interconnect project with a long-term debt issue in 2006 or 2007.

In November 2005, NSPI filed a Notice of Application for the construction of capital projects associated with achieving the air emissions requirements contained in the Provincial environmental regulations. These capital projects are for the installation of air emissions abatement equipment at the Lingan generating station. Total investment associated with this equipment is currently projected at approximately $177 million. Of this amount, $16 million is included in the 2006 NSPI capital forecast noted above. A hearing on this matter is anticipated in the first half of 2006.

OFF-BALANCE SHEET ARRANGEMENTS

Upon privatization in 1992, NSPI became 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 streams to match the related defeased debt. Approximately 70%, or $735 million, 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 consists of investments with market values 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 on a revolving non-recourse basis. As of December 31, 2005, the company had sold $80.0 million (2004 – $80.0 million) of net accounts receivable. The net proceeds from the sale were used to repay a portion of the company's debt. The agreement is in place until May 2009, with the intention that it will be renewed at that time. Securitization provides NSPI with an alternative source of short-term funding. For the year ended December 31, 2005, the average all-in cost of this funding was 2.97% (2004 – 2.64%). In the event of termination of this arrangement, NSPI would utilize another liquidity 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 derivative instruments consisting mainly of foreign exchange forward contracts, interest rate options and swaps, and oil and gas options and swaps.

Instruments 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, amounts paid or received are deferred and recognized in earnings in the same period the related hedged item is realized. Where the documentation or effectiveness requirements are not met, the non-qualifying instruments are marked-to-market and recognized in earnings in the reporting period.

The company has deferred payments and receipts on derivative instruments that are designated and effective as hedges and are recognized in the following categories on the balance sheet:

Deferred Hedging Losses (Gains) Recognized on the Balance Sheet

millions of dollars	December 31, 2005	December 31, 2004
Inventory	$ 0.2	$ 1.6
Deferred charges	–	0.1
Accounts payable and accrued charges	–	(0.3)
Deferred hedging losses	$ 0.2	$ 1.4

For the three month period and year ended December 31, the impacts of effective hedges recognized in earnings were recorded in the following categories:

Hedging Impact Recognized in Earnings

	Three months ended December 31		Year ended December 31	
millions of dollars	2005	2004	2005	2004
Fuel and purchased power increase	$ (3.9)	$ (3.7)	$ (20.5)	$ (4.9)
Interest expense increase	(0.4)	(1.1)	(1.9)	(5.0)
Hedging earnings impact	$ (4.3)	$ (4.8)	$ (22.4)	$ (9.9)

The company also enters into non-hedging derivative financial and commodity instruments. These instruments, along with the non-qualifying hedges referred to above, are marked-to-market at each reporting date.

The company had recorded the following mark-to-market transactions included on the balance sheet and recognized in earnings.

Mark-to-Market Gains (Losses) Recognized on the Balance Sheet

millions of dollars	December 31, 2005	December 31, 2004
Accounts receivable	$ 8.5	$ –
Energy marketing assets	20.1	10.3
Energy marketing liabilities	(15.0)	(9.4)
Mark-to-market gains	$ 13.6	$ 0.9

Mark-to-Market Gains (Losses) Recognized in Earnings

	Three months ended December 31		Year ended December 31	
millions of dollars	2005	2004	2005	2004
Other revenue	$ (0.5)	$ 0.8	$ 4.6	$ 0.9
Fuel and purchased power	8.5	(3.3)	8.5	–
Interest	0.4	–	–	–
Mark-to-market gains	$ 8.4	$ (2.5)	$ 13.1	$ 0.9

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 totalling $9.5 million (2004 – $10.1 million) during the three months ended December 31, 2005, and $39.7 million (2004 – $45.4 million) during the year ended December 31, 2005, 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, 2005 the amount payable to the related party is $3.0 million (December 31, 2004 – $3.2 million), is non-interest bearing and is under normal credit terms.

Disclosure Controls and Procedures

Under the supervision and participation of our management, including the President and Chief Executive Officer and the Chief Financial Officer, Emera evaluated the effectiveness of the design and operation of its disclosure controls and procedures (as defined in Multilateral Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings) as of December 31, 2005.

Based on that evaluation, the President and Chief Executive Officer and the Chief Financial Officer concluded that Emera's disclosure controls and procedures are effective in making known to them material information relating to the Company and its consolidated subsidiaries required to be disclosed in reports filed or submitted under the Multilateral Instrument.

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 pension and other employee benefits, unbilled revenue, natural gas price adjustment receivable, asset retirement obligations, useful lives for depreciable assets, and impairment assessments. Actual results may differ from these estimates.

RATE REGULATION

NSPI's and BHE's 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 regulations and the actual experience for specified expenses is based on the expectation that the regulators will approve the refund to or recovery from ratepayers of the deferred balance.

If the regulators' future actions are different from the companies' expectations, 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 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 following table reflects the sensitivities associated with a change in certain actuarial assumptions. If both the expected rate of return on plan assets and the discount rate were increased by 0.5%, the impact on the 2006 benefit cost and accrued benefit asset and liability recorded in the year end consolidated financial statements would be as follows:

millions of dollars	2006 NSPI	2006 BHE
Impact of increasing the rate of return assumption by 0.5%:		
Benefit cost	$ (2.9)	$ (0.2)
Accrued benefit asset	$ 2.9	–
Accrued benefit liability	–	$ (0.2)
Impact of increasing the discount rate assumption by 0.5%:		
Benefit cost	$ (6.4)	$ (0.5)
Accrued benefit pension asset	$ 6.4	–
Accrued benefit pension liability	–	$ (0.5)

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. NSPI's rate was 6.0% for 2005 and 2004 and BHE's rate was 6.0% for 2005, reduced from 6.25% in 2004. The expected rate to be used for 2006 is 5.25% for NSPI and 5.75% for BHE.

The expected return on plan assets is based on management's best estimate of future returns, considering economic and consensus forecasts. The 2004 and 2005 benefit cost calculations assumed that plan assets would earn a rate of return of 7.5% for NSPI and 8.0% for BHE. The 2006 benefit cost calculation is expected to use the same asset return assumptions.

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 estimate 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, 2005, unbilled revenues amount to $71.8 million on a base of annual electric revenues of approximately $1.1 billion.

NATURAL GAS PRICE ADJUSTMENT 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 to be settled in November 2007. Management has made a best estimate of the price rebate based on the contract specifications using actual and forward marketing pricing and recorded it in long-term receivables.

ASSET RETIREMENT OBLIGATIONS

The company recognizes assets 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, 2005, the asset retirement obligations recorded on the balance sheet were $71.7 million (2004 – $68.5 million). The company estimates the undiscounted amount of cash flow required to settle the obligations is approximately $309.2 million, which will be incurred between 2007 and 2061. The majority of these costs will be incurred between 2020 and 2039.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment represent 71% 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 of $20 million by 2007. The UARB approved the settlement. NSPI began phasing in the new rates in 2004. Subsequently, in its rate decision for 2005, the UARB deferred the scheduled phase-in for 2005. NSPI's 2006 rate application includes the phase-in of Year 2 rates as per the settlement agreement.

In 2004 Bangor Hydro completed a depreciation study. The study concluded that the company's accumulated depreciation was understated by approximately $6.6 million. The company received approval from FERC to implement the results of the depreciation study effective January 1, 2004. As a result of the study, Bangor Hydro began amortizing the $6.6 million over the average remaining service lives of the major plant asset classifications. Bangor Hydro also adjusted the composite depreciation rates for 2004 to reflect shorter lives as recommended by the study.

GOODWILL IMPAIRMENT ASSESSMENTS

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.

Change in Accounting Policies

In 2005, the company adopted the new accounting guidelines related to variable interest entities and disclosures by entities subject to rate regulation.

VARIABLE INTEREST ENTITIES

The Canadian Institute of Chartered Accountants ("CICA") issued Accounting Guideline 15 Consolidation of Variable Interest Entities, which applies to annual and interim periods beginning on or after November 1, 2004. A variable interest entity ("VIE") is any type of legal structure in which control is determined through contractual or other financial arrangements as opposed to traditional voting rights, if certain conditions exist. The guideline requires the enterprise which absorbs the majority of a VIE's expected losses or receives the majority of a VIE's expected residual returns, the primary beneficiary, to consolidate the VIE.

The company has variable interests in VIEs that are not consolidated because the company is not considered the primary beneficiary. These variable interests consist of purchase power agreements for renewable energy with independent power producers. The company's only obligation under these agreements is to purchase all of the energy produced, which currently is expected to approximate 100 GWh annually.

DISCLOSURES BY ENTITIES SUBJECT TO RATE REGULATION

The CICA issued Accounting Guideline 19 Disclosures by Entities Subject to Rate Regulation ("AcG-19"), which is effective for fiscal years ending on or after December 31, 2005. AcG-19 is intended to ensure that financial statement users are better informed about the existence, nature and economic effects of rate regulation, as well as its financial statement effects. Emera's financial statements and supporting notes reflect the new requirements.

FUTURE ACCOUNTING POLICY CHANGES

The company is currently assessing the financial impact of the CICA's Emerging Issue Committee Abstract 159 Conditional Asset Obligations ("EIC-159"). EIC-159 is to be applied retroactively, with restatement of prior periods, to all financial statements for interim and annual reporting periods ending after March 31, 2006. EIC-159 was issued in response to the diverse accounting practices developed with respect to the timing of liability recognition when the timing and/or method of settlement are conditional on a future event.

The company is also assessing the financial impact of CICA Handbook sections 1530 Comprehensive Income, 3855 Financial Instruments – Recognition and Measurement, 3861 Financial Instruments – Disclosure and Presentation, and 3865 Hedges. These new standards apply to interim and annual financial statements beginning on or after October 1, 2006.

Dividend Policy and Payout Ratios

Emera Inc.'s common dividend rate was $0.89 ($0.2225 per quarter) per common share in 2005 and $0.88 ($0.22 per quarter) per common share in 2004, representing a payout ratio of approximately 80% for 2005 (2004 – 73%). In January 2006, the Board of Directors approved the common share dividend of $0.89 per share ($0.2225 per quarter).

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 Board 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, credit risk, interest rates, and regulatory risk.

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. NSPI developed and put forth for regulatory approval, a portfolio strategy for fuel procurement. The strategy consists of a combination of long, medium, and short-term supply agreements. It also provides for supply and supplier diversification with credit worthy counterparties. 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 the company's coal and petroleum coke supply comes from international suppliers at prevailing market prices. The company has entered into fixed-price contractual arrangements with several suppliers as part of the fuel procurement portfolio strategy. 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, 2005 is as follows:

- For 2006, 85%
- For 2007, 23%
- For 2008, 17%

Heavy Fuel Oil

NSPI manages exposure to changes in the market price of heavy fuel oil through the use of swaps, options, and futures contracts. As at December 31, 2005, the price for the heavy fuel oil purchases has been hedged and contracted at approximately the following:

- For 2006, 90%
- For 2007, 26%

Natural Gas

NSPI has entered into multi-year contracts to purchase approximately 65 million cubic feet 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 managed using financial instruments. As at December 31, 2005, amounts of natural gas volumes that have been hedged and contracted are approximately as follows:

- For 2006, 80%
- For 2007, 54%
- For 2008, 54%

Fuel Mix

The risk due to fluctuation of the Canadian dollar against the US dollar for the cost of fuel is measured and managed. The ability to switch fuel provides a dynamic, operational and effective option in managing commodity price and supply risk.

Foreign Exchange

In 2006, NSPI expects approximately 80% of its anticipated net fuel costs to be denominated in US dollars; $US from sales of surplus natural gas will provide a natural hedge against a portion of $US denominated fuel costs. Forward contracts are used to manage the exposure to fluctuating $US exchange rates. Forward contracts are in place for approximately 93% of 2006 anticipated $US net fuel costs.

Payments in $US received from the US portion of the company's investment in the Maritimes & Northeast Pipeline will be used to repay $US debt.

Interest Rates

Emera manages interest rate risk through a combination of fixed and floating borrowing and a hedging program. Prior to hedging, floating rate debt is estimated to represent approximately 18% of total debt in 2005. Interest forward rate agreements and swaps are used to fix rates on part of the floating rate debt, while interest rate caps are used to limit exposure to movements of interest rates on floating debt. For 2006, interest on approximately 42% of floating debt is capped at a rate of 4.10%.

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

In December 2001, the Nova Scotia government released Nova Scotia's Energy Strategy, *Seizing the Opportunity*. The strategy for the electricity industry is to carefully introduce certain aspects of competition over time. The Electricity Act, passed by the Nova Scotia Legislature in 2004, has not yet been proclaimed. Once proclaimed, wholesale customers may purchase electricity from other competitive suppliers. The wholesale market in Nova Scotia is limited to the six municipal distribution utilities, which represent approximately 1.3% of NSPI's revenues.

In May 2005, the Nova Scotia Utility and Review Board approved Nova Scotia Power's Open Access Transmission Tariff ("OATT"). The OATT will facilitate competition in the wholesale market. It also ensures that Nova Scotia meets United States and other Canadian market reciprocity requirements, thus facilitating electricity exports.

Further material restructuring of the electricity industry in Nova Scotia is not expected for at least the medium term. The province's geographic location, the limits of inter-provincial transmission links, and the diversity of our customer are key factors.

NSPI faces risk with respect to the timeliness and certainty of full recovery of fuel and other costs. In its 2005 rate decision, the UARB discussed a Fuel Adjustment Mechanism ("FAM") and did not rule out the possibility of a FAM in the future. NSPI plans to work with the UARB and other stakeholders to identify and meet the conditions necessary for future approval of a FAM. In the interim, NSPI is addressing UARB concerns with regard to fuel and NSPI expects to undertake general rate cases more frequently to ensure it fully recovers fuel costs.

NSPI has applied for customer rates for 2006 to recover higher fuel expenses. The hearing is complete and the UARB's decision is anticipated in Q1, 2006.

Bangor Hydro

Bangor Hydro's business consists of four primary components which are each governed by their own regulatory structure. The components include distribution, transmission, standard costs, and supply (metering, billing, and settlement).

BHE's distribution business operates under an Alternate Rate Plan, which is in place until December, 2007. The ARP requires BHE to decrease rates each year by an assumed productivity increase of approximately 2.5% per year. As part of the ARP, a penalty is triggered if BHE does not meet certain specified service quality indices. Under the current ARP, BHE does not have any recourse to the Maine Public Utilities Commission should costs rise faster than revenues. However, the ARP does provide BHE with the potential opportunity to earn a higher return on equity than under a more traditional cost-of-service regulatory structure.

The transmission business of BHE is primarily regulated by the Federal Energy Regulatory Commission. The rates charged are determined by formula and driven by the annual report to the FERC. 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 the ongoing costs of both regulatory assets and the ongoing costs of purchasing power at above-market prices. This ability eliminates the commodity risk involved with fixed price contracts.

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

LABOUR

In June 2004 NSPI reached a 52 month agreement with 800 unionized employees, which expires in late 2007.

Bangor Hydro's contract with its unionized employees expired at the end of 2005 and a new agreement has been reached, which will expire in June 2010.

ENVIRONMENTAL PROTECTION

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. For example, hydro operations within NSPI developed strategies to identify the potential of, and increase protection against, accidental release of oil to water. Other areas of Emera also undertook initiatives to reduce potential environmental risks and associated costs.

Conformance with legislative and company requirements is verified through an environmental audit program. The 2005 program maintained an objective to review all wholly-owned operations within a three-year cycle. Results from 2005 continued to show improved environmental performance.

The Board of Directors' Environmental, Safety and Security Committee met several times throughout 2005 and continued to carry out its oversight role in ensuring focus is placed on environmental protection. Environmental performance is also regularly reviewed by the Emera executive. 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.

Atmospheric Emissions

Beginning in 2005 and continuing through the end of the decade, Air Quality Regulations under the Nova Scotia Environment Act require reductions of sulphur dioxide (SO_2), oxides of nitrogen (NOx) and mercury emitted from Nova Scotia Power facilities. In addition, the Canadian government is a signatory to the Kyoto Protocol. Emera continues to work with the federal and provincial governments to develop an implementation plan that considers the potential costs and benefits to the company and its customers.

NSPI met its 2005 Air Quality Regulations annual emissions limits. Plans have been developed to achieve the objectives in NSPI's Air Emissions Strategy, which addresses the entire suite of air emissions including those linked to greenhouse gases. In 2005, NSPI:

- invested approximately $20 million on electrostatic precipitator upgrades to reduce particulate emissions at the Tufts Cove plant,
- filed an application with the Utilities and Review Board recommending an investment of approximately $177 million for a wet flue gas desulphurization unit that will reduce sulphur dioxide emissions at Lingan, and to install low NOx burners at Lingan to reduce emissions of oxides of nitrogen,
- signed contracts with several independent power producers (IPPs) for renewable energy that will increase NSPI's renewable energy supply by 25% over 2002 levels. These contracts represent an addition of approximately 100 MW of supply, almost entirely from wind, with some biomass, and
- addressed customer feedback in the 2004 Customer Energy Forum indicating that customers want NSPI to play a stronger role in educating consumers on energy efficiency and conservation. As part of its 2006 Rate Case filing, NSPI proposed to invest $5 million annually towards new energy conservation and efficiency measures aimed at customers. The UARB's decision on this is anticipated in Q1, 2006.

