**Requirement:**

**Latest regulated annual reports of NSPI and Emera.**

**Submission:**

Please refer to Attachment 1 for NSPI's 2010 Management's Discussion & Analysis and Attachment 2 for NSPI's 2010 Financial Statements.

Please refer to Attachment 3 for Emera's 2010 Management's Discussion & Analysis and Attachment 4 for the Emera's 2010 Financial Statements.

Please refer to Partially Confidential Attachment 5 for the 2010 NSPI Regulated Financial Statements.

# Management's Discussion & Analysis

As at February 9, 2011

Management's Discussion and Analysis ("MD&A") provides a review of the results of operations of Nova Scotia Power Inc. during the fourth quarter of 2010 relative to 2009, and the full year 2010 relative to 2009 and to 2008; and its financial position at December 31, 2010 relative to 2009. 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 Nova Scotia Power Inc. annual audited financial statements and supporting notes. Nova Scotia Power Inc. follows Canadian Generally Accepted Accounting Principles ("CGAAP") including the application of rate-regulated accounting. Nova Scotia Power Inc.'s accounting policies are subject to examination and approval by the Nova Scotia Utility and Review Board ("UARB"). The accounting policies of Nova Scotia Power Inc. may differ from CGAAP for non-regulated companies.

Throughout this discussion, "Nova Scotia Power", "NSPI" and "Company" refer to Nova Scotia Power Inc.

All amounts are in Canadian dollars ("CAD").

Additional information related to Nova Scotia Power Inc., including the Company's Annual Information Form, can be found on SEDAR at www.sedar.com and on EDGAR at www.sec.gov.

## Forward Looking Information

This MD&A contains forward-looking information and forward-looking statements which reflect the current view with respect to the Company's objectives, plans, financial and operating performance, business prospects and opportunities. Certain factors that may affect future operations and financial performance are discussed, including information in the Outlook section of the MD&A. Wherever used, the words "may", "will", "intend", "estimate", "plan", "believe", "anticipate", "expect", "project" and similar expressions are intended to identify such forward-looking statements and should not be read as guarantees of future events, performance or results, and will not necessarily be accurate indications of whether, or the times at which, such events, performance or results will be achieved.

Although NSPI believes such statements are based on reasonable assumptions, such statements are subject to certain risks, uncertainties and assumptions pertaining to, but not limited to, operating performance, regulatory requirements, weather, general economic conditions, commodity prices, interest rates and foreign exchange rates. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may vary significantly from those expected. NSPI disclaims any intention or obligation to update or revise any forward-looking information or forward-looking statements, whether as a result of new information, future events or otherwise, except as required under applicable securities laws.

## Structure of MD&A

This MD&A begins with an Introduction and Strategic Overview, followed by a financial review of the statements of earnings, balance sheets and cash flow highlights; then continues with a discussion on Outlook, Liquidity and Capital Resources, Pension Funding, Off-Balance Sheet Arrangements, Transactions with Related Parties, Risk Management and Financial Instruments, Disclosure and Internal Controls, Significant Accounting Policies and Critical Accounting Estimates, Changes in Accounting Policies and Summary of Quarterly Results.

# INTRODUCTION AND STRATEGIC OVERVIEW

NSPI, created through the privatization in 1992 of the crown corporation Nova Scotia Power Corporation, is a fully-integrated regulated electric utility and the primary electricity supplier in Nova Scotia. NSPI has $4.0 billion of assets and provides electricity generation, transmission and distribution services to approximately 489,000 customers. The Company owns 2,368 megawatt ("MW") of generating capacity, of which approximately 53% is coal-fired; natural gas and/or oil comprise another 27% of capacity; and hydro and wind production total 20%. In addition, NSPI has contracts to purchase renewable energy from independent power producers ("IPP"). These IPPs own 186 MW, increasing to 226 MW in 2011, of wind and biomass fueled generation capacity. A further 85 MW of renewable capacity is being built directly or purchased under long-term contracts by NSPI and is expected to be in service by the end of 2012. NSPI also owns approximately 5,000 kilometers of transmission facilities and 29,000 kilometers of distribution facilities. The Company has a workforce of approximately 1,900 people.

NSPI is a public utility as defined in the Public Utilities Act (Nova Scotia) ("Act") 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 a general annual rate review process, but rather participates in hearings from time to time at the Company's or the UARB's request.

NSPI is regulated under a cost-of-service model, with rates set to recover prudently incurred costs of providing electricity service to customers, and provide an appropriate return to investors. NSPI's regulated return on equity ("ROE") range for 2010 was 9.1% to 9.6%, on an actual regulated common equity component of up to 40% of average regulated capitalization.

In 2009, the UARB approved a fuel adjustment mechanism ("FAM") allowing NSPI to recover fluctuating fuel expenses from customers through annual fuel rate adjustments. In 2010, revenue associated with fuel comprised approximately 45% of total revenue. As the FAM mitigates the Company's net earnings' exposure to fuel volatility, it facilitates longer planning cycles. This enables the Company to increase its focus on the impact that non-fuel components of the business have on net earnings, while retaining focus on managing fuel costs for customers. In 2010, tax benefits associated with renewable investments reduced costs and, thus NSPI did not seek a general rate adjustment with the UARB.

Although the market in Nova Scotia is otherwise mature, the transformation of energy supply to lower emission sources has created the opportunity for organic growth within NSPI, and the Company expects earnings growth of 3% to 5% annually over the next five years as new investments are made in renewable generation and transmission.

## Non-GAAP Measure

"Electric margin", defined as "Electric revenue" less "Fuel for generation and purchased power", net of the "Fuel adjustment" and fuel related foreign exchange losses or gains, is a non-GAAP financial measure used by NSPI. This measure is disclosed as management believes it provides further information regarding the impact of the FAM on NSPI's operations. Electric margin is discussed further in the Review of 2010 section.

# Developments

### Deferral of Certain Tax Benefits Related to Renewable Energy Projects for Fiscal 2010

On December 23, 2010, the UARB granted NSPI approval to defer certain tax benefits related to renewable energy projects arising in 2010. Accordingly, effective December 31, 2010, NSPI recognized a deferral of $14.5 million through an increase in regulatory amortization. The UARB will convene a proceeding in 2011 to discuss how this deferral will be applied.

### UARB Decision on Fuel Adjustment Mechanism

On December 8, 2010, the UARB approved NSPI's setting of the 2011 base cost of fuel and its recovery of all unrecovered fuel related costs as submitted in the Company's November 2010 filing. The recovery of these costs will begin January 1, 2011. The UARB approved the recovery of these costs by NSPI over three years, with 50% of the rate increase to be recovered in 2011, 30% in 2012 and 20% in 2013. The decision results in an average rate increase of approximately 4.5% for customers in 2011. Pursuant to the FAM Plan of Administration, NSPI is entitled to earn a return on the unrecovered balance of fuel related costs.

### Renewable Energy Projects

#### Port Hawkesbury Biomass Project

On October 14, 2010, the UARB approved NSPI's $208.6 million capital work order request for the Port Hawkesbury biomass project. NSPI will develop this 60-MW co-generating facility at the NewPage Port Hawkesbury Corporation ("NewPage") site. NSPI will own the facility while NewPage will construct and operate the plant as well as supply the fuel. This project is expected to be commissioned in 2013 and supply approximately 3% of the province of Nova Scotia's total electricity needs.

#### Point Tupper Wind Development Project

On June 14, 2010, the UARB approved NSPI's $27.8 million capital work order for the Point Tupper Wind Development Project. The Project went into service in August 2010.

#### Digby Wind Project

On May 28, 2010, NSPI purchased $30.1 million in wind generation assets under development related to the Digby Wind Project from a subsidiary of Emera. NSPI has requested UARB approval of this project through the submission of a capital work order. The Project was completed and went into service in December 2010 at a total cost of approximately $80.0 million. The UARB hearing took place in January 2011, and a decision is pending.

### Nova Scotia Provincial Environmental Regulations

#### Renewable Electricity Plan

On October 15, 2010, the Nova Scotia Government enacted regulations under the Electricity Act related to the Province's Renewable Electricity Plan. These regulations establish the requirement that 25% of electricity be supplied from renewable sources by 2015. These regulations build on the previously legislated requirements for 2011 and 2013 by adding an additional 5% for 2015. Recent amendments to the Electricity Act, and the new regulations, provide for the appointment, by spring 2011, of a new, independent renewable electricity administrator to conduct the procurement of at least 300 gigawatt hours ("GWh") of energy from IPPs to meet the 2015 standard. NSPI is also provided the opportunity to develop 300 GWh of renewable energy.

#### Mercury Emissions

On July 22, 2010, the Province of Nova Scotia announced, for the years 2010 through 2013, allowable mercury emissions would be increased from the previous cap of 65 kg per year. NSPI was requested to develop a plan of staged mercury emission reductions, for its generation facilities, for the period of 2010 to 2020 and meet an annual cap of 35 kg beginning in 2020.

**Canadian Federal Environmental Regulations**

**Greenhouse Gas**
On June 23, 2010, the Federal Department of Environment announced its intentions for a new national greenhouse gas ("GHG") framework for the electricity sector. This federal framework, if developed further into regulations, would require thermal coal units to meet GHG emission levels equal to, or better than, a natural gas combined cycle generating unit at a future date. Nova Scotia's existing GHG regulations require reductions in NSPI's emissions similar to the intentions of the federal framework. NSPI is reviewing the implications of this federal framework and its alignment with NSPI's current operating plans under existing Nova Scotia regulations.

**US Securities and Exchange Commission Registration**

On July 15, 2010, NSPI registered debt securities with the US Securities and Exchange Commission ("SEC") under the US Securities Act of 1933.

**Appointments**

On May 3, 2010, Elaine Sibson and Lee Bragg joined the NSPI Board of Directors.

# REVIEW OF 2010

| **Net Earnings**<br>millions of dollars | Three months ended<br>December 31 | | Year ended<br>December 31 | | |
|---|---|---|---|---|---|
| | **2010** | 2009 | **2010** | 2009 | 2008 |
| Electric revenue | **$296.4** | $302.9 | **$1,167.3** | $1,188.1 | $1,111.1 |
| Fuel for generation and purchased power | **146.2** | 138.5 | **586.7** | 500.7 | 471.4 |
| Fuel adjustment | **(24.0)** | (10.6) | **(99.0)** | 8.5 | - |
| Operating, maintenance and general | **65.0** | 58.4 | **237.5** | 215.1 | 203.7 |
| Provincial grants and taxes | **10.1** | 10.0 | **40.1** | 40.5 | 41.2 |
| Depreciation and amortization | **39.9** | 36.8 | **150.8** | 143.9 | 133.6 |
| Regulatory amortization | **23.7** | 14.7 | **36.9** | 27.2 | 17.7 |
| Other revenue | **(4.7)** | (4.0) | **(15.4)** | (14.0) | (15.5) |
| Earnings before financing charges and income taxes | **40.2** | 59.1 | **229.7** | 266.2 | 259.0 |
| Financing charges | **32.8** | 33.3 | **125.8** | 114.7 | 106.8 |
| Earnings before income taxes | **7.4** | 25.8 | **103.9** | 151.5 | 152.2 |
| Income taxes | **(13.3)** | 8.4 | **(17.4)** | 42.2 | 46.6 |
| Net earnings | **$20.7** | $17.4 | **$121.3** | $109.3 | $105.6 |

NSPI's net earnings increased $3.3 million to $20.7 million in Q4 2010, compared to $17.4 million in Q4 2009. Annual net earnings increased $12.0 million to $121.3 million in 2010 compared to $109.3 million in 2009, and $105.6 million in 2008.

Highlights of the earnings changes are summarized in the following table:

| millions of dollars | Three months ended December 31 | Year ended December 31 |
|---|---|---|
| **Net earnings – 2008** | | **$105.6** |
| Increased electric revenue due to an electricity price increase on January 1, 2009, partially offset by decreased industrial sales in the year | | 77.0 |
| Increased fuel for generation and purchased power | | (29.3) |
| Fuel adjustment related to implementation of the FAM | | (8.5) |
| Increased operating, maintenance and general ("OM&G") expenses primarily due to increased storm and reliability costs as well as customer service initiatives partially offset by decreased pension expense | | (11.4) |
| Increased depreciation and amortization primarily due to increased depreciation rates in 2009 as part of the phase-in of year-three rates as approved by the UARB | | (10.3) |
| Increased financing charges | | (7.9) |
| Increased regulatory amortization due to additional amortization of pre-2003 income tax regulatory asset | | (9.5) |
| Decreased income taxes due to decreased taxable income and lower statutory rate, partially offset by recovery of income taxes in 2008 relating to a prior year | | 4.4 |
| Other | | (0.8) |
| **Net earnings – 2009** | **$17.4** | **$109.3** |
| Decreased electric margin (see Electric Margin for explanation) | (2.0) | (11.6) |
| Increased OM&G expenses primarily due to increased pension and storm costs. Year-to-date also reflects increased spending on customer service initiatives | (6.6) | (22.4) |
| Increased depreciation and amortization due primarily to increased property, plant and equipment | (3.1) | (6.9) |
| Increased regulatory amortization due to a deferral of certain tax benefits arising in 2010, partially offset by decreased amortization of the pre-2003 income tax regulatory asset | (9.0) | (9.7) |
| Decreased income taxes due to decreased earnings before income taxes, deductions related to renewable investments and a change in the expected benefit from other accelerated tax deductions | 21.7 | 59.6 |
| Other | 2.3 | 3.0 |
| **Net earnings – 2010** | **$20.7** | **$121.3** |

Financing charges decreased $0.5 million in the quarter and increased $11.1 million for the year ended December 31, 2010. Foreign exchange gain and losses recovered through the FAM as fuel costs are included in the change in electric margin in the table above. See Electric Margin section for additional explanation.

# Net Earnings History

| millions of dollars | **2010** | 2009 | 2008 | 2007 | 2006 | 2005 |
|---|---|---|---|---|---|---|
| Net earnings | **$121.3** | $109.3 | $105.6 | $100.2 | $104.3 | $91.2 |

# Balance Sheets Highlights

| | As at December 31 | | |
|---|---|---|---|
| millions of dollars | **2010** | 2009 | 2008 |
| Total assets | **$3,991.3** | $3,465.3 | $3,490.7 |
| Total liabilities | **2,779.8** | 2,379.9 | 2,349.3 |

Significant changes in the balance sheets between December 31, 2010 and December 31, 2009 include:

| millions of dollars | **Increase (Decrease)** | Explanation |
|---|---|---|
| **Assets** | | |
| Accounts receivable | **$(79.3)** | Settlement of a receivable from a natural gas supplier, partially offset by higher posted margin to counterparties. |
| Income tax receivable | **40.6** | Recovery of income taxes due to deductions related to renewable investments and a change in the expected benefit from other accelerated tax deductions. |
| Inventory | **(11.4)** | Decreased fuel inventory levels and commodity prices, partially offset by higher materials inventory. |
| Future income tax assets | **(30.3)** | Decreased future income tax ("FIT") asset related to derivatives recognized in "Accumulated other comprehensive income (loss)" ("AOCI") and reclassification of non-capital loss carry forward FIT assets to net FIT liabilities. |
| Other assets | **173.7** | Increased FIT regulatory asset, recognition of the FAM regulatory asset in 2010 and increased pension asset, partially offset by regulatory amortization and decreased regulatory assets related to financial instruments. |
| Property, plant and equipment | **303.4** | Capital spending. |
| Construction work in progress | **126.4** | Capital spending. |
| **Liabilities and Shareholders' Equity** | | |
| Accounts payable and accrued charges and due to associated companies | **11.8** | Timing of payments. |
| Derivatives in a valid hedging relationship (including long-term portion) | **(61.4)** | Favourable commodity price and USD hedge positions and natural gas derivatives reclassified to "Held-for-trading". The effective portion of the change is recognized in AOCI. |
| Future income tax liabilities | **111.1** | Increased FIT liability on property, plant and equipment, including renewable investments and the FAM regulatory asset, partially offset by increased FIT asset on asset retirement obligations. The portion expected to be recovered from customers in future rates is recognized in "Other assets". |
| Asset retirement obligations | **37.2** | Recognition of asset retirement obligations. |
| Short-term and long-term debt (including current portion) | **286.2** | Increased debt levels to fund significant capital programs. |
| Common shares | **50.0** | Issuance of common shares. |
| Accumulated other comprehensive income | **54.8** | Primarily represents the effective portion of favourable commodity price positions partially offset by unfavourable USD hedge positions. |
| Retained earnings | **21.3** | Net earnings in excess of dividends paid. |

# Cash Flow Highlights

Significant changes in the cash flow statements between December 31, 2010 and December 31, 2009 include:

| Three months ended December 31<br>millions of dollars | **2010** | 2009 | Explanation |
|---|---|---|---|
| Cash, beginning of period | **$0.3** | $0.3 | |
| Provided by (used in): | | | |
| Operating activities | **160.4** | 101.0 | In 2010 and 2009, cash earnings and favourable non-cash working capital. |
| Investing activities | **(180.5)** | (112.3) | In 2010, capital spending including multi-year projects and renewable investments.<br>In 2009, capital spending including multi-year projects. |
| Financing activities | **20.1** | 11.3 | In 2010 and 2009, increased short-term debt, partially offset by dividends on common shares. |
| Cash, end of period | **$0.3** | $0.3 | |

| Year ended December 31<br>millions of dollars | **2010** | 2009 | Explanation |
|---|---|---|---|
| Cash, beginning of year | **$0.3** | - | |
| Provided by (used in): | | | |
| Operating activities | **300.2** | $275.2 | In 2010 and 2009, cash earnings and favourable non-cash working capital. |
| Investing activities | **(533.3)** | (268.6) | In 2010, capital spending including multi-year projects and renewable investments.<br>In 2009, capital spending including multi-year projects. |
| Financing activities | **233.1** | (6.3) | In 2010, increased debt levels and issuance of common shares, partially offset by dividends on common shares.<br>In 2009, dividends on common shares and redemption of preferred shares, partially offset by increased debt levels. |
| Cash, end of year | **$0.3** | $0.3 | |

## Electric Revenue

NSPI's electricity rates are set based on a forecast of fuel and non-fuel costs plus a reasonable return to investors. Consequently, the Company's electric revenue is comprised of revenue related to the recovery of fuel costs ("fuel electric revenue") and revenue related to the recovery of non-fuel costs ("non-fuel electric revenue").

With the introduction of the FAM on January 1, 2009, NSPI is able to seek full recovery of fuel costs through regularly scheduled rate adjustments, thus reducing the impact of volatile fuel markets on the Company's earnings. As a result, fuel electric revenue does not have a material impact on net earnings.

NSPI's customer classes contribute differently to the Company's non-fuel electric revenue. Changes in volume of residential and commercial customers, largely due to weather, have the largest impact on non-fuel electric revenue. Changes in industrial load, which are generally due to economic conditions, do not have a significant impact on non-fuel electric revenue.

The fuel electric revenue is comprised of the recovery of fuel costs incurred in the current year and the over or under-recovery of fuel costs from the prior year. Since fuel costs are recovered through the FAM, the electric margin is solely influenced by revenues relating to non-fuel costs and the FAM incentive expense or recovery. Electric revenue is summarized in the following table:

| millions of dollars | Three months ended December 31 | | Year ended December 31 | | |
|---|---|---|---|---|---|
| | **2010** | 2009 | **2010** | 2009 | 2008 |
| Fuel electric revenue current year | **$129.0** | $131.4 | **$515.7** | $511.2 | * |
| Fuel electric revenue prior year rebate | **(5.7)** | - | **(22.4)** | - | * |
| Non-fuel electric revenue | **173.1** | 171.5 | **674.0** | 676.9 | * |
| Total electric revenue | **$296.4** | $302.9 | **$1,167.3** | $1,188.1 | $1,111.1 |

* Prior to the introduction of the FAM on January 1, 2009, electric revenue was not broken into the components above.

Electric revenue decreased $6.5 million to $296.4 million in Q4 2010 compared to $302.9 million in Q4 2009. For the year ended December 31, 2010, NSPI's electric revenue decreased $20.8 million to $1,167.3 million compared to $1,188.1 million in 2009 and $1,111.1 million in 2008.

Highlights of the changes are summarized in the following table:

| millions of dollars | Three months ended December 31 | Year ended December 31 |
|---|---|---|
| **Electric revenue – 2008** | | **$1,111.1** |
| Increased electricity pricing effective January 1, 2009 | | 102.1 |
| Net change in residential and commercial sales volumes | | 4.2 |
| Decreased industrial sales to several large industrial customers | | (28.3) |
| Decreased export sales | | (1.0) |
| **Electric revenue – 2009** | **$302.9** | **$1,188.1** |
| Decreased electricity pricing effective January 1, 2010 related to the FAM rebate (fuel-electric revenue) to customers of over-recovered fuel costs in 2009 | (5.7) | (22.4) |
| Change in residential and commercial sales volumes due primarily to warmer weather | (1.7) | (10.7) |
| Increased industrial sales volume from several large industrial customers | 0.6 | 13.2 |
| Other | 0.3 | (0.9) |
| **Electric revenue – 2010** | **$296.4** | **$1,167.3** |

## Electric Sales Volumes

**Q4 Electric Sales Volumes**
GWh

| | **2010** | 2009 | 2008 |
|---|---|---|---|
| Residential | **1,080** | 1,091 | 1,093 |
| Commercial | **765** | 772 | 770 |
| Industrial | **957** | 998 | 987 |
| Other | **84** | 81 | 84 |
| Total | **2,886** | 2,942 | 2,934 |

**Year-to-Date ("YTD") Electric Sales Volumes**
GWh

| | **2010** | 2009 | 2008 |
|---|---|---|---|
| Residential | **4,147** | 4,228 | 4,179 |
| Commercial | **3,088** | 3,107 | 3,115 |
| Industrial | **3,908** | 3,642 | 4,144 |
| Other | **312** | 328 | 334 |
| Total | **11,455** | 11,305 | 11,772 |

Electric sales volume is primarily driven by general economic conditions, population and weather. Residential and commercial electricity sales are seasonal, with Q1 and Q4 the strongest periods, reflecting colder weather, and fewer daylight hours in the winter season.

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

## Electric Margin

As noted above, NSPI's fuel costs are recoverable from customers through the FAM. Differences between actual fuel costs and amounts recovered from customers through electricity rates in a period are deferred to a FAM regulatory asset or liability and recovered from or returned to customers in a subsequent period. The only effect on net earnings in relation to the recovery of fuel costs is the incentive component of the FAM with NSPI retaining or absorbing 10% of the over or under-recovered amount less the difference between the incentive threshold and the base amount to a maximum of $5 million.

NSPI's electric margin is influenced by non-fuel revenues and the FAM incentive. NSPI's electric margin is summarized in the following table:

| millions of dollars | Three months ended December 31 | | Year ended December 31 | | |
|---|---|---|---|---|---|
| | **2010** | 2009 | **2010** | 2009 | 2008 |
| Electric revenue | **$296.4** | $302.9 | **$1,167.3** | $1,188.1 | * |
| Fuel for generation and purchased power | **146.2** | 138.5 | **586.7** | 500.7 | * |
| Fuel adjustment | **(24.0)** | (10.6) | **(99.0)** | 8.5 | * |
| Fuel related foreign exchange (losses) gains | **(3.4)** | (2.2) | **(9.3)** | 3.0 | * |
| Electric margin | **$170.8** | $172.8 | **$670.3** | $681.9 | * |

* Prior to the introduction of the FAM on January 1, 2009, electric margin was not broken into the components above.

NSPI's electric margin decreased $2.0 million to $170.8 million in Q4 2010 compared to $172.8 million in Q4 2009 primarily due to the recognition of a FAM incentive expense compared to a recovery in 2009. For the year ended December 31, 2010, NSPI's electric margin decreased $11.6 million to $670.3 million in 2010 compared to $681.9 million in 2009 due to lower residential load related to warmer weather and the recognition of a FAM incentive expense compared to a recovery in 2009.

**Q4 Electric Margin / MWh**

| | **2010** | 2009 | 2008 |
|---|---|---|---|
| Dollars per MWh | **$59** | $59 | * |

**YTD Electric Margin / MWh**

| | **2010** | 2009 | 2008 |
|---|---|---|---|
| Dollars per MWh | **$59** | $60 | * |

* Prior to the introduction of the FAM on January 1, 2009, electric margin was not broken into the components above.

The change in average electric margin per MWh in 2010 compared to 2009 reflects a change in sales volume mix and recognition of a FAM incentive expense compared to a recovery in 2009.

## 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 2,368 MW, which is supplemented by 186 MW contracted with IPPs. NSPI meets the planning criteria for reserve capacity established by the Maritime Control Area and the Northeast Power Coordinating Council.

NSPI facilities continue to rank among the best in Canada on capacity related performance indicators. The high availability and capability of low cost thermal generating stations provide lower cost energy to customers. In 2010, thermal plant availability was 87% compared to 82% in 2009. The increase in availability from 2009 reflects decreased maintenance outages. Sustained high availability and low forced outage rates on low cost facilities are good indicators of sound maintenance and investment practices.

### Fuel Expense

**Q4 Production Volumes**
GWh

| | **2010** | 2009 | 2008 |
|---|---|---|---|
| Coal & petcoke | **2,049** | 2,069 | 2,177 |
| Natural gas | **438** | 534 | 249 |
| Oil & diesel | **16** | 16 | 218 |
| Renewable | **340** | 281 | 257 |
| Purchased power* | **315** | 335 | 296 |
| Total | **3,158** | 3,235 | 3,197 |

*Purchased power includes 132 GWh of renewables in 2010 (2009 – 51 GWh; 2008 – 44 GWh).

**YTD Production Volumes**
GWh

| | **2010** | 2009 | 2008 |
|---|---|---|---|
| Coal & petcoke | **7,839** | 8,177 | 9,009 |
| Natural gas | **2,275** | 1,612 | 1,258 |
| Oil & diesel | **36** | 307 | 339 |
| Renewable | **1,017** | 1,065 | 1,068 |
| Purchased power* | **997** | 931 | 889 |
| Total | **12,164** | 12,092 | 12,563 |

*Purchased power includes 355 GWh of renewables in 2010 (2009 – 149 GWh; 2008 – 148 GWh).

**Q4 Average Unit Fuel Costs**

| | **2010** | 2009 | 2008 |
|---|---|---|---|
| Dollars per MWh | **$46** | $43 | $44 |

**YTD Average Unit Fuel Costs**

| | **2010** | 2009 | 2008 |
|---|---|---|---|
| Dollars per MWh | **$48** | $41 | $38 |

Solid fuel is NSPI's dominant fuel source, supplying approximately 64% (2009 – 68%) of the Company's annual energy. Historically, solid fuels have had the lowest per unit fuel cost, after hydro and NSPI-owned wind production, which have no fuel cost component. Natural gas, oil, and purchased power are next, depending on the relative pricing of each. Economic dispatch of the generating fleet brings the lowest cost options on stream first, with the result that the incremental cost of production increases as sales volume increases.

The average unit fuel costs increased in 2010 compared to 2009 mainly as a result of higher priced import coal and solid fuel commodity mix related to emission compliance.

The average unit fuel costs increased in 2009 compared to 2008 mainly as a result of higher priced commodity contracts for coal and natural gas.

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

For the three months ended December 31, 2010, fuel for generation and purchased power increased $7.7 million to $146.2 million, compared to $138.5 million in Q4 2009. For the year ended December 31, 2010, fuel for generation and purchased power increased $86.0 million to $586.7 million compared to $500.7 million in 2009 and $471.4 million in 2008.

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 – 2008** | | **$471.4** |
| Commodity price increases | | 36.2 |
| Decreased proceeds from the resale of natural gas | | 10.3 |
| Valuation of contract receivable (see discussion below) | | 4.5 |
| Decreased sales volume | | (22.2) |
| Mark-to-market on natural gas hedges not required in 2009 primarily due to decreased production volumes | | (0.7) |
| Changes in generation mix and plant performance | | (10.2) |
| Decreased hydro production | | 1.8 |
| Primarily solid fuel handling costs previously included in OM&G expenses | | 10.7 |
| Other | | (1.1) |
| **Fuel for generation and purchased power – 2009** | **$138.5** | **$500.7** |
| Commodity price and volume increases | 0.4 | 34.5 |
| Changes in generation mix and plant performance | 12.6 | 24.3 |
| Solid fuel commodity mix and additives related to emission compliance | 0.8 | 25.3 |
| Increased proceeds from the resale of natural gas | (0.8) | (9.8) |
| Valuation of contract receivable (see discussion below) | 6.6 | 8.7 |
| (Decreased) increased sales volume | (5.1) | 2.7 |
| Increased hydro production | (6.2) | (1.1) |
| Mark-to-market on natural gas hedges recognized in 2009 as they were no longer required due to decreased 2009 production volumes | 1.5 | 2.2 |
| Other | (2.1) | (0.8) |
| **Fuel for generation and purchased power – 2010** | **$146.2** | **$586.7** |

The valuation of the contract receivable from a natural gas supplier required NSPI to utilize a combination of historical and future natural gas prices. NSPI uses market-based forward indices when determining future prices. Future prices can change from period to period which will cause a corresponding change in the value of the contract receivable. The natural gas supply contract settled in November 2010.

## Fuel Adjustment

The fuel adjustment related to the FAM includes the effect of fuel costs in both the current period and the preceding year. The difference between actual fuel costs and amounts recovered from customers in the current period is included in the fuel adjustment. This amount, less the incentive component, is deferred to a FAM regulatory asset in “Other assets” or a FAM regulatory liability in “Other Liabilities”. The FAM regulatory asset or liability includes amounts recognized as a fuel adjustment and associated interest included in “Financing charges”. Also included in the 2010 fuel adjustment is the rebate to customers of over recovered fuel costs from 2009.

Details of the fuel adjustment deferral related to the FAM are summarized in the following table:

| | | Year ended December 31 | |
|---|---|---|---|
| millions of dollars | **2010** | 2009 | 2008 |
| FAM payable – Balance at January 1 | **$(9.9)** | * | * |
| Under (over) recovery of current period fuel costs | **80.3** | $(9.9) | * |
| Rebate to customers from prior year | **22.5** | - | * |
| FAM receivable (payable) – Balance at December 31 | **$92.9** | $(9.9) | * |

*The fuel adjustment mechanism came into effect on January 1, 2009.

In December 2010, as part of the FAM regulatory process, the UARB directed NSPI to recover the rate increase approved by the UARB for the reset of 2011 fuel costs and the projected under recovery from prior years from customers over three years, with 50% of the rate increase to be recovered in 2011, 30% in 2012 and 20% in 2013.

NSPI has recognized a future income tax expense related to the fuel adjustment based on its applicable statutory income tax rate. The FAM regulatory asset or liability includes amounts recognized as a fuel adjustment and associated interest included in "Financing charges". As at December 31, 2010, NSPI's future income tax liability related to the FAM was $29.2 million (2009 – asset of $3.4 million).

## Operating, Maintenance and General

OM&G expenses increased $6.6 million to $65.0 million in Q4 2010 compared to $58.4 million in Q4 2009 and increased $22.4 million to $237.5 million for the year ended December 31, 2010 compared to $215.1 million in 2009 primarily due to increased pension and storm costs as well as customer service initiatives.

OM&G expenses increased $11.4 million to $215.1 million for the year ended December 31, 2009 compared to $203.7 million in 2008 primarily due to increased storm costs, system reliability spending and program costs associated with customer and new business initiatives, partially offset by lower pension expense.

## Provincial Grants and Taxes

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

## Depreciation and Amortization

Depreciation and amortization expense increased $3.1 million to $39.9 in Q4 2010 compared to $36.8 million in Q4 2009 and increased $6.9 million to $150.8 for the year ended December 31, 2010 compared to $143.9 million in 2009 primarily due to increased property, plant and equipment.

Depreciation and amortization expense increased $10.3 million to $143.9 for the year ended December 31, 2009 compared to $133.6 million in 2008 primarily due to the inclusion of year-three depreciation rates commencing on January 1, 2009 as approved by the UARB in its November 5, 2008 decision.

## Regulatory Amortization

Regulatory amortization increased $9.0 million to $23.7 million in Q4 2010 compared to $14.7 million in Q4 2009 and increased $9.7 million to $36.9 million for the year ended December 31, 2010 compared to $27.2 million in 2009. This increase is due primarily to a $14.5 million deferral of certain tax benefits arising in 2010 related to renewable energy projects, as approved by the UARB, partially offset by a reduction in amortization of the pre-2003 income tax regulatory asset resulting from the UARB's 2009 ROE decision of $4.8 million in 2010 (2009 – $10.0 million). The 2009 ROE decision allows NSPI to recognize additional amortization amounts in current periods and to reduce amortization in future periods to provide flexibility relating to customer rate requirements.

Regulatory amortization increased $9.5 million to $27.2 million for the year ended December 31, 2009 compared to $17.7 million in 2008 due primarily to additional amortization of the pre-2003 income tax regulatory asset resulting from the UARB's ROE decision noted above.

## Other Revenue

Other revenue, which consists of miscellaneous revenues and commercial settlements, has remained relatively unchanged for the quarter and year ended December 31, 2010 compared to 2009 and 2008.

## Financing Charges

Financing charges decreased $0.5 million to $32.8 million in Q4 2010 compared to $33.3 million in Q4 2009 and increased $11.1 million to $125.8 million for the year ended December 31, 2010 compared to $114.7 million in 2009 primarily due to higher foreign exchange costs, recovered through the FAM, and increased borrowing costs, partially offset by increased allowance for funds used during construction (“AFUDC”) related to increased capital spending.

Financing charges increased $7.9 million to $114.7 million for the year ended December 31, 2009 compared to $106.8 million in 2008 primarily due to lower foreign exchange gains in 2009 compared to 2008. In 2009, NSPI recorded income tax refund interest of $3.0 million which was received as a result of the Company amending its 1999 to 2003 corporate income tax returns. This refund interest was recorded as a reduction of "Financing charges".

## Income Taxes

NSPI uses the future income tax method of accounting for income taxes. In accordance with NSPI’s rate-regulated accounting policy as approved by the UARB, NSPI defers any future income taxes to a regulatory asset or liability where the future income taxes are expected to be included in future rates.

In 2010, NSPI was subject to provincial capital tax (0.125%), corporate income tax (34%) and Part VI.1 tax relating to preferred dividends (40%). NSPI also receives a reduction in its corporate income tax otherwise payable related to the Part VI.1 tax deduction (41% of preferred dividends).

Income taxes decreased $21.7 million to a $13.3 million income tax recovery in Q4 2010 compared to $8.4 million income tax expense in Q4 2009 and decreased $59.6 million to a $17.4 million recovery for the year ended December 31, 2010 compared to $42.2 million income tax expense in 2009 primarily due to decreased earnings before income taxes, deductions related to renewable investments and a change in the expected benefit from other accelerated tax deductions.

Income taxes decreased $4.4 million to $42.2 million for the year ended December 31, 2009 compared to $46.6 million in 2008 primarily due to decreased taxable income and a lower statutory rate in 2009 compared to 2008, partially offset by a recovery of income taxes in 2008 relating to a prior year.

In 2010, NSPI revised its estimate of the expected benefit from accelerated tax deductions. The impact for the three months and twelve months ended December 31, 2010 was to reduce income tax expense by approximately $8.0 million and $14.0 million respectively. In accordance with rate-regulated accounting, the future income tax implications of this change in estimate have been deferred to a regulatory asset in "Other assets". This change in accounting estimate has been accounted for on a prospective basis.

# OUTLOOK

## Business Environment

### Economic Environment

NSPI expects investment opportunities related to the transformation of the energy industry to lower emissions and has embarked on a significant capital plan to increase the Company's generation from renewable sources and to improve the transmission connections within its service territory as NSPI transitions to lower carbon intensive energy sources.

### Environmental Regulations

NSPI is subject to environmental regulations as set by both the Province of Nova Scotia and the Government of Canada. The Company continues to work with officials at both levels of government so as to comply with these regulations in an integrated way.

## Operations

NSPI anticipates earning a regulated ROE within its allowed range in 2011. NSPI continues to implement its strategy, which is focused on regulated investments in renewable energy and system reliability projects with a total capital program budget of approximately $350 million in 2011. The Company expects to finance its capital expenditures with funds from operations, debt and equity.

# LIQUIDITY AND CAPITAL RESOURCES

The Company generates cash mainly through its operations involving the generation, transmission and distribution of electricity. NSPI's customer base is diversified by both sales volume and revenues among residential, commercial, industrial and other customers. Circumstances that could affect the Company's ability to generate cash include general economic downturns, the loss of one or more large customers, regulatory decisions affecting customer rates and changes in environmental legislation.

In addition to internally generated funds, NSPI has access to a $600 million committed syndicated revolving bank line of credit, which includes an additional $100 million of credit extended in June 2010 when NSPI's revolving bank line was renewed for a three-year term maturing in June 2013. NSPI has an active commercial paper program for up to $400 million, of which outstanding amounts are 100% backed by the Company's bank line and this results in an equal amount of credit being considered drawn and unavailable.

As at December 31, 2010, the outstanding short-term debt is as follows:

| millions of dollars | Maturity | Credit Line Committed | Utilized | Undrawn and Available |
|---|---|---|---|---|
| Operating credit facility | June 2013 – Revolver | $600 | $289 | $311 |

NSPI has debt covenants associated with its credit facilities. These covenants are tested regularly, and the Company is in compliance with the covenant requirements.

# Debt Management

In May 2010, NSPI redeemed $100 million medium-term notes using short-term credit facilities.

In May 2010, NSPI filed a $500 million debt shelf prospectus providing the Company with access to long-term debt.

In June 2010, subsequent to filing its shelf prospectus, NSPI completed a $300 million medium-term note issue, proceeds of which were used to pay down outstanding short-term debt. These notes bear interest at the rate of 5.61% and yield 5.616% per annum until June 15, 2040.

In June 2010, NSPI issued a total of five million common shares to Emera Inc. and an Emera affiliate under common control for total proceeds of $50 million.

The weighted average coupon rate on NSPI's outstanding medium-term and debenture notes at December 31, 2010 was 6.74% (2009 – 6.80%). Approximately 27% of the debt matures over the next ten years, 70% matures between 2021 and 2040 and $50 million, or 3%, matures in 2097. The quoted market weighted average interest rate for the same or similar issues of the same remaining maturities was 4.50% as at December 31, 2010 (2009 – 4.87%).

NSPI's credit ratings issued by Dominion Bond Rating Service ("DBRS") and Standard & Poor's ("S&P") are as follows:

| | DBRS | S&P |
|---|---|---|
| Corporate | N/A | BBB+ |
| Senior unsecured debt | A (low) | BBB+ |
| Preferred stock | Pfd-2 (low) | P-2 (low) |
| Commercial paper | R-1 (low) | A-1 (low) |

# Contractual Obligations

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

| millions of dollars | | | | | | | | **Payments Due by Period** |
|---|---|---|---|---|---|---|---|---|
| | Total | 3 year renewable (1) | 2011 | 2012 | 2013 | 2014 | 2015 | After 2015 |
| Long-term debt | $1,946.8 | $241.7 | $0.1 | - | $300.0 | - | $70.0 | $1,335.0 |
| Preferred shares | 135.0 | - | - | - | - | - | 135.0 | - |
| Operating leases | 3.0 | - | 1.8 | $0.3 | 0.3 | $0.3 | 0.3 | - |
| Purchase obligations | 3,769.3 | - | 304.2 | 274.1 | 217.6 | 152.9 | 121.7 | 2,698.8 |
| Capital obligations | 111.5 | - | 76.1 | 33.9 | 1.5 | - | - | - |
| Asset retirement obligations | 440.3 | - | 1.6 | 1.9 | 1.2 | 1.2 | 1.3 | 433.1 |
| Total contractual obligations | $6,405.9 | $241.7 | $383.8 | $310.2 | $520.6 | $154.4 | $328.3 | $4,466.9 |

(1) Short-term discount notes are backed by an operating credit facility which matures in 2013.

**Operating lease obligations:** NSPI's operating lease obligations consist of operating lease agreements for office space and rail cars.

**Purchase obligations:** NSPI has purchasing commitments for electricity from independent power producers, transportation of coal, natural gas, fuel and transportation capacity on the Maritimes & Northeast Pipeline.

**Capital obligations:** NSPI has commitments to third parties for construction on capital projects and other goods and services.

**Asset retirement obligations:** The Company has asset retirement obligations for its generation, transmission and distribution assets.

The Company expects to be able to meet its obligations with cash from operations.

## Capital Resources

Capital expenditures for 2010, including AFUDC, were approximately $550 million. Significant capital expenditures included the Nuttby Mountain Wind project, the Digby Wind project, the Point Tupper Wind Development project, the Tuft's Cove 6 Waste Heat Recovery project, the Port Hawkesbury Biomass project, and the new corporate head office project.

# PENSION FUNDING

For funding purposes, NSPI determines required contributions to its defined benefit pension plans based on smoothed asset values. This reduces volatility in the cash funding requirement as the impact of investment gains and losses are recognized over a three year period. The cash required in 2011 for defined benefit pension plans will be approximately $38.8 million (2010 – $34.6 million actual). All pension plan contributions are tax deductible and will be funded with cash from operations.

NSPI's defined benefit pension plan is managed with a diversified portfolio of asset classes, investment managers and geographic investments. NSPI reviews the investment managers on a regular basis, and the plan's asset mix from time to time.

NSPI's projected contribution to defined contribution pension plans is $1.4 million for 2011 (2010 – $1.3 million actual).

# OFF-BALANCE SHEET ARRANGEMENTS

Upon privatization of the former provincially owned Nova Scotia Power Corporation ("NSPC") in 1992, NSPI became responsible for managing a portfolio of defeasance securities, which at December 31, 2010 totaled $1.0 billion. The securities are held in trust for Nova Scotia Power Finance Corporation ("NSPFC"), an affiliate of the Province of Nova Scotia. NSPI is responsible for ensuring the defeasance securities provide the principal and interest streams to match the related defeased NSPC debt. Approximately 73% of the defeasance portfolio consists of investments in the related debt, eliminating all risk associated with this portion of the portfolio; the remaining defeasance portfolio has a market value higher than the related debt, reducing the future risk of this portion of the portfolio.

# TRANSACTIONS WITH RELATED PARTIES

The Company enters into various transactions with its affiliates in the normal course of operations. All transactions are recorded, subject to terms in the Code of Conduct, at the exchange value, which is generally based on commercial rates or as agreed to by the parties. The Code of Conduct governs transactions between NSPI and its affiliates and is approved by the UARB.

Due to associated companies represents the total carrying amounts of trade payables, which are owed from NSPI to NSPI's parent company, Emera Inc., and companies wholly-owned by Emera Inc. The terms of repayment are the same as those for non-affiliate trade payables.

NSPI had sales and purchases from companies under common control of Emera Inc. as follows:

| For the millions of dollars | | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|---|
| Affiliate | Purpose of transaction | **2010** | 2009 | **2010** | 2009 |
| Emera Energy Services | Net sales (purchases) of gas, electricity | **$0.9** | $1.4 | **$(6.7)** | $25.0 |
| Other | Other services provided | **2.0** | 2.0 | **7.4** | 6.9 |
| Other | Various services purchased | **11.7** | 4.7 | **48.3** | 15.7 |

In the ordinary course of business, the Company purchased natural gas transportation capacity totaling $4.0 million (2009 – $4.4 million) during the three months ended December 31, 2010, and $18.0 million (2009 – $18.2 million) during the year ended December 31, 2010 from the Maritimes & Northeast Pipeline, an investment under significant influence of Emera Inc. The amount is recognized in “Fuel for generation and purchased power” and is measured at the exchange amount. As at December 31, 2010, the amount payable to the related party was $1.0 million (2009 – $1.5 million), and is under normal interest and credit terms.

On May 28, 2010, NSPI purchased $30.1 million in wind generation assets under development related to the Digby Wind Project from a subsidiary of Emera. This transaction was measured at the carrying amount of the assets transferred. At December 31, 2010, there was no amount due.

During the year ended December 31, 2010, the Company issued a total of 5.0 million (2009 – 0.4 million) common shares to Emera Inc. and an affiliate under common control of Emera Inc. for total consideration of $50.0 million (2009 – $4.1 million).

# RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

## Financial Risks and Financial Instruments

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

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

Derivatives that meet stringent documentation requirements, and can be proven to be effective both at the inception and over the term of the derivative, qualify for hedge accounting. Specifically, for cash flow hedges, the change in the fair value of the effective portion of hedging derivatives is deferred to “Other comprehensive income (loss)” and recognized in earnings in the same period the related hedged item is realized. Any ineffective portion of the change in the fair value of derivatives is recognized in net earnings in the reporting period.

Where the documentation or effectiveness requirements are not met, the derivative instruments are recognized at fair value with any changes in fair value recognized in net earnings in the reporting period, unless deferred as a result of regulatory accounting.

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

The Company's HFT derivatives are recorded on the balance sheet at fair value, with changes recorded in net earnings in the reporting period, unless deferred as a result of regulatory accounting. The Company has not designated any derivatives to be included in the HFT category.

The Company has contracts for the purchase and sale of natural gas at its Tufts Cove generating station ("TUC") that are considered HFT derivatives and accordingly are recognized on the balance sheet at fair value. This reflects NSPI's history of buying and reselling any natural gas not used in the production of electricity at TUC. Changes in fair value of HFT derivatives are normally recognized in net earnings. In accordance with NSPI's accounting policy for financial instruments and hedges relating to TUC fuel, NSPI has deferred any changes in fair value to a regulatory asset or liability. In 2009, the UARB approved an amendment to NSPI's accounting practice to include all TUC financial commodity hedges which are no longer required. This change in practice has impacted the timing of recognition between "Fuel for generation and purchased power" and "Fuel adjustment" as a result of the FAM implemented in 2009. The change in accounting practice was applied prospectively, beginning in 2009, as required by the UARB.

**Hedging Items Recognized on the Balance Sheet**

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

| millions of dollars | **December 31 2010** | December 31 2009 |
|---|---|---|
| Inventory | **$4.7** | $22.2 |
| Derivatives in a valid hedging relationship | **34.0** | (23.8) |
| Long-term debt | **-** | 0.1 |
| | **$38.7** | $(1.5) |

**Hedging Impact Recognized in Earnings**

The Company recognized in net earnings the following gains (losses) related to the effective portion of hedging relationships under the following categories:

| millions of dollars | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| | **2010** | 2009 | **2010** | 2009 |
| Fuel and purchased power increase | **$(9.7)** | $(27.1) | **$(64.7)** | $(38.4) |
| Financing charges decrease | **1.2** | 1.0 | **1.8** | 6.9 |
| Effectiveness losses | **$(8.5)** | $(26.1) | **$(62.9)** | $(31.5) |

The effectiveness gains (losses) reflected in the above table are offset in net earnings by the change in the fair value of the hedged item realized in the period.

The Company recognized in net earnings the following gains (losses) related to the ineffective portion of hedging relationships under the following categories:

| millions of dollars | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| | **2010** | 2009 | **2010** | 2009 |
| Fuel and purchased power decrease (increase) | **$0.1** | $(1.0) | **$(0.8)** | $(12.8) |
| Financing charges (increase) decrease | **(0.1)** | 0.3 | **(0.3)** | (0.5) |
| Ineffectiveness losses | **-** | $(0.7) | **$(1.1)** | $(13.3) |

**HFT Items Recognized on the Balance Sheet**

The Company has recognized on the balance sheet a net HFT derivatives liability of $8.1 million as at December 31, 2010 (2009 – $1.6 million asset).

**HFT Derivatives Recognized in Earnings**

The Company has recognized the following realized and unrealized (losses) gains with respect to HFT derivatives in earnings:

| millions of dollars | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| | **2010** | 2009 | **2010** | 2009 |
| Fuel and purchased power | **$(1.3)** | $1.4 | **$(1.3)** | $13.0 |
| Financing charges | **(0.1)** | (0.1) | **-** | - |
| Held-for-trading derivatives (losses) gains | **$(1.4)** | $1.3 | **$(1.3)** | $13.0 |

As discussed in note 21 of NSPI's financial statements at the reporting date, various valuation techniques are used to determine the fair value of derivative instruments. These include may include quoted market prices or, internal models using observable or non-observable market information.

# Business Risks

## Measurement of Risk

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

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

The UARB approved the implementation of a FAM for NSPI effective January 1, 2009, reducing the utility's exposure to fuel price volatility by providing a mechanism for NSPI to recover actual fuel costs. The FAM mitigates the risk to NSPI's net earnings associated with fluctuations in commodity prices and foreign exchange.

## Commodity Price Risk

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

**Coal/Petroleum Coke**
A substantial portion of NSPI's coal and petroleum coke ("petcoke") supply comes from international suppliers, which was contracted at or near the market prices prevailing at the time of contract. The Company has entered into fixed-price and index price contractual arrangements with several suppliers as part of the fuel procurement portfolio strategy. All index priced contractual arrangements are matched with a corresponding financial instrument to fix the price. The approximate percentage of coal and petcoke requirements contracted at December 31, 2010 is as follows:

- 2011 – 77%
- 2012 – 39%
- 2013 – 24%

**Heavy Fuel Oil**
NSPI manages exposure to changes in the market price of heavy fuel oil through the use of swaps, options, and forward contracts. For 2011 and 2012, NSPI currently does not have heavy fuel oil hedging requirements.

**Natural Gas**
NSPI has entered into multi-year contracts to purchase approximately 47,600 mmbtu of natural gas per day in 2011, and 39,300 mmbtu of natural gas per day in 2012. 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 when available for resale. Gas volumes not required for generation will be resold into the gas market with the margin hedged using financial instruments. As at December 31, 2010, amounts of natural gas volumes that have been economically and/or financially hedged and contracted are approximately as follows:

- 2011 – 87%
- 2012 – 35%

## Foreign Exchange Risk

NSPI enters into foreign exchange forward and swap contracts to limit the exposure of currency rate fluctuations related to fuel purchases. Currency forwards are used to fix the CAD cost to acquire USD, reducing exposure to currency rate fluctuations.

The risk due to fluctuation of the CAD against the USD for fuel purchases is measured and managed. In 2011, NSPI expects approximately 60% of its anticipated net fuel costs to be denominated in USD. USD from sales of surplus natural gas will provide a natural hedge against a portion of USD fuel costs. Forward contracts to buy $225.5 million USD were in place at December 31, 2010 at a weighted average rate of $0.99, representing 70% of 2011's anticipated USD requirements. Forward contracts to buy $443.0 million USD in 2012 through 2015 at a weighted average rate of $1.03 were in place at December 31, 2010. These contracts cover 31% of anticipated USD requirements in these years.

NSPI uses foreign exchange forward contracts to hedge the currency risk for capital projects and receivables denominated in foreign currencies. Forward contracts to buy €1.8 million were in place at December 31, 2010 at a weighted average rate of $1.56 (versus CAD) for capital projects in 2011.

## Interest Rate Risk

NSPI manages interest rate risk through a combination of fixed and floating borrowing and a hedging program. Floating-rate debt is estimated to represent approximately 16% of total debt in 2011. The Company has no interest rate hedging contracts outstanding as at December 31, 2010.

## Credit Risk

Credit risk arising as a result of contractual obligations between the Company 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.

## Labour Risk

NSPI has a contract with its union which will expire in April 2012.

## Regulatory Risk

NSPI faces risk with respect to the timeliness and certainty of full recovery of costs. The adoption and implementation of the FAM effective January 1, 2009, has helped NSPI manage that risk. The UARB oversees the FAM, including review of fuel costs, contracts and transactions. The FAM will help ensure customer rates reflect the actual price of the fuel used to make electricity. Concurrent with the implementation of the FAM in 2009, NSPI's regulated ROE range was reduced by 0.2%, changing its regulated ROE range to 9.1% to 9.6%, with rates set at 9.35%.

The first rate adjustment under the FAM, effective on January 1, 2010, was approved by the UARB on December 9, 2009. On December 8, 2010, the UARB approved NSPI's setting of the 2011 base cost of fuel and its recovery of all unrecovered fuel related costs as submitted in the Company's November 2010 filing. The recovery of these costs will begin January 1, 2011. The UARB approved the recovery of these costs by NSPI over three years, with 50% of the rate increase to be recovered in 2011, 30% in 2012 and 20% in 2013.

In December 2010, the UARB granted NSPI approval to defer certain tax benefits related to renewable energy projects arising in 2010. The UARB will convene a proceeding in 2011 to discuss how this deferral will be applied.

## Environment

### Corporate Environmental Governance

NSPI 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. NSPI has implemented this policy through development and application of environmental management systems ("EMS").

Implementation of EMS has provided a systematic focus on environmental issues so risks are identified and managed proactively. All areas of NSPI undertook initiatives in 2010 to reduce potential environmental risks and associated costs. Activities included, but were not limited to, reducing air emissions, protecting water resources, and continued management of PCB contaminated electrical equipment.

Conformance with legislative and Company requirements is verified through a comprehensive environmental audit program. There were no significant environmental or regulatory compliance issues identified during the 2010 audits. Plans are in place to promptly address any audit findings and continually improve the environmental management of the Company's operations.

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

NSPI completed an Integrated Resource Plan in 2007 and refreshed it in 2009. The Integrated Resource Plan includes current environmental requirements and assumptions on future regulations as constraints on possible generation plans. This allows for the assembly of better generation plans for the future. NSPI stakeholders were engaged in the assumptions and the scenarios to be modeled. The results of these planning exercises can be found on the NSPI website.

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

**Regulatory**

NSPI produces its electrical energy approximately 64% from coal and 19% from natural gas and/or oil. As such, it is subject to regulation with respect to air pollutants and greenhouse gas emissions. NSPI operates under a cost-of-service regulation model. Accordingly, all prudently incurred costs, including those capital and operating costs associated with meeting present and future environmental liabilities, can be recovered in rates collected from customers.

NSPI is subject to environmental regulation as set by both Canadian federal and Nova Scotia provincial governments. NSPI is in material compliance with current environmental regulations. All required permits are in place for NSPI's generating stations. These permits are generally for a ten year period but can be subject to review, variation, or suspension by the Minister of Environment of Nova Scotia.

**Climate Change and Air Emissions**

**Renewable Energy**
On October 15, 2010, the Nova Scotia Government enacted regulations under the Electricity Act related to the province's Renewable Electricity Plan. These regulations establish the requirement that 25% of electricity be supplied from renewable sources by 2015. These regulations build on the previously legislated requirements for 2011 and 2013. Recent amendments to the Electricity Act, and the new regulations, provide for the appointment, by spring 2011, of a new, independent renewable electricity administrator to conduct the procurement of at least 300 GWh of energy from IPPs to meet the 2015 standard. NSPI is also provided the opportunity to develop 300 GWh of renewable energy.

In January 2007, the Nova Scotia Government approved the Renewable Energy Standard Regulation (“RES”) to increase the percentage of renewable energy in the generation mix. In October 2009, the RES was amended. The year for 5% of electricity to be supplied from post-2001 sources of renewable energy, owned by independent power producers, was extended to 2011 from 2010. The requirement for 2013, which requires an additional 5% of renewable energy, is unchanged.

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

Greenhouse gas emissions from NSPI facilities are capped beginning in 2010 through to 2020. The 2010 to 2015 caps will be achieved by the continued success of energy efficiency and conservation programs and the addition of renewable energy to meet the 2011, 2013 and 2015 provincial renewable energy standards. The regulations also include a transmission incentive compliance mechanism recognizing expenditures on transmission which facilitates additional renewable energy sources. Up to 3% of the annual cap can be offset in this way to 2019. Further, the 2010 to 2020 period years are combined to form multi-year compliance periods recognizing the variability in electricity supply sources and demand.

Beyond 2015, reduced greenhouse gas emissions will be achieved through a combination of additional renewable energy, co-firing of biomass in existing coal power plants, import of non-emitting energy and energy efficiency and conservation as per the 2007/2009 Integrated Resource Plan.

On June 23, 2010, Environment Canada announced its intentions for a new national GHG framework for the electricity sector. This federal framework, if developed further into regulations, would require thermal coal units to meet GHG emission levels equal to, or better than, a natural gas combined cycle generating unit at a specific anniversary. Nova Scotia's existing GHG regulations require reductions in NSPI's emissions similar to the intentions of the federal framework. NSPI is reviewing the implications of this federal framework and its alignment with NSPI’s current operating plans under existing Nova Scotia regulations.

**Mercury**
On July 22, 2010, the Province of Nova Scotia announced, for the years 2010 through 2013, allowable mercury emissions would be increased from the previous cap of 65 kg per year. NSPI was requested to develop a plan of staged mercury emission reductions for its generation facilities for the period of 2010 to 2020 and to meet an annual cap of 35 kg beginning in 2020.

In 2008, NSPI carried out extensive testing on mercury abatement technology in its coal power plants. A capital program to add sorbent injection to each of the seven pulverized fuel coal units was completed in 2009. This allowed NSPI to meet the 2010 mercury emission cap of 65 kg established by the Province.

Compared to historical levels, NSPI has reduced mercury emissions by 60%.

**Nitrogen Oxide and Sulphur Dioxide Emissions**
NSPI has completed in 2009 its capital program of retrofitting low nitrogen oxide combustion firing systems on six of its seven pulverized fuel coal units. NSPI now meets the 2009 nitrogen oxide emission cap of 21,365 tonnes per year established by the province.

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

Compared to historical levels, NSPI has reduced emissions of nitrogen oxide by 40% and sulphur dioxide by 50%.

## Obligations

The Company recognizes asset retirement obligations (“ARO”) for property, plant and equipment in the period in which they are incurred if a reasonable estimate of fair value can be determined. Using the Company’s credit-adjusted risk-free rate, the fair value is determined by discounting the Company’s estimated future cash flows necessary to discharge legal obligations related to reclamation of land at the Company’s thermal, hydro, combustion turbine sites, and disposal of polychlorinated biphenyls (“PCBs”) in its transmission and distribution equipment. Estimated future cash flows are based on the Company’s completed depreciation studies, prior experience, estimated useful lives of assets, governmental regulatory requirements and the costs of activities such as demolition, restoration and remedial work based on present-day methods and technologies. Actual results may differ from these estimates.

The UARB included the amount of future expenditures associated with the removal of generation facilities in the 2003 NSPI depreciation settlement discussed under Property, Plant and Equipment in the Significant Accounting Policies and Critical Accounting Estimates section. NSPI believes that it will continue to be able to recover ARO through rates. Accordingly, changes to the ARO, or cost recognition attributable to changes in the factors discussed above, should not impact the results of operations of the Company.

Some of the Company’s hydro, transmission and distribution assets may have additional ARO. 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 ARO cannot be made at this time. Additionally, some of the Company’s transmission and distribution assets may have conditional ARO, the fair value of which cannot be reasonably estimated as sufficient information does not exist to estimate the obligations. A liability will be recognized in the period in which sufficient information becomes available.

The key assumptions used to determine the ARO are as follows:

| Asset | Credit-adjusted risk-free rate | | Estimated undiscounted future obligation (millions of dollars) | | Expected settlement date (number of years) | |
|---|---|---|---|---|---|---|
| | **2010** | 2009 | **2010** | 2009 | **2010** | 2009 |
| Thermal | **5.30%** | 5.31% | **$258.9** | $242.3 | **10 – 29** | 11 – 30 |
| Hydro | **5.27%** | 5.31% | **101.4** | 60.8 | **21 – 51** | 22 – 52 |
| Wind | **5.21%** | - | **45.5** | - | **13 – 20** | - |
| Combustion turbines | **5.25%** | 5.31% | **12.9** | 5.1 | **1 – 14** | 1 – 14 |
| Transmission & distribution | **5.74%** | 5.74% | **21.6** | 18.1 | **1 – 15** | 1 – 16 |
| | | | **$440.3** | $326.3 | | |

As at December 31, 2010, the asset retirement obligations recorded on the balance sheet were $138.7 million (2009 – $101.5 million). The Company estimates the undiscounted amount of cash flow required to settle the obligations is approximately $440.3 million, which will be incurred between 2011 and 2061. The majority of these costs will be incurred between 2020 and 2041.

# DISCLOSURE AND INTERNAL CONTROLS

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

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

The President and Chief Executive Officer and the Chief Financial Officer have evaluated, with the assistance of Company employees, the effectiveness of NSPI's DC&P and ICFR and based on that evaluation have concluded DC&P and ICFR were effective at December 31, 2010.

There have been no changes in NSPI's ICFR during the period beginning on January 1, 2010 and ended on December 31, 2010, which have materially affected, or are reasonably likely to materially affect ICFR.

# SIGNIFICANT ACCOUNTING POLICIES AND CRITICAL ACCOUNTING ESTIMATES

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

## Rate Regulation

NSPI's accounting policies are subject to examination and approval by the UARB. As a result, its rate-regulated accounting policies may differ from accounting policies for non-rate-regulated companies. These differences occur when the regulator renders its decisions on rate applications or other matters and generally involve a difference in the timing of revenue and expense recognition. The accounting for these items is based on the expectation of the future actions of the regulators.

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

## Pension and Other Post-Retirement Employee Benefits

The Company provides post-retirement benefits to employees, including defined benefit pension plans. 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 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.

Consistent with CGAAP and NSPI's accounting policy, the Company amortizes the net actuarial gain or loss, which exceeds 10% of the greater of the accrued benefit obligation ("ABO") and the market-related value of assets, over active plan members' average remaining service period, which is currently 9 years. NSPI's use of smoothed asset values further reduces the volatility related to the amortization of actuarial investment experience. As a result, the main cause of volatility in reported pension cost is the discount rate used to determine the ABO.

The discount rate used to determine benefit costs is based on high quality long-term Canadian corporate bonds. The discount rate is determined with reference to bonds which have the same duration as the ABO as at January 1 of the fiscal year rounded to the nearest 25 basis points. For benefit cost purposes, NSPI's rate was 6.50% for 2010 (2009 – 7.50%).

The expected return on plan assets is based on management's best estimate of future returns, considering economic and consensus forecasts. The benefit cost calculations assumed that plan assets would earn a rate of return of 7.25% for 2010 and 2009.

The reported benefit cost for 2010 for all defined benefit and defined contribution plans, based on management's best estimate assumptions, is $26.2 million. While there are numerous assumptions which are used to determine the benefit cost, the discount rate and asset return assumptions have an impact on the calculations.

The following shows the impact on 2010 benefit cost of a 25 basis point change (0.25%) in the discount rate and asset return assumptions:

| | Increase 0.25% | | Decrease 0.25% | |
|---|---|---|---|---|
| millions of dollars | **2010** | 2009 | **2010** | 2009 |
| Discount rate assumption | **$(3.0)** | $(0.9) | **$3.1** | $0.9 |
| Asset return assumption | **$(1.7)** | $(1.7) | **$1.7** | $1.7 |

The sensitivity to the discount rate assumption was significantly lower for 2010 benefit cost than in recent years because the net unamortized gains and losses subject to amortization fell within the 10% corridor.

As such, for 2010, small changes to the discount rate assumption do not impact the amount of actuarial gains and losses being amortized and included in the calculation of benefit cost.

## Unbilled Revenue

Electric revenues are billed on a systematic basis over a one or two-month period. At the end of each month, the Company must make an estimate of energy delivered to customers since the date their meter was last read and of related revenues earned but not yet billed. The unbilled revenue is estimated based on several factors, including current month's generation, estimated customer usage by class, weather, line losses and applicable customer rates. Based on the extent of the estimates included in the determination of unbilled revenue, actual results may differ from the estimate. As at December 31, 2010, unbilled revenues amount to $84.1 million (2009 – $85.4 million) on a base of annual electric revenues of approximately $1.2 billion (2009 – $1.2 billion).

## Contract Receivable

NSPI's natural gas purchase agreement expired in October 2010. The agreement included a price adjustment clause covering three years of natural gas purchases. The clause stated that NSPI would pay for all gas purchases at the agreed contract price, but would be entitled to a price rebate on a portion of the volumes. The first settlement took place in November 2007 for purchases to the end of October 2007 and the final settlement took place in November 2010.

## Asset Retirement Obligations

The Company recognizes ARO's 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 ARO's 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. Actual results may differ from these estimates.

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 ARO's through rates. Accordingly, changes to the ARO, or cost recognition attributable to changes in the factors discussed above, should not impact the results of operations of the Company.

## Property, Plant and Equipment

Property, plant and equipment represents 67% 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 magnitude of the Company's property, plant and equipment, changes in estimated depreciation rates can have a material 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 interveners, which recommended a four-year phase-in of new depreciation rates, which, based on assets in service in the study, would reach an overall increase in depreciation expense of $20 million by 2007. The UARB approved the settlement. NSPI began phasing the new rates in 2004. In its rate decision for 2005, the UARB deferred the scheduled phase-in for 2005. In the rate decision for 2006, the UARB included the phase-in of year-two in rates. In its February 5, 2007 decision, the UARB postponed the phase-in of year-three rates until the next rate application. In its November 5, 2008 decision, the UARB approved year-three phase-in rates effective January 1, 2009. On October 29, 2010, NSPI filed a depreciation study with the UARB.

## Income Taxes

Income taxes are determined based on the expected tax treatment of transactions recorded in the financial statements. In determining income taxes, tax legislation is interpreted, the likelihood that future tax assets will be recovered from future taxable income is assessed and assumptions about the expected timing of the reversal of future tax assets and liabilities are made. If interpretations differ from those of tax authorities or if the recovery of future tax assets or timing of reversals is not as anticipated, the provision for income taxes could increase or decrease in future periods. The amount of any such increase or decrease cannot be reasonably estimated.

# CHANGES IN ACCOUNTING POLICIES

## Future Accounting Policy Changes

### Changeover to United States Generally Accepted Accounting Principles

In February 2008, the Canadian Institute of Chartered Accountants ("CICA") announced CGAAP for publicly accountable enterprises will be replaced by International Financial Reporting Standards ("IFRS") for fiscal years beginning on or after January 1, 2011. The Company began planning its transition to IFRS in 2008 and transition activities progressed on schedule through 2009. In Q4 2009, due primarily to the continued uncertainty around the timing and eventual adoption of a rate-regulated accounting ("RRA") standard under IFRS, management of Emera, NSPI's parent company, began reviewing the option of adopting United States Generally Accepted Accounting Principles ("US GAAP") instead of IFRS. In Q1 2010, the Company decided to transition to US GAAP financial reporting standards beginning Q1 2011.

The adoption of US GAAP in Q1 2011 is expected to result in fewer significant changes in the Company's accounting policies than would have been experienced with the adoption of IFRS. Management believes this will result in financial information that is more comparable to the Company's prior years' financial statements prepared under CGAAP, making them easier for readers to understand.

US GAAP reporting is permitted by Canadian securities laws and the Toronto Stock Exchange ("TSX") for companies subject to reporting obligations under US securities laws. On July 15, 2010, NSPI registered debt securities with the SEC under the US Securities Act of 1933, thereby becoming subject to US reporting obligations. Registration with the SEC will enhance the Company's ability to access US capital markets in the future.

The Company's application of CGAAP currently relies on US GAAP for guidance on the application of RRA. RRA allows the economic impact of regulatory activities to be recognized consistent with the timing that amounts are included in customer rates. The Company believes continued recognition of its regulatory assets and liabilities under US GAAP best reflects the effect regulatory activities have on the Company's financial position. Without a RRA standard, a transition to IFRS would likely result in the accounting write-off of the Company's significant regulatory assets and liabilities, and net earnings could be subject to greater volatility on an on-going basis.

### Transition Activities

A formal project was established to transition to US GAAP for 2011, register securities of NSPI with the SEC and prepare the Company to comply with the on-going reporting requirements of the SEC and requirements of the Sarbanes-Oxley Act ("SOX"). A four-phased project approach was adopted to manage project activities. The project is proceeding on schedule to achieve its required milestones. The following is a brief overview of the activities of each phase and current status. An update on the project's status and achievement of its key milestones are provided to the Company's Audit Committee on a quarterly basis.

**Phase One: Preliminary Assessment and Planning – Completed**

Phase One was substantially completed in May 2010. It involved assessment and planning activities required to develop the initial project plan and identify resource requirements for the project. Internal resources were dedicated to the project to ensure its completion within the required timeline. KPMG LLP, who was assisting with the Company's changeover to IFRS, was engaged to continue providing technical advisory services during the Company's transition to US GAAP. In addition to resourcing activities, the Project Charter, Governance Structure and a Project Management Office were established to support the subsequent phases of the project.

Two key assessments were performed in this phase:

- The first assessment compared the most significant differences between US GAAP and CGAAP to determine which areas were most likely to impact the Company's accounting policies and financial reporting. The purpose of this assessment was to highlight areas where detailed analysis of GAAP differences was needed to determine and conclude on the nature and extent of impact. Detailed analysis activities and conclusions on the impact of US GAAP on the Company's accounting policies are discussed under Phase Two.

- The second assessment compared the requirements of the National Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings" ("NI 52-109") and those of Sections 302 ("SOX 302") and 404 ("SOX 404") of the Sarbanes-Oxley Act. The purpose of this assessment was to identify the impact of SOX 302 and SOX 404 on the Company's current NI 52-109 program over disclosure controls and procedures ("DC&P") and internal control over financial reporting ("ICFR").

  Consistent with NI 52-109, SOX 302 requires certification by the certifying officers of all publicly-traded companies that they have established, maintained and designed DC&P and ICFR and evaluated DC&P. SOX 302 requires a quarterly evaluation of DC&P while NI 52-109 requires an annual evaluation, however, NSPI is not required to file quarterly 302 certificates with the SEC. Also consistent with NI 52-109, SOX 404 requires that all publicly-traded companies must establish ICFR; document, test and maintain those controls and procedures to ensure their effectiveness; and management must report on their evaluation of the effectiveness of ICFR.

  Under SOX 404, the Company is required to obtain an external audit opinion annually on the design and effectiveness of the Company's ICFR which is not required under NI 52-109. This was the only significant difference identified between the requirements of NI 52-109 and SOX 404. The first external audit on ICFR is required as of December 31, 2011. Activities being performed to prepare the Company for SOX 404 attestation are described below.

**Phase Two: Detailed Assessment, Development and SEC Registration – Completed**

Phase Two commenced in April 2010. This phase involved registering securities of NSPI with the SEC and addressing all new requirements related to complying with US GAAP, SOX and SEC reporting obligations.

Detailed analysis was performed on those areas identified in Phase One where significant differences between US GAAP and CGAAP were most likely to impact the Company's accounting policies, financial statements, information systems, internal controls and other business activities. Areas examined included revenue recognition, hedge accounting, RRA, pension and other post-retirement benefits, income taxes, preferred shares and foreign currency. Where differences were identified, prior period financial information is being restated to US GAAP for comparative purposes in 2011. Restatement activities are part of Phase Three.

The Company's financial statements were drafted or "mocked-up" in accordance with US GAAP to identify the financial statement and disclosure impact of transitioning to US GAAP.

NSPI's regulated accounting policies were updated to reflect the transition to US GAAP. These were approved by the UARB in December 2010.

Based on the work completed in this phase and the Company's conclusion that it is able to continue with its application of RRA under US GAAP, material adjustments to the Company's reported post-transition net earnings were not identified. The on-going impact of the differences identified between CGAAP and US GAAP are mostly limited to changes in classification and presentation within the financial statements and in the extent of disclosure requirements.

Areas where the financial impact of transitioning to US GAAP is more significant are outlined below. These areas do not represent a complete list of expected changes. The net impact of all adjustments required to restate retained earnings on January 1, 2010 to US GAAP is an approximate $7 million reduction. However, the net impact of all adjustments required to restate AOCI on January 1, 2010 to US GAAP will be material. The amount of any significant adjustments to retained earnings and AOCI are identified below under the financial statement item to which the adjustments relate.

***Pension and other post-employment benefits* –** Under US GAAP, the Company will recognize its unfunded pension obligation as a liability in its financial statements and will need to recognize unamortized gains and losses associated with pension and other post-retirement benefits in AOCI in shareholders' equity. Currently, under CGAAP, the unamortized amounts together with their impact on the funded status of the pension liability or asset, are disclosed but not recognized.

<u>Financial impact</u>: Restating the amounts under US GAAP results in a $256 million unamortized loss recorded in AOCI, a $7 million reduction to retained earnings, and a $263 million increase to pension liability on January 1, 2010.

***Hedge accounting*** –The Company has determined that certain hedging strategies that qualify for hedge accounting under CGAAP do not qualify for the same treatment under US GAAP primarily due to differences in effectiveness testing requirements. Effective for hedges put in place beginning in 2010, the Company has changed its strategies to ensure compliance with US GAAP prospectively.

Prior to the Company's decision to transition to US GAAP, NSPI, in consultation with interveners and consultants for the UARB, discussed deferral accounting for all of its economic hedges. Based on these discussions and the Company's decision to adopt US GAAP, NSPI filed an amended accounting policy with the UARB requesting deferral accounting for all of its economic hedges. The UARB approved the amended regulatory accounting policy in December 2010, resulting in the deferral of the periodic changes in the fair value of these derivatives so that they impact NSPI's net earnings in a manner consistent with that achieved if hedge accounting had been applied.

<u>Financial impact</u>: NSPI's amended accounting policy results in a $44 million increase in AOCI and net regulatory assets to restate its economic hedges on January 1, 2010 to US GAAP.

***Income taxes***

*Enacted tax rates*
US GAAP requires that the enacted tax rate be used in measuring current taxes and FIT. Under CGAAP, the tax impact of the Part VI.1 tax deduction related to preferred share dividends is recorded at the substantively enacted tax rates, which is consistent with Canada Revenue Agency's assessing practice. Under US GAAP, the Company will recognize an income tax liability for the difference between the enacted tax rates and the substantively enacted tax rates for the Part VI.1 tax deduction.

Financial impact: Restating the amounts under US GAAP results in a $9 million increase to income tax payable and decrease to retained earnings on January 1, 2010.

*Investment tax credits*
Under CGAAP, certain investment tax credits related to qualifying scientific research and development expenditures are recorded as a reduction to property, plant and equipment. Under US GAAP, the Company will recognize the investment tax credit as a reduction in tax expense.

Financial impact: Restating the amounts under US GAAP results in a $4 million increase to property, plant and equipment and retained earnings on January 1, 2010.

*Uncertain tax positions*
During 2010, the Company revised its estimate of the expected benefit from accelerated tax deductions under CGAAP. A portion of the impact of the 2010 revised estimate is related to the US GAAP guidance for determining the unit of account and resulting expected benefit. As a result, for US GAAP, the Company will recognize a portion of the 2010 change in estimate in years prior to January 1, 2010.

Financial impact: Restating the amounts under US GAAP results in a $4 million decrease in income tax payable and increase retained earnings on January 1, 2010.

*US GAAP transition adjustments*
Under US GAAP, the Company will recognize the FIT impact on the US GAAP adjustments for pension and other post-employment benefits and hedge accounting as noted above, and on other US GAAP adjustments to the balance sheet.

Financial impact: Material adjustments are expected to restate FIT assets and liabilities on January 1, 2010 to US GAAP. The amount of these adjustments is still being determined, however, the impact of a change in FIT expense (recoveries) will be deferred to a regulatory asset or liability where the FIT is expected to be included in future rates. The net impact of income tax adjustments under US GAAP required to restate retained earnings and AOCI on January 1, 2010 is not expected to be material due to rate-regulated accounting.

The Company has various agreements with external parties that reference CGAAP as the basis for satisfying financial reporting requirements, including covenant calculations. NSPI renegotiated its revolving credit facility with its banking syndicate in June 2010 and in Q4 2010, and reached an agreement with its trustee to bilaterally amend its respective trust indentures by way of supplemental indentures. This amended agreement allows for USGAAP as the basis for satisfying financial reporting requirements.

The impact of the transition to US GAAP on information systems is minimal.

All Phase Two activities are complete.

**Phase Three: Implementation – In-Progress**

Phase Three began in July 2010 and involves implementing the changes identified and planned in Phase Two that are necessary to comply with US GAAP in 2011, along with SOX and SEC reporting obligations as they become effective.

2009 and 2010 financial information prepared under CGAAP is being restated to US GAAP for comparative purposes in 2011, with most adjustments now complete and the remainder to be completed in Q1 2011, including restatement of Q4 2010. Reconciliation of prior period financial information from CGAAP to US GAAP, along with other significant transitional disclosure, will be presented in the 2011 financial statements.

The Company's financial reporting processes and consolidation software are being reconfigured to support the preparation of US GAAP financial statements in 2011 and the consolidation of prior period restatements. The required changes are not significant and will be on-going through Q1 2011.

As of July 15, 2010, NSPI is an SEC registrant and subject to SEC reporting obligations. NSPI is now required to furnish all filings made with the Canadian securities regulatory authorities concurrently with the SEC.

Changes are being implemented to business processes and ICFR to help ensure an efficient SOX 404 attestation process. Changes will be completed in Q1 2011.

Education and training activities have occurred throughout all project phases. In this phase, education activities are focused on ensuring all personnel and senior management impacted by the transition understand the new requirements and have the skills and expertise necessary to ensure the organization's on-going ability to report under US GAAP, fulfill its reporting obligations to the SEC and comply with SOX. Members of the Company's Board of Directors participated in education sessions in Q4 2010. Additional education sessions are planned in Q1 2011, including one for members of the Company's Audit Committee to review the financial impact of the transition, prior period restatements and the Company's transitional disclosure.

With the exception of the Q4 2010 restatements, the activities of this phase were originally planned to be substantially completed in December 2010, however, certain implementation activities identified above will be completed in February 2011. These delays do not jeopardize the project's ability to meet its key milestones, nor the Company's ability to meet its Q1 2011 reporting obligations.

**Phase Four: Operational Support – In-Progress**

Phase Four began January 2011 and is scheduled to be completed by the end of Q2 2011. The impact of transitioning to US GAAP and complying with SEC reporting obligations and SOX requirements will be fully integrated into the Company's financial reporting processes at that time.

Final transitional activities will be completed in this phase.

Following release of the Company's Q1 2011 financial statements, the project will be formally closed and internal resources currently dedicated to the project will resume responsibility for financial reporting activities within the business.

## Recently Issued US GAAP Accounting Standards

As indicated above, beginning with its external reporting in Q1 2011, the Company will retrospectively adopt US GAAP as its accounting framework and will no longer prepare its consolidated financial statements under CGAAP. In evaluating the impact of adopting US GAAP, the Company has considered US GAAP accounting standards currently in effect through December 31, 2010. In 2011, additional US GAAP standards will become effective and the Company will adopt them in accordance with their individual transition guidelines. The identified issued standards that have effective dates in 2011 and may be relevant to the Company are set out below.

**Revenue Recognition**
In October 2009, the Financial Accounting Standards Board ("FASB") issued Accounting Standard Update ("ASU") 2009-13, *Revenue Recognition (Topic 605): Multiple-Deliverable Revenue Arrangements*. ASU 2009-13 amends existing US GAAP revenue recognition guidance to eliminate the requirement that all undelivered elements have vendor specific objective evidence of selling price ("VSOE") or third party evidence of selling price ("TPE") before an entity can recognize the portion of an overall arrangement fee that is attributable to items that already have been delivered. In the absence of VSOE and TPE for one or more delivered or undelivered elements in a multiple-element arrangement, entities will be required to estimate the selling prices of those elements. The overall arrangement fee will be allocated to each

element (both delivered and undelivered items) based on their relative selling prices, regardless of whether those selling prices are evidenced by VSOE or TPE or are based on the entity's estimated selling price. Application of the "residual method" of allocating an overall arrangement fee between delivered and undelivered elements will no longer be permitted upon adoption of ASU 2009-13. Additionally, the new guidance will require entities to disclose more information about their multiple-element revenue arrangements. ASU 2009-13 is effective prospectively for revenue arrangements entered into or materially modified in fiscal years beginning on or after June 15, 2010. The Company will adopt ASU 2009-13 effective January 1, 2011 but does not expect that its adoption will have a material impact on its financial statements.

**Fair Value Measurements**
In January 2010, the FASB issued ASU 2010-06, *Improving Disclosures about Fair Value Measurements*. ASU 2010-06 amends FASB Accounting Standards Codification ("ASC") Topic 820, *Fair Value Measurements and Disclosures*, to require reporting entities to make new disclosures about recurring or nonrecurring fair-value measurements including significant transfers into and out of Level 1 and Level 2 fair-value measurements and information about purchases, sales, issuances, and settlements on a gross basis in the reconciliation of Level 3 fair-value measurements. The ASU also clarifies existing fair-value measurement disclosure guidance about the level of disaggregation, inputs, and valuation techniques. Except for the detailed Level 3 roll forward disclosures, the guidance in the ASU was effective for interim and annual reporting periods beginning after December 15, 2009. The new disclosures about purchases, sales, issuances, and settlements in the roll forward activity for Level 3 fair-value measurements are effective for fiscal years beginning after December 15, 2010. The Company will adopt the disclosure requirements of ASU 2010-06 in its 2011 US GAAP financial reporting but does not expect they will have a material impact on its financial statements.

**Goodwill Impairment**
In December 2010, the FASB issued ASU 2010-28 Intangibles—Goodwill and Other (Topic 350): *When to Perform Step 2 of the Goodwill Impairment Test for Reporting Units with Zero or Negative Carrying Amounts*. ASU 2010-28 amends ASC 350-20 to modify Step 1 of the goodwill impairment test for reporting units with zero or negative carrying amounts. For those reporting units, an entity is required to perform Step 2 of the goodwill impairment test if it is more likely than not that a goodwill impairment exists. In determining whether it is more likely than not that a goodwill impairment exists, an entity should consider whether there are any adverse qualitative factors indicating that an impairment may exist consistent with the existing guidance in US GAAP. ASU 2010-28 is effective for interim periods and fiscal years beginning on or after December 15, 2010. The Company will adopt ASU 2010-28 effective January 1, 2011 but does not expect that its adoption will have a material impact on its financial statements.

# SUMMARY OF QUARTERLY RESULTS

| For the quarter ended<br>millions of dollars | **Q4 2010** | Q3 2010 | Q2 2010 | Q1 2010 | Q4 2009 | Q3 2009 | Q2 2009 | Q1 2009 |
|---|---|---|---|---|---|---|---|---|
| Total revenues | **$301.1** | $270.3 | $270.6 | $340.7 | $306.9 | $267.5 | $276.9 | $350.8 |
| Net earnings applicable to common shares | **20.7** | 22.4 | 14.9 | 63.3 | 17.4 | 16.6 | 22.8 | 52.5 |

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.

# NOVA SCOTIA POWER INC.

# Financial Statements

# December 31, 2010 and 2009

# MANAGEMENT REPORT

**Management's Responsibility for Financial Reporting**

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

The 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. NSPI is regulated by the Nova Scotia Utility and Review Board, which also examines and approves NSPI's accounting policies and practices. In preparation of these 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 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 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 financial statements.

NSPI 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 NSPI'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 financial statements. The Board carries out this responsibility principally through its Audit, Nominating & Corporate Governance Committee ("Committee").

The Committee is appointed by the Board, and its members are directors who are not officers or employees of NSPI. 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 financial statements and the external auditors' report. The Committee reports its findings to the Board for consideration when approving the 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 financial statements have been audited by Grant Thornton LLP, the external auditors, in accordance with Canadian generally accepted auditing standards. Grant Thornton LLP has full and free access to the Committee.

February 9, 2011

"Robert R. Bennett"
President and Chief Executive Officer

"Nancy Tower, FCA"
Chief Financial Officer

## INDEPENDENT AUDITORS' REPORT

To the Shareholders of Nova Scotia Power Inc.

We have audited the accompanying financial statements of Nova Scotia Power Inc., which comprise the balance sheets as at December 31, 2010 and 2009, the statements of earnings, changes in shareholders' equity and cash flows for the years then ended, and a summary of significant accounting policies and other explanatory information.

### Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

### Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the company's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the company's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

### Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Nova Scotia Power Inc. as at December 31, 2010 and 2009, and its results of operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Halifax, Canada
February 9, 2011

"Grant Thornton LLP"
Chartered Accountants

**Nova Scotia Power Inc.**
**Statements of Earnings**
**Year Ended December 31**

| millions of dollars | 2010 | 2009 |
|---|---|---|
| Revenue | | |
| Electric | **$1,167.3** | $1,188.1 |
| Other | **15.4** | 14.0 |
| | **1,182.7** | 1,202.1 |
| Cost of operations | | |
| Fuel for generation and purchased power (note 22) | **586.7** | 500.7 |
| Fuel adjustment (note 4) | **(99.0)** | 8.5 |
| Operating, maintenance and general (note 22) | **237.5** | 215.1 |
| Provincial grants and taxes | **40.1** | 40.5 |
| Depreciation and amortization | **150.8** | 143.9 |
| Regulatory amortization | **36.9** | 27.2 |
| | **953.0** | 935.9 |
| Earnings before financing charges and income taxes | **229.7** | 266.2 |
| Financing charges (note 6) | **125.8** | 114.7 |
| Earnings before income taxes | **103.9** | 151.5 |
| Income taxes (note 7) | **(17.4)** | 42.2 |
| Net earnings applicable to common shares | **$121.3** | $109.3 |

*See accompanying notes to the financial statements.*

**Nova Scotia Power Inc.**
**Balance Sheets**
**As at December 31**

| millions of dollars | 2010 | 2009 |
|---|---|---|
| **Assets** | | |
| Current assets | | |
| Cash | **$0.3** | $0.3 |
| Accounts receivable (note 8) | **192.5** | 271.8 |
| Income tax receivable | **40.6** | - |
| Inventory (note 9) | **154.2** | 165.6 |
| Prepaid expenses | **6.1** | 5.7 |
| Future income tax assets (note 7) | **4.1** | 34.4 |
| Derivatives in a valid hedging relationship | **24.7** | 19.4 |
| Held-for-trading derivatives | **6.3** | 8.9 |
| | **428.8** | 506.1 |
| Derivatives in a valid hedging relationship | **20.8** | 29.8 |
| Held-for-trading derivatives | **8.2** | 6.2 |
| Other assets (note 10) | **512.8** | 339.1 |
| Intangibles (note 11) | **72.5** | 65.7 |
| Property, plant and equipment (note 12) | **2,669.0** | 2,365.6 |
| Construction work in progress | **279.2** | 152.8 |
| | **2,948.2** | 2,518.4 |
| | **$3,991.3** | $3,465.3 |
| **Liabilities and Shareholders' Equity** | | |
| Current liabilities | | |
| Current portion of long-term debt (note 16) | **$0.1** | $100.7 |
| Short-term debt (note 15) | **48.3** | 198.2 |
| Accounts payable and accrued charges | **221.3** | 213.9 |
| Due to associated companies (note 22) | **5.1** | 0.7 |
| Income tax payable | **-** | 1.2 |
| Dividends payable | **1.7** | 1.7 |
| Derivatives in a valid hedging relationship | **2.2** | 53.0 |
| Held-for-trading derivatives | **20.8** | 12.2 |
| | **299.5** | 581.6 |
| Derivatives in a valid hedging relationship | **9.4** | 20.0 |
| Held-for-trading derivatives | **1.8** | 1.3 |
| Future income tax liabilities (notes 4, 7) | **163.1** | 52.0 |
| Asset retirement obligations (note 14) | **138.7** | 101.5 |
| Other liabilities (note 10) | **98.6** | 91.5 |
| Long-term debt (note 16) | **1,933.7** | 1,397.0 |
| Preferred shares (note 17) | **135.0** | 135.0 |
| Shareholders' equity | | |
| Common shares (note 18) | **984.7** | 934.7 |
| Accumulated other comprehensive income (loss) | **10.8** | (44.0) |
| Retained earnings | **216.0** | 194.7 |
| | **1,211.5** | 1,085.4 |
| | **$3,991.3** | $3,465.3 |

Change in accounting estimate (note 2), Contingencies (note 23), Commitments (notes 5, 21 and 24), Guarantees (note 25)

*See accompanying notes to the financial statements.*

Approved on behalf of the Board of Directors

"George Caines"
Chairman

"Robert R. Bennett"
President and Chief Executive Officer

**Nova Scotia Power Inc.**
**Statements of Cash Flows**
**Year Ended December 31**

| millions of dollars | **2010** | 2009 |
|---|---|---|
| **Operating activities** | | |
| Net earnings applicable to common shares | **$121.3** | $109.3 |
| Non-cash items: | | |
| Depreciation and amortization | **150.8** | 143.9 |
| Amortization of other assets | **14.8** | 14.8 |
| Regulatory amortization | **36.9** | 27.2 |
| Allowance for funds used during construction | **(17.1)** | (7.8) |
| Interest (recovery) expense on deferral of FAM | **(3.8)** | 1.4 |
| Future income taxes (note 7) | **29.7** | (3.4) |
| Post-retirement benefits | **(14.0)** | (17.3) |
| Fuel adjustment (note 4) | **(99.0)** | 8.5 |
| Changes in fair value of derivative instruments | **15.5** | (8.3) |
| Other non-cash operating items | **1.5** | 0.5 |
| Other cash operating items | **0.2** | (6.1) |
| | **236.8** | 262.7 |
| Change in non-cash operating working capital (note 19) | **63.4** | 12.5 |
| Net cash provided by operating activities | **300.2** | 275.2 |
| **Investing activities** | | |
| Property, plant and equipment | **(517.7)** | (253.6) |
| Intangibles | **(10.0)** | (10.1) |
| Retirement spending net of salvage | **(5.6)** | (4.9) |
| Net cash used in investing activities | **(533.3)** | (268.6) |
| **Financing activities** | | |
| Retirements of long-term debt | **(100.0)** | (125.0) |
| Issuance of long-term debt | **300.0** | 250.0 |
| Increase in short-term debt | **90.4** | 123.8 |
| Issuance of common shares | **50.0** | - |
| Redemption of preferred shares | **-** | (125.0) |
| Dividends on common shares | **(100.0)** | (126.0) |
| Other financing activities | **(7.3)** | (4.1) |
| Net cash provided by (used in) financing activities | **233.1** | (6.3) |
| Increase in cash | **-** | 0.3 |
| Cash, beginning of year | **0.3** | - |
| Cash, end of year | **$0.3** | $0.3 |

| **Supplemental disclosure of cash paid (recovered):** | | |
|---|---|---|
| Interest | **$115.5** | $96.4 |
| Income and capital taxes | **$(4.4)** | $37.3 |

*See accompanying notes to the financial statements.*

**Nova Scotia Power Inc.**
**Statements of Changes in Shareholders' Equity**

| **For the year ended December 31, 2010**<br>millions of dollars | Common Shares | Accumulated Other Comprehensive Income (Loss) ("AOCI") | Retained Earnings | Total AOCI and Retained Earnings |
|---|---|---|---|---|
| Balance, December 31, 2009 | $934.7 | $(44.0) | $194.7 | $150.7 |
| Comprehensive income: | | | | |
| Net earnings applicable to common shares | - | - | 121.3 | 121.3 |
| Net gain on derivatives in a valid hedging relationship | - | 9.4 | - | 9.4 |
| Reclassification of hedging losses included in income | - | 62.9 | - | 62.9 |
| Reclassification of hedging gains included in inventory | - | (17.5) | - | (17.5) |
| Total comprehensive income | - | 54.8 | 121.3 | 176.1 |
| Issuance of common shares (note 18) | 50.0 | - | - | - |
| Dividends declared on common shares | - | - | (100.0) | (100.0) |
| Balance, December 31, 2010 | $984.7 | $10.8 | $216.0 | $226.8 |

| **For the year ended December 31, 2009**<br>millions of dollars | Common Shares | AOCI | Retained Earnings | Total AOCI and Retained Earnings |
|---|---|---|---|---|
| Balance, December 31, 2008 | $930.6 | $(0.6) | $211.4 | $210.8 |
| Comprehensive income: | | | | |
| Net earnings applicable to common shares | - | - | 109.3 | 109.3 |
| Net loss on derivatives in a valid hedging relationship | - | (113.2) | - | (113.2) |
| Reclassification of hedging losses included in income | - | 40.5 | - | 40.5 |
| Reclassification of hedging losses included in inventory | - | 29.3 | - | 29.3 |
| Total comprehensive (loss) income | - | (43.4) | 109.3 | 65.9 |
| Issuance of common shares (note 18) | 4.1 | - | - | - |
| Dividends declared on common shares | - | - | (126.0) | (126.0) |
| Balance, December 31, 2009 | $934.7 | $(44.0) | $194.7 | $150.7 |

*See accompanying notes to the financial statements.*

# Nova Scotia Power Inc.
# Notes to the Financial Statements

**December 31, 2010 and 2009**

## 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nova Scotia Power Inc., created through the privatization in 1992 of the crown corporation Nova Scotia Power Corporation, is a fully-integrated regulated electric utility and the primary electricity supplier in Nova Scotia. 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 UARB'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 a reasonable return to investors. NSPI's regulated return on equity ("ROE") range for 2010 was 9.1% to 9.6% (with 9.35% used to set rates) on an allowed common equity component up to 40% of NSPI's total regulated capitalization. In January 2010, NSPI reached an agreement with stakeholders on its calculation of regulated ROE. The agreement establishes that NSPI will continue to use actual capital structure, actual equity and actual net earnings to calculate actual annual regulated ROE. The agreement was approved by the UARB. The UARB has set, as a condition, that NSPI will maintain its average actual regulated annual common equity at a level no higher than 40% beginning in 2010 and until the next general rate case.

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

NSPI follows Canadian generally accepted accounting principles ("CGAAP"). The accounting policies approved by the regulator of NSPI may differ from CGAAP 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 CGAAP. Where the differences between CGAAP and CGAAP for rate-regulated companies are considered significant, disclosure of the policy has been made in these notes to the financial statements.

### a. Measurement Uncertainty

The preparation of financial statements in accordance with CGAAP 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. Estimates and assumptions are based upon historical experience, current conditions and assumptions believed to be reasonable at the time the estimate is made. Due to changing circumstances and the inherent uncertainty in making estimates, actual results may differ significantly from current estimates. Estimates are reviewed periodically, with any resulting adjustments reported in earnings in the period they arise.

The most significant estimates include: measurement of property plant and equipment depreciation rates (note 1e), intangible assets amortization rates (note 1f), post-employment benefits (note 3), income taxes (note 7), accounts receivable (note 8), regulatory assets and liabilities (note 10), asset retirement obligations (note 14), financial instruments (note 21) and contingencies (note 23). Actual results may differ from these estimates.

b. **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.
- 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 recognized as "Other liabilities".

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

c. **Allowance for Funds Used during Construction**

*Accounting for the impact of rate regulation:*

In accordance with accounting policies determined by the UARB, NSPI provides 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", "Construction work in progress" and "Intangibles" 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 rate-regulated accounting policies. In absence of rate-regulated accounting, net earnings for 2010 would have been $7.8 million lower (2009 – $3.8 million).

d. **Regulatory Amortization**

*Accounting for the impact of rate regulation:*

In December 2010, the UARB granted NSPI approval to defer certain tax benefits related to renewable energy projects arising in 2010 through an increase in regulatory amortization. The UARB will convene a proceeding in 2011 to discuss how this deferral will be applied. In the absence of UARB approval, 2010 earnings would have been $14.5 million higher.

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

In January 2010, NSPI reached an agreement with stakeholders on its calculation of regulated ROE. The agreement includes a provision which provides the Company with flexibility in its amortization of the pre-2003 income taxes to accelerate additional amortization amounts in current periods and subsequently reduce amounts in future periods. In the absence of UARB approved recovery, the liability would have been expensed when incurred. More details are provided in note 10.

The UARB agreed to allow NSPI to defer taxes not reflected in rates for the period January 1, 2005 until April 1, 2005, the date when new rates became effective. The UARB approved recovery of this regulatory asset over eight years, commencing April 1, 2007.

The UARB agreed to allow NSPI to defer demand side management program expenses for the period January 1, 2008 until December 31, 2009. The UARB approved recovery of this regulatory asset over six years commencing January 1, 2009.

The UARB agreed to allow NSPI to defer vegetation management spending of $2.0 million in 2008 to be recovered in rates in a future period. The period of recovery of this asset will be determined during the next general rate case.

In the absence of UARB approved deferrals for taxes, demand side management and vegetation management expenses would have been expensed as incurred. More details are provided in note 10.

e. **Property, Plant and Equipment**

Property, plant and equipment are recorded at original cost, including AFUDC, net of contributions in aid of construction including energy tax credits.

Depreciation is determined by the straight-line method, based on the estimated remaining service lives of the depreciable assets in each category. The service lives of regulated assets are determined based on formal depreciation studies, which require UARB approval.
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 include significant changes in regulation, a change in the Company's strategy or underperformance relative to projected future operating results.

*Accounting for the impact of rate regulation:*

During 2003, following completion of a depreciation study and a negotiated agreement with stakeholders, NSPI's regulator approved new depreciation rates which were to be phased in over four years beginning in 2004. In the decision on NSPI's 2005 rate application, the UARB delayed the phase-in of year-two rates for one year. In the decision on NSPI's 2006 rate application, the UARB approved restarting of the phase-in including year-two in 2006 rates. In its February 2007 decision, the UARB postponed the scheduled year-three phase-in of increased depreciation rates until the next rate application. In its November 2008 decision, the UARB approved the year-three phase-in effective January 1, 2009.

Absent consideration of growth in plant-in-service, the phase-in of new depreciation rates will increase depreciation expense by a cumulative increase of $20 million over the phase-in period. In the absence of UARB 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** | **2010** | 2009 |
|---|---|---|
| Generation | | |
| Thermal | **2.50%** | 2.50% |
| Gas turbines | **2.47%** | 2.47% |
| Combustion turbines | **3.33%** | 3.33% |
| Hydroelectric | **1.51%** | 1.51% |
| Wind turbines | **5.00%** | 5.00% |
| Transmission | **2.76%** | 2.76% |
| Distribution | **4.15%** | 4.15% |
| General plant | **7.07%** | 7.07% |
| General plant under capital lease | **13.18%** | 14.25% |
| Weighted average depreciation rate | **3.00%** | 3.13% |

In accordance with regulator-approved accounting policies, when depreciable property, plant and equipment of NSPI 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 would be charged to net earnings as incurred.

### f. Intangible Assets

Intangible assets consist primarily of land rights and computer software. Amortization is determined by the straight-line method, based on the estimated remaining service lives of the depreciable assets in each category. The service lives of regulated assets are determined based on formal depreciation studies which require UARB approval as discussed in property, plant and equipment in note 1(e). The estimated weighted average service life for the Company's intangible assets is 57 years (2009 – 63 years).

When indicators of impairment exist, the Company determines whether the net carrying amount of the intangible assets 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:*

In the absence of UARB approval of amortization rates, NSPI would be required to set rates based on management's best estimates of useful lives. The average rates for the major categories are summarized as follows:

| **Function** | **2010** | 2009 |
|---|---|---|
| Transmission | **1.21%** | 1.21% |
| Distribution | **1.57%** | 1.57% |
| Other | **12.16%** | 12.03% |
| Weighted average amortization rate | **4.67%** | 3.66% |

### g. Capitalization Policy

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

### 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 CGAAP, 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(e). Payments on operating leases are expensed as incurred.

### i. Income Taxes and Investment Tax Credits

NSPI follows the future income tax method of accounting for income taxes. The difference between the tax basis of assets and liabilities and their carrying value on the balance sheet is used to calculate future tax assets and liabilities. The future tax assets and liabilities have been measured using substantively enacted tax rates that will be in effect when the differences are expected to reverse.

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 NSPI's rate-regulated accounting policy as approved by the UARB, NSPI defers any future income taxes from the statements of earnings and AOCI to a regulatory asset or liability where the future income taxes are expected to be included in future rates. More details are provided in note 7.

**j. Employee Future Benefits**

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

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

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

For any given year, when the net actuarial gain (loss), less the actuarial gain (loss) not yet included in the market-related value of plan assets, exceeds 10% of the greater of the accrued benefit obligation and the market-related value of the plan assets, an amount equal to the excess divided by the average remaining service period ("ARSP") is amortized on a straight-line basis. For NSPI, the ARSP of the active employees is 9 years as at December 31, 2010 and 2009.

On January 1, 2000, NSPI adopted the accounting standard on employee future benefits using the prospective application method. The transitional obligation (asset) resulting from the initial application is amortized on a linear basis 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 "Other assets" or "Other liabilities" on the balance sheet.

**k. 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. There were no short-term investments outstanding as at December 31, 2010 or 2009.

**l. Inventory**

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

**m. Debt Financing Costs**

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

**n. Derivative Financial & Commodity Instruments**

The Company classifies financial assets and financial liabilities as held-for-trading, loans and receivables, other financial liabilities or derivatives in valid hedging relationships. All financial instruments are initially recorded at fair value on the balance sheet. Subsequent measurements of the financial instruments are based on their classification.

Held-for-trading ("HFT") derivative financial assets and liabilities consist mainly of foreign exchange forward contracts, and coal, oil and gas options and swaps. The Company has not designated any non-derivative financial assets or liabilities as held-for-trading. HFT financial instruments are initially recorded at their fair value. The Company has classified its derivatives not in valid hedging relationships as held-for-trading and recognizes changes in fair value of its HFT derivatives in earnings of the reporting period.

Loans and receivables include cash and cash equivalents and accounts receivable and are measured at amortized cost using the effective interest method. Gains and losses are included in earnings and recorded in "Operating, maintenance and general expenses".

Other financial liabilities, which include accounts payable and accrued charges, preferred shares, short-term debt and long-term debt, are recognized at amortized cost. Preferred share dividends paid are recognized using the effective interest method. Interest expense and debt financing expenses related to the Company's long-term debt and short-term debt are recognized using the effective interest method.

Derivatives in valid hedging relationships are categorized as cash flow hedges and fair value hedges. The Company uses cash flow hedges to manage changes in commodity prices, foreign exchange rates, and interest rates. The Company uses fair value hedges to hedge the fair value of commodity positions.

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

The Company recognizes the fair value of all its hedges on its balance sheet.

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

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

Where documentation and effectiveness requirements are not met, the change in fair value of the derivative is recognized in earnings in the reporting period.

If a cash flow hedge is terminated, the effective portion of the change in fair value of the hedging derivative up until the date of termination remains in AOCI and is recognized in earnings, inventory or construction work in progress in the same period the related hedged risk is realized. The change in fair value of the derivative, if retained, would then be recognized in earnings from the termination date onward.

Amounts received or paid related to derivatives used to hedge foreign exchange and commodity price risks on fuel purchases are recognized in “Fuel for generation and purchased power” or “Inventory”. Amounts received or paid related to derivatives used to hedge foreign exchange on capital purchases are recognized in “Construction work in progress”. Amounts received or paid related to derivatives used to hedge interest rate risks are recognized over the term of the hedged item in “Financing charges”. Amounts received or paid related to HFT derivatives are reflected in “Other revenue”, unless alternative treatment is available as approved by the UARB.

Cash flows related to HFT derivatives and derivatives in valid hedging relationships are reflected in “Operating activities” and “Investing activities” on the statement of cash flows.

*Accounting for the impact of rate regulation:*

In accordance with Handbook Standard 3865 Hedges, NSPI determined that it cannot meet the probability requirement of the standard for its derivatives in place to hedge natural gas and heavy fuel oil for its Tufts Cove generating station (“TUC”). This is due to the generating station’s ability to fuel switch and NSPI’s economic dispatch based on the cost of these two fuels. The UARB has allowed NSPI to apply hedge accounting to these derivatives as long as the other requirements of the Handbook are met. In 2009, the UARB approved an amendment to NSPI’s accounting practice to include all TUC derivatives which are no longer required. Absent UARB approval, NSPI would be required to recognize the changes in fair value of these derivatives in net earnings of the period.

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

Further details on the regulatory assets and liabilities recognized as a result of the above can be found in note 10.

**o. 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.

**p. Research and Development Costs**

All research and development costs are expensed in the year incurred unless they qualify for deferral as a part of property, plant and equipment or intangible assets.

## 2. CHANGE IN ACCOUNTING ESTIMATE

In 2010, the Company revised its estimate of the expected benefit from accelerated tax deductions. The impact for the three months and twelve months ended December 31, 2010 was to reduce income tax expense by approximately $8.0 million and $14.0 million respectively. In accordance with rate-regulated accounting, the future income tax implications of this change in estimate have been deferred to a regulatory asset in "Other assets". This change in accounting estimate has been accounted for on a prospective basis.

## 3. EMPLOYEE FUTURE BENEFITS

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

The measurement date for the assets and obligations of each benefit plan is December 31, 2010.

### 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, 2010 | December 31, 2011 |
| Acquired companies pension plan | December 31, 2010 | December 31, 2011 |

### Total cash amount

Total cash amount for 2010, made up of contributions to its funded defined-benefit pension plans, contributions to its defined-contribution pension plan, employer paid premiums for its post-retirement health care plan, and amounts paid directly to retirees and beneficiaries in other plans, was $40.2 million (2009 – $32.1 million).

## Accrued pension and non-pension benefit asset (liability)

| | 2010 | | 2009 | |
|---|---|---|---|---|
| millions of dollars | **Defined benefit pension plans** | **Non-pension benefits plan** | Defined benefit pension plans | Non-pension benefits plans |
| **Assumptions (weighted average)** | | | | |
| Accrued benefit obligation – December 31: | | | | |
| Discount rate | **5.50%** | **5.50%** | 6.50% | 6.50% |
| Rate of compensation increase | **3% to 5.5%** | **3% to 5.5%** | 3% to 5.5% | 3% to 5.5% |
| Health care trend - initial (next year) | **-** | **4.00%** | - | 5.00% |
| - ultimate | **-** | **4.00%** | - | 4.00% |
| - year ultimate reached | **-** | **2011** | - | 2011 |
| Benefit cost for year ending December 31: | | | | |
| Discount rate | **6.50%** | **6.50%** | 7.50% | 7.50% |
| Expected long-term return on plan assets | **7.25%** | **-** | 7.25% | - |
| Rate of compensation increase | **3% to 5.5%** | **3% to 5.5%** | 3% to 5.5% | 3% to 5.5% |
| Health care trend - initial (current year) | **-** | **5.00%** | - | 6.00% |
| - ultimate | **-** | **4.00%** | - | 4.00% |
| - year ultimate reached | **-** | **2011** | - | 2011 |
| **Accrued benefit obligations** | | | | |
| Balance, January 1 | **$785.2** | **$36.3** | $667.2 | $36.1 |
| Employer current service cost | **9.0** | **1.4** | 6.5 | 1.3 |
| Employee contributions | **5.5** | **-** | 5.2 | - |
| Interest cost | **50.0** | **2.3** | 49.0 | 2.6 |
| Past service adjustment | **(1.0)** | **-** | - | - |
| Actuarial losses | **122.3** | **4.1** | 95.4 | 0.4 |
| Benefits paid | **(39.5)** | **(4.3)** | (38.1) | (4.1) |
| Balance, December 31 | **931.5** | **39.8** | 785.2 | 36.3 |
| **Fair value of plan assets** | | | | |
| Balance, January 1 | **592.1** | **-** | 508.8 | - |
| Employer contributions | **34.6** | **$4.3** | 26.9 | 4.1 |
| Employee contributions | **5.5** | **-** | 5.2 | - |
| Actual return on plan assets | **55.7** | **-** | 89.3 | - |
| Benefits paid | **(39.5)** | **(4.3)** | (38.1) | (4.1) |
| Balance, December 31 | **648.4** | **-** | 592.1 | - |
| **Reconciliation of financial status to accrued benefit asset, December 31** | | | | |
| Fair value of plan assets | **648.4** | **-** | 592.1 | - |
| Accrued benefit obligations | **931.5** | **39.8** | 785.2 | 36.3 |
| **Plan deficit** | **(283.1)** | **(39.8)** | (193.1) | (36.3) |
| Unamortized past service (gains) costs | **(0.3)** | **1.4** | (0.4) | 1.6 |
| Unamortized actuarial losses (gains) | **363.5** | **2.1** | 257.0 | (2.2) |
| Unamortized transitional obligation | **(0.9)** | **4.5** | 0.1 | 6.7 |
| Accrued benefit asset (liability) | **$79.2** | **$(31.8)** | $63.6 | $(30.2) |

The amounts recognized in “Other assets” and “Other liabilities” are as follows:

| | 2010 | | 2009 | |
|---|---|---|---|---|
| millions of dollars | **Defined benefit pension plans** | **Non-pension benefits plan** | Defined benefit pension plans | Non-pension benefits plans |
| Accrued benefit asset | **$110.7** | **-** | $94.2 | - |
| Accrued benefit liability | **(31.5)** | **$(31.8)** | (30.6) | $(30.2) |
| Net accrued benefit asset (liability) | **$79.2** | **$(31.8)** | $63.6 | $(30.2) |

| **Defined benefit plans asset allocation (% of plan assets)** | **2010** | | 2009 | |
|---|---|---|---|---|
| | **Employee pension plan** | **Acquired companies pension plan** | Employee pension plan | Acquired companies pension plan |
| Equity securities | **65%** | **64%** | 64% | 62% |
| Debt securities | **34%** | **36%** | 36% | 37% |
| Cash | **1%** | **-** | - | 1% |
| Total | **100%** | **100%** | 100% | 100% |

As at December 31, 2010, the pension funds do not hold any material investments in Emera Inc. or Nova Scotia Power Inc. securities.

**Plans with accrued benefit obligations in excess of assets**

As at December 31, 2010, all post-retirement benefit plans have accrued benefit obligations in excess of assets.

| **Benefits cost components** millions of dollars | **2010** | | 2009 | |
|---|---|---|---|---|
| **Defined benefit plan** | **Defined benefit pension plans** | **Non-pension benefits plan** | Defined benefit pension plans | Non-pension benefits plan |
| **Costs arising from events during the year:** | | | | |
| Current service costs | **$9.0** | **$1.4** | $6.5 | $1.3 |
| Interest on accrued benefits | **50.0** | **2.3** | 49.0 | 2.6 |
| Less: actual return on plan assets | **(55.7)** | **-** | (89.3) | - |
| Actuarial losses on accrued benefit obligation | **122.3** | **4.1** | 95.4 | 0.4 |
| Past service gain | **(1.0)** | **-** | - | - |
| **Future benefit costs before adjustments** | **124.6** | **7.8** | 61.6 | 4.3 |
| **Adjustments to recognize long-term nature of costs:** | | | | |
| Difference between expected return on assets and actual return | **6.2** | **-** | 40.8 | - |
| Amortization of transitional obligation | **-** | **2.2** | - | 2.2 |
| Difference between amortization of actuarial gains and actual actuarial gains on accrued benefit obligations | **(112.8)** | **(4.3)** | (94.8) | (0.7) |
| Difference between amortization of past service costs and past service costs for the year | **1.0** | **0.2** | - | 0.2 |
| Total cost recognized | **$19.0** | **$5.9** | $7.6 | $6.0 |
| | | | | |
| **Defined contribution plan** | | | | |
| Employer cost | **$1.3** | **-** | $1.0 | - |

The expected return on plan assets is determined based on the market-related value of plan assets of $684.6 million at January 1, 2010 (2009 – $670.5 million), adjusted for interest on certain cash flows during the year.

**Sensitivity analysis for non-pension benefits plans**

The health care cost trend significantly influences the amounts presented for health care plans. An increase or decrease of one percentage point of the assumed health care cost trend would have had the following impact in 2010:

| millions of dollars | **Increase** | **Decrease** |
|---|---|---|
| Current service cost and interest cost | - | - |
| Accrued benefit obligation, December 31 | $1.5 | $(1.4) |

## 4. FUEL ADJUSTMENT

The UARB approved the implementation of a Fuel Adjustment Mechanism ("FAM") in the 2009 General Rate Decision effective January 1, 2009. The fuel adjustment related to the FAM includes the effect of fuel costs in both the current period and the preceding year. The difference between actual fuel costs and amounts recovered from customers in the current period is included in the fuel adjustment. This amount, less the incentive component, is deferred to a FAM regulatory asset in "Other assets" or a FAM regulatory liability in "Other liabilities". Also included in the 2010 fuel adjustment is the rebate to customers of over recovered fuel costs from 2009.

Details of the fuel adjustment related to the FAM are summarized in the following table:

| millions of dollars | **2010** | 2009 |
|---|---|---|
| (Under) over recovery of current period fuel costs | **$(76.6)** | $8.5 |
| Rebate to customers from prior year | **(22.4)** | - |
| Fuel adjustment | **$(99.0)** | $8.5 |

The Company has recognized a future income tax expense related to the fuel adjustment based on NSPI's applicable statutory income tax rate. The FAM regulatory asset or liability includes amounts recognized as a fuel adjustment and associated interest included in "Financing charges". As at December 31, 2010, NSPI's FAM regulatory asset was $92.9 million (2009 – liability of $9.9 million), and future income tax liability related to the FAM was $29.2 million (2009 – asset of $3.4 million).

In the absence of UARB approval, the fuel adjustment would not have been recognized and earnings for the year ended December 31, 2010 would be $80.4 million ($56.3 million after-tax) lower (2009 – $9.9 million or $6.5 million after-tax higher).

## 5. OPERATING LEASES

The Company has entered into operating lease agreements for office space and rail cars, which expire in 2011 and 2015. Future minimum annual lease payments under the leases are as follows:

| millions of dollars | |
|---|---|
| 2011 | $1.8 |
| 2012 | 0.3 |
| 2013 | 0.3 |
| 2014 | 0.3 |
| 2015 | 0.3 |
| | $3.0 |

For the year ended December 31, 2010, the Company recognized $9.6 million (2009 – $9.5 million) of operating leases for office space and telecommunications services in "Operating, maintenance and general expense".

## 6. FINANCING CHARGES

Financing charges consists of the following:

| millions of dollars | **2010** | 2009 |
|---|---|---|
| Interest - long-term debt | **$109.0** | $98.2 |
| - short-term debt | **1.6** | 1.0 |
| Preferred share dividends (note 17) | **7.9** | 9.5 |
| Amortization of defeasance cost (note 10) | **12.1** | 12.1 |
| Amortization of debt financing costs | **1.8** | 1.8 |
| Allowance for funds used during construction | **(17.1)** | (7.8) |
| Interest (recovery) expense on deferral of FAM | **(3.8)** | 1.4 |
| Foreign exchange losses (gains) recovered through the FAM | **9.3** | (3.0) |
| Banking fees and other | **5.0** | 1.5 |
| | **$125.8** | $114.7 |

## 7. INCOME TAXES

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

| millions of dollars | | **2010** | | 2009 |
|---|---|---|---|---|
| Earnings before income taxes | **$103.9** | | $151.5 | |
| Income taxes, at statutory rates | **35.3** | **34.0%** | 53.0 | 35.0% |
| Future income taxes on regulated earnings deferred to regulatory assets (note 10) | **(53.4)** | **(51.4)** | (22.9) | (15.1) |
| Non-deductible preferred share dividends | **2.7** | **2.6** | 3.3 | 2.2 |
| Non-deductible regulatory amortization (note 10) | **11.8** | **11.4** | 9.3 | 6.1 |
| Change in estimate of prior year expected benefit of tax deductions | **(4.7)** | **(4.5)** | - | - |
| Recovery of prior year income taxes | **(4.4)** | **(4.2)** | - | - |
| Difference in tax rate for future income taxes not deferred to regulatory assets | **(1.9)** | **(1.8)** | 0.1 | 0.1 |
| Other | **(2.8)** | **(2.8)** | (0.6) | (0.4) |
| | **(17.4)** | **(16.7)%** | 42.2 | 27.9% |
| Income taxes – current | **(47.1)** | | 45.6 | |
| Income taxes – future | **$29.7** | | $(3.4) | |

The future income tax assets and liabilities comprise the following:

| | Current portion | | Long-term portion | |
|---|---|---|---|---|
| millions of dollars | **2010** | 2009 | **2010** | 2009 |
| **Future income tax assets:** | | | | |
| Inventory | **$2.5** | $2.3 | **-** | - |
| Share-based compensation | **2.4** | 2.5 | **-** | - |
| Derivatives | **(0.9)** | 25.3 | **-** | - |
| Tax loss carry forwards | **-** | 4.1 | **-** | - |
| Other | **0.1** | 0.2 | **-** | - |
| | **$4.1** | $34.4 | **-** | - |
| **Future income tax liabilities:** | | | | |
| Property, plant and equipment | **-** | - | **$176.8** | $82.2 |
| Derivatives | **-** | - | **4.0** | 3.2 |
| Asset retirement obligations | **-** | - | **(62.4)** | (45.2) |
| Deferral of FAM | | | **29.2** | (3.4) |
| Pension | **-** | - | **21.3** | 14.9 |
| Defeasance costs | **-** | - | **19.2** | 20.0 |
| Intangibles | **-** | - | **(23.6)** | (23.2) |
| Other | **-** | **-** | **(1.4)** | 3.5 |
| | **-** | - | **$163.1** | $52.0 |

The offset to substantially all of the net future income tax assets and liabilities noted above have been recorded as a regulatory asset in "Other assets". These amounts include a gross up to reflect the income tax associated with future revenues required to fund these net future income tax liabilities.

*Accounting for the impact of rate regulation:*

In the absence of rate-regulated accounting, future income tax expenses would have been recorded against net earnings and net earnings would be $60.1 million lower in 2010 (2009 – $18.9 million).

## 8. ACCOUNTS RECEIVABLE

At December 31, 2010, the Company had unbilled revenue included in accounts receivable in the amount of $84.1 million (2009 – $85.4 million). The unbilled revenue is an estimate of the amount of revenue related to energy delivered to customers since the date their meters were last read. Actual results may differ from this estimate.

NSPI had a natural gas purchase agreement, which settled in November 2010, which included a price adjustment clause covering three years of natural gas purchases. The clause stated NSPI would pay for all gas purchases at the agreed contract price, but would be entitled to a price rebate on a portion of the volumes, settled in November 2007 and November 2010. At December 31, 2009, the receivable was $82.1 million.

## 9. INVENTORY

The change in inventory is due to the following:

| For the year ended | Fuel inventory December 31 | | Materials inventory December 31 | |
|---|---|---|---|---|
| millions of dollars | **2010** | 2009 | **2010** | 2009 |
| Inventory, beginning of period | **$139.3** | $101.6 | **$26.3** | $25.2 |
| Purchases | **327.5** | 355.4 | **43.2** | 37.1 |
| Write-down of inventory to net realizable value | **-** | - | **(0.9)** | (0.7) |
| Inventories expensed | **(340.9)** | (317.7) | **(21.8)** | (21.1) |
| Inventories capitalized | **-** | - | **(24.6)** | (21.4) |
| Other | **-** | - | **6.1** | 7.2 |
| Inventory, end of period | **$125.9** | $139.3 | **$28.3** | $26.3 |

The Company has not pledged inventory as security for liabilities.

## 10. OTHER ASSETS AND LIABILITIES

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

| millions of dollars | **2010** | 2009 |
|---|---|---|
| **Other assets:** | | |
| *Regulatory assets:* | | |
| Future income tax regulatory asset | **$136.9** | $25.2 |
| Unamortized defeasance costs | **94.6** | 106.7 |
| Deferral of FAM | **92.9** | - |
| Pre-2003 income tax and related interest | **56.9** | 75.2 |
| Deferral of income and capital taxes not included in Q1 2005 rates | **10.0** | 11.9 |
| Deferral of demand side management | **7.5** | 9.7 |
| Deferral of vegetation management | **2.0** | 2.0 |
| Deferral of Tufts Cove derivatives | **1.3** | 9.6 |
| Held-for-trading natural gas contracts | **-** | 3.9 |
| | **402.1** | 244.2 |
| *Non-regulatory assets:* | | |
| Accrued pension asset (note 3) | **110.7** | 94.2 |
| Other | **-** | 0.7 |
| | **110.7** | 94.9 |
| | **$512.8** | $339.1 |

| | **2010** | 2009 |
|---|---|---|
| **Other liabilities:** | | |
| *Regulatory liabilities:* | | |
| 2010 renewable tax benefits deferral | **$14.5** | - |
| Held-for-trading natural gas contracts | **12.3** | $4.7 |
| Deferral of Tufts Cove derivatives | **2.0** | 10.4 |
| Deferral of FAM | **-** | 9.9 |
| | **28.8** | 25.0 |
| *Non-regulatory liabilities:* | | |
| Accrued pension and non-pension benefit liability (note 3) | **63.3** | 60.8 |
| Unearned revenue | **1.1** | 1.7 |
| Other | **5.4** | 4.0 |
| | **69.8** | 66.5 |
| | **$98.6** | $91.5 |

**Regulatory assets consist of:**

**Future Income Tax Regulatory Asset**
In accordance with the Company's rate-regulated accounting policies covering income taxes, NSPI deferred any future income taxes to a regulatory asset where the future income taxes are expected to be included in future rates. Absent this accounting policy, NSPI's 2010 net earnings would be $60.1 million lower (2009 – $18.9 million).

**Unamortized Defeasance Costs**
Upon privatization in 1992, NSPI became responsible for managing a portfolio of defeasance securities held in trust, which as at December 31, 2010 and 2009 totaled $1.0 billion. The excess of the cost of defeasance investments over the face value of the related debt is deferred on the balance sheet and amortized over the life of the defeased debt as permitted by the UARB. In the absence of UARB approval, the losses would have been expensed as incurred and net earnings would be $12.1 million higher in 2010 and 2009.

**Deferral of Fuel Adjustment Mechanism**
As discussed in Note 4, the UARB approved the implementation of a FAM in NSPI's 2009 General Rate Decision effective January 1, 2009.

In the absence of UARB approval, the fuel adjustment would not have been recognized and net earnings for the year ended December 31, 2010 would be $80.4 million ($56.3 million after-tax) lower (2009 – $9.9 million or $6.5 million after-tax higher).

**Pre-2003 Income Tax and Related Interest**
NSPI has a regulatory asset related to pre-2003 income taxes that have been paid, but not yet recovered from customers. This circumstance arose when NSPI claimed capital cost allowance deductions in its corporate income tax returns that were ultimately disallowed by a decision of the Supreme Court of Canada. NSPI applied to the regulator to include recovery of these costs in customer rates. In its February 2007 decision, the UARB approved recovery of this regulatory asset over eight years, commencing April 1, 2007.

In January 2010, NSPI reached an agreement with stakeholders on its calculation of regulated ROE. The agreement provides the Company with flexibility in amortizing the pre-2003 income tax regulatory asset allowing the Company to recognize additional amortization in current periods and reducing amounts in future periods. Accordingly, to allow flexibility relating to future customer rate requirements, NSPI recorded an additional discretionary $4.8 million of regulatory amortization expense for the year ended December 31, 2010 (December 31, 2009 – $10.0 million). In the absence of UARB approved recovery, the liability would have been expensed when incurred, therefore net earnings would be $18.3 million higher in 2010 (2009 – $24.6 million).

In 2009, NSPI recorded an income tax recovery of $5.5 million relating to manufacturing and processing deductions claimed for its 1999-2003 amended corporate income tax returns, which reduced the regulatory asset.

**Deferral of Income and Capital Taxes Not Included in Q1 2005 Rates**
The UARB agreed to allow NSPI to defer taxes not reflected in rates for the period January 1, 2005 until April 1, 2005, the date when new rates became effective. In 2005, NSPI deferred $16.7 million consisting of $4.5 million of provincial and federal grants and $12.2 million in income taxes reflecting increases in these taxes since rates were last set in 2002. In its February 2007 decision, the UARB approved recovery of this regulatory asset over eight years, commencing April 1, 2007. In the absence of UARB approval, these taxes would not have been deferred and net earnings for 2010 would be $1.9 million higher (2009 – $1.9 million).

**Deferral of Demand Side Management**
The UARB agreed to allow NSPI to defer up to $12.8 million of demand side management expenditures for the period January 1, 2008 through December 31, 2009, to be recovered in rates over six years commencing January 1, 2009. In the absence of the UARB's approval, these costs would not have been deferred and net earnings for 2010 would be $2.2 million higher (2009 – $9.4 million lower).

**Deferral of Vegetation Management**
The UARB agreed to allow NSPI to defer up to $2.0 million of vegetation management spending in 2008 to be recovered in rates in a future period. The investment in vegetation management spending was part of a specific initiative to improve the reliability of service provided to customers. In the absence of UARB approval, these costs would have been expensed as incurred.

**Deferral of Tufts Cove Derivatives**
In accordance with Handbook Standard 3865 Hedges, NSPI determined that it could not meet the probability requirement of the standard for its derivatives in place to hedge natural gas and heavy fuel oil for TUC. This is due to the generating station's ability to fuel switch and NSPI's economic dispatch based on the relative cost of these two fuels. The UARB has allowed NSPI to apply hedge accounting to these

derivatives as long as the other requirements of the Handbook are met. This accounting policy permits NSPI to defer the fair value of hedges that are no longer required because of fuel switching.

In 2009, the UARB approved an amendment to NSPI's accounting practice to include all Tufts Cove financial commodity hedges which are no longer required. This change in practice will impact the timing of recognition between "Fuel for generation and purchased power" and "Fuel adjustment" as a result of the FAM implemented in 2009. The change in accounting practice has been applied prospectively beginning January 1, 2009, as required by the UARB.

Absent UARB approval, NSPI would be required to recognize the change in fair value of these derivatives in "Fuel for generation and purchased power" with an offset to "Fuel adjustment". However, with the approval of FAM, there would be no material earnings impact.

**Held-for-trading Natural Gas Contracts**
In accordance with implementing Standard 3855 Financial Instruments – Recognition and Measurement, the Company has contracts for the purchase and sale of natural gas at TUC that are considered HFT derivatives and accordingly are recognized on the balance sheet at fair value. This reflects NSPI's history of buying and reselling any natural gas not used in the production of electricity at TUC. Changes in fair value of HFT derivatives are normally recognized in net earnings. In accordance with NSPI's rate-regulated accounting policy for financial instruments and hedges relating to TUC fuel, NSPI has deferred any changes in fair value to a regulatory asset or liability. Absent UARB approval, NSPI would be required to recognize the changes in fair value of these derivatives in earnings. However, with the approval of FAM, there would be no material earnings impact.

**Regulatory liabilities consist of:**

**2010 Renewable Tax Benefits Deferral**
In 2010, the UARB granted NSPI approval to defer certain tax benefits related to renewable energy projects arising in 2010. The UARB will convene a proceeding in 2011 to discuss how this deferral will be applied. Absent UARB approval these benefits would not have been deferred and net earnings would be $14.5 million higher.

**Held-for-trading Natural Gas Contracts**
As discussed above, in accordance with NSPI's accounting policy for financial instruments and hedges relating to TUC fuel, NSPI has deferred any changes in fair value of its natural gas contracts to a regulatory asset or liability. Absent UARB approval, NSPI would be required to recognize the changes in fair value of these derivatives in earnings. However, with the approval of FAM, there would be no material earnings impact.

**Deferral of Tufts Cove Derivatives**
As discussed above, NSPI has an accounting policy that permits NSPI to defer the fair value of any TUC financial commodity hedges that are no longer required. Absent UARB approval, NSPI would be required to recognize the changes in fair value of these derivatives in earnings. However, with the approval of FAM, there would be no material earnings impact.

## 11. INTANGIBLES

Intangibles are comprised of the following:

| millions of dollars | Cost | Accumulated Amortization | 2010 Net Book Value |
|---|---|---|---|
| Transmission | **$51.7** | **$16.3** | **$35.4** |
| Distribution | **19.7** | **5.4** | **14.3** |
| Other | **32.4** | **9.6** | **22.8** |
| | **$103.8** | **$31.3** | **$72.5** |

| millions of dollars | Cost | Accumulated Amortization | 2009 Net Book Value |
|---|---|---|---|
| Transmission | $51.7 | $15.7 | $36.0 |
| Distribution | 17.6 | 5.1 | 12.5 |
| Other | 30.0 | 12.8 | 17.2 |
| | $99.3 | $33.6 | $65.7 |

Amortization expense for the year ended December 31, 2010 was $4.3 million (2009 – $3.2 million).

## 12. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is comprised of the following:

| millions of dollars | Cost | Accumulated Depreciation | 2010 Net Book Value |
|---|---|---|---|
| Generation | | | |
| Thermal | **$1,965.1** | **$827.5** | **$1,137.6** |
| Gas Turbines | **33.0** | **24.8** | **8.2** |
| Combustion Turbines | **83.5** | **17.6** | **65.9** |
| Hydroelectric | **424.4** | **148.4** | **276.0** |
| Wind Turbines | **219.7** | **2.5** | **217.2** |
| Transmission | **598.6** | **312.5** | **286.1** |
| Distribution | **1,178.7** | **649.2** | **529.5** |
| General plant including capital lease | **318.8** | **170.3** | **148.5** |
| | **$4,821.8** | **$2,152.8** | **$2,669.0** |

| millions of dollars | Cost | Accumulated Depreciation | 2009 Net Book Value |
|---|---|---|---|
| Generation | | | |
| Thermal | $1,902.6 | $796.4 | $1,106.2 |
| Gas Turbines | 32.8 | 24.0 | 8.8 |
| Combustion Turbines | 73.8 | 15.1 | 58.7 |
| Hydroelectric | 401.7 | 144.1 | 257.6 |
| Wind Turbines | 2.1 | 0.7 | 1.4 |
| Transmission | 569.2 | 306.6 | 262.6 |
| Distribution | 1,141.9 | 626.3 | 515.6 |
| General plant including capital lease | 312.0 | 157.3 | 154.7 |
| | $4,436.1 | $2,070.5 | $2,365.6 |

## 13. INTEREST IN JOINTLY CONTROLLED PROJECT

In November 2009, NSPI signed a 20-year operating agreement with Renewable Energy Services Ltd. ("RESL") for operation of a 23.3 MW wind energy project at Point Tupper, Nova Scotia. NSPI will acquire and retain title to specific property, plant and equipment, which is less than 50% of the total project combined assets. Each company is entitled to its proportionate share of the net operating revenues based on the relative value of their assets.

NSPI has provided a guarantee for the indebtedness of RESL in connection with the project. The guarantee is up to a maximum of $23.5 million. NSPI holds a security interest in the assets of RESL, including the project assets.

Beginning August 2010, following the commencement of service, NSPI has recorded its share of the net operating revenues of the project. As at December 31, 2010, $25.4 million was included in "Property, plant and equipment" for NSPI's portion of the Point Tupper wind energy project. NSPI's share of the cash flows and the net earnings was immaterial for the year.

## 14. ASSET RETIREMENT OBLIGATIONS

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

The change in ARO is due to the following:

| millions of dollars | **2010** | 2009 |
|---|---|---|
| Balance, beginning of year | **$101.5** | $87.6 |
| Accretion included in depreciation expense | **3.5** | 3.3 |
| Accretion deferred to regulatory asset | **2.1** | 1.5 |
| Liabilities settled | **(1.2)** | (1.2) |
| Additions | **32.8** | 10.3 |
| Balance, end of year | **$138.7** | $101.5 |

The key assumptions used to determine the ARO are as follows:

| Asset | Credit-adjusted risk-free rate | Estimated undiscounted future obligation (millions of dollars) | Expected settlement date |
|---|---|---|---|
| Thermal | 5.30% | $258.9 | 10 – 29 years |
| Hydro | 5.27% | 101.4 | 21 – 51 years |
| Wind | 5.21% | 45.5 | 13 – 20 years |
| Combustion turbines | 5.25% | 12.9 | 1 – 14 years |
| Transmission & distribution | 5.74% | 21.6 | 1 – 15 years |
| | | $440.3 | |

Some of the Company's hydro, transmission and distribution assets may have additional ARO. 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 ARO cannot be made at this time.

Additionally, some of the Company's transmission and distribution assets may have conditional ARO, the fair value of which cannot be reasonably estimated as sufficient information does not exist to estimate the obligation. A liability will be recognized in the period in which sufficient information becomes available.

*Accounting for the impact of rate regulation:*

Any difference between the amount approved by the UARB as depreciation expense and the amount that would have been calculated under the accounting standard for ARO is recognized as a regulatory asset in "Property, plant and equipment". In the absence of this deferral, net earnings for 2010 would be $2.1 million lower (2009 – $1.5 million).

## 15. SHORT-TERM DEBT

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

| millions of dollars | **2010** |
|---|---|
| Advances against the operating line of credit, which when drawn upon, bears interest at the prime rate plus 0.50%; the prime rate on December 31, 2010 was 3.00%. | **$1.6** |
| Short-term discount notes bearing interest at prevailing market rates, which on December 31, 2010, averaged 1.07%. | **46.7** |
| | **$48.3** |

| millions of dollars | 2009 |
|---|---|
| Advances against the operating line of credit, which when drawn upon, bears interest at the prime rate plus 1.25%; the prime rate on December 31, 2009 was 2.50%. | $4.9 |
| Short-term discount notes bearing interest at prevailing market rates, which on December 31, 2009, averaged 0.35%. | 193.3 |
| | $198.2 |

This short-term debt is unsecured.

## 16. LONG-TERM DEBT

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

| | Effective Average Interest Rate % | | | Amount Outstanding | |
|---|---|---|---|---|---|
| millions of dollars | **2010** | 2009 | Years of Maturity | **2010** | 2009 |
| Medium-term notes (1) | **6.56** | 6.60 | 2011 – 2097 | **$1,610.0** | $1,410.0 |
| Debentures | **9.75** | 9.75 | 2019 | **95.0** | 95.0 |
| Short-term discount notes (2) | **1.07** | - | 3 year renewal | **241.7** | - |
| Capital lease obligations | **6.30** | 3.89 | Various | **0.1** | 3.7 |
| | | | | **1,946.8** | 1,508.7 |
| Amount due within one year | | | | **(0.1)** | (100.7) |
| Unamortized debt financing costs | | | | **(13.0)** | (11.0) |
| | | | | **$1,933.7** | $1,397.0 |

(1) Included in the medium-term notes above is an NSPI medium-term note of $40.0 million bearing interest at 8.50%, maturing in 2026, and is extendable until 2056 at the option of the holders.
(2) Short-term discount notes are backed by an operating credit facility which matures in 2013.

As at December 31, 2010, long-term debt and obligations under a capital lease are due as follows:

| millions of dollars | |
|---|---|
| Year of Maturity | **Debt** |
| Three year renewable | $241.7 |
| 2011 | 0.1 |
| 2012 | - |
| 2013 | 300.0 |
| 2014 | - |
| 2015 | 70.0 |
| Greater than 5 years | 1,335.0 |
| | $1,946.8 |

## 17. PREFERRED SHARES

NSPI's preferred shares are classified as a financial liability on the balance sheet.

**Authorized:**
Unlimited number of First Preferred Shares, issuable in series.
Unlimited number of Second Preferred Shares, issuable in series.

| **Issued and outstanding:** | Millions of Shares | Preferred Share Capital millions of dollars |
|---|---|---|
| December 31, 2008 | 10.4 | $260.0 |
| Redemption of Series C First Preferred Shares | (5.0) | (125.0) |
| December 31, 2009 | 5.4 | 135.0 |
| December 31, 2010 | **5.4** | **$135.0** |

As at December 31, 2010 and 2009, the Company had 5.4 million 5.9% Series D preferred shares with the following redemption features:

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

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

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

**Series C First Preferred Shares:**
On April 1, 2009, NSPI redeemed its outstanding Cumulative Redeemable First Preferred Shares, Series C for a redemption price of $25 per share for a total of $125 million. Each share was entitled to a $1.225 per share per annum fixed cumulative preferential dividend, as and when declared by the Board of Directors, accruing from the date of issue and payable quarterly on the first day of January, April, July and October of each year.

## 18. COMMON SHARES

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

| **Issued and outstanding:** | Millions of Shares |
|---|---|
| December 31, 2008 | 106.8 |
| Issued for non-cash consideration | 0.4 |
| December 31, 2009 | 107.2 |
| Issued for cash consideration | 5.0 |
| December 31, 2010 | 112.2 |

### EMPLOYEE COMMON SHARE PURCHASE PLANS

Employees may participate in Emera's Employee Common Share Purchase Plan to which the Company and employees make cash contributions for the purpose of purchasing common shares of NSPI's parent company, Emera Inc. ("Emera"), and which allows reinvestment of dividends.

### SHARE-BASED COMPENSATION PLAN

#### Deferred Share Unit Plan and Performance Share Unit Plan

The Company has deferred share unit ("DSU") and performance share unit ("PSU") (formerly restricted share unit) plans.

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

Under the executive and senior management DSU plan, each participant may elect to defer all or a percentage of their annual incentive award in the form of DSUs with the provision 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 average fifty day year-end stock closing share price of an Emera 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 then by the average fifty day stock closing share price of an Emera common share. Payments are usually made in cash. At the sole discretion of the Management Resources and Compensation Committee ("MRCC"), payments may be made in the form of actual shares. Any participant who is a United States taxpayer shall receive payment on the first business day following the six month anniversary of their termination. Under the Directors' DSU plan on or after January 1, 2010, a United States taxpayer may elect one of several dates as the payment date for DSUs recorded in the participant's account provided such elections are made in accordance with the deadlines under the plan for deferral elections and provided the payment dated elected shall not be a date that falls after December 31 of the calendar year that begins immediately following the termination date.

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

PSUs are granted annually for three-year overlapping performance cycles. The 2010 PSUs were granted based on the average of Emera's stock closing price for the fifty trading days prior to December 31 of the prior year and multiplied by a dividend ratio factor of 1.15 and a discount factor of 1.191 for share price appreciation. Dividend equivalents are awarded and are used to purchase additional PSUs. The PSU value varies according to the Emera common share market price and corporate performance.

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

| | Employee DSUs Outstanding | Employee PSUs Outstanding | Director DSUs Outstanding |
|---|---|---|---|
| December 31, 2008 | 81,061 | 118,183 | 42,789 |
| Granted | 19,089 | 48,812 | 9,167 |
| Retirement, termination, disability & death | (49,735) | - | - |
| Payout | - | (32,850) | - |
| December 31, 2009 | 50,415 | 134,145 | 51,956 |
| Granted | 13,777 | 45,560 | 12,165 |
| Payout | - | (33,783) | - |
| December 31, 2010 | 64,192 | 145,922 | 64,121 |

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 PSU 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, 2010, $3.2 million (2009 – $2.4 million) of compensation expense related to the options granted, units issued and shares purchased by employees was recognized in "Operating, maintenance and general expense".

## 19. SUPPLEMENTAL CASH FLOW INFORMATION

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

| millions of dollars | **2010** | 2009 |
|---|---|---|
| Increase in accounts receivable | **$(0.3)** | $(71.5) |
| Decrease in contract receivable | **82.1** | 56.4 |
| Decrease (increase) in inventory | **11.4** | (38.8) |
| (Increase) decrease in prepaid expenses | **(0.4)** | 0.5 |
| Change in posted margin included in accounts receivable | **(2.5)** | 25.1 |
| Increase in other accounts payable and accrued charges and due to associated companies | **11.8** | 35.8 |
| Change in heavy fuel oil hedging balance in AOCI | **3.1** | (4.3) |
| Change in income taxes receivable/payable | **(41.8)** | 9.3 |
| Change in non-cash operating working capital | **$63.4** | $12.5 |

## 20. CAPITAL MANAGEMENT

The Company includes shareholders' equity (excluding AOCI), short-term and long-term debt, preferred shares, and cash and cash equivalents in the definition of capital as follows:

| millions of dollars | **2010** | 2009 |
|---|---|---|
| Shareholders' equity, excluding AOCI | **$1,200.7** | $1,129.4 |
| Debt | **1,982.1** | 1,695.9 |
| Preferred shares | **135.0** | 135.0 |
| Cash and cash equivalents | **(0.3)** | (0.3) |
| | **$3,317.5** | $2,960.0 |

The Company's objective when managing capital is to ensure sufficient liquidity exists by maintaining access to capital markets in order to allow the Company to support its capital program. The Company is in compliance with its debt covenants and targets a long-term capital structure consistent or within these parameters. The covenants are maintained by the Company through the issuance of common shares, medium-term notes, preferred shares, or other indebtedness.

NSPI is subject to regulation by the UARB with a maximum allowed common equity component effective January 1, 2010 of 40% (2009 – 45%). The Company is in compliance with this requirement.

In January 2010, NSPI reached an agreement with stakeholders on its calculation of regulated ROE. The agreement establishes that NSPI will continue to use actual capital structure, actual equity and actual net earnings to calculate actual annual regulated ROE. The agreement was approved by the UARB. The UARB have set, as a condition, NSPI will maintain its average actual regulated annual common equity at a level no higher than 40% in 2010 and until the next general rate case.

The Company's trust indentures, applicable to the senior unsecured debenture and senior unsecured medium-term notes, provide that the Company's funded debt cannot exceed 75% of total capitalization as defined in the agreements. The Company's syndicated bank credit facility limits its debt to 65% of total capitalization. The Company is in compliance with all of its financial debt covenants.

## 21. FINANCIAL INSTRUMENTS

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

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

Financial instruments include the following:

| | | **2010** | | 2009 |
|---|---|---|---|---|
| millions of dollars | **Carrying Amount** | **Fair Value** | Carrying Amount | Fair Value |
| Cash | **$0.3** | **$0.3** | $0.3 | $0.3 |
| Accounts receivable | **192.5** | **192.5** | 271.8 | 271.8 |
| Derivatives held in a valid hedging relationship (current and long-term portion) | | | | |
| Cash flow hedges | **45.5** | **45.5** | 41.2 | 41.2 |
| Fair value hedges | **-** | **-** | 8.0 | 8.0 |
| Held-for-trading derivatives (current and long-term portion) | **14.5** | **14.5** | 15.1 | 15.1 |
| Total financial assets | **$252.8** | **$252.8** | $336.4 | $336.4 |
| | | | | |
| Accounts payable and accrued charges | **$221.3** | **$221.3** | $213.9 | $213.9 |
| Short-term debt | **48.3** | **48.3** | 198.2 | 198.2 |
| Derivatives held in a valid hedging relationship (current and long-term portion) | | | | |
| Cash flow hedges | **11.6** | **11.6** | 73.0 | 73.0 |
| Held-for-trading derivatives (current and long-term portion) | **22.6** | **22.6** | 13.5 | 13.5 |
| Long-term debt (including current portion) | **1,933.8** | **2,280.5** | 1,497.7 | 1,712.8 |
| Preferred shares | **135.0** | **152.3** | 135.0 | 151.2 |
| Total financial liabilities | **$2,372.6** | **$2,736.6** | $2,131.3 | $2,362.6 |

**Fair value hierarchy**

A fair value hierarchy is used to categorize valuation techniques used in the determination of fair value. Quoted market prices are Level 1, internal models using observable market information as inputs are Level 2, and internal models without observable market information as inputs are Level 3.

The fair value hierarchy of financial assets and liabilities accounted for at fair value at December 31, 2010 was as follows:

| | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| (millions of dollars) | | | | |
| Financial assets: | | | | |
| Cash | $0.3 | - | - | $0.3 |
| Derivatives in a valid hedging relationship (current and long-term portion) | | | | |
| Cash flow hedges | 41.2 | $4.3 | - | 45.5 |
| Held-for-trading derivatives (current and long-term portion) | - | 1.9 | $12.6 | 14.5 |
| Total financial assets | $41.5 | $6.2 | $12.6 | $60.3 |
| Financial liabilities: | | | | |
| Derivatives in a valid hedging relationship (current and long-term portion) | | | | |
| Cash flow hedges | $1.0 | $10.6 | - | $11.6 |
| Held-for-trading derivatives (current and long-term portion) | - | 1.3 | $21.3 | 22.6 |
| Total financial liabilities | $1.0 | $11.9 | $21.3 | $34.2 |

Changes in the fair value of financial assets classified as Level 3 in fair value hierarchy of $86.1 million during the year ended December 31, 2010, were as follows:

| millions of dollars | Accounts receivable | Derivatives in a valid hedging relationship – Cash flow hedge | Held-for-trading derivatives | Total |
|---|---|---|---|---|
| Balance at January 1, 2010 | $82.1 | $1.5 | $15.1 | $98.7 |
| Total loss realized and unrealized | | | | |
| Included in earnings | (5.8) | - | - | (5.8) |
| Purchases, issuances, settlements | (76.3) | (1.5) | (0.7) | (78.5) |
| Transfer to Level 2 | - | - | (1.9) | (1.9) |
| Transfer to Held-for-trading | - | - | 0.1 | 0.1 |
| Balance at December 31, 2010 | - | - | $12.6 | $12.6 |

Changes in the fair value of financial liabilities classified as Level 3 in fair value hierarchy of $11.4 million during the year ended December 31, 2010, were as follows:

| millions of dollars | Derivatives in a valid hedging relationship – Cash flow hedges | Held-for-trading derivatives | Total |
|---|---|---|---|
| Balance at January 1, 2010 | $(2.1) | $(7.8) | $(9.9) |
| Total (loss) gain realized and unrealized | | | |
| Included in earnings | (0.8) | (1.3) | (2.1) |
| Included in AOCI | 11.3 | - | 11.3 |
| Purchases, issuances, settlements | (28.3) | 6.5 | (21.8) |
| Transfer to Level 2 | - | 1.3 | 1.3 |
| Transfer to Held-for-trading | 19.9 | (20.0) | (0.1) |
| Balance at December 31, 2010 | - | $(21.3) | $(21.3) |

## ACCOUNTS RECEIVABLE AND ACCOUNTS PAYABLE AND ACCRUED CHARGES

The carrying value of accounts receivable, accounts payable and accrued charges is a reasonable approximation of fair value. Losses included in earnings and recorded in "Operating, maintenance and general expenses" are \$3.7 million (2009 – \$4.5 million).

The allowance for doubtful accounts was \$4.0 million as at January 1, 2010 (2009 – \$2.8 million) and \$2.5 million as at December 31, 2010 (2009 – \$4.0 million). Changes in the allowance were due to changes in the provision related to specific customers and to changes in mix and volume of accounts receivable.

## PREFERRED SHARES, LONG-TERM DEBT AND SHORT-TERM DEBT

The fair value of preferred shares is based on market rates.

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

## DERIVATIVES IN VALID HEDGING RELATIONSHIPS

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

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

| millions of dollars | **2010** | 2009 |
|---|---|---|
| Fuel and purchased power increase | **\$(64.7)** | \$(38.4) |
| Financing charges decrease | **1.8** | 6.9 |
| Total losses | **\$(62.9)** | \$(31.5) |

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

| millions of dollars | **2010** | 2009 |
|---|---|---|
| Fuel and purchased power increase | **\$(0.8)** | \$(12.8) |
| Financing charges increase | **(0.1)** | - |
| Total losses | **\$(0.9)** | \$(12.8) |

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

| millions of dollars | **2010** | 2009 |
|---|---|---|
| Financing charges increase | **\$(0.2)** | \$(0.5) |
| Total losses | **\$(0.2)** | \$(0.5) |

The Company expects to reclassify \$1.7 million of gains currently included in AOCI to net earnings over the next 12 months related to hedged items realized in net earnings.

### Interest Rates

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

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

The Company has no interest rate hedging contracts outstanding as at December 31, 2010.

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

The Company enters into natural gas swap contracts to limit exposure to fluctuations in natural gas prices. As at December 31, 2010, the Company had hedged approximately 87% of all natural gas purchases and sales associated with its forecasted natural gas burn and resale for 2011, and 35% for 2012.

The Company enters into oil swap contracts to limit exposure to fluctuations in world prices of heavy fuel oil. For 2011 and 2012, NSPI currently does not have heavy fuel oil hedging requirements.

The Company enters into solid fuel swap contracts to limit exposure to fluctuations in world prices of solid fuel. As at December 31, 2010, the Company had hedged approximately 77% of all solid fuel purchases for 2011, 39% for 2012, 24% for 2013 and 9% for 2014.

**Foreign Exchange**
A substantial amount of NSPI's fuel supply comes from international suppliers and is subject to foreign exchange risk. As part of its fuel management strategy, NSPI manages exposure to foreign exchange through forward contracts.

NSPI enters into foreign exchange forward and swap contracts to limit exposure on fuel purchases to currency rate fluctuations. Currency forwards are used to fix the Canadian dollar ("CAD") cost to acquire United States dollars ("USD"), reducing exposure to currency rate fluctuations. Forward contracts to buy USD $225.5 million are in place at a weighted average rate of $0.99 representing over 70% of 2011 anticipated USD requirements. Forward contracts to buy USD $443.0 million in 2012 through 2015 at a weighted average rate of $1.03 were outstanding at December 31, 2010 to manage exposure of 31% of anticipated USD requirements in these years. As at December 31, 2010, there were no fuel-related foreign exchange swaps outstanding.

NSPI may use foreign exchange forward contracts to hedge the currency risk for capital projects and receivables denominated in foreign currencies. Forward contracts to buy €1.8 million are in place at a weighted average rate of 1.56 (versus CAD) for capital projects in 2011.

**HELD-FOR-TRADING DERIVATIVES**

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

The fair value of derivatives is estimated by obtaining prevailing market rates from investment dealers.