SUMMARY OF QUARTERLY REPORTS

For the quarter ended
millions of dollars (except earnings per common share)

	Q4 2005	Q3 2005	Q2 2005	Q1 2005	Q4 2004	Q3 2004	Q2 2004	Q1 2004
Total revenues	$297.1	$273.9	$275.5	$309.7	$286.5	$260.1	$268.8	$318.8
Net earnings from continuing operations	$ 37.7	$ 18.1	$ 19.1	$ 47.2	$ 30.7	$ 22.0	$ 29.5	$ 45.4
Net earnings applicable to common shares	$ 37.7	$ 15.9	$ 19.3	$ 48.3	$ 31.4	$ 22.1	$ 29.8	$ 46.5
Earnings per common share – basic:								
Continuing operations	$ 0.34	$ 0.16	$ 0.18	$ 0.43	$ 0.29	$ 0.20	$ 0.27	$ 0.42
Discontinued operations	–	(0.02)	–	0.01	0.01	–	–	0.01
	$ 0.34	$ 0.14	$ 0.18	$ 0.44	$ 0.30	$ 0.20	$ 0.27	$ 0.43
Earnings per common share – diluted:								
Continuing operations	$ 0.34	$ 0.16	$ 0.18	$ 0.41	$ 0.27	$ 0.20	$ 0.27	$ 0.40
Discontinued operations	–	(0.02)	–	0.01	0.01	–	–	0.01
	$ 0.34	$ 0.14	$ 0.18	$ 0.42	$ 0.28	$ 0.20	$ 0.27	$ 0.41

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") 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 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 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 fulfils 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 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 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 10, 2006



Christopher G. 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, 2005 and 2004, and the consolidated statements of earnings, retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2005 and 2004 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 10, 2006

Ernst & Young LLP

Ernst & Young LLP
Chartered Accountants

consolidated financial statements

Consolidated Statements of Earnings

Year Ended December 31 millions of dollars (except earnings per common share)	2005	2004
Revenue		
Electric	$ 1,125.9	$ 1,095.7
Other	42.1	38.5
	1,168.0	1,134.2
Cost of operations		
Fuel for generation and purchased power	432.0	350.0
Operating, maintenance and general	248.2	245.2
Provincial, state, and municipal taxes	48.4	46.3
Provincial tax deferral (note 14)	(4.5)	–
Depreciation	136.1	131.2
Regulatory amortization	19.4	26.1
Allowance for funds used during construction	(4.4)	(4.0)
	875.2	794.8
Earnings from operations	292.8	339.4
Equity earnings (note 6)	6.5	6.2
Earnings before interest and income taxes	299.3	345.6
Interest (note 7)	117.4	126.8
Amortization of defeasance costs	13.2	15.1
Other income (note 8)	(8.0)	–
Earnings before income taxes	176.7	203.7
Income taxes (note 9)	53.5	62.7
Income taxes deferral (note 14)	(12.2)	–
Net earnings before non-controlling interest	135.4	141.0
Non-controlling interest (note 10)	13.3	13.4
Net earnings from continuing operations	122.1	127.6
(Loss) earnings from discontinued operations, net of tax (note 17)	(0.9)	2.2
Net earnings applicable to common shares	$ 121.2	$ 129.8
Earnings per common share – basic (note 11)		
Continued operations	$ 1.12	$ 1.18
Discontinued operations	(0.01)	0.02
	$ 1.11	$ 1.20
Earnings per common share – diluted (note 11)		
Continued operations	$ 1.10	$ 1.14
Discontinued operations	(0.01)	0.02
	$ 1.09	$ 1.16

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Retained Earnings

Year Ended December 31 millions of dollars	2005	2004
Retained earnings, beginning of year	$ 399.6	$ 365.3
Net earnings applicable to common shares	121.2	129.8
	520.8	495.1
Dividends	97.4	95.5
Retained earnings, end of year	$ 423.4	$ 399.6

See accompanying notes to the consolidated financial statements.

Consolidated Balance Sheets

As at December 31
millions of dollars

Assets	2005	2004
Current assets		
Cash and cash equivalents	$ 21.5	$ 42.7
Restricted cash	5.8	18.2
Accounts receivable (note 12)	231.8	176.1
Income tax receivable	15.1	2.4
Inventory	76.1	73.4
Prepaid expenses	15.9	5.4
Future income tax assets (note 9)	9.3	3.6
Energy marketing assets	16.0	10.3
	391.5	332.1
Long-term receivables (note 13)	48.4	24.9
Energy marketing assets	4.1	–
Deferred charges (note 14)	508.3	575.3
Future income tax assets (note 9)	19.0	34.1
Goodwill (note 19)	97.1	107.7
Investments (note 6)	101.0	96.8
Property, plant & equipment (note 15)	2,786.8	2,714.6
Construction work in progress	40.0	63.7
	2,826.8	2,778.3
	$ 3,996.2	$ 3,949.2
Liabilities and Shareholders' Equity		
Current liabilities		
Current portion of long-term debt (note 22)	$ 152.9	$ 100.8
Short-term debt (note 21)	88.1	145.4
Accounts payable and accrued charges	248.6	233.4
Income tax payable	1.5	1.4
Dividends payable	3.2	3.2
Energy marketing liabilities	12.1	9.4
	506.4	493.6
Energy marketing liabilities	2.9	–
Future income tax liabilities (note 9)	78.9	82.2
Asset retirement obligations (note 20)	71.7	68.5
Deferred credits (note 14)	77.5	80.8
Long-term debt (note 22)	1,631.8	1,626.5
Non-controlling interest (note 10)	260.8	260.8
Shareholders' equity		
Common shares (note 23)	1,041.0	1,019.2
Foreign exchange translation adjustment (note 25)	(98.2)	(82.0)
Retained earnings	423.4	399.6
	1,366.2	1,336.8
	$ 3,996.2	$ 3,949.2

Contingencies (note 27), Commitments (note 28), Guarantees (note 29).

See accompanying notes to the consolidated financial statements.

Approved on behalf of the Board of Directors

Derek Oland
Chairman

Christopher G. Huskilson
President and Chief Executive Officer

Consolidated Statements of Cash Flows

Year Ended December 31 millions of dollars	2005	2004
Operating activities		
Net earnings before non-controlling interest	$ 135.4	$ 141.0
Non-cash items:		
Depreciation	136.1	131.2
Deferral of provincial taxes and income taxes	(16.7)	–
Amortization of deferred charges	15.6	19.0
Equity earnings	(6.5)	(6.2)
Regulatory amortization	19.4	26.1
Allowance for funds used during construction	(4.4)	(4.0)
Future income taxes	3.3	(10.5)
Other non-cash operating items	17.2	26.4
Discontinued operations	1.2	2.9
Other cash operating items	(23.4)	(28.9)
	277.2	297.0
Change in non-cash operating working capital	(112.9)	7.6
Net cash provided by operating activities	164.3	304.6
Financing activities		
Retirements of long-term debt	(126.7)	(165.3)
Issuance of long-term debt	275.9	–
(Reduction of) increase in short-term debt	(143.7)	165.6
Issuance of common shares	20.9	9.8
Dividends on common shares	(97.4)	(95.5)
Dividends paid by subsidiaries to non-controlling interest	(14.1)	(14.1)
Long-term financing of asset sale	15.0	10.0
Accounts receivable securitization	–	30.0
Other financing activities	1.8	2.1
Net cash used in financing activities	(68.3)	(57.4)
Investing activities		
Property, plant and equipment	(129.3)	(151.6)
Proceeds on disposition (note 17)	18.4	–
Investments	41.7	(42.6)
Acquisition (note 16)	(55.2)	(6.0)
Retirement spending net of salvage	(4.7)	(4.7)
Proceeds from sale of assets	–	1.7
Decrease (increase) in restricted cash	11.9	(11.3)
Net cash used in investing activities	(117.2)	(214.5)
(Decrease) increase in cash and cash equivalents	(21.2)	32.7
Cash and cash equivalents, beginning of year	42.7	10.0
Cash and cash equivalents, end of year	$ 21.5	$ 42.7
Cash and cash equivalents consists of:		
Cash	$ 6.9	$ 24.8
Short-term investments	14.6	17.9
Cash and cash equivalents, end of year	$ 21.5	$ 42.7
Supplemental disclosure of cash paid:		
Interest	$ 120.7	$ 130.8
Income and capital taxes	$ 61.6	$ 83.1

See accompanying notes to the consolidated financial statements.

notes to the consolidated financial statements

December 31, 2005 and 2004

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Emera Inc. ("Emera" or the Company), 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 allowed regulated rate of return on common equity ("ROE") range is 9.3% to 9.8%, with common equity allowed to grow to 40% of the capital structure. Rates were last set using 9.55% ROE with a common equity component of 37.5% of total capitalization.

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 substantial 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 55% of BHE's electric rates represent distribution services, 30% related to stranded costs recoveries, and 15% 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").

For distribution services, BHE operates under an Alternate Rate Plan ("ARP"), which provides for an earnings band of 5% to 17% return on equity on distribution operations, with rates set at the midpoint of 11%. There is a 50/50 sharing mechanism between BHE and customers outside of the earnings band. The ARP also includes performance standards and provides for average annual reductions in distribution rates of approximately 2.5% for five years, to 2007.

The MPUC provides an allowed return on equity of 10% on BHE's stranded assets. BHE is required to hold stranded cost proceedings at least every three years to adjust any substantial differences in stranded cost estimates from prior periods that may arise because of differences between forecast and sales volume or the output of facilities subject to purchase power agreements.

Transmission rates are set by FERC annually on July 1, based on prior year's revenue requirement. The current allowed ROE for transmission operations is 11.25%.

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

Emera follows Canadian generally accepted accounting principles ("GAAP"). The accounting policies approved by the regulators of NSPI and Bangor Hydro 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: Derivative financial and commodity instruments 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 a deferred credit.

Accounting for the impact of rate regulation:

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 on electric revenue in the absence of regulation.

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 and Bangor Hydro 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 the 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. The unamortized portion of the generation station is included in property, plant and equipment. 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. More details are provided in note 15.

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 deferred assets and deferred liabilities and include costs related to terminating/restructuring purchased power contracts, the Seabrook nuclear project, decommissioning costs for Maine Yankee, obligations to Hydro-Quebec, and the stranded cost revenue requirement levelizer, and are described in more detail in note 14.

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 11 years (2004 – 14 years). Unregulated generation assets have an estimated average service life of 41 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 are being phased in over four years beginning in 2004. Depreciation is now computed on the straight-line basis based on the phase-in period contained within the settlement agreement. In the March 31, 2005 decision on NSPI's 2005 rate application, the UARB delayed the phase-in of year two rates for one year. Absent consideration of growth in plant-in-service, the phase-in of new depreciation rates will increase depreciation expense by approximately $5 million per year for a cumulative increase of $20 million over the four-year 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	2005	2004
Generation		
Thermal	2.38%	2.38%
Gas turbines	2.18%	2.18%
Combustion turbines	3.33%	5.00%
Hydro-electric	1.26%	1.26%
Wind turbines	5.00%	5.00%
Transmission	2.68%	2.68%
Distribution	3.96%	3.96%
General plant	5.62%	6.21%
General plant under capital lease	9.50%	–
Weighted average depreciation rate	2.93%	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	2005	2004
Transmission	43	42
Distribution	36	40
Other	16	15
Weighted average service life	32	34

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 Nova Scotia Power and Bangor Hydro include labour, inventories, and other non-labour costs directly attributable to the capital activity. In addition, in order to ensure the full cost approach, 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, and employee benefits, insurance, inventory costs, and fleet operating and maintenance costs. Nova Scotia Power and Bangor Hydro calculate a rate depending on the type of capital project and only eligible operating expenditures are used in the calculation. NSPI and BHE apply overhead costs based on direct labour costs. 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. NSPI and Bangor Hydro 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 9.

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 NSPI's 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 10 years as at December 31, 2005 (2004 – 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 13 years as at December 31, 2005 (2004 – 13 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 a deferred asset or credit 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 3.53% at December 31, 2005 (December 31, 2004 – 2.37%).

m. Inventory

Inventories of materials and supplies are valued at the lower of average cost and market. Fuel inventory is valued at the lower of cost, using the first-in, first-out method, and net realizable value.

n. Debt Financing and Defeasance Costs

Financing costs pertaining to debt issues are amortized over the life of the related debt.

Upon privatization in 1992, NSPI became responsible for managing a portfolio of approximately $1.1 billion of defeasance securities held in trust. 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.

o. Derivative Financial and Commodity Instruments

The Company uses various derivative financial instruments to hedge its exposure to foreign exchange, interest rate, and commodity price risks. If the documentation and effectiveness requirements are met, gains and losses on these instruments are deferred and recognized in earnings in the same period the related hedged risk is realized (settlement accounting). Where documentation and effectiveness requirements are not met, the instruments are marked-to-market in the period of ineffectiveness with an adjustment to earnings.

If a hedging relationship is terminated, gains and losses on the instruments up until the date of termination are deferred and recognized in the same period the related hedged risk is realized. The instruments, if retained, would then be marked-to-market from the termination date on.

Amounts received or paid related to instruments used to hedge foreign exchange and commodity price risks are recognized in the cost of fuel purchases. Amounts received or paid, including any gains and losses on instruments used to hedge interest rate risks, are recognized over the term of the hedged item in interest expense. The derivatives are not recorded on the balance sheet.

Non-hedging derivative financial and commodity instruments are entered into and are marked-to-market at each reporting date and are reflected on the balance sheet as energy marketing assets or energy marketing liabilities. The net margin recognized is reflected in other revenue.

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, and recognizes its pro-rata share of any revenue and expenses in the Company's statement of earnings. 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, Maine Yankee Atomic Power Company, Maine Electric Power Company Inc., and Intragas Energy using the equity method.

Long-term investments over which Emera does not have significant influence are accounted for on the cost basis.

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 are deferred and included in a separate component of shareholders' equity.

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

Variable Interest Entities

In June 2003, the Canadian Institute of Chartered Accountants issued Accounting Guideline 15 Consolidation of Variable Interest Entities. This guideline applies to annual and interim periods beginning on or after November 1, 2004. A variable interest entity ("VIE") is any type of legal structure in which control is determined through contractual or other financial arrangements as opposed to traditional voting rights, if certain conditions exist. The guideline requires the enterprise which absorbs the majority of a VIE's expected losses or receives the majority of a VIE's expected residual returns, the primary beneficiary, to consolidate the VIE.

The Company has variable interests in VIEs that are not consolidated because the Company is not considered the primary beneficiary. These VIEs consist of purchase power agreements for renewable energy with independent power producers. The Company's only obligation under these agreements is to purchase all of the energy produced, which currently is expected to approximate 100 GWh annually.

Disclosures by Entities Subject to Rate Regulation

In May 2005, the CICA issued Accounting Guideline 19 Disclosures by Entities Subject to Rate Regulation. The guideline applies to fiscal years ending on or after December 31, 2005. The guideline requires entities subject to rate regulation to disclose general information about the rate setting process and discuss how rate regulation has effected its financial statements. Emera's financial statements and supporting notes reflect the new requirements.

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 reportable segments are the same as those described in the summary of significant accounting policies.

Reportable 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 energy marketing margin and electric revenue from the Company's investment in Bear Swamp.

millions of dollars	Nova Scotia Power		Bangor Hydro		Other*		Total	
	2005	2004	2005	2004	2005	2004	2005	2004
Revenues from external customers	$ 962.8	$ 933.8	$ 147.0	$ 168.6	$ 58.2	$ 31.8	$ 1,168.0	$ 1,134.2
Depreciation	119.5	116.0	14.9	14.0	1.7	1.2	136.1	131.2
Cost of operations, including depreciation	722.1	639.1	110.5	126.1	42.6	29.6	875.2	794.8
Net inter-segment revenues/ (expenses)	193.4	153.0	(2.7)	(2.0)	(190.7)	(151.0)	–	–
Equity earnings	–	–	–	–	6.5	6.2	6.5	6.2
Interest expense	97.9	100.1	12.1	13.5	7.4	13.2	117.4	126.8
Other income	8.0	–	–	–	–	–	8.0	–
Income taxes	45.5	59.2	9.4	10.2	(1.4)	(6.7)	53.5	62.7
Net earnings from continuing operations	91.2	107.3	14.9	18.5	16.0	1.8	122.1	127.6
Net earnings applicable to common shareholders	91.2	107.3	14.9	18.5	15.1	4.0	121.2	129.8
Assets	3,061.5	2,992.8	582.6	599.8	352.1	356.6	3,996.2	3,949.2
Goodwill	–	–	97.1	100.3	–	7.4	97.1	107.7
Goodwill included in loss on disposition	–	–	–	–	7.4	–	7.4	–
Capital expenditures	100.4	142.5	30.5	33.8	53.6	(18.7)	184.5	157.6

*Other consists of items related to corporate activities and other subsidiaries.

4. EMPLOYEE FUTURE BENEFITS

Nova Scotia Power

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.