The Company has recognized the following realized and unrealized gains and losses with respect to HFT derivatives in earnings:

| millions of dollars | **2010** | 2009 |
|---|---|---|
| Fuel and purchased power (increase) decrease | **$(1.3)** | $13.0 |
| Total (losses) gains | **$(1.3)** | $13.0 |

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

**Derivatives not in valid hedging relationships**
On December 31, 2010, the Company held natural gas and oil derivatives, which were not in valid hedging relationships.

## RISK MANAGEMENT

### Market Risk

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

As at December 31, 2010, the Company determined that market risk exposure associated with its financial instruments would affect the Company's financial results as follows:

| millions of dollars | Net earnings increase (decrease) | AOCI increase (decrease) |
|---|---|---|
| $1 per one million British Thermal Unit increase in the price of natural gas * | $(0.1) | - |
| $5 per barrel increase in the price of heavy fuel oil | - | - |
| $15 per metric tonne increase in the price of coal | - | $29.8 |
| $0.01 decrease in the strength of the Canadian relative to the US dollar | - | 7.1 |
| 100 basis point increase in the central bank interest rates | (0.1) | - |

* Fuel costs are recoverable through the FAM, thus natural gas price changes would not materially impact net earnings. .

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

### Credit risk

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

As at December 31, 2010, the maximum exposure the Company has to credit risk is $252.5 million, which includes accounts receivable, the assets related to derivatives in a valid hedging relationship, and held-for-trading derivatives.

The Company transacts with counterparties as part of its risk management strategy for managing commodity price, foreign exchange and interest rate risk. Counterparties that exceed established credit limits can provide a cash deposit or letter of credit to the Company for the value in excess of the credit limit where contractually required. The Company also obtains cash deposits from electric customers. The total cash deposits and letters of credit on hand as at December 31, 2010, was $12.4 million, which mitigates the Company's maximum credit risk exposure. The Company uses the cash as payment for the amount receivable or returns the cash deposit to the counterparty where the credit limit is no longer exceeded or where the customer is no longer considered a high risk account.

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

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

As at December 31, 2010, the Company had $29.6 million (2009 – $30.8 million) in financial assets considered to be past due, which have been outstanding for an average of 70 days. The fair value of these financial assets was $27.3 million (2009 – $27.0 million), the difference of which is included in the allowance for doubtful accounts. These assets primarily relate to accounts receivable from electric revenue.

**Concentration risk**

The Company's concentration of risks as at December 31, 2010 was as follows:

| | millions of dollars | % of total exposure |
|---|---|---|
| **Accounts receivable** | | |
| Residential | $96.3 | 38% |
| Commercial | 48.6 | 19% |
| Industrial | 32.3 | 13% |
| Other | 15.3 | 6% |
| | 192.5 | 76% |
| **Derivatives** (in a valid hedging relationship and held-for-trading; current and long-term portions) | | |
| Credit rating of A- or above | 47.5 | 19% |
| Credit rating of BBB- to BBB+ | 9.1 | 4% |
| Not rated | 3.4 | 1% |
| | 60.0 | 24% |
| | $252.5 | 100% |

**Liquidity risk**

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

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

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

The Company's financial instrument liabilities mature as follows:

| | **3 year renewable (1)** | **2011** | **2012** | **2013** | **2014** | **> 2014** | **Total** |
|---|---|---|---|---|---|---|---|
| Accounts payable and accrued charges | - | $221.3 | - | - | - | - | $221.3 |
| Short-term debt | - | 48.3 | - | - | - | - | 48.3 |
| Long-term debt | $241.7 | 0.1 | - | $300.0 | - | $1,405.0 | 1,946.8 |
| Preferred shares | - | - | - | - | - | 135.0 | 135.0 |
| Derivatives held in a valid hedging relationship | - | 2.2 | - | 6.2 | $1.8 | 1.4 | 11.6 |
| Held-for-trading derivatives | - | 20.8 | $1.8 | - | - | - | 22.6 |
| Total financial liabilities | $241.7 | $292.7 | $1.8 | $306.2 | $1.8 | $1,541.4 | $2,385.6 |

(1) Short-term discount notes are backed by an operating credit facility which matures in 2013.

The Company has available the following credit facilities as at December 31, 2010 for the management of liquidity risk:

| millions of dollars | **Available** | **Used** | **Unused** |
|---|---|---|---|
| Bank operating and commercial paper | $600.0 | $289.0 | $311.0 |

## 22. RELATED PARTY TRANSACTIONS

The Company enters into various transactions with its affiliates in the normal course of operations. All transactions are recorded, subject to terms in the Code of Conduct, at the exchange value, which is generally based on commercial rates or as agreed to by the parties. The Code of Conduct governs transactions between NSPI and its affiliates and is approved by the UARB.

Due to associated companies represents the total carrying amounts of trade payables, which are owed from NSPI to NSPI's parent company, Emera Inc., and companies wholly-owned by Emera Inc. The terms of repayment are the same as those for non-affiliate trade payables.

NSPI had sales and purchases from companies under common control of Emera Inc. as follows:

millions of dollars

| Affiliate | Purpose of Transaction | **2010** | 2009 |
|---|---|---|---|
| Emera Energy Services | Net (purchases) sales of gas and electricity | **$(6.7)** | $25.0 |
| Other | Other services provided | **7.4** | 6.9 |
| Other | Various services purchased | **48.3** | 15.7 |

In the ordinary course of business, the Company purchased natural gas transportation capacity totaling $18.0 million (2009 – $18.2 million) during the year ended December 31, 2010, from the Maritimes & Northeast Pipeline, an investment under significant influence of Emera Inc. The amount is recognized in "Fuel for generation and purchased power" and is measured at the exchange amount. As at December 31, 2010, the amount payable to the related party was $1.0 million (2009 – $1.5 million), and is under normal interest and credit terms.

On May 28, 2010, NSPI purchased $30.1 million in wind generation assets under development related to the Digby Wind Project from a subsidiary of Emera. This transaction was measured at the carrying amount of the assets transferred. At December 31, 2010, there was no amount due.

During the year ended December 31, 2010, the Company issued a total of 5.0 million (2009 – 0.4 million) common shares to Emera Inc. and an affiliate under common control for total consideration of $50.0 million (2009 – $4.1 million).

## 23. CONTINGENCIES

A number of individuals who live in proximity to the Company's Trenton generating station have filed a statement of claim against NSPI in respect of emissions from the operation of the plant for the period 2001 forward. The Company has filed a defence to the Claim. The plaintiffs claim unspecified damages as a result of interference with enjoyment of, or damage to, their property and adverse health effects they allege were caused by such emissions. The outcome, and therefore an estimate of any contingent loss, of this litigation are not determinable.

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

## 24. COMMITMENTS

In addition to commitments outlined elsewhere in these notes, NSPI had the following significant commitments as at December 31, 2010:

- An annual requirement to purchase approximately 650 GWh of electricity from independent power producers over varying contract lengths up to 40 years.
- Requirements to purchase approximately 15,000 mmbtu of natural gas per day for 22 months; an average of 13,000 mmbtu per day for 28 months; 14,000 mmbtu per day for 10 months and 20,000 mmbtu for two years starting in November 2011.
- Commitments to purchase 4,000 mmbtu per day of transportation capacity on the Maritimes and Northeast Pipeline, a related party, for 10 months, 15,000 mmbtu for 22 months, and an average of 13,000 mmbtu for 28 months. These have an approximate cost of $17.6 million through 2013.
- Responsibility for managing a portfolio of approximately $1.0 billion of defeasance securities held in trust. The defeasance securities must provide the principal and interest payment streams of the related defeased debt. Approximately 73% or $726 million of the defeasance portfolio consists of investments in the related debt, eliminating all risk associated with this portion of the portfolio.
- A commitment to a third party for the unloading and transportation of solid fuel for ten years beginning in late 2002 at an approximate cost of $16 million per year.
- Commitments to third parties for the handling and transportation of solid fuel for $7 million in 2011 and $4 million per year from 2012 to 2014.
- Commitments to third parties for 2011 to 2014, to purchase and transport 3.8 million metric tons (“mts”) of import coal, 1.7 million mts of domestic coal and 3.2 million mts of marine freight.
- Commitments to third parties for construction on a capital project in 2011 and 2012 at an approximate cost of $91 million and to purchase other goods and services in 2011 and 2012 at an approximate cost of $19 million.

## 25. GUARANTEES

NSPI had the following guarantees at December 31, 2010:

- The Company has letters of credit issued totaling $20.7 million that extend to 2011 and/or are renewed annually to secure payments to various vendors, including counterparties, and to secure obligations under an unfunded pension plan.
- The Company has provided a guarantee for the indebtedness of a third party, up to a maximum of $23.5 million, related to future purchased power. NSPI holds a security interest in the assets of the third party.

## 26. COMPARATIVE INFORMATION

Certain of the comparative figures have been reclassified to conform to the financial statement presentation adopted for 2010.

## OPERATING STATISTICS (Unaudited)
## FIVE-YEAR SUMMARY

| Year Ended December 31 | **2010** | 2009 | 2008 | 2007 | 2006 |
|---|---|---|---|---|---|
| Electric energy sales (GWh) | | | | | |
| Residential | **4,147.2** | 4,227.7 | 4,178.8 | 4,144.6 | 3,926.9 |
| Commercial | **3,088.5** | 3,107.3 | 3,114.6 | 3,160.5 | 3,023.0 |
| Industrial | **3,907.7** | 3,642.4 | 4,144.6 | 4,191.4 | 2,874.4 |
| Other | **311.7** | 328.1 | 334.2 | 365.9 | 681.2 |
| Total electric energy sales | **11,455.1** | 11,305.5 | 11,772.2 | 11,862.4 | 10,505.5 |
| Sources of energy (GWh) | | | | | |
| Thermal – coal | **7,838.7** | 8,177.3 | 9,008.9 | 9,561.4 | 9,128.1 |
| – oil | **36.1** | 306.9 | 339.6 | 515.3 | 431.4 |
| – natural gas | **2,275.0** | 1,611.5 | 1,257.9 | 1,057.1 | 390.3 |
| Hydro | **991.5** | 1,063.4 | 1,065.3 | 908.8 | 995.7 |
| Wind | **25.3** | 1.8 | 2.4 | 2.4 | 2.4 |
| Purchases | **997.1** | 930.7 | 888.6 | 653.9 | 404.6 |
| Total generation and purchases | **12,163.7** | 12,091.6 | 12,562.7 | 12,698.9 | 11,352.5 |
| Losses and internal use | **708.6** | 786.1 | 790.5 | 836.5 | 847.0 |
| Total electric energy sold | **11,455.1** | 11,305.5 | 11,772.2 | 11,862.4 | 10,505.5 |
| Electric customers | | | | | |
| Residential | **442,824** | 439,338 | 435,847 | 431,697 | 427,734 |
| Commercial | **34,864** | 34,678 | 34,509 | 34,266 | 34,047 |
| Industrial | **2,485** | 2,499 | 2,496 | 2,503 | 2,487 |
| Other | **9,256** | 9,153 | 9,062 | 9,572 | 9,376 |
| Total electric customers | **489,429** | 485,668 | 481,914 | 478,038 | 473,644 |
| 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 | **304** | 304 | 304 | 304 | 304 |
| Hydroelectric | **395** | 395 | 395 | 395 | 395 |
| Wind turbines | **76** | 1 | 1 | 1 | 1 |
| Independent power producers | **186** | 137 | 85 | 85 | 79 |
| | **2,554** | 2,430 | 2,378 | 2,378 | 2,372 |
| Total number of employees | **1,900** | 1,865 | 1,791 | 1,740 | 1,698 |
| km of transmission lines (69 kV and over) | **5,000** | 5,000 | 5,000 | 5,000 | 5,000 |
| km of distribution lines (25 kV and under) | **29,000** | 27,000 | 26,000 | 25,000 | 25,000 |

## FIVE YEAR SUMMARY (Unaudited)

| Year Ended December 31 (millions of dollars) | **2010** | 2009 | 2008 | 2007 | 2006 |
|---|---|---|---|---|---|
| **Statements of Earnings Information** | | | | | |
| Revenue | **$1,182.7** | $1,202.1 | $1,126.6 | $1,113.7 | $977.5 |
| Cost of operations | | | | | |
| Fuel for generation and purchased power | **586.7** | 500.7 | 471.4 | 433.7 | 292.8 |
| Fuel adjustment | **(99.0)** | 8.5 | - | - | - |
| Operating, maintenance and general | **237.5** | 215.1 | 203.7 | 206.0 | 202.5 |
| Provincial grants and taxes | **40.1** | 40.5 | 41.2 | 40.4 | 40.3 |
| Depreciation and amortization | **150.8** | 143.9 | 133.6 | 131.1 | 127.8 |
| Regulatory amortization | **36.9** | 27.2 | 17.7 | 17.2 | 8.6 |
| | **953.0** | 935.9 | 867.6 | 828.4 | 672.0 |
| | **229.7** | 266.2 | 259.0 | 285.3 | 305.5 |
| Financing charges | **125.8** | 114.7 | 106.8 | 123.0 | 130.6 |
| Other income | **-** | - | - | - | (8.9) |
| | **103.9** | 151.5 | 152.2 | 162.3 | 183.8 |
| Income taxes | **(17.4)** | 42.2 | 46.6 | 62.1 | 79.5 |
| Net earnings applicable to common shares | **121.3** | 109.3 | 105.6 | 100.2 | 104.3 |
| Common dividends | **100.0** | 126.0 | 75.0 | 193.0 | 50.0 |
| Earnings retained for use in Company | **$21.3** | $(16.7) | $30.6 | $(92.8) | $54.3 |
| Cost of fuel for generation – coal | **$327.0** | $293.9 | $282.1 | $276.0 | $266.2 |
| – oil | **12.2** | 5.4 | 17.7 | 49.7 | 34.2 |
| – natural gas | **169.3** | 138.5 | 92.5 | 52.0 | (41.6) |
| Purchased power | **78.2** | 62.9 | 79.1 | 56.0 | 34.0 |
| Total cost of fuel for generation and purchased power | **$586.7** | $500.7 | $471.4 | $433.7 | $292.8 |
| **Balance Sheets Information** | | | | | |
| Current assets | **$428.8** | $506.1 | $477.3 | $361.7 | $288.7 |
| Long-term receivable | **-** | - | 56.4 | 7.7 | - |
| Derivatives in a valid hedging relationship | **20.8** | 29.8 | 115.5 | 10.4 | - |
| Held-for-trading derivatives | **8.2** | 6.2 | 54.0 | 47.6 | - |
| Other assets* | **512.8** | 339.1 | 353.7 | 358.8 | 371.8 |
| Intangibles | **72.5** | 65.7 | 58.7 | 58.8 | 58.6 |
| Property, plant and equipment and construction work in progress | **2,948.2** | 2,518.4 | 2,375.1 | 2,337.5 | 2,342.4 |
| Total assets | **$3,991.3** | $3,465.3 | $3,490.7 | $3,182.5 | $3,061.5 |
| Current liabilities | **$299.5** | 581.6 | $586.7 | $356.5 | $205.0 |
| Derivatives in a valid hedging relationship | **9.4** | 20.0 | 51.3 | 33.1 | - |
| Held-for-trading derivatives | **1.8** | 1.3 | 11.7 | 1.2 | - |
| Future income tax liabilities | **163.1** | 52.0 | - | - | - |
| Asset retirement obligations | **138.7** | 101.5 | 87.6 | 83.5 | 77.7 |
| Other liabilities* | **98.6** | 91.5 | 180.3 | 167.6 | 5.8 |
| Long-term debt | **1,933.7** | 1,397.0 | 1,296.7 | 1,314.3 | 1,405.5 |
| Preferred shares | **135.0** | 135.0 | 135.0 | 260.0 | 260.0 |
| Common shares | **984.7** | 934.7 | 930.6 | 830.6 | 830.6 |
| Accumulated other comprehensive income (loss) | **10.8** | (44.0) | (0.6) | (48.4) | - |
| Retained earnings | **216.0** | 194.7 | 211.4 | 184.1 | 276.9 |
| Total equity and liabilities | **$3,991.3** | $3,465.3 | $3,490.7 | $3,182.5 | $3,061.5 |
| **Statements of Cash Flow Information** | | | | | |
| Cash provided by operating activities | **$300.2** | $275.2 | $174.3 | $306.4 | $283.6 |
| Cash used in investing activities | **$(533.3)** | $(268.6) | $(163.4) | $(124.4) | $(101.8) |
| Cash provided by (used in) financing activities | **$233.1** | $(6.3) | $(12.8) | $(188.3) | $(177.1) |

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

# Management's Discussion & Analysis

As at February 11, 2011

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 2010 relative to 2009, and the full year 2010 relative to 2009 and to 2008; and its financial position at December 31, 2010 relative to 2009. 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 Inc. follows Canadian Generally Accepted Accounting Principles ("CGAAP"), including the application of rate-regulated accounting policies for Emera Inc.'s rate-regulated subsidiaries. Emera Inc.'s wholly-owned subsidiaries - Nova Scotia Power Inc. ("NSPI"), Bangor Hydro Electric Company ("Bangor Hydro"), Maine Public Service Company ("MPS") and Emera Brunswick Pipeline Company Ltd. ("Brunswick Pipeline") are subject to rate regulation and the accounting policies used by these entities may differ in regard to the timing of recognition of certain assets, liabilities, revenue and expenses, from those used by Emera Inc.'s non rate-regulated companies. NSPI's accounting policies are subject to examination and approval by the Nova Scotia Utility and Review Board ("UARB"). Bangor Hydro and MPS' accounting policies are subject to examination and approval by the Maine Public Utilities Commission ("MPUC") and the Federal Energy Regulatory Commission ("FERC").

Throughout this discussion, "Emera Inc.", "Emera" and "company" 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.

## Forward Looking Information

This MD&A contains forward-looking information and forward-looking statements which reflect the current view with respect to the company's objectives, plans, financial and operating performance, business prospects and opportunities. Certain factors that may affect future operations and financial performance are discussed, including information in the Outlook section of the MD&A. Wherever used, the words "may", "will", "intend", "estimate", "plan", "believe", "anticipate", "expect", "project" and similar expressions are intended to identify such forward-looking statements and should not be read as guarantees of future events, performance or results, and will not necessarily be accurate indications of whether, or the times at which, such events, performance or results will be achieved.

Although Emera believes such statements are based on reasonable assumptions, such statements are subject to certain risks, uncertainties and assumptions pertaining to, but not limited to, operating performance, regulatory requirements, weather, general economic conditions, commodity prices, interest rates and foreign exchange rates. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may vary significantly from those expected. Emera disclaims any intention or obligation to update or revise any forward-looking information or forward-looking statements, whether as a result of new information, future events or otherwise, except as required under applicable securities laws.

## Structure of MD&A

This MD&A begins with an Introduction and Strategic Overview followed by a consolidated financial review including consolidated statements of earnings, balance sheets and cash flow highlights and outstanding share data; then presents information on NSPI, Bangor Hydro (includes Maine & Maritimes Corporation (“MAM”)) and Pipelines (includes Brunswick Pipeline and Maritimes & Northeast Pipeline). All other operations are grouped and discussed under Other, Including Corporate Costs and include Emera Energy (includes Emera Energy Services, Bayside Power Limited Partnership (“Bayside Power”) and Bear Swamp Power Company LLC. (“Bear Swamp”)); Emera Utility Services (“EUS”); Caribbean (includes Grand Bahama Power Company Limited (“GBPC”), Light and Power Holdings (“LPH”), the parent company of Barbados Light and Power Company Limited (“BLPC”); St. Lucia Electricity Services (“Lucelec”), and ICD Utilities Limited (“ICDU”)); and corporate activities. Outlook, Liquidity and Capital Resources, Pension Funding, Off-Balance Sheet Arrangements, Transactions with Related Parties, Dividends and Payout Ratios, Risk Management and Financial Instruments, Disclosure and Internal Controls, Significant Accounting Policies and Critical Accounting Estimates, Changes in Accounting Policies and Summary of Quarterly Results are presented on a consolidated basis.

# INTRODUCTION AND STRATEGIC OVERVIEW

Emera Inc. is an energy and services company with $6.3 billion in assets. The company invests in electricity generation, transmission and distribution as well as gas transmission and utility energy services. Emera’s strategy is focused on the transformation of the electricity industry to cleaner generation and the delivery of that clean energy to market. Emera has interests throughout northeastern North America, in three Caribbean countries and in California.

Emera’s goal is to deliver annual consolidated earnings growth of 4% to 6%, and to build and diversify its earnings base with a focus on cleaner energy in its markets. Emera will continue to seek growth from its existing businesses and will leverage its core strength in the electricity business as it pursues both acquisitions and greenfield development opportunities in regulated electricity transmission and distribution and low risk generation.

Over 90% of Emera’s revenues are earned by regulated entities - NSPI, Bangor Hydro and Brunswick Pipeline. NSPI is a wholly-owned fully integrated regulated utility with $4.0 billion of assets which provides electricity generation, transmission and distribution services to approximately 489,000 customers in the province of Nova Scotia. Bangor Hydro is an electric transmission and distribution company with $730.4 million of assets serving approximately 118,000 customers in eastern Maine. In December 2010, Emera purchased all of the outstanding shares of Maine and Maritimes Corporation (“MAM”), the parent company of MPS, a regulated electric transmission and distribution utility serving approximately 36,000 electricity customers in northern Maine. At December 31, 2010, MAM’s assets and liabilities have been included on Emera’s consolidated balance sheet. These businesses operate as monopolies in their service territories. Brunswick Pipeline is a 145-kilometre pipeline carrying re-gasified liquefied natural gas (“LNG”) from the Canaport™ LNG terminal in Saint John, New Brunswick to the United States border. This regulated pipeline operates under a 25-year firm service agreement with Repsol Energy Canada.

The success of Emera’s primary businesses is integral to the creation of shareholder value, providing strong, predictable earnings and growing cash flows to fund dividends and reinvestment.

Although markets in Nova Scotia and Maine are otherwise mature, the transformation of energy supply to lower emission sources has created the opportunity for organic growth within NSPI and Bangor Hydro. Both companies expect earnings growth of 3% to 5% annually over the next five years as new investments are made in renewable generation and transmission.

Emera also has interests in three Caribbean countries. In December 2010, Emera purchased an additional 55.4 % direct and indirect interest in GBPC bringing total ownership to 80.4%. At December 31, 2010, GBPC's assets and liabilities have been included on Emera's consolidated balance sheet. Emera also has a 38% interest in LPH, the parent company of BLPC and a 19% interest in Lucelec, a vertically-integrated electric utility on the Caribbean island of St. Lucia.

Emera's remaining revenues are earned by a growing group of strategic investments that are expected to contribute more significantly to Emera's earnings in the coming years. These are described in more detail in the relevant sections of the MD&A.

# Non-GAAP Measures

Emera uses financial measures that do not have a standardized meaning under CGAAP.

**Emera Energy – Bear Swamp**
"Earnings per common share – basic, absent the Bear Swamp after-tax mark-to-market adjustment", "Contribution to consolidated net earnings, absent the Bear Swamp after-tax mark-to-market adjustment" and "Contribution to consolidated net earnings per common share, absent the Bear Swamp after-tax mark-to-market adjustment" are non-GAAP financial measures used by Emera. Management discloses these financial measures as it believes the inclusion of the mark-to-market adjustment in Emera Energy's financial results does not accurately reflect its operational performance. Many investors use this financial measure to assess Emera's overall financial performance. The adjustment is discussed further in the Significant Item section and Other, Including Corporate Costs.

**NSPI**
"Electric margin", defined as "Electric revenue" less "Fuel for generation and purchased power", net of the "Fuel adjustment" and fuel related foreign exchange losses or gains, is a non-GAAP financial measure used by NSPI. This measure is disclosed as management believes it provides further information regarding the impact of the fuel adjustment mechanism ("FAM") on NSPI's operations. Electric margin is discussed further in the NSPI Review of 2010 section.

# CONSOLIDATED FINANCIAL REVIEW

## Consolidated Financial Highlights

| millions of dollars (except earnings per common share) | Three months ended December 31 | | Year ended December 31 | | |
|---|---|---|---|---|---|
| | **2010** | 2009 | **2010** | 2009 | 2008 |
| Revenues | **$392.7** | $406.5 | **$1,553.7** | $1,483.5 | $1,331.9 |
| Net earnings applicable to common shares | **39.6** | 37.5 | **191.1** | 175.7 | 144.1 |
| Earnings per common share – basic | **0.35** | 0.33 | **1.68** | 1.56 | 1.29 |
| Earnings per common share – diluted | **0.34** | 0.33 | **1.65** | 1.52 | 1.26 |
| Cash dividends declared per share | **-** | 0.2725 | **1.16** | 1.03 | 0.97 |

| | Three months ended December 31 | | Year ended December 31 | | |
|---|---|---|---|---|---|
| **Operating Unit Contributions** | **2010** | 2009 | **2010** | 2009 | 2008 |
| NSPI | **$20.7** | $17.4 | **$121.3** | $109.3 | $105.6 |
| Bangor Hydro | **7.8** | 7.0 | **31.9** | 27.5 | 23.1 |
| Pipelines | **8.8** | 8.4 | **35.0** | 24.2 | 15.4 |
| Other | **3.3** | 8.9 | **16.1** | 14.3 | 3.5 |
| Corporate (costs) recovery and other | **(1.0)** | (4.2) | **(13.2)** | 0.4 | (3.5) |
| Net earnings applicable to common shares | **$39.6** | $37.5 | **$191.1** | $175.7 | $144.1 |
| Net earnings applicable to common shares, absent the Bear Swamp after-tax mark-to-market adjustment | **$42.2** | $34.3 | **$199.7** | $175.0 | $148.9 |
| Earnings per common share – basic | **$0.35** | $0.33 | **$1.68** | $1.56 | $1.29 |
| Earnings per common share – basic, absent the Bear Swamp after-tax mark-to-market adjustment | **$0.38** | $0.30 | **$1.76** | $1.55 | $1.33 |

| | As at December 31 | | |
|---|---|---|---|
| | **2010** | 2009 | 2008 |
| Total assets | **$6,329.1** | $5,284.5 | $5,269.4 |
| Total liabilities | **4,555.5** | 3,778.6 | 3,723.2 |

## Developments

### Emera

**Agreement with Nalcor Energy on Lower Churchill Project**

On November 18, 2010, Emera and Nalcor Energy ("Nalcor"), with the endorsement of the governments of Nova Scotia and Newfoundland and Labrador, signed a term sheet which includes the obligation to negotiate and conclude final agreements for an estimated $6.2 billion hydro-electric development that would bring energy from a new hydro-electric generating facility at Muskrat Falls on the Lower Churchill River in Labrador to consumers in Newfoundland and Labrador, Nova Scotia, other Maritime provinces and New England. This development is expected to result in a strong regional system that enhances the ability to move energy among provinces, improve reliability of the system and is consistent with Emera's focus on cleaner, affordable electricity.

The proposed agreement between Emera and Nalcor would see:

- Nalcor construct and own an estimated $2.9 billion, 824 megawatt ("MW") hydro-electric generating facility at Muskrat Falls on the Lower Churchill River in Labrador, with a planned in-service date of 2017.
- Emera and Nalcor together develop an estimated $2.1 billion electricity transmission project in Newfoundland and Labrador to enable the movement of the Muskrat Falls energy between

Labrador and the island of Newfoundland (the "Island Link"). Emera invest approximately $600 million in the Island Link.

- Emera build and own an estimated $1.2 billion transmission project between the island of Newfoundland and Nova Scotia, including a 180-kilometre subsea cable, in return for 20% of the energy output from Muskrat Falls for 35 years (the "Maritime Link").

Agreements resulting from this term sheet will be subject to a number of conditions including final approval of the Boards of Directors of Emera and Nalcor, approval of regulators in the provinces of Nova Scotia and Newfoundland and Labrador and all environmental approvals.

Effective January 24, 2011, Rick Janega, previously the Executive Vice President and Chief Operating Officer of Nova Scotia Power Inc. assumed the role of President, Emera, Newfoundland and Labrador. In this role, he will report to Nancy Tower when she assumes her role as CEO, Emera, Newfoundland and Labrador effective May 1, 2011.

**Additional Investment in Grand Bahama Power Company Limited**

On December 22, 2010, Emera purchased an additional 55.4% direct and indirect interest in GBPC for $88.1 million USD ($87.7 million CAD), bringing total ownership to 80.4%. GBPC is an integrated utility with 19,000 customers and 137-MW of installed oil-fired capacity. The Grand Bahama Port Authority regulates GBPC and has granted the utility a licensed, regulated and exclusive franchise to produce, transmit, and distribute electricity on the island until 2054. There is a fuel pass through mechanism and flexible tariff adjustment policies to ensure that costs are recovered and a reasonable return earned. The purchase was funded with existing credit facilities.

**Maine & Maritimes Corporation**

On December 21, 2010, Emera purchased all of the outstanding shares of MAM for $80.4 million USD ($81.9 million CAD). MAM is the parent company of MPS, a regulated electric transmission and distribution utility serving approximately 36,000 electricity customers in northern Maine. The purchase was funded with existing credit facilities.

**Strategic Partnership with Algonquin Power & Utilities Corp.**

On January 1, 2011, Emera and Algonquin Power & Utilities Corp. ("APUC") closed their acquisition of the California-based electricity distribution and related generation assets of NV Energy, Inc. for total consideration of $131.8 million USD ($134.2 million CAD), subject to final adjustments. Emera and APUC own and operate these assets through a newly formed utility company, California Pacific Electric Company, LLC ("California Pacific"). APUC and Emera own respectively a 50.001% and 49.999% interest in California Pacific Utility Ventures, LLC ("CPUV"), which wholly-owns California Pacific. The amount paid by Emera for its 49.999% equity investment in the common shares of CPUV is $30.9 million USD ($31.5 million CAD).

In April 2009, Emera entered into a subscription agreement with APUC, giving Emera the right to acquire 8.523 million APUC common shares, which represented a 9.9% interest in APUC at that time, upon the closing of the California Pacific transaction. Upon the January 1, 2011 closing of the California Pacific transaction, Emera exchanged the subscription receipts it acquired under the April 2009 subscription agreement into 8.523 million APUC common shares, issued at $3.25 per share. As a result of this transaction, Emera owns an approximate 8.2% equity interest in APUC. Under the April 2009 subscription agreement, Emera is entitled to purchase additional APUC common equity to bring its interest to 15%.

On December 9, 2010, Emera announced its intention to purchase 12 million subscription receipts from APUC at an issue price of $5.00 each for a total purchase price of $60 million. Emera will issue a promissory note to APUC in the principal amount of $60 million in exchange for the subscription receipts. The subscription receipts will be convertible to 12 million APUC common shares upon the acquisition by APUC's regulated subsidiary, Liberty Energy Utilities Co., of all issued and outstanding shares of Granite

State Electric Company and Energy North Natural Gas Inc., two regulated electric utilities, currently owned by National Grid USA. On the closing of the National Grid transaction and following the exercise of Emera's anti-dilution rights, Emera's percentage ownership interest in APUC will be approximately 15%. Proceeds from the subscription receipts will be used by APUC to finance a portion of this acquisition, which is expected to close in late 2011. The purchase of the subscription receipts has received conditional Toronto Stock Exchange approval.

### Barbados Light & Power Company Limited

On December 20, 2010, Emera offered to purchase all issued and outstanding common shares from LPH shareholders at a cash price of $25.70 Barbadian dollars. This offer closed on January 24, 2011. On January 25, 2011, Emera purchased 7.2 million shares of LPH at a cash price per share of $25.70 Barbadian dollars representing an additional interest of 41.9%. With this additional investment of $91.9 million, Emera became the majority shareholder of LPH, with a total interest of 79.9%.

Previously, on May 11, 2010, Emera acquired a 38% interest in LPH, the parent company of BLPC, for $85 million USD. BLPC is the sole utility operator on the island of Barbados, serving 120,000 customers. BLPC has three power generation stations with 239 MW of installed capacity. A fuel pass through mechanism ensures costs are recovered and a cost-of-service regulation provides for an approved 12.75% return on equity. This transaction was immediately accretive and was financed with existing credit facilities.

### Dividends

In February 2010, the Board of Directors approved a quarterly dividend increase, effective May 3, 2010, to $0.2825 per common share, and in September 2010, approved a further increase to $0.3250 effective November 1, 2010 reflecting an increase on an annualized basis to $1.30 per common share.

### Appointments

Effective May 1, 2011, Nancy Tower, presently the Executive Vice President and Chief Financial Officer of Emera and Nova Scotia Power Inc., will assume the role of Executive Vice President, Business Development for Emera Inc. In addition to overall responsibility for business development as previously noted, Ms. Tower will also oversee the Emera partnership with Nalcor including the execution of the Lower Churchill Project as the CEO, Emera, Newfoundland and Labrador.

On September 24, 2010, Sylvia Chrominska and Richard Sergel joined the Emera Board of Directors.

## NSPI

### Deferral of Certain Tax Benefits Related to Renewable Energy Projects for Fiscal 2010

On December 23, 2010, the UARB granted NSPI approval to defer certain tax benefits related to renewable energy projects arising in 2010. Accordingly, effective December 31, 2010, NSPI recognized a deferral of $14.5 million through an increase in regulatory amortization. The UARB will convene a proceeding in 2011 to discuss how this deferral will be applied.

### UARB Decision on Fuel Adjustment Mechanism

On December 8, 2010, the UARB approved NSPI's setting of the 2011 base cost of fuel and its recovery of all unrecovered fuel related costs as submitted in NSPI's November 2010 filing. The recovery of these costs will begin January 1, 2011. The UARB approved the recovery of these costs by NSPI over three years, with 50% of the rate increase to be recovered in 2011, 30% in 2012 and 20% in 2013. The decision results in an average rate increase of approximately 4.5% for customers in 2011. Pursuant to the FAM Plan of Administration, NSPI is entitled to earn a return on the unrecovered balance of fuel related costs.

## Renewable Energy Projects

### Port Hawkesbury Biomass Project

On October 14, 2010, the UARB approved NSPI's $208.6 million capital work order request for the Port Hawkesbury biomass project. NSPI will develop this 60-MW co-generating facility at the NewPage Port Hawkesbury Corporation ("NewPage") site. NSPI will own the facility while NewPage will construct and operate the plant as well as supply the fuel. This project is expected to be commissioned in 2013 and supply approximately 3% of the province of Nova Scotia's total electricity needs.

### Point Tupper Wind Development Project

On June 14, 2010, the UARB approved NSPI's $27.8 million capital work order for the Point Tupper Wind Development Project. The Project went into service in August 2010.

### Digby Wind Project

On May 28, 2010, NSPI purchased $30.1 million in wind generation assets under development related to the Digby Wind Project from a subsidiary of Emera. NSPI has requested UARB approval of this project through the submission of a capital work order. The Project was completed and went into service in December 2010 at a total cost of approximately $80.0 million. The UARB hearing took place in January 2011, and a decision is pending.

## Nova Scotia Provincial Environmental Regulations

### Renewable Electricity Plan

On October 15, 2010, the Nova Scotia Government enacted regulations under the Electricity Act related to the Province's Renewable Electricity Plan. These regulations establish the requirement that 25% of electricity be supplied from renewable sources by 2015. These regulations build on the previously legislated requirements for 2011 and 2013 by adding an additional 5% for 2015. Recent amendments to the Electricity Act, and the new regulations, provide for the appointment, by spring 2011, of a new, independent renewable electricity administrator to conduct the procurement of at least 300 gigawatt hours ("GWh") of energy from independent power producers ("IPPs") to meet the 2015 standard. NSPI is also provided the opportunity to develop 300 GWh of renewable energy.

### Mercury Emissions

On July 22, 2010, the Province of Nova Scotia announced, for the years 2010 through 2013, allowable mercury emissions would be increased from the previous cap of 65 kg per year. NSPI was requested to develop a plan of staged mercury emission reductions, for its generation facilities, for the period of 2010 to 2020 and meet an annual cap of 35 kg beginning in 2020.

## Canadian Federal Environmental Regulations

### Greenhouse Gas

On June 23, 2010, the Federal Department of Environment announced its intentions for a new national greenhouse gas ("GHG") framework for the electricity sector. This federal framework, if developed further into regulations, would require thermal coal units to meet GHG emission levels equal to, or better than, a natural gas combined cycle generating unit at a future date. Nova Scotia's existing GHG regulations require reductions in NSPI's emissions similar to the intentions of the federal framework. NSPI is reviewing the implications of this federal framework and its alignment with NSPI's current operating plans under existing Nova Scotia regulations.

## US Securities and Exchange Commission Registration

On July 15, 2010, NSPI registered debt securities with the US Securities and Exchange Commission ("SEC") under the US Securities Act of 1933.

### Appointments

On May 3, 2010, Elaine Sibson and Lee Bragg joined the NSPI Board of Directors.

## Bangor Hydro

### Collective Agreement

In July 2010, Bangor Hydro reached an agreement with its unionized employees, which will expire in July 2015.

### Keene Road 345 kV Substation Project

In December 2010, Bangor Hydro's Keene Road 345 kilovolt ("kV") Substation Project was completed at total cost of approximately $33.0 million USD.

# Significant Item

### Bear Swamp Mark-to-Market Adjustment

As part of its long-term energy and capacity supply agreement, expiring in 2021, with the Long Island Power Authority ("LIPA"), Bear Swamp has contracted with its joint venture partner to provide the power necessary to produce the requirements of the LIPA contract. One of the contracts between Bear Swamp and Emera's joint venture partner is marked-to-market through earnings, as it does not meet the stringent accounting requirements of hedge accounting.

As at December 31, 2010, the fair value of the derivative was a net liability of $8.2 million (December 31, 2009 – $6.2 million net asset). The fair value of this derivative is subject to market volatility of power prices and will reverse over the life of the agreement.

The mark-to-market adjustment relating to this position was as follows:

| millions of dollars (except earnings per common share) | Three months ended December 31 | | Year ended December 31 | | |
|---|---|---|---|---|---|
| | **2010** | 2009 | **2010** | 2009 | 2008 |
| Mark-to-market (loss) gain | **$(4.4)** | $5.5 | **$(14.4)** | $1.2 | $(8.1) |
| After-tax mark-to-market (loss) gain | **$(2.6)** | $3.2 | **$(8.6)** | 0.7 | $(4.8) |
| Earnings per common share – basic | **$0.35** | $0.33 | **$1.68** | $1.56 | $1.29 |
| Earnings per common share – basic, absent the Bear Swamp after-tax mark-to-market adjustment | **$0.38** | $0.30 | **$1.76** | $1.55 | $1.33 |

# Review of 2010

# Emera Consolidated Statements of Earnings

| millions of dollars (except earnings per common share) | Three months ended December 31 | | Year ended December 31 | | |
|---|---|---|---|---|---|
| | **2010** | 2009 | **2010** | 2009 | 2008 |
| Electric revenue | **$362.1** | $368.1 | **$1,436.1** | $1,402.0 | $1,280.8 |
| Finance income from direct financing lease | **13.7** | 15.2 | **56.5** | 25.3 | - |
| Other revenue | **16.9** | 23.2 | **61.1** | 56.2 | 51.1 |
| | **392.7** | 406.5 | **1,553.7** | 1,483.5 | 1,331.9 |
| Fuel for generation and purchased power | **176.8** | 168.8 | **718.7** | 583.5 | 525.1 |
| Fuel adjustment | **(24.0)** | (10.6) | **(99.0)** | 8.5 | - |
| Operating, maintenance and general | **92.0** | 84.5 | **336.1** | 294.4 | 266.8 |
| Provincial, state, and municipal taxes | **12.3** | 12.4 | **49.1** | 49.9 | 49.4 |
| Depreciation and amortization | **45.7** | 42.2 | **173.6** | 164.9 | 151.3 |
| Regulatory amortization | **24.6** | 16.4 | **41.3** | 35.7 | 28.5 |
| | **65.3** | 92.8 | **333.9** | 346.6 | 310.8 |
| Equity earnings | **2.3** | 2.0 | **13.6** | 14.0 | 15.2 |
| Financing charges | **43.8** | 45.1 | **168.4** | 135.3 | 123.2 |
| | **23.8** | 49.7 | **179.1** | 225.3 | 202.8 |
| Income taxes | **(13.4)** | 12.4 | **(12.8)** | 48.9 | 58.1 |
| Net earnings before non-controlling interest | **37.2** | 37.3 | **191.9** | 176.4 | 144.7 |
| Non-controlling interest | **(2.4)** | (0.2) | **(2.3)** | 0.7 | 0.6 |
| Net earnings | **39.6** | 37.5 | **194.2** | 175.7 | 144.1 |
| Preferred share dividends | **-** | - | **3.1** | - | - |
| Net earnings applicable to common shares | **$39.6** | $37.5 | **$191.1** | $175.7 | $144.1 |
| Earnings per common share – basic | **$0.35** | $0.33 | **$1.68** | $1.56 | $1.29 |
| Earnings per common share – diluted | **$0.34** | $0.33 | **$1.65** | $1.52 | $1.26 |

Emera Inc.'s consolidated net earnings applicable to common shares increased $2.1 million to $39.6 million in Q4 2010 compared to $37.5 million for the same period in 2009. Emera's annual consolidated net earnings applicable to common shares increased $15.4 million to $191.1 million in 2010 compared to $175.7 million in 2009, and $144.1 million in 2008.

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 applicable to common shares – 2008** | | **$144.1** |
| NSPI – Increased net earnings due to an electricity price increase, partially offset by increased fuel expense; operating, maintenance and general ("OM&G") expense and depreciation and amortization | | 3.7 |
| Bangor Hydro – Increased net earnings due mainly to a transmission rate increase and a weaker average CAD in 2009 | | 4.4 |
| Pipelines – Increased net earnings from Brunswick Pipeline due to allowance for funds used during construction ("AFUDC") on construction of the pipeline in the first half of the year and financing income from commencement of pipeline operations in July 2009, partially offset by increased intercompany financing charges related to the financing of the pipeline | | 8.8 |
| Other – Increased net earnings primarily related to the after-tax mark-to-market adjustments on the favourable commodity price positions in Bear Swamp and Emera Energy | | 10.8 |
| Corporate costs and other – Decreased due to increased income tax recovery and intercompany financing revenues | | 3.9 |
| **Consolidated net earnings applicable to common shares – 2009** | **$37.5** | **$175.7** |
| NSPI – Increased net earnings primarily due to decreased income taxes resulting from decreased earnings before income taxes, deductions related to renewable investments and a change in the expected benefit from other accelerated tax deductions | 3.3 | 12.0 |
| Bangor Hydro – Increased net earnings primarily due to transmission rate increases and increased transmission pool revenue related to recovery of regionally funded transmission investments, partially offset by a stronger average CAD in 2010 | 0.8 | 4.4 |
| Pipelines – Increased net earnings primarily due to Brunswick Pipeline's service commencement in July 2009 as compared to a full year in 2010 | 0.4 | 10.8 |
| Other – Decreased net earnings in the quarter due primarily to Bear Swamp's mark-to-market loss, operational issues at GBPC, partially offset by improved energy marketing results. Year over year increase is due to increased EUS earnings and improved energy marketing results, partially offset by Bear Swamp's mark-to-market loss | (5.6) | 1.8 |
| Corporate costs and other – Decreased in the quarter due to deferral of business development costs. Year over year increase is primarily due to increased financing charges | 3.2 | (13.6) |
| **Consolidated net earnings applicable to common shares – 2010** | **$39.6** | **$191.1** |

Q4 basic earnings per share were $0.35 in 2010 compared to $0.33 in 2009; and $1.68 for the full year 2010 compared to $1.56 in 2009 and $1.29 in 2008.

# Consolidated Net Earnings History

| millions of dollars | **2010** | 2009 | 2008 | 2007 | 2006 | 2005 |
|---|---|---|---|---|---|---|
| Net earnings applicable to common shares | **$191.1** | $175.7 | $144.1 | $151.3 | $125.8 | $121.2 |
| Net earnings applicable to common shares, absent the Bear Swamp after-tax mark-to-market adjustment | **$199.7** | $175.0 | $148.9 | $141.9 | $125.8 | $121.2 |

# Earnings per Share History

| Dollars | **2010** | 2009 | 2008 | 2007 | 2006 | 2005 |
|---|---|---|---|---|---|---|
| Earnings per share | **$1.68** | $1.56 | $1.29 | $1.36 | $1.14 | $1.11 |
| Earnings per share, absent the Bear Swamp after-tax mark-to-market adjustment | **$1.76** | $1.55 | $1.33 | $1.28 | $1.14 | $1.11 |

# Consolidated Balance Sheets Highlights

Significant changes in the consolidated balance sheets between December 31, 2010 and December 31, 2009 include:

| millions of dollars | Increase (Decrease) | Explanation |
|---|---|---|
| **Assets** | | |
| Cash and cash equivalents | **$(12.4)** | See consolidated cash flow highlights section. |
| Restricted cash | **58.6** | Cash in trust related to purchase of APUC subscription receipts. |
| Accounts receivable | **(16.6)** | Settlement of a receivable from a natural gas supplier, partially offset by higher posted margin to counterparties and acquisition of MAM and increased investment in GBPC. |
| Income tax receivable | **39.7** | Recovery of income taxes due to deductions related to renewable investments and a change in the expected benefit from other accelerated tax deductions. |
| Other Assets | **224.7** | Increased future income tax ("FIT") regulatory asset, recognition of the FAM regulatory asset in 2010 and acquisition of MAM, partially offset by regulatory amortization and decreased regulatory assets related to financial instruments. |
| Future income tax assets (including long-term portion) | **(10.0)** | Decreased FIT asset related primarily to derivatives recognized in accumulated other comprehensive loss ("AOCI") partially offset by increased US mark-to-market losses on held-for-trading derivatives. |
| Goodwill | **91.3** | Goodwill on acquisition of MAM and increased investment in GBPC. |
| Intangibles | **11.4** | Software and land rights acquisitions in NSPI and acquisition of MAM. |
| Investments subject to significant influence | **20.5** | Primarily the acquisition of a 38% interest in LPH, offset by the consolidation of GBPC since acquiring a controlling interest. |
| Net investment in direct financing lease | **11.3** | Costs related to direct financing lease of Brunswick Pipeline. |
| Property, plant & equipment | **517.0** | Capital spending, primarily in NSPI, acquisition of MAM and further investment in GBPC. |
| Construction work in progress | **112.8** | Capital spending, primarily in NSPI, and a further investment in GBPC. |
| **Liabilities and Shareholders' Equity** | | |
| Accounts payable and accrued charges | **93.7** | Timing of payments largely associated with capital projects and increased amount of business activity. |
| Derivatives in a valid hedging relationship (including long-term portion) | **(56.8)** | Favourable commodity price and USD price positions and natural gas derivatives reclassified to "Held-for-trading". The effective portion of the change is recognized in AOCI. |
| Held-for-trading derivatives (including long-term portion) | **14.7** | Unfavourable commodity price positions in Emera Energy. |
| Future income tax liabilities | **165.7** | Increased FIT liability on property, plant and equipment, including renewable investments, FAM regulatory asset and FIT in MAM, partially offset by increased FIT asset on asset retirement obligations. The portion expected to be recovered from customers in future rates is recognized in "Other assets". |
| Asset retirement obligations | **37.3** | Recognition of asset retirement obligations in NSPI. |
| Other liabilities | **13.6** | Acquisitions of MAM and further investment in GBPC. |
| Short-term debt and long-term debt (including current portion) | **520.9** | Increased debt levels to fund significant capital programs, acquisition of MAM, further investment in GBPC and investment in LPH. |
| Non-controlling interest | **(11.4)** | Increased investment in GBPC. |
| Common shares | **39.8** | Issuance of common shares. |
| Preferred shares | **146.7** | Issuance of preferred shares. |
| Accumulated other comprehensive loss | **22.0** | Primarily represents the effective portion of favourable commodity price positions, partially offset by the unfavourable effect of the CAD on Emera's investment in Bangor Hydro. |
| Retained earnings | **59.1** | Net earnings in excess of dividends declared. |

# Consolidated Cash Flow Highlights

Significant changes in the consolidated cash flow statements between December 31, 2010 and December 31, 2009 include:

| Three months ended December 31<br>millions of dollars | **2010** | 2009 | Explanation |
|---|---|---|---|
| Cash and cash equivalents, beginning of period | **$47.5** | $27.7 | |
| Provided by (used in): | | | |
| Operating activities | **185.5** | 94.7 | In 2010 and 2009, cash earnings and favourable non-cash operating working capital. |
| Investing activities | **(442.8)** | (163.9) | In 2010, capital spending, including multi-year projects and renewable investments in NSPI and acquisition of further interest in GBPC and purchase of MAM. |
| | | | In 2009, capital spending, including multi-year projects in NSPI and the completion of Brunswick Pipeline. |
| Financing activities | **219.0** | 63.8 | In 2010, increased debt levels, partially offset by dividends on common and preferred shares. |
| | | | In 2009, increased debt levels, partially offset by dividends on common shares. |
| Foreign currency impact on cash balances | **0.2** | (0.5) | |
| Cash and cash equivalents, end of period | **$9.4** | $21.8 | |

| Year ended December 31<br>millions of dollars | **2010** | 2009 | Explanation |
|---|---|---|---|
| Cash and cash equivalents, beginning of year | **$21.8** | $12.2 | |
| Provided by (used in): | | | |
| Operating activities | **416.4** | 310.2 | In 2010, cash earnings and favourable non-cash operating working capital. |
| | | | In 2009, cash earnings partially offset by unfavourable non-cash working capital. |
| Investing activities | **(894.8)** | (367.2) | In 2010, capital spending, including multi-year projects and renewable investments in NSPI, investment in LPH, an additional investment in GBPC and purchase of MAM. |
| | | | In 2009, capital spending including multi-year projects in NSPI, Brunswick Pipeline, and acquisition of Bayside, partially offset by a return of capital from M&NP. |
| Financing activities | **466.2** | 70.5 | In 2010, increased debt levels and the issuance of preferred shares, partially offset by dividends on common and preferred shares. |
| | | | In 2009, increased long-term debt, partially offset by decreased short-term debt, dividends on common shares and redemption of NSPI's preferred shares. |
| Foreign currency impact on cash balances | **(0.2)** | (3.9) | |
| Cash and cash equivalents, end of year | **$9.4** | $21.8 | |

Operating activities increased $106.2 million to $416.4 million for the year ended December 31, 2010 compared to $310.2 million in 2009 primarily due to lower accounts receivable and the settlement of a contract receivable from a natural gas supplier, higher accounts payable and accrued charges, offset by income tax receivable in 2010 compared to income tax payable in 2009.

# Outstanding Share Data

| Issued and Outstanding: | Millions of Shares | Common Share Capital millions of dollars |
|---|---|---|
| December 31, 2008 | 112.21 | $1,081.4 |
| Issued for cash under purchase plans | 0.45 | 8.7 |
| Options exercised under senior management share option plan | 0.32 | 5.8 |
| Share-based compensation | - | 0.8 |
| December 31, 2009 | 112.98 | $1,096.7 |
| Issued for cash under purchase plans | 1.32 | 32.8 |
| Options exercised under senior management share option plan | 0.32 | 6.0 |
| Share-based compensation | - | 1.0 |
| December 31, 2010 | 114.62 | $1,136.5 |

As at January 31, 2011, the number of issued and outstanding common shares was 114.69 million.

# NOVA SCOTIA POWER INC.

## Overview

NSPI, created through the privatization in 1992 of the crown corporation Nova Scotia Power Corporation, is a fully-integrated regulated electric utility and the primary electricity supplier in Nova Scotia. NSPI has $4.0 billion of assets and provides electricity generation, transmission and distribution services to approximately 489,000 customers. The company owns 2,368 MW of generating capacity, of which approximately 53% is coal-fired; natural gas and/or oil comprise another 27% of capacity; and hydro and wind production total 20%. In addition, NSPI has contracts to purchase renewable energy from IPPs. These IPPs own 186 MW, increasing to 226 MW in 2011, of wind and biomass fueled generation capacity. A further 85 MW of renewable capacity is being built directly or purchased under long-term contract by NSPI and is expected to be in service by the end of 2012. NSPI also owns approximately 5,000 kilometers of transmission facilities and 29,000 kilometers of distribution facilities. NSPI has a workforce of approximately 1,900 people.

NSPI is a public utility as defined in the Public Utilities Act (Nova Scotia) (“Act”) 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. NSPI is not subject to a general annual rate review process, but rather participates in hearings from time to time at NSPI’s or the UARB’s request.

NSPI is regulated under a cost-of-service model, with rates set to recover prudently incurred costs of providing electricity service to customers, and provide an appropriate return to investors. NSPI’s regulated return on equity (“ROE”) range for 2010 was 9.1% to 9.6%, on an actual regulated common equity component of up to 40% of average regulated capitalization.

In 2009, the UARB approved a FAM, allowing NSPI to recover fluctuating fuel expenses from customers through annual fuel rate adjustments. In 2010, revenue associated with fuel comprised approximately 45% of total revenue. As the FAM mitigates NSPI’s net earnings’ exposure to fuel volatility, it facilitates longer planning cycles. This enables NSPI to increase its focus on the impact that non-fuel components of the business have on net earnings, while retaining focus on managing fuel costs for customers. In 2010, tax benefits associated with renewable energy investments reduced costs and, thus NSPI did not seek a general rate adjustment with the UARB.

## Review of 2010

| **NSPI** millions of dollars (except earnings per common share) | Three months ended December 31 | | Year ended December 31 | | |
|---|---|---|---|---|---|
| | **2010** | 2009 | **2010** | 2009 | 2008 |
| Electric revenue | **$296.4** | $302.9 | **$1,167.3** | $1,188.1 | $1,111.1 |
| Fuel for generation and purchased power | **146.2** | 138.5 | **586.7** | 500.7 | 471.4 |
| Fuel adjustment | **(24.0)** | (10.6) | **(99.0)** | 8.5 | - |
| Operating, maintenance and general | **65.0** | 58.4 | **237.5** | 215.1 | 203.7 |
| Provincial grants and taxes | **10.1** | 10.0 | **40.1** | 40.5 | 41.2 |
| Depreciation and amortization | **39.9** | 36.8 | **150.8** | 143.9 | 133.6 |
| Regulatory amortization | **23.7** | 14.7 | **36.9** | 27.2 | 17.7 |
| Other revenue | **(4.7)** | (4.0) | **(15.4)** | (14.0) | (15.5) |
| Earnings before financing charges and income taxes | **40.2** | 59.1 | **229.7** | 266.2 | 259.0 |
| Financing charges | **32.8** | 33.3 | **125.8** | 114.7 | 106.8 |
| Earnings before income taxes | **7.4** | 25.8 | **103.9** | 151.5 | 152.2 |
| Income taxes | **(13.3)** | 8.4 | **(17.4)** | 42.2 | 46.6 |
| Contribution to consolidated net earnings applicable to common shares | **$20.7** | $17.4 | **$121.3** | $109.3 | $105.6 |
| Contribution to consolidated earnings per common share | **$0.18** | $0.15 | **$1.07** | $0.97 | $0.94 |

NSPI's contribution to consolidated net earnings applicable to common shares increased $3.3 million to $20.7 million in Q4 2010, compared to $17.4 million in Q4 2009. Annual contribution to consolidated net earnings applicable to common shares increased $12.0 million to $121.3 million in 2010 compared to $109.3 million in 2009, and $105.6 million in 2008.

Highlights of the contribution to consolidated 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 applicable to common shares – 2008** | | **$105.6** |
| Increased electric revenue due to an electricity price increase on January 1, 2009, partially offset by decreased industrial sales in the year | | 77.0 |
| Increased fuel for generation and purchased power | | (29.3) |
| Fuel adjustment related to implementation of the FAM | | (8.5) |
| Increased OM&G expenses primarily due to increased storm and reliability costs as well as customer service initiatives, partially offset by decreased pension expense | | (11.4) |
| Increased depreciation and amortization primarily due to increased depreciation rates in 2009 as part of the phase-in of year-three rates as approved by the UARB | | (10.3) |
| Increased financing charges | | (7.9) |
| Increased regulatory amortization due to additional amortization of pre-2003 income tax regulatory asset | | (9.5) |
| Decreased income taxes due to decreased taxable income and lower statutory rate, partially offset by recovery of income taxes in 2008 relating to a prior year | | 4.4 |
| Other | | (0.8) |
| **Contribution to consolidated net earnings applicable to common shares – 2009** | **$17.4** | **$109.3** |
| Decreased electric margin (see Electric Margin for explanation) | (2.0) | (11.6) |
| Increased OM&G expenses primarily due to increased pension and storm costs. Year-to-date also reflects increased spending on customer service initiatives | (6.6) | (22.4) |
| Increased depreciation and amortization primarily due to increased property, plant and equipment | (3.1) | (6.9) |
| Increased regulatory amortization due to a deferral of certain tax benefits arising in 2010, partially offset by decreased amortization of the pre-2003 income tax regulatory asset | (9.0) | (9.7) |
| Decreased income taxes due to decreased earnings before income taxes, deductions related to renewable investments and a change in the expected benefit from other accelerated tax deductions | 21.7 | 59.6 |
| Other | 2.3 | 3.0 |
| **Contribution to consolidated net earnings applicable to common shares – 2010** | **$20.7** | **$121.3** |

Financing charges decreased $0.5 million in the quarter and increased $11.1 million for the year ended December 31, 2010. Foreign exchange gain and losses recovered through the FAM as fuel costs are included in the change in electric margin in the table above. See Electric Margin section for additional explanation.

## Electric Revenue

NSPI's electricity rates are set based on a forecast of fuel and non-fuel costs plus a reasonable return to investors. Consequently, the company's electric revenue is comprised of revenue related to the recovery of fuel costs ("fuel electric revenue") and revenue related to the recovery of non-fuel costs ("non-fuel electric revenue").

With the introduction of the FAM, on January 1, 2009, NSPI is able to seek full recovery of fuel costs through regularly scheduled rate adjustments, thus reducing the impact of volatile fuel markets on NSPI's earnings. As a result, fuel electric revenue does not have a material impact on net earnings.

NSPI's customer classes contribute differently to the NSPI's non-fuel electric revenue. Changes in volume of residential and commercial customers, largely due to weather, have the largest impact on non-fuel electric revenue. Changes in industrial load, which are generally due to economic conditions, do not have a significant impact on non-fuel electric revenue.

The fuel electric revenue is comprised of the recovery of fuel costs incurred in the current year and the over or under-recovery of fuel costs from the prior year. Since fuel costs are recovered through the FAM, the electric margin is solely influenced by revenues relating to non-fuel costs and the FAM incentive expense or recovery. Electric revenue is summarized in the following table:

| millions of dollars | Three months ended December 31 | | Year ended December 31 | | |
|---|---|---|---|---|---|
| | **2010** | 2009 | **2010** | 2009 | 2008 |
| Fuel electric revenue current year | **$129.0** | $131.4 | **$515.7** | $511.2 | * |
| Fuel electric revenue prior year rebate | **(5.7)** | - | **(22.4)** | - | * |
| Non-fuel electric revenue | **173.1** | 171.5 | **674.0** | 676.9 | * |
| Total electric revenue | **$296.4** | $302.9 | **$1,167.3** | $1,188.1 | $1,111.1 |

* Prior to the introduction of the FAM on January 1, 2009, electric revenue was not broken into the components above.

Electric revenue decreased $6.5 million to $296.4 million in Q4 2010 compared to $302.9 million in Q4 2009. For the year ended December 31, 2010, NSPI's electric revenue decreased $20.8 million to $1,167.3 million compared to $1,188.1 million in 2009 and $1,111.1 million in 2008.

Highlights of the changes are summarized in the following table:

| millions of dollars | Three months ended December 31 | Year ended December 31 |
|---|---|---|
| **Electric revenue – 2008** | | **$1,111.1** |
| Increased electricity pricing effective January 1, 2009 | | 102.1 |
| Net change in residential and commercial sales volumes | | 4.2 |
| Decreased industrial sales to several large industrial customers | | (28.3) |
| Decreased export sales | | (1.0) |
| **Electric revenue – 2009** | **$302.9** | **$1,188.1** |
| Decreased electricity pricing effective January 1, 2010 related to the FAM rebate (fuel-electric revenue) to customers of over-recovered fuel costs in 2009 | (5.7) | (22.4) |
| Change in residential and commercial sales volumes due primarily to warmer weather | (1.7) | (10.7) |
| Increased industrial sales volume from several large industrial customers | 0.6 | 13.2 |
| Other | 0.3 | (0.9) |
| **Electric revenue – 2010** | **$296.4** | **$1,167.3** |

## Electric Sales Volumes

**Q4 Electric Sales Volumes**
GWh

| | **2010** | 2009 | 2008 |
|---|---|---|---|
| Residential | **1,080** | 1,091 | 1,093 |
| Commercial | **765** | 772 | 770 |
| Industrial | **957** | 998 | 987 |
| Other | **84** | 81 | 84 |
| Total | **2,886** | 2,942 | 2,934 |

**Year-to-Date ("YTD") Electric Sales Volumes**
GWh

| | **2010** | 2009 | 2008 |
|---|---|---|---|
| Residential | **4,147** | 4,228 | 4,179 |
| Commercial | **3,088** | 3,107 | 3,115 |
| Industrial | **3,908** | 3,642 | 4,144 |
| Other | **312** | 328 | 334 |
| Total | **11,455** | 11,305 | 11,772 |

Electric sales volume is primarily driven by general economic conditions, population and weather. Residential and commercial electricity sales are seasonal, with Q1 and Q4 the strongest periods, reflecting colder weather, and fewer daylight hours in the winter season.

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

## Electric Margin

As noted above, all fuel costs are recoverable from customers through the FAM. Differences between actual fuel costs and amounts recovered from customers through electricity rates in a period are deferred to a FAM regulatory asset or liability and recovered from or returned to customers in a subsequent period. The only effect on net earnings in relation to the recovery of fuel costs is the incentive component of the FAM with NSPI retaining or absorbing 10% of the over or under-recovered amount less the difference between the incentive threshold and the base amount to a maximum of $5 million.

NSPI's electric margin is influenced by non-fuel revenues and the FAM incentive. NSPI's electric margin is summarized in the following table:

| millions of dollars | Three months ended December 31 | | Year ended December 31 | | |
|---|---|---|---|---|---|
| | **2010** | 2009 | **2010** | 2009 | 2008 |
| Electric revenue | **$296.4** | $302.9 | **$1,167.3** | $1,188.1 | * |
| Fuel for generation and purchased power | **146.2** | 138.5 | **586.7** | 500.7 | * |
| Fuel adjustment | **(24.0)** | (10.6) | **(99.0)** | 8.5 | * |
| Fuel related foreign exchange (losses) gains | **(3.4)** | (2.2) | **(9.3)** | 3.0 | * |
| Electric margin | **$170.8** | $172.8 | **$670.3** | $681.9 | * |

* Prior to the introduction of the FAM on January 1, 2009, electric margin was not broken into the components above.

NSPI's electric margin decreased $2.0 million to $170.8 million in Q4 2010 compared to $172.8 million in Q4 2009 primarily due to the recognition of a FAM incentive expense compared to a recovery in 2009. For the year ended December 31, 2010, NSPI's electric margin decreased $11.6 million to $670.3 million in 2010 compared to $681.9 million in 2009 due to lower residential load related to warmer weather and the recognition of a FAM incentive expense compared to a recovery in 2009.

**Q4 Electric Margin / MWh**

| | **2010** | 2009 | 2008 |
|---|---|---|---|
| Dollars per MWh | **$59** | $59 | * |

**YTD Electric Margin / MWh**

| | **2010** | 2009 | 2008 |
|---|---|---|---|
| Dollars per MWh | **$59** | $60 | * |

* Prior to the introduction of the FAM on January 1, 2009, electric margin was not broken into the components above.

The change in average electric margin per MWh in 2010 compared to 2009 reflects a change in sales volume mix and recognition of a FAM incentive expense compared to a recovery in 2009.

## Fuel for Generation and Purchased Power

### Capacity

To ensure reliability of service, NSPI maintains a generating capacity greater than firm peak demand. The total NSPI-owned generation capacity is 2,368 MW, which is supplemented by 186 MW contracted with IPPs. NSPI meets the planning criteria for reserve capacity established by the Maritime Control Area and the Northeast Power Coordinating Council.

NSPI facilities continue to rank among the best in Canada on capacity related performance indicators. The high availability and capability of low cost thermal generating stations provide lower cost energy to customers. In 2010, thermal plant availability was 87% compared to 82% in 2009. The increase in availability from 2009 reflects decreased maintenance outages. Sustained high availability and low forced outage rates on low cost facilities are good indicators of sound maintenance and investment practices.

### Fuel Expense

**Q4 Production Volumes**
GWh

| | **2010** | 2009 | 2008 |
|---|---|---|---|
| Coal & petcoke | **2,049** | 2,069 | 2,177 |
| Natural gas | **438** | 534 | 249 |
| Oil & diesel | **16** | 16 | 218 |
| Renewable | **340** | 281 | 257 |
| Purchased power* | **315** | 335 | 296 |
| Total | **3,158** | 3,235 | 3,197 |

*Purchased power includes 132 GWh of renewables in 2010 (2009 – 51 GWh; 2008 – 44 GWh).

**YTD Production Volumes**
GWh

| | **2010** | 2009 | 2008 |
|---|---|---|---|
| Coal & petcoke | **7,839** | 8,177 | 9,009 |
| Natural gas | **2,275** | 1,612 | 1,258 |
| Oil & diesel | **36** | 307 | 339 |
| Renewable | **1,017** | 1,065 | 1,068 |
| Purchased power* | **997** | 931 | 889 |
| Total | **12,164** | 12,092 | 12,563 |

*Purchased power includes 355 GWh of renewables in 2010 (2009 – 149 GWh; 2008 – 148 GWh).

**Q4 Average Unit Fuel Costs**

| | **2010** | 2009 | 2008 |
|---|---|---|---|
| Dollars per MWh | **$46** | $43 | $44 |

**YTD Average Unit Fuel Costs**

| | **2010** | 2009 | 2008 |
|---|---|---|---|
| Dollars per MWh | **$48** | $41 | $38 |

Solid fuel is NSPI's dominant fuel source, supplying approximately 64% (2009 – 68%) of NSPI's annual energy. Historically, solid fuels have had the lowest per unit fuel cost, after hydro and NSPI-owned wind production, which have no fuel cost component. Natural gas, oil, and purchased power are next, depending on the relative pricing of each. Economic dispatch of the generating fleet brings the lowest cost options on stream first, with the result that the incremental cost of production increases as sales volume increases.

The average unit fuel costs increased in 2010 compared to 2009 mainly as a result of higher priced import coal and solid fuel commodity mix related to emission compliance.

The average unit fuel costs increased in 2009 compared to 2008 mainly as a result of higher priced commodity contracts for coal and natural gas.

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 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 NSPI's fuel cost risk management strategies are included in the Business Risks section. Fuel contracts may be exposed to broader global conditions which may include impacts on delivery reliability and price, despite contracted terms.

For the three months ended December 31, 2010, fuel for generation and purchased power increased $7.7 million to $146.2 million, compared to $138.5 million in Q4 2009. For the year ended December 31, 2010, fuel for generation and purchased power increased $86.0 million to $586.7 million compared to $500.7 million in 2009 and $471.4 million in 2008.

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 – 2008** | | **$471.4** |
| Commodity price increases | | 36.2 |
| Decreased proceeds from the resale of natural gas | | 10.3 |
| Valuation of contract receivable (see discussion below) | | 4.5 |
| Decreased sales volume | | (22.2) |
| Mark-to-market on natural gas hedges not required in 2009 primarily due to decreased production volumes | | (0.7) |
| Changes in generation mix and plant performance | | (10.2) |
| Decreased hydro production | | 1.8 |
| Primarily solid fuel handling costs previously included in OM&G expenses | | 10.7 |
| Other | | (1.1) |
| **Fuel for generation and purchased power – 2009** | **$138.5** | **$500.7** |
| Commodity price and volume increases | 0.4 | 34.5 |
| Changes in generation mix and plant performance | 12.6 | 24.3 |
| Solid fuel commodity mix and additives related to emission compliance | 0.8 | 25.3 |
| Increased proceeds from the resale of natural gas | (0.8) | (9.8) |
| Valuation of contract receivable (see discussion below) | 6.6 | 8.7 |
| (Decreased) increased sales volume | (5.1) | 2.7 |
| Increased hydro production | (6.2) | (1.1) |
| Mark-to-market on natural gas hedges recognized in 2009 as they were no longer required due to decreased 2009 production volumes | 1.5 | 2.2 |
| Other | (2.1) | (0.8) |
| **Fuel for generation and purchased power – 2010** | **$146.2** | **$586.7** |

The valuation of the contract receivable from a natural gas supplier required NSPI to utilize a combination of historical and future natural gas prices. NSPI uses market-based forward indices when determining future prices. Future prices can change from period to period which will cause a corresponding change in the value of the contract receivable. The natural gas supply contract settled in November 2010.

## Fuel Adjustment

The fuel adjustment related to the FAM includes the effect of fuel costs in both the current period and the preceding year. The difference between actual fuel costs and amounts recovered from customers in the current period is included in the fuel adjustment. This amount, less the incentive component, is deferred to a FAM regulatory asset in “Other assets” or a FAM regulatory liability in “Other Liabilities”. The FAM regulatory asset or liability includes amounts recognized as a fuel adjustment and associated interest included in “Financing charges”. Also included in the 2010 fuel adjustment is the rebate to customers of over recovered fuel costs from 2009.

Details of the fuel adjustment deferral related to the FAM are summarized in the following table:

| | Year ended December 31 | | |
|---|---|---|---|
| millions of dollars | **2010** | 2009 | 2008 |
| FAM payable – Balance at January 1 | **$(9.9)** | * | * |
| Under (over) recovery of current period fuel costs | **80.3** | $(9.9) | * |
| Rebate to customers from prior year | **22.5** | - | * |
| FAM receivable (payable) – Balance at December 31 | **$92.9** | $(9.9) | * |

*The fuel adjustment mechanism came into effect on January 1, 2009.

In December 2010, as part of the FAM regulatory process, the UARB directed NSPI to recover the rate increase approved by the UARB for the reset of 2011 fuel costs and the projected under recovery from prior years from customers over three years, with 50% of the rate increase to be recovered in 2011, 30% in 2012 and 20% in 2013.

NSPI has recognized a future income tax expense related to the fuel adjustment based on its applicable statutory income tax rate. The FAM regulatory asset or liability includes amounts recognized as a fuel adjustment and associated interest included in “Financing charges”. As at December 31, 2010, NSPI’s future income tax liability related to the FAM was $29.2 million (2009 – asset of $3.4 million).

## Operating, Maintenance and General

OM&G expenses increased $6.6 million to $65.0 million in Q4 2010 compared to $58.4 million in Q4 2009 and increased $22.4 million to $237.5 million for the year ended December 31, 2010 compared to $215.1 million in 2009 primarily due to increased pension and storm costs as well as customer service initiatives.

OM&G expenses increased $11.4 million to $215.1 million for the year ended December 31, 2009 compared to $203.7 million in 2008 primarily due to increased storm costs, system reliability spending and program costs associated with customer and new business initiatives, partially offset by lower pension expense.

## Provincial Grants and Taxes

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

## Depreciation and Amortization

Depreciation and amortization expense increased $3.1 million to $39.9 in Q4 2010 compared to $36.8 million in Q4 2009 and increased $6.9 million to $150.8 for the year ended December 31, 2010 compared to $143.9 million in 2009 primarily due to increased property, plant and equipment.

Depreciation and amortization expense increased $10.3 million to $143.9 for the year ended December 31, 2009 compared to $133.6 million in 2008 primarily due to the inclusion of year-three depreciation rates commencing on January 1, 2009 as approved by the UARB in its November 5, 2008 decision.

## Regulatory Amortization

Regulatory amortization increased $9.0 million to $23.7 million in Q4 2010 compared to $14.7 million in Q4 2009 and increased $9.7 million to $36.9 million for the year ended December 31, 2010 compared to $27.2 million in 2009. This increase is due primarily to a $14.5 million deferral of certain tax benefits arising in 2010 related to renewable energy projects, as approved by the UARB, partially offset by a reduction in amortization of the pre-2003 income tax regulatory asset resulting from the UARB’s 2009 ROE decision of $4.8 million in 2010 (2009 – $10.0 million). The 2009 ROE decision allows NSPI to recognize additional amortization amounts in current periods and to reduce amortization in future periods to provide flexibility relating to customer rate requirements.

Regulatory amortization increased $9.5 million to $27.2 million for the year ended December 31, 2009 compared to $17.7 million in 2008 due primarily to additional amortization of the pre-2003 income tax regulatory asset resulting from the UARB’s ROE decision noted above.

## Other Revenue

Other revenue, which consists of miscellaneous revenues and commercial settlements, has remained relatively unchanged for the quarter and year ended December 31, 2010 compared to 2009 and 2008.

## Financing Charges

Financing charges decreased \$0.5 million to \$32.8 million in Q4 2010 compared to \$33.3 million in Q4 2009 and increased \$11.1 million to \$125.8 million for the year ended December 31, 2010 compared to \$114.7 million in 2009 primarily due to higher foreign exchange costs, recovered through the FAM, and increased borrowing costs, partially offset by increased AFUDC related to increased capital spending.

Financing charges increased \$7.9 million to \$114.7 million for the year ended December 31, 2009 compared to \$106.8 million in 2008 primarily due to lower foreign exchange gains in 2009 compared to 2008. In 2009, NSPI recorded income tax refund interest of \$3.0 million which was received as a result of NSPI amending its 1999 to 2003 corporate income tax returns. This refund interest was recorded as a reduction of "Financing charges".

## Income Taxes

NSPI uses the future income tax method of accounting for income taxes. In accordance with NSPI's rate-regulated accounting policy as approved by the UARB, NSPI defers any future income taxes to a regulatory asset or liability where the future income taxes are expected to be included in future rates.

In 2010, NSPI was subject to provincial capital tax (0.125%), corporate income tax (34%) and Part VI.1 tax relating to preferred dividends (40%). NSPI also receives a reduction in its corporate income tax otherwise payable related to the Part VI.1 tax deduction (41% of preferred dividends).

Income taxes decreased \$21.7 million to a \$13.3 million income tax recovery in Q4 2010 compared to \$8.4 million income tax expense in Q4 2009 and decreased \$59.6 million to a \$17.4 million recovery for the year ended December 31, 2010 compared to \$42.2 million income tax expense in 2009 primarily due to decreased earnings before income taxes, deductions related to renewable investments and a change in the expected benefit from other accelerated tax deductions.

Income taxes decreased \$4.4 million to \$42.2 million for the year ended December 31, 2009 compared to \$46.6 million in 2008 primarily due to decreased taxable income and a lower statutory rate in 2009 compared to 2008, partially offset by a recovery of income taxes in 2008 relating to a prior year.

In 2010, NSPI revised its estimate of the expected benefit from accelerated tax deductions. The impact for the three months and twelve months ended December 31, 2010 was to reduce income tax expense by approximately \$8.0 million and \$14.0 million respectively. In accordance with rate-regulated accounting, the future income tax implications of this change in estimate have been deferred to a regulatory asset in "Other assets". This change in accounting estimate has been accounted for on a prospective basis.

# BANGOR HYDRO

**All amounts in the Bangor Hydro section are reported in USD unless otherwise stated.**

## Overview

Bangor Hydro's core business is the transmission and distribution of electricity. Bangor Hydro is the second largest electric utility in Maine. Electricity generation is deregulated in Maine, and several suppliers compete to provide customers with the commodity that is delivered through the Bangor Hydro T&D network. Bangor Hydro owns and operates approximately 1,000 kilometers of transmission facilities, and 7,200 kilometers of distribution facilities. Bangor Hydro currently has approximately $150 million of additional transmission development in progress. Bangor Hydro's workforce is approximately 290 people.

In addition to T&D assets, Bangor Hydro has net regulatory assets (stranded costs), which arose through the restructuring of the electricity industry in the state in the late 1990s, and as a result of rate and accounting orders issued by its regulator. Bangor Hydro's net regulatory assets primarily include the costs associated with the restructuring of an above-market power purchase contract, and the unamortized portion on its loss on the sale of its investment in the Seabrook nuclear facility. Unlike T&D operational assets, which are generally sustained with new investment, the net stranded cost regulatory asset pool diminishes over time as elements are amortized through charges to earnings and recovered through rates. These net regulatory assets total approximately $77.5 million at December 31, 2010 (2009 – $76.6 million) or 10% of Bangor Hydro's net asset base (2009 – 11%).

Approximately 44% of Bangor Hydro's electric revenue represents distribution service, 45% is associated with transmission service and 11% relates to stranded cost recoveries. The rates for each element are established in distinct regulatory proceedings. Bangor Hydro's distribution operations and stranded costs are regulated by the MPUC. The transmission operations are regulated by the FERC.

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

Transmission rates are set by the FERC annually on June 1, based upon a formula that utilizes prior year actual transmission investments and expenses, adjusted for current year forecasted transmission investments and expenses. In 2009, Bangor Hydro implemented this forward-looking rate formula for its local transmission investments, replacing an approach which had resulted in a lag in the recovery of transmission investments and costs. The allowed ROE for transmission operations ranges from 11.14% for low voltage local transmission up to 12.64% for high voltage regionally-funded transmission developed as a result of the regional system plan.

In December 2007, the MPUC issued an order approving an approximate 39% reduction in stranded cost rates for the three-year period beginning March 1, 2008. The reduced stranded cost revenues are offset for the most part by decreased regulatory amortizations, decreased purchased power costs, and increased resale of purchased power. The allowed ROE used in setting the new stranded cost rates was 8.5%. Prior to that, stranded cost rates provided for an allowed ROE of 10%. On June 1, 2009, Bangor Hydro further reduced its stranded cost rates for a one year period by approximately 15% to reflect an over-collection of certain stranded cost revenues and expenses under a full reconciliation rate mechanism.

# Review of 2010

| **Bangor Hydro** millions of USD (except earnings per common share) | Three months ended December 31 | | Year ended December 31 | | |
|---|---|---|---|---|---|
| | **2010** | 2009 | **2010** | 2009 | 2008 |
| T&D electric revenues | **$28.7** | $25.9 | **$109.0** | $102.8 | $97.6 |
| Resale of purchased power | **4.6** | 4.9 | **18.3** | 18.9 | 20.4 |
| Transmission pool revenue | **4.6** | 3.0 | **21.5** | 14.0 | 16.5 |
| Total revenue | **37.9** | 33.8 | **148.8** | 135.7 | 134.5 |
| Fuel for generation and purchased power | **7.9** | 7.6 | **31.0** | 29.4 | 32.2 |
| Operating, maintenance and general | **10.2** | 7.4 | **36.3** | 30.9 | 28.8 |
| Property taxes | **1.6** | 1.7 | **6.8** | 6.3 | 5.4 |
| Depreciation | **4.3** | 4.0 | **16.7** | 16.0 | 15.3 |
| Regulatory amortization | **0.9** | 1.6 | **4.2** | 7.4 | 10.1 |
| Other | **(0.5)** | (0.5) | **(2.3)** | (2.6) | (3.8) |
| Earnings before financing charges and income taxes | **13.5** | 12.0 | **56.1** | 48.3 | 46.5 |
| Financing charges | **1.6** | 2.2 | **7.0** | 10.4 | 11.1 |
| Earnings before income taxes | **11.9** | 9.8 | **49.1** | 37.9 | 35.4 |
| Income taxes | **4.3** | 3.3 | **18.2** | 13.5 | 13.9 |
| Contribution to consolidated net earnings applicable to common shares – USD | **$7.6** | $6.5 | **$30.9** | $24.4 | $21.5 |
| Contribution to consolidated net earnings applicable to common shares – CAD | **$7.8** | $7.0 | **$31.9** | $27.5 | $23.1 |
| Contribution to consolidated earnings per common share – CAD | **$0.07** | $0.06 | **$0.28** | $0.24 | $0.21 |
| Net earnings weighted average foreign exchange rate – CAD /USD | **$1.03** | $1.08 | **$1.03** | $1.13 | $1.07 |

Bangor Hydro's contribution to consolidated net earnings applicable to common shares increased by $1.1 million to $7.6 million in Q4 2010 compared to $6.5 million in Q4 2009. Annual contribution to consolidated net earnings applicable to common shares increased by $6.5 million to $30.9 million compared to $24.4 million in 2009 and $21.5 million in 2008. 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 applicable to common shares – 2008** | | **$21.5** |
| Increased T&D electric revenues due to transmission rate increases and additional transmission revenues from wind generation | | 5.2 |
| Lower net transmission pool revenue due to increased regional charges | | (2.5) |
| Increased OM&G expenses due to increased storm, regulatory and labour costs | | (2.1) |
| Decreased financing charges primarily due to lower short-term interest rates | | 0.7 |
| Other | | 1.6 |
| **Contribution to consolidated net earnings applicable to common shares – 2009** | **$6.5** | **$24.4** |
| Increased electric operating revenues due primarily to transmission rate increases in 2009 and 2010 | 2.8 | 6.2 |
| Higher transmission pool revenue due to the recovery of the increase in regionally-funded transmission investments | 1.6 | 7.5 |
| Increased OM&G expenses due to higher pension, post-retirement benefits and payroll costs as well as lower capitalized overheads | (2.8) | (5.4) |
| Decreased financing charges due to higher AFUDC related to capital investment | 0.6 | 3.4 |
| Increased income taxes due to higher earnings in 2010 | (1.0) | (4.7) |
| Other | (0.1) | (0.5) |
| **Contribution to consolidated net earnings applicable to common shares – 2010** | **$7.6** | **$30.9** |

Bangor Hydro's contribution to consolidated net earnings applicable to common shares – CAD decreased $0.4 million in Q4 2010 compared to Q4 2009 and $3.1 million in 2010 compared to 2009 due to the impact of the stronger CAD.

## Electric Revenue

**Q4 Electric Sales Volumes**
GWh

| | **2010** | 2009 | 2008 |
|---|---|---|---|
| Residential | **155** | 154 | 155 |
| Commercial | **147** | 145 | 145 |
| Industrial | **84** | 78 | 90 |
| Other | **3** | 3 | 2 |
| Total | **389** | 380 | 392 |

**YTD Electric Sales Volumes**
GWh

| | **2010** | 2009 | 2008 |
|---|---|---|---|
| Residential | **591** | 591 | 591 |
| Commercial | **594** | 588 | 604 |
| Industrial | **363** | 342 | 350 |
| Other | **12** | 12 | 10 |
| Total | **1,560** | 1,533 | 1,555 |

**Q4 Electric Revenues**
millions of dollars

| | **2010** | 2009 | 2008 |
|---|---|---|---|
| Residential | **$13.6** | $12.6 | $12.8 |
| Commercial | **10.3** | 9.1 | 8.7 |
| Industrial | **2.9** | 2.4 | 3.0 |
| Other | **1.9** | 1.8 | 1.4 |
| Total | **$28.7** | $25.9 | $25.9 |

**YTD Electric Revenues**
millions of dollars

| | **2010** | 2009 | 2008 |
|---|---|---|---|
| Residential | **$50.6** | $48.3 | $47.6 |
| Commercial | **39.4** | 35.9 | 34.5 |
| Industrial | **11.5** | 10.2 | 10.0 |
| Other | **7.5** | 8.4 | 5.5 |
| Total | **$109.0** | $102.8 | $97.6 |

**Q4 Electric Average Revenue / MWh**

| | **2010** | 2009 | 2008 |
|---|---|---|---|
| Dollars per MWh | **$74** | $68 | $66 |

**YTD Electric Average Revenue / MWh**

| | **2010** | 2009 | 2008 |
|---|---|---|---|
| Dollars per MWh | **$70** | $67 | $63 |

The changes in average revenue per MWh in 2010 compared to 2009 reflect increases in transmission rates on June 1, 2010, November 1, 2009 and June 1, 2009, partially offset by the impact of a stranded cost rate decrease on June 1, 2009.

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 increased by $2.8 million to $28.7 million in Q4 2010 compared to $25.9 million in Q4 2009 and increased $6.2 million to $109.0 million for the year ended December 31, 2010 compared to $102.8 million for 2009 due to increased transmission rates, including the impact of moving to a forward-looking rate formula, and increased commercial and industrial load, partially offset by a reduction in stranded cost rates.

Electric revenues increased $5.2 million to $102.8 million for the year ended December 31, 2009 compared to $97.6 million for 2008 due to increased transmission rates, including the impact of moving to a forward-looking rate formula in 2009, partially offset by a reduction in stranded cost rates.

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

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

## Transmission Pool Revenue

Bangor Hydro recovers the cost of its regionally-funded transmission infrastructure investment, through transmission pool revenue based on a regional formula that is updated on June 1 of each year. Transmission pool revenue, less transmission infrastructure investment charges, is recovered from the customers of member utilities of the New England Power Pool (“NEPOOL“).

Transmission pool revenue increased by $1.6 million to $4.6 million in Q4 2010 compared to $3.0 million in Q4 2009 and increased $7.5 million to $21.5 million for the year ended December 31, 2010 compared to $14.0 million for 2009 due primarily to increased revenue received associated with an increase in Bangor Hydro’s regionally funded transmission investments in 2010.

Transmission pool revenue decreased $2.5 million to $14.0 million for the year ended December 31, 2009 compared to $16.5 million for 2008 due to greater regional charges related to increased regional transmission investments.

## Regulatory Amortization

Regulatory amortization has a minimal impact on earnings as a result of the stranded cost regulatory reconciliation mechanism as provided for by a MPUC ruling as noted previously.

## Financing Charges

Financing charges decreased $0.6 million to $1.6 million in Q4 2010 compared to $2.2 million in Q4 2009 and decreased $3.4 million to $7.0 million for the year ended December 31, 2010, compared to $10.4 million in 2009 primarily due to lower short-term interest rates in 2010 and increased AFUDC.

Financing charges decreased $0.7 million to $10.4 million for the year ended December 31, 2009, compared to $11.1 million in 2008 primarily due to lower short-term interest rates in 2009.

## 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 income tax rate).

# PIPELINES

## Overview

Pipelines is composed of the company's investments in Brunswick Pipeline, a wholly-owned subsidiary, along with its 12.9% interest in M&NP.

Brunswick Pipeline is a 145-kilometre pipeline delivering natural gas from the Canaport™ LNG import terminal near Saint John, New Brunswick, to markets in the northeastern United States. The pipeline, which received National Energy Board ("NEB") approval for shipping gas in January 2009 and went into service on July 16, 2009, transports re-gasified LNG for Repsol Energy Canada under a 25-year firm service agreement. The NEB, which regulates Brunswick Pipeline, has classified it as a Group 2 pipeline.

The company acquired a 12.9% interest in M&NP in 1999. M&NP is a $2 billion, 1,400-kilometre pipeline which transports natural gas from offshore Nova Scotia to markets in Maritime Canada and the northeastern United States.

## Review of 2010

| **Pipelines** millions of dollars | Three months ended December 31 | | Year ended December 31 | | |
|---|---|---|---|---|---|
| | **2010** | 2009 | **2010** | 2009 | 2008 |
| Brunswick Pipeline | | | | | |
| Finance income from direct financing lease | **$13.7** | $15.2 | **$56.5** | $25.3 | - |
| AFUDC | **-** | - | **-** | 18.8 | $15.6 |
| Financing charges | **7.8** | 8.8 | **30.7** | 30.1 | 12.4 |
| Brunswick Pipeline net earnings | **5.9** | 6.4 | **25.8** | 14.0 | 3.2 |
| M&NP net earnings | **2.9** | 2.0 | **9.2** | 10.2 | 12.2 |
| Contribution to consolidated net earnings applicable to common shares | **$8.8** | $8.4 | **$35.0** | $24.2 | $15.4 |
| Contribution to consolidated earnings per common share | **$0.08** | $0.07 | **$0.31** | $0.22 | $0.14 |

Pipelines' contribution to consolidated net earnings applicable to common shares increased $0.4 million to $8.8 million in Q4 2010 compared to $8.4 million in Q4 2009. Annual contribution to consolidated net earnings applicable to common shares increased $10.8 million to $35.0 million in 2010 compared to $24.2 million in 2009 and $15.4 million in 2008.

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 applicable to common shares – 2008** | | **$15.4** |
| Brunswick Pipeline – Financing income from the pipeline as it became operational in July 2009 | | 25.3 |
| Brunswick Pipeline –Increased AFUDC on construction of the pipeline prior to the pipeline commencing service | | 3.2 |
| Brunswick Pipeline – Increased intercompany financing charges related to capital spending | | (17.7) |
| M&NP – Net earnings decrease | | (2.0) |
| **Contribution to consolidated net earnings applicable to common shares – 2009** | **$8.4** | **$24.2** |
| Brunswick Pipeline – Financing income from the pipeline as it became operational in July 2009 | (1.5) | 31.2 |
| Brunswick Pipeline – Cessation of AFUDC as the pipeline became operational | - | (18.8) |
| M&NP – Net earnings increase (decrease) | 0.9 | (1.0) |
| Other | 1.0 | (0.6) |
| **Contribution to consolidated net earnings applicable to common shares – 2010** | **$8.8** | **$35.0** |

## Maritimes & Northeast Pipeline

Equity earnings for M&NP increased by $0.9 million to $2.9 million in Q4 2010 compared to $2.0 million in Q4 2009. For the year ended December 31, 2010, equity earnings decreased $1.0 million to $9.2 million compared to $10.2 million in 2009 due to increased financing charges on the US portion of the pipeline as a result of debt recapitalization and the recognition of a portion of the EnCana Marketing (USA) Inc. (“Encana”) settlement in the first half of 2009, combined with a stronger Canadian dollar in 2010 compared to 2009.

In May 2009, M&NP recapitalized the US portion of the pipeline by issuing a $500 million USD long-term debt. The net proceeds of the debt issuance were distributed to the partners. Emera’s portion of the net proceeds was $64.2 million USD ($73.8 million CAD), and was recorded as a return of capital from M&NP.

## Income Taxes

Brunswick Pipeline uses the future income tax method of accounting for income taxes. In accordance with rate-regulated accounting, Brunswick Pipeline defers any future income taxes to a regulatory asset or liability where the future income taxes are expected to be included in the future tolls. M&NP equity earnings are recorded net of tax.

# OTHER, INCLUDING CORPORATE COSTS

Other, Including Corporate Costs, includes Emera Energy; Emera Utility Services; Caribbean investments; and corporate costs and other.

Emera Energy includes:

- Emera Energy Services Inc., a physical energy business which purchases and sells natural gas and electricity and provides related energy asset management services
- Bayside Power, a 260-MW gas-fired merchant electricity generating facility in Saint John, New Brunswick
- Emera's 50% joint venture ownership of Bear Swamp, a 600-MW pumped storage hydro-electric facility in northern Massachusetts.

Emera Utility Services is a utility services contractor.

Caribbean Investments include:

- An effective direct interest of 50% in GBPC, a vertically-integrated electric utility on Grand Bahama Island and a 30.4% indirect interest in GBPC through ICD Utilities Limited
- A 38% interest in LPH, the parent company of BLPC, the electric utility on the island of Barbados. In January 2011, Emera's interest in LPH increased to 79.9%.
- A 19% interest in Lucelec, a vertically-integrated electric utility on the island of St. Lucia.

Corporate and other costs pertain to certain Emera-wide functions such as executive management, strategic planning, treasury services, financial reporting, tax planning, business development, corporate governance. Corporate and other costs also include financing charges and income taxes associated with corporate activities.

## Review of 2010

Emera Energy and Emera Utility Services' operations are reported on earnings before financing charges and income taxes ("EBIT"). Caribbean operations, which include GBPC, LPH and Lucelec, are reported on an equity earnings basis.

| **Other**<br>millions of dollars (except earnings per common share) | Three months ended December 31 | | Year ended December 31 | | |
|---|---|---|---|---|---|
| | **2010** | 2009 | **2010** | 2009 | 2008 |
| Emera Energy | **$(1.0)** | $14.8 | **$5.7** | $20.7 | $15.0 |
| Emera Utility Services | **2.9** | 0.3 | **7.0** | 1.8 | 3.1 |
| Caribbean | **1.7** | 0.2 | **7.0** | 2.9 | 2.4 |
| | **3.6** | 15.3 | **19.7** | 25.4 | 20.5 |
| Financing charges | **1.1** | 0.8 | **3.2** | 5.2 | 10.3 |
| Income taxes | **(0.8)** | 5.6 | **0.4** | 5.9 | 6.7 |
| Contribution to consolidated net earnings applicable to common shares | **$3.3** | $8.9 | **$16.1** | $14.3 | $3.5 |
| Bear Swamp after-tax mark-to-market adjustment | **(2.6)** | 3.2 | **(8.6)** | 0.7 | (4.8) |
| Contribution to consolidated net earnings, absent the Bear Swamp after-tax mark-to-market adjustment | **$5.9** | $5.7 | **$24.7** | $13.6 | $8.3 |
| Contribution to consolidated net earnings per common share | **0.03** | $0.07 | **$0.14** | $0.11 | $0.01 |
| Contribution to consolidated net earnings per common share, absent the Bear Swamp after-tax mark-to-market adjustment | **$0.06** | $0.04 | **$0.22** | $0.10 | $0.06 |

The total contribution of Other to consolidated net earnings applicable to common shares decreased $5.6 million to $3.3 million in Q4 2010 compared to $8.9 million in Q4 2009. Annual contribution to consolidated net earnings applicable to common shares increased $1.8 million to $16.1 million in 2010 compared to $14.3 million in 2009 and $3.5 million in 2008.

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 applicable to common shares – 2008** | | **$3.5** |
| Emera Energy – Increased earnings primarily due to favorable changes in Bear Swamp's mark-to-market, and the acquisition of Bayside in September 2009, partially offset by higher power costs in Bear Swamp and reduced transportation mitigation opportunities in Energy Services | | 5.7 |
| Emera Utility Services – Decreased earnings reflecting project start dates being delayed into 2010 and unfavourable market conditions | | (1.3) |
| Decreased financing charges primarily due to lower interest rates in Bear Swamp and decreased average external debt | | 5.1 |
| Other | | 1.3 |
| **Contribution to consolidated net earnings applicable to common shares – 2009** | **$8.9** | **$14.3** |
| Emera Energy – Decreased earnings due primarily to Bear Swamp's mark-to-market loss, its lower earnings and the stronger CAD, partially offset by improved Emera Energy Services Inc. results | (15.8) | (15.0) |
| Emera Utility Services – Increased earnings due primarily to the successful completion of large construction projects and the expansion of the communications business | 2.6 | 5.2 |
| Caribbean – Increased equity earnings due primarily to LPH acquisition in May 2010 | 1.5 | 4.1 |
| Decreased financing charges year-to-date due primarily to lower interest expense due to lower LIBOR rates in 2010 and higher foreign exchange losses in 2009 | (0.3) | 2.0 |
| Decreased income taxes due primarily to decreased earnings in Emera Energy | 6.4 | 5.5 |
| **Contribution to consolidated net earnings applicable to common shares – 2010** | **$3.3** | **$16.1** |

**Bear Swamp Mark-to-Market Adjustment**

Bear Swamp has an agreement to supply energy and capacity to the Long Island Power Authority ("LIPA") through to 2021. Bear Swamp has contracted with its joint venture partner to provide the power necessary to produce the requirements of the LIPA contract. One of the contracts between Bear Swamp and Emera is marked-to-market through earnings, as it does not meet the stringent accounting requirements for hedge accounting.

As at December 31, 2010, the fair value of the contract was a net liability of $8.2 million (December 31, 2009 – $6.2 million net asset). The fair value of this derivative is subject to market volatility of power prices and will reverse over the life of the agreement.

## Income Taxes

GBPC, LPH and Lucelec's equity earnings are recorded net of tax. Variations in income tax expense are largely affected by earnings and foreign exchange fluctuations, along with changes in the statutory tax rate.

Income taxes decreased $6.4 million to a $0.8 million income tax recovery in Q4 2010 compared to $5.6 million income tax expense in Q4 2009 and decreased $5.5 million to $0.4 million income tax expense for the year ended December 31, 2010 compared to a $5.9 million income tax expense in 2009 primarily due to a decrease in earnings in Emera Energy.

Income taxes decreased $0.8 million to $5.9 million for the year ended December 31, 2009 compared to $6.7 million in 2008.

## Corporate Costs and Other

| **Corporate costs and other**<br>millions of dollars (except earnings per common share) | Three months ended<br>December 31 | | Year ended<br>December 31 | | |
|---|---|---|---|---|---|
| | **2010** | 2009 | **2010** | 2009 | 2008 |
| Revenue | **$7.7** | $8.7 | **$30.6** | $30.0 | $12.4 |
| Corporate costs | **3.8** | 9.2 | **22.9** | 21.8 | 15.4 |
| Financing charges | **8.3** | 8.8 | **32.2** | 22.3 | 10.5 |
| Income taxes | **(3.4)** | (5.1) | **(14.4)** | (14.5) | (10.0) |
| Preferred shares dividends | **-** | - | **3.1** | - | - |
| Total corporate (costs) recovery and other | **$(1.0)** | $(4.2) | **$(13.2)** | $0.4 | $(3.5) |

### Revenue

Revenue, which consists of intercompany interest from Brunswick Pipeline, has remained relatively unchanged for Q4 2010 compared to Q4 2009 and for the year ended December 31, 2010 compared to 2009.

Revenue increased $17.6 million to $30.0 million for the year ended December 31, 2009, compared to $12.4 million in 2008 due to the financing of Brunswick Pipeline.

### Corporate Costs

Corporate costs decreased by $5.4 million to $3.8 million in Q4 2010 compared to $9.2 million in Q4 2009 due primarily to deferral of business development costs, partially offset by an increase in deferred compensation costs.  For the year ended December 31, 2010, corporate costs has remained relatively unchanged compared to 2009.

Corporate costs increased $6.4 million to $21.8 million for the year ended December 31, 2009 compared to $15.4 million in 2008 due primarily to an increase in business development and deferred compensation costs.

### Financing Charges

Financing charges decreased $0.5 million to $8.3 million in Q4 2010 compared to $8.8 million in Q4 2009 and increased $9.9 million to $32.2 million for the year ended December 31, 2010 compared to $22.3 million in 2009 due primarily to higher interest rates and higher debt levels to finance acquisitions.

Financing charges increased $11.8 million to $22.3 million for the year ended December 31, 2009 compared to $10.5 million in 2008 due primarily to increased debt to finance the construction of Brunswick Pipeline.

### 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.

Income taxes recovery decreased $1.7 million to $3.4 million in Q4 2010 compared to $5.1 million in Q4 2009 primarily due to decreased corporate costs and remained relatively unchanged for the year ended December 31, 2010 compared to 2009.

Income taxes recovery increased $4.5 million to $14.5 million for the year ended December 31, 2009 compared to $10.0 million in 2008 due to increased corporate costs and financing charges for the year.

# OUTLOOK

## Business Environment

**Economic Environment**

Emera will continue to pursue investment opportunities related to the transformation of the energy industry to lower emissions and has embarked on a significant capital plan to increase the company's generation from renewable sources, to improve the transmission connections within its service territories, and to expand access to natural gas as Emera transitions to a cleaner, greener company.

**Environmental Regulations**

NSPI is subject to environmental regulations as set by both the Province of Nova Scotia and the Government of Canada. NSPI continues to work with officials at both levels of government so as to comply with these regulations in an integrated way.

## Operating Unit Outlook

**NSPI**

NSPI anticipates earning a regulated ROE within its allowed range in 2011. NSPI continues to implement its strategy, which is focused on regulated investments in renewable energy and system reliability projects, with a total capital program budget of approximately $350 million in 2011. NSPI expects to finance its capital expenditures with funds from operations, debt and equity.

**Bangor Hydro**

Bangor Hydro's USD earnings are expected to be slightly higher in 2011 due to the recovery of investments in new transmission assets. Bangor Hydro continues to execute on its transmission development plan, with approximately $150 million USD of large transmission projects in various stages of development. These projects, recoverable through regional transmission rates, are expected to provide returns on equity of 11.64%. In 2011, Bangor Hydro expects to invest approximately $87 million USD, including approximately $54 million USD for major transmission projects. Bangor Hydro expects to finance its capital expenditures with funds from operations and debt.

**Pipelines**

Pipelines earnings are expected to be lower in 2011 as a result of less favourable USD hedged exchange rates in 2011 compared to 2010 and as a result of capital lease accounting which yields declining earnings over the life of the asset.

**Other, Including Corporate Costs**

Earnings from Other, Including Corporate Costs, are expected to be higher in 2011 due to increased scale of business, offset by higher financing costs. Emera Newfoundland and Labrador plans to invest approximately $25 million in the Maritime Link and the Island Link Transmission Projects.

Emera expects to invest $115 million in the capital programs of its Caribbean companies.

# LIQUIDITY AND CAPITAL RESOURCES

The company generated cash in 2010 mainly through the operations of NSPI and Bangor Hydro, its two primary regulated utilities involved in the generation, transmission and distribution of electricity and Brunswick Pipeline. NSPI's and Bangor Hydro's customer bases are diversified by both sales volumes and revenues among residential, commercial, industrial and other customers. Circumstances that could affect the company's ability to generate cash include general economic downturns in its markets, the loss of one or more large customers, regulatory decisions affecting customer rates and changes in environmental legislation. NSPI and Bangor Hydro are each capable of paying dividends to Emera provided they do not breach their debt to capitalization ratios after giving effect to the dividend payment.

In addition to internally generated funds, Emera and NSPI have in aggregate access to $1.2 billion committed syndicated revolving bank lines of credit, of which $505 million is undrawn and available as at December 31, 2010. Emera and NSPI each have access to $600 million of this credit. NSPI has an active commercial paper program for up to $400 million, of which outstanding amounts are 100% backed by its bank lines and this results in an equal amount of credit being considered drawn and unavailable.

In June 2010, Emera's and NSPI's revolving bank lines were each renewed for $600 million, for a three-year term maturing in June 2013. NSPI's bank line was increased by $100 million to $600 million as part of this renewal process.

As at December 31, 2010, the outstanding short-term debt is as follows:

| millions of dollars | **Maturity** | **Credit Line Committed** | **Utilized** | **Undrawn and Available** |
|---|---|---|---|---|
| Emera – Operating and acquisition credit facility | June 2013 – Revolver | $600 | $406 | $194 |
| NSPI – Operating credit facility | June 2013 – Revolver | 600 | 289 | 311 |
| Bangor Hydro – in USD – Operating credit facility | September 2013 – Revolver | 80 | 42 | 38 |
| Other – in USD – Operating credit facilities | Various | 18 | 3 | 15 |

Emera and its subsidiaries have debt covenants associated with their credit facilities. These covenants are tested regularly, and the company is in compliance with the covenant requirements.

## Debt Management

### Emera

In May 2010, Emera filed a $500 million debt and preferred equity shelf prospectus providing the company with access to long-term debt and equity.

In June 2010, Emera issued six million 4.40% Cumulative Five-Year Rate Reset First Preferred Shares, Series A ("First Preferred Shares, Series A"). The $150 million First Preferred Shares, Series A were issued at $25.00 per share for net after-tax proceeds of $146.7 million.

The weighted average coupon rate of Emera's outstanding medium-term notes at December 31, 2010 was 4.45% (2009 – 4.45%). All of the outstanding debt matures within the next ten years. The quoted market weighted average interest rate for the same or similar issues of the same remaining maturities was 3.73% as at December 31, 2010 (2009 – 4.43%).

Emera's credit ratings issued by Dominion Bond Rating Service ("DBRS") and Standard & Poor's ("S&P") are as follows:

| | DBRS | S&P |
|---|---|---|
| Long-term corporate | BBB (high) | BBB+ |
| Preferred Stock | Pfd-3 (high) | P-2 (Low) |

## NSPI

In May 2010, NSPI redeemed $100 million medium-term notes using short-term credit facilities.

In May 2010, NSPI filed a $500 million debt shelf prospectus providing NSPI with access to long-term debt.

In June 2010, NSPI completed a $300 million medium-term note issue, proceeds of which were used to pay down outstanding short-term debt. These notes bear interest at the rate of 5.61% and yield 5.616% per annum until June 15, 2040.

The weighted average coupon rate on NSPI's outstanding medium-term and debenture notes at December 31, 2010 was 6.74% (2009 – 6.80%). Approximately 27% of the debt matures over the next ten years, 70% matures between 2021 and 2040 and $50 million, or 3%, matures in 2097. The quoted market weighted average interest rate for the same or similar issues of the same remaining maturities was 4.50% as at December 31, 2010 (2009 – 4.87%).

NSPI's credit ratings issued by DBRS and S&P's are as follows:

| | DBRS | S&P |
|---|---|---|
| Corporate | N/A | BBB+ |
| Senior unsecured debt | A (low) | BBB+ |
| Preferred stock | Pfd-2 (low) | P-2 (low) |
| Commercial paper | R-1 (low) | A-1 (low) |

## Bangor Hydro

In June 2010, Bangor Hydro increased its revolving bank line by $20 million, and renewed it through September 2013.

The weighted-average coupon rate on Bangor Hydro's outstanding long-term debt at December 31, 2010, was 6.96% (2009 – 6.92%). Approximately 87% of the debt matures over the next 10 years; the remaining issue matures in 2022. The quoted market weighted average interest rate for the same or similar issues of the same remaining maturities was 3.81% as of December 31, 2010 (2009 – 5.57%).

Bangor Hydro has no public debt, 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, Bangor Hydro expects to have sufficient access to competitively priced funds in the unsecured debt market.

## Contractual Obligations

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

| millions of dollars | | | | | | | | Payments Due by Period |
|---|---|---|---|---|---|---|---|---|
| | **Total** | 3 year renewable (1) | 2011 | 2012 | 2013 | 2014 | 2015 | After 2015 |
| Long-term debt | $3,037.8 | $530.3 | $12.7 | $83.6 | $305.0 | $304.9 | $74.7 | $1,726.6 |
| Preferred shares issued by subsidiary | 135.0 | - | - | - | - | - | 135.0 | - |
| Operating leases | 7.0 | - | 2.7 | 1.1 | 0.6 | 0.6 | 0.6 | 1.4 |
| Purchase obligations | 4,247.5 | - | 388.4 | 385.6 | 306.8 | 243.1 | 191.6 | 2,732.0 |
| Capital obligations | 111.5 | - | 76.1 | 33.9 | 1.5 | - | - | - |
| Asset retirement obligations | 451.3 | - | 1.7 | 2.0 | 1.3 | 1.3 | 1.4 | 443.6 |
| Total contractual obligations | $7,990.1 | $530.3 | $481.6 | $506.2 | $615.2 | $549.9 | $403.3 | $4,903.6 |

(1) Short-term discount notes utilized against a $600 million operating credit facility which matures in June 2013 are included in long-term debt as the company has the intention and the unencumbered ability to refinance the obligations for a period greater than one year.

**Operating lease obligations:** The company's operating lease obligations consist of operating lease agreements for office space, rail cars, telecommunications services, and certain other equipment.

**Purchase obligations:** The company has purchasing commitments for electricity from IPPs, transportation of coal, natural gas, fuel and transportation capacity on the Maritimes & Northeast Pipeline.

**Capital obligations:** The company has commitments to third parties for construction on capital projects and other goods and services.

**Asset retirement obligations:** The company has asset retirement obligations for its generation, transmission and distribution assets and its pipeline.

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

## Capital Resources

Capital expenditures for 2010, including AFUDC, were approximately $591 million and included:

- $527 million in NSPI;
- $46 million in Bangor Hydro;
- $13 million in Brunswick Pipeline; and
- $5 million in Other.

# PENSION FUNDING

For funding purposes, Emera determines required contributions to its defined benefit pension plans based on smoothed asset values. This reduces volatility in the cash funding requirement as the impact of investment gains and losses are recognized over a three year period. The cash required in 2011 for defined benefit pension plans will be approximately $39.5 million (2010 – $34.7 million actual). All pension plan contributions are tax deductible and will be funded with cash from operations.

Emera’s defined benefit pension plans are managed with a diversified portfolio of asset classes, investment managers and geographic investments. Emera reviews the investment managers on a regular basis, and the plans’ asset mixes from time to time.

Emera’s projected contributions to defined contribution pension plans are $2.7 million for 2011 (2010 – $1.4 million actual).

# OFF-BALANCE SHEET ARRANGEMENTS

Upon privatization of the former provincially owned Nova Scotia Power Corporation (“NSPC”) in 1992, NSPI became responsible for managing a portfolio of defeasance securities, which at December 31, 2010, totaled $1.0 billion. The securities are held in trust for Nova Scotia Power Finance Corporation (“NSPFC”), an affiliate of the Province of Nova Scotia. NSPI is responsible for ensuring the defeasance securities provide the principal and interest streams to match the related defeased NSPC debt. Approximately 73% of the defeasance portfolio consists of investments in the related debt, eliminating all risk associated with this portion of the portfolio; the remaining defeasance portfolio has a market value higher than the related debt, reducing the future risk of this portion of the portfolio.

# TRANSACTIONS WITH RELATED PARTIES

In the ordinary course of business, Emera purchased natural gas transportation capacity totaling $12.8 million (2009 – $12.5 million) during the three months ended December 31, 2010, and $55.1 million (2009 – $47.4 million) during the year ended December 31, 2010, 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, 2010, the amount payable to the related party was $3.9 million (2009 – $4.6 million), is non-interest bearing and is under normal credit terms.

# DIVIDENDS AND PAYOUT RATIOS

In February 2010, the Board of Directors approved a quarterly dividend increase, effective May 3, 2010, to $0.2825 per common share, and in September 2010, approved a further increase to $0.3250 effective November 1, 2010 reflecting an increase on an annualized basis to $1.30 per common share.

Emera Inc.’s common dividend rate was $1.21 ($0.2725 in Q1, $0.2825 in Q2; and $0.3250 per quarter in Q3 and Q4) per common share in 2010 and $1.03 ($0.2525 per quarter in Q1, Q2 and Q3; and $0.2725 in Q4) for 2009, representing a payout ratio of approximately 70.1% in 2010 and 65.9% in 2009.

Effective September 25, 2009, Emera changed its Common Shareholders Dividend Reinvestment and Share Purchase Plan to provide for a discount of up to 5% from the average market price of Emera’s common shares for common shares purchased in connection with the reinvestment of cash dividends under this Plan. The Board of Directors of Emera also decided on September 25, 2009, that the discount would be 5% effective on and after the quarterly dividend payment on November 16, 2009, to shareholders of record on November 2, 2009.

# RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

## Financial Risks and Financial Instruments

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

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

Derivatives that meet stringent documentation requirements, and can be proven to be effective both at the inception and over the term of the derivative, qualify for hedge accounting. Specifically, for cash flow hedges, the change in the fair value of the effective portion of hedging derivatives is deferred to "AOCI" and recognized in earnings in the same period that the related hedged item is realized. Any ineffective portion of the change in the fair value of derivatives is recognized in net earnings in the reporting period.

Where the documentation or effectiveness requirements are not met, the derivative instruments are recognized at fair value with any changes in fair value recognized in net earnings in the reporting period, unless deferred as a result of regulatory accounting.

For fair value hedges, the change in fair value of the hedging derivatives and the hedged item are recorded in net earnings. Therefore, the change in fair value of the ineffective portion of hedging derivatives will impact net earnings in the reporting period.

The company's HFT derivatives are recorded on the balance sheet at fair value, with changes recorded in net earnings in the reporting period, unless deferred as a result of regulatory accounting. The company has not designated any derivatives to be included in the HFT category.

NSPI has contracts for the purchase and sale of natural gas at its Tufts Cove generating station ("TUC") that are considered HFT derivatives and accordingly are recognized on the balance sheet at fair value. This reflects NSPI's history of buying and reselling any natural gas not used in the production of electricity at TUC. Changes in fair value of HFT derivatives are normally recognized in net earnings. In accordance with NSPI's accounting policy for financial instruments and hedges relating to TUC fuel, NSPI has deferred any changes in fair value to a regulatory asset or liability. In 2009, the UARB approved an amendment to NSPI's accounting practice to include all TUC financial commodity hedges which are no longer required. This change in practice has impacted the timing of recognition between "Fuel for generation and purchased power" and "Fuel adjustment" as a result of the FAM implemented in 2009. The change in accounting practice was applied prospectively, beginning in 2009, as required by the UARB.

**Hedging Items Recognized on the Balance Sheet**

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

| millions of dollars | **December 31 2010** | December 31 2009 |
|---|---|---|
| Inventory | **$4.7** | $22.2 |
| Derivatives in a valid hedging relationship | **24.6** | (29.5) |
| Long-term debt | **-** | 0.1 |
| | **$29.3** | $(7.2) |

**Hedging Impact Recognized in Earnings**

The company recognized in net earnings the following gains (losses) related to the effective portion of hedging relationships under the following categories:

| millions of dollars | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| | **2010** | 2009 | **2010** | 2009 |
| Finance income from direct financing lease increase | **$1.7** | $2.2 | **$7.7** | $2.8 |
| Fuel and purchased power increase | **(11.8)** | (27.1) | **(73.3)** | (46.3) |
| Financing charges decrease | **1.2** | 1.0 | **1.8** | 6.9 |
| Effectiveness losses | **$(8.9)** | $(23.9) | **$(63.8)** | $(36.6) |

The effectiveness gains (losses) reflected in the above table are offset in net earnings by the change in the fair value of the hedged item realized in the period.

The company recognized in net earnings the following gains (losses) related to the ineffective portion of hedging relationships under the following categories:

| millions of dollars | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| | **2010** | 2009 | **2010** | 2009 |
| Fuel and purchased power increase | **$(0.7)** | $(1.0) | **$(1.6)** | $(14.2) |
| Financing charges (increase) decrease | **(0.1)** | 0.3 | **(0.3)** | (0.5) |
| Ineffectiveness losses | **$(0.8)** | $(0.7) | **$(1.9)** | $(14.7) |

**HFT Items Recognized on the Balance Sheet**

The company has recognized on the balance sheet a net HFT derivatives liability of $11.7 million as at December 31, 2010 (2009 – $9.4 million asset).

**HFT Derivatives Recognized in Earnings**

The company has recognized the following realized and unrealized gains (losses) with respect to HFT derivatives in earnings:

| millions of dollars | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| | **2010** | 2009 | **2010** | 2009 |
| Electric revenue | **$(1.9)** | - | **$4.4** | $0.6 |
| Other revenue | **3.8** | - | **1.8** | (5.7) |
| Fuel and purchased power | **(1.3)** | $1.4 | **(1.3)** | 12.4 |
| Financing charges | **(0.1)** | (0.1) | **-** | - |
| Held-for-trading derivatives gains (losses) | **$0.5** | $1.3 | **$4.9** | $7.3 |

As discussed in note 29 of Emera's financial statements at the reporting date, various valuation techniques are used to determine the fair value of derivative instruments. These may include quoted market prices or internal models using observable or non-observable market information.

The company has a derivative contract, as discussed in Significant Item, where no observable market exists, therefore modeling techniques are employed using assumptions reflective of current market rates, yield curves and forward prices, as applicable, to interpolate certain prices.

# Business Risks

## Measurement of Risk

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

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

The UARB approved the implementation of a FAM for NSPI effective January 1, 2009, reducing the utility's exposure to fuel price volatility by providing a mechanism for NSPI to recover actual fuel costs. The FAM mitigates the risk to NSPI's net earnings associated with fluctuations in commodity prices and foreign exchange.

## Commodity Price Risk

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

**Coal/Petroleum Coke**
A substantial portion of NSPI's coal and petroleum coke ("petcoke") supply comes from international suppliers, which was contracted at or near the market prices prevailing at the time of contract. The company has entered into fixed-price and index price contractual arrangements with several suppliers as part of the fuel procurement portfolio strategy. All index-priced contractual arrangements are matched with a corresponding financial instrument to fix the price. The approximate percentage of coal and petcoke requirements contracted at December 31, 2010 is as follows:

- 2011 – 77%
- 2012 – 39%
- 2013 – 24%

**Heavy Fuel Oil**
NSPI manages exposure to changes in the market price of heavy fuel oil through the use of swaps, options, and forward contracts. For 2011 and 2012, NSPI currently does not have heavy fuel oil hedging requirements.

**Natural Gas**
NSPI has entered into multi-year contracts to purchase approximately 47,600 mmbtu of natural gas per day in 2011, and 39,300 mmbtu of natural gas per day in 2012. 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 when available for resale. Gas volumes not required for generation will be resold into the gas market with the margin hedged using financial instruments. As at December 31, 2010, amounts of natural gas volumes that have been economically and/or financially hedged and contracted are approximately as follows:

- 2011 – 87%
- 2012 – 35%

**Purchased Power**
Emera, along with its joint venture partner, have entered into a contract with Bear Swamp to fix the price of power necessary to produce the energy requirements of the LIPA contract. As at December 31, 2010, amounts of purchased power Emera has financially hedged are approximately as follows:

- 2011 – 103%
- 2012 – 95%
- 2013 – 95%
- 2014 – 95%
- 2015 – 94%

## Foreign Exchange Risk

The company enters into foreign exchange forward and swap contracts to limit exposure on foreign currency transactions such as fuel purchases, revenue streams and capital expenditures.

The risk due to fluctuation of the CAD against the USD for fuel purchases in NSPI is measured and managed. In 2011, NSPI expects approximately 60% of its anticipated net fuel costs to be denominated in USD. USD from sales of surplus natural gas will provide a natural hedge against a portion of USD fuel costs. Forward contracts to buy $225.5 million USD were in place at December 31, 2010 at a weighted average rate of $0.99, representing 70% of 2011's anticipated USD requirements. Forward contracts to buy $443.0 million USD in 2012 through 2015 at a weighted average rate of $1.03 were in place at December 31, 2010. These contracts cover 31% of anticipated USD requirements in these years. As at December 31, 2010, there were no fuel-related foreign exchange swaps outstanding.

NSPI uses foreign exchange forward contracts to hedge the currency risk for capital projects and receivables denominated in foreign currencies. Forward contracts to buy €1.8 million were in place at December 31, 2010 at a weighted average rate of $1.56 (versus CAD) for capital projects in 2011.

Brunswick Pipeline uses forward contracts to hedge the currency risk associated with revenue streams denominated in foreign currencies. Forward contracts to sell $52 million USD in 2011 were in place at December 31, 2010 at an average rate of $1.07 and sell $63 million USD in 2012 through 2015 at a weighted average rate of $1.07. These contracts cover 91% of anticipated USD revenue inflows in 2011 and 27% of anticipated USD revenue inflows in 2012 through 2015.

## Interest Rate Risk

Emera manages interest rate risk through a combination of fixed and floating borrowing and a hedging program. Floating-rate debt is estimated to represent approximately 20% of total debt in 2011. The company has two interest rate hedging contracts outstanding as at December 31, 2010, fixing the variable interest rates on $22.6 million USD of Maine Public Utilities Financing Bank bonds at MPS.

## Credit Risk

Credit risk arising as a result of contractual obligations between the company 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.

## Labour Risk

NSPI has a contract with its union which will expire in April 2012. Bangor Hydro entered into a new collective bargaining agreement in July 2010 which will expire in July 2015. MPS also has a contract with its union, which will expire in October 2013.

## Regulatory Risk

### NSPI

NSPI faces risk with respect to the timeliness and certainty of full recovery of costs. The adoption and implementation of the FAM effective January 1, 2009, has helped NSPI manage that risk. The UARB oversees the FAM, including review of fuel costs, contracts and transactions. The FAM will help ensure customer rates reflect the actual price of the fuel used to make electricity. Concurrent with the implementation of the FAM in 2009, NSPI's regulated ROE range was reduced by 0.2%, changing its regulated ROE range to 9.1% to 9.6%, with rates set at 9.35%.

The first rate adjustment under the FAM, effective on January 1, 2010, was approved by the UARB on December 9, 2009. On December 8, 2010, the UARB approved NSPI's setting of the 2011 base cost of fuel and its recovery of all unrecovered fuel related costs as submitted in NSPI's November 2010 filing. The recovery of these costs will begin January 1, 2011. The UARB approved NSPI's recovery of these costs over three years, with 50% of the rate increase to be recovered in 2011, 30% in 2012 and 20% in 2013.

In December 2010, the UARB granted NSPI approval to defer certain tax benefits related to renewable energy projects arising in 2010. The UARB will convene a proceeding in 2011 to discuss how this deferral will be applied.

### Bangor Hydro

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

Bangor Hydro's distribution business operates under the regulation of the MPUC and operates under a traditional cost-of-service regulatory structure. In late 2007, the MPUC approved a modest increase in distribution rates under the traditional cost-of-service regulatory structure. In the event that costs rise faster than revenues, Bangor Hydro has the ability to return to the MPUC to request a further increase in rates.

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

Bangor Hydro also has the ability to recover stranded costs of both regulatory assets and purchasing power at above-market prices under a full reconciliation mechanism. This ability eliminates the commodity risk involved with fixed price purchase power contracts.

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

**MPS**

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

MPS' distribution business operates under the regulation of the MPUC and operates under a traditional cost-of-service regulatory structure. In July 2006, the MPUC approved an increase of approximately 11% in distribution rates, effective July 15, 2006. The allowed ROE used in setting these distribution rates was 10.2%, with a common equity component of 50%. In the event that costs rise faster than revenues, MPS has the ability to return to the MPUC to request a further increase in rates on January 1, 2012 or any time thereafter.

The transmission business of MPS is primarily regulated by the FERC. Transmission rates are set annually through the Open Access Transmission Tariff ("OATT"). Rates derived from the previous calendar year's results go into effect June 1 for wholesale customers and July 1 for retail customers. The allowed ROE for transmission operations is 10.5%, and is based on the actual common equity. The allowed ROE is determined by negotiation with customers in the formula change years of the OATT, which occur every three years. The last OATT formula change year was 2009.

MPS also has the ability to recover stranded costs of regulatory assets.

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

## Environment

**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 so risks are identified and managed proactively. All areas of Emera undertook initiatives in 2010 to reduce potential environmental risks and associated costs. Activities included, but were not limited to, reducing air emissions, protecting water resources, and continued management of PCB contaminated electrical equipment.

Conformance with legislative and company requirements is verified through a comprehensive environmental audit program. There were no significant environmental or regulatory compliance issues identified during the 2010 audits. Plans are in place to promptly address any audit findings and continually improve the environmental management of the company's operations.

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

NSPI completed an Integrated Resource Plan in 2007 and refreshed it in 2009. The Integrated Resource Plan includes current environmental requirements and assumptions on future regulations as constraints on possible generation plans. This allows for better generation planning for the future. NSPI stakeholders were engaged in the assumptions and the scenarios to be modeled. The results of these planning exercises can be found on the NSPI website.

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

**Regulatory**

NSPI produces its electrical energy approximately 64% from coal and 19% from natural gas and/or oil. As such, it is subject to regulation with respect to air pollutants and greenhouse gas emissions. NSPI operates under a cost-of-service regulation model. Accordingly, all prudently incurred costs, including those capital and operating costs associated with meeting present and future environmental liabilities, can be recovered in rates collected from customers.

NSPI is subject to environmental regulation as set by both Canadian federal and Nova Scotia provincial governments. NSPI is in material compliance with current environmental regulations. All required permits are in place for NSPI's generating stations. These permits are generally for a ten year period but can be subject to review, variation, or suspension by the Minister of Environment of Nova Scotia.

Bangor Hydro and MPS are regulated by the United States Environmental Protection Agency as to compliance with the Federal Water Pollution Control Act, the Clean Air Act, and other U.S. federal statutes governing the treatment and disposal of hazardous wastes. Bangor Hydro and MPS are also regulated by the Maine Department of Environmental Protection.

Brunswick Pipeline is a federally regulated undertaking and must operate in accordance with the NEB Act, the Onshore Pipeline Regulations, 1999, and the Canada Labour Code Part II, the Canadian Environmental Protection Act and any applicable provincial environmental regulations.

**Climate Change and Air Emissions**

**Renewable Energy**
On October 15, 2010, the Nova Scotia Government enacted regulations under the Electricity Act related to the province's Renewable Electricity Plan. These regulations establish the requirement that 25% of electricity be supplied from renewable sources by 2015. These regulations build on the previously legislated requirements for 2011 and 2013. Recent amendments to the Electricity Act, and the new regulations, provide for the appointment, by spring 2011, of a new, independent renewable electricity administrator to conduct the procurement of at least 300 GWh of energy from IPPs to meet the 2015 standard. NSPI is also provided the opportunity to develop 300 GWh of renewable energy.

In January 2007, the Nova Scotia Government approved the Renewable Energy Standard Regulation (“RES”) to increase the percentage of renewable energy in the generation mix. In October 2009, the RES was amended. The target date for 5% of electricity to be supplied from post-2001 sources of renewable energy, owned by independent power producers, was extended to 2011 from 2010. The target for 2013, which requires an additional 5% of renewable energy, is unchanged.

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

Greenhouse gas emissions from NSPI facilities are capped beginning in 2010 through to 2020. The 2010 to 2015 caps will be achieved by the continued success of energy efficiency and conservation programs and the addition of renewable energy to meet the 2011, 2013 and 2015 provincial renewable energy standards. The regulations also include a transmission incentive compliance mechanism recognizing expenditures on transmission which facilitates additional renewable energy sources. Up to 3% of the annual cap can be offset in this way to 2019. Further, the 2010 to 2020 period years are combined to form multi-year compliance periods recognizing the variability in electricity supply sources and demand.

Beyond 2015, reduced greenhouse gas emissions will be achieved through a combination of additional renewable energy, co-firing of biomass in existing coal power plants, import of non-emitting energy and energy efficiency and conservation as per the 2007/2009 Integrated Resource Plan.

On June 23, 2010, Environment Canada announced its intentions for a new national GHG framework for the electricity sector. This federal framework, if developed further into regulations, would require thermal coal units to meet GHG emission levels equal to, or better than, a natural gas combined cycle generating unit at a specific anniversary. Nova Scotia's existing GHG regulations require reductions in NSPI's emissions similar to the intentions of the federal framework. NSPI is reviewing the implications of this federal framework and its alignment with NSPI’s current operating plans under existing Nova Scotia regulations.

**Mercury**
On July 22, 2010, the Province of Nova Scotia announced, for the years 2010 through 2013, allowable mercury emissions would be increased from the previous cap of 65 kg per year. NSPI was requested to develop a plan of staged mercury emission reductions for its generation facilities for the period of 2010 to 2020 and to meet an annual cap of 35 kg beginning in 2020.

In 2008, NSPI carried out extensive testing on mercury abatement technology in its coal power plants. A capital program to add sorbent injection to each of the seven pulverized fuel coal units was completed in 2009. This allowed NSPI to meet the 2010 mercury emission cap of 65 kg established by the Province.

Compared to historical levels, NSPI has reduced mercury emissions by 60%.

**Nitrogen Oxide and Sulphur Dioxide Emissions**
NSPI has completed in 2009 its capital program of retrofitting low nitrogen oxide combustion firing systems on six of its seven pulverized fuel coal units. NSPI now meets the 2009 nitrogen oxide emission cap of 21,365 tonnes per year established by the province.

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

Compared to historical levels, NSPI has reduced emissions of nitrogen oxide by 40% and sulphur dioxide by 50%.

## Obligations

The company recognizes asset retirement obligations (“ARO”) for property, plant and equipment in the period in which they are incurred if a reasonable estimate of fair value can be determined. Using the company’s credit-adjusted risk-free rate, the fair value is determined by discounting the company’s estimated future cash flows necessary to discharge legal obligations related to reclamation of land at the company’s thermal, hydro, combustion turbine sites, pipelines and disposal of polychlorinated biphenyls (“PCBs”) in its transmission and distribution equipment. Estimated future cash flows are based on the company’s completed depreciation studies, prior experience, estimated useful lives of assets, governmental regulatory requirements and the costs of activities such as demolition, restoration and remedial work based on present-day methods and technologies. Actual results may differ from these estimates.

The UARB included the amount of future expenditures associated with the removal of generation facilities in the 2003 NSPI depreciation settlement discussed under Property, Plant and Equipment in the Significant Accounting Policies and Critical Accounting Estimates section. NSPI believes that it will continue to be able to recover ARO through rates. Accordingly, changes to the ARO, or cost recognition attributable to changes in the factors discussed above, should not impact the results of the company’s operations.

Some of the company's hydro, transmission and distribution assets may have additional ARO. 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 ARO cannot be made at this time. Additionally, some of the company's transmission and distribution assets may have conditional ARO, the fair value of which cannot be reasonably estimated as sufficient information does not exist to estimate the obligations. A liability will be recognized in the period in which sufficient information becomes available.

The key assumptions used to determine the ARO are as follows:

| Asset | Credit-adjusted risk-free rate | | Estimated undiscounted future obligation (millions of dollars) | | Expected settlement date (number of years) | |
|---|---|---|---|---|---|---|
| | **2010** | 2009 | **2010** | 2009 | **2010** | 2009 |
| Thermal | **5.30%** | 5.31% | **$258.9** | $242.3 | **10 – 29** | 11 - 30 |
| Hydro | **5.27%** | 5.31% | **101.4** | 60.8 | **21 – 51** | 22 – 52 |
| Wind | **5.21%** | - | **45.5** | - | **13 – 20** | - |
| Combustion turbines | **5.25%** | 5.31% | **12.9** | 5.1 | **1 – 14** | 1 – 14 |
| Transmission & distribution | **5.74%** | 5.74% | **21.6** | 18.1 | **1 – 15** | 1 – 16 |
| Pipeline | **3.80%** | 3.80% | **11.0** | 11.0 | **39** | 40 |
| | | | **$451.3** | $337.3 | | |

As at December 31, 2010, the asset retirement obligations recorded on the balance sheet were $141.8 million (2009 – $104.5 million). The company estimates the undiscounted amount of cash flow required to settle the obligations is approximately $451.3 million, which will be incurred between 2011 and 2061. The majority of these costs will be incurred between 2020 and 2041.

# DISCLOSURE AND INTERNAL CONTROLS

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

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

The President and Chief Executive Officer and the Chief Financial Officer have evaluated, with the assistance of company employees, the effectiveness of Emera and its consolidated subsidiaries' DC&P and ICFR and based on that evaluation, have concluded DC&P and ICFR were effective at December 31, 2010.

There have been no changes in Emera or its consolidated subsidiaries' ICFR during the period beginning on January 1, 2010 and ending on December 31, 2010, which have materially affected, or are reasonably likely to materially affect ICFR.

# SIGNIFICANT ACCOUNTING POLICIES AND CRITICAL ACCOUNTING ESTIMATES

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

## Rate Regulation

The rate-regulated accounting policies of NSPI, Bangor Hydro, MPS and Brunswick Pipeline may differ from accounting policies for non-rate-regulated companies. NSPI, Bangor Hydro and MPS accounting policies are subject to examination and approval by their respective regulators. These accounting policy differences occur when the regulators render their decisions on rate applications or other matters and generally involve a difference in the timing of revenue and expense recognition. The accounting for these items is based on the expectation of the future actions of the regulators.

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

## Pension and Other Post-Retirement Employee Benefits

The company provides post-retirement benefits to employees, including defined benefit pension plans. 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 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.

Consistent with CGAAP and Emera's accounting policy, the company amortizes the net actuarial gain or loss, which exceeds 10% of the greater of the accrued benefit obligation ("ABO") and the market-related value of assets, over active plan members' average remaining service period, which is currently 9 years. Emera's use of smoothed asset values further reduces the volatility related to the amortization of actuarial investment experience. As a result, the main cause of volatility in reported pension cost is the discount rate used to determine the ABO.

The discount rate used to determine benefit costs is based on high quality long-term Canadian corporate bonds for NSPI's pension plan and US corporate bonds for Bangor Hydro's pension plan. The discount rate is determined with reference to bonds which have the same duration as the ABO as at January 1 of the fiscal year rounded to the nearest 25 basis points. For benefit cost purposes, NSPI's rate was 6.50%

for 2010 (2009 – 7.50%) and Bangor Hydro's rate was 6.00% for 2010 (2009 – 6.75%). MPS' rate for 2010 was 5.75% for pension plans and 5.85% for non-pension plans and GBPC's rate was 6.00%.

The expected return on plan assets is based on management's best estimate of future returns, considering economic and consensus forecasts. The benefit cost calculations assumed that plan assets would earn a rate of return of 7.25% for 2010 and 2009 for NSPI and 8.00% for 2010 (2009 – 8.00%) for Bangor Hydro. The assumed rate of return on plan assets for 2010 was 8.5% for MPS and 6.00% for GBPC.

The reported benefit cost for 2010, based on management's best estimate assumptions, is $34.1 million. While there are numerous assumptions which are used to determine the benefit cost, the discount rate and asset return assumptions have an impact on the calculations.

The following shows the impact on 2010 benefit cost of a 25 basis point change (0.25%) in the discount rate and asset return assumptions:

| | 0.25% Increase | | 0.25% Decrease | |
|---|---|---|---|---|
| millions of dollars | 2010 | 2009 | 2010 | 2009 |
| Discount rate assumption | $(3.5) | $(1.3) | $3.6 | $1.4 |
| Asset return assumption | $(1.8) | $(1.9) | $1.8 | $1.9 |

The sensitivity to the discount rate assumption was significantly higher for 2010 benefit cost than in 2009 because, in 2010, the existing net unamortized gains and losses subject to amortization fell outside the 10% corridor and any additional change impacts the amortization and expense calculations.

## 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 Bangor Hydro, MPS and GBPC. At the end of each month, the company must make an estimate of energy delivered to customers since the date their meter was last read and of related revenues earned but not yet billed. The unbilled revenue is estimated based on several factors, including current month's generation, estimated customer usage by class, weather, line losses and applicable customer rates. Brunswick Pipeline also makes an estimate of toll revenues at the end of each month. Based on the extent of the estimates included in the determination of unbilled revenue, actual results may differ from the estimate. As at December 31, 2010, unbilled revenues amount to $102.7 million (2009 – $98.4 million) on a base of annual electric revenues of approximately $1.4 billion (2009 – $1.4 billion).

## Contract Receivable

NSPI's natural gas purchase agreement expired in October 2010. The agreement included a price adjustment clause covering three years of natural gas purchases. The clause stated that NSPI would pay for all gas purchases at the agreed contract price, but would be entitled to a price rebate on a portion of the volumes. The first settlement took place in November 2007 for purchases to the end of October 2007 and the final settlement took place in November 2010.

## Property, Plant and Equipment

Property, plant and equipment represents 54.5% 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 magnitude of the company's property, plant and equipment, changes in estimated depreciation rates can have a material 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 interveners, which recommended a four-year phase-in of new depreciation rates, which, based on assets in service in the study, would reach an overall increase in depreciation expense of $20 million by 2007. The UARB approved the settlement. NSPI began phasing in the new rates in 2004. In its rate decision for 2005, the UARB deferred the scheduled phase-in for 2005. In the rate decision for 2006, the UARB included the phase-in of year-two in rates. In its February 5, 2007 decision, the UARB postponed the phase-in of year-three rates until the next rate application. In its November 5, 2008 decision, the UARB approved year-three phase-in rates effective January 1, 2009. On October 29, 2010, NSPI filed a depreciation study with the UARB.

## Income Taxes

Income taxes are determined based on the expected tax treatment of transactions recorded in the consolidated financial statements. In determining income taxes, tax legislation is interpreted in a variety of jurisdictions, the likelihood that future tax assets will be recovered from future taxable income is assessed and assumptions about the expected timing of the reversal of future tax assets and liabilities are made. If interpretations differ from those of tax authorities or if the recovery of future tax assets or timing of reversals is not as anticipated, the provision for income taxes could increase or decrease in future periods. The amount of any such increase or decrease cannot be reasonably estimated.

## Asset Retirement Obligations

The company recognizes ARO's 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 ARO's 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. Actual results may differ from these estimates.

## Goodwill Impairment Assessments

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

Impairment assessments are based on fair market value assessments. Fair market value is determined by use of net present value financial models that incorporate management's assumptions about future profitability. There was no impairment provision required in 2010 or 2009.

# CHANGES IN ACCOUNTING POLICIES

## Future Accounting Policy Changes

### Changeover to United States Generally Accepted Accounting Principles

In February 2008, the Canadian Institute of Chartered Accountants ("CICA") announced CGAAP for publicly accountable enterprises will be replaced by International Financial Reporting Standards ("IFRS") for fiscal years beginning on or after January 1, 2011. The company began planning its transition to IFRS in 2008 and transition activities progressed on schedule through 2009. In Q4 2009, due primarily to the continued uncertainty around the timing and eventual adoption of a rate-regulated accounting ("RRA") standard under IFRS, management began reviewing the option of adopting United States Generally Accepted Accounting Principles ("US GAAP") instead of IFRS. In Q1 2010, Emera's Board of Directors approved the transition to US GAAP financial reporting standards beginning Q1 2011.

The adoption of US GAAP in Q1 2011 is expected to result in fewer significant changes in the company's accounting policies than would have been experienced with the adoption of IFRS. Management believes this will result in financial information that is more comparable to the company's prior years' financial statements prepared under CGAAP, making them easier for readers to understand.

US GAAP reporting is permitted by Canadian securities laws and the Toronto Stock Exchange ("TSX") for companies subject to reporting obligations under US securities laws. Emera Inc. plans to file registration statements with the SEC prior to releasing its Q1 2011 financial results. On July 15, 2010, NSPI registered debt securities with the SEC under the US Securities Act of 1933, thereby becoming subject to US reporting obligations. Registration with the SEC will enhance the company's ability to access US capital markets in the future.

The company's application of CGAAP currently relies on US GAAP for guidance on the application of RRA. RRA allows the economic impact of regulatory activities to be recognized consistent with the timing that amounts are included in customer rates. The company believes continued recognition of its regulatory assets and liabilities under US GAAP best reflects the effect regulatory activities have on the company's financial position. More than 90% of the company's revenues are earned by its wholly-owned regulated subsidiaries NSPI, Bangor Hydro and Brunswick Pipeline. Without a RRA standard, a transition to IFRS would likely result in the accounting write-off of the company's significant regulatory assets and liabilities, and net earnings could be subject to greater volatility on an on-going basis.

### Transition Activities

A formal project was established to transition to US GAAP for 2011, register securities of Emera and NSPI with the SEC and prepare both companies to comply with the on-going reporting requirements of the SEC and requirements of the Sarbanes-Oxley Act ("SOX"). A four-phased project approach was adopted to manage project activities. The project is proceeding on schedule to achieve its required milestones. The following is a brief overview of the activities of each phase and current status. An update on the project's status and achievement of its key milestones are provided to the company's Audit Committee on a quarterly basis.

### Phase One: Preliminary Assessment and Planning – Completed

Phase One was substantially completed in May 2010. It involved assessment and planning activities required to develop the initial project plan and identify resource requirements for the project. Internal resources were dedicated to the project to ensure its completion within the required timeline. KPMG LLP, who was assisting with the company's changeover to IFRS, was engaged to continue providing technical advisory services during the company's transition to US GAAP. In addition to resourcing activities, the

Project Charter, Governance Structure and a Project Management Office were established to support the subsequent phases of the project.

Two key assessments were performed in this phase:

- The first assessment compared the most significant differences between US GAAP and CGAAP to determine which areas were most likely to impact the company's accounting policies and financial reporting. The purpose of this assessment was to highlight areas where detailed analysis of GAAP differences was needed to determine and conclude on the nature and extent of impact. Detailed analysis activities and conclusions on the impact of US GAAP on the company's accounting policies are discussed under Phase Two.

- The second assessment compared the requirements of the National Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings" ("NI 52-109") and those of Sections 302 ("SOX 302") and 404 ("SOX 404") of the Sarbanes-Oxley Act. The purpose of this assessment was to identify the impact of SOX 302 and SOX 404 on the company's current NI 52-109 program over disclosure controls and procedures ("DC&P") and internal control over financial reporting ("ICFR").

  Consistent with NI 52-109, SOX 302 requires certification by the certifying officers of all publicly-traded companies that they have established, maintained and designed DC&P and ICFR and evaluated DC&P. SOX 302 requires a quarterly evaluation of DC&P while NI 52-109 requires an annual evaluation; however, NSPI and Emera are not required to file quarterly 302 certificates with the SEC. Also consistent with NI 52-109, SOX 404 requires that all publicly-traded companies must establish ICFR; document, test and maintain those controls and procedures to ensure their effectiveness; and management must report on their evaluation of the effectiveness of ICFR.

  Under SOX 404, the company is required to obtain an external audit opinion annually on the design and effectiveness of the company's ICFR which is not required under NI 52-109. This was the only significant difference identified between the requirements of NI 52-109 and SOX 404. The first external audit on ICFR is required as of December 31, 2011 for NSPI and as of December 31, 2012 for Emera. Activities being performed to prepare the company for SOX 404 attestation are described below.

**Phase Two: Detailed Assessment, Development and SEC Registration – Substantially Completed**

Phase Two commenced in April 2010. This phase involves registering securities of Emera and NSPI with the SEC and addressing all new requirements related to complying with US GAAP, SOX and SEC reporting obligations.

Detailed analysis was performed on those areas identified in Phase One where significant differences between US GAAP and CGAAP were most likely to impact the company's accounting policies, financial statements, information systems, internal controls and other business activities. Areas examined included revenue recognition, hedge accounting, RRA, pension and other post-retirement benefits, income taxes, preferred shares and foreign currency. Where differences were identified, prior period financial information is being restated to US GAAP for comparative purposes in 2011. Restatement activities are part of Phase Three.

The company's financial statements were drafted or "mocked-up" in accordance with US GAAP to identify the financial statement and disclosure impact of transitioning to US GAAP.

NSPI's regulated accounting policies were updated to reflect the transition to US GAAP. These were approved by the UARB in December 2010.

Based on the work completed in this phase and the company's conclusion that it is able to continue with its application of RRA under US GAAP, material adjustments to the company's reported post-transition net earnings were not identified. The on-going impact of the differences identified between CGAAP and US GAAP are mostly limited to changes in classification and presentation within the financial statements and in the extent of disclosure requirements.

Areas where the financial impact of transitioning to US GAAP is more significant are outlined below. These areas do not represent a complete list of expected changes. The net impact of all adjustments required to restate retained earnings on January 1, 2010 to US GAAP is not expected to be material. However, the net impact of all adjustments required to restate AOCI on January 1, 2010 to US GAAP will be material. The amount of any significant adjustments to retained earnings and AOCI are identified below under the financial statement item to which the adjustments relate.

***Pension and other post-employment benefits* –** Under US GAAP, the company will recognize its unfunded pension obligation as a liability in its financial statements and will need to recognize unamortized gains and losses associated with pension and other post-retirement benefits in AOCI in shareholders' equity. Currently, under CGAAP, the unamortized amounts together with their impact on the funded status of the pension liability or asset, are disclosed but not recognized.

Financial impact: Restating the amounts under US GAAP results in a $283 million after-tax unamortized loss recorded in AOCI, a $308 million increase to pension liability, an $18 million increase to FIT assets, and a $7 million reduction to retained earnings on January 1, 2010.

***Hedge accounting*** –The company has determined that certain hedging strategies that qualify for hedge accounting under CGAAP do not qualify for the same treatment under US GAAP primarily due to differences in effectiveness testing requirements. Effective for hedges put in place beginning in 2010, the company changed its strategies to ensure compliance with US GAAP prospectively.

Prior to the company's decision to transition to US GAAP, NSPI, in consultation with interveners and consultants for the UARB, discussed deferral accounting for all of its economic hedges. Based on these discussions and the company's decision to adopt US GAAP, NSPI filed an amended accounting policy with the UARB requesting deferral accounting for all of its economic hedges. The UARB approved the amended regulatory accounting policy in December 2010, resulting in the deferral of the periodic changes in the fair value of these derivatives so that they impact NSPI's net earnings in a manner consistent with that achieved if hedge accounting had been applied.

Financial impact: NSPI's amended accounting policy results in a $44 million increase in AOCI and net regulatory assets to restate its economic hedges on January 1, 2010 to US GAAP. The impact of derecognizing hedge accounting on certain economic hedges under US GAAP related to Emera's other affiliates requires a $7 million decrease to AOCI, an $11 million increase to retained earnings and a $4 million increase to investment in direct finance lease on January 1, 2010.

***Income taxes***

*Enacted tax rates*
US GAAP requires that the enacted tax rate be used in measuring current taxes and FIT. Under CGAAP, the tax impact of the Part VI.1 tax deduction related to preferred share dividends is recorded at the substantively enacted tax rates, which is consistent with Canada Revenue Agency's assessing practice. Under US GAAP, the company will recognize an income tax liability for the difference between the enacted tax rates and the substantively enacted tax rates for the Part VI.1 tax deduction.

Financial impact: Restating the amounts under US GAAP results in a $9 million increase to income tax payable and decrease to retained earnings on January 1, 2010.

*Investment tax credits*
Under CGAAP, certain investment tax credits related to qualifying scientific research and development expenditures are recorded as a reduction to property, plant and equipment. Under US GAAP, the company will recognize the investment tax credit as a reduction in tax expense.

Financial impact: Restating the amounts under US GAAP results in a $4 million increase to property, plant and equipment and retained earnings on January 1, 2010.

*Uncertain tax positions*
During 2010, the company revised its estimate of the expected benefit from accelerated tax deductions under CGAAP. A portion of the impact of the 2010 revised estimate is related to the US GAAP guidance for determining the unit of account and resulting expected benefit. As a result, for US GAAP, the company will recognize a portion of the 2010 change in estimate in years prior to January 1, 2010.

Financial impact: Restating the amounts under US GAAP results in a $4 million decrease in income tax payable and increase retained earnings on January 1, 2010.

*US GAAP transition adjustments*
Under US GAAP, the company will recognize the FIT impact on the US GAAP adjustments for pension and other post-employment benefits and hedge accounting as noted above, and on other US GAAP adjustments to the balance sheet.

Financial impact: As noted above, an $18 million increase to FIT assets is expected as a result of the $301 million ($283 million after-tax) increase in AOCI for pension and post-employment benefits. Other material adjustments are expected to restate FIT assets and liabilities on January 1, 2010 to US GAAP. The amount of these adjustments is still being determined, however, the impact of a change in FIT expense (recoveries) will be deferred to a regulatory asset or liability where the FIT is expected to be included in future rates of regulated subsidiaries. Other than the adjustment noted above, the net impact of income tax adjustments under US GAAP required to restate retained earnings and AOCI on January 1, 2010 is not expected to be material due to rate-regulated accounting.

The company has various agreements with external parties that reference CGAAP as the basis for satisfying financial reporting requirements, including covenant calculations. Emera and NSPI renegotiated their revolving credit facilities with their banking syndicates in June 2010 and in Q4 2010, and both Emera and NSPI reached an agreement with their trustee to bilaterally amend their respective trust indentures by way of supplemental indentures. These amended agreements each allow for US GAAP as the basis for satisfying financial reporting requirements.

The impact of the transition to US GAAP on information systems is minimal.

All Phase Two activities are complete, with the exception of Emera's registration with the SEC, which is planned for Q1 2011. NSPI's registration with the SEC was completed in July 2010.

**Phase Three: Implementation – In-Progress**

Phase Three began in July 2010 and involves implementing the changes identified and planned in Phase Two that are necessary to comply with US GAAP in 2011, along with SOX and SEC reporting obligations as they become effective.

2009 and 2010 financial information prepared under CGAAP is being restated to US GAAP for comparative purposes in 2011, with most adjustments now complete and the remainder to be completed in Q1 2011, including restatement of Q4 2010. Reconciliation of prior period financial information from CGAAP to US GAAP, along with other significant transitional disclosure, will be presented in the 2011 financial statements.

The company's financial reporting processes and consolidation software are being reconfigured to support the preparation of US GAAP financial statements in 2011 and the consolidation of prior period restatements. The required changes are not significant and will be on-going through Q1 2011.

As of July 15, 2010, NSPI is an SEC registrant and subject to SEC reporting obligations. NSPI is now required to furnish all filings made with the Canadian securities regulatory authorities concurrently with the SEC.

Changes are being implemented to business processes and ICFR to help ensure an efficient SOX 404 attestation process. Changes will be completed in Q1 and Q2 2011 for NSPI and Emera, respectively.

Education and training activities have occurred throughout all project phases. In this phase, education activities are focused on ensuring all personnel and senior management impacted by the transition understand the new requirements and have the skills and expertise necessary to ensure the organization's on-going ability to report under US GAAP, fulfill its reporting obligations to the SEC and comply with SOX. Members of the company's Board of Directors participated in education sessions in Q4 2010. Additional education sessions are planned in Q1 2011, including one for members of the company's Audit Committee to review the financial impact of the transition, prior period restatements and the company's transitional disclosure.

With the exception of the Q4 2010 restatements, the activities of this phase were originally planned to be substantially completed in December 2010, however, certain implementation activities identified above will be completed in February 2011. These delays do not jeopardize the project's ability to meet its key milestones, nor the company's ability to meet its Q1 2011 reporting obligations.