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 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 measurement date for the assets and obligations of each benefit plan is December 31, 2005.

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, 2005	December 31, 2006
Acquired companies pension plan	December 31, 2005	December 31, 2006

Total Cash Amount

Total cash amount for 2005, made up of NSPI 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 $29.9 million (2004 – $34.2 million).

ACCRUED PENSION AND NON-PENSION BENEFIT ASSET (LIABILITY)

millions of dollars	2005 Defined-benefit pension plans	2005 Non-pension benefits plans	2004 Defined-benefit pension plans	2004 Non-pension benefits plans
Assumptions (weighted average)				
Accrued benefit obligation – December 31:				
Discount rate	5.25%	5.25%	6.0%	6.0%
Rate of compensation increase	3.0 to 5.5%	3.0 to 5.5%	3.0 to 5.5%	3.0 to 5.5%
Health care trend – initial	–	9.0%	–	10.0%
– ultimate	–	4.0%	–	4.0%
– year ultimate reached	–	2011	–	2010
Benefit cost for year ending December 31:				
Discount rate	6.0%	6.0%	6.0%	6.0%
Expected long-term return on plan assets	7.5%	–	7.5%	–
Rate of compensation increase	3.0 to 5.5%	3.0 to 5.5%	3.0 to 5.5%	3.0 to 5.5%
Health care trend – initial	–	10.0%	–	11.0%
– ultimate	–	4.0%	–	4.0%
– year ultimate reached	–	2011	–	2010
Accrued benefit obligations				
Balance, January 1	$ 640.3	$ 31.1	$ 624.0	$ 31.2
Employer current service cost	9.6	1.2	10.0	1.2
Employee contributions	4.7	–	5.0	–
Interest cost	38.1	1.8	36.8	1.9
Past service amendments	–	–	(7.3)	–
Actuarial losses (gains)	114.3	3.2	1.3	(1.4)
Benefits paid	(30.2)	(2.5)	(29.5)	(1.8)
Other	0.7	–	–	–
Balance, December 31	$ 777.5	$ 34.8	$ 640.3	$ 31.1
Fair value of plan assets				
Balance, January 1	$ 516.0	$ –	$ 471.3	$ –
Employer contributions	26.7	2.5	31.6	1.8
Employee contributions	4.7	–	5.0	–
Actual investment income	64.0	–	37.6	–
Benefits paid	(30.2)	(2.5)	(29.5)	(1.8)
Balance, December 31	$ 581.2	$ –	$ 516.0	$ –
Reconciliation of financial status to accrued benefit asset, December 31				
Fair value of plan assets	$ 581.2	$ –	$ 516.0	$ –
Accrued benefit obligations	777.5	34.8	640.3	31.1
Plan deficit	(196.3)	(34.8)	(124.3)	(31.1)
Unamortized past service gains	(0.6)	–	(0.6)	–
Unamortized actuarial losses (gains)	273.5	(1.6)	191.3	(5.2)
Unamortized transitional obligation	0.1	15.7	0.2	17.9
Accrued benefit asset (liability)	$ 76.7	$ (20.7)	$ 66.6	$ (18.4)

The expected return on plan assets is determined based on the market-related value of plan assets of $550.9 million at January 1, 2005 (January 1, 2004 – $519.8 million), adjusted for interest on certain cash flows during the year.

DEFINED BENEFIT PLANS ASSET ALLOCATION

	2005		2004	
percent of plan assets	Employee pension plan	Acquired companies pension plan	Employee pension plans	Acquired companies pension plan
Equity securities	66%	60%	67%	56%
Debt securities	33%	37%	31%	41%
Cash	1%	3%	2%	3%
Total	100%	100%	100%	100%

As at December 31, 2005, the pension funds do not hold any material investments in Emera Inc. or Nova Scotia Power Inc. securities. Any such investment would primarily be held indirectly through pooled investment funds.

Plans with Accrued Benefit Obligations in Excess of Assets

As at December 31, 2005, all post-retirement benefit plans have accrued pension obligations in excess of assets.

BENEFITS EXPENSE

	2005		2004	
millions of dollars	Defined-benefit pension plans	Non-pension benefits plan	Defined-benefit pension plans	Non-pension benefits plan
Defined benefit plan				
Costs arising from events during the year:				
Current service costs	$ 9.6	$ 1.2	$ 10.0	$ 1.2
Interest on accrued benefits	38.1	1.8	36.8	1.9
Less: actual return on plan assets	(64.0)	–	(37.6)	–
Actuarial losses (gains) on accrued benefit obligation	114.3	3.2	1.3	(1.4)
Past service gains	–	–	(7.3)	–
Other	0.7	–	–	–
Future benefit costs before adjustments	98.7	6.2	3.2	1.7
Adjustments to recognize long-term nature of costs:				
Difference between expected return on assets and actual return	23.0	–	(1.1)	–
Amortization of transitional obligation	–	2.2	–	2.2
Difference between amortization of actuarial losses (gains) and actual actuarial losses (gains) on accrued benefit obligations	(105.1)	(3.6)	6.5	1.1
Difference between amortization of past service costs and past service costs for the year	–	–	7.6	–
Total defined benefits expense	$ 16.6	$ 4.8	$ 16.2	$ 5.0
Defined contribution plan				
Employer expense	$ 0.7	$ –	$ 0.8	$ –

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 the following impact in 2005:

millions of dollars	Increase	Decrease
Current service cost and interest cost	$ 0.2	$ (0.1)
Accrued benefit obligation, December 31	$ 1.9	$ (1.6)

Bangor Hydro

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.

Other retirement benefit plans include an unfunded pension arrangement and a contributory health care plan.

The measurement date for the assets and obligations of each benefit plan is December 31, 2005.

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, 2004	December 31, 2005

Total Cash Amount

Total cash amount for 2005, 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 $5.3 million (2004 – $6.5 million).

ACCRUED PENSION AND NON-PENSION BENEFIT LIABILITY

millions of dollars	2005 Defined-benefit pension plans	2005 Non-pension benefits plans	2004 Defined-benefit pension plans	2004 Non-pension benefits plans
Assumptions (weighted average)				
Accrued benefit obligation – December 31:				
Discount rate	5.75%	5.75%	6.00%	6.00%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%
Health care trend – initial	–	9.20%	–	12.00%
– ultimate	–	5.00%	–	5.00%
– year ultimate reached	–	2011	–	2010
Benefit cost for year ending December 31:				
Discount rate	6.00%	6.00%	6.25%	6.25%
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	–	10.80%	–	12.00%
– ultimate	–	5.00%	–	5.00%
– year ultimate reached	–	2010	–	2010
Accrued benefit obligations				
Balance, January 1	$ 86.8	$ 33.9	$ 93.2	$ 37.9
Employer current service cost	1.6	0.8	1.6	0.7
Interest cost	5.0	2.2	5.3	2.3
Past service amendments	–	(5.0)	–	–
Actuarial losses (gains)	0.1	7.3	(2.3)	(2.2)
Benefits paid	(4.6)	(2.5)	(4.9)	(2.3)
Foreign currency translation adjustment	(3.1)	(1.1)	(6.1)	(2.5)
Balance, December 31	$ 85.8	$ 35.6	$ 86.8	$ 33.9
Fair value of plan assets				
Balance, January 1	$ 51.0	$ 1.1	$ 51.8	$ 1.2
Employer contributions	2.7	2.4	4.0	2.2
Retiree medical contributions	–	0.1	–	–
Actual investment income	3.1	–	3.9	–
Benefits paid	(4.6)	(2.5)	(4.9)	(2.3)
Foreign currency translation adjustment	(1.6)	(0.1)	(3.8)	–
Balance, December 31	$ 50.6	$ 1.0	$ 51.0	$ 1.1
Reconciliation of financial status to accrued benefit asset, December 31				
Fair value of plan assets	$ 50.6	$ 1.0	$ 51.0	$ 1.1
Accrued benefit obligations	85.8	35.6	86.8	33.9
Plan deficit	(35.2)	(34.6)	(35.8)	(32.8)
Unamortized past service costs	2.1	(4.8)	2.6	–
Unamortized actuarial losses	24.0	9.7	24.7	3.6
Unamortized transitional obligation	–	4.1	–	4.8
Accrued benefit liability	$ (9.1)	$ (25.6)	$ (8.5)	$ (24.4)

For the defined benefit pension plan, the expected return on plan assets is determined based on the market-related value of plan assets of $52.8 million at January 1, 2005 (January 1, 2004 – $55.4 million), adjusted for interest on certain cash flows during the year.

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DEFINED BENEFIT PLANS ASSET ALLOCATION

percent of plan assets	2005 Employee pension plan	2004 Employee pension plan
Equity securities	62%	60%
Debt securities	37%	39%
Other	1%	1%
Total	100%	100%

As at December 31, 2005, 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 Obligations in Excess of Assets

As at December 31, 2005, all post-retirement benefit plans have accrued pension obligations in excess of assets.

BENEFITS EXPENSE

millions of dollars	2005 Defined-benefit pension plans	2005 Non-pension benefits plan	2004 Defined-benefit pension plans	2004 Non-pension benefits plan
Defined benefit plan				
Costs arising from events during the year:				
Current service costs	$ 1.6	$ 0.8	$ 1.6	$ 0.7
Interest on accrued benefits	5.0	2.2	5.3	2.3
Less: actual return on plan assets	(3.1)	–	(3.9)	–
Actuarial losses (gains) on accrued benefit obligation	0.1	7.3	(2.3)	(2.2)
Past service costs	–	(5.0)	–	–
Future benefit costs before adjustments	3.6	5.3	0.7	0.8
Adjustments to recognize long-term nature of costs:				
Difference between expected return on assets and actual return	(1.2)	–	(0.8)	–
Amortization of transitional obligation	–	0.6	–	0.7
Difference between amortization of actuarial losses (gains) and actual actuarial losses (gains) on accrued benefit obligations	0.9	(6.6)	3.1	3.0
Difference between amortization of past service costs and past service costs for the year	0.4	5.0	1.0	–
Total defined benefits expense	$ 3.7	$ 4.3	$ 4.0	$ 4.5
Defined contribution plan				
Employer expense	$ 0.2	–	$ 0.4	–

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 the following impact in 2005:

millions of dollars	Increase	Decrease
Current service cost and interest cost	$ 0.6	$ (0.5)
Accrued benefit obligation, December 31	$ 6.9	$ (5.3)

Accounting for the impact of rate regulation:

When Bangor Hydro was purchased by Emera, BHE received regulatory approval to continue amortizing certain existing schedules 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 $53.0 million (2004 – $54.0 million) and the total defined benefits expense for 2005 would be $5.8 million (2004 – $6.0 million).

5. OPERATING LEASES

The Company has entered into operating lease agreements for office space, telecommunication services, and certain other equipment, which expire in 2006 to 2020. Future minimum annual lease payments under the leases are as follows:

millions of dollars	
2006	$ 6.3
2007	6.2
2008	6.2
2009	5.4
2010	4.4
Thereafter	4.2
	$ 32.7

For the year ended December 31, 2005 the Company recognized $6.2 million (2004 – $5.2 million) in operating, maintenance and general expense.

6. INVESTMENTS AND EQUITY EARNINGS

Investments are comprised of the following:

	2005		2004	
millions of dollars	Carrying value	Equity earnings	Carrying value	Equity earnings
Equity accounted investments				
Maritimes & Northeast Pipeline	$ 92.8	$ 6.5	$ 88.0	$ 6.2
Maine Yankee Atomic Power Company	2.4	–	3.1	–
Maine Electric Power Company Inc.	1.5	–	1.4	–
Intragas Energy	1.9	–	1.9	–
Total equity investments	98.6	6.5	94.4	6.2
Long-term portfolio investments	2.4	–	2.4	–
	$ 101.0	$ 6.5	$ 96.8	$ 6.2

7. INTEREST

Interest expense consists of the following:

millions of dollars	2005	2004
Interest on long-term debt	$ 104.8	$ 110.7
Interest on short-term debt	14.6	15.2
Amortization of debt financing	1.9	1.7
Foreign exchange (gains) losses	(3.9)	1.6
Defeasance earnings and other interest income	–	(2.4)
	$ 117.4	$ 126.8

8. OTHER INCOME

During 2005, Nova Scotia Power received a payment of $10.5 million, less $2.5 million of associated costs, from a gas supplier as part of renegotiations of certain contractual matters.

9. INCOME TAXES

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

millions of dollars	2005		2004	
Earnings before taxes	$ 176.7		$ 203.7	
Income taxes, at statutory rates	67.4	38.1%	77.7	38.1%
Unrecorded future income taxes on regulated earnings	(10.8)	(6.1)	(13.7)	(6.7)
Equity earnings not subject to tax	(2.7)	(1.5)	(2.4)	(1.2)
Large corporations tax	4.2	2.4	4.4	2.2
Other	(4.6)	(2.6)	(3.3)	(1.6)
	53.5	30.3%	62.7	30.8%
Income taxes – current	50.2		73.2	
Income taxes – future	$ 3.3		$ (10.5)	

The future income tax assets and liabilities comprise the following:

	Current portion		Long-term portion	
millions of dollars	2005	2004	2005	2004
Future income tax assets:				
Tax loss carry forwards	$ 7.8	$ 3.7	$ 14.6	$ 33.2
Financing	1.4	0.3	0.2	0.2
Property, plant and equipment	–	–	3.2	1.2
Other	0.1	(0.4)	1.0	(0.5)
	$ 9.3	$ 3.6	$ 19.0	$ 34.1
Future income tax liabilities:				
Property, plant and equipment			$ 80.0	$ 80.3
Deferred charges			16.6	21.0
Deferred credits			(10.8)	(10.7)
Tax loss carry forwards			(2.6)	(2.6)
Financing			(4.2)	(5.2)
Other			(0.1)	(0.6)
			$ 78.9	$ 82.2

As at December 31, 2005, the company has tax losses of $64.7 million, which are reflected in future income tax assets or netted against future income liabilities as appropriate, and expire as follows:

millions of dollars	
2006	$ 0.1
2007	–
2008	1.9
2009	16.7
2010	10.8
2011	–
2012	–
Thereafter	35.2
	$ 64.7

Accounting for the impact of rate regulation:
At December 31, 2005, the unrecorded future income tax assets of NSPI are approximately $21 million (2004 – $39 million), consisting of deductible temporary differences of $55 million (2004 – $103 million). In the absence of the UARB's approval of NSPI's taxes payable accounting policy, NSPI would have had a future income tax expense of $11.0 million in 2005 (2004 – $13.5 million).

10. NON-CONTROLLING INTEREST

The non-controlling interest consists of the preferred shares of Nova Scotia Power Inc. and Bangor Hydro-Electric Company. Dividends on the preferred shares and related taxes are reflected in non-controlling interest expense.

Non-controlling interest expense consists of preferred share dividends less a net recovery of income tax expense of $0.8 million (2004 – $0.8 million). The income tax recovery of $6.4 million in 2005 (2004 – $6.4 million) is reflected as a reduction of preferred share dividends with an offsetting increase in income tax expense.

millions of dollars	2005	2004
Preferred share dividend	$ 14.1	$ 14.2
Part VI.1 tax on preferred share dividends	5.6	5.6
Part I tax recovery related to the Part VI.1 tax deduction	(6.4)	(6.4)
	$ 13.3	$ 13.4

11. EARNINGS PER SHARE

Earnings per share for 2005 are as follows:

			2005
	Net earnings ($ millions)	Weighted average common shares (millions)	EPS ($)
Basic EPS	$ 121.2	109.5	$ 1.11
Series C preferred shares of NSPI	5.8	6.6	(0.01)
Series D preferred shares of NSPI	7.5	7.1	(0.01)
Diluted EPS	$ 134.5	123.2	$ 1.09

Restricted share units and deferred share units, and senior management share options, whose exercise price exceeded the average market price for the period, were excluded from the above calculation because they did not dilute earnings per share.

Earnings per share for 2004 are as follows:

	2004		
	Net earnings ($ millions)	Weighted average common shares (millions)	EPS ($)
Basic EPS	$ 129.8	108.6	$ 1.20
Restricted Share Units and Deferred Share Units	–	0.5	(0.01)
Series C preferred shares of NSPI	5.8	6.9	(0.02)
Series D preferred shares of NSPI	7.5	7.4	(0.01)
Diluted EPS	$ 143.1	123.4	$ 1.16

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

12. ACCOUNTS RECEIVABLE

In May 2004 NSPI renewed 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 accounted for at carrying value in deferred charges. Fees related to securitization are expensed as incurred.

At December 31, 2005 net accounts receivables sold amounted to $80 million (2004 – $80 million). This agreement is in place until 2009 with the intention that it will be renewed at that time.

At December 31, 2005, the Company had unbilled revenue included in accounts receivable in the amount of $71.8 million (2004 – $74.6 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.

13. LONG-TERM RECEIVABLE

The current portion of the long-term receivable, which arose from Emera's 2003 sale of its 8.4% interest in the offshore platforms and sub-sea field gathering lines of the Sable Offshore Energy Project to Pengrowth Corporation, is $20.0 million (2004 – $15.0 million) and has been classified in accounts receivable on the balance sheet. As at December 31, 2005, no amount (2004 – $20 million) remains classified as long-term. Late payments bear interest at prime plus 500 basis points. The receivable is collateralized by the assets sold.

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, to be settled in November 2007. Management's best estimate of the price rebate, based on the contract specifications using actual and forward market pricing, of $48.4 million (2004 – $4.9 million) is reflected in long-term receivables.

14. DEFERRED CHARGES AND CREDITS

Deferred charges and credits, including the impact of rate-regulated accounting policies, include the following:

millions of dollars	2005	2004
Deferred charges:		
Regulatory assets:		
Pre-2003 income tax liability and related interest	$ 146.7	$ 150.0
Costs to terminate/restructure purchased power contracts	28.0	48.0
Maine Yankee decommissioning costs	19.7	24.8
Seabrook nuclear project	19.6	22.2
Deferral of income and capital taxes not included in Q1, 2005 rates	16.7	–
Stranded cost revenue requirement levelizers	13.3	–
Deferred restructuring costs	8.7	11.0
Hydro-Quebec obligation	5.2	5.7
Other	6.9	10.9
	264.8	272.6
Non-regulatory assets:		
Unamortized debt financing and defeasance costs	171.2	184.0
Accrued pension and non-pension benefit asset (note 4)	56.0	48.2
Retained interest in accounts receivable securitized (note 12)	7.6	7.5
Funds placed in escrow on acquisition of generating stations	–	48.8
345 KV line to New Brunswick	–	7.8
Other	8.7	6.4
	243.5	302.7
	$ 508.3	$ 575.3
Deferred credits:		
Regulatory liabilities:		
Other	3.4	4.1
	3.4	4.1
Non-regulatory liabilities:		
Accrued pension and non-pension benefit liability (note 4)	34.7	32.9
Maine Yankee decommissioning liability	19.7	24.8
Hydro-Quebec obligation	5.2	5.7
Unearned revenue	5.0	4.9
Other	9.5	8.4
	74.1	76.7
	$ 77.5	$ 80.8

Regulatory assets consist of:

Pre-2003 Income Tax Liability and Related Interest

NSPI has a $146.7 million 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 decision on NSPI's 2005 rate application, the UARB approved the amortization and recovery of this regulatory asset over eight years, commencing in 2007. In the absence of UARB approved recovery, the liability would have been expensed when incurred.

Costs to Terminate/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 has been attempting to alleviate the adverse impact of these high-cost contracts and in doing so has incurred costs to terminate or restructure certain of the contracts. The MPUC has allowed Bangor Hydro to defer these costs and recover them in stranded cost rates. The contract termination is being recovered over an 11-year period, ending in February 2006, while the contract restructuring is being recovered over a 20-year period ending in June 2018. The annual amortization is approximately $19.4 million, and is reduced to $4.8 million in 2006. In the absence of the MPUC's approval, these costs would have been expensed as incurred and earnings would have been $19.4 million ($11.7 million after-tax) higher in 2005 (2004 – $20.7 million or $12.4 million after-tax).

Maine Yankee Decommissioning Costs

Bangor Hydro owns 7% of the common stock of Maine Yankee, which in 1997 permanently shut down its nuclear generating plant. Pursuant to a contract with Maine Yankee, BHE is required to pay its pro-rata share of Maine Yankee's operating expenses including decommissioning costs. BHE's share of the estimated decommissioning costs were approximately $5.0 million in 2005 (2004 – $5.1 million). Maine Yankee expense recovery is included in BHE's stranded cost revenues, and along with all stranded cost revenues, purchased power, and Hydro-Quebec costs, are fully reconcilable starting March 1, 2005. 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 $5.0 million ($3.0 million after-tax) higher in 2005 (2004 – $5.1 million or $3.0 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 2005 would be $2.1 million ($1.2 million after-tax) higher (2004 – $2.2 million or $1.3 million after-tax).

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. The amount of the amortization period is pending approval by the UARB. In the absence of the UARB's approval, these taxes would not have been deferred and net earnings would have been $16.7 million lower in 2005.

Deferred Stranded Cost Revenue Requirement Levelizer

Bangor Hydro's current stranded cost rates are designed to recover their cumulative stranded cost revenue requirements over a three-year period from March 2005 to February 2008. While the stranded cost revenue requirements differ throughout the period due to changes in purchased power expenses and varying amortization periods for regulatory assets and liabilities, 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. For the period March 2005 to February 2006 BHE will defer $15.0 million of costs and will amortize the deferral almost evenly over the periods March 2006 to February 2007,

and March 2007 to February 2008. 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 regulatory approval, earnings for 2005 would be $13.9 million ($8.4 million after-tax) lower (2004 – $4.2 million or $2.5 million after-tax).

Deferred Restructuring Costs

In order to provide rate stability, the UARB allows NSPI to defer the cost of large early retirement and severance programs, and amortize the resulting deferred charges on a straight-line basis over a three-year period, commencing in the period in which the program is initiated.

In conjunction with Bangor Hydro's Alternative Rate Plan, BHE has been provided with accounting orders from the MPUC to defer and amortize over ten years certain employee transition costs. Eligible for deferral are 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 2005 earnings would be $2.1 million ($2.0 million after-tax) higher (2004 – $4.0 million or $3.8 million after-tax).

Hydro-Quebec Obligation

The obligation associated with Hydro-Quebec represents the estimated present value of Bangor Hydro's estimated future payments for net costs associated with ownership and operation of the Hydro-Quebec intertie between the New England utilities and Hydro-Quebec. The obligation has been recognized as a long-term deferred credit, 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, 2005 earnings would be $0.5 million ($0.3 million after-tax) higher (2004 – $0.7 million or $0.4 million after-tax).

Other

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 $4.1 million ($2.4 million after-tax) higher in 2005 (2004 – $2.2 million or $1.3 million after-tax).

Deferred assets include:

Funds Placed in Escrow on Acquisition of Generating Stations

Brookfield Power Corporation (formerly Brascan Power Corporation) and Emera Inc., in a 50/50 joint venture, acquired Bear Swamp, a 600 megawatt pumped storage hydro-electric facility in northern Massachusetts, for a total of US $92 million (Emera's share – US $46 million). As at December 31, 2004, each party had a deposit of US $4.5 million, pending completion of the transaction. The transaction was completed in May 2005.

A second joint venture acquisition, the 49 MW Bellow Falls hydro-electric facility, did not receive the required regulatory approval. Emera's escrow deposit was returned in Q4, 2005.

Regulatory liabilities include:

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 $0.9 million ($0.6 million after-tax) lower in 2005 (2004 – $3.7 million or $2.2 million after-tax).

notes to the consolidated financial statements

15. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is comprised of the following:

millions of dollars	Cost	Accumulated Depreciation	2005 Net Book Value
Generation			
Thermal	$ 1,719.1	$ 634.1	$ 1,085.0
Gas Turbines	31.1	21.5	9.6
Combustion Turbines	76.5	10.5	66.0
Hydro-electric	427.6	123.4	304.2
Wind Turbines	2.0	0.3	1.7
Transmission	672.3	300.1	372.2
Distribution	1,284.0	571.2	712.8
Other	371.6	137.2	234.4
Other, under capital lease	0.9	–	0.9
	$ 4,585.1	$ 1,798.3	$ 2,786.8

millions of dollars	Cost	Accumulated Depreciation	2004 Net Book Value
Generation			
Thermal	$ 1,651.8	$ 604.0	$ 1,047.8
Gas Turbines	38.3	26.1	12.2
Combustion Turbines	76.0	3.0	73.0
Hydro-electric	364.9	118.6	246.3
Wind Turbines	2.0	0.2	1.8
Transmission	664.8	287.5	377.3
Distribution	1,254.0	535.4	718.6
Other	366.3	128.7	237.6
	$ 4,418.1	$ 1,703.5	$ 2,714.6

Accounting for the impact of rate regulation:

At December 31, 2005, the Glace Bay generating station had a net book value of $12.9 million (2004 – $17.8 million). During the year NSPI amortized $6.2 million (2004 – $6.2 million) related to the plant, and capitalized $1.3 million in AFUDC (2004 – $1.5 million) to the plant value. 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.

16. ACQUISITION

On May 24, 2005 Emera and Brookfield Power Corporation (formerly Brascan Power Corporation), in a 50/50 joint venture, acquired Bear Swamp, a 600 megawatt ("MW") pumped storage hydro-electric facility in northern Massachusetts. Emera's share of the purchase price was $61.2 million. The facility sells energy, capacity and ancillary products to the New England Power Pool. Also included in the acquisition is the nearby 10 MW Fife Brook run-of-river hydro-electric facility.

The acquisition has been accounted for under the purchase method of accounting using proportionate consolidation, and accordingly, Emera's pro-rata share of the results of operations since the date of acquisition have been included in the consolidated statement of earnings.

Emera's share of the transaction is summarized as follows:

millions of dollars	
Net assets acquired	
Inventory	$ 0.2
Property, plant and equipment	61.8
Deferred charges	0.2
Accrued liabilities	(0.1)
Deferred credits	(0.9)
Total cash consideration	$ 61.2

17. DISCONTINUED OPERATIONS AND DISPOSAL OF LONG-LIVED ASSETS

Effective September 30, 2005 Emera Fuels, a subsidiary of Emera, sold its heating oil distribution business. Emera Fuels is included in the segment "Other" in Note 3 Segment Information.

Emera Fuels has been accounted for as discontinued operations. Accordingly, prior periods have been reclassified to reflect this change. The following provides additional information with respect to amounts included in (loss) earnings from discontinued operations on the consolidated statements of earnings:

millions of dollars	2005	2004
Revenue	$ 69.7	$ 87.8
Earnings before income taxes	$ 0.3	$ 2.7
Loss on disposition, net of tax	$ (1.6)	–

The following summarizes the transaction:

millions of dollars	
Cash proceeds on disposition	$ 18.6
Disposition costs	0.2
Net cash proceeds on disposition	18.4
Net assets included in disposition	19.3
Loss on disposition	0.9
Income taxes	0.7
Loss on disposition, net of tax	$ 1.6

Accounting for the impact of rate regulation:

In December 2004 Bangor Hydro sold its corporate office facilities to a third party for cash consideration of $0.9 million. A $2.5 million loss on the disposition was netted against accumulated depreciation in accordance with Bangor Hydro's accounting policy approved by FERC. Absent regulator approval, BHE earnings would have been $2.5 million ($1.5 million after-tax) lower in 2004.

18. INTEREST IN JOINT VENTURE

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

millions of dollars	2005
Current assets	$ 3.3
Non-current assets	57.4
	$ 60.7
Current liabilities	$ 3.4
Non-current liabilities	–
	$ 3.4
Revenues	$ 26.6
Expenses	(22.4)
Net earnings	$ 4.2
Cash provided by operations	$ 7.0
Cash used in investing activities	(62.6)
Cash provided by financing activities	57.5
Increase in cash	$ 1.9

19. GOODWILL

The change in goodwill is due to the following:

millions of dollars	2005	2004
Balance, beginning of year	$ 107.7	$ 115.1
Disposition of Emera Fuels	(7.4)	–
Change in foreign exchange rate	(3.2)	(7.4)
Balance, end of year	$ 97.1	$ 107.7

20. ASSET RETIREMENT OBLIGATIONS

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

millions of dollars	2005	2004
Balance, beginning of year	$ 68.5	$ 65.1
Accretion included in depreciation expense	0.9	0.8
Accretion deferred to regulatory asset	2.7	2.6
Disposition of Emera Fuels	(0.2)	–
Other	(0.2)	–
Balance, end of year	$ 71.7	$ 68.5

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
Steam	5.3%	$ 242.3	15 – 34 years
Hydro	5.3%	60.8	26 – 56 years
Combustion turbines	5.3%	5.1	2 – 18 years
Other	7.4% – 8.6%	1.0	5 – 10 years
		$ 309.2	

Some of the Company's transmission and distribution assets may also have 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.

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 the absence of this deferral, net earnings for 2005 would be $2.7 million lower (2004 – $2.6 million).

21. SHORT-TERM DEBT

For the year ended December 31, 2005, short-term debt consists of LIBOR loans of $58.1 million issued against lines of credit. LIBOR loans bear interest at prevailing market rates, which on December 31, 2005 averaged 4.93%. The operating line of credit consists of advances of $5.4 million, which when drawn upon bears interest at the prime rate, which on December 31, 2005 was 5.00%. The short-term debt in NSPI and Emera is unsecured. Bangor Hydro has borrowings outstanding under its revolving credit loan agreement of $21.1 million that bears interest at 5.1%. This revolving credit loan is unsecured. Emera Energy Services has a US base rate loan for $3.5 million that bears interest at 7.25% (US prime) and is unsecured.

For the year ended December 31, 2004, short-term debt consists of commercial paper of $0.2 million, bankers' acceptances of $30.9 million, and LIBOR loans of $73.9 million issues against lines of credit. Commercial paper, bankers' acceptances and LIBOR loans bear interest at prevailing market rates, which on December 31, 2004 averaged 2.56%, 3.13%, and 3.00%, respectively. The operating lines of credit consist of advances of $15.1 million, which when drawn upon bears interest at the prime rate, which on December 31, 2004 was 4.25%. The short-term debt in NSPI and Emera is unsecured. Also, Bangor Hydro has a revolving credit loan agreement of $25.3 million that bears interest at 3.3%. This revolving credit loan is secured by a First Mortgage Bond.

22. LONG-TERM DEBT

Long-term debt includes the issues detailed below. All long-term debt instruments are issued under trust indentures at fixed interest rates, and are unsecured unless noted below. Also included are certain bankers' 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.

millions of dollars	Effective Average Interest Rate % 2005	2004	Years of Maturity	Amount Outstanding 2005	2004
Emera					
Medium Term Notes	6.000	6.000	2006	$ 100.0	$ 100.0
Private Placement – secured by a letter of credit	6.297	6.297	2006	10.0	10.0
Bankers' Acceptances	–	3.115	One year renewable	–	8.0
NSPI					
Medium Term Notes	6.608	7.114	2006 – 2097	1,250.0	1,100.0
Debentures	9.750	9.750	2019	95.0	95.0
Commercial paper	3.020	2.557	One year renewable	182.0	262.0
Capital lease obligations	4.410	–	2011	0.9	–
Bangor Hydro (issued and payable in US$)					
General & Refunding Mortgage Bonds	9.742	9.742	2020 – 2022	58.3	60.2
Financing Authority of Maine	–	7.030	2005	–	23.8
Municipal Review Committee	5.000	5.000	2008	6.9	9.5
Senior unsecured note	6.090	6.090	2012	23.3	24.1
Senior unsecured notes	5.310	5.310	2018	58.3	60.2
Less: Sinking Funds				–	(25.5)
				1,784.7	1,727.3
Less: Amount due within one year				152.9	100.8
				$ 1,631.8	$ 1,626.5

An NSPI medium term note ("MTN") of $40.0 million bearing interest at 5.20%, maturing in 2029, is redeemable at the option of the holder in 2006. If not redeemed the interest rate on the MTN increases to 6.28% until maturity. Another NSPI MTN of $40.0 million, maturing in 2026, is extendable until 2056 at the option of the holder.

As at December 31, 2005 long-term debt and obligations under a capital lease are due as follows:

Year of Maturity millions of dollars	2005
One year renewable	$ 182.0
2006	152.9
2007	3.2
2008	121.6
2009	130.4
2010	105.3
Greater than 5 years	1,089.3
	$ 1,784.7

23. COMMON SHARES

Authorized:

Unlimited number of non-par value Common Shares.

Issued and Outstanding:

millions of dollars	Millions of Shares	Common Share Capital
January 1, 2004	108.26	$1,008.4
Issued for cash under purchase plans	0.41	7.0
Options exercised under senior management share option plan	0.20	2.8
Share-based compensation	–	1.0
December 31, 2004	108.87	1,019.2
Issued for cash under purchase plans	0.43	7.9
Options exercised under senior management share option plan	0.80	13.0
Share-based compensation	–	0.9
December 31, 2005	110.10	$1,041.0

As at December 31, 2005, there were 0.3 million (2004 – 1.1 million) common shares reserved for issuance under the senior management common share option plan, and 1.3 million (2004 – 1.4 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 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 there under. The holder of the option has no rights as a shareholder until the option is exercised and shares have been issued. The maximum number of such shares optioned to anyone cannot exceed one 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 a change of responsibility at the Company's request, such option may, subject to the terms thereof and any other terms of the plan, be exercised at anytime 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 anytime 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.

	2005		2004	
	Shares under option	Weighted average exercise price	Shares under option	Weighted average exercise price
Outstanding, beginning of year	1,939,750	$ 16.76	1,480,600	$ 15.98
Granted	569,500	$ 19.46	649,800	$ 17.77
Exercised	(797,775)	$ 16.43	(190,650)	$ 14.17
Expired	(15,000)	$ 17.55	–	–
Outstanding, end of year	1,696,475	$ 17.81	1,939,750	$ 16.76
Exercisable, end of year	702,750	$ 17.13	689,025	$ 16.41

The weighted average contractual life of options outstanding at December 31, 2005 is 7.6 years (2004 – 7.5 years). The range of exercise prices for the options outstanding at December 31, 2005 is $13.70 to $19.50 (2004 – $12.38 to $19.30).