**Phase Four: Operational Support – In-Progress**

Phase Four began January 2011 and is scheduled to be completed by the end of Q2 2011. The impact of transitioning to US GAAP and complying with SEC reporting obligations and SOX requirements will be fully integrated into the company's financial reporting processes at that time.

Final transitional activities will be completed in this phase.

Following release of the company's Q1 2011 financial statements, the project will be formally closed and internal resources currently dedicated to the project will resume responsibility for financial reporting activities within the business.

## Recently Issued US GAAP Accounting Standards

As indicated above, beginning with its external reporting in Q1 2011, the company will retrospectively adopt US GAAP as its accounting framework and will no longer prepare its consolidated financial statements under CGAAP. In evaluating the impact of adopting US GAAP, the company has considered US GAAP accounting standards currently in effect through December 31, 2010. In 2011, additional US GAAP standards will become effective and the company will adopt them in accordance with their individual transition guidelines. The identified issued standards that have effective dates in 2011 and may be relevant to the company are set out below.

**Revenue Recognition**
In October 2009, the Financial Accounting Standards Board ("FASB") issued Accounting Standard Update ("ASU") 2009-13, *Revenue Recognition (Topic 605): Multiple-Deliverable Revenue Arrangements*. ASU 2009-13 amends existing US GAAP revenue recognition guidance to eliminate the requirement that all undelivered elements have vendor specific objective evidence of selling price ("VSOE") or third party evidence of selling price ("TPE") before an entity can recognize the portion of an overall arrangement fee that is attributable to items that already have been delivered. In the absence of VSOE and TPE for one or more delivered or undelivered elements in a multiple-element arrangement, entities will be required to estimate the selling prices of those elements. The overall arrangement fee will be allocated to each

element (both delivered and undelivered items) based on their relative selling prices, regardless of whether those selling prices are evidenced by VSOE or TPE or are based on the entity's estimated selling price. Application of the "residual method" of allocating an overall arrangement fee between delivered and undelivered elements will no longer be permitted upon adoption of ASU 2009-13. Additionally, the new guidance will require entities to disclose more information about their multiple-element revenue arrangements. ASU 2009-13 is effective prospectively for revenue arrangements entered into or materially modified in fiscal years beginning on or after June 15, 2010. The company will adopt ASU 2009-13 effective January 1, 2011 but does not expect that its adoption will have a material impact on its consolidated financial statements.

**Fair Value Measurements**
In January 2010, the FASB issued ASU 2010-06, *Improving Disclosures about Fair Value Measurements*. ASU 2010-06 amends FASB Accounting Standards Codification ("ASC") Topic 820, *Fair Value Measurements and Disclosures*, to require reporting entities to make new disclosures about recurring or nonrecurring fair-value measurements including significant transfers into and out of Level 1 and Level 2 fair-value measurements and information about purchases, sales, issuances, and settlements on a gross basis in the reconciliation of Level 3 fair-value measurements. The ASU also clarifies existing fair-value measurement disclosure guidance about the level of disaggregation, inputs, and valuation techniques. Except for the detailed Level 3 roll forward disclosures, the guidance in the ASU was effective for interim and annual reporting periods beginning after December 15, 2009. The new disclosures about purchases, sales, issuances, and settlements in the roll forward activity for Level 3 fair-value measurements are effective for fiscal years beginning after December 15, 2010. The company will adopt the disclosure requirements of ASU 2010-06 in its 2011 US GAAP financial reporting but does not expect they will have a material impact on its consolidated financial statements.

**Goodwill Impairment**
In December 2010, the FASB issued ASU 2010-28 Intangibles—Goodwill and Other (Topic 350): *When to Perform Step 2 of the Goodwill Impairment Test for Reporting Units with Zero or Negative Carrying Amounts*. ASU 2010-28 amends ASC 350-20 to modify Step 1 of the goodwill impairment test for reporting units with zero or negative carrying amounts. For those reporting units, an entity is required to perform Step 2 of the goodwill impairment test if it is more likely than not that a goodwill impairment exists. In determining whether it is more likely than not that a goodwill impairment exists, an entity should consider whether there are any adverse qualitative factors indicating that an impairment may exist consistent with the existing guidance in US GAAP. ASU 2010-28 is effective for interim periods and fiscal years beginning on or after December 15, 2010. The company will adopt ASU 2010-28 effective January 1, 2011 but does not expect that its adoption will have a material impact on its consolidated financial statements.

# SUMMARY OF QUARTERLY RESULTS

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

| | **Q4 2010** | Q3 2010 | Q2 2010 | Q1 2010 | Q4 2009 | Q3 2009 | Q2 2009 | Q1 2009 |
|---|---|---|---|---|---|---|---|---|
| Total revenues | **$392.7** | $373.5 | $357.4 | $430.1 | $389.1 | $339.1 | $333.8 | $404.1 |
| Net earnings applicable to common shares | **39.6** | 44.8 | 29.6 | 77.1 | 37.5 | 37.3 | 38.1 | 62.8 |
| Earnings per common share – basic | **0.35** | 0.39 | 0.26 | 0.68 | 0.33 | 0.33 | 0.34 | 0.56 |
| Earnings per common share – diluted | **0.34** | 0.39 | 0.26 | 0.66 | 0.33 | 0.33 | 0.33 | 0.53 |

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.

Emera

# EMERA INC.

# Consolidated Financial Statements

# December 31, 2010 and 2009

Emera

# MANAGEMENT REPORT

**Management's Responsibility for Financial Reporting**

The accompanying consolidated financial statements of Emera Inc. 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., one of Emera's wholly-owned electric utilities and principal subsidiary, is regulated by the Nova Scotia Utility and Review Board, which also examines and approves NSPI's accounting policies and practices. Emera's other wholly-owned electric utility and subsidiaries, Bangor Hydro Electric Company and Maine Public Service Company, are regulated by the Federal Energy Regulatory Commission and the Maine Public Utilities Commission, which also examine and approve Bangor Hydro Electric Company and Maine Public Service Company's accounting policies and practices. Emera Brunswick Pipeline Company Ltd., which is wholly-owned, is regulated by the National Energy Board.

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 Inc. 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 Inc.'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 Inc. The Audit Committee meets periodically with management, as well as with the internal auditors and with the external auditors, to discuss internal controls over the financial reporting process, auditing matters and financial reporting issues, to satisfy itself that each party is properly discharging its responsibilities, and to review the annual report, the consolidated financial statements and the external auditors' report. The Audit Committee reports its findings to the Board for consideration when approving the consolidated financial statements for issuance to the shareholders. The Audit Committee also considers, for review by the Board and approval by the shareholders, the appointment of the external auditors.

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

February 11, 2011

"Christopher Huskilson"

President and Chief Executive Officer

"Nancy Tower, FCA"

Chief Financial Officer

Emera

## INDEPENDENT AUDITORS' REPORT

To the Shareholders of Emera Inc.

We have audited the accompanying consolidated financial statements of Emera Inc., which comprise the consolidated statement of financial position as at December 31, 2010 and 2009, and the consolidated statement of earnings, consolidated statement of changes in equity and consolidated statement of cash flows for the years then ended, and a summary of significant accounting policies and other explanatory information.

### Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

### Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audits to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal controls relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal controls. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

### Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Emera Inc. as at December 31, 2010 and 2009, and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Halifax, Canada
February 11, 2011

"Ernst & Young LLP"

Chartered Accountants

Emera

**Emera Inc.**
**Consolidated Statements of Earnings**
**Year Ended December 31**

| millions of dollars (except earnings per common share) | 2010 | 2009 |
|---|---|---|
| Revenue | | |
| Electric | **$1,436.1** | $1,402.0 |
| Finance income from direct financing lease (note 16) | **56.5** | 25.3 |
| Other | **61.1** | 56.2 |
| | **1,553.7** | 1,483.5 |
| Cost of operations | | |
| Fuel for generation and purchased power | **718.7** | 583.5 |
| Fuel adjustment (note 5) | **(99.0)** | 8.5 |
| Operating, maintenance and general | **336.1** | 294.4 |
| Provincial, state, and municipal taxes | **49.1** | 49.9 |
| Depreciation and amortization | **173.6** | 164.9 |
| Regulatory amortization | **41.3** | 35.7 |
| | **1,219.8** | 1,136.9 |
| | **333.9** | 346.6 |
| Equity earnings (note 7) | **13.6** | 14.0 |
| Financing charges (note 8) | **168.4** | 135.3 |
| Earnings before income taxes and non-controlling interest | **179.1** | 225.3 |
| Income taxes (note 9) | **(12.8)** | 48.9 |
| Net earnings before non-controlling interest | **191.9** | 176.4 |
| Non-controlling interest (note 18) | **(2.3)** | 0.7 |
| Net earnings | **194.2** | 175.7 |
| Preferred share dividends | **3.1** | - |
| Net earnings applicable to common shares | **$191.1** | $175.7 |
| Earnings per common share – basic (note 11) | **$1.68** | $1.56 |
| Earnings per common share – diluted (note 11) | **$1.65** | $1.52 |

*See accompanying notes to the consolidated financial statements.*

Emera

**Emera Inc.**
**Consolidated Balance Sheets**
**As at December 31**

| millions of dollars | **2010** | 2009 |
|---|---|---|
| **Assets** | | |
| Current assets | | |
| Cash and cash equivalents | **$9.4** | $21.8 |
| Restricted cash | **59.6** | 1.0 |
| Accounts receivable (note 12) | **396.5** | 413.1 |
| Income tax receivable | **50.7** | 11.0 |
| Inventory (note 13) | **177.8** | 174.5 |
| Prepaid expenses | **9.8** | 7.4 |
| Future income tax assets (note 9) | **28.2** | 46.7 |
| Derivatives in a valid hedging relationship | **28.4** | 26.3 |
| Held-for-trading derivatives | **22.1** | 13.1 |
| | **782.5** | 714.9 |
| Derivatives in a valid hedging relationship | **26.1** | 30.9 |
| Held-for-trading derivatives | **15.3** | 30.7 |
| Other assets (note 14) | **652.1** | 427.4 |
| Future income tax assets (note 9) | **12.9** | 4.4 |
| Goodwill (note 21) | **178.9** | 87.6 |
| Intangibles (note 15) | **103.5** | 92.1 |
| Investments subject to significant influence (note 7) | **238.9** | 218.4 |
| Available-for-sale investments (note 29) | **47.0** | 47.3 |
| Net investment in direct financing lease (note 16) | **488.2** | 476.9 |
| Property, plant & equipment (note 17) | **3,450.7** | 2,933.7 |
| Construction work in progress | **333.0** | 220.2 |
| | **3,783.7** | 3,153.9 |
| | **$6,329.1** | $5,284.5 |

Emera

**Emera Inc.**
**Consolidated Balance Sheets (continued)**
**As at December 31**

| millions of dollars | **2010** | 2009 |
|---|---|---|
| **Liabilities and Shareholders' Equity** | | |
| Current liabilities | | |
| Current portion of long-term debt (note 24) | **$12.7** | $108.1 |
| Short-term debt (note 23) | **228.1** | 300.3 |
| Accounts payable and accrued charges | **399.6** | 305.9 |
| Income tax payable | **8.4** | 9.3 |
| Dividends payable | **1.8** | 1.7 |
| Derivatives in a valid hedging relationship | **8.6** | 61.0 |
| Held-for-trading derivatives | **31.1** | 18.6 |
| | **690.3** | 804.9 |
| Derivatives in a valid hedging relationship | **21.3** | 25.7 |
| Held-for-trading derivatives | **18.0** | 15.8 |
| Future income tax liabilities (note 9) | **359.8** | 194.1 |
| Asset retirement obligations (note 22) | **141.8** | 104.5 |
| Other liabilities (note 14) | **161.7** | 148.1 |
| Long-term debt (note 24) | **3,006.9** | 2,318.4 |
| Preferred shares issued by subsidiary (note 10) | **135.0** | 135.0 |
| Non-controlling interest (note 18) | **20.7** | 32.1 |
| Shareholders' equity | | |
| Common shares (note 25) | **1,136.5** | 1,096.7 |
| Preferred shares (note 26) | **146.7** | - |
| Contributed surplus | **3.7** | 3.6 |
| Accumulated other comprehensive loss | **(164.7)** | (186.7) |
| Retained earnings | **651.4** | 592.3 |
| | **1,773.6** | 1,505.9 |
| | **$6,329.1** | $5,284.5 |

Change in accounting estimate (note 2), Contingencies (note 31), Commitments (notes 6, 29 and 32), Guarantees (note 33), Subsequent events (note 35)
*See accompanying notes to the consolidated financial statements.*

Approved on behalf of the Board of Directors

"John McLennan" "Christopher Huskilson"

Chairman President and Chief Executive Officer

Emera

**Emera Inc.**
**Consolidated Statements of Cash Flows**
**Year Ended December 31**

| millions of dollars | 2010 | 2009 |
|---|---|---|
| **Operating activities** | | |
| Net earnings | **$194.2** | $175.7 |
| Non-cash items: | | |
| Depreciation and amortization | **173.6** | 164.9 |
| Amortization of other assets | **16.9** | 18.8 |
| Equity earnings | **(13.6)** | (14.0) |
| Fuel adjustment (note 5) | **(99.0)** | 8.5 |
| Regulatory amortization | **41.3** | 35.7 |
| Allowance for funds used during construction | **(22.2)** | (28.9) |
| Interest (recovery) expense on deferral of FAM | **(3.8)** | 1.4 |
| Future income taxes (note 9) | **34.7** | (2.1) |
| Post-retirement benefits | **(11.4)** | (16.4) |
| Non-controlling interest | **(2.3)** | 0.7 |
| Changes in fair value of derivatives instruments | **26.0** | (19.8) |
| Other non-cash operating items | **(6.1)** | 3.4 |
| Other cash operating items | **7.8** | 8.0 |
| | **336.1** | 335.9 |
| Change in non-cash operating working capital (note 27) | **80.3** | (25.7) |
| Net cash provided by operating activities | **416.4** | 310.2 |
| **Investing activities** | | |
| Property, plant and equipment | **(527.2)** | (326.6) |
| Intangibles | **(14.2)** | (12.5) |
| Increase in restricted cash | **(58.4)** | (0.3) |
| Retirement spending net of salvage | **(16.3)** | (8.9) |
| Acquisitions (note 18) | **(267.0)** | (36.7) |
| Net investment in direct financing lease | **(10.8)** | (53.4) |
| Investments | **(0.9)** | 71.2 |
| Net cash used in investing activities | **(894.8)** | (367.2) |
| **Financing activities** | | |
| Retirements of long-term debt | **(346.8)** | (130.0) |
| Issuance of long-term debt | **542.3** | 725.0 |
| Increase (decrease) in short-term debt | **232.5** | (279.6) |
| Issuance of common shares | **39.3** | 14.9 |
| Issuance of preferred shares | **145.2** | - |
| Dividends on common shares | **(132.0)** | (115.8) |
| Dividends on preferred shares | **(3.0)** | - |
| Redemption of preferred shares issued by a subsidiary | **-** | (125.0) |
| Other financing activities | **(11.3)** | (19.0) |
| Net cash provided by financing activities | **466.2** | 70.5 |
| Effect of exchange rate changes on cash and cash equivalents | **(0.2)** | (3.9) |
| (Decrease) increase in cash and cash equivalents | **(12.4)** | 9.6 |
| Cash and cash equivalents, beginning of year | **21.8** | 12.2 |
| Cash and cash equivalents, end of year | **$9.4** | $21.8 |

| **Cash and cash equivalents consists of:** | | |
|---|---|---|
| Cash | **$9.4** | $21.5 |
| Short-term investments | **-** | 0.3 |
| Cash and cash equivalents, end of year | **$9.4** | $21.8 |

| **Supplemental disclosure of cash paid (recovered):** | | |
|---|---|---|
| Interest | **$149.7** | $127.4 |
| Income and capital taxes | **$(2.1)** | $49.0 |

*See accompanying notes to the consolidated financial statements.*

**Emera Inc.**
**Consolidated Statements of Changes in Shareholders' Equity**

| **For the year ended December 31, 2010**<br>millions of dollars | Common Shares | Preferred Shares | Contributed Surplus | Accumulated Other Comprehensive (Loss) Income ("AOCI") | Retained Earnings | Total AOCI and Retained Earnings |
|---|---|---|---|---|---|---|
| Balance, December 31, 2009 | $1,096.7 | - | $3.6 | $(186.7) | $592.3 | $405.6 |
| Comprehensive income: | | | | | | |
| Net earnings | - | - | - | - | 194.2 | 194.2 |
| Net gains on derivatives in a valid hedging relationship | - | - | - | 10.7 | - | 10.7 |
| Reclassification of hedging losses included in income | - | - | - | 61.5 | - | 61.5 |
| Reclassification of hedging gains included in inventory | - | - | - | (17.5) | - | (17.5) |
| Unrealized foreign exchange loss on translation of self-sustaining foreign operations | - | - | - | (32.7) | - | (32.7) |
| Total comprehensive income | - | - | - | 22.0 | 194.2 | 216.2 |
| Issuance of preferred shares (note 26) | - | $146.7 | - | - | - | - |
| Dividends declared on common shares | - | - | - | - | (132.0) | (132.0) |
| Dividends declared on preferred shares | - | - | - | - | (3.1) | (3.1) |
| Dividends paid by subsidiaries to non-controlling interest | - | - | - | - | - | - |
| Common shares issued under purchase plans | 32.8 | - | - | - | - | - |
| Senior management stock options exercised | 6.0 | - | (0.5) | - | - | - |
| Stock option expense | - | - | 0.6 | - | - | - |
| Other share-based compensation | 1.0 | - | - | - | - | - |
| Balance, December 31, 2010 | $1,136.5 | $146.7 | $3.7 | $(164.7) | $651.4 | $486.7 |

| **For the year ended December 31, 2009**<br>millions of dollars | Common Shares | Contributed Surplus | AOCI | Retained Earnings | Total AOCI and Retained Earnings |
|---|---|---|---|---|---|
| Balance, December 31, 2008 | $1,081.4 | $3.4 | $(69.2) | $532.4 | $463.2 |
| Comprehensive income: | | | | | |
| Net earnings | - | - | - | 175.7 | 175.7 |
| Net losses on derivatives in a valid hedging relationship | - | - | (99.9) | - | (99.9) |
| Reclassification of hedging losses included in income | - | - | 33.2 | - | 33.2 |
| Reclassification of hedging losses included in inventory | - | - | 29.3 | - | 29.3 |
| Unrealized foreign exchange loss on translation of self-sustaining foreign operations | - | - | (80.4) | - | (80.4) |
| Other | - | - | 0.3 | - | 0.3 |
| Total comprehensive (loss) income | - | - | (117.5) | 175.7 | 58.2 |
| Dividends declared on common shares | - | - | - | (115.8) | (115.8) |
| Dividends paid by subsidiaries to non-controlling interest | - | - | - | - | - |
| Common shares issued under purchase plans | 8.7 | - | - | - | - |
| Senior management stock options exercised | 5.8 | (0.4) | - | - | - |
| Stock option expense | - | 0.6 | - | - | - |
| Other share-based compensation | 0.8 | - | - | - | - |
| Balance, December 31, 2009 | $1,096.7 | $3.6 | $(186.7) | $592.3 | $405.6 |

*See accompanying notes to the consolidated financial statements.*

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# Emera Inc.
# Notes to the Consolidated Financial Statements

**December 31, 2010 and 2009**

## 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Emera Inc. (“Emera” or “the Company”), incorporated in the Province of Nova Scotia, is engaged in the production and sale of electric energy and transportation of natural gas through its principal subsidiaries, Nova Scotia Power Inc. (“NSPI”), Bangor Hydro Electric Company (“Bangor Hydro”), Maine Public Service Company (“MPS”), Grand Bahama Power Company Limited (“GBPC”) and Emera Brunswick Pipeline Company Ltd. (“Brunswick Pipeline”).

NSPI, created through the privatization in 1992 of the crown corporation Nova Scotia Power Corporation, is a fully-integrated regulated electric utility and the primary electricity supplier in Nova Scotia. 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’s accounting policies are subject to examination and approval by the UARB.

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 a reasonable return to investors. NSPI’s regulated return on equity (“ROE”) range for 2010 was 9.1% to 9.6% on an allowed common equity component up to 40% of NSPI’s total regulated capitalization. Beginning January 1, 2009, NSPI implemented a Fuel Adjustment mechanism which allows NSPI to recover all prudent fuel cost from customers. This allows NSPI risk profile to be reduced as the timeliness and certainty of full fuel recovery is managed. The reduction of the risk due to less fuel volatility has allowed NSPI to manage the non-fuel rate requirement more strategically.

In January 2010, NSPI reached an agreement with stakeholders on its calculation of regulated ROE. The agreement establishes that NSPI will continue to use actual capital structure, actual equity and actual net earnings to calculate actual annual regulated ROE. The agreement was approved by the UARB. The UARB has set, as a condition, that NSPI will maintain its average actual regulated annual common equity at a level no higher than 40% beginning in 2010 and until the next general rate case.

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 Bangor Hydro T&D network. In addition to the T&D network, Bangor Hydro has certain 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 44% of Bangor Hydro’s electric rates represent distribution services, 11% relate to stranded costs recoveries, and 45% 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”). Bangor Hydro’s accounting policies are subject to examination and approval by FERC and the MPUC.

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

In December 2007, the MPUC issued an order approving an approximately 39% reduction in stranded cost rates for the three-year period beginning March 1, 2008. The allowed ROE used in setting the new stranded cost rates is 8.5%. Prior to that, stranded cost rates provided for an allowed ROE of 10%. Transmission rates are set by the FERC annually on June 1, based upon a formula that utilizes prior year actual transmission investments and expenses, adjusted for current year forecasted transmission investments and expenses. The allowed ROE for

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transmission operations ranges from 11.14% for low voltage local transmission up to 12.64% for high voltage regionally-funded transmission developed as a result of the regional system plan.

Maine & Maritimes Corporation (“MAM”) was acquired on December 21, 2010. Located in northern Maine, MAM’s core business is also the transmission and distribution of electricity through its regulated electric utility, MPS. Similar to Bangor Hydro, in addition to its T&D network, MPS has net regulatory assets (stranded costs). Approximately 57% of MPS’s electric rates represent distribution services, 34% relate to stranded cost recoveries, and 9% to transmission services. The rates for each element are established in distinct regulatory proceedings. The transmission operations are regulated by FERC, and the distribution operations and stranded costs are regulated by the MPUC. MPS’s accounting policies are subject to examination and approval by FERC and the MPUC.

MPS operates under a traditional cost-of-service regulatory structure. In July 2006, the MPUC approved an increase of approximately 11% in distribution rates, effective July 15, 2006. The allowed ROE used in setting these distribution rates was 10.2%, with a common equity component of 50%.

In March 2010, the MPUC issued an order approving a continuation of the levelized stranded cost rates established in rate orders in 2003 and 2006. These rates are in effect for the two year rate effective period January 1, 2010 through December 31, 2011. The allowed ROE used in setting the new stranded costs was 9.4% in 2010 and 8.6% in 2011, down from the 10.2% ROE allowed in the 2006 stranded cost rate order.

Transmission rates are set annually through the Open Access Transmission Tariff (“OATT”). Rates derived from the previous calendar year’s results go into effect June 1 for wholesale customers and July 1 for retail customers. The allowed ROE for transmission operations is 10.5%, and is based on the actual common equity. The rates under the 2010 OATT went into effect June 1, 2010 for wholesale customers and July 1, 2010 for retail customers. However, the 2010 OATT has not yet been settled, and accordingly the actual rates allowed for the 2010-2011 rate effective period could differ from the rates currently being charged.

On December 22, 2010, Emera purchased a 50% interest in GBPC and an additional 10.7% interest in ICD Utilities Limited (“ICDU”), owner of the remaining 50% interest in GBPC, bringing Emera’s total ownership of GBPC to 80.4%. Emera has determined it has control of GBPC through the combination of both direct and indirect interests. GBPC is an integrated utility with 19,000 customers on Grand Bahama Island and has 137 megawatts (“MW”) of installed oil-fired capacity. The Grand Bahama Port Authority regulates the utility and has granted GBPC a licensed, regulated and exclusive franchise to produce, transmit, and distribute electricity on the island until 2054. There is a fuel pass through mechanism and flexible tariff adjustment policies to ensure that costs are recovered and a reasonable return earned. GBPC is authorized by the Port Authority to adjust fuel costs included in its rates to the extent the weighted average cost of fuel delivered into GBPC’s power plant storage facilities exceeds or is less than $20 Bahamian dollars per barrel.

Brunswick Pipeline, a $485 million, 145-kilometre pipeline carrying re-gasified liquefied natural gas (“LNG”), delivers natural gas from the Canaport™ LNG import terminal near Saint John, New Brunswick, to markets in the northeastern United States. The pipeline went into service on July 16, 2009. The pipeline travels through southwest New Brunswick and connects with the Maritimes and Northeast Pipeline (“M&NP”) at the Canada/US border near Baileyville, Maine.

Canaport™ LNG is a partnership of Repsol YPF, S.A. (“Repsol”) and Irving Oil Limited. Emera has negotiated a 25 year firm service agreement with Repsol Energy Canada to transport natural gas through the Brunswick Pipeline. Toll rates were negotiated to achieve a return on project equity in the range of 11% to 14%. The National Energy Board (”NEB”), which regulates Brunswick Pipeline, has classified it as a Group 2 pipeline.

Emera follows Canadian generally accepted accounting principles (“CGAAP”). The accounting policies approved by the regulators of NSPI, Bangor Hydro, MPS and Brunswick Pipeline may differ from CGAAP 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 CGAAP. Where the differences between CGAAP and CGAAP for rate-regulated companies are considered significant, disclosure of the policy has been made in these notes to the consolidated financial statements.

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**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 CGAAP 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. Estimates and assumptions are based upon historical experience, current conditions and assumptions believed to be reasonable at the time the estimate is made. Due to changing circumstances and the inherent uncertainty in making estimates, actual results may differ significantly from current estimates. Estimates are reviewed periodically, with any resulting adjustments reported in earnings in the period they arise.

The most significant estimates include: measurement property plant and equipment depreciation rates (note 1f), intangible assets amortization rates (note 1g), post-employment benefits (note 4), income taxes (note 9), accounts receivable (note 12), of regulatory assets and liabilities (note 14), asset retirement obligations (note 22) financial instruments (note 29), and contingencies (note 31). 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.
- Finance income from direct financing lease: Under the direct financing lease method, the Company records the net investment in a lease, which consists of the sum of the minimum lease payments, estimated executory costs less the unearned income. The difference between the gross investment and the cost of the leased item for direct financing lease is recorded as unearned income at the inception of the lease. The unearned income is recognized in income over the life of the lease using a constant rate of interest equal to the internal rate of return on the lease.
- Energy Marketing: Derivatives that are not entered into for hedging purposes are recognized at fair market value at year-end.
- Other: Revenues are recognized on the accrual basis, which includes an estimate for services performed and goods delivered during the year but billed subsequent to year-end.
- Unearned revenue is recognized as “Other liabilities”.

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

**d.** **Allowance for Funds Used during Construction**

*Accounting for the impact of rate regulation:*

In accordance with their rate-regulated accounting policies, NSPI, Bangor Hydro, MPS and Brunswick Pipeline provide for the cost of financing construction work in progress by including an allowance for funds used during construction (“AFUDC”) as an addition to the cost of property constructed, using a weighted average cost-of-capital. AFUDC is included in “Property, plant and equipment”, “Intangibles”, “Construction work in progress” and “Net investment in direct financing lease” for financial reporting purposes and is charged to operations through depreciation over the service life of the related assets and recovered through future revenues and through financing income from direct financing lease. 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 rate-regulated accounting policies.

## e. Regulatory Amortization

*Accounting for the impact of rate regulation:*

In December 2010, the UARB granted NSPI approval to defer certain tax benefits related to renewable energy projects arising in 2010 through an increase in regulatory amortization. The UARB will convene a proceeding in 2011 to discuss how this deferral will be applied. In the absence of UARB approval, 2010 earnings would have been $14.5 million higher.

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

In January 2010, NSPI reached an agreement with stakeholders on its calculation of regulated ROE. The agreement includes a provision which provides the Company with flexibility in its amortization of the pre-2003 income taxes to accelerate additional amortization amounts in current periods and subsequently reduce amounts in future periods. In the absence of UARB approved recovery, the liability would have been expensed when incurred. More details are provided in note 14.

The UARB agreed to allow NSPI to defer taxes not reflected in rates for the period January 1, 2005 until April 1, 2005, the date when new rates became effective. The UARB approved recovery of this regulatory asset over eight years, commencing April 1, 2007.

The UARB agreed to allow NSPI to defer demand side management program expenses for the period January 1, 2008 until December 31, 2009. The UARB approved recovery of this regulatory asset over six years commencing January 1, 2009.

The UARB agreed to allow NSPI to defer vegetation management spending of $2.0 million in 2008 to be recovered in rates in a future period. The period of recovery of this asset will be determined during the next general rate case.

In the absence of UARB approved deferrals for taxes, demand side management and vegetation management expenses would have been expensed as incurred. More details are provided in note 14.

In accordance with rate and accounting orders issued by the MPUC, Bangor Hydro and MPS have recorded regulatory assets and liabilities on their balance sheets. These regulatory assets and liabilities are being amortized over varying lives expiring through to 2018 through charges to earnings. These regulatory assets and liabilities are included in “Other assets” and “Other liabilities” and include costs related to restructuring of purchased power contracts, the Seabrook nuclear project, decommissioning costs for Maine Yankee, obligations to Hydro-Québec, and the stranded cost revenue requirement levelizer, and are described in more detail in note 14.

## f. Property, Plant and Equipment

Property, plant and equipment are recorded at original cost, net of contributions in aid of construction including energy tax credits.

Depreciation is determined by the straight-line method, based on the estimated remaining service lives of the depreciable assets in each category. The service lives of regulated assets are determined based on formal depreciation studies, which require UARB approval or FERC and MPUC

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approvals. The estimated weighted average service life for the Company's unregulated general assets is 7 years (2009 – 9 years). Unregulated generation assets have an estimated weighted average service life of 35 years (2009 – 33 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 include significant changes in regulation, a change in the Company's strategy or underperformance relative to projected future operating results.

*Accounting for the impact of rate regulation:*

During 2003, following completion of a depreciation study and a negotiated agreement with stakeholders, NSPI's regulator approved new depreciation rates which were to be phased in over four years beginning in 2004. In the decision on NSPI's 2005 rate application, the UARB delayed the phase-in of year-two rates for one year. In the decision on NSPI's 2006 rate application, the UARB approved restarting of the phase-in including year-two in 2006 rates. In its February 2007 decision, the UARB postponed the scheduled year-three phase-in of increased depreciation rates until the next rate application. In its November 2008 decision, the UARB approved the year-three phase-in effective January 1, 2009.

Absent consideration of growth in plant-in-service, the phase-in of new depreciation rates will increase depreciation expense by a cumulative increase of $20 million over the phase-in period. In the absence of UARB 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 | **2010** | 2009 |
|---|---|---|
| Generation | | |
| Thermal | **2.50%** | 2.50% |
| Gas turbines | **2.47%** | 2.47% |
| Combustion turbines | **3.33%** | 3.33% |
| Hydroelectric | **1.51%** | 1.51% |
| Wind turbines | **5.00%** | 5.00% |
| Transmission | **2.76%** | 2.76% |
| Distribution | **4.15%** | 4.15% |
| General plant | **7.07%** | 7.07% |
| General plant under capital lease | **13.18%** | 14.25% |
| Weighted average depreciation rate | **3.00%** | 3.13% |

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, Bangor Hydro implemented the results of a depreciation study that was approved by its regulators.

The estimated average service lives in years for the major categories of plant-in-service are summarized as follows:

| **Function** | **2010** | 2009 |
|---|---|---|
| Transmission | **44** | 45 |
| Distribution | **35** | 35 |
| Other | **17** | 16 |
| Weighted average service life | **38** | 36 |

MPS's depreciation is determined by the straight-line method, based on the estimated service lives of the depreciable assets in each category. In 2007, MPS implemented the results of a depreciation study approved by its regulators. The estimated average service lives in years for the major categories of plant-in-service are summarized as follows:

| Function | 2010 |
|---|---|
| Transmission | **46** |
| Distribution | **31** |
| Other | **28** |
| Weighted average service life | **33** |

In accordance with regulator-approved accounting policies, when depreciable property, plant and equipment of NSPI, Bangor Hydro and MPS 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 would be charged to net earnings as incurred.

## g. Intangible Assets

Intangible assets consist primarily of land rights and computer software. Amortization is determined by the straight-line method, based on the estimated remaining service lives of the depreciable assets in each category. The service lives of regulated assets are determined based on formal depreciation studies which require the appropriate regulator's approval as discussed in property, plant and equipment in note 1(f). The estimated weighted average service life for the Company's intangible assets is 54 years (2009 – 57 years).

When indicators of impairment exist, the Company determines whether the net carrying amount of the intangible assets 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:*

In the absence of UARB approval of amortization rates, NSPI would be required to set rates based on management's best estimates of useful lives. The average rates for the major categories are summarized as follows:

| Function | 2010 | 2009 |
|---|---|---|
| Transmission | **1.21%** | 1.21% |
| Distribution | **1.57%** | 1.57% |
| Other | **12.16%** | 12.03% |
| Weighted average amortization rate | **4.67%** | 3.66% |

In the absence of the MPUC's approval of amortization rates, Bangor Hydro would be required to set rates based on management's best estimates of useful lives. The average rates for the major categories are summarized as follows:

| Function | 2010 | 2009 |
|---|---|---|
| Distribution | **1.43%** | 1.41% |
| Other | **14.10%** | 12.36% |
| Weighted average amortization rate | **9.30%** | 8.81% |

In the absence of the MPUC's approval of amortization rates, MPS would also be required to set rates based on management's best estimates of useful lives. The average rates for the major categories are summarized as follows:

| Function | 2010 |
|---|---|
| Transmission | **1.20%** |
| Distribution | **0.70%** |
| Other | **21.76%** |
| Weighted average amortization rate | **14.72%** |

**h. Capitalization Policy**

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

**i. 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 CGAAP, 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.

**j. Income Taxes and Investment Tax Credits**

Emera follows the future income tax method of accounting for income taxes. The difference between the tax basis of assets and liabilities and their carrying value on the balance sheet is used to calculate future tax assets and liabilities. The future tax assets and liabilities have been measured using substantively enacted tax rates that will be in effect when the differences are expected to reverse.

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 rate-regulated accounting, NSPI and Brunswick Pipeline defer any future income taxes from the statements of earnings and AOCI to a regulatory asset or liability where the future income taxes are expected to be included in future rates and tolls respectively. Bangor Hydro and MPS use the future income tax method where allowed for ratemaking purposes. NSPI, Bangor Hydro, MPS and Brunswick Pipeline would be required to recognize all future income tax expense and recovery in the absence of their regulator-approved accounting policies. More details are provided in note 9.

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**k. Employee Future Benefits**

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

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

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

For any given year, when the net actuarial gain (loss), less the actuarial gain (loss) not yet included in the market-related value of plan assets, exceeds 10% of the greater of the accrued benefit obligation and the market-related value of the plan assets, an amount equal to the excess divided by the average remaining service period ("ARSP") is amortized on a straight-line basis. For NSPI, the ARSP of the active employees is 9 years as at December 31, 2010 and 2009. For Bangor Hydro, this excess is amortized on a straight-line basis over the expected ARSP, in accordance with ratemaking purposes, which is 11 years as at December 31, 2010 and 2009. At December 31, 2010, MPS has no actuarial gains or losses not yet included in the market-related value of the plan assets. For Emera Inc., the ARSP of the active employees is 10 years as at December 31, 2010 (2009 – 11 years).

On January 1, 2000, Emera adopted the accounting standard on employee future benefits using the prospective application method. The transitional obligation (asset) resulting from the initial application is amortized on a linear basis 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 "Other assets" or "Other liabilities" on the balance sheet.

**l. Share-Based Compensation**

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

**m. 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. There were no short-term investments outstanding at December 31, 2010. The 2009 effective interest rate was 0.55%.

**n. Inventory**

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

Emera

**o. Debt Financing Costs**

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

**p. Derivative Financial & Commodity Instruments**

The Company classifies financial assets and financial liabilities as held-for-trading, available-for-sale, loans and receivables, other financial liabilities or derivatives in valid hedging relationships. All financial instruments are initially recorded at fair value on the consolidated statement of financial position. Subsequent measurements of the financial instruments are based on their classification.

Held-for-trading ("HFT") derivative financial assets and liabilities consist mainly of foreign exchange forward contracts, interest caps and collars, coal, oil and gas options; swaps; and natural gas contracts. The Company has not designated any non-derivative financial assets or liabilities as held-for-trading. HFT financial instruments are initially recorded at their fair value. The Company has classified its derivatives not in valid hedging relationships as held-for-trading and recognizes changes in fair value of its HFT derivatives in earnings of the reporting period.

The available-for-sale investments are recognized at fair value, with changes in those fair values recorded in "Other comprehensive income" unless actively quoted prices are not available for fair value measurement, in which case available-for-sale investments are measured at cost.

Loans and receivables include cash and cash equivalents and accounts receivable and are measured at amortized cost using the effective interest method. Gains and losses are included in earnings and recorded in "Operating, maintenance and general expenses".

Other financial liabilities, which include accounts payable and accrued charges, preferred shares issued by a subsidiary, short-term debt and long-term debt, are recognized at amortized cost. Preferred share dividends paid by a subsidiary are recognized using the effective interest method. Interest expense and debt financing expenses related to the Company's long-term debt and short-term debt are recognized using the effective interest method.

Derivatives in valid hedging relationships are categorized as cash flow hedges and fair value hedges. The Company uses cash flow hedges to manage changes in commodity prices, foreign exchange rates, and interest rates. The Company uses fair value hedges to hedge the fair value of commodity positions.

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

The Company recognizes the fair value of all its hedges on its balance sheet.

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

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

Where documentation and effectiveness requirements are not met, the change in fair value of the derivative is recognized in earnings in the reporting period.

If a cash flow hedge is terminated, the effective portion of the change in fair value of the hedging derivative up until the date of termination remains in AOCI and is recognized in earnings, inventory or construction work in progress in the same period the related hedged risk is realized. The change in fair value of the derivative, if retained, would then be recognized in earnings from the termination date onward.

Amounts received or paid related to derivatives used to hedge foreign exchange and commodity price risks on fuel purchases are recognized in “Fuel for generation and purchased power” or “Inventory”. Amounts received or paid related to derivatives used to hedge foreign exchange on capital purchases are recognized in “Construction work in progress”. Amounts received or paid related to derivatives used to hedge interest rate risks are recognized over the term of the hedged item in “Financing charges”.

Cash flows related to HFT derivatives and derivatives in valid hedging relationships are reflected in “Operating activities” on the statement of cash flows.

*Accounting for the impact of rate regulation:*

In accordance with Handbook Standard 3865 Hedges, NSPI determined that it cannot meet the probability requirement of the standard for its derivatives in place to hedge natural gas and heavy fuel oil for its Tufts Cove generating station (“TUC”). This is due to the generating station’s ability to fuel switch and NSPI’s economic dispatch based on the cost of these two fuels. The UARB has allowed NSPI to apply hedge accounting to these derivatives as long as the other requirements of the Handbook are met. In 2009, the UARB approved an amendment to NSPI’s accounting practice to include all TUC derivatives which are no longer required. Absent UARB approval, NSPI would be required to recognize the changes in fair value of these derivatives in net earnings of the period.

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

MPS has two cash flow hedges used to fix the interest rates on two variable-rate debt issues. The MPUC has allowed MPS recovery of the fixed interest costs in MPS’ rates. The fair value of the interest rate hedges is recognized in “Derivatives in a valid hedging relationship”.

Further details on the regulatory assets and liabilities recognized as a result of the above can be found in note 14.

**q. 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 events 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.

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**r. Long-Term Investments**

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

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

**s. Foreign Currency Translation**

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

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

**t. Research and Development Costs**

All research and development costs are expensed in the year incurred unless they qualify for deferral as a part of property, plant and equipment or intangible assets.

## 2. CHANGE IN ACCOUNTING ESTIMATE

In 2010, NSPI revised its estimate of the expected benefit from accelerated tax deductions. The impact for the three months and twelve months ended December 31, 2010 was to reduce income tax expense by approximately $8.0 million and $14.0 million respectively. In accordance with rate-regulated accounting, the future income tax implications of this change in estimate have been deferred to a regulatory asset in "Other assets". This change in accounting estimate has been accounted for on a prospective basis.

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### 3. SEGMENT INFORMATION

The Company has three reportable segments which are determined based on Emera's operating activities: NSPI, engaged in the production and sale of electric energy in Nova Scotia; Bangor Hydro, engaged in the transmission and distribution of electric energy in central Maine; Brunswick Pipeline, engaged in the transportation of natural gas through its pipeline for Repsol; and Other, including MPS, GBPC, revenue generated from energy marketing margin and electric revenue from the Company's investment in Bear Swamp. The Company evaluates performance based on contribution to consolidated net earnings applicable to common shareholders. The accounting policies of the reported segments are the same as those described in the summary of significant accounting policies.

| millions of dollars | NSPI | Bangor Hydro | Brunswick Pipeline | Other* | Total |
|---|---|---|---|---|---|
| **Year ended December 31, 2010** | | | | | |
| Revenues from external customers | $1,182.6 | $155.7 | $56.5 | $158.9 | $1,553.7 |
| Depreciation and amortization | 150.8 | 17.2 | 0.1 | 5.5 | 173.6 |
| Cost of operations, including depreciation | 953.0 | 97.8 | 0.1 | 168.9 | 1,219.8 |
| Equity earnings | - | - | - | 13.6 | 13.6 |
| Interest expense | 110.6 | 11.5 | - | 29.1 | 151.2 |
| Income taxes | (17.4) | 18.8 | - | (14.2) | (12.8) |
| Net earnings applicable to common shareholders | 121.3 | 31.9 | 25.8 | 12.1 | 191.1 |
| Net inter-segment (expenses) revenues | (47.6) | (1.6) | (31.5) | 80.7 | - |
| Capital expenditures | 510.5 | 40.6 | 12.7 | 4.6 | 568.4 |
| **As at December 31, 2010** | | | | | |
| Total assets | 3,991.3 | 730.4 | 502.7 | 1,104.7 | 6,329.1 |
| Investments subject to significant influence | - | 0.7 | - | 238.2 | 238.9 |
| Goodwill | - | 82.9 | - | 96.0 | 178.9 |

| millions of dollars | NSPI | Bangor Hydro | Brunswick Pipeline | Other* | Total |
|---|---|---|---|---|---|
| **Year ended December 31, 2009** | | | | | |
| Revenues from external customers | $1,201.9 | $157.7 | $25.3 | $98.6 | $1,483.5 |
| Depreciation and amortization | 143.9 | 18.3 | 0.1 | 2.6 | 164.9 |
| Cost of operations, including depreciation | 935.9 | 103.0 | 0.1 | 97.9 | 1,136.9 |
| Equity earnings | - | - | - | 14.0 | 14.0 |
| Interest expense | 99.2 | 13.0 | - | 21.8 | 134.0 |
| Income taxes | 42.2 | 15.3 | - | (8.6) | 48.9 |
| Net earnings applicable to common shareholders | 109.3 | 27.5 | 14.0 | 24.9 | 175.7 |
| Net inter-segment revenues (expenses) | 16.2 | (0.9) | (30.5) | 15.2 | - |
| Capital expenditures | 263.7 | 55.9 | 50.8 | 22.1 | 392.5 |
| **As at December 31, 2009** | | | | | |
| Total assets | 3,465.3 | 738.0 | 447.7 | 633.5 | 5,284.5 |
| Investments subject to significant influence | - | 2.2 | - | 216.2 | 218.4 |
| Goodwill | - | 87.2 | - | 0.4 | 87.6 |

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

## 4. EMPLOYEE FUTURE BENEFITS

### NOVA SCOTIA POWER PLANS

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

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

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

The measurement date for the assets and obligations of each benefit plan is December 31, 2010.

### 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, 2010 | December 31, 2011 |
| Acquired companies pension plan | December 31, 2010 | December 31, 2011 |

### Total cash amount

Total cash amount for 2010, made up of contributions to its funded defined-benefit pension plans, contributions to its defined-contribution pension plan, employer paid premiums for its post-retirement health care plan, and amounts paid directly to retirees and beneficiaries in other plans, was $40.4 million (2009 – $32.5 million) for NSPI and Emera.

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### Accrued pension and non-pension benefit asset (liability)

| | 2010 | | 2009 | |
|---|---|---|---|---|
| millions of dollars | **Defined benefit pension plans** | **Non-pension benefits plans** | Defined benefit pension plans | Non-pension benefits plans |
| **Assumptions (weighted average)** | | | | |
| Accrued benefit obligation – December 31: | | | | |
| Discount rate | **5.50%** | **5.50%** | 6.50% | 6.50% |
| Rate of compensation increase | **3% to 5.5%** | **3% to 5.5%** | 3% to 5.5% | 3% to 5.5% |
| Health care trend - initial (next year) | **-** | **4.00%** | - | 5.00% |
| - ultimate | **-** | **4.00%** | - | 4.00% |
| - year ultimate reached | **-** | **2011** | - | 2011 |
| Benefit cost for year ending December 31: | | | | |
| Discount rate | **6.50%** | **6.50%** | 7.50% | 7.50% |
| Expected long-term return on plan assets | **7.25%** | **7.25%** | 7.25% | - |
| Rate of compensation increase | **3% to 5.5%** | **3% to 5.5%** | 3% to 5.5% | 3% to 5.5% |
| Health care trend - initial (current year) | **-** | **5.00%** | - | 6.00% |
| - ultimate | **-** | **4.00%** | - | 4.00% |
| - year ultimate reached | **-** | **2011** | - | 2011 |
| **Accrued benefit obligations** | | | | |
| Balance, January 1 | **$787.8** | **$36.3** | $669.5 | $36.1 |
| Employer current service cost | **9.5** | **1.5** | 6.8 | 1.4 |
| Employee contributions | **5.7** | **-** | 5.4 | - |
| Interest cost | **50.2** | **2.3** | 49.1 | 2.6 |
| Past service adjustment | **(1.0)** | **-** | - | - |
| Actuarial losses | **122.4** | **4.1** | 95.1 | 0.4 |
| Benefits paid | **(39.5)** | **(4.3)** | (38.1) | (4.2) |
| Balance, December 31 | **935.1** | **39.9** | 787.8 | 36.3 |
| **Fair value of plan assets** | | | | |
| Balance, January 1 | **593.1** | **-** | 509.2 | - |
| Employer contributions | **34.7** | **4.3** | 27.2 | $4.2 |
| Employee contributions | **5.7** | **-** | 5.4 | - |
| Actual return on plan assets | **55.6** | **-** | 89.4 | - |
| Benefits paid | **(39.5)** | **(4.3)** | (38.1) | (4.2) |
| Balance, December 31 | **649.6** | **-** | 593.1 | - |
| **Reconciliation of financial status to accrued benefit asset, December 31** | | | | |
| Fair value of plan assets | **649.6** | **-** | 593.1 | - |
| Accrued benefit obligations | **935.1** | **39.9** | 787.8 | 36.3 |
| **Plan deficit** | **(285.5)** | **(39.9)** | (194.7) | (36.3) |
| Unamortized past service (gains) costs | **(0.3)** | **1.4** | (0.4) | 1.6 |
| Unamortized actuarial losses (gains) | **364.5** | **2.1** | 257.8 | (2.2) |
| Unamortized transitional obligation | **(0.9)** | **4.5** | 0.1 | 6.7 |
| Accrued benefit asset (liability) | **$77.8** | **$(31.9)** | $62.8 | $(30.2) |

The amounts recognized in “Other assets” and “Other liabilities” are as follows:

| | 2010 | | 2009 | |
|---|---|---|---|---|
| millions of dollars | **Defined benefit pension plans** | **Non-pension benefits plans** | Defined benefit pension plans | Non-pension benefits plans |
| Accrued benefit asset | **$110.7** | **-** | $94.4 | - |
| Accrued benefit liability | **(32.9)** | **$(31.9)** | (31.6) | $(30.2) |
| Net accrued benefit asset (liability) | **$77.8** | **$(31.9)** | $62.8 | $(30.2) |

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| Defined benefit plans asset allocation (% of plan assets) | 2010 | | 2009 | |
|---|---|---|---|---|
| | **Employee pension plan** | **Acquired companies pension plan** | Employee pension plan | Acquired companies pension plan |
| Equity securities | **65%** | **64%** | 64% | 62% |
| Debt securities | **34%** | **36%** | 36% | 37% |
| Cash | **1%** | **-** | - | 1% |
| Total | **100%** | **100%** | 100% | 100% |

As at December 31, 2010, the pension funds do not hold any material investments in Emera Inc. or Nova Scotia Power Inc. securities.

**Plans with accrued benefit obligations in excess of assets**

As at December 31, 2010, all post-retirement benefit plans have accrued benefit obligations in excess of assets.

| **Benefits cost components** millions of dollars | **2010** | | 2009 | |
|---|---|---|---|---|
| **Defined benefit plan** | **Defined benefit pension plans** | **Non-pension benefits plan** | Defined benefit pension plans | Non-pension benefits plan |
| **Costs arising from events during the year:** | | | | |
| Current service costs | **$9.5** | **$1.5** | $6.8 | $1.4 |
| Interest on accrued benefits | **50.2** | **2.3** | 49.1 | 2.6 |
| Less: actual return on plan assets | **(55.6)** | **-** | (89.4) | - |
| Actuarial losses on accrued benefit obligation | **122.4** | **4.1** | 95.1 | 0.5 |
| Past service gains | **(1.0)** | **-** | - | - |
| **Future benefit costs before adjustments** | **125.5** | **7.9** | 61.6 | 4.5 |
| **Adjustments to recognize long-term nature of costs:** | | | | |
| Difference between expected return on assets and actual return | **6.0** | **-** | 41.0 | - |
| Amortization of transitional obligation | **-** | **2.2** | - | 2.2 |
| Difference between amortization of actuarial gains and actual actuarial gains on accrued benefit obligations | **(112.8)** | **(4.3)** | (94.6) | (0.8) |
| Difference between amortization of past service costs and past service costs for the year | **1.0** | **0.2** | - | 0.2 |
| Total cost recognized | **$19.7** | **$6.0** | $8.0 | $6.1 |
| | | | | |
| **Defined contribution plan** | | | | |
| Employer cost | **$1.4** | **-** | $1.1 | - |

The expected return on plan assets is determined based on the market-related value of plan assets of $685.6 million at January 1, 2010 (2009 – $671.1 million), adjusted for interest on certain cash flows during the year.

**Sensitivity analysis for non-pension benefits plans**

The health care cost trend significantly influences the amounts presented for health care plans. An increase or decrease of one percentage point of the assumed health care cost trend would have had the following impact in 2010:

| millions of dollars | **Increase** | **Decrease** |
|---|---|---|
| Current service cost and interest cost | - | - |
| Accrued benefit obligation, December 31 | $1.5 | $(1.4) |

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## BANGOR HYDRO PLANS

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

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

The measurement date for the assets and obligations of each benefit plan is December 31, 2010.

### Valuation date for defined-benefit plans

Bangor Hydro 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, 2009 | December 31, 2010 |

### Total cash amount

Total cash amount for 2010, made up of Bangor Hydro 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 \$5.0 million (2009 – \$5.2 million).

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## Accrued pension and non-pension benefit liability

| | 2010 | | 2009 | |
|---|---|---|---|---|
| millions of dollars | **Defined benefit pension plans** | **Non-pension benefits plans** | Defined benefit pension plans | Non-pension benefits plans |
| **Assumptions (weighted average)** | | | | |
| Accrued benefit obligation – December 31: | | | | |
| Discount rate | **5.60%** | **5.60%** | 6.00% | 6.00% |
| Rate of compensation increase | **3.75%** | **N/A** | 3.75% | N/A |
| Health care trend - initial (next year) | **-** | **9.25%** | - | 10.00% |
| - ultimate | **-** | **5.00%** | - | 5.00% |
| - year ultimate reached | **-** | **2017** | - | 2017 |
| Benefit cost for year ending December 31: | | | | |
| Discount rate | **6.00%** | **6.00%** | 6.75% | 6.75% |
| Expected long-term return on plan assets | **8.00%** | **5.00%** | 8.00% | 5.00% |
| Rate of compensation increase | **3.75%** | **N/A** | 3.75% | N/A |
| Health care trend - initial (current year) | **-** | **10.00%** | - | 7.60% |
| - ultimate | **-** | **5.00%** | - | 5.00% |
| - year ultimate reached | **-** | **2017** | - | 2015 |
| **Accrued benefit obligations** | | | | |
| Balance, January 1 | **$81.8** | **$41.8** | $84.6 | 53.6 |
| Employer current service cost | **1.4** | **0.7** | 1.3 | 0.6 |
| Interest cost | **4.7** | **2.3** | 5.1 | 2.3 |
| Past service amendments | **-** | **-** | - | (14.5) |
| Actuarial losses (gains) | **4.7** | **(0.2)** | 8.3 | 8.4 |
| Benefits paid | **(3.7)** | **(1.4)** | (4.2) | (1.1) |
| Foreign currency translation adjustment | **(4.2)** | **(2.1)** | (13.3) | (7.5) |
| Balance, December 31 | **84.7** | **41.1** | 81.8 | 41.8 |
| **Fair value of plan assets** | | | | |
| Balance, January 1 | **49.8** | **1.0** | 47.9 | 1.2 |
| Employer contributions | **3.6** | **1.4** | 3.5 | 1.3 |
| Actual return on plan assets | **5.8** | **-** | 10.5 | (0.1) |
| Benefits paid | **(3.7)** | **(1.4)** | (4.2) | (1.1) |
| Foreign currency translation adjustment | **(2.7)** | **(0.1)** | (7.9) | (0.3) |
| Balance, December 31 | **52.8** | **0.9** | 49.8 | 1.0 |
| **Reconciliation of financial status to accrued benefit asset, December 31** | | | | |
| Fair value of plan assets | **52.8** | **0.9** | 49.8 | 1.0 |
| Accrued benefit obligations | **84.7** | **41.1** | 81.8 | 41.8 |
| **Plan deficit** | **(31.9)** | **(40.2)** | (32.0) | (40.8) |
| Unamortized past service costs (gains) | **0.5** | **(11.2)** | 0.7 | (14.8) |
| Unamortized actuarial losses | **33.2** | **21.0** | 33.0 | 24.2 |
| Unamortized transitional obligation | **-** | **-** | - | 1.6 |
| Accrued benefit asset (liability) | **$1.8** | **$(30.4)** | $1.7 | $(29.8) |

| **Defined benefit plans asset allocation (% of plan assets)** | **2010** | 2009 |
|---|---|---|
| | **Employee pension plan** | Employee pension plan |
| Equity securities | **65%** | 65% |
| Debt securities | **34%** | 34% |
| Other | **1%** | 1% |
| Total | **100%** | 100% |

As at December 31, 2010, 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.

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**Plans with accrued benefit obligation in excess of assets**

As at December 31, 2010, all post-retirement benefit plans have accrued pension obligations in excess of assets.

**Benefits cost components**

| millions of dollars | 2010 | | 2009 | |
|---|---|---|---|---|
| **Defined benefit plan** | **Defined benefit pension plans** | **Non-pension benefit plans** | Defined benefit pension plans | Non-pension benefits plans |
| **Costs arising from events during the year:** | | | | |
| Current service costs | **$1.4** | **$0.7** | $1.3 | $0.6 |
| Interest on accrued benefits | **4.7** | **2.3** | 5.1 | 2.3 |
| Less: actual (loss) on plan assets | **(5.8)** | **-** | (10.5) | - |
| Actuarial losses (gains)on accrued benefit obligation | **4.7** | **(0.2)** | 8.3 | 8.4 |
| Past service amendment | **-** | **-** | - | (14.5) |
| **Future benefit costs before adjustments** | **5.0** | **2.8** | 4.2 | (3.2) |
| **Adjustments to recognize long-term nature of costs:** | | | | |
| Difference between expected return on assets and actual return | **1.1** | **(0.1)** | 5.5 | (0.2) |
| Amortization of transitional obligation | **-** | **-** | - | 0.6 |
| Difference between amortization of actuarial (gains) losses and actual actuarial (gains) losses on accrued benefit obligations | **(3.1)** | **2.1** | (7.5) | (7.1) |
| Difference between amortization of past service costs and past service costs for the year | **0.2** | **(1.3)** | 0.2 | 12.7 |
| Total cost recognized | **$3.2** | **$3.5** | $2.4 | $2.8 |
| | | | | |
| **Defined contribution plan** | | | | |
| Employer cost | **$0.4** | **-** | $0.3 | - |

For the defined benefit pension plan, the expected return on plan assets is determined on the market-related value of plan assets of $53.4 million at January 1, 2010 (2009 – $58.6 million), adjusted for interest on certain cash flows during the year.

**Sensitivity analysis for non-pension plans**

The health care cost trend significantly influences the amounts presented for health care plans. An increase or decrease of one percentage point of the assumed health care cost trend would have had the following impact in 2010:

| | **Increase** | **Decrease** |
|---|---|---|
| Current service cost and interest cost | $0.5 | $(0.4) |
| Accrued benefit obligation, December 31 | $7.0 | $(5.6) |

*Accounting for the impact of rate regulation:*

When Bangor Hydro was purchased by Emera, Bangor Hydro received regulatory approval to continue amortizing certain existing balances over a period of 10 years. Under CGAAP, as a result of the purchase, these unamortized balances would have been recognized immediately in the year Bangor Hydro was purchased. In the absence of the regulatory policy, Bangor Hydro's total accrued benefit liability would be $34.9 million (2009 – $38.5 million) and the total defined benefits expense for 2010 would be $5.0 million (2009 – $3.3 million).

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**MAINE & MARITIMES PLANS**

MAM's subsidiary, MPS, maintains a non-contributory defined-benefit pension plan, and a contributory defined-contribution 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 post-employment indexing from time to time, subject to approval by the MPS Board of Directors. Employees hired after January 1, 2006, are not eligible for participation in the defined benefit pension plan. Effective December 31, 2006, future salary and service accruals ceased. Employees hired after October 1, 2005, are not eligible for the retiree health care plan.

Other retirement benefit plans include an unfunded supplemental executive plan and an unfunded defined benefit agreement. The estimated liabilities for these plans are approximately $0.2 million.

The measurement date for the assets and obligations of each benefit plan is December 31, 2010.

**Valuation date for defined-benefit plans**

MPS 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, 2009 | December 31, 2010 |

**Total cash amount**

Total cash amount for 2010, made up of MPS 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 $2.1 million.

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## Accrued pension and non-pension benefit liability

| | | 2010 |
|---|---|---|
| millions of dollars | **Defined benefit pension plan** | **Non-pension benefits plan** |
| **Assumptions (weighted average)** | | |
| Accrued benefit obligation – December 31: | | |
| Discount rate | **5.40%** | **5.40%** |
| Rate of compensation increase | **-** | **N/A** |
| Health care trend - initial (next year) | **-** | **9.00%** |
| - ultimate | **-** | **4.50%** |
| - year ultimate reached | **-** | **2070** |
| Benefit cost for year ending December 31: | | |
| Discount rate | **5.75%** | **5.85%** |
| Expected long-term return on plan assets | **8.50%** | **8.50%** |
| Rate of compensation increase | **-** | **N/A** |
| Health care trend - initial (current year) | **-** | **10.00%** |
| - ultimate | **-** | **5.00%** |
| - year ultimate reached | **-** | **2070** |
| **Accrued benefit obligations** | | |
| Balance, January 1 | **$20.0** | **$3.1** |
| Employer current service cost | **-** | **0.1** |
| Interest cost | **1.0** | **0.2** |
| Past service amendments | **-** | **-** |
| Actuarial losses | **1.0** | **2.3** |
| Benefits paid | **(1.1)** | **(0.3)** |
| Foreign currency translation adjustment | **(1.0)** | **(0.2)** |
| Balance, December 31 | **19.9** | **5.2** |
| **Fair value of plan assets** | | |
| Balance, January 1 | **14.7** | **2.2** |
| Employer contributions | **1.0** | **0.1** |
| Actual return on plan assets | **2.2** | **0.3** |
| Benefits paid | **(1.1)** | **(0.2)** |
| Foreign currency translation adjustment | **(0.9)** | **(0.1)** |
| Balance, December 31 | **15.9** | **2.3** |
| **Reconciliation of financial status to accrued benefit asset, December 31** | | |
| Fair value of plan assets | **15.9** | **2.3** |
| Accrued benefit obligations | **19.9** | **5.2** |
| **Plan deficit** | **(4.0)** | **(2.9)** |
| Unamortized past service gains | **-** | **(6.2)** |
| Unamortized actuarial losses | **5.1** | **5.6** |
| Unamortized transitional obligation | **-** | **-** |
| Accrued benefit asset (liability) | **$1.1** | **$(3.5)** |

| **Defined benefit plans asset allocation (% of plan assets)** | **2010** |
|---|---|
| | **Employee pension plan** |
| Equity securities | **68%** |
| Debt securities | **24%** |
| Other | **8%** |
| Total | **100%** |

For the defined benefit pension plan, the expected rate of return on plan assets is determined on the market-related value of plan assets of $14.5 million at January 1, 2010, adjusted for interest on certain cash flows during the year.

As at December 31, 2010, the pension fund does not directly hold any investments in Emera, Bangor Hydro or MAM 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.

### Sensitivity analysis for non-pension plans

The health care cost trend significantly influences the amounts presented for health care plans. An increase or decrease of one percentage point of the assumed health care cost trend would have had the following impact in 2010:

| | Increase | Decrease |
|---|---|---|
| Current service cost and interest cost | - | - |
| Accrued benefit obligation, December 31 | $0.8 | $(0.6) |

*Accounting for the impact of rate regulation:*

When MAM was purchased by Emera, MPS recorded a regulatory asset to continue amortizing certain existing balances over a period of 13 years. Under CGAAP, as a result of the purchase, these unamortized balances would have been recognized immediately in the year MAM was purchased. In the absence of the regulatory policy, MAM's total accrued benefit liability would be $6.9 million.

## GRAND BAHAMA POWER COMPANY LIMITED PLANS

GBPC maintains a non-contributory defined-benefit pension plan for unionized employees and a separate non-contributory defined-benefit pension plan for non-union employees. The defined benefit pension plans are based on the years of service and average salary at the time the employee retires.

The Company also has gratuity plans for its employees, payable upon retirement. Employees get 2 weeks pay for every year worked, capped at 52 weeks.

The measurement date for the assets and obligations of each benefit plan is December 31, 2010.

### Valuation date for defined-benefit plans

GBPC 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, 2009 | December 31, 2010 |

### Total cash amount

Total cash amount for 2010, made up of GBPC contributions to its funded defined-benefit pension plan, was $0.4 million.

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## Accrued pension and non-pension benefit liability

| millions of dollars | 2010<br>Defined benefit pension plans | Non-pension benefits plans |
|---|---|---|
| **Assumptions (weighted average)** | | |
| Accrued benefit obligation – December 31: | | |
| Discount rate | **6.00%** | **6.00%** |
| Rate of compensation increase | | |
| - Union Plan | **4.00%** | **2.00%** |
| - Non Union Plan | **5.00%** | **2.00%** |
| Benefit cost for year ending December 31: | | |
| Discount rate | **6.00%** | **6.00%** |
| Expected long-term return on plan assets | **6.00%** | **-** |
| Rate of compensation increase | **4.00%** | **-** |
| - Union Plan | **4.00%** | **2.00%** |
| - Non Union Plan | **5.00%** | **2.00%** |
| **Accrued benefit obligations** | | |
| Balance, January 1 | **$8.4** | **2.8** |
| Employer current service cost | **0.3** | **-** |
| Interest cost | **0.5** | **-** |
| Actuarial losses | **(0.1)** | **-** |
| Benefits paid | **(0.2)** | **-** |
| Foreign currency translation adjustment | **(0.4)** | **(0.1)** |
| Balance, December 31 | **8.5** | **2.7** |
| **Fair value of plan assets** | | |
| Balance, January 1 | **5.5** | **-** |
| Employer contributions | **0.4** | **-** |
| Actual return on plan assets | **0.1** | **-** |
| Benefits paid | **(0.2)** | **-** |
| Foreign currency translation adjustment | **(0.2)** | **-** |
| Balance, December 31 | **5.6** | **-** |
| **Reconciliation of financial status to accrued benefit asset, December 31** | | |
| Fair value of plan assets | **5.6** | **-** |
| Accrued benefit obligations | **8.5** | **2.7** |
| **Plan deficit** | **(2.9)** | **(2.7)** |
| Unamortized actuarial losses | **1.5** | **-** |
| Accrued benefit liability | **$(1.4)** | **$(2.7)** |

| **Defined benefit plans asset allocation (union plan) (% of plan assets)** | **2010**<br>**Employee pension plan** |
|---|---|
| Equity securities | **29%** |
| Debt securities | **54%** |
| Other | **17%** |
| Total | **100%** |

| **Defined benefit plans asset allocation (non-union plan) (% of plan assets)** | **2010**<br>**Employee pension plan** |
|---|---|
| Equity securities | **55%** |
| Debt securities | **39%** |
| Other | **6%** |
| Total | **100%** |

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## 5. FUEL ADJUSTMENT

The UARB approved the implementation of a Fuel Adjustment Mechanism ("FAM") for NSPI in the 2009 General Rate Decision effective January 1, 2009. The fuel adjustment related to the FAM includes the effect of fuel costs in both the current period and the preceding year. The difference between actual fuel costs and amounts recovered from customers in the current period is included in the fuel adjustment. This amount, less the incentive component, is deferred to a FAM regulatory asset in "Other assets" or a FAM regulatory liability in "Other liabilities". Also included in the 2010 fuel adjustment is the rebate to customers of over recovered fuel costs from 2009.

Details of the fuel adjustment related to the FAM are summarized in the following table:

| millions of dollars | **2010** | 2009 |
|---|---|---|
| (Under) over recovery of current period fuel costs | **$(76.6)** | $8.5 |
| Rebate to customers from prior year | **(22.4)** | - |
| Fuel adjustment | **$(99.0)** | $8.5 |

The Company has recognized a future income tax expense related to the fuel adjustment based on NSPI's applicable statutory income tax rate. The FAM regulatory asset or liability includes amounts recognized as a fuel adjustment and associated interest included in "Financing charges". As at December 31, 2010, NSPI's FAM regulatory asset was $92.9 million (2009 – liability of $9.9 million), and future income tax liability related to the FAM was $29.2 million (2009 – asset of $3.4 million).

In the absence of UARB approval, the fuel adjustment would not have been recognized and earnings for the year ended December 31, 2010 would be $80.4 million ($56.3 million after-tax) lower (2009 – $9.9 million or $6.5 million after-tax higher).

## 6. OPERATING LEASES

The Company has entered into operating lease agreements for office space, rail cars, telecommunication services, and certain other equipment, which expire in 2011 to 2020. Future minimum annual lease payments under the leases are as follows:

| millions of dollars | |
|---|---|
| 2011 | $2.7 |
| 2012 | 1.1 |
| 2013 | 0.6 |
| 2014 | 0.6 |
| 2015 | 0.6 |
| Thereafter | 1.4 |
| | $7.0 |

For the year ended December 31, 2010, the Company recognized $10.1 million (2009 – $9.9 million) of operating leases in "Operating, maintenance and general expense".

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## 7. INVESTMENTS SUBJECT TO SIGNIFICANT INFLUENCE AND EQUITY EARNINGS

Investments subject to significant influence are comprised of the following:

| | 2010 | | 2009 | |
|---|---|---|---|---|
| millions of dollars | **Carrying value** | **Equity earnings** | Carrying value | Equity earnings |
| Maritimes & Northeast Pipeline | **$118.8** | **$9.1** | $116.8 | $10.2 |
| Light and Power Holdings | **90.2** | **5.4** | - | - |
| St. Lucia Electricity Services Ltd. | **25.0** | **2.1** | 25.5 | 2.4 |
| Atlantic Hydrogen Inc. | **3.6** | **(0.4)** | - | - |
| Maine Electric Power Company Inc. | **0.9** | **-** | 2.0 | - |
| Maine Yankee Atomic Power Company | **0.2** | **-** | 0.2 | - |
| Grand Bahama Power Company Limited (1) | **-** | **(2.6)** | 73.9 | 1.4 |
| Other | **0.2** | **-** | - | - |
| | **$238.9** | **$13.6** | $218.4 | $14.0 |

(1) As discussed under note 18 Acquisitions, Emera purchased in December 2010 an additional 55.4% of direct and indirect interest in GBPC. The acquisition has been accounted for under the purchase method of accounting as Emera determined it has control of GBPC. For the quarter and the year ended December 31, 2010 and 2009, equity earnings included Emera's 25% interest in GBPC.

Equity investments include a $14.5 million difference between the cost and the underlying net book value of the investees' assets as at the date of acquisition. The excess is attributable to goodwill and is therefore not subject to amortization.

## 8. FINANCING CHARGES

Financing charges consists of the following:

| millions of dollars | **2010** | 2009 |
|---|---|---|
| Interest - long-term debt | **$142.0** | $115.6 |
| - short-term debt | **9.2** | 18.4 |
| Preferred share dividends paid by subsidiary (note 10) | **8.0** | 9.5 |
| Amortization of defeasance cost | **12.1** | 12.1 |
| Amortization of debt financing costs | **3.6** | 5.4 |
| Allowance for funds used during construction | **(22.2)** | (28.9) |
| Interest (recovery) expense on deferral of FAM | **(3.8)** | 1.4 |
| Foreign exchange losses | **0.9** | 0.5 |
| Foreign exchange losses (gains) recovered through the FAM | **9.3** | (3.0) |
| Banking fees and other | **9.3** | 4.3 |
| | **$168.4** | $135.3 |

## 9. INCOME TAXES

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

| millions of dollars | | **2010** | | 2009 |
|---|---|---|---|---|
| Earnings before income taxes | **$179.1** | | $225.3 | |
| Income taxes, at statutory rates | **60.9** | **34.0%** | 78.9 | 35.0% |
| Future income taxes on regulated earnings deferred to regulatory assets (note 14) | **(67.5)** | **(37.7)** | (33.5) | (14.9) |
| Equity earnings not subject to tax | **(5.9)** | **(3.3)** | (5.8) | (2.6) |
| Change in estimate of prior year expected benefit of tax deductions | **(4.7)** | **(2.6)** | - | - |
| Recovery of prior year income taxes | **(4.4)** | **(2.5)** | - | - |
| Non-deductible preferred share dividends | **2.7** | **1.5** | 3.3 | 1.5 |
| Non-deductible regulatory amortization (note 14) | **11.8** | **6.7** | 9.3 | 4.1 |
| Other | **(5.7)** | **(3.2)** | (3.3) | (1.4) |
| | **(12.8)** | **(7.1)%** | 48.9 | 21.7% |
| Income taxes – current | **(47.5)** | | 51.0 | |
| Income taxes – future (note 5) | **$34.7** | | $(2.1) | |

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The future income tax assets and liabilities comprise the following:

| | Current portion | | Long-term portion | |
|---|---|---|---|---|
| millions of dollars | **2010** | 2009 | **2010** | 2009 |
| Future income tax assets: | | | | |
| Derivatives | **$7.6** | $25.8 | **-** | - |
| Tax loss carry forwards | **7.6** | 13.3 | **$9.2** | $2.4 |
| Property, plant and equipment | **-** | - | **1.1** | 0.8 |
| Other | **13.0** | 7.6 | **2.6** | 1.2 |
| | **$28.2** | $46.7 | **$12.9** | $4.4 |

| | | | | |
|---|---|---|---|---|
| Future income tax liabilities: | | | | |
| Property, plant and equipment | **-** | - | **$353.7** | $233.7 |
| Net investment in direct financing lease | **-** | - | **32.0** | 18.8 |
| Tax loss carry forwards | **-** | - | **(24.9)** | (27.8) |
| Derivatives | **-** | - | **3.7** | 3.4 |
| Asset retirement obligations | **-** | - | **(63.2)** | (45.9) |
| Pension | **-** | - | **9.8** | 14.9 |
| Defeasance costs | **-** | - | **19.2** | 20.0 |
| Intangibles | **-** | - | **(26.9)** | (26.4) |
| Deferral of FAM | **-** | - | **29.2** | (3.4) |
| Other | **-** | - | **27.2** | 6.8 |
| | **-** | - | **$359.8** | $194.1 |

As at December 31, 2010, the Company has tax losses of $128.2 million (2009 – $131.9 million), which are reflected in future income tax assets or netted against future income tax liabilities as appropriate, and begin to expire in 2014. The Company has recognized a future tax asset for the amount more likely than not to be realized.

*Accounting for the impact of rate regulation:*

In the absence of rate-regulated accounting, future income tax expenses would have been recorded against net earnings and net earnings would be $73.4 million lower in 2010 (2009 – $20.2 million).

## 10. PREFERRED SHARES ISSUED BY SUBSIDIARY

Preferred shares issued by subsidiary consist of NSPI's preferred shares and are classified as a financial liability on the balance sheet.

**Authorized:**
Unlimited number of First Preferred Shares, issuable in series.
Unlimited number of Second Preferred Shares, issuable in series.

| **Issued and outstanding:** | Millions of Shares | Preferred Share Capital millions of dollars |
|---|---|---|
| December 31, 2008 | 10.4 | $260.0 |
| Redemption of Series C First Preferred Shares | (5.0) | (125.0) |
| December 31, 2009 | 5.4 | 135.0 |
| December 31, 2010 | **5.4** | **$135.0** |

As at December 31, 2010 and 2009, the Company had 5.4 million 5.9% Series D preferred shares with the following redemption features:

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

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

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

**Series C First Preferred Shares:**
On April 1, 2009, NSPI redeemed its outstanding Cumulative Redeemable First Preferred Shares, Series C for a redemption price of $25 per share for a total of $125 million. Each share was entitled to a $1.225 per share per annum fixed cumulative preferential dividend, as and when declared by the Board of Directors, accruing from the date of issue and payable quarterly on the first day of January, April, July and October of each year.

## 11. EARNINGS PER SHARE

Earnings per share for 2010 are as follows:

| | Net earnings (millions of dollars) | Weighted average common shares (millions) | **2010** EPS ($) |
|---|---|---|---|
| Basic EPS | **$191.1** | **113.7** | **$1.68** |
| Series D preferred shares of NSPI | **7.5** | **5.1** | **(0.01)** |
| Performance share units and deferred share units | **-** | **0.8** | **(0.01)** |
| Other share-based compensation | **-** | **0.7** | **(0.01)** |
| Diluted EPS | **$198.6** | **120.3** | **$1.65** |

Earnings per share for 2009 are as follows:

| | Net earnings (millions of dollars) | Weighted average common shares (millions) | 2009 EPS ($) |
|---|---|---|---|
| Basic EPS | $175.7 | 112.5 | $1.56 |
| Series C preferred shares of NSPI | 1.5 | 1.5 | (0.01) |
| Series D preferred shares of NSPI | 7.8 | 6.3 | (0.02) |
| Performance share units and deferred share units | - | 0.7 | (0.01) |
| Other share-based compensation | - | 0.3 | - |
| Diluted EPS | $185.0 | 121.3 | $1.52 |

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

## 12. ACCOUNTS RECEIVABLE

At December 31, 2010, the Company had unbilled revenue included in accounts receivable in the amount of $102.7 million (2009 – $98.4 million). The unbilled revenue for NSPI, Bangor, MPS and GBPC is an estimate of the amount of revenue related to energy delivered to customers since the date their meters were last read. The unbilled revenue related to Brunswick Pipeline is an estimate of toll revenue at the end of each month. Actual results may differ from these estimates.

NSPI had a natural gas purchase agreement, which settled in November 2010, which included a price adjustment clause covering three years of natural gas purchases. The clause stated NSPI would pay for all gas purchases at the agreed contract price, but would be entitled to a price rebate on a portion of the volumes, settled in November 2007 and November 2010. At December 31, 2009, the receivable was $82.1 million.

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## 13. INVENTORY

The change in inventory is due to the following:

| For the year ended | Fuel inventory December 31 | | Materials inventory December 31 | |
|---|---|---|---|---|
| millions of dollars | **2010** | 2009 | **2010** | 2009 |
| Inventory, beginning of period | **$144.5** | $101.7 | **$30.0** | $29.5 |
| Purchases | **327.9** | 362.0 | **45.7** | 39.3 |
| Write-down of inventory to net realizable value | **-** | - | **(1.2)** | (0.7) |
| Inventories expensed | **(346.4)** | (319.2) | **(22.5)** | (22.1) |
| Inventories capitalized | **-** | - | **(26.5)** | (23.2) |
| Increase in inventory resulting from acquisitions | **3.1** | - | **14.2** | - |
| Other | **-** | - | **9.0** | 7.2 |
| Inventory, end of period | **$129.1** | $144.5 | **$48.7** | $30.0 |

The Company has not pledged inventory as security for liabilities.

## 14. OTHER ASSETS AND LIABILITIES

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

| millions of dollars | **2010** | 2009 |
|---|---|---|
| **Other assets:** | | |
| *Regulatory assets:* | | |
| Future income tax regulatory asset | **$199.6** | $63.6 |
| Unamortized defeasance costs | **94.6** | 106.7 |
| Deferral of FAM | **92.9** | - |
| Pre-2003 income tax and related interest | **56.9** | 75.2 |
| Costs to restructure purchased power contracts | **24.3** | 15.4 |
| Seabrook nuclear project | **14.3** | 10.4 |
| Deferral of income and capital taxes not included in Q1 2005 rates | **10.0** | 11.9 |
| Deferral of demand side management | **7.5** | 9.7 |
| Hydro-Québec obligation | **5.7** | 6.3 |
| Maine Yankee decommissioning costs | **3.8** | 3.5 |
| Deferral of vegetation management | **2.0** | 2.0 |
| Deferred restructuring costs | **1.8** | 2.9 |
| Stranded cost revenue requirement levelizers | **1.4** | 3.5 |
| Deferral of Tufts Cove derivatives | **1.3** | 9.6 |
| Held-for-trading natural gas contracts | **-** | 3.9 |
| Other | **13.9** | 3.6 |
| | **530.0** | 328.2 |
| *Non-regulatory assets:* | | |
| Accrued pension asset – NSPI plan (note 4) | **110.7** | 94.4 |
| Accrued pension asset – Bangor Hydro plan (note 4) | **1.8** | 1.7 |
| Accrued pension asset – MPS plan (note 4) | **1.1** | - |
| Other | **8.5** | 3.1 |
| | **122.1** | 99.2 |
| | **$652.1** | $427.4 |

| | 2010 | 2009 |
|---|---|---|
| **Other liabilities:** | | |
| *Regulatory liabilities:* | | |
| 2010 renewable tax benefits deferral | **$14.5** | - |
| Held-for-trading natural gas contracts | **12.3** | $4.7 |
| Deferral of Tufts Cove derivatives | **2.0** | 10.4 |
| Deferral of FAM | **-** | 9.9 |
| Other | **4.9** | 6.6 |
| | **33.7** | 31.6 |
| *Non-regulatory liabilities:* | | |
| Accrued pension and non-pension benefit liability – NSPI plan (note 4) | **64.8** | 61.8 |
| Accrued non-pension benefit liability – Bangor Hydro plan (note 4) | **30.4** | 29.8 |
| Accrued non-pension benefit liability – MPS plan (note 4) | **3.5** | - |
| Accrued non-pension benefit liability – GBPC plan (note 4) | **4.1** | - |
| Hydro-Québec obligation | **5.7** | 6.3 |
| Maine Yankee decommissioning liability | **3.8** | 3.5 |
| Unearned revenue | **1.1** | 1.7 |
| Other | **14.6** | 13.4 |
| | **128.0** | 116.5 |
| | **$161.7** | $148.1 |

**Regulatory assets consist of:**

**Future Income Tax Regulatory Asset**
In accordance with the Company's rate-regulated accounting policies covering income taxes, Emera deferred any future income taxes to a regulatory asset where the future income taxes are expected to be included in future rates. Absent this accounting policy, Emera's 2010 net earnings would be $73.4 million lower (2009 – $20.2 million).

**Unamortized Defeasance Costs**
Upon privatization in 1992, NSPI became responsible for managing a portfolio of defeasance securities held in trust, which as at December 31, 2010 and 2009, totaled $1.0 billion. The excess of the cost of defeasance investments over the face value of the related debt is deferred on the balance sheet and amortized over the life of the defeased debt as permitted by the UARB. In the absence of UARB approval, the losses would have been expensed as incurred and net earnings would be $12.1 million higher in 2010 and 2009.

**Deferral of Fuel Adjustment Mechanism**
As discussed in Note 5, the UARB approved the implementation of a FAM in NSPI's 2009 General Rate Decision effective January 1, 2009.

In the absence of UARB approval, the fuel adjustment would not have been recognized and net earnings for the year ended December 31, 2010 would be $80.4 million ($56.3 million after-tax) lower (2009 – $9.9 million or $6.5 million after-tax higher).

**Pre-2003 Income Tax and Related Interest**
NSPI has a regulatory asset related to pre-2003 income taxes that have been paid, but not yet recovered from customers. This circumstance arose when NSPI claimed capital cost allowance ("CCA") deductions in its corporate income tax returns that were ultimately disallowed by a decision of the Supreme Court of Canada. NSPI applied to the regulator to include recovery of these costs in customer rates. In its February 5, 2007 decision, the UARB approved recovery of this regulatory asset over eight years, commencing April 1, 2007.

In January 2010, NSPI reached an agreement with stakeholders on its calculation of regulated ROE. The agreement provides the Company with flexibility in amortizing the pre-2003 income tax regulatory asset allowing the Company to recognize additional amortization in current periods and reducing amounts in future periods. Accordingly, to allow flexibility relating to future customer rate requirements, NSPI recorded an additional discretionary $4.8 million of regulatory amortization expense for the year ended December 31,

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2010 (December 31, 2009 – $10.0 million). In the absence of UARB approved recovery, the liability would have been expensed when incurred, therefore net earnings would be $18.3 million higher in 2010 (2009 – $24.6 million).

In 2009, NSPI recorded an income tax recovery of $5.5 million relating to manufacturing and processing deductions claimed for its 1999-2003 amended corporate income tax returns, which reduced the regulatory asset.

**Costs to Restructure Power Purchase Contracts**
Bangor Hydro has power purchase contracts, which it was required to negotiate when oil prices were high, with several independent power producers known as small power production facilities. The cost of power from these facilities is more than Bangor Hydro would incur from other sources if it were not obligated under these contracts. Bangor Hydro attempted to alleviate the adverse impact of these high-cost contracts and in doing so incurred costs to restructure certain of the contracts. The MPUC has allowed Bangor Hydro to defer these costs and recover them in stranded cost rates. The contract restructuring costs are being recovered over a 20-year period ending in June 2018. The annual amortization is approximately $2.0 million. In the absence of the MPUC's approval, these BHE costs would have been expensed as incurred and net earnings would have been $1.8 million ($1.0 million after-tax) higher in 2010 (2009 – $1.9 million or $1.1 million after-tax).

MPS also had a similar power purchase contract, which expired December 31, 2006. The MPUC allowed MPS to defer the cost of the purchased power in excess of the market price at which MPS was able to sell the power. MPS is in the process of recovering this regulatory asset in stranded costs. Recovery of this regulatory asset varies each year, in accordance with the approved stranded cost rates, in order to maintain levelized stranded cost rates.

**Seabrook Nuclear Project**
Bangor Hydro and MPS were participants 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 finalized 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. For BHE, in the absence of MPUC approval, the loss on sale would have been recognized when incurred and net earnings would have been $1.8 million ($1.0 million after-tax) higher in 2010 (2009 – $1.9 million or $1.1 million after-tax). MPS deferred $43.1 million of costs associated with Seabrook, scheduled for recovery through 2016.

**Deferral of Income and Capital Taxes Not Included in Q1 2005 Rates**
The UARB agreed to allow NSPI to defer taxes not reflected in rates for the period January 1, 2005 until April 1, 2005, the date when new rates became effective. In 2005, NSPI deferred $16.7 million consisting of $4.5 million of provincial and federal grants and $12.2 million in income taxes reflecting increases in these taxes since rates were last set in 2002. In its February 2007 decision, the UARB approved recovery of this regulatory asset over eight years, commencing April 1, 2007. In the absence of UARB approval, these taxes would not have been deferred and net earnings for 2010 would be $1.9 million higher (2009 – $1.9 million).

**Deferral of Demand Side Management**
The UARB agreed to allow NSPI to defer up to $12.8 million of demand side management expenditures for the period January 1, 2008, through December 31, 2009, to be recovered in rates over six years commencing January 1, 2009. In the absence of the UARB's approval, these costs would not have been deferred and net earnings for 2010 would be $2.2 million higher (2009 – $9.4 million lower).

**Hydro-Québec Obligation**
The obligation associated with Hydro-Québec represents the estimated present value of Bangor Hydro's estimated future payments for net costs associated with ownership and operation of the Hydro-Québec intertie between the New England utilities and Hydro-Québec. The obligation has been recognized in "Other liabilities" 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 regulatory approval, 2010 net earnings would be $0.2 million ($0.1 million after-tax) higher (2009 – $0.4 million or $0.2 million after-tax).

**Maine Yankee Decommissioning Costs**
Bangor Hydro owns 7% of the common stock of Maine Yankee and MPS owns 5% of the common stock of Maine Yankee. In 1997, Maine Yankee permanently shut down its nuclear generating plant. Pursuant to a contract with Maine Yankee, Bangor Hydro and MPS are required to pay their pro-rata shares of Maine Yankee's decommissioning costs. Bangor Hydro's share of the estimated decommissioning costs were approximately $2.4 million in 2010 (2009 – $3.8 million). Maine Yankee expense recovery is included in Bangor Hydro's stranded cost revenues, and along with all stranded cost revenues, purchased power, and Hydro-Québec costs, are fully recoverable. For any variance between the actual amount of these items and the amounts used in setting rates, a regulatory deferral is recorded with a credit or charge to regulatory amortizations at both Bangor Hydro and MPS. Any over or under-recovery will be reviewed at future rate proceedings with the MPUC. For BHE, in the absence of regulatory approval, the Maine Yankee decommissioning costs would have been expensed when incurred and net earnings would have been $1.0 million ($0.6 million after-tax) higher in 2010 (2009 – $0.4 million or $0.2 million after-tax).

**Deferral of Vegetation Management**
The UARB agreed to allow NSPI to defer up to $2.0 million of vegetation management spending in 2008 to be recovered in rates in a future period. The investment in vegetation management spending was part of a specific initiative to improve the reliability of service provided to customers. In the absence of UARB approval, these costs would have been expensed as incurred.

**Deferred Restructuring Costs**
In conjunction with Bangor Hydro's Alternative Rate Plan, Bangor Hydro was provided with accounting orders from the MPUC to defer and amortize over ten years certain employee transition costs. Eligible for deferral were the 2002 and 2003 employee transition costs related to reductions in the cost of operations and employee transition costs associated with Bangor Hydro's automated meter reading project and the outsourcing of information technology support in 2004 and 2005. In the absence of regulatory approval, these costs would have been expensed as incurred and 2010 net earnings would have been $1.0 million ($0.6 million after-tax) higher (2009 – $1.1 million or $0.7 million after-tax).

**Stranded Cost Revenue Requirement Levelizer**
Bangor Hydro's stranded cost rates are reset every three years and are designed to recover Bangor Hydro's cumulative stranded cost revenue requirements over the three-year period. The most recently approved stranded cost rates are in effect from March 2008 to February 2011. While the stranded cost revenue requirements differ throughout the period due to changes in stranded cost revenues and expenses, the annual stranded cost revenues are the same during the period. To levelize the impact of the varying revenue requirements, cost or revenue deferrals are recognized. This levelizer is recognized only as result of regulatory accounting and the stranded cost ratemaking process. Absent regulatory accounting, the levelizer mechanism would not exist, and the methodology for determining Bangor Hydro's rates associated with stranded costs is not known. In the absence of regulatory approval, net earnings for 2010 would be $2.0 million ($1.2 million after-tax) higher (2009 – $0.2 million or $0.1 million after-tax).

**Deferral of Tufts Cove Derivatives**
In accordance with Handbook Standard 3865 Hedges, NSPI determined that it could not meet the probability requirement of the standard for its derivatives in place to hedge natural gas and heavy fuel oil for TUC. This is due to the generating station's ability to fuel switch and NSPI's economic dispatch based on the relative cost of these two fuels. The UARB has allowed NSPI to apply hedge accounting to these derivatives as long as the other requirements of the Handbook are met. This accounting policy permits NSPI to defer the fair value of hedges that are no longer required because of fuel switching.

In 2009, the UARB approved an amendment to NSPI's accounting practice to include all Tufts Cove financial commodity hedges which are no longer required. This change in practice will impact the timing of recognition between "Fuel for generation and purchased power" and "Fuel adjustment" as a result of the FAM implemented in 2009. The change in accounting practice has been applied prospectively, beginning January 1, 2009, as required by the UARB.

Absent UARB approval, NSPI would be required to recognize the change in fair value of these derivatives in "Fuel for generation and purchased power" with an offset to "Fuel adjustment". However, with the approval of FAM, there would be no material earnings impact.

**Held-for-trading Natural Gas Contracts**
In accordance with implementing Standard 3855 Financial Instruments – Recognition and Measurement, the Company has contracts for the purchase and sale of natural gas at TUC that are considered HFT derivatives and accordingly are recognized on the balance sheet at fair value. This reflects NSPI's history of buying and reselling any natural gas not used in the production of electricity at TUC. Changes in fair value of HFT derivatives are normally recognized in net earnings. In accordance with NSPI's rate-regulated accounting policy for financial instruments and hedges relating to TUC fuel, NSPI has deferred any changes in fair value to a regulatory asset or liability. Absent UARB approval, NSPI would be required to recognize the changes in fair value of these derivatives in earnings. However, with the approval of FAM, there would be no material earnings impact.

**Other**
Bangor Hydro and MPS have 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 BHE net earnings would have been $7.1 million ($4.2 million after-tax) higher in 2010 (2009 – $2.6 million or $1.6 million after-tax).

**Regulatory liabilities consist of:**

**2010 Renewable Tax Benefit Deferral**
In 2010, the UARB granted NSPI approval to defer certain tax benefits related to renewable energy projects arising in 2010. The UARB will convene a proceeding in 2011 to discuss how this deferral will be applied. Absent UARB approval, these benefits would not have been deferred and net earnings would be $14.5 million higher.

**Held-for-trading Natural Gas Contracts**
As discussed above, in accordance with NSPI's accounting policy for financial instruments and hedges relating to TUC fuel, NSPI has deferred any changes in fair value of its natural gas contracts to a regulatory asset or liability. Absent UARB approval, NSPI would be required to recognize the changes in fair value of these derivatives in earnings. However, with the approval of FAM, there would be no material earnings impact.

**Deferral of Tufts Cove Derivatives**
As discussed above, NSPI has an accounting policy that permits NSPI to defer the fair value of any TUC financial commodity hedges that are no longer required. Absent UARB approval, NSPI would be required to recognize the changes in fair value of these derivatives in earnings. However, with the approval of FAM, there would be no material earnings impact.

**Other**
Bangor Hydro and MPS have 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 net earnings would have been $1.7 million ($1.0 million after-tax) higher in 2010 (2009 – $0.3 million or $0.1 million after-tax).

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## 15. INTANGIBLES

Intangibles are comprised of the following:

| millions of dollars | | | **2010** |
|---|---|---|---|
| | Cost | Accumulated Amortization | Net Book Value |
| Transmission | **$74.1** | **$16.8** | **$57.3** |
| Distribution | **26.1** | **6.9** | **19.2** |
| Other | **41.5** | **14.5** | **27.0** |
| | **$141.7** | **$38.2** | **$103.5** |

| millions of dollars | | | 2009 |
|---|---|---|---|
| | Cost | Accumulated Amortization | Net Book Value |
| Transmission | $69.4 | $15.7 | $53.7 |
| Distribution | 23.4 | 6.6 | 16.8 |
| Other | 41.7 | 20.1 | 21.6 |
| | $134.5 | $42.4 | $92.1 |

Amortization expense for the year ended December 31, 2010 is $5.4 million (2009 – $4.6 million).

## 16. NET INVESTMENT IN DIRECT FINANCING LEASE

Brunswick Pipeline commenced service on July 16, 2009, transporting re-gasified LNG for Repsol Energy Canada under a 25 year firm service agreement. The agreement meets the definition of a direct financing capital lease for accounting purposes. The net investment in direct financing lease is the sum of the expected toll revenues, less the estimated operating costs on the pipeline shown net of unearned finance income. The unearned income is recognized in income over the life of the lease using a constant rate of interest equal to the internal rate of return on the lease.

| millions of dollars | **2010** | 2009 |
|---|---|---|
| Total minimum lease payments to be received | **$1,678.1** | $1,746.9 |
| Less: amounts representing estimated executory costs | **(258.7)** | (252.2) |
| Minimum lease payments receivable | **1,419.4** | 1,494.7 |
| Less: unearned finance lease income | **(931.2)** | (1,017.8) |
| Total net investment in direct financing lease | **$488.2** | $476.9 |

Future minimum lease payments to be received for the next five years:

| millions of dollars | For the year ended December 31 | | | | |
|---|---|---|---|---|---|
| | 2011 | 2012 | 2013 | 2014 | 2015 |
| Minimum lease payments to be received | $57.9 | $58.8 | $58.8 | $60.0 | $61.6 |
| Less: amounts representing estimated executory costs | 8.9 | 9.1 | 9.3 | 9.4 | 9.6 |
| Minimum lease payments receivable | $49.0 | $49.7 | $49.5 | $50.6 | $52.0 |

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## 17. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is comprised of the following:

| | | | **2010** |
|---|---|---|---|
| millions of dollars | Cost | Accumulated Depreciation | Net Book Value |
| Generation | | | |
| Thermal | **$1,965.1** | **$827.5** | **$1,137.6** |
| Diesel & Steam | **126.9** | **52.4** | **74.5** |
| Gas Turbines | **89.3** | **29.8** | **59.5** |
| Combustion Turbines | **83.5** | **17.6** | **65.9** |
| Hydroelectric | **474.0** | **154.4** | **319.6** |
| Wind Turbines | **219.7** | **2.5** | **217.2** |
| Transmission | **922.6** | **359.6** | **563.0** |
| Distribution | **1,601.2** | **800.2** | **801.0** |
| Other | **430.4** | **222.7** | **207.7** |
| Other, under capital lease | **6.8** | **2.1** | **4.7** |
| | **$5,919.5** | **$2,468.8** | **$3,450.7** |

| | | | 2009 |
|---|---|---|---|
| millions of dollars | Cost | Accumulated Depreciation | Net Book Value |
| Generation | | | |
| Thermal | $1,902.6 | $796.4 | $1,106.2 |
| Gas Turbines | 85.9 | 25.0 | 60.9 |
| Combustion Turbines | 78.8 | 20.4 | 58.4 |
| Hydroelectric | 454.8 | 148.9 | 305.9 |
| Wind Turbines | 2.1 | 0.7 | 1.4 |
| Transmission | 811.6 | 338.1 | 473.5 |
| Distribution | 1,418.0 | 714.8 | 703.2 |
| Other | 396.6 | 181.6 | 215.0 |
| Other, under capital lease | 10.7 | 1.5 | 9.2 |
| | $5,161.1 | $2,227.4 | $2,933.7 |

## 18. ACQUISITIONS

### Grand Bahama Power Company Limited

On December 22, 2010, Emera purchased a 50% interest in GBPC and an additional 10.7% interest in ICDU, owner of the remaining 50% interest in GBPC, for $88.1 million USD ($87.7 million CAD), bringing Emera's total ownership of GBPC to 80.4%. GBPC is an integrated utility with 19,000 customers and has 137 megawatts ("MW") of installed oil-fired capacity. The Grand Bahama Port Authority regulates the utility and has granted GBPC a licensed, regulated and exclusive franchise to produce, transmit, and distribute electricity on the island until 2054. There is a fuel pass through mechanism and flexible tariff adjustment policies to ensure that costs are recovered and a reasonable return earned.

The acquisition has been accounted for under the purchase method of accounting as Emera has determined it has control of GBPC through the combination of both direct and indirect interests. At December 31, 2010, the assets and liabilities of GBPC have been consolidated on Emera's balance sheet and there was no material earnings impact in 2010 related to this transaction. GBPC is included in the segments "Other" in Note 3 Segment Information. The following summarizes the transaction:

| **Preliminary purchase price allocation:** | millions of dollars |
|---|---|
| Net working capital | $4.0 |
| Property, plant and equipment | 96.8 |
| Goodwill | 34.2 |
| Long-term debt | (47.3) |
| Total net assets | $87.7 |

When Emera purchased its 50% interest in ICDU in September 2008, the transaction included goodwill of $15.2 million CAD. Also included in ICDU was inherent goodwill of $11.5 million CAD from when ICDU purchased its 50% interest in GBPC. As Emera now controls both companies and consolidates both GBPC and ICDU's assets and liabilities, all of the goodwill is now recognized in Emera.

The purchase price allocation has not yet been finalized as the Company has not completed the valuation of property, plant and equipment in GBPC and therefore the allocation of the purchase price has been estimated, and is subject to change.

The purchase price was funded with existing credit facilities.

**Maine & Maritimes Corporation**

On December 21, 2010, Emera purchased all of the outstanding shares of MAM for $80.4 million USD ($81.9 million CAD). MAM is the parent company of MPS, a regulated electric transmission and distribution utility serving approximately 36,000 electricity customers in northern Maine.

The acquisition has been accounted for under the purchase method of accounting as Emera has determined it has control of MAM. There was no material earnings impact in 2010 related to this transaction. MAM is included in the segments "Other" in Note 3 Segment Information. The following summarizes the transaction:

| **Purchase price allocation:** | millions of dollars |
|---|---|
| Net working capital | $1.3 |
| Property, plant and equipment | 69.4 |
| Regulatory and other assets | 34.5 |
| Goodwill | 35.9 |
| Regulatory and other liabilities | (36.2) |
| Long-term debt | (23.0) |
| Total net assets | $81.9 |

The purchase price allocation has not been finalized. A third party valuation of the assets was not performed because the fair value of the regulated assets are equal to their rate base since a regulated utility can only recover its cost/book value (i.e. rate base) plus a fair return.

The purchase price was funded with existing credit facilities.

**Barbados Light & Power Company Limited**

On May 11, 2010, Emera acquired a 38% interest in Light & Power Holdings Ltd. ("LPH"), the parent company of Barbados Light & Power Company Limited ("BLPC"), for $85 million USD. BLPC is the sole utility operator on the island of Barbados, serving approximately 120,000 customers. BLPC has three power generation stations with 239 MW of installed capacity. There is a fuel pass through mechanism to ensure costs are recovered and a reasonable return earned.

The acquisition has been accounted for as an equity investment, and accordingly, the investment was initially recorded at cost. Emera's pro-rata share of the results since acquisition have been included in the carrying value of the investment and consolidated statements of earnings. Any dividends received or receivable reduces the carrying value of the investment. The carrying value of the investment and equity earnings related to the investment as at December 31, 2010 were $90.2 million and $5.4 million respectively. LPH is included in the segment "Other" in Note 3 Segment Information. The purchase was financed with existing credit facilities.

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**Bayside Power LP**

On September 1, 2009, Emera's subsidiary, Emera Energy Inc., purchased 100% interest in the Bayside Power Limited Partnership ("Bayside") for $32.9 million cash consideration. Bayside owns a 260-megawatt gas-fired combined cycle electricity generating facility, built in 1999, and located in Saint John, New Brunswick. Bayside has a contract to 2021 to supply electricity for the months of November through March; and operates as a merchant facility, selling into the Maritimes and northeastern United States markets, for the balance of the year. Bayside can, at its sole option, extend the winter supply contract for an additional 5 years, through to March 31, 2026.

The acquisition has been accounted for under the purchase method of accounting as Emera Energy Inc. controls Bayside. Accordingly, the results of operations since the date of acquisition have been included in the consolidated statement of earnings. Bayside is included in the segment "Other" in Note 3 Segment Information.

The final fair value based on the purchase price allocation was as follows:

| | millions of dollars |
|---|---|
| Net working capital | $2.6 |
| Property, plant and equipment | 46.9 |
| Mark-to-market on long-term gas supply purchase contracts liability | (10.7) |
| Future income taxes liability | (5.9) |
| Total net assets | $32.9 |

The purchase price was funded with existing credit facilities.

## 19. INTEREST IN JOINT VENTURES

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

| millions of dollars | **2010** | 2009 |
|---|---|---|
| Current assets | **$10.6** | $7.8 |
| Non-current assets | **52.8** | 67.2 |
| | **$63.4** | $75.0 |
| | | |
| Current liabilities | **$8.6** | $13.5 |
| Non-current liabilities | **76.1** | 78.5 |
| | **$84.7** | $92.0 |
| | | |
| Revenues | **$28.1** | $53.4 |
| Expenses | **(27.2)** | (39.0) |
| Net earnings | **$0.9** | $14.4 |
| | | |
| Cash provided by operations | **$14.7** | $17.3 |
| Cash used in investing activities | **(1.6)** | (0.5) |
| Cash used in financing activities | **(12.6)** | (16.1) |
| Increase in cash | **$0.5** | $0.7 |

## 20. INTEREST IN JOINTLY CONTROLLED PROJECTS

In November 2009, NSPI signed a 20-year operating agreement with Renewable Energy Services Ltd. ("RESL") for operation of a 23.3 MW wind energy project at Point Tupper, Nova Scotia. NSPI will acquire and retain title to specific property, plant and equipment, which is less than 50% of the total project combined assets. Each company is entitled to its proportionate share of the net operating revenues based on the relative value of their assets.

NSPI has provided a guarantee for the indebtedness of RESL in connection with the project. The guarantee is up to a maximum of $25.4 million. NSPI holds a security interest in the assets of RESL, including the project assets.

Beginning August 2010, following the commencement of service, NSPI has recorded its share of the net operating revenues of the project. As at December 31, 2010, $25.4 million was included in "Property, plant and equipment" for NSPI's portion of the Point Tupper wind energy project. NSPI's share of the cash flows and the net earnings was immaterial for the year.

MPS is a party to a collaborative arrangement with Central Maine Power ("CMP") to develop the Maine Power Connection Project. The terms of the arrangement were established in the Joint Development Agreement, dated October 1, 2008. The cost of development activities, including acquisition of land in the transmission corridor and acquisition of necessary governmental and regulatory permits and approvals, are shared between MPS and CMP, with MPS paying 10% of such costs, and CMP 90%. MPS has deferred in "Other assets" $0.9 million of costs associated with the MPC project as of December 31, 2010.

## 21. GOODWILL

The change in goodwill is due to the following:

| millions of dollars | **2010** | 2009 |
|---|---|---|
| Balance, beginning of year | **$87.6** | $102.0 |
| Acquisitions | **95.6** | - |
| Change in foreign exchange rate | **(4.3)** | (14.4) |
| Balance, end of year | **$178.9** | $87.6 |

## 22. ASSET RETIREMENT OBLIGATIONS

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

The change in ARO is due to the following:

| millions of dollars | **2010** | 2009 |
|---|---|---|
| Balance, beginning of year | **$104.5** | $88.0 |
| Accretion included in depreciation expense | **3.6** | 3.4 |
| Accretion deferred to regulatory asset | **2.1** | 1.5 |
| Liabilities settled | **(1.2)** | (1.2) |
| Additions | **32.8** | 12.8 |
| Balance, end of year | **$141.8** | $104.5 |

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The key assumptions used to determine the ARO are as follows:

| Asset | Credit-adjusted risk-free rate | Estimated undiscounted future obligation (millions of dollars) | Expected settlement date |
|---|---|---|---|
| Thermal | 5.30% | $258.9 | 10 – 29 years |
| Hydro | 5.27% | 101.4 | 21 – 51 years |
| Wind | 5.21% | 45.5 | 13 – 20 years |
| Combustion turbines | 5.25% | 12.9 | 1 – 14 years |
| Transmission & distribution | 5.74% | 21.6 | 1 – 15 years |
| Pipeline | 3.80% | 11.0 | 39 years |
| | | $451.3 | |

Some of the Company's hydro, transmission and distribution assets may have additional ARO. 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 ARO cannot be made at this time.

Additionally, some of the Company's transmission and distribution assets may have conditional ARO, the fair value of which cannot be reasonably estimated as sufficient information does not exist to estimate the obligation. A liability will be recognized in the period in which sufficient information becomes available.

*Accounting for the impact of rate regulation:*

Any difference between the amount approved by the regulator of NSPI as depreciation expense and the amount that would have been calculated under the accounting standard for ARO is recognized as a regulatory asset in "Property, plant and equipment". In the absence of this deferral, net earnings for 2010 would be $2.1 million lower (2009 – $1.5 million).

## 23. SHORT-TERM DEBT

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

| millions of dollars | **2010** |
|---|---|
| Short-term discount notes bearing interest at prevailing market rates plus applicable fees, which on December 31, 2010, averaged 2.20% | **$176.3** |
| LIBOR loans bearing interest at prevailing market rates plus applicable fees, which on December 31, 2010, averaged 2.01%. | **19.1** |
| Advances, which when drawn upon against operating lines of credit, bear interest at the prime rate plus a bank spread, which on December 31, 2010, was 3.00% in Canada, 3.25% in the US and Bahamian prime of 5.50%. | **5.0** |
| Promissory note issued to Algonquin Power & Utilities Corp. | **27.7** |
| | **$228.1** |

| millions of dollars | 2009 |
|---|---|
| Short-term discount notes bearing interest at prevailing market rates plus applicable fees, which on December 31, 2009, averaged 0.35%. | $193.3 |
| LIBOR loans bearing interest at prevailing market rates plus applicable fees, which on December 31, 2009, averaged 0.88%. | 49.4 |
| Advances, which when drawn upon against operating lines of credit, bear interest at the prime rate plus a bank spread, which on December 31, 2009, was 2.25% in Canada and 3.25% in the US. | 29.9 |
| Promissory note issued to Algonquin Power & Utilities Corp. | 27.7 |
| | $300.3 |

This short-term debt is unsecured.

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## 24. LONG-TERM DEBT

Long-term debt includes the issuances detailed below. Medium-term notes and debentures are issued under trust indentures at fixed interest rates, and are unsecured unless noted below. Also included are certain 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 % 2010 | 2009 | Years of Maturity | Amount Outstanding 2010 | 2009 |
|---|---|---|---|---|---|
| **Emera** | | | | | |
| Bankers acceptances, LIBOR loans and advances (1) | **2.82** | 2.77 | 3 year renewal | **$250.0** | $221.6 |
| Medium-term notes | **4.45** | 4.45 | 2014 - 2019 | **475.1** | 475.0 |
| Capital lease obligations | **4.85** | 4.84 | Various | **2.5** | 3.6 |
| **NSPI** | | | | | |
| Medium-term notes (2) | **6.56** | 6.60 | 2011 - 2097 | **1,610.0** | 1,410.0 |
| Debentures | **9.75** | 9.75 | 2019 | **95.0** | 95.0 |
| Short-term discount notes (3) | **1.07** | - | 3 year renewal | **241.7** | - |
| Capital lease obligations | **6.30** | 3.89 | Various | **0.1** | 3.7 |
| **Bangor Hydro** | | | | | |
| (issued and payable in USD) | | | | | |
| LIBOR loans & demand loans (1) | **2.26** | - | 3 year renewal | **38.6** | - |
| General & refunding mortgage bonds – secured by property, plant and equipment | **9.74** | 9.74 | 2020 - 2022 | **49.7** | 52.3 |
| Senior unsecured notes | **5.66** | 5.64 | 2011 - 2017 | **105.8** | 116.1 |
| **Bear Swamp** | | | | | |
| (issued and payable in USD) | | | | | |
| Senior non-revolving credit facility secured by the assets of Bear Swamp | **1.44** | 1.00 | 2012 | **60.6** | 65.4 |
| **Maine and Maritimes** | | | | | |
| (issued and payable in USD) | | | | | |
| Maine Public Utility Financing Bank Bonds (4) | **0.32** | - | 2021 - 2025 | **22.4** | - |
| LIBOR loans | **1.38** | - | 2011 | **1.0** | - |
| Capital lease obligations | **7.85** | - | 2011 - 2012 | **0.1** | - |
| **GBPC** | | | | | |
| (issued and payable in Bahamian dollars) | | | | | |
| LIBOR loans | **5.96** | - | 2014 | **35.5** | - |
| Medium-term notes | **7.07** | - | 2020 - 2032 | **49.7** | - |
| | | | | **3,037.8** | 2,442.7 |
| Amount due within one year | | | | **(12.7)** | (108.1) |
| Unamortized debt financing costs | | | | **(18.2)** | (16.2) |
| | | | | **$3,006.9** | $2,318.4 |

(1) Bankers acceptances, LIBOR loans and advances are drawn against operating credit facilities which mature in 2013.
(2) Included in the medium-term notes above is an NSPI medium-term note of $40.0 million bearing interest at 8.50%, maturing in 2026, and is extendable until 2056 at the option of the holders.
(3) Short-term discount notes are backed by an operating credit facility which matures in 2013.
(4) The interest on these USD variable rate bonds is fixed through the MPS interest rate swaps. The 1996 Series bonds of $13.6 million, due in 2021, are fixed at 4.42%, while the 2000 Series bonds of $9.0 million, due in 2025, are fixed at 4.53%.

As at December 31, 2010, long-term debt and obligations under a capital lease are due as follows:

| millions of dollars | |
|---|---|
| Year of Maturity | |
| Three year renewable | $530.3 |
| 2011 | 12.7 |
| 2012 | 83.6 |
| 2013 | 305.0 |
| 2014 | 304.9 |
| 2015 | 74.7 |
| Greater than 5 years | 1,726.6 |
| | $3,037.8 |

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## 25. COMMON SHARES

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

| **Issued and outstanding:** | Millions of shares |
|---|---|
| December 31, 2008 | 112.21 |
| Issued for cash under purchase plans | 0.45 |
| Options exercised under senior management share option plan | 0.32 |
| December 31, 2009 | 112.98 |
| Issued for cash under purchase plans | 1.32 |
| Options exercised under senior management share option plan | 0.32 |
| December 31, 2010 | **114.62** |

As at December 31, 2010, there were 3.8 million (2009 – 4.1 million) common shares reserved for issuance under the senior management common share option plan, and 0.5 million (2009 – 0.7 million) common shares reserved for issuance under the employee common share purchase plan.

In February 2010, the Board of Directors approved a quarterly dividend increase to $0.2825 per common share effective May 3, 2010 and in September 2010 approved a further increase to $0.3250 effective November 1, 2010, reflecting an increase on an annualized basis to $1.30 per common share.

### DIVIDEND REINVESTMENT AND EMPLOYEE COMMON SHARE PURCHASE PLANS

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

Effective September 25, 2009, Emera changed its Common Shareholders Dividend Reinvestment and Share Purchase Plan (“the Plan”) to provide for a discount of up to 5% from the average market price of Emera’s common shares for common shares purchased in connection with the reinvestment of cash dividends under the Plan. The Board of Directors of Emera also decided that the discount would be 5% effective on and after the quarterly dividend payment on November 16, 2009, to shareholders of record on November 2, 2009.

### SHARE-BASED COMPENSATION PLAN

#### Common Share Option Plan

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

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

If, before the expiry of an option in accordance with its terms, the optionee ceases to be an eligible person due to retirement or termination for other than just cause, such option may, subject to the terms thereof and any other terms of the plan, be exercised at 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.

| | **2010** | | 2009 | |
|---|---|---|---|---|
| | Shares under option | Weighted average exercise price | Shares under option | Weighted average exercise price |
| Outstanding, beginning of year | **2,082,150** | **$19.99** | 2,197,725 | $19.39 |
| Granted | **389,378** | **24.49** | 375,000 | 21.99 |
| Exercised | **(325,450)** | **19.29** | (322,075) | 20.44 |
| Expired | **-** | **-** | (168,500) | 17.34 |
| Outstanding, end of year | **2,146,078** | **$21.02** | 2,082,150 | $19.99 |
| Exercisable, end of year | **1,256,550** | **$19.72** | 1,216,175 | $19.08 |

The weighted average contractual life of options outstanding at December 31, 2010 is 6.7 years (2009 – 6.6 years). The range of exercise prices for the options outstanding at December 31, 2010 is $13.70 to $31.02 (2009 – $13.70 to $22.59).

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:

| | **2010** | 2009 |
|---|---|---|
| Expected dividend yield | **4.55%** | 4.92% |
| Expected volatility | **14.00%** | 13.90% |
| Risk-free interest rate | **3.91%** | 4.00% |
| Expected life | **7 years** | 7 years |
| Weighted average grant date fair value | **$2.25** | $1.49 |

**Deferred Share Unit Plan and Performance Share Unit Plan**

The Company has deferred share unit (“DSU”) and performance share unit (“PSU”) (formerly restricted share unit) plans.

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

Under the executive and senior management DSU plan, each participant may elect to defer all or a percentage of their annual incentive award in the form of DSUs with the provision 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 average fifty day year-end stock closing share price of an Emera 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 average fifty day stock closing share price of an Emera common share. Payments are usually made in cash. At the sole discretion of the Management Resources and Compensation Committee (“MRCC”), payments may be made in the form of actual shares. Any participant who is a United

States taxpayer shall receive payment on the first business day following the six month anniversary of their termination.

Under the Directors' DSU plan on or after January 1, 2010, a United States taxpayer may elect one of several dates as the payment date for DSUs recorded in the participant's account provided such elections are made in accordance with the deadlines under the plan for deferral elections and provided the payment dated elected shall not be a date that falls after December 31 of the calendar year that begins immediately following the termination date.

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

PSUs are granted annually for three-year overlapping performance cycles. The 2010 PSUs were granted based on the average of Emera's stock closing price for the fifty trading days prior to December 31 of the prior year and multiplied by a dividend ratio factor of 1.15 and a discount factor of 1.191 for share price appreciation. Dividend equivalents are awarded and are used to purchase additional PSUs. The PSU value varies according to the Company's common share market price and corporate performance.

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

| | Employee DSUs Outstanding | Employee PSUs Outstanding | Director DSUs Outstanding |
|---|---|---|---|
| December 31, 2008 | 280,249 | 283,347 | 87,202 |
| Granted | 59,792 | 132,916 | 33,257 |
| Retirement, termination, disability & death | (53,987) | (4,620) | - |
| Payout | - | (73,925) | - |
| December 31, 2009 | 286,054 | 337,718 | 120,459 |
| Granted | 52,267 | 112,573 | 35,605 |
| Retirement, termination, disability & death | - | (4,370) | - |
| Payout | - | (83,660) | (20,668) |
| December 31, 2010 | 338,321 | 362,261 | 135,396 |

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 PSU 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, 2010, $12.2 million (2009 – $7.3 million) of compensation expense related to options granted, units issued, and shares purchased by employees was recognized in "Operating, maintenance and general expense".

## 26. PREFERRED SHARES

**Authorized:**
Unlimited number of First Preferred Shares, issuable in series.

| **Issued and outstanding:** | Millions of Shares | Preferred share capital millions of dollars |
|---|---|---|
| December 31, 2009 | - | - |
| Issuance of First Preferred Shares, Series A | 6.0 | $146.7 |
| December 31, 2010 | **6.0** | **$146.7** |

In June 2010, Emera issued six million 4.40% Cumulative Five-Year Rate Reset First Preferred Shares, Series A ("First Preferred Shares, Series A"). The $150 million First Preferred Shares, Series A were issued at $25.00 per share for net after-tax and transaction costs proceeds of $146.7 million.

As the First Preferred Shares, Series A are neither redeemable at the option of the shareholder nor have a mandatory redemption date, they are classified as equity and the associated dividends will be deducted on the consolidated statements of earnings immediately before arriving at “Net earnings applicable to common shares” and will be shown on the consolidated statement of equity as a deduction from retained earnings.

The First Preferred Shares, Series A are entitled to receive fixed cumulative preferred cash dividends in the amount of $1.10 per share per annum for each year up to and including May 15, 2015. For each five-year period after this date, the holders of First Preferred Shares, Series A are entitled to receive reset fixed cumulative preferred cash dividends. The reset annual dividends per share will be determined by multiplying the $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada Bond Yield on the applicable reset date plus 1.84%.

The holders of First Preferred Shares, Series A will have the right, at their option, to convert their shares into an equal number of Cumulative Floating Rate First Preferred Shares, Series B of the Company on August 15, 2015 and every five years thereafter.

The First Preferred Shares, Series B have the same characteristics as the Series A shares, with the exception of the calculation of the floating dividend rate for the Series B shares being the sum of the T-bill rate plus 1.84%.

The holders of the First Preferred Shares, Series B will have the right, at their option, to convert their shares into an equal number of Series A shares of the Company on August 15, 2020 and every five years thereafter.

On August 15, 2015 and August 15, 2020 respectively and on August 15 every five years thereafter, the Company has the right to redeem for cash the outstanding First Preferred Shares, Series A or B in whole or in part at a price of $25 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption.

## 27. SUPPLEMENTAL CASH FLOW INFORMATION

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

| millions of dollars | **2010** | 2009 |
|---|---|---|
| Decrease (increase) in accounts receivable | **$25.7** | $(95.6) |
| Decrease (increase) in inventory | **12.4** | (43.9) |
| Increase in prepaid expenses | **(2.0)** | (8.4) |
| Decrease in contract receivable | **-** | 56.4 |
| Change in posted margin included in accounts receivable | **15.6** | 56.9 |
| Increase in other accounts payable and accrued charges | **65.1** | 7.1 |
| Change in heavy fuel oil hedging balance in AOCI | **3.1** | (4.3) |
| Change in income tax payable/receivable | **(39.6)** | 6.1 |
| | **$80.3** | $(25.7) |

## 28. CAPITAL MANAGEMENT

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

| millions of dollars | **2010** | 2009 |
|---|---|---|
| Shareholders’ equity, excluding AOCI | **$1,938.3** | $1,692.6 |
| Debt | **3,247.7** | 2,726.8 |
| Preferred shares issued by subsidiary | **135.0** | 135.0 |
| Non-controlling interest related to Bangor Hydro | **0.5** | 0.5 |
| Non-controlling interest related to ICDU | **20.2** | 31.6 |
| Cash and cash equivalents | **(9.4)** | (21.8) |
| | **$5,332.3** | $4,564.7 |

The Company's objective when managing capital is to ensure sufficient liquidity exists by maintaining access to capital markets in order to allow the Company to acquire, build and maintain its regulated electric utilities, low risk unregulated generation and energy infrastructure businesses. The Company has a strategy of managing its capital structure through its various wholly-owned subsidiaries, while ensuring it is in compliance with its debt covenants. This strategy is managed by the Company through the issuance from time to time of common and preferred shares, bonds, medium-term notes, or other indebtedness.

Each of the Company's regulated utilities maintains a capital structure based on the structure that is approved by each utility's regulator and the capital structure is reflected in customer rates.

The Company's short and long-term debt agreements provide that the Company's consolidated debt cannot exceed 70% of the Company's capitalization.

## 29. FINANCIAL INSTRUMENTS

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

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

Financial instruments include the following:

| | | **2010** | | 2009 |
|---|---|---|---|---|
| millions of dollars | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| Cash and cash equivalents | **$9.4** | **$9.4** | $21.8 | $21.8 |
| Restricted cash | **59.6** | **59.6** | 1.0 | 1.0 |
| Accounts receivable | **396.5** | **396.5** | 413.1 | 413.1 |
| Derivatives held in a valid hedging relationship (current and long-term portion) | | | | |
| Cash flow hedges | **54.5** | **54.5** | 49.2 | 49.2 |
| Fair value hedges | **-** | **-** | 8.0 | 8.0 |
| Held-for-trading derivatives (current and long-term portion) | **37.4** | **37.4** | 43.8 | 43.8 |
| Total financial assets | **$557.4** | **$557.4** | $536.9 | $536.9 |
| | | | | |
| Accounts payable and accrued charges | **$399.6** | **$399.6** | $305.9 | $305.9 |
| Short-term debt | **228.1** | **228.1** | 300.3 | 300.3 |
| Derivatives held in a valid hedging relationship (current and long-term portion) | | | | |
| Cash flow hedges | **29.9** | **29.9** | 86.7 | 86.7 |
| Held-for-trading derivatives (current and long-term portion) | **49.1** | **49.1** | 34.4 | 34.4 |
| Long-term debt (including current portion) | **3,019.6** | **3,434.5** | 2,426.5 | 2,661.3 |
| Preferred shares issued by a subsidiary | **135.0** | **152.3** | 135.0 | 151.2 |
| Total financial liabilities | **$3,861.3** | **$4,293.5** | $3,288.8 | $3,539.8 |

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**Fair value hierarchy**

A fair value hierarchy is used to categorize valuation techniques used in the determination of fair value. Quoted market prices are Level 1, internal models using observable market information as inputs are Level 2, and internal models without observable market information as inputs are Level 3.

The fair value hierarchy of financial assets and liabilities accounted for at fair value at December 31, 2010 are as follows:

| millions of dollars | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| Financial assets: | | | | |
| Cash and cash equivalents | $9.4 | - | - | $9.4 |
| Restricted cash | 59.6 | - | - | 59.6 |
| Derivatives in a valid hedging relationship (current and long-term portion) | | | | |
| Cash flow hedges | 41.7 | $12.8 | - | 54.5 |
| Held-for-trading derivatives (current and long-term portion) | 1.5 | 14.6 | $21.3 | 37.4 |
| Total financial assets | $112.2 | $27.4 | $21.3 | $160.9 |
| | | | | |
| Financial liabilities: | | | | |
| Derivatives in a valid hedging relationship (current and long-term portion) | | | | |
| Cash flow hedges | $15.8 | $14.1 | - | $29.9 |
| Held-for-trading derivatives (current and long-term portion) | (0.4) | 10.5 | $39.0 | 49.1 |
| Preferred shares issued by subsidiary | - | 152.3 | - | 152.3 |
| Total financial liabilities | $15.4 | $176.9 | $39.0 | $231.3 |

Changes in the fair value of financial assets classified as Level 3 in fair value hierarchy of $108.5 million during the year ended December 31, 2010, were as follows:

| millions of dollars | Accounts receivable | Derivatives in a valid hedging relationship – Cash flow hedge | Held-for-trading derivatives | Total |
|---|---|---|---|---|
| Balance at January 1, 2010 | $82.1 | $1.5 | $46.2 | $129.8 |
| Total (loss) gain realized and unrealized | | | | |
| Included in earnings | (5.8) | - | (22.4) | (28.2) |
| Included in AOCI | - | - | - | - |
| Purchases, issuances, settlements | (76.3) | (1.5) | (0.7) | (78.5) |
| Transfer to Level 2 | - | - | (1.9) | (1.9) |
| Transfer to Held-for-trading | - | - | 0.1 | 0.1 |
| Balance at December 31, 2010 | - | - | $21.3 | $21.3 |

Changes in the fair value of financial liabilities classified as Level 3 in fair value hierarchy of $7.8 million during the year ended December 31, 2010, were as follows:

| millions of dollars | Derivatives in a valid hedging relationship – Cash flow hedge | Held-for-trading derivatives | Total |
|---|---|---|---|
| Balance at January 1, 2010 | $(2.1) | $(29.1) | $(31.2) |
| Total (loss) gain realized and unrealized | | | |
| Included in earnings | (0.8) | 2.2 | 1.4 |
| Included in AOCI | 11.3 | - | 11.3 |
| Purchases, issuances, settlements | (28.3) | 6.5 | (21.8) |
| Transfer from Level 2 | - | 1.3 | 1.3 |
| Transfer to Held-for-trading | 19.9 | (19.9) | - |
| Balance at December 31, 2010 | - | $(39.0) | $(39.0) |

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## ACCOUNTS RECEIVABLE AND ACCOUNTS PAYABLE AND ACCRUED CHARGES

The carrying value of accounts receivable, accounts payable and accrued charges is a reasonable approximation of fair value. Losses included in earnings and recorded in "Operating, maintenance and general expenses" are $3.8 million (2009 – $6.1 million).

The allowance for doubtful accounts was $5.6 million as at January 1, 2010 (2009 – $4.5 million) and $6.9 million as at December 31, 2010 (2009 – $5.6 million). Changes in the allowance were due to changes in the provision related to specific customers and to changes in mix and volume of accounts receivable.

## PREFERRED SHARES ISSUED BY A SUBSIDIARY, LONG-TERM DEBT AND SHORT-TERM DEBT

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

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

## DERIVATIVES IN VALID HEDGING RELATIONSHIPS

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

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

| millions of dollars | **2010** | 2009 |
|---|---|---|
| Financing income increase | **$7.7** | $2.8 |
| Fuel and purchased power increase | **(73.3)** | (46.3) |
| Financing charges decrease | **1.8** | $6.9 |
| Total losses | **$(63.8)** | $(36.6) |

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

| millions of dollars | **2010** | 2009 |
|---|---|---|
| Fuel and purchased power increase | **$(1.6)** | $(14.2) |
| Financing charges increase | **(0.1)** | - |
| Total losses | **$(1.7)** | $(14.2) |

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

| millions of dollars | **2010** | 2009 |
|---|---|---|
| Financing charges increase | **$(0.2)** | $(0.5) |
| Total losses | **$(0.2)** | $(0.5) |

The Company expects to reclassify $4.7 million of losses currently included in AOCI to net earnings over the next 12 months related to hedged items realized in net earnings.

### Interest Rates

The Company maintains a portfolio of debt instruments which includes short-term instruments and long-term instruments with staggered maturities. The Company uses diversification as a risk management strategy and deals with several counterparties so as to mitigate concentration risk.

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

The Company has two interest rate hedging contracts outstanding as at December 31, 2010. These interest rate hedging contracts are used to fix the variable interest rates on the two issues of Maine Public Utilities

Financing Bank bonds at MPS. MPS's obligation under these bonds totals $22.6 million USD, $13.6 million USD of which is fixed at 4.42%, and $9.0 million USD of which is fixed at 4.53%.

**Commodity Prices**

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

The Company enters into natural gas swap contracts to limit exposure to fluctuations in natural gas prices. As at December 31, 2010, the Company had hedged approximately 87% of all natural gas purchases and sales associated with its forecasted natural gas burn and resale for 2011, and 35% for 2012.

The Company enters into oil swap contracts to limit exposure to fluctuations in world prices of heavy fuel oil. For 2011 and 2012, NSPI currently does not have heavy fuel oil hedging requirements.

The Company enters into solid fuel swap contracts to limit exposure to fluctuations in world prices of solid fuel. As at December 31, 2010, the Company had hedged approximately 77% of all solid fuel purchases for 2011, 39% for 2012, 24% for 2013 and 9% for 2014.

The Company enters into power swaps to limit exposure to fluctuations in power prices. At December 31, 2010, the Company has hedged 103% of 2011 requirements, 95% of 2012 requirements, 95% of 2013 requirements and approximately 95% of the requirements for 2014.

**Foreign Exchange**

The Company enters into foreign exchange forward and swap contracts to limit exposure on foreign currency transactions such as fuel purchases, revenue streams and capital expenditures.

The risk due to fluctuation of the CAD against the USD for fuel purchases in NSPI is measured and managed. In 2011, NSPI expects approximately 60% of its anticipated net fuel costs to be denominated in USD. USD from sales of surplus natural gas will provide a natural hedge against a portion of USD fuel costs. Forward contracts to buy $225.5 million USD were in place at a weighted average rate of $0.99, representing 70% of 2011 anticipated USD requirements. Forward contracts to buy $443.0 million USD in 2012 through 2015 at a weighted average rate of $1.03 were in place at December 31, 2010. These contracts cover 31% of anticipated USD requirements in these years. As at December 31, 2010, there were no fuel-related foreign exchange swaps outstanding.

NSPI may use foreign exchange forward contracts to hedge the currency risk for capital projects and receivables denominated in foreign currencies. Forward contracts to buy €1.8 million are in place at a weighted average rate of $1.56 (versus CAD) for capital projects in 2011.

Brunswick Pipeline uses forward contracts to hedge the currency risk associated with revenue streams denominated in foreign currencies. Forward contracts to sell $52 million USD were in place in 2011 at an average rate of $1.07 and sell $63 million USD in 2012 through 2015 at a weighted average rate of $1.07. These contracts cover 91% of anticipated USD revenue inflows in 2011 and 27% of anticipated USD revenue inflows in 2012 through 2015.

**HELD-FOR-TRADING DERIVATIVES**

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

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

The Company has recognized the following realized and unrealized gains and losses with respect to HFT derivatives in earnings:

| millions of dollars | **2010** | 2009 |
|---|---|---|
| Electric revenue | **$4.4** | $0.6 |
| Other revenue | **1.8** | (5.7) |
| Fuel and purchased power | **(1.3)** | 12.4 |
| Financing charges | **-** | - |
| Held-for-trading derivative gains | **$4.9** | $7.3 |

**Energy marketing assets and liabilities**
On December 31, 2010, the Company held derivative financial and commodity instruments within its trading group.

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

**Derivatives not in valid hedging relationships**
On December 31, 2010, the Company held natural gas, power and oil derivatives, which were not in valid hedging relationships. This includes a certain swap in place to economically hedge the power necessary to produce the energy requirements of the long-term power supply agreement with the Long Island Power Authority, which is marked-to-market through earnings as it does not meet the stringent accounting requirements of hedge accounting.

## RISK MANAGEMENT

### Market Risk

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

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

As at December 31, 2010, the Company determined that market risk exposure associated with its financial instruments would affect the Company's financial results as follows:

| millions of dollars | Net earnings increase (decrease) | AOCI increase (decrease) |
|---|---|---|
| $1 per one million British Thermal Unit increase in the price of natural gas* | $4.4 | - |
| $5 per barrel increase in the price of heavy fuel oil | - | - |
| $15 per metric tonne increase in the price of coal | - | $29.8 |
| $0.01 decrease in the strength of the Canadian relative to the US dollar | - | 6.1 |
| 100 basis point increase in the central bank interest rates | 0.1 | - |
| $1 per megawatt hour increase in the price of power | (0.1) | 0.8 |

*NSPI fuel costs are recoverable through the FAM, thus the above amount is the impact on earnings not related to NSPI.

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

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**Interest Rate Risk**

Emera manages interest rate risk through a combination of fixed and floating borrowing and a hedging program. Floating-rate debt is estimated to represent approximately 20% of total debt in 2011 (2010 – 24%). The company had two interest rate hedging contracts outstanding as at December 31, 2010 (2009 – nil), fixing the variable interest rates on $22.6 million USD of Maine Public Utilities Financing Bank bonds at MPS.

**Credit risk**

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

As at December 31, 2010, the maximum exposure the Company has to credit risk is $488.4 million, which includes accounts receivable, assets related to derivatives in a valid hedging relationship, and held-for-trading derivatives.

The Company transacts with counterparties as part of its risk management strategy for managing commodity price, foreign exchange and interest rate risk. Counterparties that exceed established credit limits can provide a cash deposit or letter of credit to the Company for the value in excess of the credit limit where contractually required. The Company also obtains cash deposits from electric customers. The total cash deposits and letters of credit on hand as at December 31, 2010, was $17.5 million (2009 – $30.3 million), which mitigates the Company's maximum credit risk exposure. The Company uses the cash as payment for the amount receivable or returns the cash deposit to the counterparty where the credit limit is no longer exceeded or where the customer is no longer considered a high risk account.

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

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

As at December 31, 2010, the Company had $32.3 million (2009 – $34.6 million) in financial assets considered to be past due, which have been outstanding for an average of 70 days. The fair value of these financial assets is $29.8 million (2009 – $30.8 million), the difference of which is included in the allowance for doubtful accounts. These assets primarily relate to accounts receivable from electric revenue.

Emera

### Concentration risk

The Company's concentration of risks as at December 31, 2010, is as follows:

| | millions of dollars | % of total exposure |
|---|---|---|
| **Accounts receivable** | | |
| Regulated utilities | | |
| Residential | $121.2 | 24.8% |
| Commercial | 62.8 | 12.9 |
| Industrial | 38.8 | 8.0 |
| Other | 16.2 | 3.3 |
| | 239.0 | 49.0 |
| Trading group | | |
| Credit rating of A- or above | - | - |
| Credit rating of BBB- to BBB+ | 10.2 | 2.0 |
| Not rated | 28.1 | 5.8 |
| Fully collateralized | 82.4 | 16.9 |
| | 120.7 | 24.7 |
| Other accounts receivable | 36.8 | 7.5 |
| | 396.5 | 81.2 |
| **Derivatives** (in a valid hedging relationship and held-for-trading; current and long-term portions) | | |
| Credit rating of A- or above | 56.5 | 11.6 |
| Credit rating of BBB- to BBB+ | 11.8 | 2.4 |
| Not rated | 23.6 | 4.8 |
| | 91.9 | 18.8 |
| | 488.4 | 100.0% |

### Liquidity risk

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

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

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

The Company's financial instrument liabilities mature as follows:

| | **3 year renewable (1)** | **2011** | **2012** | **2013** | **2014** | **>2014** | **Total** |
|---|---|---|---|---|---|---|---|
| Accounts payable and accrued charges | - | $399.6 | - | - | - | - | $399.6 |
| Short-term debt | - | 228.1 | - | - | - | - | 228.1 |
| Long-term debt | $530.3 | 12.7 | $83.6 | $305.0 | $304.9 | $1,801.3 | 3,037.8 |
| Preferred shares issued by subsidiary | - | - | - | - | - | 135.0 | 135.0 |
| Derivatives held in a valid hedging relationship | | | | | | | |
| Cash flow hedge | - | 8.6 | 3.7 | 8.9 | 3.4 | 5.3 | 29.9 |
| Held-for-trading derivatives | - | 30.7 | 6.8 | 3.9 | 3.1 | 4.6 | 49.1 |
| Total financial liabilities | $530.3 | $679.7 | $94.1 | $317.8 | $311.4 | $1,946.2 | $3,879.5 |

(1) Bankers acceptances, LIBOR loans and advances are drawn against operating credit facilities which mature in 2013.

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The Company has available the following credit facilities as at December 31, 2010, for the management of liquidity risk:

| millions of dollars | Maturity | Credit Line Committed | Utilized | Undrawn and Available |
|---|---|---|---|---|
| Emera – Operating and acquisition credit facility | June 2013 – Revolver | $600 | $406 | $194 |
| NSPI – Operating credit facility | June 2013 – Revolver | 600 | 289 | 311 |
| Bangor Hydro – in USD – Operating credit facility | September 2013 – Revolver | 80 | 42 | 38 |
| Other – in USD – Operating credit facilities | Various | 18 | 3 | 15 |

**AVAILABLE-FOR-SALE INVESTMENTS**

Available-for-sale investments include the Company's investment in OpenHydro Group Limited ("OpenHydro") and Algonquin Power & Utilities Corp. The investments are recognized at their cost of $47.0 million. The fair value of these investments have not been recognized or disclosed because the shares and subscription receipts are not actively traded in an open market. The Company does not intend to dispose of the investment in OpenHydro in the near term. The market for any disposition of OpenHydro shares would be with an existing shareholder or a new private investor.

## 30. RELATED PARTY TRANSACTIONS

In the ordinary course of business, Emera purchased natural gas transportation capacity totaling $55.1 million (2009 – $47.4 million) during the year ended December 31, 2010, 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, 2010, the amount payable to the related party is $3.9 million (2009 – $4.6 million), is non-interest bearing and is under normal credit terms.

## 31. CONTINGENCIES

A number of individuals who live in proximity to NSPI's Trenton generating station have filed a statement of claim against NSPI in respect of emissions from the operation of the plant for the period 2001 forward. The Company has filed a defence to the claim. The plaintiffs claim unspecified damages as a result of interference with enjoyment of, or damage to, their property and adverse health effects they allege were caused by such emissions. The outcome, and therefore an estimate of any contingent loss, of this litigation are not determinable.

Bangor Hydro has a potential liability to Great Lake Hydro America LLC for headwater benefits on the Penobscot River in connection with hydro assets sold to PPL Generation, LLC in 1999. On May 25, 2010, a FERC Administrative Law Judge issued an initial decision ruling that a May 7, 1999 Release was a valid and enforceable release of liability for headwater benefits received by Bangor Hydro prior to May 7, 1999. The initial decision became final on July 7, 2010, by operation of FERC rules. Any liability of Bangor Hydro for pre-May 1999 headwater benefits that may not be covered by the Release and for the period after the Release, but prior to the PPL sale, is immaterial.

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

## 32. COMMITMENTS

In addition to commitments outlined elsewhere in these notes, the Company had the following significant commitments at December 31, 2010:

**Emera**

- The Company has a commitment to purchase approximately 43,000 mmbtu per day of transportation capacity on the US portion of the Maritimes & Northeast Pipeline, a related party, for the next two years, at an approximate average cost of $9 million per year.
- The Company has a commitment to purchase 10,000 mmbtu per day of transportation capacity on the US portion of the Maritimes & Northeast Pipeline, a related party, from Q2 2013 until Q1 2016, at an approximate average cost of $2 million per year.
- Bayside has a commitment to purchase approximately 36,500 mmbtu of natural gas per day until November 2015 and an additional 7,000 mmbtu per day until December 2012.
- Bayside has a commitment to March 31, 2021 to supply approximately 900 GWh of electricity annually for the months of November through March.
- Bayside has a commitment to purchase approximately 43,500 mmbtu per day of transportation capacity on the Canadian portion of the Maritimes & Northeast Pipeline, a related party, until 2015, at an approximate average cost of $12 million per year.

**NSPI**

- NSPI has an annual requirement to purchase approximately 650 GWh of electricity from independent power producers over varying contract lengths up to 40 years.
- NSPI has requirements to purchase approximately 15,000 mmbtu of natural gas per day for 22 months; an average of 13,000 mmbtu per day for 28 months; 14,000 mmbtu per day for 10 months and 20,000 mmbtu for two years starting in November 2011.
- NSPI has commitments to purchase 4,000 mmbtu per day of transportation capacity on the Maritimes and Northeast Pipeline, a related party, for 10 months, 15,000 mmbtu for 22 months, and an average of 13,000 mmbtu for 28 months. These have an approximate cost of $17.6 million through 2013.
- NSPI has the responsibility for managing a portfolio of approximately $1.0 billion of defeasance securities held in trust. The defeasance securities must provide the principal and interest payment streams of the related defeased debt. Approximately 73% or $726 million of the defeasance portfolio consists of investments in the related debt, eliminating all risk associated with this portion of the portfolio.
- NSPI has a commitment to a third party for the unloading and transportation of solid fuel for ten years beginning in late 2002 at an approximate cost of $16.0 million per year.
- NSPI has commitments to third parties for the handling and transportation of solid fuel for $7 million in 2011 and $4 million per year from 2012 to 2014.
- NSPI has commitments to third parties for 2011 to 2014, to purchase and transport 3.8 million metric tons ("mts") of import coal, 1.7 million mts of domestic coal and 3.2 million mts of marine freight.
- NSPI has commitments to third parties for construction on capital project in 2011 and 2012 at an approximate cost of $91 million and to purchase other goods and services in 2011 and 2012 at an approximate cost of $19 million.

**Bangor Hydro**

- Bangor Hydro has various contract commitments to purchase annually, net of resale revenues, approximately $10 million USD to $12 million USD of electricity for the period from 2011 to 2018 from independent power producers. These commitments are reduced to less than $2 million USD each year from 2019 to 2026.

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## 33. GUARANTEES

Emera had the following guarantees at December 31, 2010:

- The Company issued letters of credit totaling $55.7 million, which generally expire annually unless renewed. These letters of credit secure payment to various vendors, the obligations of NSPI and Bangor Hydro under their unfunded pension plans, and in the case of MPS, secure the Maine Public Utility Financing Bank bonds principal and interest.
- NSPI has provided a guarantee for the indebtedness of a third party, up to a maximum of $23.5 million, related to future purchased power. NSPI holds a security interest in the assets of the third party.

## 34. ECONOMIC DEPENDENCE

One of the company's subsidiaries, Brunswick Pipeline, has an agreement through 2034 for the sale of its product to one customer. For the year ended December 31, 2010, this customer accounted for 13.7% of the consolidated net earnings (2009 – 8.0%).

## 35. SUBSEQUENT EVENTS

On January 1, 2011, Emera and APUC announced the closing of their acquisition of the California-based electricity distribution and related generation assets of NV Energy, Inc. Total consideration for this transaction is $131.8 million USD, subject to final adjustments. APUC and Emera own respectively a 50.001% and 49.999% interest in California Pacific Utility Ventures, LLC ("CPUV"), which wholly-owns the California-based assets. Also, as an element of the transaction, Emera exchanged certain previously announced subscription receipts into 8.523 million APUC common shares.

On January 25, 2011, subsequent to the offer made on December 20, 2010 to purchase all issued and outstanding common shares from LPH shareholders, Emera purchased 7.2 million shares of LPH at a cash price per share of $25.70 Barbadian dollars representing an additional interest of 41.6%. With this additional investment of $91.9 million CAD, Emera became the majority shareholder of LPH, with a total interest of 79.9%.

## 36. COMPARATIVE INFORMATION

Certain of the comparative figures have been reclassified to conform to the financial statement presentation adopted for 2010.