Deferred Share Unit Plan and Restricted Share Unit Plan

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

Under the DSU plan Directors of the Company who are resident in Canada 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 DSU plan for executive and senior management, 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.

In addition, special DSU awards may be made from time to time by the Management Resources and Compensation Committee ("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. The first cycle runs from January 1, 2003 through December 31, 2005. RSUs are granted at fair value on the grant date and 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, involuntary termination, disability or death.

	Employee DSUs Outstanding	Employee RSUs Outstanding	Director DSUs Outstanding
Balance at January 1, 2004	–	129,370	13,226
Granted	140,130	175,880	18,796
December 31, 2004	140,130	305,250	32,022
Granted	33,463	132,280	14,381
Retirement, termination, disability & death	(43,307)	(76,281)	(6,967)
December 31, 2005	130,286	361,249	39,436

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 marked-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, 2005, $3.7 million (2004 – $5.8 million) of compensation expense related to options granted, units issued, and shares purchased by employees was recognized in operating, maintenance and general expense.

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:

	2005	2004
Expected dividend yield	5.20%	5.25%
Expected volatility	14.12%	14.30%
Risk-free interest rate	4.32%	4.47%
Expected life	7 years	7 years

24. FINANCIAL INSTRUMENTS

The Company manages its exposure to foreign exchange, interest rate, and commodity risks in accordance with established risk management policies and procedures using derivative instruments consisting mainly of foreign exchange forward contracts, interest options and swaps, and oil and gas options and swaps.

Non-hedging derivative financial and commodity instruments are entered into and are marked-to-market at each reporting date. The net margin recognized is reflected in other revenue.

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

Financial instruments include the following:

millions of dollars	2005 Carrying Amount Liability (Asset)	2005 Fair Value Liability (Asset)	2004 Carrying Amount Liability (Asset)	2004 Fair Value Liability (Asset)
Long-term debt	$ 1,784.7	$ 2,076.0	$ 1,727.3	$ 1,970.0
Short-term debt	88.1	88.1	145.4	145.4
Derivative financial instruments (hedges)				
Interest rate swaps	0.1	0.2	1.1	2.8
Interest rate caps and collars	(0.3)	(0.3)	(0.1)	0.9
Natural gas swaps	(4.0)	(13.4)	–	1.1
Oil swaps	(3.5)	(16.1)	–	(0.1)
Foreign exchange contracts	–	33.9	–	28.2
Derivative financial instruments (non-hedges)				
Energy marketing assets	(20.1)	(20.1)	(10.3)	(10.3)
Energy marketing liabilities	15.0	15.0	9.4	9.4

Long-Term Debt and Short-Term Debt

The fair value of Emera'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 Emera, for debt of the same remaining maturities.

Derivative Financial Instruments

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

Interest Rates

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

Interest rate cap contracts limiting floating rate interest on $150 million short-term debt over 2006 to a fixed interest rate of 4.10% were outstanding at December 31, 2005.

Commodity Prices

The Company purchased natural gas swap contracts in 2005 to limit exposure to fluctuations in natural gas prices. As at December 31, 2005, the Company had hedged approximately 80% of all natural gas purchases and sales for 2006.

The Company enters into oil swap contracts to limit exposure to fluctuations in world prices of heavy fuel oil. As at December 31, 2005, the Company has hedged approximately 90% of 2006 requirements.

The Company has non-hedging derivative financial instruments whose value is marked-to-market at each reporting date. On December 31, 2005 the Company held natural gas, power and oil financial instruments which were marked-to-market.

Foreign Exchange

Emera enters into foreign exchange forward, option, and swap contracts to limit exposure 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 US $534.5 million over 2006 to 2009 at a weighted average rate of CAD $1.2188 were outstanding at December 31, 2005. There were also option contracts to hedge US $9.3 million in 2006 at an average rate of CAD $1.2164 in 2006 outstanding at December 31, 2005.

The Company has non-hedging financial instruments whose value is marked-to-market at each reporting date. On December 31, 2005, the Company held foreign exchange financial instruments which were marked-to-market.

Risk Management

Commodity Price and Foreign Exchange Risk

A substantial amount of NSPI's fuel supply comes from international suppliers, and is subject to commodity price and foreign exchange risk. NSPI manages exposure to commodity price risk utilizing a combination of physical fixed-price fuel contracts and financial instruments providing fixed or maximum prices. Foreign exchange risk is managed through forward and option contracts. The risk inherent in the Canadian dollar cost of fuel is measured and managed on a portfolio basis.

The ability to switch fuel provides a dynamic, operational and effective option in managing commodity price and supply risk.

Interest Rate Risk

The Company makes use of various financial instruments to hedge against interest rate risk, as discussed above. Additionally, the Company uses diversification as a 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 interest rate concentration risk.

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 outside of the sphere of electric customers, counterparty creditworthiness is assessed through reports of credit rating agencies or other available financial information.

25. FOREIGN EXCHANGE TRANSLATION ADJUSTMENT

millions of dollars	2005	2004
Balance, beginning of year	$ (82.0)	$ (61.1)
Effect of exchange rate changes	(16.2)	(20.9)
Balance, end of year	$ (98.2)	$ (82.0)

26. RELATED PARTY TRANSACTIONS

During the year, in the ordinary course of business, the Company purchased transportation capacity totaling $39.7 million (2004 – $45.4 million) from the Maritimes and Northeast Pipeline, an investment under significant influence of the Company. The amount is recognized in fuel for generation or netted against energy marketing margin in other revenue, and is measured at the exchange amount. At December 31, 2005 the amount payable to the related party is $3.0 million (2004 – $3.2 million) and is non-interest bearing and is under normal credit terms.

27. CONTINGENCIES

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

As part of an ongoing litigation against a coal supplier, Nova Scotia Power was required to post an $11.5 million bond. The bond may be called if NSPI does not prosecute the claim without delay, or if the claim is not successful. It is not determinable whether NSPI will be successful with its claim, and accordingly, an estimate of the potential contingent loss cannot be made.

28. COMMITMENTS

Emera had the following significant commitments at December 31, 2005:

- The Company has a commitment to a third party, beginning in early 2004 for seven years, to outsource management of the Company's computer infrastructure at an annual cost ranging from $8.6 million to $10.4 million.
- NSPI has an annual requirement to purchase approximately 282 GWh of electricity from independent power producers over varying contract lengths ranging from nine to twenty years.
- NSPI is required to purchase approximately 61.6 million cubic feet of natural gas per day for the next five years (subject to offshore gas production), and an additional 4 million cubic feet per day, at the option of the supplier, for five years.
- NSPI has commitments to purchase approximately 65,000 mmbtu per day of transportation capacity on the Maritimes and Northeast Pipeline, a related party, for the next five years, with renewal rights at NSPI's option for an indefinite period of time, at an approximate cost of $16 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 streams of the related defeased debt. Approximately 70%, or $735 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 transportation of coal to the Lingan and Point Aconi generation stations for ten years beginning in late 2002 at an approximate cost of $15 million per year.
- NSPI has a commitment to purchase approximately 30,000 mmbtu per day of US transportation on the US side of the Maritimes and Northeast Pipeline. The cost of this commitment over the five year term of the contract is approximately $12.8 million annually.
- NSPI has a commitment to third parties for 2006 to 2009 to purchase 2.42 million metric tons ("mts") of import coal, 1.598 million mts of petroleum coke, 360,000 mts of domestic coal and 4.4 million mts of marine freight.
- NSPI has a commitment to a third party beginning in 2005 for 10 years to operate the Point Tupper Marine Terminal at an annual cost of $3.4 million per year.
- Bangor Hydro has various contracts committing it to purchase annually approximately $12 million to $14 million of electricity for the period from 2006 to 2017 from independent power producers. These commitments are reduced to approximately $2.3 million from 2018 to 2023.
- Bangor Hydro has entered into operating lease agreements for office space (expiring in 2020) and certain transportation and other equipment (expiring in 2006 through 2012) at an annual cost ranging from $0.2 million to $0.7 million.
- Emera Energy Services has entered into physical trading commitments for 2006 and 2007, the fair value of which is reflected in energy marketing assets and liabilities on the balance sheet. The future sales commitments are $419.8 million for 2006 and $78.9 million for 2007 and the future purchase commitments are $403.8 million for 2006 and $96.4 million for 2007.

29. GUARANTEES

Emera had the following guarantees at December 31, 2005:

- The Company has letters of credit issued against its operating facility totaling $25.2 million (2004 – $27.2 million). Emera's outstanding letters of credit are to secure a private placement borrowing that matures in 2006 and to secure payments to various vendors that expire in 2006. Nova Scotia Power's letters of credit extend to 2006 or are renewed annually and secure payments to various vendors. Bangor Hydro's letter of credit is to secure obligations under an unfunded pension plan and is renewed annually.

30. COMPARATIVE INFORMATION

Certain of the comparative figures have been reclassified to conform to the financial statement presentation adopted for 2005.

Operating Statistics

FIVE-YEAR SUMMARY

Year Ended December 31	2005	2004	2003	2002	2001
Electric energy sales (GWh)					
Residential	4,602.7	4,632.4	4,391.1	4,401.6	3,901.7
Commercial	3,614.1	3,567.4	3,586.1	3,401.8	2,862.3
Industrial	4,600.3	4,556.1	4,449.8	4,225.9	3,952.5
Other	716.7	819.1	1,375.4	1,641.8	654.1
Total electric energy sales	13,533.8	13,575.0	13,802.4	13,671.1	11,370.6
Sources of energy (GWh)					
Thermal – coal	9,116.3	9,490.2	9,218.7	8,861.6	8,854.8
– oil	1,581.3	1,699.3	1,537.2	289.2	690.8
– natural gas	194.3	97.0	119.5	1,578.7	1,129.1
Hydro	1,060.6	983.5	1,176.8	1,108.7	692.2
Wind	1.8	2.4	2.6	0.3	–
Purchases	2,576.6	2,339.9	2,724.5	2,765.9	776.6
Total generation and purchases	14,530.9	14,612.3	14,779.3	14,604.4	12,143.5
Losses and internal use	997.1	1,037.3	976.9	933.3	772.9
Total electric energy sold	13,533.8	13,575.0	13,802.4	13,671.1	11,370.6
Electric customers					
Residential	520,671	515,726	509,824	501,233	492,256
Commercial	50,321	49,353	48,846	47,914	46,974
Industrial	2,515	2,455	2,393	2,325	2,292
Other	9,094	8,684	8,341	11,663	10,932
Total electric customers	582,601	576,218	569,404	563,135	552,454
Capacity					
Generating nameplate capacity (MW)					
Coal fired	1,243	1,243	1,243	1,243	1,243
Dual fired	350	350	350	350	350
Gas turbines	323	319	274	225	225
Hydro-electric	395	395	395	395	395
Wind turbines	1	1	1	1	–
Independent power producers	74	66	67	66	66
	2,386	2,374	2,330	2,280	2,279
Total number of employees	2,075	2,249	2,359	2,476	2,666
km of transmission lines	6,100	6,100	6,100	6,100	6,100
km of distribution lines	32,000	32,000	32,000	32,000	32,000

FIVE-YEAR SUMMARY

Year Ended December 31 (millions of dollars)	2005	2004	2003	2002	2001
Statements of Earnings Information					
Revenue	$ 1,168.0	$ 1,134.2	$ 1,146.8	$ 1,161.2	$ 932.2
Cost of operations					
Fuel for generation and power purchased	432.0	350.0	363.3	453.2	341.6
Operating, maintenance and general	248.2	245.2	258.6	276.5	187.4
Provincial, state and municipal taxes	48.4	46.3	40.9	30.1	20.8
Provincial tax deferral	(4.5)	–	–	–	–
Depreciation	136.1	131.2	126.9	127.0	107.3
Regulatory amortization	19.4	26.1	18.2	23.9	9.3
Allowance for funds used during construction	(4.4)	(4.0)	(5.1)	(4.9)	(5.5)
	875.2	794.8	802.8	905.8	660.9
Earnings from operations	292.8	339.4	344.0	255.4	271.3
Equity earnings	6.5	6.2	8.6	7.0	9.6
Earnings before interest and income taxes	299.3	345.6	352.6	262.4	280.9
Interest	117.4	126.8	133.6	144.0	122.7
Amortization of defeasance costs	13.2	15.1	16.7	19.4	19.8
Other income	(8.0)	–	–	–	–
Earnings before income taxes	176.7	203.7	202.3	99.0	138.4
Income taxes	53.5	62.7	60.9	5.5	14.3
Income taxes deferral	(12.2)	–	–	–	–
Net earnings before non-controlling interest	135.4	141.0	141.4	93.5	124.1
Non-controlling interest	13.3	13.4	13.2	10.6	12.2
Net earnings from continuing operations	122.1	127.6	128.2	82.9	111.9
(Loss) earnings from discontinued operations	(0.9)	2.2	1.0	0.7	2.3
Net earnings applicable to common shares	121.2	129.8	129.2	83.6	114.2
Common dividends	97.4	95.5	92.8	84.4	81.0
Earnings retained for use in Company	$ 23.8	$ 34.3	$ 36.4	$ (0.8)	$ 33.2
Cost of fuel for generation – coal	$ 260.9	$ 209.1	$ 211.9	$ 229.6	$ 202.9
– oil	100.2	91.1	90.4	20.6	40.3
– natural gas	(35.4)	(30.6)	(58.4)	62.5	35.4
Power purchased	106.3	80.4	119.4	140.5	63.0
Total cost of fuel for generation and power purchased	$ 432.0	$ 350.0	$ 363.3	$ 453.2	$ 341.6
Balance Sheets Information					
Current assets	$ 391.5	$ 332.1	$ 305.5	$ 331.7	$ 334.4
Other assets	676.9	742.0	705.6	600.3	635.1
Investments	101.0	96.8	102.8	112.2	98.6
Property, plant and equipment	2,826.8	2,778.3	2,777.0	2,863.7	2,891.3
Total assets	$ 3,996.2	$ 3,949.2	$ 3,890.9	$ 3,907.9	$ 3,959.4
Current liabilities	$ 506.4	$ 493.6	$ 520.2	$ 697.6	$ 938.9
Other liabilities	231.0	231.5	207.8	193.0	190.2
Long-term debt	1,631.8	1,626.5	1,589.5	1,417.8	1,381.4
Non-controlling interest	260.8	260.8	260.8	267.5	267.5
Common shares	1,041.0	1,019.2	1,008.4	1,000.2	845.4
Foreign currency translation adjustment	(98.2)	(82.0)	(61.1)	2.9	6.0
Retained earnings	423.4	399.6	365.3	328.9	330.0
Total equity and liabilities	$ 3,996.2	$ 3,949.2	$ 3,890.9	$ 3,907.9	$ 3,959.4
Statements of Cash Flow information					
Cash provided by operating activities	$ 164.3	$ 304.6	$ 251.9	$ 272.4	$ 157.3
Cash used in (provided by) financing activities	$ 68.3	$ 57.4	$ 184.4	$ 157.3	$ (507.2)
Cash used in investing activities	$ 117.2	$ 214.5	$ 85.2	$ 109.6	$ 566.2
Financial ratios ($ per common share)					
Earnings per common share	$ 1.11	$ 1.20	$ 1.20	$ 0.85	$ 1.20

board of directors and committees

BOARD OF DIRECTORS

Derek Oland (Chair)
Chairman and Chief Executive Officer
Moosehead Breweries Limited
New River Beach, New Brunswick

Christopher G. Huskilson
President and Chief Executive Officer
Emera Inc. and Nova Scotia Power Inc.
Wellington, Nova Scotia

Wesley Armour (appointed November 2005)
President and Chief Executive Officer
Armour Transportation Systems
Moncton, New Brunswick

Robert S. Briggs
Company Director
Former President and Chief Executive Officer
Bangor Hydro-Electric Company
Carrabassett Valley, Maine

George A. Caines, Q.C.
Partner
Stewart McKelvey Stirling Scales
Halifax, Nova Scotia

Dr. Gail Cook-Bennett
Chair
Canada Pension Plan Investment Board
Toronto, Ontario

R. Irene d'Entremont, C.M.
President
M.I.T. Electronics and
ITG Information Management Inc.
Yarmouth, Nova Scotia

Allan L. Edgeworth (appointed November 2005)
President
ALE Energy Inc.
Calgary, Alberta

M. Edward MacNeil (retiring May 2006)
Company Director
Former International Representative
International Brotherhood of Electrical Workers
Sydney, Nova Scotia

John T. McLennan
Company Director
Former Vice-Chair and Chief Executive Officer
Allstream Inc.
Mahone Bay, Nova Scotia

Dr. Elizabeth Parr-Johnston
President
Parr Johnston Economic and Policy Consultants
Chester Basin, Nova Scotia

Kenneth C. Rowe (retiring May 2006)
Chairman and Chief Executive Officer
IMP Group International Inc.
Halifax, Nova Scotia

Paul D. Sobey
President and Chief Executive Officer
Empire Company Limited
Kingshead, Pictou County, Nova Scotia

COMMITTEES

Audit
George A. Caines (Chair)
Robert S. Briggs
Dr. Gail Cook-Bennett
Kenneth C. Rowe

Environment, Safety and Security
R. Irene d'Entremont (Chair)
Allan L. Edgeworth
M. Edward MacNeil

Management Resources and Compensation
Dr. Elizabeth Parr-Johnston (Chair)
R. Irene d'Entremont
Allan L. Edgeworth
John T. McLennan

Nominating and Corporate Governance
Paul D. Sobey (Chair)
Dr. Gail Cook-Bennett
John T. McLennan

shareholder information

Dividend Payments in 2005

Subject to Approval by the Board of Directors, common share dividends for Emera Inc. are payable on or about the 15th for February, May, August and November. A first quarter dividend of $0.2225 has been declared payable February 15, 2006.