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## OPERATING STATISTICS (Unaudited)
## FIVE-YEAR SUMMARY

| Year Ended December 31 | **2010** | 2009 | 2008 | 2007 | 2006 |
|---|---|---|---|---|---|
| Electric energy sales (GWh) | | | | | |
| Residential | **4,738.2** | 4,819.2 | 4,769.6 | 4,738.5 | 4,516.0 |
| Commercial | **5,584.4** | 3,694.4 | 3,721.1 | 3,768.5 | 3,621.1 |
| Industrial | **4,268.2** | 3,985.3 | 4,491.5 | 4,568.4 | 3,246.7 |
| Other | **1,117.1** | 1,636.9 | 1,115.2 | 1,320.4 | 1,550.8 |
| Total electric energy sales | **15,707.9** | 14,135.8 | 14,097.4 | 14,395.8 | 12,934.6 |
| Sources of energy (GWh) | | | | | |
| Thermal – coal | **7,838.7** | 8,177.3 | 9,008.9 | 9,561.4 | 9,128.1 |
| – oil | **36.1** | 306.9 | 340.7 | 516.6 | 431.9 |
| – natural gas | **4,183.0** | 2,141.4 | 1,257.9 | 1,057.1 | 390.3 |
| Hydro | **1,023.5** | 1,101.4 | 1,102.3 | 936.8 | 1,034.7 |
| Wind | **25.3** | 1.8 | 2.4 | 2.4 | 2.4 |
| Purchases | **3,633.4** | 3,444.1 | 3,493.2 | 3,534.7 | 3,144.7 |
| Total generation and purchases | **16,740.0** | 15,172.9 | 15,205.4 | 15,609.0 | 14,132.1 |
| Losses and internal use | **1,032.1** | 1,037.1 | 1,108.0 | 1,213.2 | 1,197.5 |
| Total electric energy sold | **15,707.9** | 14,135.8 | 14,097.4 | 14,395.8 | 12,934.6 |
| Electric customers | | | | | |
| Residential | **588,935** | 539,333 | 535,494 | 530,955 | 526,014 |
| Commercial | **61,620** | 51,768 | 54,461 | 51,083 | 50,780 |
| Industrial | **2,558** | 2,543 | 2,541 | 2,543 | 2,526 |
| Other | **9,422** | 9,155 | 9,064 | 9,574 | 9,378 |
| Total electric customers | **662,535** | 602,799 | 601,560 | 594,155 | 588,698 |
| Capacity | | | | | |
| Generating nameplate capacity (MW) | | | | | |
| Coal fired | **1,243** | 1,243 | 1,243 | 1,243 | 1,243 |
| Dual fired | **350** | 350 | 365 | 350 | 350 |
| Gas turbines | **614** | 579 | 304 | 319 | 323 |
| Hydroelectric | **995** | 995 | 1,005 | 1,005 | 1,005 |
| Wind turbines | **76** | 1 | 1 | 1 | 1 |
| Diesel | **46** | - | - | - | - |
| Steam | **51** | - | - | - | - |
| Independent power producers | **347** | 172 | 120 | 120 | 120 |
| | **3,722** | 3,340 | 3,038 | 3,038 | 3,042 |
| Total number of employees | **2,972** | 2,350 | 2,215 | 2,194 | 2,149 |
| km of transmission lines | **6,700** | 6,300 | 6,100 | 6,200 | 6,100 |
| km of distribution lines | **40,900** | 33,800 | 33,000 | 32,000 | 32,000 |

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## FIVE YEAR SUMMARY (Unaudited)

| Year Ended December 31 (millions of dollars) | **2010** | 2009 | 2008 | 2007 | 2006 |
|---|---|---|---|---|---|
| **Statements of Earnings Information** | | | | | |
| Revenue | **$1,553.7** | $1,483.5 | $1,331.9 | $1,339.5 | $1,166.0 |
| Cost of operations | | | | | |
| Fuel for generation and purchased power | **718.7** | 583.5 | 525.1 | 494.5 | 347.7 |
| Fuel adjustment | **(99.0)** | 8.5 | - | - | - |
| Operating, maintenance and general | **336.1** | 294.4 | 266.8 | 264.8 | 255.6 |
| Provincial, state and municipal taxes | **49.1** | 49.9 | 49.4 | 47.5 | 48.0 |
| Depreciation and amortization | **173.6** | 164.9 | 151.3 | 149.3 | 145.2 |
| Regulatory amortization | **41.3** | 35.7 | 28.5 | 31.4 | 22.8 |
| | **1,219.8** | 1,136.9 | 1,021.1 | 987.5 | 819.3 |
| | **333.9** | 346.6 | 310.8 | 352.0 | 346.7 |
| Equity earnings | **13.6** | 14.0 | 15.2 | 12.8 | 4.9 |
| Other income | **-** | - | - | - | 8.9 |
| Financing charges | **168.4** | 135.3 | 123.2 | 133.2 | 148.1 |
| Earnings before income taxes | **179.1** | 225.3 | 202.8 | 231.6 | 212.4 |
| Income taxes | **(12.8)** | 48.9 | 58.1 | 80.3 | 86.6 |
| Net earnings before non-controlling interest | **191.9** | 176.4 | 144.7 | 151.3 | 125.8 |
| Non-controlling interest | **(2.3)** | 0.7 | 0.6 | - | - |
| Net earnings | **194.2** | 175.7 | 144.1 | 151.3 | 125.8 |
| Preferred share dividends | **3.1** | - | - | - | - |
| Net earnings applicable to common shares | **191.1** | 175.7 | 144.1 | 151.3 | 125.8 |
| Dividends on common and preferred shares | **135.1** | 115.8 | 107.9 | 99.9 | 98.3 |
| Dividends paid by subsidiaries to non-controlling interest | **-** | - | 1.9 | - | - |
| Earnings retained for use in the Company | **$56.0** | $59.9 | $34.3 | $51.4 | $27.5 |
| Cost of fuel for generation – coal | **$327.0** | 293.9 | $282.1 | $276.0 | $266.2 |
| – oil | **12.2** | 5.4 | 17.7 | 49.7 | 34.3 |
| – natural gas | **169.3** | 138.5 | 92.5 | 52.0 | (41.6) |
| Purchased power | **210.2** | 145.7 | 132.8 | 116.8 | 88.8 |
| Total cost of fuel for generation and purchased power | **$718.7** | $583.5 | $525.1 | $494.5 | $347.7 |
| **Balance Sheets Information** | | | | | |
| Current assets | **$782.5** | $714.9 | $681.8 | $567.0 | $491.3 |
| Other assets * | **932.3** | 628.3 | 793.8 | 600.4 | 577.3 |
| Intangibles | **103.5** | 92.1 | 101.8 | 83.8 | 92.1 |
| Investments subject to significant influence | **238.9** | 218.4 | 317.6 | 124.5 | 98.5 |
| Net investment in direct financing lease | **488.2** | 476.9 | - | - | - |
| Property, plant and equipment and construction work in progress | **3,783.7** | 3,153.9 | 3,374.4 | 2,845.4 | 2,789.8 |
| Total assets | **$6,329.1** | $5,284.5 | $5,269.4 | $4,221.1 | $4,049.0 |
| Current liabilities | **$690.3** | $804.9 | $880.1 | $506.6 | $491.0 |
| Other liabilities * | **702.6** | 488.2 | 509.3 | 417.7 | 231.8 |
| Long-term debt | **3,006.9** | 2,318.4 | 2,159.2 | 1,676.4 | 1,657.4 |
| Preferred shares issued by subsidiary | **135.0** | 135.0 | 135.0 | 260.0 | 260.0 |
| Non-controlling interest | **20.7** | 32.1 | 39.6 | 0.6 | 0.7 |
| Common shares | **1,136.5** | 1,096.7 | 1,081.4 | 1,066.2 | 1,055.2 |
| Preferred shares | **146.7** | - | - | - | - |
| Contributed surplus | **3.7** | 3.6 | 3.4 | 3.0 | 2.2 |
| Accumulated other comprehensive loss | **(164.7)** | (186.7) | (69.2) | (209.0) | (100.2) |
| Retained earnings | **651.4** | 592.3 | 530.6 | 499.6 | 450.9 |
| Total equity and liabilities | **$6,329.1** | $5,284.5 | $5,269.4 | $4,221.1 | $4,049.0 |
| **Statements of Cash Flow Information** | | | | | |
| Cash provided by operating activities | **$416.4** | $310.2 | $237.2 | $351.4 | $332.5 |
| Cash used in investing activities | **$894.8** | $367.2 | $671.6 | $288.9 | $196.9 |
| Cash provided by (used in) financing activities | **$466.2** | $70.5 | $420.2 | $(55.6) | $(143.4) |
| **Financial ratios ($ per common share)** | | | | | |
| Earnings per common share | **$1.68** | $1.56 | $1.29 | $1.36 | $1.14 |

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

# Financial Statements

## Nova Scotia Power Inc.
## Statement of Earnings (Regulated)

| **For the** | Three months ended | | | | Twelve months ended | | | |
|---|---|---|---|---|---|---|---|---|
| millions of dollars | December 31 | | | | December 31 | | | |
| | ***Actual 2010*** | *Budget 2010* | *Test Year 2009* | *Prior Year 2009* | ***Actual 2010*** | *Budget 2010* | *Test Year 2009* | *Prior Year 2009* |
| Revenue | | | | | | | | |
| Electric | **$ 296.4** | [redacted] | $ 318.7 | $ 302.9 | **$ 1,167.3** | [redacted] | $ 1,241.3 | $ 1,188.1 |
| Other | **4.7** | | 3.5 | 4.0 | **15.2** | | 14.2 | 14.0 |
| | **301.1** | | 322.2 | 306.9 | **1,182.5** | | 1,255.5 | 1,202.1 |
| Cost of operations | | | | | | | | |
| Fuel for generation and purchased power | **147.0** | | 144.0 | 138.5 | **587.0** | | 545.0 | 500.4 |
| Fuel adjustment | **(26.3)** | | - | (9.3) | **(102.7)** | | - | 13.5 |
| Operating, maintenance, and general | **63.1** | | 54.3 | 55.3 | **229.5** | | 216.7 | 207.1 |
| Provincial grants and taxes | **10.1** | | 10.0 | 10.0 | **40.1** | | 40.1 | 40.5 |
| Depreciation and amortization | **39.9** | | 37.0 | 36.7 | **150.5** | | 145.0 | 143.5 |
| Regulatory amortization | **29.2** | | 4.6 | 14.7 | **42.4** | | 18.3 | 27.2 |
| | **263.0** | | 249.9 | 245.9 | **946.8** | | 965.1 | 932.2 |
| Earnings before financing charges and income taxes | **38.1** | | 72.3 | 61.0 | **235.7** | | 290.4 | 269.9 |
| Financing charges | **32.8** | | 31.7 | 33.3 | **125.7** | | 126.2 | 114.5 |
| Earnings before income taxes | **5.3** | | 40.6 | 27.7 | **110.0** | | 164.2 | 155.4 |
| Income taxes | **(11.9)** | | 15.2 | 9.2 | **(11.3)** | | 64.7 | 43.6 |
| Net earnings | **17.2** | | 25.4 | 18.5 | **121.3** | | 99.5 | 111.8 |
| 2009 ROE settlement (AAA-2) | **5.5** | | - | - | **5.5** | | - | - |
| Net earnings applicable to common shares | **$ 22.7** | | $ 25.4 | $ 18.5 | **$ 126.8** | | $ 99.5 | $ 111.8 |

## Balance Sheet (Regulated)

| **As at** | **December 31** | *December 31* |
|---|---|---|
| Millions of dollars | ***2010*** | *2009* |
| **Assets** | | |
| Current assets | | |
| Cash | **$0.3** | $0.3 |
| Accounts receivable | **192.5** | 271.8 |
| Due from associated companies | **76.0** | 62.5 |
| Income tax receivable | **40.6** | - |
| Inventory | **154.2** | 165.6 |
| Prepaid expenses | **6.1** | 7.0 |
| Future income tax assets | **1.7** | 34.4 |
| Derivatives in a valid hedging relationship | **24.7** | 19.4 |
| Held-for-trading derivatives | **6.3** | 8.9 |
| | **502.4** | 569.9 |
| Derivatives in a valid hedging relationship | **20.8** | 29.8 |
| Held-for-trading derivatives | **8.2** | 6.2 |
| Other assets | **512.8** | 339.1 |
| Intangibles | **72.5** | 65.7 |
| Property, plant, and equipment | **2,661.7** | 2,358.0 |
| Construction work in progress | **272.2** | 150.0 |
| | **2,933.9** | 2,508.0 |
| | **$4,050.6** | $3,518.7 |

| | **December 31** | *December 31* |
|---|---|---|
| | ***2010*** | *2009* |
| **Liabilities and Shareholders' Equity** | | |
| Current liabilities | | |
| Current portion of long-term debt | **$0.1** | $100.7 |
| Short-term debt | **48.3** | 199.5 |
| Accounts payable and accrued charges | **221.3** | 213.9 |
| Due to associated companies | **5.1** | 0.7 |
| Income tax payable | **-** | 1.2 |
| Dividends payable | **1.7** | 1.7 |
| Derivatives in a valid hedging relationship | **2.2** | 53.0 |
| Held-for-trading derivatives | **20.8** | 12.2 |
| | **299.5** | 582.9 |
| Derivatives in a valid hedging relationship | **9.4** | 20.0 |
| Held-for-trading derivatives | **1.8** | 1.3 |
| Future income tax liabilities | **164.8** | 52.0 |
| Asset retirement obligations | **138.7** | 101.5 |
| Other liabilities | **98.6** | 91.5 |
| Long-term debt | **1,933.7** | 1,397.0 |
| Preferred shares | **135.0** | 135.0 |
| Shareholders' equity | | |
| Common shares | **984.7** | 934.7 |
| Accumulated other comprehensive income (loss) | **10.8** | (44.0) |
| Retained earnings | **273.6** | 246.8 |
| | **1,269.1** | 1,137.5 |
| | **$4,050.6** | $3,518.7 |

| millions of dollars | Actual 2010 | [redacted] | Three months ended December 31 Test Year 2009 | Three months ended December 31 Prior Year 2009 | Actual 2010 | [redacted] | Twelve months ended December 31 Test Year 2009 | Twelve months ended December 31 Prior Year 2009 |
|---|---|---|---|---|---|---|---|---|
| **Residential** | **$ 137.1** | | $ 141.9 | $ 140.4 | **$ 531.0** | | $ 542.8 | $ 547.3 |
| **Commercial** | | | | | | | | |
| Small General | **7.7** | | 8.8 | 8.0 | **30.3** | | 33.6 | 31.3 |
| General | **65.6** | | 70.3 | 67.3 | **258.8** | | 276.6 | 265.5 |
| Large General | **8.8** | | 9.3 | 8.9 | **36.2** | | 38.0 | 37.1 |
| **Total Commercial** | **82.1** | | 88.4 | 84.2 | **325.3** | | 348.2 | 333.9 |
| **Industrial** | | | | | | | | |
| Small Industrial | **6.2** | | 6.6 | 6.2 | **25.7** | | 26.1 | 25.9 |
| Medium Industrial | **11.4** | | 13.6 | 11.8 | **44.0** | | 53.2 | 46.0 |
| Large Industrial | **17.1** | | 17.7 | 17.2 | **68.0** | | 71.1 | 69.8 |
| Extra large industrial 2P-RTP | **26.4** | | 32.9 | 30.5 | **111.3** | | 130.3 | 105.4 |
| GRLF | **0.1** | | 0.4 | 0.1 | **1.2** | | 1.1 | 0.6 |
| Mersey | **4.8** | | 5.3 | 1.5 | **19.1** | | 21.1 | 16.1 |
| **Total Industrial** | **66.0** | | 76.5 | 67.3 | **269.3** | | 302.9 | 263.8 |
| **Other** | | | | | | | | |
| Municipal | **4.4** | | 4.5 | 4.5 | **16.8** | | 17.6 | 17.6 |
| Unmetered | **6.5** | | 6.8 | 6.5 | **24.3** | | 25.2 | 24.6 |
| **Total Other** | **10.9** | | 11.3 | 11.0 | **41.1** | | 42.8 | 42.2 |
| **Total In-Province Electric Revenue** | **$ 296.1** | | $ 318.1 | $ 302.9 | **$ 1,166.7** | | $ 1,236.7 | $ 1,187.2 |
| **Export Revenue** | **0.3** | | 0.6 | 0.0 | **0.6** | | 4.6 | 0.9 |
| **Total Electric Revenue** | **$ 296.4** | | $ 318.7 | $ 302.9 | **$ 1,167.3** | | $ 1,241.3 | $ 1,188.1 |

## Operating, Maintenance and General (Regulated)

| **For the** millions of dollars | | | Three months ended December 31 | | | | Twelve months ended December 31 | |
|---|---|---|---|---|---|---|---|---|
| | ***Actual 2010*** | [redacted] | *Test Year 2009* | *Prior Year 2009* | ***Actual 2010*** | [redacted] | *Test Year 2009* | *Prior Year 2009* |
| Corporate Groups | **$ 12.6** | [redacted] | $ 11.3 | $ 12.3 | **$ 47.4** | [redacted] | $ 44.8 | $ 43.8 |
| Power Production | **26.2** | [redacted] | 22.2 | 25.4 | **94.2** | [redacted] | 88.8 | 85.1 |
| Technical & Construction | **3.4** | [redacted] | 0.8 | 3.1 | **11.7** | [redacted] | 3.5 | 9.1 |
| Customer Operations | **19.7** | [redacted] | 16.7 | 17.4 | **72.6** | [redacted] | 66.6 | 62.5 |
| Customer Service | **8.1** | [redacted] | 7.7 | 8.7 | **34.4** | [redacted] | 30.7 | 29.8 |
| Corporate Adjustments | **(6.9)** | [redacted] | (4.4) | (11.6) | **(30.8)** | [redacted] | (17.7) | (23.2) |
| **Total Operating, Maintenance and General** | **$ 63.1** | [redacted] | $ 54.3 | $ 55.3 | **$ 229.5** | [redacted] | $ 216.7 | $ 207.1 |

## Summary of Unregulated Adjustments

| As at<br>Millions of dollars | December 31<br>2010 |
|---|---|

**Unregulated Retained Earnings**

| | |
|---|---|
| Unregulated retained earnings - December 31, 2009 | $52.1 |
| Donations and sponsorships | 1.5 |
| Director share units /Restricted share units | 2.9 |
| Management fees | 0.8 |
| Unregulated portion of management incentive | 2.6 |
| New Page natural gas (gain) loss | (0.3) |
| FAM Incentive | 3.7 |
| Depreciation expense, unregulated assets | 0.3 |
| Other | 0.1 |
| Income taxes, unregulated adjustments | (6.1) |
| Subtotal | 5.5 |
| **Unregulated retained earnings - December 31, 2010** | **$57.6** |

**Unregulated Property, Plant and Equipment & Construction Work in Progress**

| | |
|---|---|
| Kentville Electric Purchase Price Discrepancy | $2.3 |
| Combustion Turbine Purchase Price Discrepancy | 4.0 |
| Unregulated Land | 1.0 |
| Unregulated portion of Lower Water Street | 4.2 |
| Burnside Natural Gas Conversion Project | 2.8 |
| **Total** | **$14.3** |

**Unregulated Future Income Tax**

| | |
|---|---|
| Decrease to future income tax assets related to unregulated expenditures | $2.4 |
| Increase to future income tax liabilities related to unregulated expenditures | 1.7 |
| **Total Unregulated Future Income Tax** | **$4.1** |

**Unregulated Due from Associated Companies**

| | |
|---|---|
| Effect of unregulated adjustments | **$76.0** |

## Regulated Return on Equity December 31, 2010

Millions of dollars

| *As of* | Regulated Equity | Regulated Capitalization |
|---|---|---|
| December 31, 2009 | $1,181.5 | $2,951.2 |
| March 31, 2010 | 1,244.9 | 3,082.3 |
| June 30, 2010 | 1,311.0 | 3,199.5 |
| September 30, 2010 | 1,335.7 | 3,261.5 |
| December 31, 2010 | 1,258.3 | 3,299.5 |
| Total | $6,331.4 | $15,794.0 |
| **Average (Five Quarters)** | **$1,266.3** | **$3,158.8** |
| **Average Common Equity (Five Quarters)** | | **40.1%** |
| **Average Common Equity adjusted to a deemed equity of 40%** | **$1,263.5** | |
| **Regulated Net Earnings - December 31, 2010** | **$121.3** | |
| **Regulated ROE (Regulated Net Earnings/Average Regulated Common Equity adjusted to 40%)** | **9.6%** | |

*Regulated Return on Equity is calculated at year-end and included in the fourth quarter and annual regulated financial statements.*

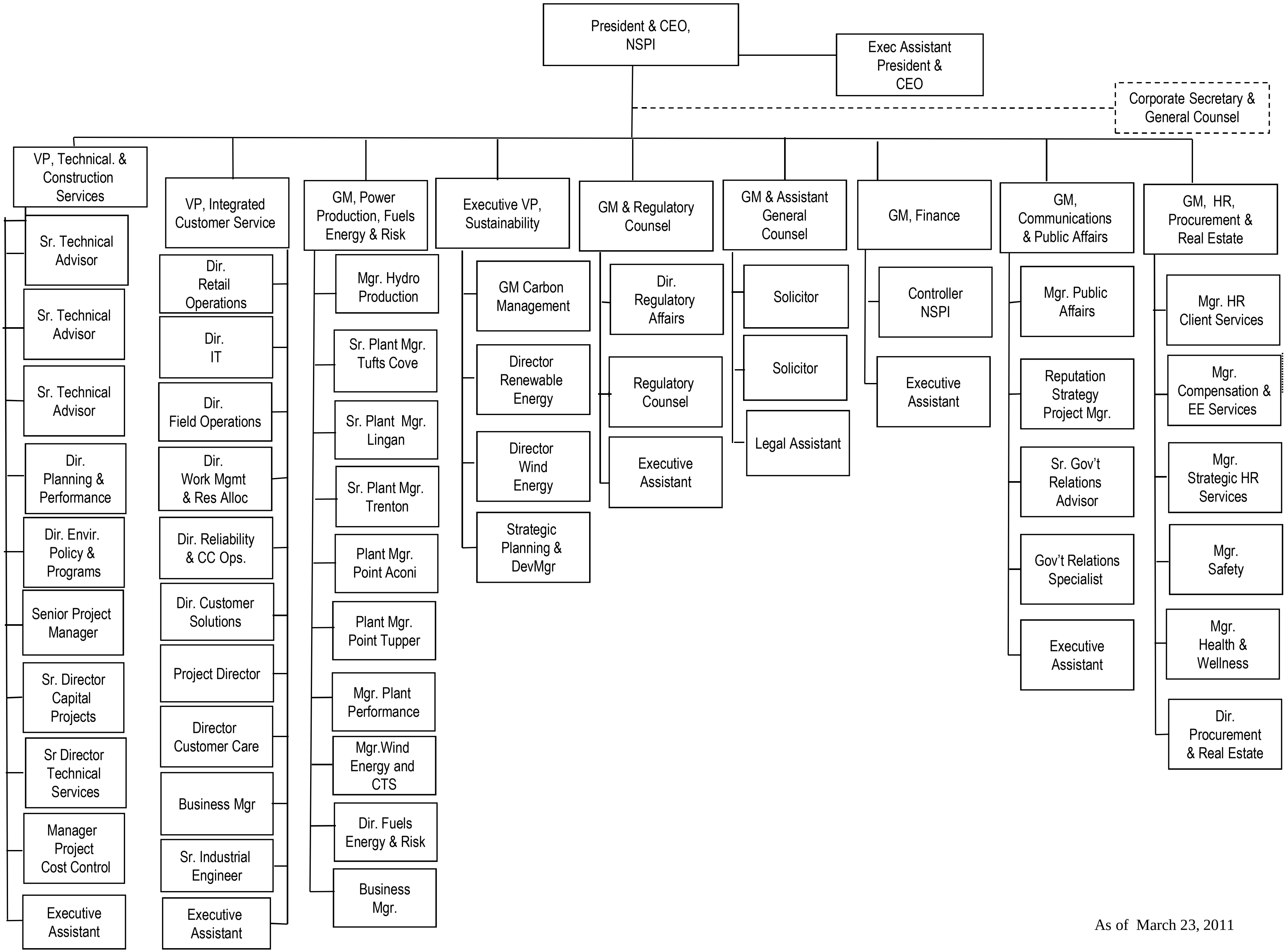
**Requirement:**

**Current organization chart of NSPI showing all positions reporting no further than two levels down from the President and CEO, including a full organizational chart for the positions reporting to the Director, Fuels, Energy, and Risk Management.**

**Submission:**

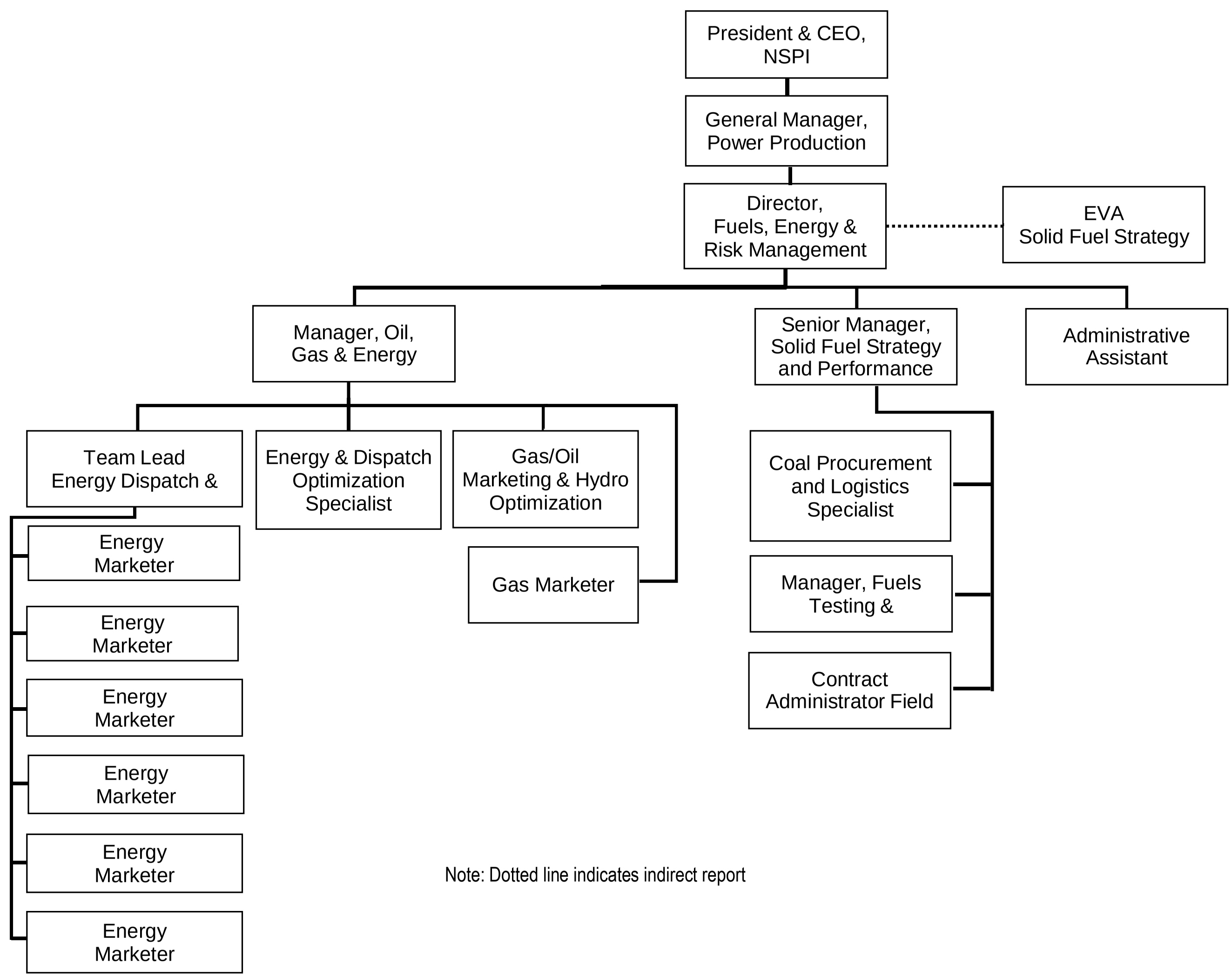
Please refer to Attachments 1 and 2.

# NSPI Organizational Chart




As of March 23, 2011

## Fuels Energy and Risk Management Organization Chart




Note: Dotted line indicates indirect report

**Requirement:**

**Copy of latest OM&G review undertaken since last rate filing.**

**Submission:**

An independent operations review of Nova Scotia Power Inc. was filed with the UARB July 19, 2008 by Kaiser Associates in the 2009 General Rate Application. The Public Redacted Version of the Report is included as Attachment 1.

NS Power has updated the key conclusions and metrics of the 2008 Kaiser Report. Please refer to Appendix B of the Direct Evidence (DE-03 – DE-04, Appendix B).

# Operations Review of Nova Scotia Power Inc.

PUBLIC REDACTED

*Report prepared for:*

Nova Scotia Utility and Review Board

By:

June 19th, 2008 - REVISED

*Prepared by:*

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## Executive Summary

Kaiser initiated its review of Nova Scotia Power Inc. ("NSPI") in November 2007 in response to our project's Engagement Letter, dated October 17, 2007. In order to complete the operational review, Kaiser performed an internal analysis of NSPI and an external benchmarking to relevant, comparable utilities focusing on Operations, Maintenance and General (OM&G) expenses.

Following its research and analysis presented in the detailed findings, Kaiser believes that NSPI is a well managed utility that operates at a lower OM&G cost basis than its comparators when adjusted for its scale. NSPI has shown a rise in costs from 2004-2006, driven by investments in Emergency Services Restoration, vegetation management and a onetime adjustment made for pension expense. These expenses were reviewed and approved by the UARB. In addition NSPI was affected by external factors, for example: particularly adverse weather in the province; and, a major customer was not in service in 2006, depressing revenue. Preliminary data for 2007 shows OM&G expenditures are projected to remain flat. While NSPI does appear to be run well by management, there are areas of operation which it differs from other utilities and it can evaluate practices utilized by other operators. Accordingly, Kaiser has identified systems, policies and/or procedures that some of the comparables have taken to manage OM&G expenses.

Finally, it should be noted that Kaiser's review of NSPI's executive compensation is not included in the detailed findings report as detailed further on page v.

## Update to Revised Version

The information as well as conclusions drawn contained within this report are primarily as of the time of the original submission, March 28th, 2008. Since then, NSPI has submitted an itemized list of comments to the UARB and Kaiser.. In situations where the comments from NSPI were straightforward data corrections, Kaiser has made the alteration. In situations where NSPI's comments are based on interpretation or drawing conclusions from data, Kaiser has not made changes to its findings. An index of NSPI's comments and Kaiser's changes to the detailed findings will be made available to the Board.

By the nature of closed benchmarking, in which Kaiser does not have full access to information on the target operator or comparators, there is the possibility of new or subsequent information surfacing which may affect the report's conclusions. Kaiser would be interested in amending its report if the Board determines it wants further research and analysis conducted.

## Internal Analysis of NSPI

Kaiser conducted a thorough investigation of internal operations within NSPI's fossil fuel power plants and the support structure. The team conducted quick walkthroughs of NSPI's wind, hydro and tidal plants. This activity included, but was not limited to:

- Interviews with NSPI personnel
- Review of internal documentation, manuals and metrics with particular emphasis on OM&G expenditures

- Follow-up questions and documentation requests for NSPI personnel

Kaiser used this up-front diagnostic to prioritize its focus areas for the benchmarking study and as a baseline for recommendations. The internal assessment identified four critical areas for improvement which formed the core of research areas for benchmarking. All four areas reflect a lack of standardization and centralization within NSPI's operations:

- Work Management System (WMS) – Rather than use an integrated WMS, NSPI relies on a number of different WMSs aligned by function (customer operations, maintenance, etc.) leading to lack of coordination and sub-optimal utilization. NSPI management is aware of this problem and is taking steps to address the WMS; NSPI management has a $6-7M application for a transmission and distribution WMS upgrade in its 2008 capital budget. WMS is a key area of study in benchmarking and a critical recommendation. Although the integrated nature of WMS means it affects multiple areas of company operations, Kaiser has presented its findings and recommendations related to WMS in the Customer Operations section (pages 75-86). As Kaiser has cautioned the UARB, there are significant efficiencies to be gained, however, implementing an enterprise-wide, integrated WMS is a substantial investment which carries significant risk and will require the commitment of personnel resources.
- KPIs – NSPI uses a basic list of KPIs for its plants, supplemented by unique KPIs by plant. The suite of KPIs currently focuses on raw output measures (e.g. total OM&G), instead Kaiser recommends that the KPIs should focus on efficiency measurements or on year over year changes (e.g. OM&G excluding fuel costs /MWh)
- Organizational Design – NSPI does not utilize a standard organizational design across its existing plants. Due to attrition in its Point Tupper plant, NSPI is testing an alternate organizational structure, which after evaluation may be expanded for use in other facilities. This structure is much less hierarchical in nature, therefore relies less on highly experienced supervisory staff. NSPI uses a distributed model in organizing its plants, allowing for operational flexibility but also possibly creating redundancies in engineering and support functions.
- Procurement – NSPI recently centralized procurement functions, with immediate positive effects seen in efficiency and accountability. NSPI is facing staffing shortages in procurement, which may constrain further efficiency gains in this area.

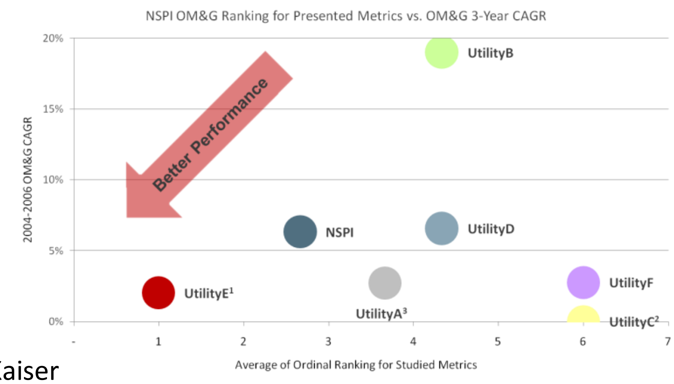
Kaiser's internal assessment (pages 2-15) is included in the main body of the report, with the detailed trip report included in the Appendix.

## Benchmarking against Comparable Utilities & Preliminary Findings

Kaiser used a three phased approach to benchmark comparable utilities, as is laid out in the detailed findings report. First, an initial screening identified utilities to be reviewed (page 18). Second, a high level review of the benchmarks' operations compared OM&G expenses as a function of performance (pages 22-34). Third, best-in-class characteristics for 1-3 comparables were determined and researched in-depth to determine systems/processes that NSPI should consider.

## Recommendation on Reasonable Level of OM&G Expense

On the basis of the benchmarking comparisons, Kaiser believes that NSPI compares favorably to the benchmark firms on OM&G expense when normalized by power generated, number of customers, number of employees and amount of revenue generated. As the chart to the right shows, NSPI ranks better than benchmarked comparables across scaled OM&G metrics, but has a higher growth rate in OM&G expense.[1] Since the OM&G increases are primarily linked to Board approved operational investments, and a Board approved change in accrual for pensions, Kaiser suggests future reviews of OM&G expense should be broken into two tiers for presentation:




1. Expense increases for ongoing expenses; these should be targeted to track at or just above local inflation rates.
2. Expenses associated with major capital outlays that would affect OM&G such as systems improvements.

<u>Breaking into these two categories allows NSPI to demonstrate that it is, in fact, containing its ongoing costs within inflation while making incremental operational investments.</u>

## Detailed Benchmarking

The table below identifies comparables utilized, and in-depth areas of focus for each section.

| | Focus Areas | Comparables Studied | Pages |
|---|---|---|---|
| **Power Production** | Organizational Design<br>KPIs<br>Procurement<br>Key Initiatives | High Level Comparables – Utilities A-D<br><br>Deeper Coverage – Utilities A, D | 35-60 |
| **Customer Operations** | Vegetation Management<br>T&D maintenance<br>Outsourcing<br>Work Management Systems | High Level Comparables – Utilities D, E, F<br><br>Deeper Coverage – Utilities D, F | 61-89 |

[1] A more detailed explanation of this chart is available on page 34. Ordinal rankings are comparable ranking for OM&G $: per GWh; per Revenue; per Customer

| | | | |
|---|---|---|---|
| **Customer Service** | Customer Spend/Satisfaction<br>Organizational Structure<br>Metering<br>Customer Service In-sourcing | High Level Comparables – Utilities C, D, E<br><br>Deeper Coverage – Utilities C, E | 90-113 |
| **Regulatory Affairs** | Organizational design<br>Amount of time spend with Board | High Level Comparables – Utilities A, B, C | 114-128 |

## Deep Dive Benchmarking

As suggested in the January 30th progress update, Kaiser suggests a further deep dive benchmarking to develop more detailed and more actionable recommendations. This deep dive would involve benchmarking power production activities at a plant level instead of a company level. Plant level benchmarking would take into account types and vintages of technology used in power production as it affects OM&G and other expenses.

## Detailed Recommendations and Quantification

Combining insights from the internal assessment and the benchmarking, Kaiser has developed a set of recommendations by research area. For informational purposes, Kaiser has quantified potential annual cost savings associated with each recommendation. These figures should be considered rough estimates and not a precise calculation of expected savings. Kaiser has limited its recommendations to significant items, several of which would require further analysis by NSPI to determine a more accurate potential savings. Since solutions such as a new work management system are typically highly customized, Kaiser has not included the cost or calculated an ROI associated with each recommendation. Although not directly quantified below, it is expected that improvements in reliability and call center operations would yield improvements in customer satisfaction as well.

**Power Production (page 60)**

Since plant operations vary dramatically by technology, vintage, etc. it is not possible to make quantifiable recommendations for power production without performing a deeper dive on power production. The following are Kaiser's general recommendations.

**Org Design**

Research indicates that NSPI has a greater number of direct reports as well as less accountability in plants, particularly in the maintenance and planning areas. NSPI should develop a plan for the board identifying its org. design and workforce plan over the coming years as part of its succession planning initiative. The plan should address some of the standardization of organization and centralization issues raised in the detailed findings.

**Procurement**

NSPI has begun to address longer term procurement issues which will prevent cost spikes/shortages in sourcing fuel and materials. NSPI has recently implemented a dual tiered structure similar to benchmarked firms, this should help increase accountability while maintaining responsiveness.

**Green Power**

NSPI will continue to need to make investments in renewable sources of energy. It should seek to partner with other firms, or local/provincial stakeholders for experimental technologies.

**Customer Operations (pages 88-89)**

**Vegetation Management – Approximate savings - $0.5M – 1M/year**

Increase in proactive seeding and herbicide use can reduce long term costs vs. reliance on mechanical methods.

**T&D Maintenance - $1M/year**

Step wise line replacements and identification integrated with vegetation management results in fewer breakdowns and improved customer satisfaction.

**WMS – $12M – 20M/year**

Improvements in customer operations and savings in power production are factored into savings calculation. Efficiencies around completing planned maintenance instead of constantly being reactive are the key driver of savings.

Kaiser is aware that NSPI has presented the Board with an application as part of its 2008 capital budget for replacing the T&D component of its WMS. **It is Kaiser's opinion that this measure is inadequate.** NSPI should evaluate the cost-benefit of an integrated WMS and present these findings to the Board. The WMS implementation may be done in stages, but the full plan (with full costs and timetable) should be presented to the Board in advance. The Board should be aware that costs for this system may be $50-70M, but comparable utilities have achieved successful payback for systems in 5-7 years. The Board should similarly be aware that comparable utilities took up to 200 additional staff and 5+ years to implement.

**Customer Service (page 113)**

**Call Center Operations and Billing - $1M – 3M/year**

Increased automation around call handling and billing can significantly reduce ongoing expenses for customer service.

**Metering - $0.5-1M/year**

Moving meters from inside to outside locations reduces cost by $0.60 per meter read.

## Executive Compensation

In agreement with the Board, Kaiser did not include its review of NSPI's executive compensation in this report. This information has been included in a separate report filed with the Board covering both executive compensation and management qualifications.

# Table of Contents for Detailed Findings Report


| Section | Page |
|---|---|
| Executive Summary | i |
| Analysis of NSPI Operations | 1 |
| Comparables Screening | 16 |
| Benchmarking Research and Recommendations | 21 |
| Power Production | 35 |
| Customer Operations | 61 |
| Customer Service | 90 |
| Regulatory Affairs | 114 |
| Appendix | 130 |

# Analysis of NSPI Operations

# Kaiser's primary means of gathering information and insights about NSPI was through its site visits

- Audit and assessment of the power generation fleet in November 2007, site visits included:
  - Natural Gas / Oil Fired Plants – Tuft's Cove
  - Coal-Fired Plants – Point Aconi, Point Tupper, Lingan and Trenton
  - Oil-Fired Combustion Turbines
  - Hydro Units including maintenance centers and selected hydro locations
  - Annapolis Tidal Production Plant
  - Brief visit to the Wind Plants at Grand Etang and Little Brook
  - More details of the site visits are covered on the following pages
  - Detailed plant reports are available in the appendix

- The primary objectives of the internal assessment were:
  - To understand the underlying processes and practices used by NSPI to manage each of the identified categories
  - To review previous NSPI operations reviews
  - To conduct audit visits of the major generating, customer operations and customer service facilities
  - To present initial conclusions and recommendations as a result of the audit visits
  - To provide observations necessary to develop internal analysis

# Kaiser (KA) conducted detailed reviews of the below facilities during November 2007

| Sites Visited | Extent of Visit / Evaluation | Rationale |
|---|---|---|
| Coal-Fired Plants<br>• Visited Point Aconi, Point Tupper, Lingan and Trenton | • Each site was visited by Kaiser personnel<br>– Interviewed plant managers at each plant<br>– Reviewed KPIs at each plant | • Base load largest capital and OM&G expenditure in the fleet of generation |
| Natural Gas<br>• Visited Tufts Cove plant and thermal production facilities | • Evaluated thermal production facilities<br>– Consisted of review of processes, procedures, operations expenditures and maintenance expenditures related to:<br>– Planning<br>– Execution of Plans<br>– Effectiveness of predictive and preventative maintenance including:<br>– Software and systems in place<br>– Environmental and safety | • Thermal production at these plants accounts for bulk of production budget operations, maintenance and general |
| Oil-Fired Combustion Turbines<br>• Visited Tuft's Cove and Burnside CTs | • Walkthrough of processes, procedures, systems and software tools incorporated into an overall assessment of:<br>– Budget effectiveness<br>– KPI development<br>– Plan execution<br>– Performance related to peers | • Represents the load following capacity that NSPI relies on during load swings and peak demand periods |
| Hydro Units<br>• Visited a Mersey System Maintenance shop, Mersey River Hydro and Wreck Cove | • Reviewed the operations, maintenance and maintenance center of select plants | • Maintenance of the hydro plants is similar across the board<br>– Have central locations and maintain the fleet of generators from central locations |
| Tidal Production<br>• Visited Annapolis tidal production plant | • Reviewed the operation and maintenance of plant | • Long term maintenance is important in evaluating performance, OM&G costs associated with this technology |
| Wind Plants<br>• Cursory review of two wind plants located in Grand Etang and Little Brook | • Desk top review of operations and maintenance | • Small number of wind turbines causes operations and maintenance of installed capacity to be high in comparison to other utility scale wind farms in North America<br>– As scale of these projects becomes larger, the OM&G as a percentage of costs will decrease |

# An internal analysis identified potential areas of opportunity and guided Kaiser's external benchmarking research

- Following site visits and subsequent analysis, Kaiser has focused on the following:
  - Organizational Design (page 6)
  - Operational Metrics (page 7)
  - Workforce Management Practices (page 8-10)
  - Power Production Cost Analysis (page 11-12)
  - Procurement (page 13)
  - Workforce and Maintenance Management Systems (page 14)
- Observations, Preliminary Conclusions and Future Actions are offered in the following pages on an exception basis – focusing on those areas where Kaiser has perceived notable activities and/or opportunities
- Detailed observations are available as part of the Trip Report in the Appendix (page 134-179)

# Org. Design: KA found significant variation from location to location – opportunities may exist to pool resources in engineering, predictive / preventative maintenance and life preservation

| Location | No. of Employees | No. of Direct Reports* | Areas of Responsibility | Staffing of Major Functions | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Engin. | Mech. | Prod.** | Oper.** | Fuel | Maint. | Chem. / Envir. | Analysts |
| Lingan | | | | | | | | | | | |
| Point Tupper | | | | | | | | | | | |
| Trenton | | | | | | | | | | | |
| Point Aconi | | | | | | | | | | | |
| Tuft's Cove (TUC) | | | | | | | | | | | |

Information Redacted

*Kaiser suggests that organizational uniformity across these 5 NSPI thermal plants presents the opportunity to:*
1. *Simplify the reporting relationships to the plant manager*
2. *Reduce on-plant staff by centralizing functions in the accounting, predictive / preventative maintenance, engineering and planning areas*
3. *Develop standardized approach to maintenance and planning functions*

*No. of Direct Reports to Plant Manager; **Production and Operations are synonymous

# KPIs: During its site visits, Kaiser found KPIs similar to those used in other utilities, exceptions and additional KPIs are available in the benchmarking section

| KPIs | Definition | Comments |
|---|---|---|

Information Redacted

# Workforce Management Practices: KA determined that internal processes are strong, particularly in safety processes and monitoring

Kaiser's review of NSPI's operations noted a number of exemplary efforts and initiatives in managing and involving the labor workforce. In Kaiser's experience, some of these programs may be unique in the industry. In particular, Kaiser noted:

- Outage labor practices
- Safety consciousness and practices
- Production planning
- Union / management relations
- Staffing / training
- Employee development & compensation

# Workforce Management Practices: KA determined that internal processes are strong, particularly in safety processes and monitoring (continued)

## Outage Labor Practices

- NSPI has formed a skilled labor pool to inexpensively provide temporary skilled labor during outages
  - Utilized for nearly all shutdown labor
  - Excepting for specialized services where subcontractors are used (via preferred supplier agreements) due to need for specialized tools / equipment and skills: e.g. boilers. TR bag house, generator, compressor maintenance, predictive monitoring, ash haulage, local machinery and security

## Safety

- Widespread use of good safety practices
  - Regular use of risk assessment practices at most sites and by COPS
  - Hard hats, safety shoes, hearing and eye protection were mandatory during all tours
  - Several plants begin work day with brief morning meeting focused on safety termed “Seven Minutes for Safety”
  - All sites have a JOHSC (Joint Occupational Health and Safety Committee) made up of representatives throughout the plant
  - Operating shift personnel have the responsibility as 1st responder for onsite emergencies
- Excellent safety results

## Daily Production / Weekly Planning

- Most stations hold daily production and weekly planning meetings
- “Hit list” discussed at daily meetings
  - Safety, environmental, reliability are high priority
- All plants effectively plan outage work, major overhauls and repairs
- Annual shortages are driven by regulatory requirements
  - Appears that outages are rolled into forced outages when possible

# Workforce Management Practices: KA noted positive union relations and staff development practices are in place

## Union / Management Relations

- Evidence of strong union / management relations – few grievances filed in recent years
- New contract with IBEW has provided labor flexibility to:
  - Move employees from site to site, if necessary
  - Assign employees to shifts
  - Bring in additional employees from a labor pool (with three different pay classifications)
- Can use the "Continental Shift" (DR 50- Loop Seal Project) during overhauls, and major projects
  - Allows labor pool employees to work back shifts and non-traditional shifts - may bridge a weekend at a straight time rate of pay
- Multi-tasking:
  - NSPI has ability to use employees with multiple skills, where needed; i.e. a work order may require a multi-trade crew to perform maintenance, so that mechanical, electrical and instrument technician skills may be required to repair a pump – now all of these skills may reside in one person, eliminating the cost and scheduling difficulties associated with multiple trades
  - At Point Tupper and Point Aconi, operating employees are sometimes taken off shift during major overhauls to help with maintenance
- Management at Point Tupper has included its union leadership in its interviewing and selection process for new hires
- Quarterly meetings are scheduled with the employees to discuss plant performance

## Staffing / Training

- Core staffing levels determined by a special project team in 2006
  - People were hired proactively in advance of the pending attrition
- Significant training before a power engineer is deemed competent on shift – NSPI is taking a proactive approach to transfer the knowledge of senior employees before they retire
  - Accounts for some of the additional overtime expenses to cover a shift (while training the new employees) and the payroll cost to carry new employees before the current employees retire
- Believe they have turned the corner on training; apparently, necessary overtime to cover shift positions is starting to trend downward

## Employee Development & Compensation

- All employees design a personal development plan at beginning of each year
  - Last year, all but one employee completed personal development review (DR 25)
- All non-union and management employees have an incentive compensation program based on the balanced scorecard performance
  - Three payout levels for performance: Threshold, Target, and Stretch (DR 33)
  - Key Performance Indicators for this program are Generation, OM&G Investment, Capital Investment, Fuel Cost Forecast, Fuel Cost/MWh, OM&G cost/MWh, Heat Rate, Bunker C Burn, Safety Reportable Incidents, and Environmental Reportable Incidents
  - Results are tracked monthly and year-to-date
  - Monthly with appropriate Corporate Personnel, Plant Manager, and Business Manager for each location to review latest results
  - Each manager and director provide an update on their performance and any concerns or issues that may impact the year end targets (DR 11)

# Power Production Cost Analysis: KA believes plant level OM&G costs are reasonable, but additional focus could be paid to labor, fleet fuel and water

## Labor

- Regular Labor accounts for about 50% of total plant OM&G expenses at Tuft's Cove, Lingan, Trenton, and Point Aconi
- At Point Tupper it is about 62% (which is high compared to other plants)
- Overtime at all of the sites is between 8-10% (5-7% is typical) of total labor costs
- Better balance of contract labor could result in reduction in overtime costs
- Based on discussions with the plants, overtime is high in operations due to the training requirements for new employees
- Labor pool accounts for 6-7% of costs Except at Point Tupper (4% - did not have a scheduled outage in 2007) and Tuft's Cove (3%)

## Projected and Expected Cost Increases

- Upward pressure on OM&G is expected in many categories since these costs are tied to the cost of crude, i.e.:
  - Freight, post and delivery
  - Chemicals
  - Gases
  - Lubricants
  - Travel
  - Materials
- Labor:
  - General wage increases of 2.5% implemented July 27, 2007 (DR 4)
  - For several classes of employees market adjustment increase of $1.50/hr is due on January 1, 2008 and, $1.00/hr on October 1, 2010
  - Additional general wage increases are due on:
    - December 2008 (3.5%)
    - March 2010 (4%)
    - March 2011 (4%)
    - Base payroll will increase by addition of 19 maintenance tradesman and 8 janitors

# Power Production Cost Analysis (Cont.)

## Fleet Fuel

- Fleet fuel (used for the coal moving equipment) runs between 1% of total non-labor expenditures at Point Tupper and 4% at Point Aconi
  - Point Tupper takes advantage of PTMT advantage to reduce fleet fuel expenses
  - Opportunity to reduce costs in this category is likely minimal due to rising fuel costs
  - Many utility operators include fleet fuel in their fuel adjustment clause.

## Water

- Cost of purchasing water from the local municipality stands out at several facilities
  - 2007 forecast is 3% of non-labor OM&G budget for Lingan;, 5% for Trenton; 9% for Tuft's Cove
  - Might be particularly high at Tuft's Cove because of cycling nature of its operation
  - Could possibly reduce through condensate recovery tanks, deep wells, or desalination

# Procurement: KA believes centralized systems are in place, but NSPI needs to catch-up in critical spares contingency planning and asset management planning

## Procurement Organization – Roles / Responsibilities

**Central Procurement**

- NSPI has recently revised its procurement and inventory organization, centralizing the function
- Central procurement office handles major purchases and high volume items (e.g., coal)
  - Negotiate major contacts
- Buyers and buyer analysts report to purchasing managers

**Plant Level**

- Each station has a storekeeper that reports to the procurement organization
  - 24 total storekeepers that report to warehouse managers or supervisors
  - Need to clear purchases over $200k with central procurement
  - Controls are improving – procurement controls have been a corporate focus for the past 18 months
  - Now, only 12 purchasers can commit company resources
  - Carrying costs are approximately 3½% of inventory
- Each plant has its own warehouse
  - Supervisor is on location
  - Conduct aging reviews within warehouses
- Most procurement buyers are embedded within organization
  - Each thermal plant has a buyer on location:
    - Handles less costly local / unique purchasing for plant and larger commodity purchases
- Oracle is the procurement software platform; J.D. Edwards is used for inventory control
- Have developed an asset tool to gauge severity that plants use to assess risk

**T&D**

- Have central warehouses and satellite warehouses

## Training

- New employees in procurement will undergo a 3 year training program – much of the program is virtual (internet-based)
- Active recruiting program to replace retiring personnel with new skill sets

# Procurement: KA believes centralized systems are in place, but NSPI needs to catch-up in critical spares contingency planning and asset management planning (continued)

## Critical Spares Contingency Planning

- Prioritized critical spares contingency planning over the past 2 years mainly as a result of recent transformer failure at Tuft's Cove
- Developed tool for evaluating spares
  - Evaluates probability of failure and severity (e.g. cost of replacing vs. risk of not fixing - performance, safety and environment)

## Asset Management Planning

- Centralized initiative focused on planning for lead times for technology / equipment
  - Trying to get to get to the point where they have plan for 2-3 years in advance
    - 2 year goal in place to have 2-3 year asset plans for all major technology / equipment
  - Follow form-based process that must be approved by the Plant Manager

## Inventory

- Recently implemented a centralized model for carrying inventory
  - Is now a "front-office" issue
- Centralized group is responsible for striking balance between investment and availability
  - Group is accountable for tracking inventory costs
- Currently have vending machines at 3 plant locations
  - Plant workers can swipe card to quickly attain small items
  - Demonstrated to increase productivity, reducing warehouse trips by 25-30 trips / day

## MRO's

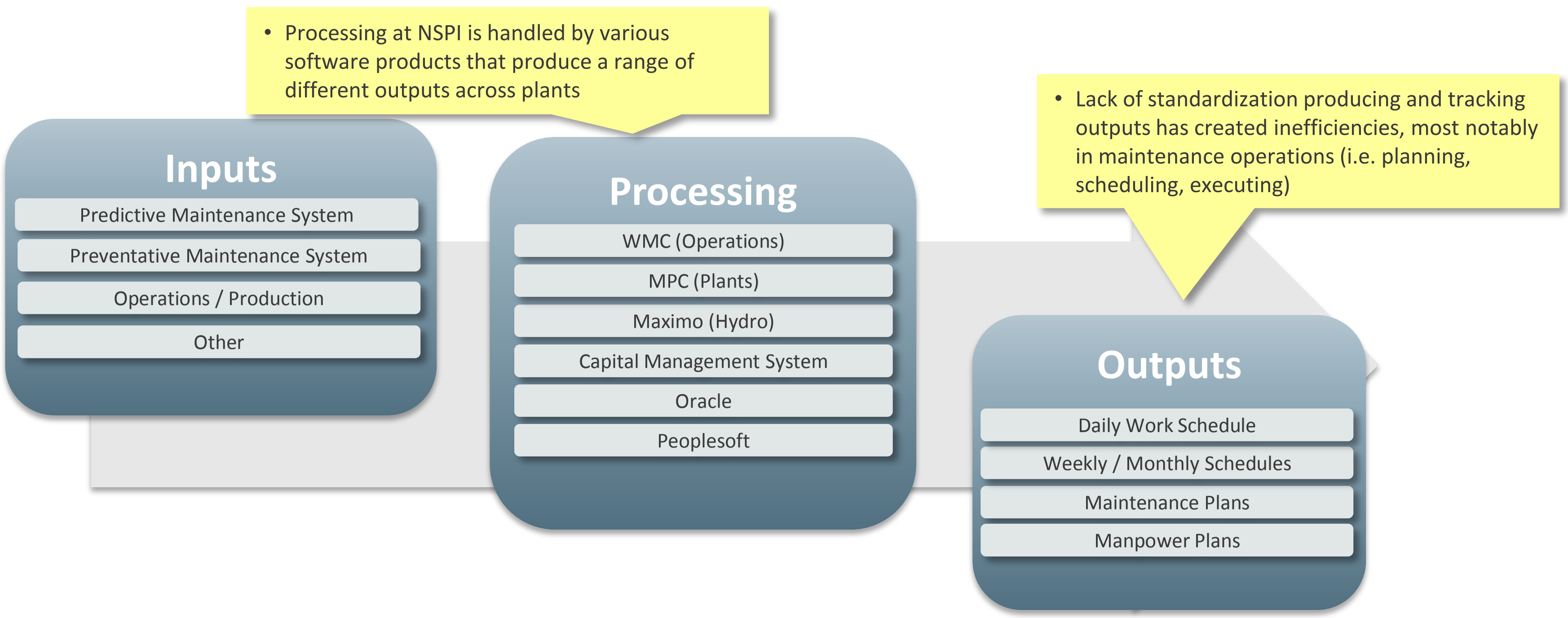
- Materials and contracts combined account for largest percentage of total non-labor expenditures
  - Ranging from 75-87% of the total non-labor costs
  - MRO agreements could reduce carrying costs of consumables and capital deployed and # of FTEs (procurement has 58 staff)

# Procurement: Primary challenge for procurement is in long term planning to avoid unexpected costs as a result of difficulties in sourcing critical parts

## Main Procurement Concerns Going Forward

- Planning far enough into the future to get a multi-year view of changing needs
- Escalating costs of raw materials
- Developing alternate supply lines
- Developing deeper relationships with suppliers to promote innovation/cost improvements
- Reducing supplier base – goal: 80% of spending from 3% of supplier base (develop % of spend in supply base as a key metric)

# Workforce and Maintenance Management Systems (WMS): KA finds lack of integrated WMS does not support a stream-lined and efficient process




- Planning, scheduling of work needs standardization and accountability across the organization
  - Requirements for setting work plans vary significantly by location
  - Minimal accountability around setting / maintaining an effective schedule
  - Kaiser has found significant cost savings in other utilities from having an accountable, integrated WMS
  - Currently proposed WMS only addresses T&D, maintaining the fragmented nature of the WMS

# Comparables Screening

# KA screened a diverse mix of potential candidates throughout its benchmarking selection process according to the following criteria

**Power Profile**

- What is the generation capacity operated by candidate (as measured by GW)?
- Does candidate operate similar technologies?

**Revenue Generation and Customer Base**

- How much revenue does candidate organization generate per customer served?
- How does geography affect customer base and transmission?

**Structure of Organization**

- How many employees does the candidate employ?
- Is candidate a Crown Corporation or private?
- Is candidate a regulated or non-regulated entity?

**Best in Class Characteristics**

- Does candidate demonstrate BIC characteristics?
- In which functional groups does candidate demonstrate the highest performance?
- Can NSPI improve its operations based on examples from candidate organization?

Representative Candidates Screened by Kaiser

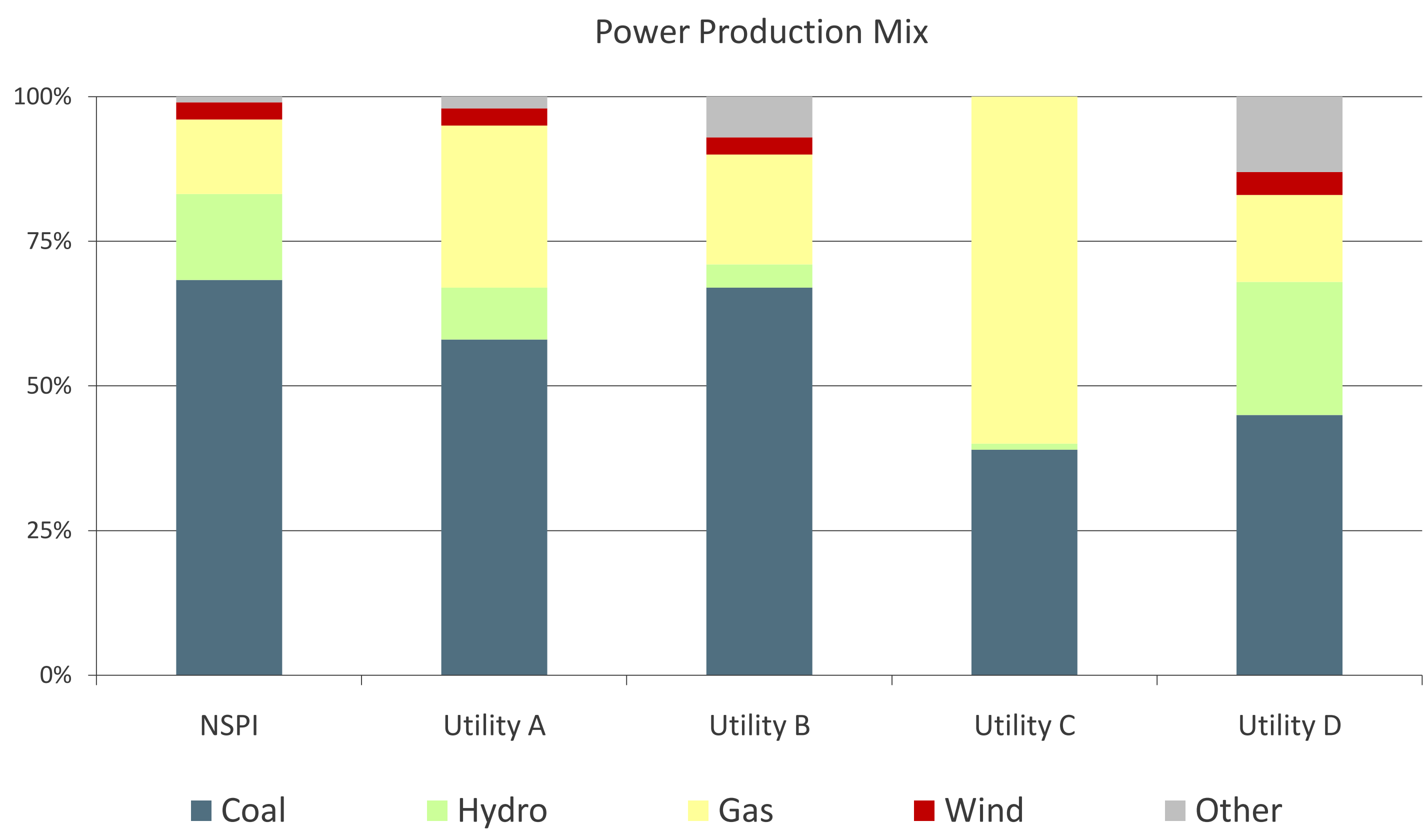
Information Redacted

# KA selected the following 4 companies as Principal Comparables

| Comparable | Generation Capacity | Employees | BIC Characteristics* |
|---|---|---|---|
| Utility A | Information Redacted | | |
| Utility B | | | |
| Utility C | | | |
| Utility D | | | |

*As measured by lowest Incapability Factor (IcbF) by the Canadian Electricity Association (released July 11, 2007)

# Utility A, Utility B and Utility D are most comparable to NSPI based on fuel source




*Utility A, Utility B and Utility D look to be the closest comparables based on mix for power production*

# Principal comparables are supplemented by companies that demonstrate Best-in-Class characteristics in specific functional groups

Increased overall relevance of comparable

## Principal Comparables

Information Redacted

- The selected principal comparables are closest to NSPI as measured by the following metrics:
  - Generation capacity (MW)
  - Revenue/Customer
  - Employee Count
  - Technology
- Kaiser benchmarked 1-4 principal comparables in each functional group

## Best in Class Comparables

Information Redacted

- Best in Class comparables demonstrate characteristics in specific functional groups to lower overall OM&G expenses (i.e., vegetation management, MRO, use of non-core labor, customer service, etc.) but may not be similar in size to NSPI

*Comparable practices identified as effective are would need to be assessed within NSPI's operating environment to fully assess the opportunity*

# Benchmarking Research & Recommendations

*Baseline Comparison*

*Power Production*

*Customer Operations (COPS)*

*Customer Service*

*Regulatory Affairs*

# The benchmarking research approach is built on making baseline comparisons between utilities as the basis for driving detailed analysis

## Baseline Comparisons

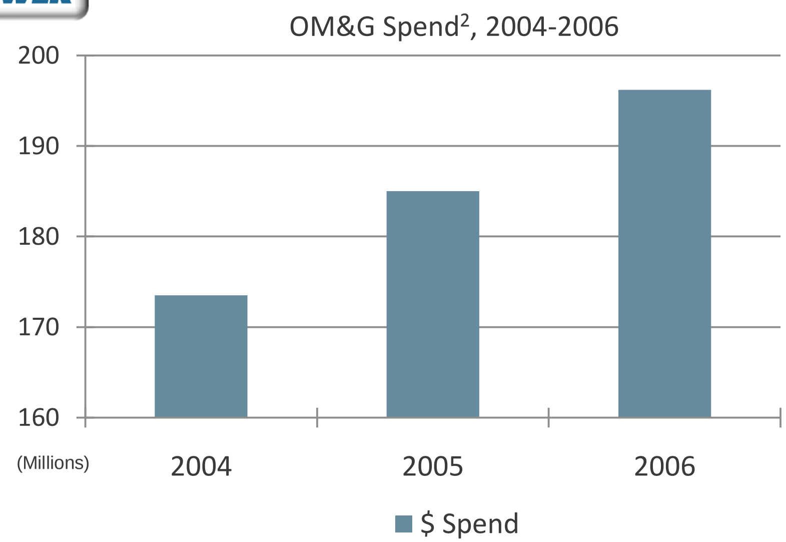
### OM&G Breakdown (pages 23-29)

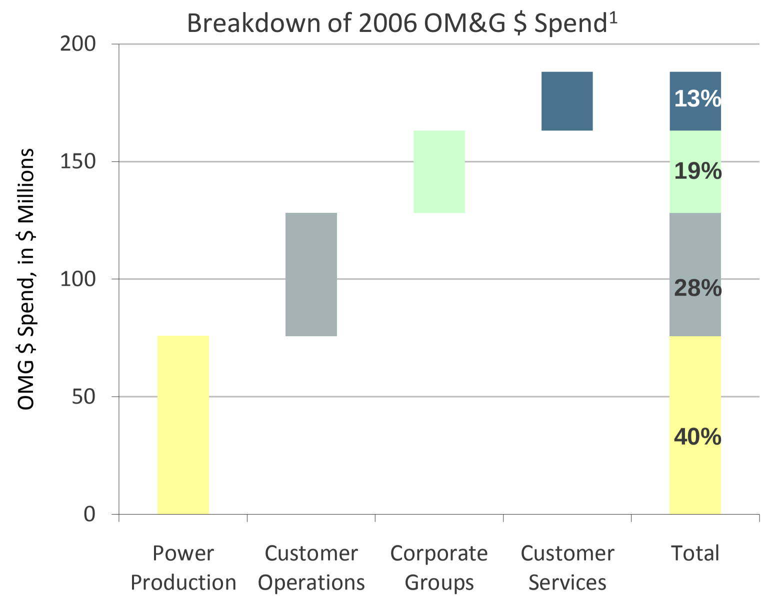
- Utilities reviewed include:
  - Primary comparables Utilities A-D
  - Functional best-in-class comparables: Utilities E, F
- Categories of OM&G vary by company making a component by component comparison difficult across companies

### Aggregate OM&G Comparison (pages 31-34)

- It is possible to look at aggregate OM&G spend for an apples-to-apples comparison
- Kaiser performed baseline benchmarking of aggregate OM&G spend using the following metrics:
  - OM&G expense per Gigawatt hour (GWh)
  - OM&G expense per customer
  - OM&G expense as a percent of revenue

# OM&G Breakdown: Nova Scotia Power has shown a steady increase in OM&G expense, which has outpaced its percentage revenue growth




| | 2004 | 2005 | 2006 |
|---|---|---|---|
| OM&G $[2] | $ 173M | $ 185M | $ 196M |
| % Growth in OM&G $ | N/A | 6.6 % | 6.1 % |
| OM&G as % of Revenue | 18.7 % | 19.4 % | 20.2 %[3] |
| Growth in OM&G as % of Revenue | N/A | 3.7 % | 4.1 % |

**OM&G Drivers**

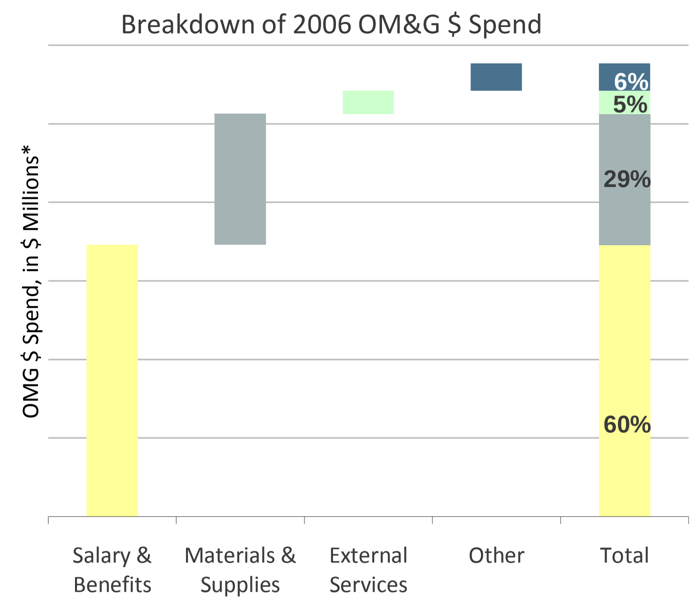
- NSPI's yearly OM&G increases are partially from "catch-up" investments / improvements & increased pension expenses
- Recent OM&G increases are partially due to weather events
  - E.g., NSPI has been forced to spend more in overtime costs associated with weather-related outages
- Other OM&G drivers have been UARB approved investments – veg. mgmt investment, succession planning, fuel procurement planning, Emergency Service Restoration Plan

[1]Total is prior to Corporate Adjustments
[2]Total includes Corporate Adjustments
[3] Percent of Revenue may be skewed due to Stora shutdown in 2006. Forecast for 2007 = 18.2%

# <u>OM&G Breakdown:</u> Utility A has been able to reduce OM&G costs in dollar terms (by $19M) and as a % of revenue over the past year

**Information Redacted**

| | 2004 | 2005 | 2006 |
|---|---|---|---|
| OM&G $ | **Information Redacted** | | |
| % Growth in OM&G $ | N/A | 9.0% | -3.2% |
| OM&G as % of Revenue | 21% | 21% | 21% |
| Growth in OM&G as % of Revenue | N/A | -0.9% | -1.9% |




**<u>Possible OM&G Drivers</u>**

- Utility A's attributes its OM&G reductions to increased planning for maintenance activities, the result of improved work management and IT systems

# OM&G Breakdown: Utility B's rapid increase in OM&G spend attributable to acquisition fueled growth in 2005 & 2006 has been matched by revenue growth

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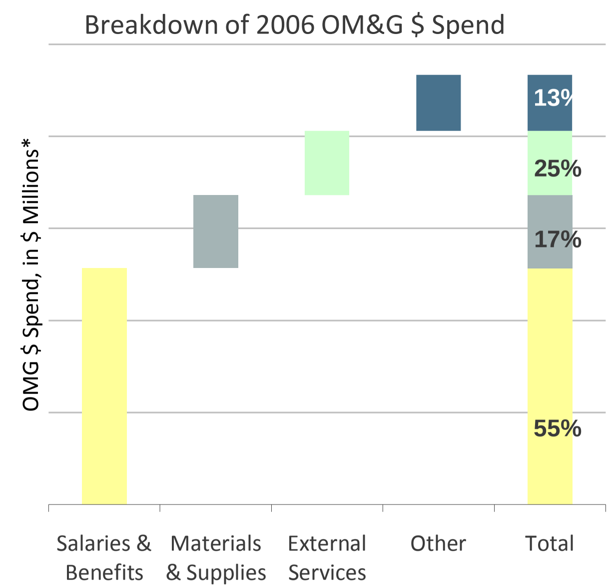


| | 2004 | 2005 | 2006 |
|---|---|---|---|
| OM&G $ | Information Redacted | | |
| % Growth in OM&G $ | N/A | 10.2% | 28.2% |
| OM&G as % of Revenue | 33% | 29% | 30% |
| Growth in OM&G as % of Revenue | N/A | -12% | 3% |

Information Redacted

**Possible OM&G Drivers**

- Utility B's yearly OM&G increases appears to be due to acquisitions in 2005 and 2006
- Decrease in OM&G as a percentage of revenue may be due to acquisitions that have generated cost savings

# OM&G Breakdown: Utility C sold its retail operations in 2004, resulting in improved OM&G as % of revenue[1]

Information Redacted

| | 2004 | 2005 | 2006 |
|---|---|---|---|
| OM&G $ | Information Redacted | | |
| % Growth in OM&G $ | N/A | -31.7% | -10.9% |
| OM&G as % of Revenue | 49% | 41% | 38% |
| Growth in OM&G as % of Revenue | N/A | -16.3% | -7.3% |

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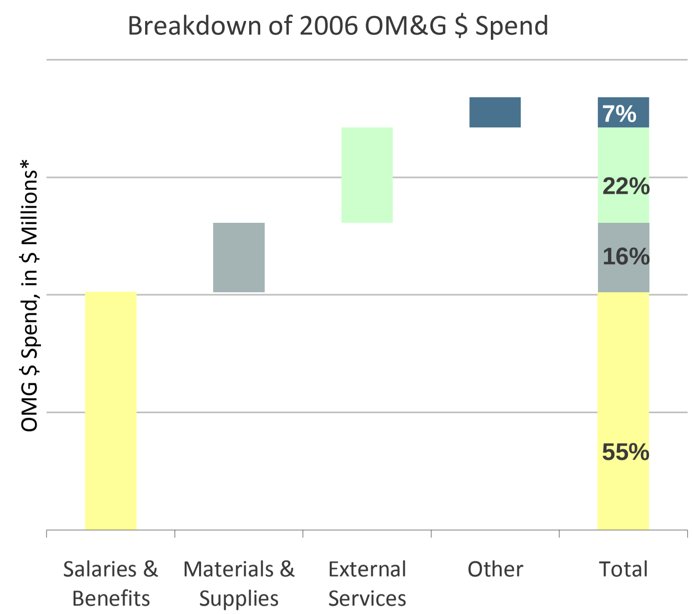


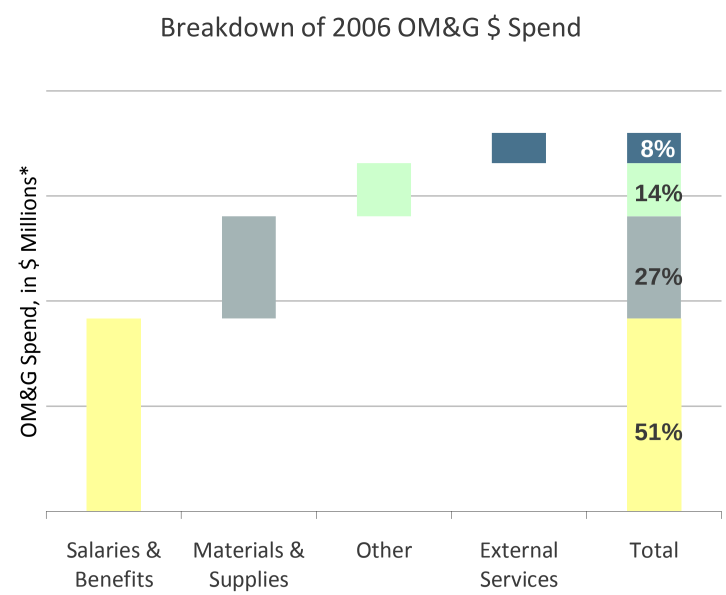

**Possible OM&G Drivers**

- Utility C's decrease in OM&G is as a result the sale of its retail operations in 2004
- Utility C's decrease in OM&G as % of revenue may result from rate increases and a focus on power production

# OM&G Breakdown: Utility D's revenue increases have reduced OM&G as a % of revenue while the actual OM&G $ figure increases at a similar rate to NSPI

Information Redacted

| | 2004 | 2005 | 2006 |
|---|---|---|---|
| OM&G $ | | Information Redacted | |
| % Growth in OM&G $ | N/A | 6.0% | 7.1% |
| OM&G as % of Revenue | 29% | 26% | 24% |
| Growth in OM&G as % of Revenue | N/A | -10.4% | -7% |



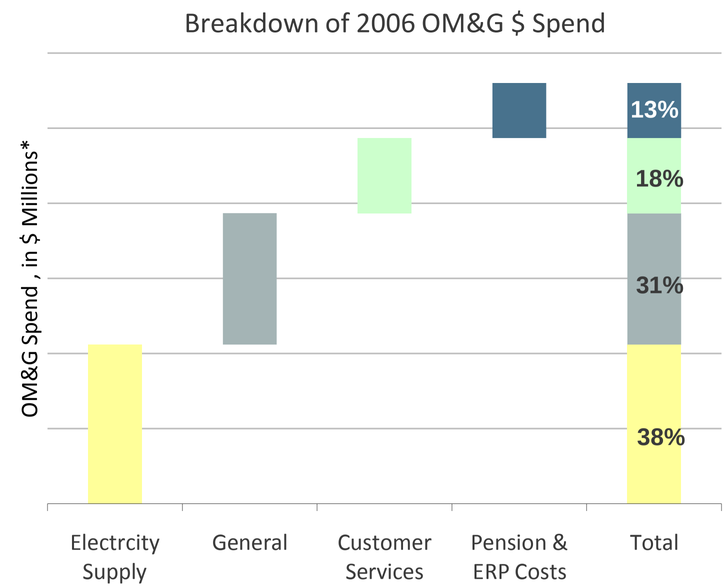

## Possible OM&G Drivers

- Utility D's increase in yearly OM&G appears to result from higher salaries and investments in older plants as well as long-term planning projects
- Utility D's decrease in OM&G as % of revenue is partially a result from rate increases to end consumers

# **OM&G Breakdown:** Utility E has held costs flat by implementing cost saving practices / technology within Customer Service and COPS

**Information Redacted**

| | 2004 | 2005 | 2006 |
|---|---|---|---|
| OM&G $ | | Information Redacted | |
| % Growth in OM&G $ | N/A | 3.7% | 0.4% |
| OM&G as % of Revenue | 13% | 13% | 13% |
| Growth in OM&G as % of Revenue | N/A | 0% | 0% |



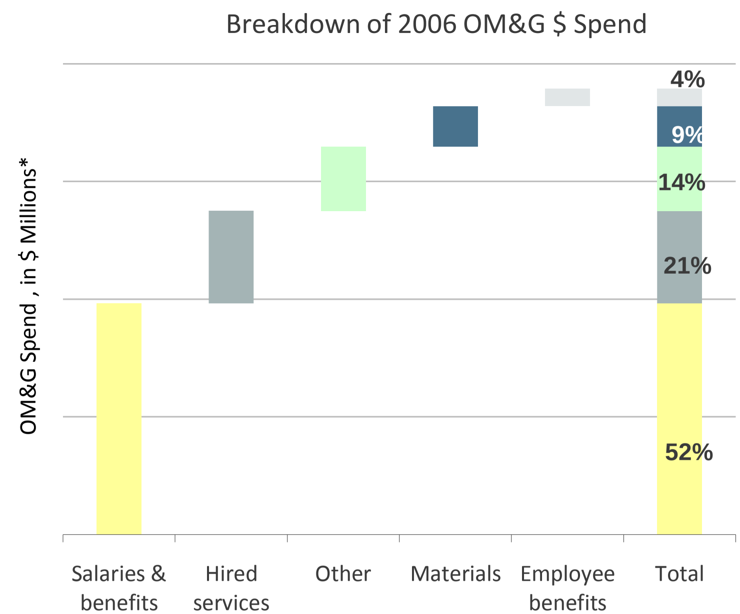

**Possible OM&G Drivers**

- Utility E has avoided increases in OM&G as % of revenue by making successful process and technology improvements (e.g., reducing customer service labor costs by implementing new technology)
- Utility E purchases a majority of its power and therefore does not need to account for power production related OM&G increases

# <u>OM&G Breakdown:</u> Utility F has been able to limit increases in OM&G expenses over the past 2 years

Information Redacted

| | 2004 | 2005 | 2006 |
|---|---|---|---|
| OM&G $ | | Information Redacted | |
| % Growth in OM&G $ | N/A | 1.4% | 4.1% |
| OM&G as % of Revenue | 27% | 26% | 24% |
| Growth in OM&G as % of Revenue | N/A | -3.7% | -7.7% |