A quarterly dividend of $0.30625 is payable on the 1st of January, April, July and October for Nova Scotia Power Inc.'s Series C First Preferred Shares.

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 9, July 28 and November 3, 2006. Year-end results for 2006 will be released in February 2007.

Annual General Meeting

The Annual General Meeting is scheduled to be held May 9, 2006 at 2:00 p.m. (Atlantic Time) at the World Trade and Convention Centre in Halifax, Nova Scotia.

Corporate Office

Emera Inc.
1894 Barrington Street, Barrington Tower
Halifax, Nova Scotia B3J 2A8
T: 902.450.0507 or 1.800.450.0507

Transfer Agent

Computershare Trust Company of Canada
Purdy's Wharf Tower II
1969 Upper Water Street, Suite 2008
Halifax, NS B3J 3R7
T: 1.800.564.6253
F: 902.420.2764

Investor Services

T: 902.428.6060 or 1.800.358.1995
F: 902.428.6181
E: investors@emera.com

Financial Analysts, Portfolio Managers and Institutional Investors

Director, Investor and External Relations
Judy A. Steele, FCA
T: 902.428.6999
F: 902.428.6665
E: judy.steele@emera.com

Share Listings

Toronto Stock Exchange (TSX)
Common Shares: EMA
Preferred Shares: NSI.PR.C, NSI.PR.D

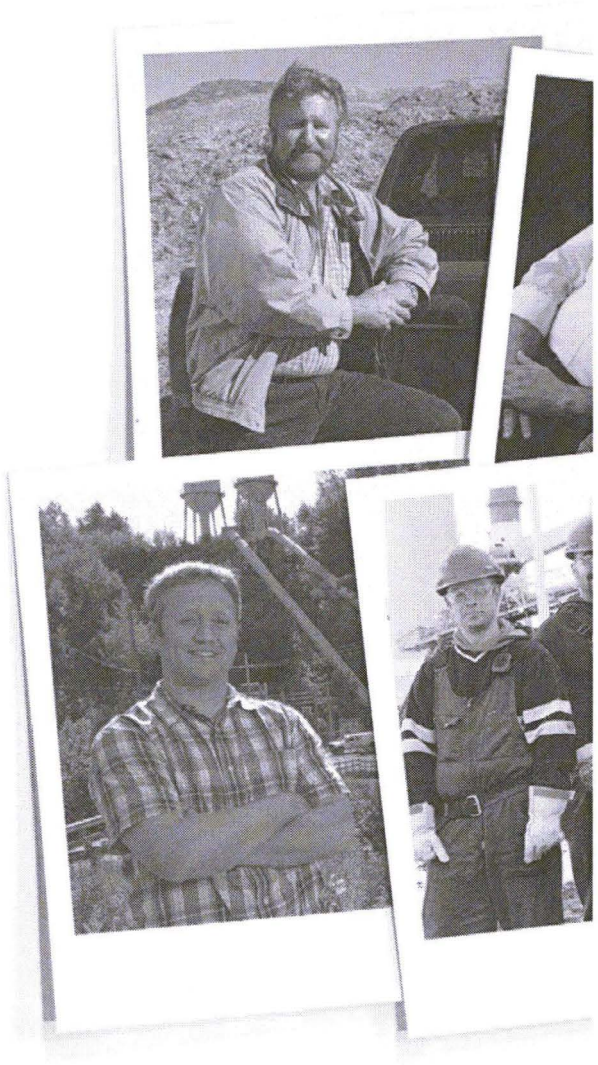
Shares Outstanding

Common Shares: 110,095,193 million
(as of December 31, 2005)

Dividends Paid in 2005

$0.89 per Common Share

Design and Coordination: Ove Design & Communications Ltd. www.ovedesign.com



Emera

www.emera.com

2005 progress report

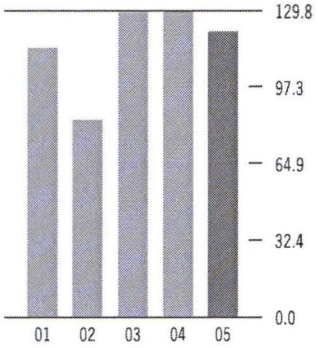


open dialogue

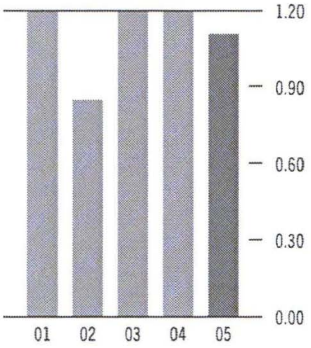
Emera

financial highlights

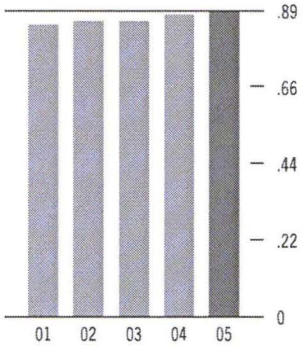
Earnings
(millions of dollars)



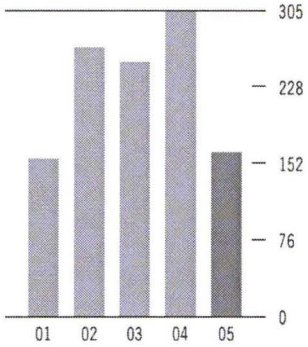
Earnings Per Share
(dollars)



Dividends
(dollars)



Net Cash Provided by Operating Activities
(millions of dollars)



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Our Management Team 2
President's Message 3
Open for Discussion 4
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Emera Inc. (EMA-TSX) is an energy and services company with $4.0 billion in assets. Electricity is Emera's core business. The company has two wholly-owned regulated electric utility subsidiaries, Nova Scotia Power Inc. and Bangor Hydro-Electric Company, which together serve 580,000 customers. Nova Scotia Power supplies over 95% of the electric generation, transmission and distribution in Nova Scotia. Bangor Hydro provides electricity transmission and distribution service to 110,000 customers in eastern Maine. It is a member of the New England Power Pool, and is interconnected with the other New England utilities to the south and with New Brunswick Power to the north. Emera also owns a 12.9% interest in the Maritimes & Northeast Pipeline; a 50% joint venture interest in the 600 MW Bear Swamp hydro-electric facility in Massachusetts; and Emera Energy Services, which manages energy assets on behalf of third parties and provides related services. Visit Emera on the web at **www.emera.com**.

NOVA SCOTIA POWER
An Emera Company

Bangor Hydro
ELECTRIC COMPANY

Emera

Emera Inc.
1894 Barrington Street
Barrington Tower
Halifax, Nova Scotia

Eyes open. Ears open. Minds open. We are seeing new ways, listening to new ideas, and thinking about how we do business. We are engaging our customers, partners and employees in an ongoing dialogue, to understand what's truly important to them. Thanks to this dialogue, we are changing how we do what we do. Working together today, we can meet the opportunity and challenge of tomorrow.

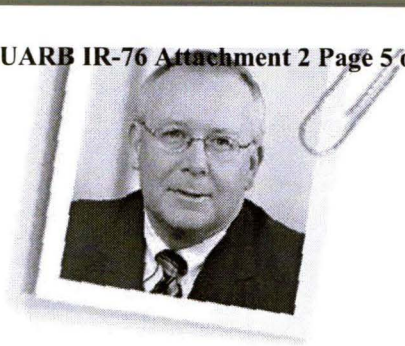
our management team



Top from left to right: Robert Hanf, *General Counsel*; **Sarah MacDonald**, *Vice President, Human Resources*; **Jim Connors**, Q.C., *Vice President, Regulatory Affairs*; **Wayne Crawley**, *Vice President, Corporate Strategy and Development*; **Ray Robinson**, *Vice President, Integrated Operations*; **Rick Smith**, *Corporate Secretary*; **Todd Sattler**, *Vice President, Energy Services*

Bottom from left to right: Nancy Tower, FCA, *Chief Financial Officer*; **Chris Huskilson**, *President and Chief Executive Officer*; **Ralph Tedesco**, *Chief Operating Officer, Nova Scotia Power Inc.*

a message from the president and chief executive officer



At the Emera family of companies, we have spent the last year listening to those who care about what we do and taking action to deliver the kind of changes people expect of us.

Whether it's Nova Scotia Power or Bangor Hydro, Emera's utilities have a unique responsibility to our partners in Nova Scotia and Maine – our customers, our communities, our regulators and our governments at local, provincial, state and federal levels.

Because of this responsibility, we need strong, dependable relationships with our partners to achieve progress, build sustainable growth and, most importantly, deliver better service to our customers.

What has resulted from these partnerships in 2005?

Our customers and other partners told us they expected to see more done to strengthen reliability, diversify our energy sources, reduce air emissions and improve communication.

We listened and took action, including signing a new agreement to build the largest wind farm in Atlantic Canada, installing clean air devices at our plants, and adopting a new customer communications plan targeting emergency preparedness and outages.

Do we have more to do? Absolutely. But it's clear that 2005 saw progress for our customers and investors through stronger partnerships.

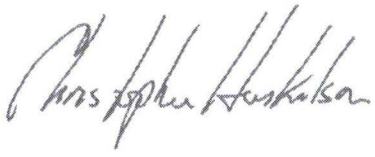
Now it's time to build on the foundation we have established together. Our building blocks for the future are based on the following:

1) A cleaner environment – more action to improve our air emissions, more clean energy production and more information to help our customers choose ways to conserve energy and be energy efficient.
2) Reliable electricity – major new investments in our system and stronger links with the region.
3) Connecting with customers – new measures to make it easier for our customers to do business with us.

These are the changes we are bringing about.

Building a relationship of trust with all our partners – customers, communities, regulators, governments, employees, and shareholders – is more than just reaching out. It's good business sense.

Yours truly,



Christopher G. Huskilson
President and Chief Executive Officer, Emera

people



"Nova Scotia Power really heard us... they played back what we told them was important to us during the first Customer Energy Forum... and they've already made great strides, adding more wind power to the system."

Terri Lloyd – *Customer Energy Forum 2004 & 2005*

open for discussion

Electricity is the spark of modern life. Essential to many of the comforts we enjoy, it is also critical to health and well-being, economic growth and development.

At Emera, we care about electricity. It is our business and our responsibility. We recognize that others care too. Customers, governments, regulators, industry, environmental leaders, and many other stakeholders bring important perspectives.

This past year has been about sharing points of view. We've been asking our stakeholders questions about what's important to them, and helping them to understand what that means inside our business, and on their bill.

Together, we have started an ongoing dialogue, exchanging ideas about service and reliability, the environment, conservation and renewable energy, our economy, and the way we interact with our customers.

The energy world is changing. Demand for energy is increasing. Prices, too, are on the rise. At the same time, citizens and their governments are looking for ways to reduce the environmental costs of energy.

We too must change. Working with our customers, partners and employees, we are finding new ways to meet those challenges. It starts with being open.

For information on energy conservation and efficiency, visit Nova Scotia Power at *www.nspower.ca* and follow the links from the home page.

For more about the Bangor Hydro Northeast Reliability Interconnect, visit *www.bhe.com* under Quick Links.



Randy Rawlston, Vice President, Manufacturing of Tandus Canada, on the factory floor in Truro, Nova Scotia. Tandus is a leading supplier of quality commercial and residential carpet to the global marketplace. The Truro plant recently underwent a major expansion, and worked closely with Nova Scotia Power to increase its capacity and find solutions to help manage energy costs.

Engaging Our Customers

Customer Energy Forums

In late 2004, Nova Scotia Power hosted its first ever ***Customer Energy Forum***, an innovative process to stimulate public dialogue on important energy issues.

Experts provided information on the trade-offs involved in future power generation options. Customers declared their priorities. They voted for more renewable energy, especially from wind, and sent a strong signal that NSPI needs to play a bigger role in energy conservation.

NSPI gained insights and immediately revised business plans to speed up the pace of renewable development, vaulting Nova Scotia into the front ranks among Canadian provinces.

In 2005, when it came to turning ideas about conservation into action, again, we went to customers for help.

Cleaner, Greener Choices – a discussion paper, was designed to provide as many customers as possible with the opportunity to tell us their ideas on the best ways to promote conservation and energy efficiency.

In October, over 100 customers from different social backgrounds, communities and businesses came together at Nova Scotia Power's second Customer Energy Forum. We explored issues concerning energy efficiency and conservation, and our customers offered insights into how we could help them deal with rising energy costs and better manage environmental concerns.

Feedback from the Discussion Paper, the Energy Forum and follow-up research helped Nova Scotia Power shape its proposed plan to increase its investment in conservation and energy efficiency five-fold to $5 million for 2006.

Terri Lloyd, of Sackville, Nova Scotia, shared her views on renewable energy and conservation in Nova Scotia Power's Customer Energy Forums. She is turning ideas into action, installing energy efficient compact fluorescent light bulbs in her home.



Getting Connected – The Northeast Reliability Interconnect

Reliability, stability and power quality... combined with reasonable rates, these elements create a robust electrical system. Bangor Hydro is committed to building a strong system to meet the needs of Maine today and to keep pace with the economic developments that must take place to assure a prosperous future.

We took a major stride toward that goal in 2005 as the Northeast Reliability Interconnect (NRI), a 345 kV electric transmission line between the Bangor area and New Brunswick, Canada, received the final two required environmental permits.

Building a major interconnect that travels 81 miles through two countries is a task that can't and shouldn't be taken on alone. Many stakeholders had an interest. At Bangor Hydro we wanted to fully understand any concerns and find ways to build consensus on the best strategies for environmental protection.

Interested groups and individuals throughout Maine worked with Bangor Hydro to pioneer a process of criteria development and decision making to select the route for the NRI.

The open input and decision making process led to the selection of a route that meets local needs and acts in the best interests of the environment. The project is soon moving into the first stages of construction.

Listening Closely and Taking Action

Customers tell us they want better communication. They want us to be easier to do business with, and they need more detailed and timely information from Emera, especially when electricity service is disrupted by weather or other events. We listened, and made improvements to customer communications in 2005.

Changes to Nova Scotia Power's call centre operations have increased access to information ten-fold. Based on the advice of our customers and external experts on how to improve communication before, during and after major storms, we also launched a comprehensive outage communication plan featuring:

- Emergency preparedness television and radio advertisements – often in partnership with the Nova Scotia Emergency Measures Organization – to reinforce emergency preparedness tips and encourage planning;
- A brochure sent to every household and business in Nova Scotia to highlight emergency preparedness practices; and
- A critical customer communication brochure for those at particular medical risk during a power outage.

We have more to do. Together with our customers, partners, employees and communities, we are engaged in an ongoing dialogue that will continue to provide benefit.

Building Better Relationships

Understanding the issues facing our communities involves bringing the right people together, asking the right questions and listening to the answers. It means getting closer to communities by building better relationships between the people who understand their needs and the people who can help deliver solutions.

Emera and its family of companies are taking a more proactive approach to the way we work with local government partners who speak for, and act on behalf of, their constituents. By strengthening face-to-face relationships with local government and emergency services providers, and by providing continuous, two-way lines of communications, we are learning more and more about community issues and are able to provide ongoing community support.

In the Halifax Regional Municipality, for instance, we are working closely with officials to understand the issues facing this fast growing area. For example, we are working together to develop options for energy-efficient street and traffic lights.

Engaging Our Employees

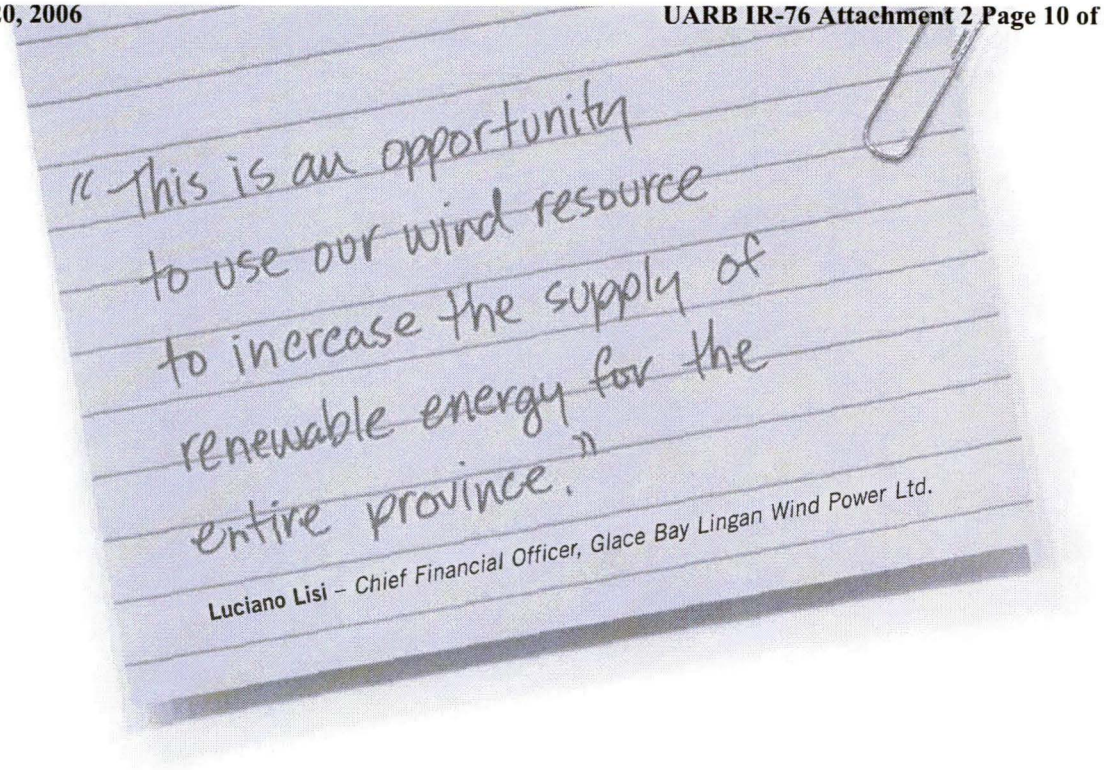
Opening the Floor at Bangor Hydro

Employee surveys at Bangor Hydro showed that employees wanted more opportunities for face-to-face communications with executives and senior management. They wanted to hear directly about corporate goals, objectives and plans, and to have more opportunities to ask questions and get answers from company leaders.

Let's Talk, a company-wide employee town hall, was introduced. First developed at Nova Scotia Power, Let's Talk uses telephone and web technology to enable management and employees across the company to have regular conversations about the business, and to share thoughts and ideas.

Louis Digout, Chief Administrative Officer of the Municipality of Richmond County, Cape Breton, and Richard Cook and Ken Paruch of Nova Scotia Power regularly meet to find ways to provide ongoing support for the community and resolve local issues.





open to new ideas

Improving our environmental performance is critically important to our customers and our partners. For Emera, that means three things:

- Incorporating cleaner, greener energy sources into Nova Scotia's provincial system;
- Reducing NSPI's air emissions to meet Nova Scotia's energy strategy; and
- Collectively using energy more efficiently.

To reach these goals we must diversify the ways we make electricity. We must communicate, share information and work with customers and partners to find new opportunities. We must explore new technologies and new frontiers. And we are. We are open to new ideas, and making measured progress in reaching our goals for a cleaner environment for us all.

To learn more about Natural Resources Canada's Canadian Renewable Energy Network, see *www.canren.gc.ca*

For more information on wind powered energy, see the Canadian Wind Energy Association at *www.canwea.ca*



Luciano Lisi, Chief Financial Officer, Glace Bay Lingan Wind Power, stands at the base of one of nine wind turbines being built near NSPI's Lingan generating station. The site, expected to be fully operational in fall of 2007, will produce enough energy to supply over 4,000 homes.

Conservation and Energy Efficiency

Renewable Energy... Why Wind?

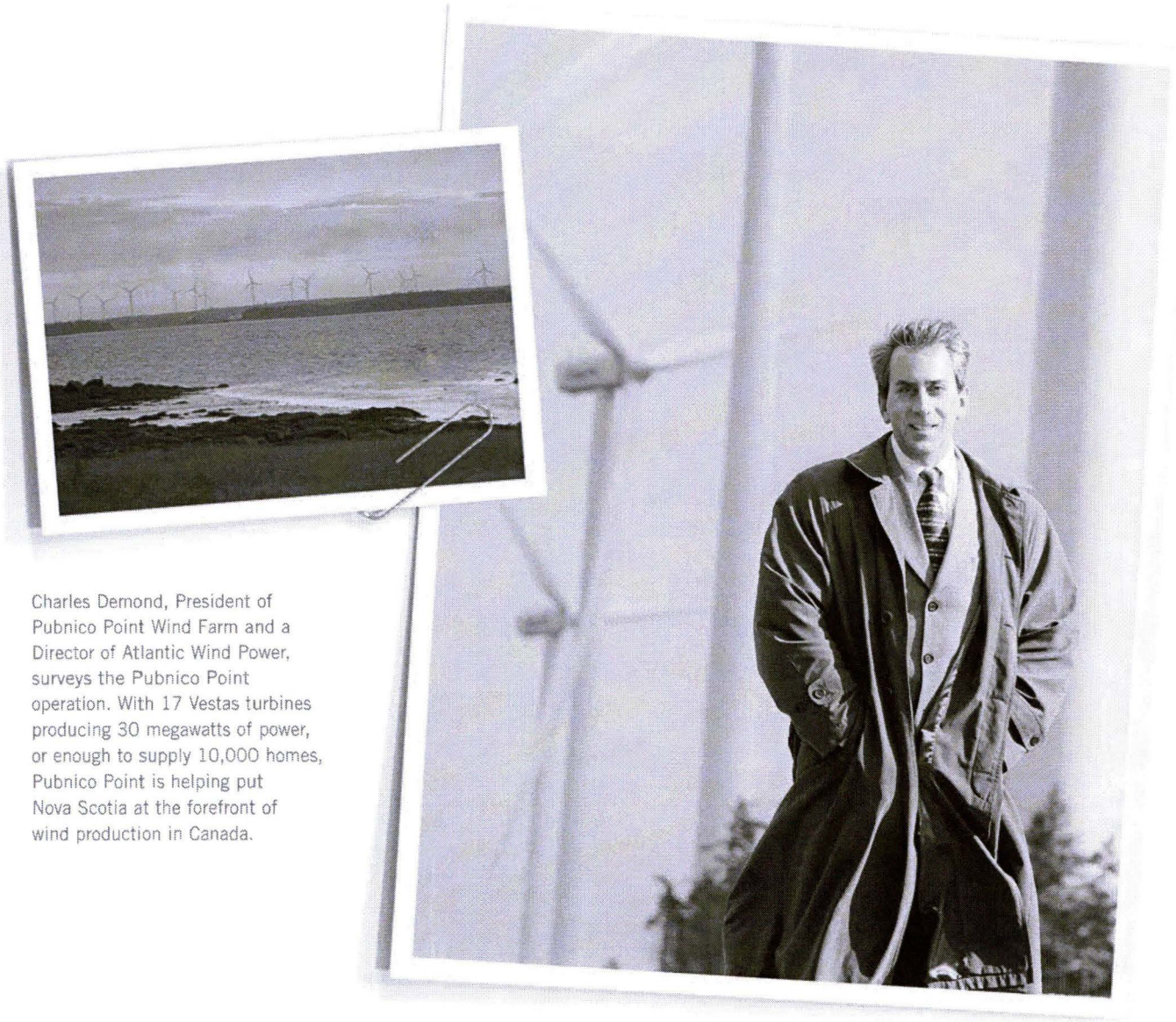
Our customers have expressed strong support for electricity produced from renewable wind energy.

Atlantic Canada, with its coastal geography, has strong winds and holds great potential for wind development.

In 2005, we accelerated the pace of wind energy development. With Glace Bay Lingan Wind Power, we contracted for power from a 12-megawatt wind farm consisting of nine turbines situated next to Nova Scotia Power's Lingan generating station. It is expected to be fully operational by the fall of 2007, and will produce about 42 gigawatt hours of energy annually, or enough to supply over 4,000 homes.

Under another agreement, Nova Scotia Power will purchase renewable energy from the largest wind farm in Atlantic Canada. Amherst Wind Energy Project – a joint venture between a New Brunswick company and EHN, one of the largest developers of wind energy in the world – will add another 31 megawatts, or enough energy to supply 10,000 homes, by 2007.

Combined with the 30 megawatts at Pubnico Point and successful solicitations for power from smaller energy producers across the province, NSPI will exceed provincially set targets for renewable power generation. With contracts in place for 100 megawatts of wind energy, Nova Scotia is among the front ranks of the industry in Canada.



Charles Demond, President of Pubnico Point Wind Farm and a Director of Atlantic Wind Power, surveys the Pubnico Point operation. With 17 Vestas turbines producing 30 megawatts of power, or enough to supply 10,000 homes, Pubnico Point is helping put Nova Scotia at the forefront of wind production in Canada.

More Renewable Energy Choices for Nova Scotia

Nova Scotians can expect to see more wind turbines and solar panels attached to farms, businesses and homes in the coming year. In fall 2005, NSPI expanded its net metering program. This innovative approach to energy production for individual consumption provides customers with the opportunity to install renewable electricity systems of up to 100 kilowatts, and connect those systems to the provincial electricity grid. Net metering is a creative way for our customers to meet their own energy needs from renewable sources and still have the security of being able to draw electricity from the provincial system when required.

Reducing Emissions

Environmental Investments at Tufts Cove and Lingan

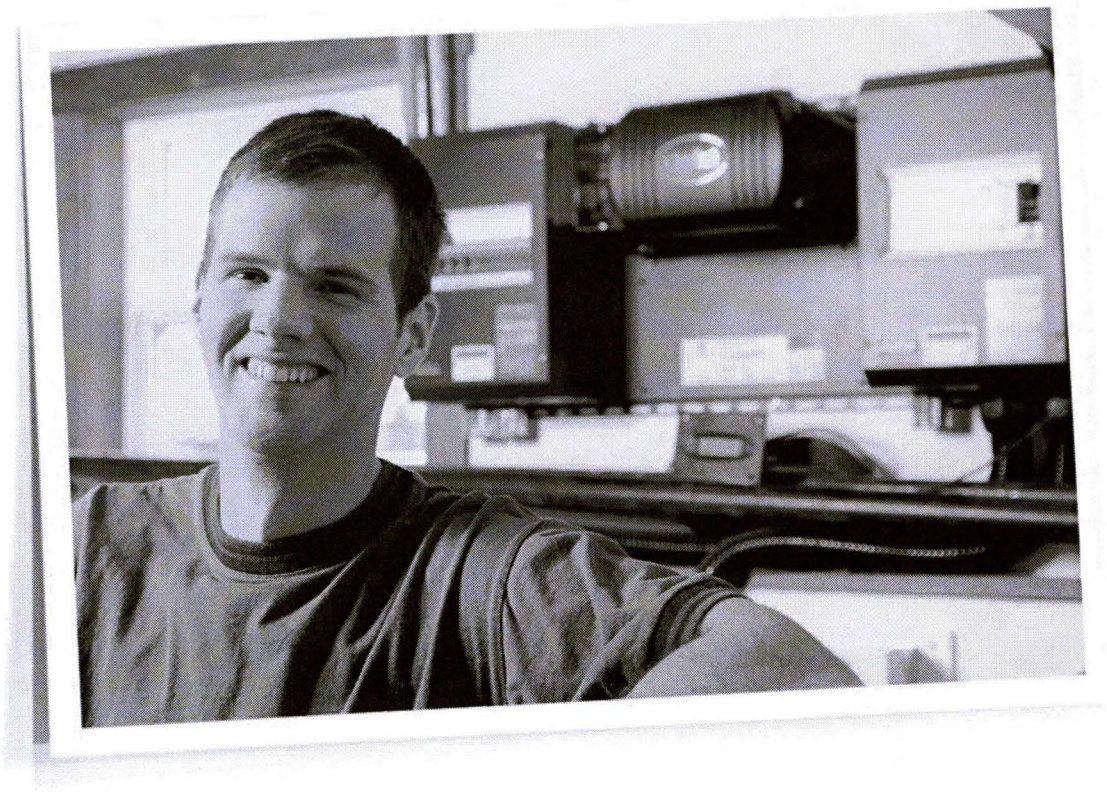
Cleaner air. It is an expectation our customers have, and one that Emera and our employees share.

Using cleaner fuels to make electricity is a key part of NSPI's strategy to reduce emissions. Meeting new targets also requires using innovative technologies.

In 2005, NSPI completed installation of pollution control equipment at its oil-fired plant at Tufts Cove in Dartmouth. This $22 million investment in electrostatic precipitator upgrades significantly reduced emissions.

In November, we announced plans to invest an additional $172 million to install wet flue gas desulphurization units or "scrubbers" to reduce emissions at the Lingan generating station. The scrubbers will capture more than 95 percent of the sulphur dioxide released by the burning of coal at Lingan Units 3 and 4.

Customers like Mark McCormick have more choice when it comes to how they power their homes. Mark, a participant in Nova Scotia Power's Net Metering program, produces his own renewable energy and connects into the provincial power grid when needed.



Where We Are, and Where We Are Going

Emera is committed to operating in a manner that is respectful and protective of the environment, and in full compliance with regulatory and legal requirements. In our business, air emissions associated with generating electricity are the key environmental issue. The following commentary provides customers and stakeholders with information about our performance to date for these emissions, and our plans to reduce them in future.

Sulphur Dioxide

Sulphur dioxide (SO_2) contributes to acid rain and smog. It results from the combustion of sulphur found naturally in most fossil fuels. Since 1995, Nova Scotia Power's SO_2 emissions have been capped at 145,000 tonnes.

The Nova Scotia Energy Strategy requires a 25% reduction of SO_2 emissions in the province beginning in 2005. NSPI succeeded in meeting the new, lower cap primarily through increased use of lower sulphur fuels.

A further 25% reduction in the SO_2 emissions cap for NSPI will come into effect in 2010. NSPI has proposed to invest $172 million in environmental technology at its Lingan generating station to meet these new requirements.

Oxides of Nitrogen

Oxides of nitrogen (NOx) comprise several different combinations of oxygen and nitrogen, both found in the air. NOx contributes to acid rain and smog, is a key component in the development of ground level ozone, and is formed when fossil fuels are burned at high temperatures.

The Nova Scotia Energy Strategy requires a 20% reduction in NOx emissions from 2000 levels, or a cap of 21,360 tonnes by 2009. NSPI plans to meet the new cap by installing low-NOx combustion firing systems at several facilities between now and 2008. In 2006, NSPI is seeking regulatory approval to invest $5 million to begin equipping the Lingan generating station with this system.

Mercury

Mercury emissions from power generation result from naturally occurring mercury found in most fossil fuels.

NSPI's mercury emissions have been steadily decreasing since 2000 through the use of lower mercury fuels. The first mercury limit came into effect in 2005, as part of the Nova Scotia Energy Strategy. It caps NSPI's annual mercury emissions at 168 kg.

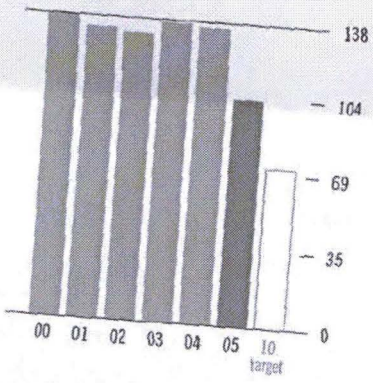
Discussions to further reduce mercury emission caps by 2010 are taking place at the national level. NSPI is actively evaluating other technological and operational options for significantly reducing its mercury output to meet expected lower limits.

Carbon Dioxide

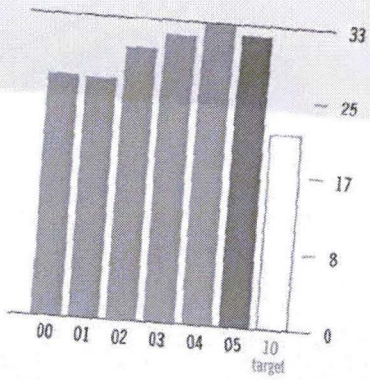
Of the six main greenhouse gases (GHG) that are included in the Kyoto Protocol, carbon dioxide is seen as the largest contributor to climate change. As a signatory to the Kyoto Protocol, Canada has set an ambitious target of reducing national emissions to a level 6% lower than they were in 1990. This target represents an almost 30% reduction of emissions below what they are otherwise projected to be in 2008.

Provincial carbon dioxide emission caps are not yet in place. However, we do know that demand for electricity continues to increase and that there are no simple solutions to achieve the emission reductions of the magnitude our country must meet to fulfill our commitment to Kyoto. As we confront these challenges, NSPI will continue to use a multi-pronged approach of more low emissions generation, judicious fuel selection, energy efficiency and conservation initiatives, increased use of renewables and, if necessary, the use of economic instruments that encourage other parties to lower greenhouse gas emissions in our region.

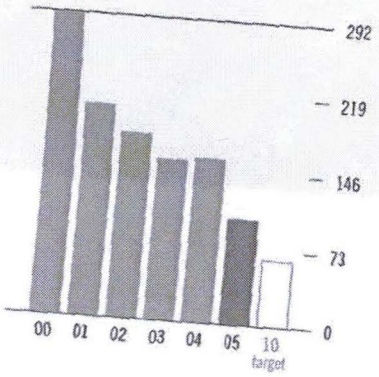
Sulphur Dioxide (SO_2) Emissions
(thousands of tonnes)



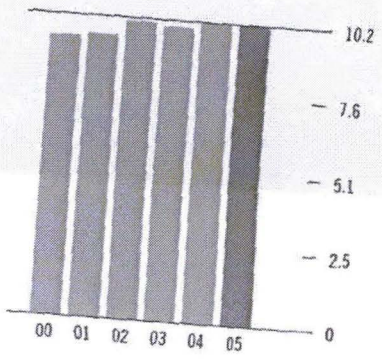
Oxides of Nitrogen (NOx) Emissions
(thousands of tonnes)

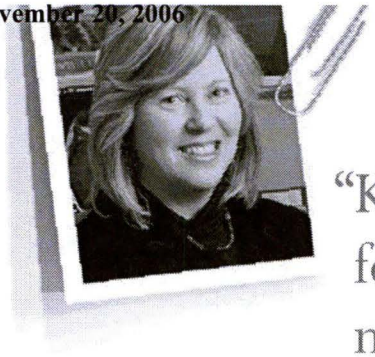


Mercury (Hg) Emissions
(kilograms)



Carbon Dioxide (CO_2) Emissions
(megatonnes)





"Keeping people close to home for diagnostic services is not only more convenient, it's healthier for our patients. With Emera's support, we've been able to provide an important health service to the community."

Pamela Ellsworth – *Executive Director, Cape Breton Regional Hospital*

opening doors

Listening to the concerns of our customers and partners is about more than energy. It's about understanding what's important to them as a community. Along with being active members of the places where we live and work, comes responsibility. Through our corporate giving initiatives, we are able to reach out, helping to reduce financial burdens, improve access to health care, and help customers better manage energy costs.

Our employees believe in supporting community initiatives. Through the Employee Charitable Fund, employees at Emera have raised $2.5 million for charities in our Maritime neighbourhoods and beyond.

To learn more about the organizations presented in this report, visit them online:
www.clean.ns.ca
www.cbdha.nshealth.ca/partnersincare.html
maritime.salvationarmy.ca
www.cdha.nshealth.ca/QE2foundation/workingmiracles
www.unitedwayem.org



The Energy Team at École Burton Ettinger Elementary in Halifax takes energy conservation to heart. As part of the Towards a Brighter Future program, teams like the one at Burton Ettinger promote small ideas that make big reductions in energy use. **From left to right: (back row)** Brianna McPhee, Panagiota Eleferos, Ainslee Isnor; **(front row)** Ariel Gay, Kadi Pestana-Marchand, Ashton Isnor, Rouxan Arandy.

Towards a Brighter Future

Towards a Brighter Future is a student-driven, educational opportunity, bringing simple, cost-effective, energy-efficient practices to schools. Created by Clean Nova Scotia in partnership with Emera and Nova Scotia Power, Towards a Brighter Future provides the opportunity for students, teachers, principals and custodians to learn about energy conservation and climate change.

Through the program, students get the information and tools they need to develop initiatives aimed at reducing energy consumption in schools, and help reduce the greenhouse gas emissions linked to climate change.

In its second year, the number of schools participating in this program in the Halifax Regional Municipality has increased from six to ten. In addition to providing funding assistance, NSPI is working with our employees to supply key information on energy efficient practices that students and staff can incorporate into their schools.

Quality Health Care, Close to Home

Many Cape Bretoners have traditionally made the long trip to Halifax for many forms of medical treatment. In response, NSPI employees from power production and customer operations join together each year to gather pledges and raise funds for the Rotary Whaler Boat Race in support of the Cape Breton Regional Hospital Foundation.

All money raised goes toward the purchase of new and much needed medical equipment.





Nova Scotia Power employees support the Cape Breton Regional Hospital Foundation. **From left to right:** Peggy MacLellan, NSPI; Asta King, NSPI; Ken Paruch, NSPI; Barb Hynes, NSPI; Pam Ellsworth, Executive Director, Cape Breton Regional Hospital Foundation; Dave Muise, President, Sydney Sunrise Rotary Club; Shawn Lively, NSPI.

Below: The Cape Breton Regional Hospital Foundation funds important medical equipment purchases from donations raised in part by Nova Scotia Power employees through the Rotary Whaler Boat Race.

Making a Difference

Care and Comfort for People in Need

Many people, at one time or another, struggle to cover the cost of household essentials. Keeping Nova Scotians warm – no matter what their circumstances – is something Emera, Nova Scotia Power and our employees take to heart. Families facing an emergency financial situation in winter can turn to the Good Neighbour Energy Fund for help with the cost of all forms of home heating, including firewood, coal, fuel oil, propane and electricity.

The Good Neighbour Energy Fund is made possible through donations from employees, customers and the company. Administered by the Salvation Army, in 2005 these donations helped more than 400 families.

Growing concern from our customers and partners about the rising cost of home heating in 2005 led Emera to increase its financial support to $250,000. With this increase, the Salvation Army estimates it will be able to help 1,000 families in 2006.

Fighting an Epidemic

Almost 50,000 Nova Scotians suffer from diabetes, a chronic and debilitating disease that can cause adult blindness, heart disease, kidney failure and stroke. The impact on our communities and health care system is significant and growing.

The Diabetes Primary Care Initiative is an innovative program that allows hospital specialists to work with family doctors and their patients in communities throughout the province. The goal is to help patients improve their management of the disease and provide individuals at high risk for developing diabetes with the tools they need to prevent it.

Emera and Nova Scotia Power continued our support of this important health initiative in 2005. We have pledged $500,000 over three years to the Diabetes Primary Care Initiative through the QE II Health Science Centre Foundation Working Miracles Capital Campaign.

The Spirit of Giving

In 2005, Bangor Hydro employees surpassed their charitable giving goal, raising almost $55,000 for the United Way of Eastern Maine. Participation in the campaign also increased over the previous year by 40 percent. A portion of the amount raised will go directly to the United Way of America to assist victims of Hurricane Katrina. The remainder will stay in Eastern Maine and help address local issues.


The Chronicle Herald

...isey, centre, and daughter Haley Cockrill and son Daniel Cockrill in their now-warm Dartmo...
...e on Thursday. (TED PRITCHA...

Help filling the tank

Fund available to assist with home heating

By PATRICIA LAUNT

Karla Morrisey ran out of heating oil Monday and didn't have the money to fill her tank.

"I'm a single mother and I got behind before Christmas and have had a hard time catching up," said the Dartmouth resident. "I wasn't sure what going to do."

"If people are low, I try to get them the assistance as soon as possible," said Karl Lange, the program's co-ordinator. He said people have told him they sometimes resort to using kitchen stove to house.

applications.

Nova Scotia Power funds the progra... its dona...

Sometimes people need a helping hand. With Emera's support, Karl Lange, Administrator of the Good Neighbour Energy Assistance Program at the Salvation Army, is there for those who need a little extra help heating their homes.

finance and operations

SUMMARY CONSOLIDATED STATEMENTS OF EARNINGS

Year Ended December 31 millions of dollars (except earnings per common share)	2005	2004
Revenue		
Electric	$ 1,125.9	$ 1,095.7
Other	42.1	38.5
	1,168.0	1,134.2
Fuel for generation and purchased power	432.0	350.0
Operating, maintenance and general	248.2	245.2
Provincial, state, and municipal taxes	43.9	46.3
Depreciation	136.1	131.2
Regulatory amortization	19.4	26.1
Interest	117.4	126.8
Amortization of defeasance costs	13.2	15.1
Other	(18.0)	(12.4)
Earnings before income taxes and non-controlling interest	175.8	205.9
Income taxes	41.3	62.7
Non-controlling interest	13.3	13.4
Net earnings applicable to common shares	$ 121.2	$ 129.8
Earnings per common share – basic	$ 1.11	$ 1.20
Earnings per common share – diluted	$ 1.09	$ 1.16

OPERATING UNIT CONTRIBUTIONS

Year Ended December 31 millions of dollars	2005	2004
Nova Scotia Power	$ 91.2	$ 107.3
Bangor Hydro-Electric	14.9	18.5
Other	15.1	4.0
Consolidated net earnings	$ 121.2	$ 129.8

For Emera's 2005 Financial Report
and Management Information Circular, go to
www.emera.com/investors/annual_report.shtml

Safety First

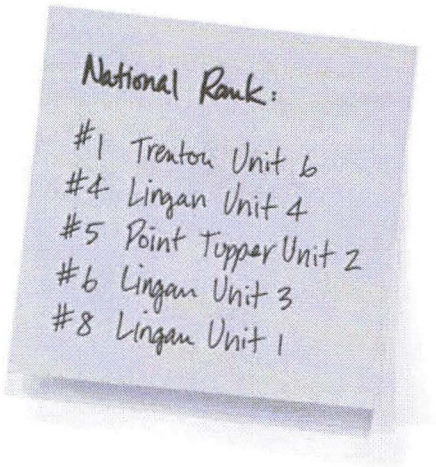
Creating a safe and effective environment that allows workers to take charge of their own health and well-being is important at Bangor Hydro (BHE) – so important, that we wanted to put our safety management systems to the test.

In June of 2004, BHE applied for membership in the Voluntary Protection Program (VPP) administered by the US Department of Labor's Occupational Safety and Health Administration (OSHA). Approval into VPP is OSHA's official recognition of the outstanding efforts of employers and employees who have achieved exemplary occupational safety and health within their organization.

Following a two-year application process and an in-depth, on-site audit of Bangor Hydro's safety management systems, protective equipment and training programs, BHE became an OSHA VPP Company in April 2005 – a distinction shared by only one other T&D company east of Indiana.

In addition, OSHA listed Bangor Hydro's Accident/Incident Review Process as an Industry Best Practice. The process provides a system for employees to report potential accidents in a safe and welcoming environment, and uses these reports to foster professional development and open lines of communication.

Nova Scotia Power also demonstrated strong safety performance in 2005, and was rewarded with best performance in the All Injury Frequency category and third best in the Disabling Injury/Illness Rate category in Canada, as ranked by the Canadian Electricity Association (CEA). NSPI was ranked against 16 reporting utilities from across Canada.



Trenton Unit 6 Receives Top Honours

Nova Scotia Power's outstanding operational performance continued in 2005. For the second year in a row, an NSPI generating unit was recognized as the top performing plant in Canada. The Canadian Electricity Association (CEA) named Trenton Unit 6 first in the country for its capability to operate at capacity for more than 98 percent of the total hours in a year. NSPI's Point Tupper received this honour last year.

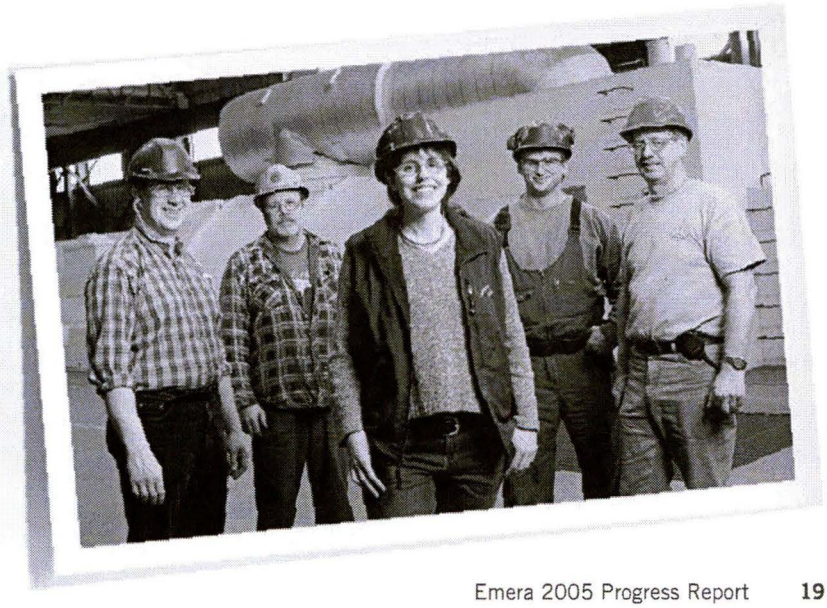
In addition to earning top honours for Trenton Unit 6, four other Nova Scotia Power units were ranked in the top ten among close to 90 thermal plants in the country.

Bear Swamp Acquisition Completed

In 2005, in partnership with Brookfield Power, Emera completed its acquisition of Bear Swamp, a 600 megawatt pumped storage hydro-electric generating facility in northern Massachusetts.

Bear Swamp is located on the Deerfield River. The facility sells energy, capacity and ancillary products to the New England Power Pool. Also included in the acquisition is the nearby 10 megawatt Fife Brook run-of-river hydro facility.

The acquisition complements our skill set and risk profile, increases our renewable energy portfolio and continues to build our presence in the northeastern United States.



Marie Thomas, Plant Manager, and her employees led Nova Scotia Power's Trenton generating station to top performance honours as recognized by the Canadian Electricity Association. **From left to right:** Sheldon Dickie, Brian Noonan, Marie Thomas, Rick Mosher and Hartley MacDonald.

directors and company information

BOARD OF DIRECTORS

Derek Oland (Chair)
Chairman and Chief Executive Officer
Moosehead Breweries Limited
New River Beach, New Brunswick

Christopher G. Huskilson
President and Chief Executive Officer
Emera Inc. and Nova Scotia Power Inc.
Wellington, Nova Scotia

Wesley Armour
(appointed November 2005)
President and
Chief Executive Officer
Armour Transportation Systems
Moncton, New Brunswick

Robert S. Briggs
Company Director
Former President and
Chief Executive Officer
Bangor Hydro-Electric Company
Carrabassett Valley, Maine

George A. Caines, Q.C.
Partner
Stewart McKelvey Stirling Scales
Halifax, Nova Scotia

Dr. Gail Cook-Bennett
Chair
Canada Pension Plan
Investment Board
Toronto, Ontario

R. Irene d'Entremont, C.M.
President
M.I.T. Electronics and
ITG Information Management Inc.
Yarmouth, Nova Scotia

Allan L. Edgeworth
(appointed November 2005)
President
ALE Energy Inc.
Calgary, Alberta

M. Edward MacNeil
(retiring May 2006)
Company Director
Former International Representative
International Brotherhood of
Electrical Workers
Sydney, Nova Scotia

John T. McLennan
Company Director
Former Vice-Chair and
Chief Executive Officer
Allstream Inc.
Mahone Bay, Nova Scotia

Dr. Elizabeth Parr-Johnston
President
Parr Johnston Economic
and Policy Consultants
Chester Basin, Nova Scotia

Kenneth C. Rowe
(retiring May 2006)
Chairman and Chief Executive Officer
IMP Group International Inc.
Halifax, Nova Scotia

Paul D. Sobey
President and Chief Executive Officer
Empire Company Limited
Kingshead, Pictou County,
Nova Scotia

CORPORATE OFFICE

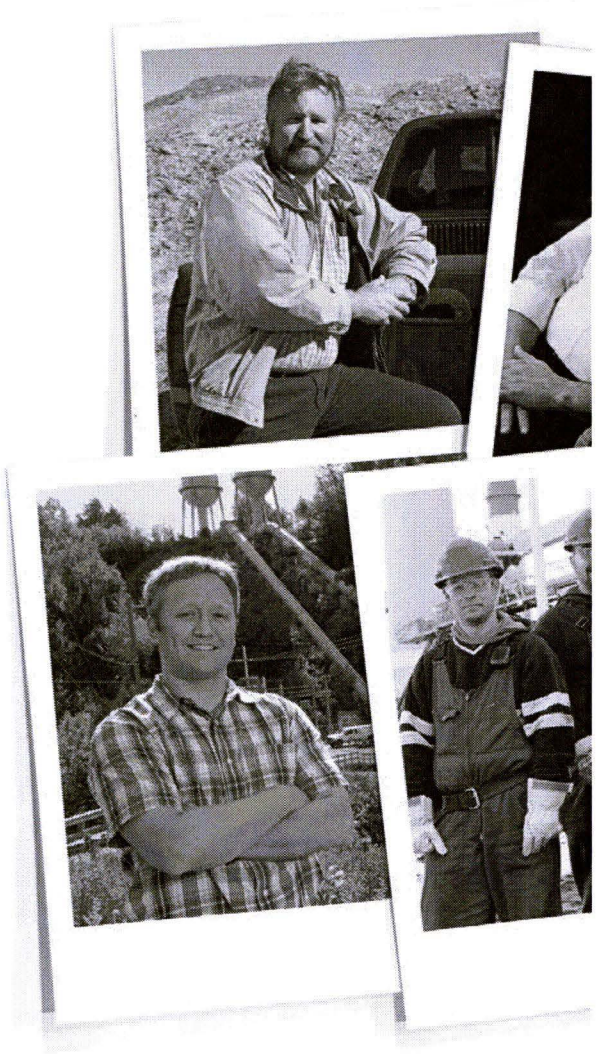
Emera Inc.
1894 Barrington Street
Barrington Tower
Halifax, Nova Scotia B3J 2A8
T: 902.450.0507 or
1.888.450.0507

SHARE LISTINGS

Toronto Stock Exchange (TSX)
Common Shares: EMA
Preferred Shares: NSI.PR.C,
NSI.PR.D



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