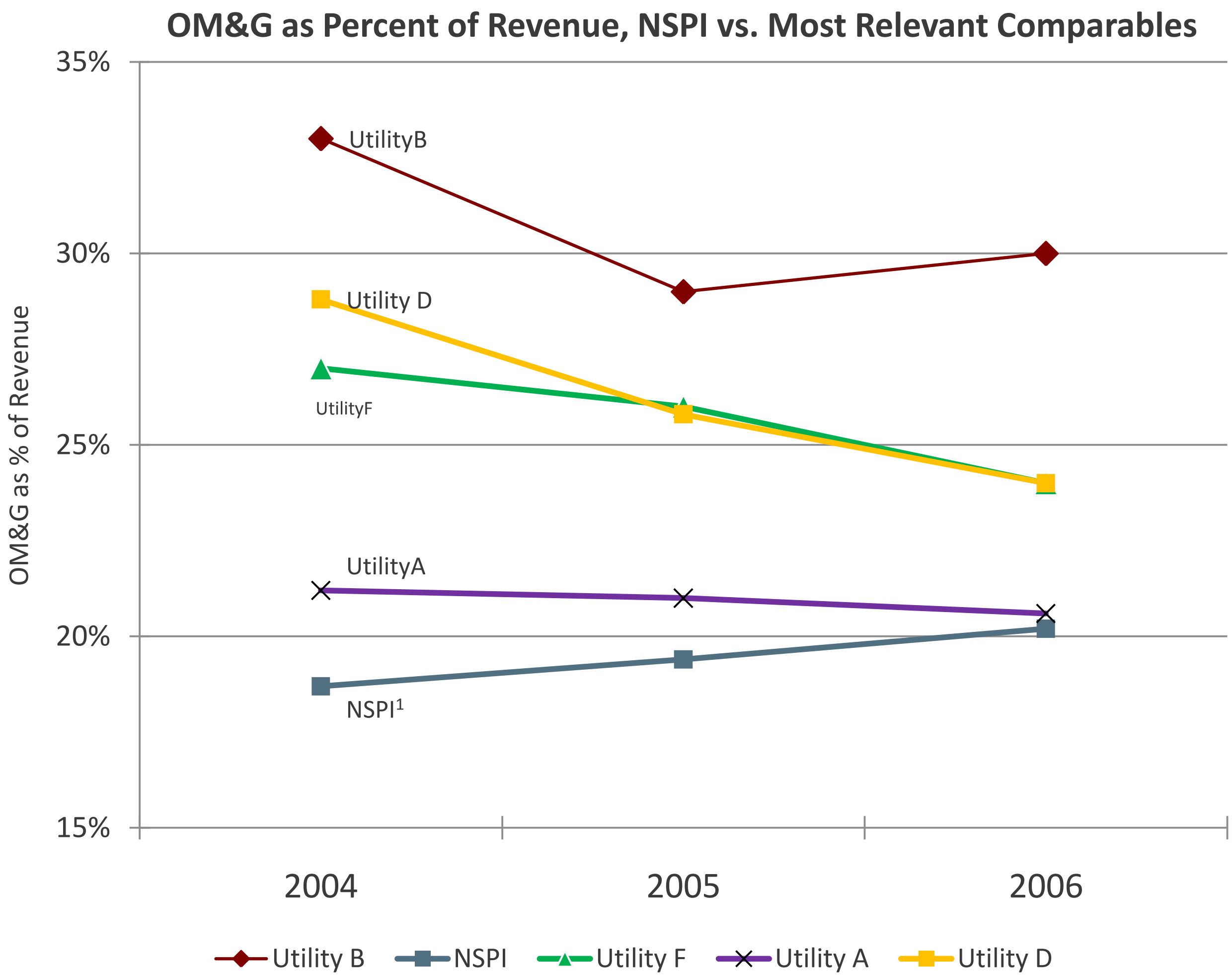



**<u>Possible OM&G Drivers</u>**

- Utility F's yearly increase in OM&G costs may be a result of salary increases and process and technology investments / improvements (e.g., Customer Service and COPS workforce management improvements)
- Utility F's decrease in OM&G as % of revenue is partially due to recent rate increases

# Nova Scotia Power is superior to its comparables in OM&G/Revenue, its upward trend 2004-2006 is expected to be reversed in 2007 based on increased revenue earned

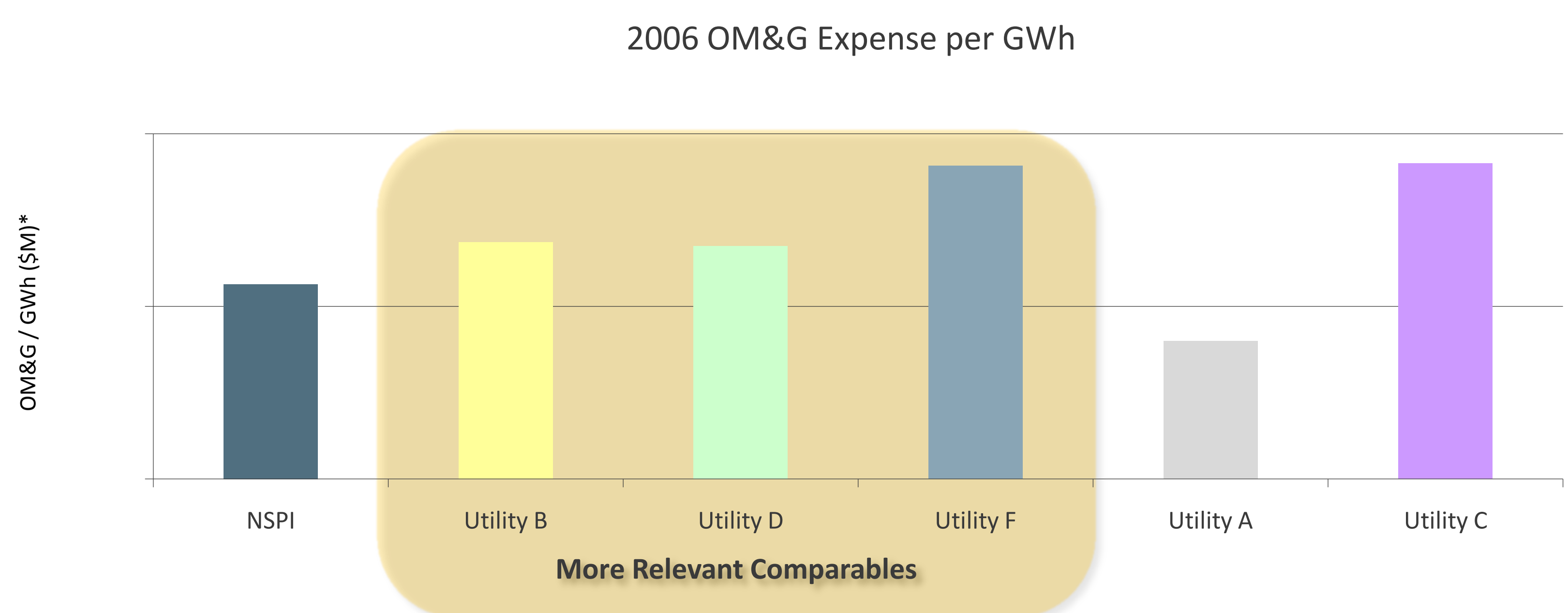
## OM&G Spend vs. Revenue, 2004 – 2006 for NSPI and Comparables




**Information Redacted**

[1] NSPI Percent of Revenue in 2006 may be skewed downwards. Forecast for 2007 = 18.2%*

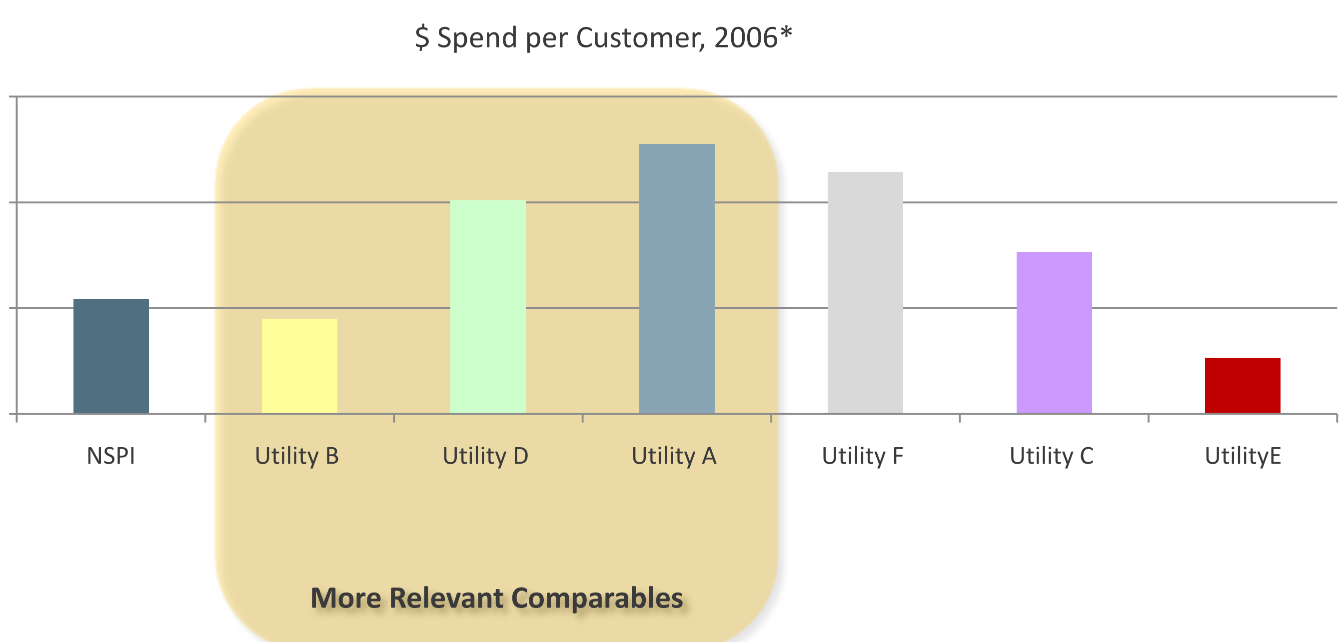
# Aggregate OM&G Comparison: NSPI has lower OM&G expense per GWh than most of the comparable utilities




| | NSPI | Utility B | Utility D | Utility F | Utility A | Utility C |
|---|---|---|---|---|---|---|
| GWh (2006) | | | | | | |
| OM&G $ (2006) | | | | | | |
| OM&G $ / GWh | | | | | | |

Information Redacted

# Aggregate OM&G Comparison: NSPI has lower OM&G $ per customer than most of its comparable utilities[1]

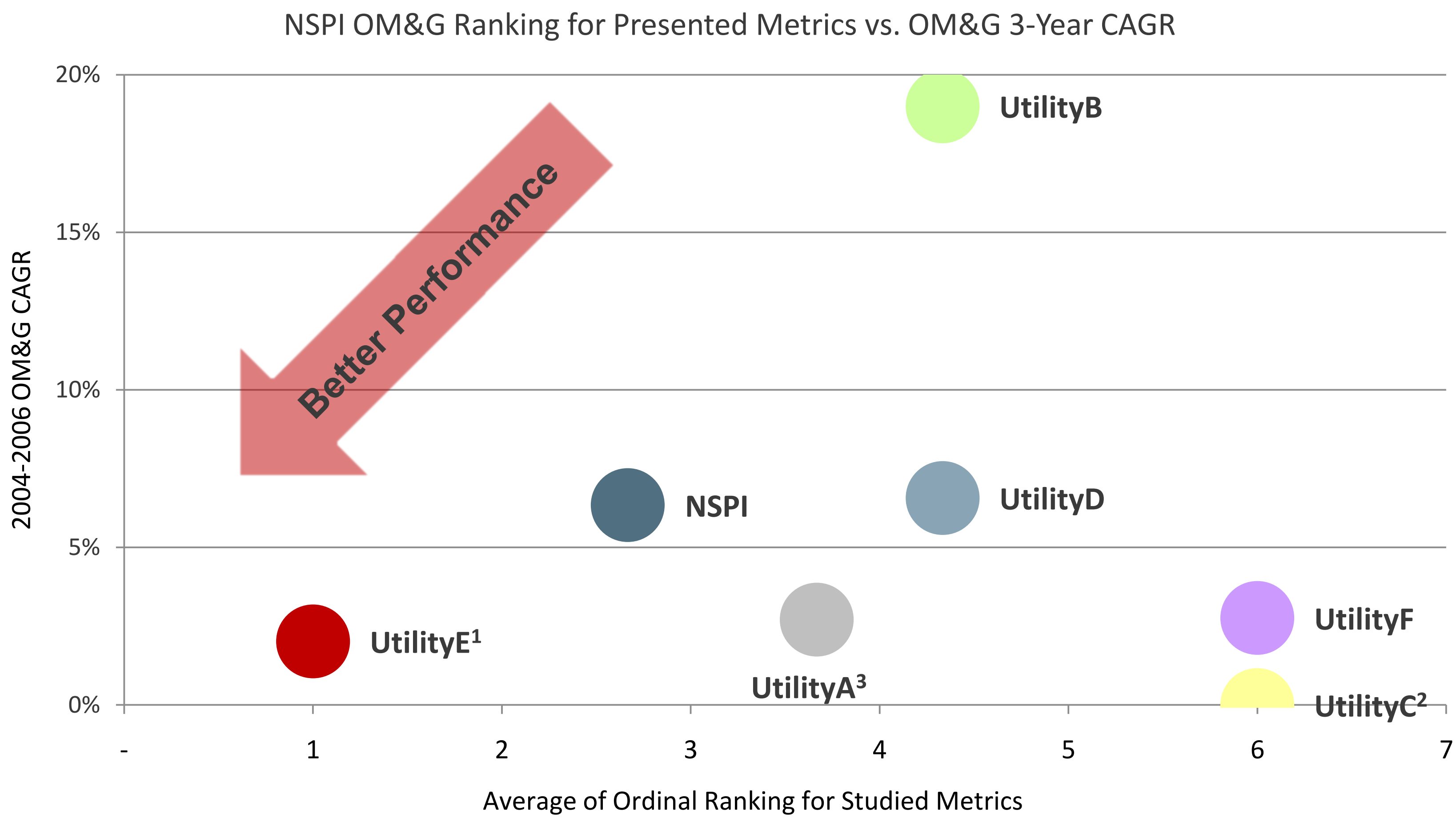



| $ Spend per Customer | 2006 |
|---|---|
| NSPI | $ 435 |
| Utility B | $ 392 |
| Utility D | $ 807 |
| Utility A | $ 915 |
| Utility F | $ 1,020 |
| Utility C | $ 613 |
| UtilityE[1] | $ 212 |

[1]UtilityE purchases most of its power*

**Information Redacted**

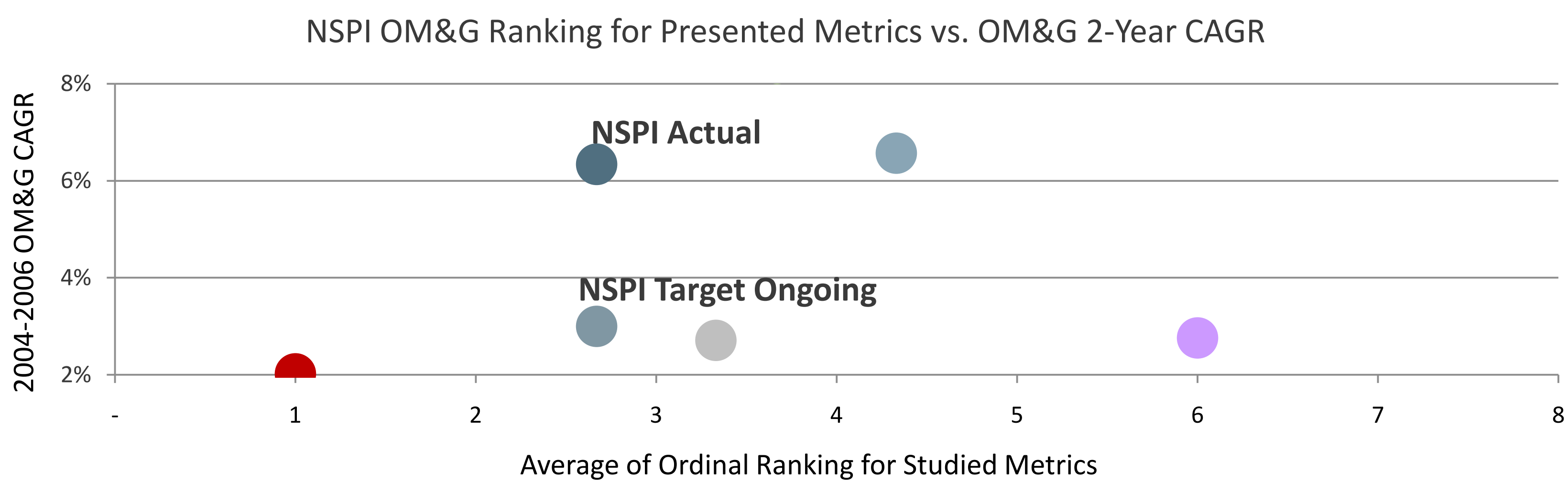
# Aggregate OM&G Comparison: Although its OM&G expenses have been increasing at a faster rate than some of its comparables, NSPI's aggregate OM&G spend is reasonable compared to its competitors




*Explanation of calculation of ordinal rankings shown on following page*

[1]UtilityE purchases most of its power* [2] Utility C's 3 Year CAGR is -22% after sales of divisions [3] Utility A is not a vertically integrated utility

## Aggregate OM&G Comparison: NSPI should take a two-step approach to presenting OM&G expenses:
## 1) Ongoing items in line with local inflation (2.5-3%);
## 2) New costs associated with Board approved investments (variable)




| | NSPI | Utility D | Utility A | Utility F | Utility C | Utility B | UtilityE[1] |
|---|---|---|---|---|---|---|---|
| % of Revenue | 2 | 5 | 3 | 5 | 7 | 6 | 1 |
| per GWh | 3 | 4 | 2 | 6 | 7 | 5 | 1 |
| per Customer | 3 | 4 | 6 | 7 | 4 | 2 | 1 |
| Average | 2.7 | 4.3 | 3.7 | 6.0 | 6.0 | 4.3 | 1.0 |

*NSPI has been successful in containing ongoing costs to inflation or less, presenting Board approved investments separately will demonstrate management's ability to contain costs*

[1]UtilityE purchases most of its power*

# Benchmarking Research

Baseline Comparison

**Power Production**

Customer Operations

Customer Service

Regulatory Affairs

# Benchmarking research has reviewed the following aspects of Power Production and identified a number of opportunities

- High Level Comparison
- Procurement
- Organizational Design
    - Procurement
    - Maintenance / Rebuilds
- KPIs
- Key Investments
- Recommendations

**Primary and Best-in-Class Comparables**

**Information Redacted**

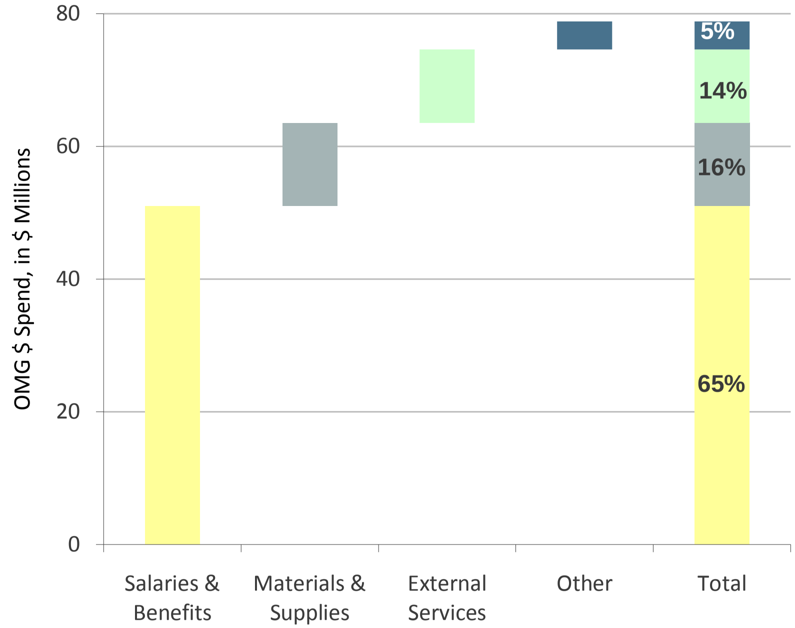
# High Level Comparison: NSPI was benchmarked against the primary comparables in power production

| | NSPI | Utility A | Utility B | Utility C | Utility D |
|---|---|---|---|---|---|
| Headquarters | Halifax, Nova Scotia | | | | |
| Market Size | 465,424 | | | | |
| Generation Cap | 2,320 MW | | | | |
| Total Revenue | $ 997.5M | | | | |
| Total OM&G Budget | $ 200M | | | | |
| Total Employees | 1,685 | | | | |
| Plants | 44 | | | | |
| Power Gen Employees | 455 (coal & gas) | | | | |
| Power Gen OM&G ($) | $ 68M | | | | |
| Production (GWh) | 11,352 | | | | |
| Generation Availability (%) | 93 | 89 | 94 | 95 | 82 (coal only) |

Information Redacted

# High Level Comparison: NPSI's increases in OM&G for Power Production are driven in part by additional costs associated with resource and risk management

Breakdown of 2007 OM&G $ Spend - Power Production

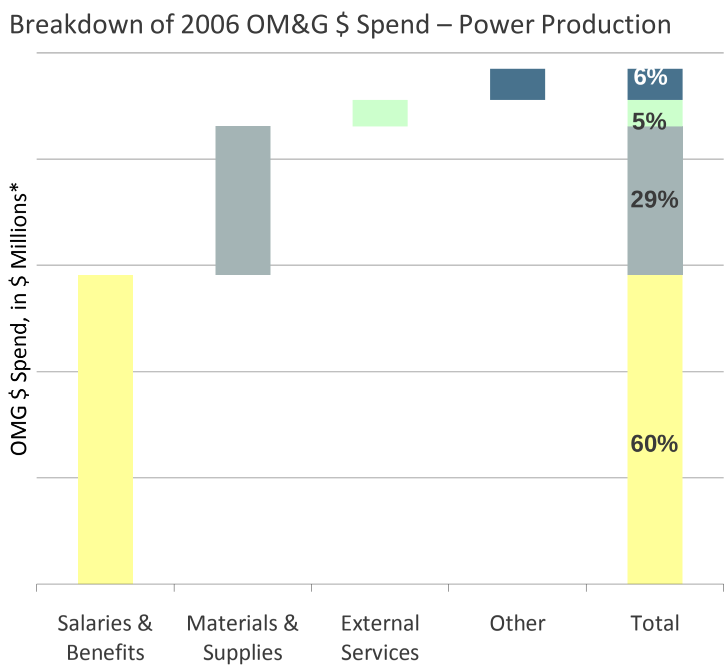



| | OM&G Percentage | $ Spend (2007F) |
|---|---|---|
| Salaries & Benefits | 65% | $ 51M |
| Materials & Supplies | 16% | $ 13M |
| External Services | 14% | $ 11M |
| Other | 5% | $ 4M |
| Total | 100% | $ 79M |

| | 2005 | 2006 | 2007F |
|---|---|---|---|
| OM&G $ | $ 64.7M | $ 68.7M | $ 79M |
| Annual Growth | | 6.1% | 14% |

*Increase in 2007 forecasted driven by a $9M increase in head office costs (reallocation from corporate costs) associated with power production*

# High Level Comparison: In line with its overall OM&G spend, Utility A has been able to limit OM&G growth over the last 3 years



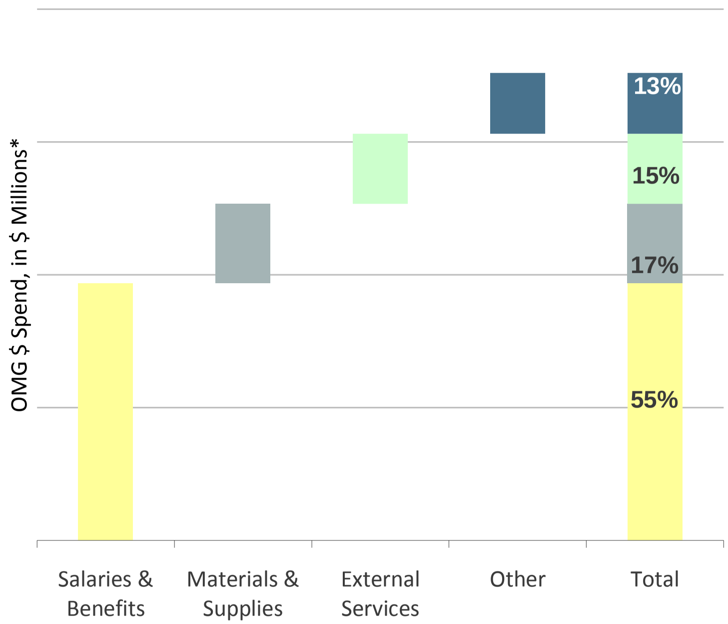

| | OM&G Percentage | $ Spend (2006) |
|---|---|---|
| Salaries & Benefits | 60% | Information Redacted |
| Materials & Supplies | 29% | |
| External Services | 5.2% | |
| Other | 6% | |
| Total | 100% | |

| | 2004 | 2005 | 2006 |
|---|---|---|---|
| OM&G $ | Information Redacted | | |
| Annual Growth | | 6.9% | 0.8% |

*Utility A identified an increase in planned maintenance as a key driver of OM&G containment from 2005-2006*

# High Level Comparison: Utility B uses significantly less purchased power than NSPI, particularly when adjusted for amount of GWh supplied

Breakdown of 2006 OM&G $ Spend – Power Production



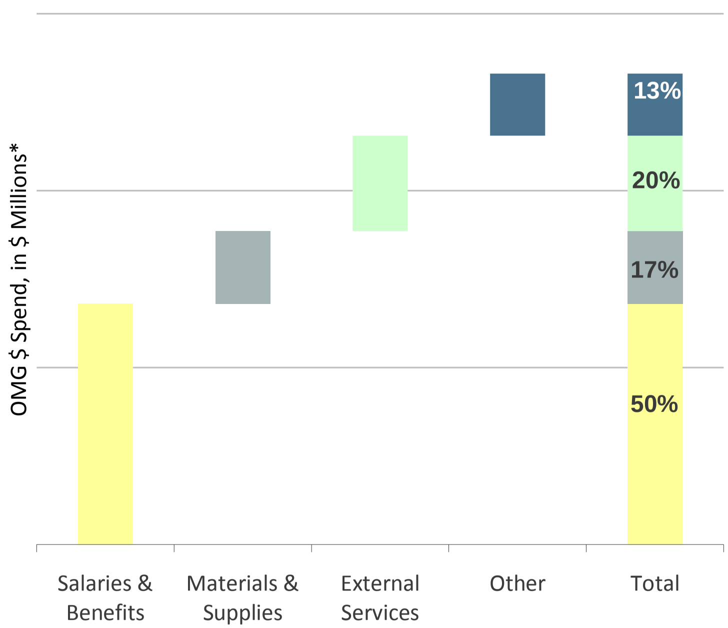

| | OM&G Percentage | $ Spend (2006) |
|---|---|---|
| Salaries & Benefits | 55% | Information Redacted |
| Materials & Supplies | 17% | |
| External Services | 15% | |
| Other | 13% | |
| Total | 100% | |

| | 2004 | 2005 | 2006 |
|---|---|---|---|
| OM&G $ | Information Redacted | | |
| Annual Growth | | 7.4% | 40% |

*Utility B's acquisitions of in 2005-2006 were key drivers in OM&G increases in those years*

# High Level Comparison: Utility C operates independently of Utility C's retail operations after re-structuring in 2004-2005

Breakdown of 2006 OM&G $ Spend – Power Production



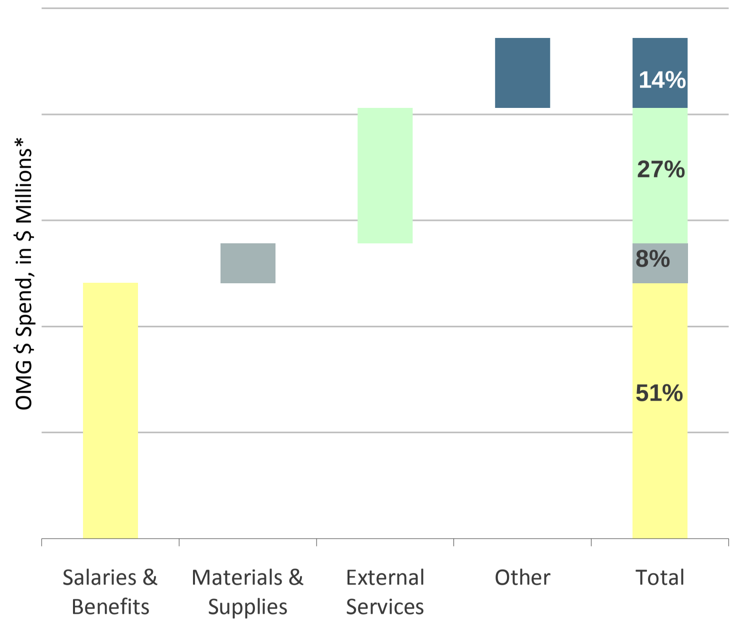

| | OM&G Percentage | $ Spend (2006) |
|---|---|---|
| Salaries & Benefits | 50% | Information Redacted |
| Materials & Supplies | 17% | |
| External Services | 20% | |
| Other | 13% | |
| Total | 100% | |

| | 2004 | 2005 | 2006 |
|---|---|---|---|
| OM&G $ | Information Redacted | | |
| Annual Growth | | 34.6% | 8.6% |

*Utility C's spike in 2005 OM&G expense was attributed to the first full year of operation a new generating plant, which incurred additional labor & material costs*

# High Level Comparison: Utility D relies on external services and labor more than NPSI in its power production operations

Breakdown of 2006 OM&G $ Spend – Power Production

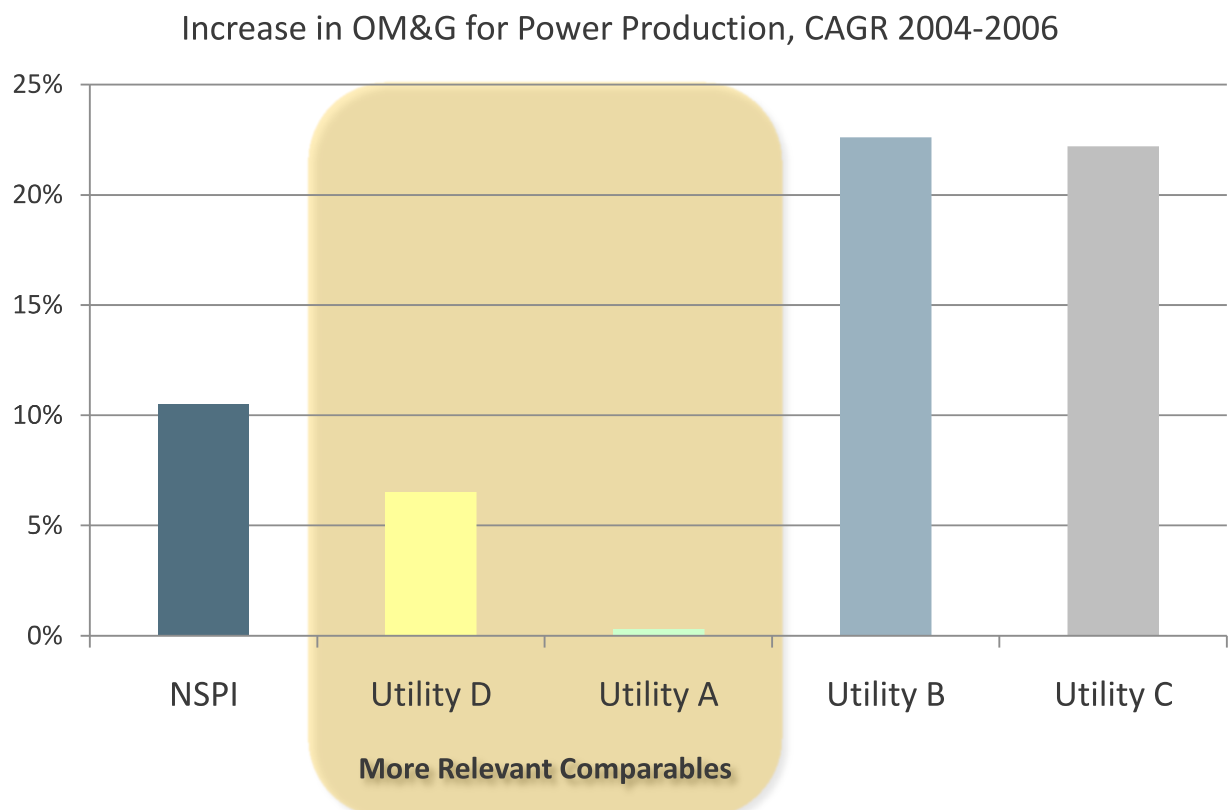



| | OM&G Percentage | $ Spend (2006) |
|---|---|---|
| Salaries & Benefits | 51% | Information Redacted |
| Materials & Supplies | 8% | |
| External Services | 27% | |
| Other | 14% | |
| Total | 100% | |

| | 2004[1] | 2005[1] | 2006 |
|---|---|---|---|
| OM&G $ | Information Redacted | | |
| Annual Growth | | 6.0% | 7.1% |

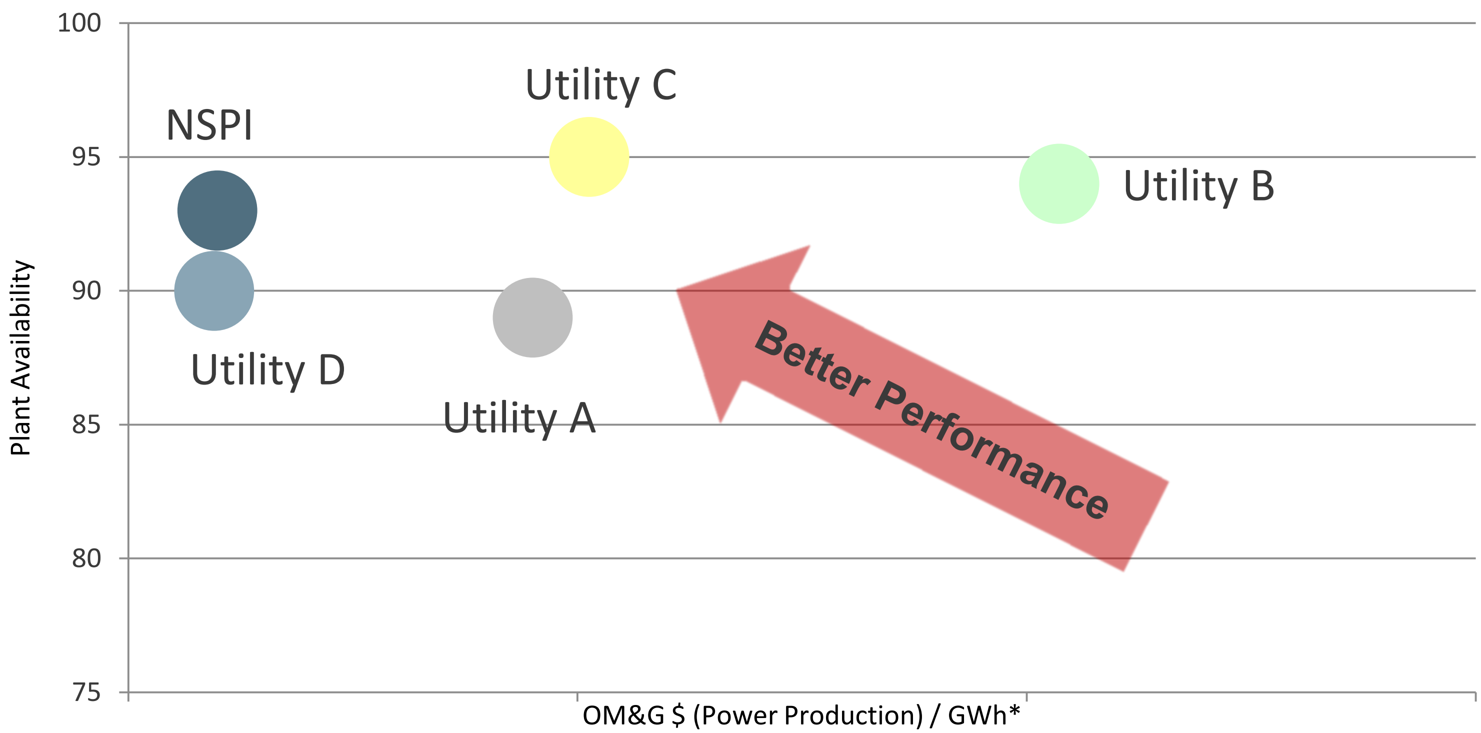
[1] Figures calculated using overall OM&G trend for Utility D

# <u>High Level Comparison:</u> NSPI's OM&G for power production has grown faster than its most relevant comparables 2004-2006



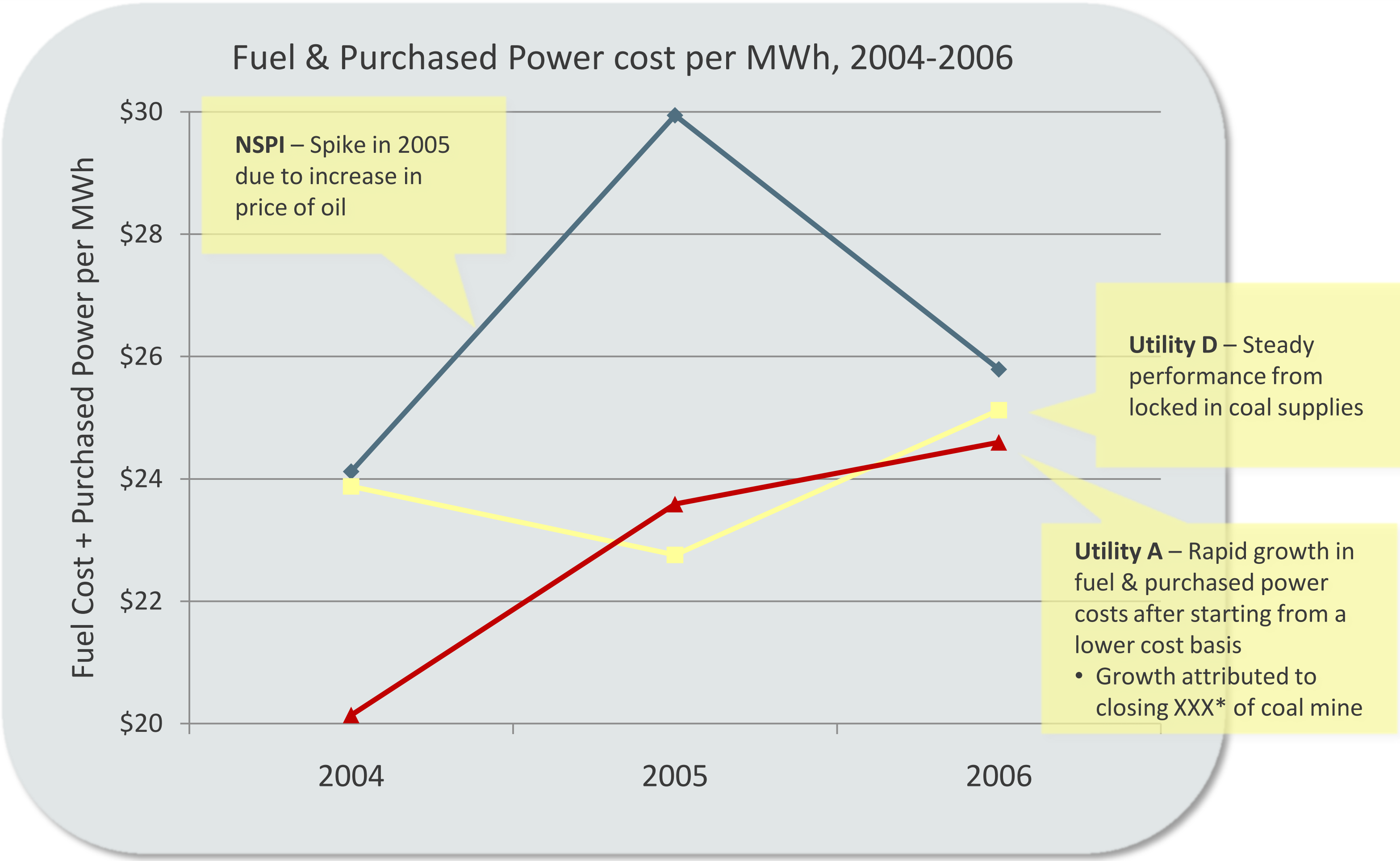

*Utility B and Utility C have been aggressively expanding production by opening new plants and through acquisition in 2004-2006*

# High Level Comparison: NSPI has lower OM&G for Power Production per GWh, while maintaining comparable or superior plant availability



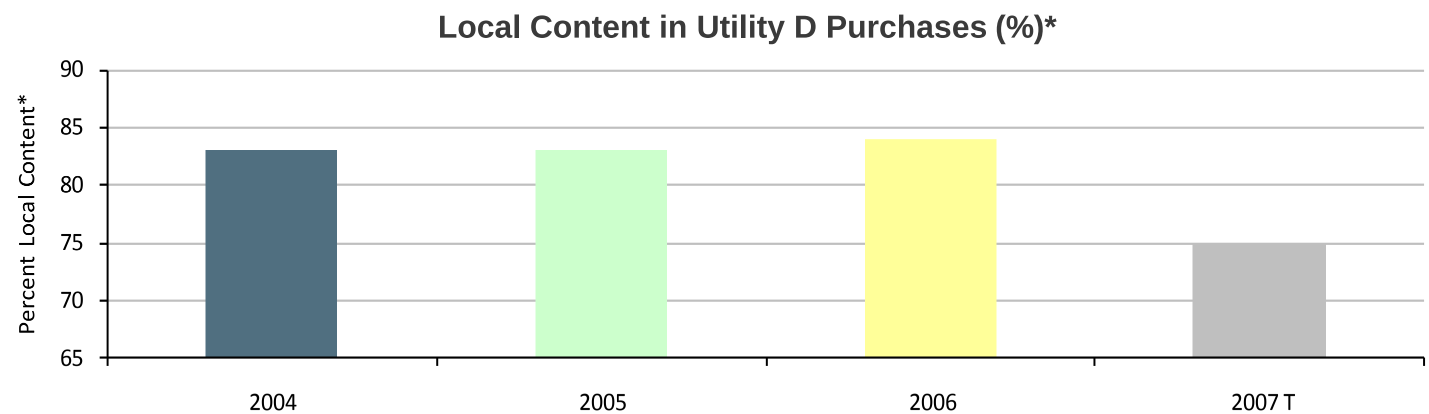

| All figures 2006 | NSPI | Utility C | Utility B | Utility D | Utility A |
|---|---|---|---|---|---|
| OM&G $ (Power Production)/ GWh | Information Redacted | | | | |
| Plant Availability | 93 | 95 | 94 | 90 | 89 |

# Procurement: NSPI's fuel and power purchases are currently at comparable rates to Utility A and Utility D




*After 2005 spike, NSPI successfully reduced its reliance on oil as a fuel source in 2006 by 70% and compensated by increasing coal (+10%) and natural gas (+121%)*

# <u>Procurement:</u> Utility D is mandated to use geographic location as the primary driver behind its sourcing efforts, but is shifting towards a focus on a broader base of suppliers

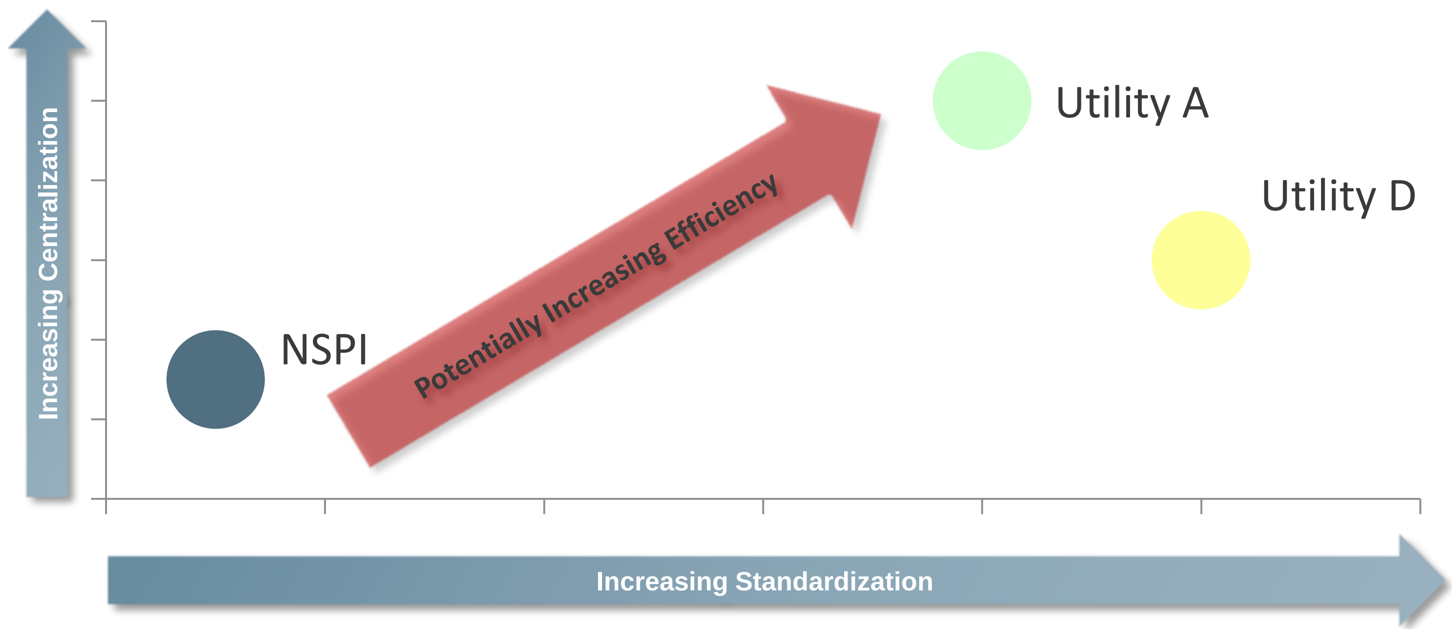



| | 2004 | 2005 | 2006 | 2007 Target |
|---|---|---|---|---|
| % Local Content in Purchases* | 83% | 83% | 84% | 75% |

*Utility D's shift to a broader supplier base is similar to the long term procurement planning currently under way at NSPI (as documented in the internal analysis)*

# Org. Design: KA's assessment of power plant's org. structures categorizes along 2 key dimensions, centralization and standardization

Standardization vs. Centralization in Power Plants

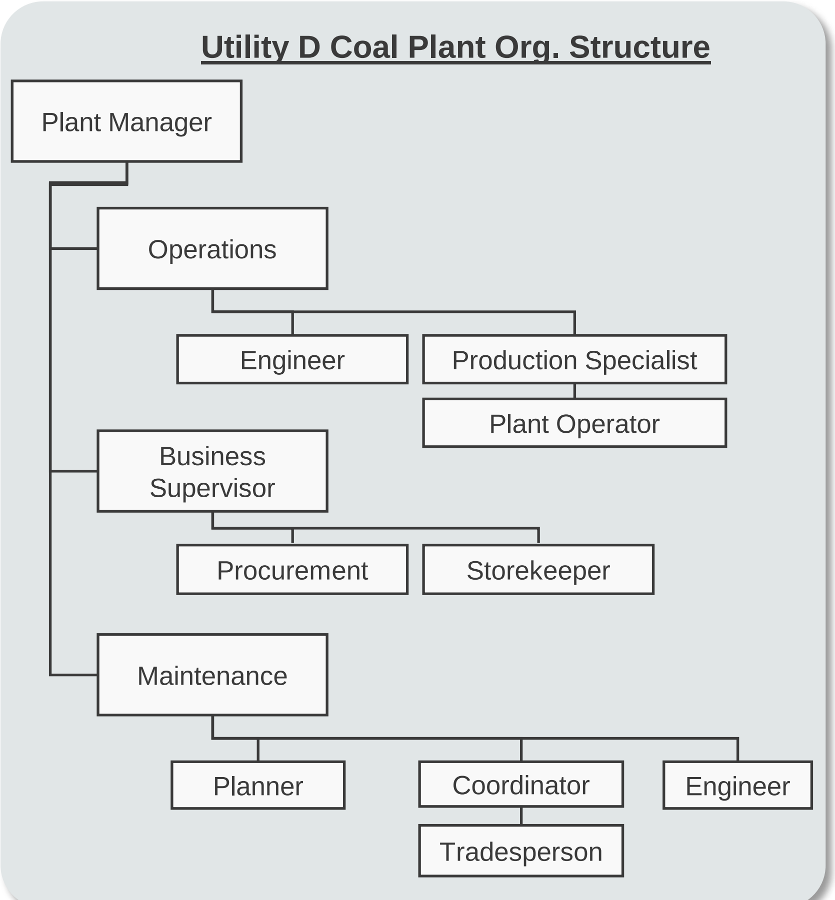



Potential benefits of centralization
- Increased sharing of resources/best practices
- Elimination of redundant support services

Potential benefits of standardization
- Increased accountability for specific tasks (e.g. planning/scheduling)

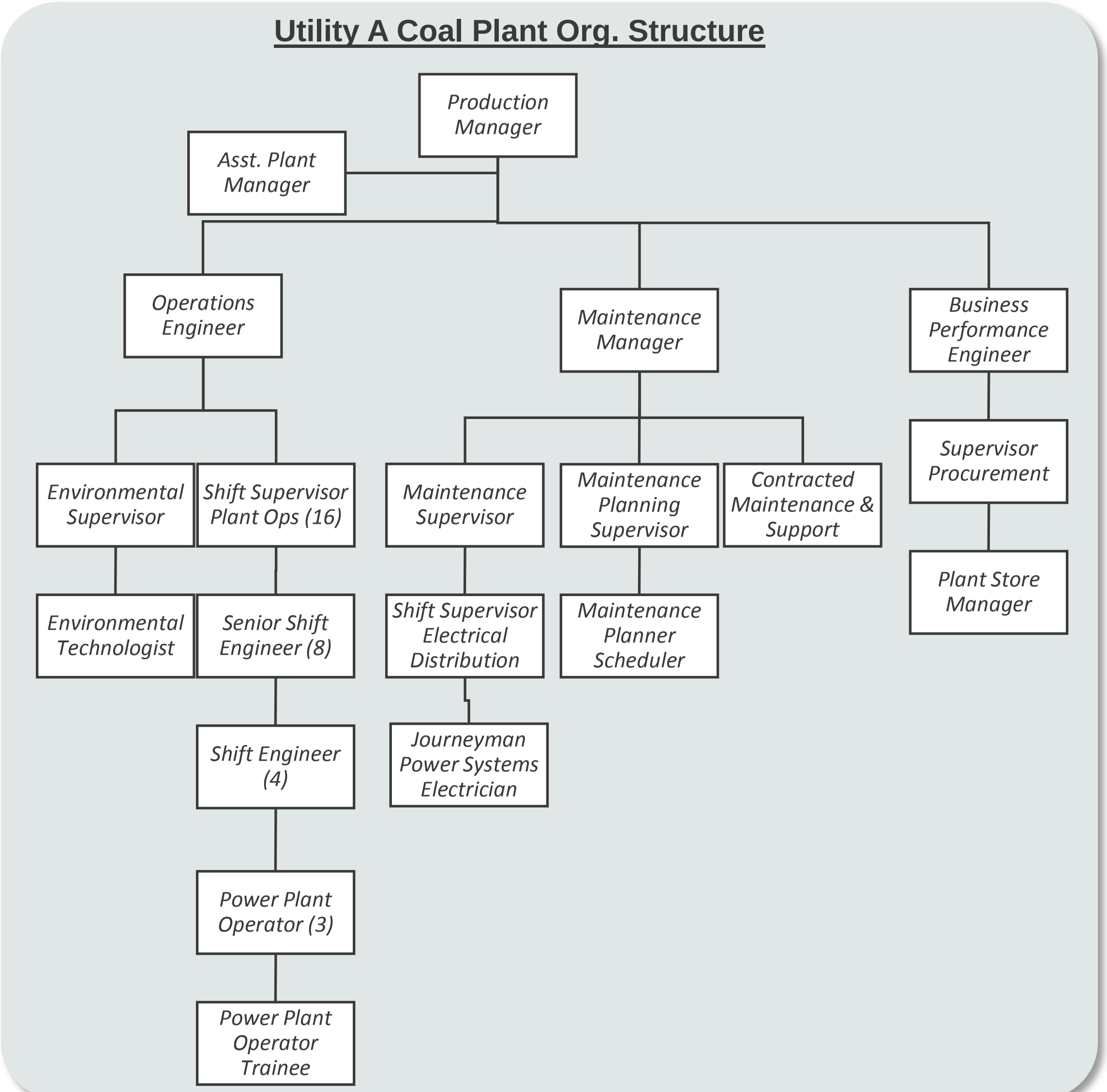
Note: Graphs is representative and not to scale

# Org. Design: Utility D utilizes a standard org structure across its coal plants as opposed to NSPI's variable structure



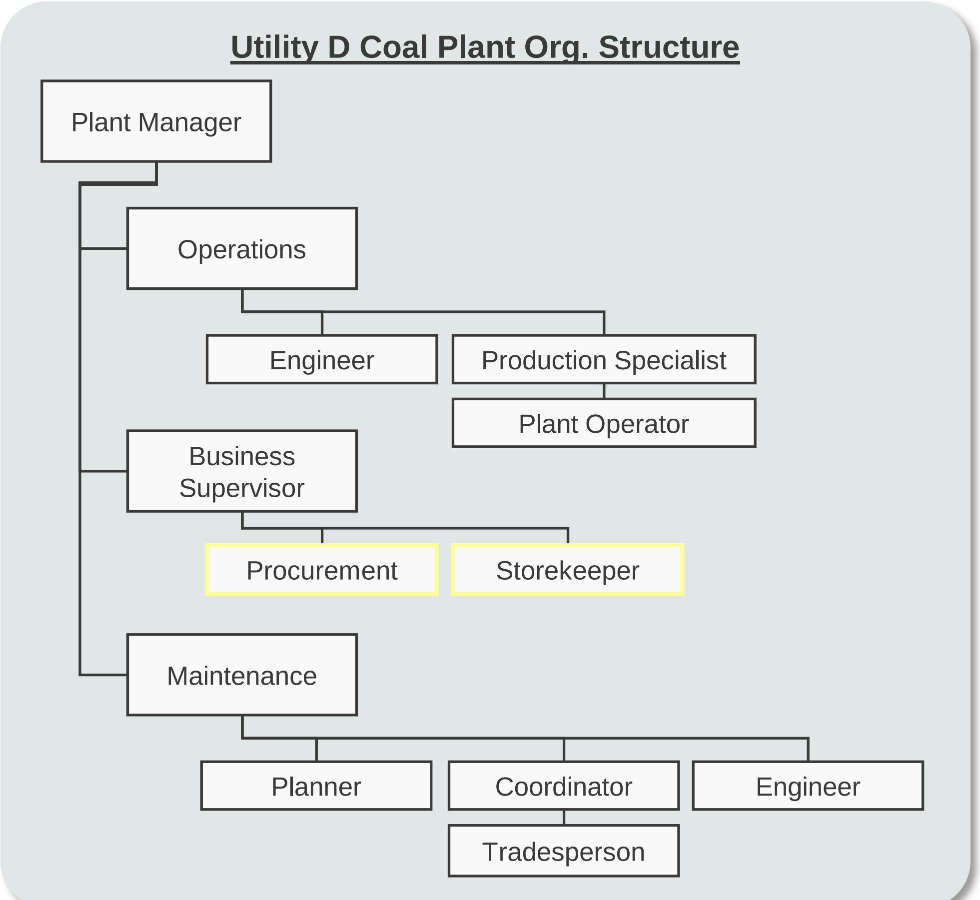

| Position | Duties |
|---|---|
| Plant Manager | • Responsible for meeting production goals of plant within the budget<br>– Compares preventative maintenance costs with replacement costs to determine when to replace<br>• Assesses staffing levels and plans outages |
| Planner | • Researches, plans and creates work orders for designated work categories<br>– Instrumentation, electrical, mechanics, welders, machinists |
| Coordinator | • Coordinates resources and workload<br>– Schedules work for internal labor and external contractors |
| Tradesperson | • Supervises trades people<br>• Attends weekly planning meetings and contributes to advanced scheduling |
| Business Supervisor | • Develops budget and tracks performance against budget<br>• Accountable for cash flow<br>• Oversees stores and procurement |
| Procurement | • Responsible for procurement of maintenance, repair, and operations parts<br>– Ability to do bulk buys for plant<br>– Integration between maintenance management and materials management drives procurement |
| Storekeeper | • Manages inventory<br>– Tracks costs, movement, and number of times an item is used<br>• Receives and issues parts |
| Production Specialist | • Manages two shifts of plant operators<br>• Operators monitor unit operations and perform preventive maintenance |
| Charge Engineer | • Lead engineer in charge of plant operations<br>– Issues work permits and approves work requiring changes in operations |
| Operator | • Monitors unit operation at control center<br>• Performs inspections and tests<br>– Fire pump test, gas gun checks, run cleaning system on condenser, perform environmental checks |

# Org. Design: Utility A utilizes a centralized, standard organizational structure allowing sister plants to share resources and best practices




- For the most part, Utility A power generation facilities have a centralized organizational structure
  - Dedicated resources work only at the facility assigned
  - Employees regularly transfer from one facility to another
- Sister plants (same fuel type) located within a close distance will share resources

# Org. Design – Procurement: Utility D utilizes a distributed procurement function with minimal additional staffing at the plant level, similar to NSPIs




| Position | Duties |
|---|---|
| **Procurement** | • Responsible for procurement of maintenance, repair, and operations parts<br>– Ability to do bulk buys for plant<br>– Integration between maintenance management and materials management drives procurement |
| **Storekeeper** | • Manages inventory<br>– Tracks costs, movement, and number of times an item is used<br>• Receives and issues parts |

*Giving plants greater procurement authority enables them to more quickly address their individual needs*

# Org. Design – Procurement: Utility A maintains procurement specialists onsite with a centralized procurement policy

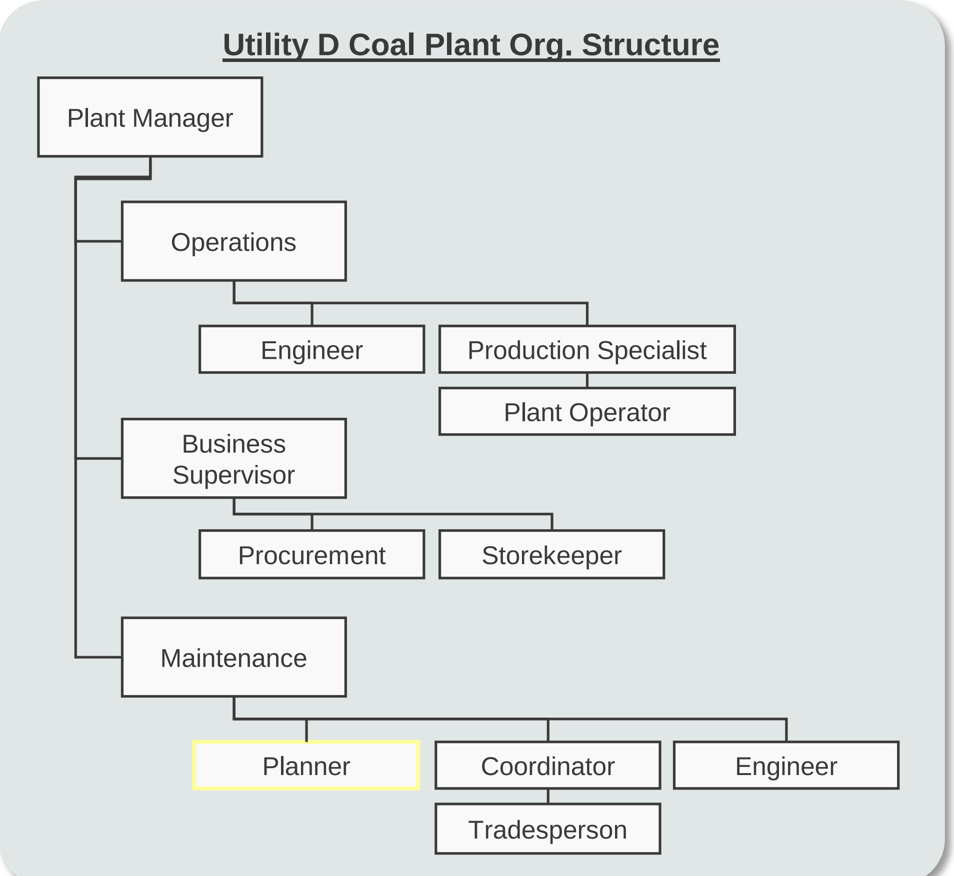
- Materials procurement policy at Utility A is centralized with day-to-day sourcing performed onsite
  - Onsite team ensures critical parts required for maintenance are sourced and purchased as soon as possible
  - Onsite team reduces the turnaround time for unplanned maintenance due mechanical problems
- Each site consists of a store manager that oversees the contract and purchasing of replacement parts and equipment
- Centralized team monitors/coordinates activities of onsite teams

**Example**

- A unit of a Utility A's coal-fired plant had to shut down due to a issue with a blade that malfunctioned (blade was purchased several years ago and typically lasts 30 years)
  - Maintenance teams worked with onsite procurement specialists to source new blades despite industry shortages
  - The unit was off-line for a month and a half
  - Utility A predicted that they could have been off-line much longer if the proper teams weren't on site

*Dual-tiered structure helps turn around critical sourcing issues faster while adhering to company-wide policies on procurement; NSPI has recently implemented a similar structure*

# Org. Design – Maintenance/Rebuilds: Utility D provides a responsive and proactive maintenance function by consolidating work order planning, processing, and execution under the planner role




| Position | Duties |
|---|---|
| **Planner** | • New (Created 2001 / 2002) owner of maintenance activities<br>– Schedules and plans work for functional & engineering staff |

*Plants begin each day with a review of the SAP generated work plan*

# Org. Design – Maintenance/Rebuilds: Utility A effectively applied a wireless sensor system integrated with SAP WMS to increase maintenance efficiency

- XXX* Work Process Management System with RFID technology
- XXX* is used to link field maintenance workers directly to Utility A's SAP ERP suite & work management modules, and Oracle databases, through a wireless handheld device and mobile field service software
- Work management system automatically dispatches and closes out orders
  - 802.11b sensors (WLAN radios with sensors that monitors vibration and temperature) that trigger messages to a technician's mobile device when gauge reaches critical points
- Initial testing was at the XX* facility in Q2, 2004
- Global implementation began in 2006

- Results:
  - XXX* system paid for itself in 4 months
  - Turnaround time on routine tasks cut by 50%, for experienced and non experienced workers
  - Time lag in paper maintenance inspecting and reporting reduced from 2 days to 30 minutes

| | Cost/Benefits |
|---|---|
| **Sensors** | $800 each |
| **2 year benefits** | $15M |

*Utility A was the winner of POWER magazine's Award for excellence in Operations and Maintenance**

# Org. Design: NSPI has a higher number of direct reports compared to Utility D and Utility A at the plant level

| Utility | Plant | No. of Employees | No. of Direct Reports |
|---|---|---|---|
| NSPI | Lingan | Information Redacted | |
| | Point Tupper | | |
| | Trenton | | |
| | Point Aconi | | |
| | Tuft's Cove | | |
| Utility D | | | |
| Utility A | | | |

| Utility | Average Ratio of Direct Reports to Employees |
|---|---|
| NSPI Plants | 1 : 16 |
| Utility D Coal Plants | 1 : 69 |
| Utility A Coal Plants | 1 : 77 |

*Utility D and Utility A operate with fewer direct reports than NSPI. This may result in greater efficiency and cost-savings due to:*

- *Clearer chain of command and more seamless decision-making*
- *Fewer senior-level salaries at the plant level*

*No. of Direct Reports to Plant Manager – excludes Admin Assistant (where applicable)

– Production and Operations are synonymous

# Org. Design: NSPI trails Utility A's average MW/employee due to the latter's centralized org structure with fewer plant supervisors

| Company | Plant | MegaWatts (MW) | Employees[1] | MW / Employee |
|---|---|---|---|---|
| NSPI | Lingan | | | |
| | Point Tupper | | | |
| | Trenton | | | |
| | Point Aconi | | | |
| | Tuft's Cove | | | |
| Utility D Coal | | | | |
| Utility A Coal | | | | |

Information Redacted

| Company | Average MW / Employee | Standard Deviation |
|---|---|---|
| NSPI | 3.9 | 1.77 |
| Utility D Coal | 2.6 | 0.19 |
| Utility A Coal | 4.4 | 0.02 |

[1]NSPI's total employees calculated from plant-specific organizational charts

*Both Utility D and Utility A show a much lower standard deviation in Average MW/Employee, a demonstration of their standardized org. structures*

# KPIs: Utility D and Utility A use unique financial and staff oriented KPIs which differ from NSPI's power production KPIs

| Company | KPI | Definition | Target | '07 | '06 | '05 |
|---|---|---|---|---|---|---|
| Utility D | Injury severity rate | Severity of injuries at work during the year based on days lost due to injury | | | | |
| | Injury frequency rate | Number of injuries or illnesses that resulted in lost work time during the year. | | | | |
| | Attract and Retain staff % | | | | | |
| | Coal unit availability 1-yr average (EAP %) | Overall availability of coal units to generate maximum continuous rating. A high level of coal unit availability is an important factor in minimizing fuel and purchased power costs. Below target in '06 due to unscheduled extension of popular river power station overhaul | | | | |
| | Generating fleet | New- Overall availability of generating fleet to generate at its maximum continuous rating . Measure demonstrates effectiveness and optimization of the corp's overall generation asset maintenance strategy. | | | | |
| | Unqualified EMS audit | | | | | |
| | Environmental emission | | | | | |
| Utility A | Plant availability (%) | Percentage of time a generating unit is capable of running, regardless of whether or not it is generating electricity | | | | |
| | Production (GWh) | Amount of electricity generated | | | | |
| | Contracted Production (%) | % of total produced internally | | | | |
| | Injury Frequency Rate | Measure of all fatal, lost time and medical aid injuries | | | | |
| | OM&G ($/installed MWh) | OM&G per MWh | | | | |
| | Cap Ex Sustaining ($ mil) | Investment in existing plants | | | | |
| | Cap Ex Growth ($ mil) | Investment in new/refurbished plants | | | | |
| | # of work orders open | Number of high priority work orders open | | | | |

**Information Redacted**

# KPIs: NSPI tracks similar power production KPIs as Utility D and Utility A, but could improve long term planning by tracking additional environmental and work force KPIs

| | | NSPI | Utility D | Utility A |
|---|---|---|---|---|
| Top KPIs | Generation | Generation vs. Forecast<br>Fuel Cost vs. Forecast<br>Heat Rate vs. Forecast | Generating fleet availability<br>Coal unit availability 1-yr average (EAP %) | Plant availability (%)<br>Contracted Production (%) |
| | Operating Expenses | OM&G vs. Forecast | Operating Expense / KWh | Operating Expense / KWh |
| | Capital Deployment | Capital vs. Forecast | | Cap Ex Sustaining ($ mil)<br>Cap Ex Growth ($ mil) |
| | Workforce/Safety | | Attract and Retain staff %<br>Injury frequency rate | Injury Frequency Rate |

**Kaiser has identified a number of additional KPIs that are tracked by other utilities, some of which may be tracked by NSPI**

- Environmental Emissions
- Electric / Steam Production Ratio
- System Losses (%)
- Energy Sales / Circuit (MWh / km)
- Employees / Customer
- Work Management Efficiency
- Maintenance Work and Rework
- Diversity Candidates (i.e., sourcing candidates)
- Fuel Consumption Rate / KWH
- Planned vs. Unplanned Maintenance Ratio
- Absenteeism
- Work Order Backlog
- Customer / Distribution Circuit (km)
- Labor Productivity (MWh / Labor)

*Kaiser did not investigate NSPI's forecasting methodology to determine that they are set at an appropriate level*

# Key Investments: Utility D works with local and provincial authorities to help cut the OM&G burden of long range environmental and capacity planning

Information Redacted

| Clean Coal Power Production | | |
|---|---|---|
| Feasibility Study | Cost | Information Redacted |
| Proposed Plan Profile | Cost | |
| | MW | |
| | Target Date | |

*Utility D is spending **$ XM** on its study of clean coal feasibility and associated planning; This is matched by a further **$ XM** local government**

# **<u>Key Investments:</u>** Utility A is investing jointly with Utility B on generation to cost share and reduce its risk for new generation capacity

<u>New Power Generation and Fuel Sourcing</u>

**Information Redacted**

**Upcoming Generation Investments**

**Information Redacted**

*Like NSPI's investment in tidal power, Utility A is pushing investment in renewable energy in part to reverse its  a poor environmental reputation*

**Information Redacted**

# Recommendations: Without a deeper dive analysis, KA is unable to quantify recommendations in power production, but can make more general suggestions

| Opp. Area | Recommendation |
|---|---|
| Org. Design | • NSPI should plan and present to the board their organizational design strategy for the coming years. The plan should address:<br>– Standardization of functions/structures for increased planning and accountability<br>– Centralization of staff functions for potential cost savings<br>– Resource pooling at like plants<br>– Potential reduction in the number of supervisors<br>– Plans for knowledge management in anticipation of large wave of retirements |
| Procurement | • NSPI is beginning to look at procurement with increased planning and out of region focus<br>• Increased focus on spare parts planning is ongoing to catch up inventory stocks<br>– Policies and processes on procurement should be reflected in org. structure implemented at the plant level |
| Green Power | • NSPI will need to continue to make investments in hydro, wind and tidal plants to:<br>– Meet rising consumer demand for green energy<br>– Reduce volatility associated with fuel and purchased power<br>• If possible, NSPI should seek to cost share with local stakeholders |

# Benchmarking Research

*Baseline Comparison*

*Power Production*

*Customer Operations*

*Customer Service*

*Regulatory Affairs*

# Benchmarking research has reviewed the following aspects of Customer Operations and identified a number of opportunities

- High Level Comparison
- Vegetation Management
- T&D Line Maintenance / Life Extensions
- Workforce Management Systems (WMS)
  - Work Order Scheduling / Processing
  - Organizational Design
  - Knowledge Management / Capture
  - Communications
  - System Improvements
- Outsourcing
- Recommendations

**Primary and Best-in-Class Comparables**

**Information Redacted**

# High Level Comparison: Customer Operations (COPS) Benchmarked Companies

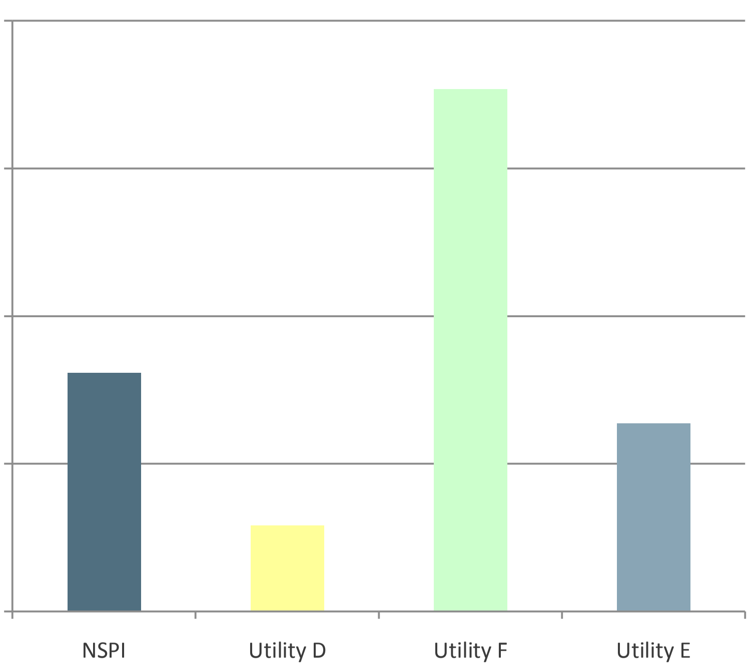
| | | Primary | BIC Comparable | |
|---|---|---|---|---|
| | NSPI | Utility D | Utility E[2] | Utility F |
| **Territory Served** | Nova Scotia | | | |
| ***Customers / T&D (km)*** | 15.3 | | | |
| **Customers** | 465,424 | | | |
| **T&D Lines (km)** | 30,370 | | | |
| **Sales GWh** | 11,573 | | **Information Redacted** | |
| **Employees** | 1,800 | | | |
| **OM&G Expense** | $ 196M | | | |
| **Crown Corporation (Y/N)** | No | | | |
| **SAIFI (2007)** | 2.91 | Lower than NSPI* | Same as NSPI* | Lower than NSPI* |
| **SAIDI (2007)** | 5.25 | Lower than NSPI* | Lower than NSPI* | Lower than NSPI* |
| **CAIDI (2007)** | 1.80 | Higher than NSPI* | Lower than NSPI* | Lower than NSPI* |

[2] Utility E purchases most of its power, it is included in this section for its vegetation management practices*

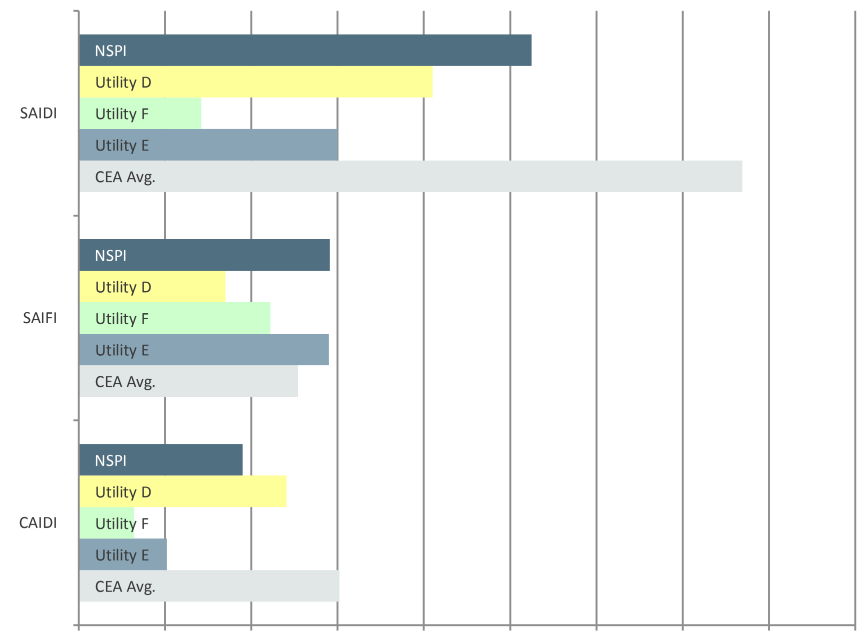
**Information Redacted**

# High Level Comparison: NSPI spends more per km of operations territory than 2 of 3 benchmarks, yet has the highest frequency of outages

## OM&G Spend per T&D km

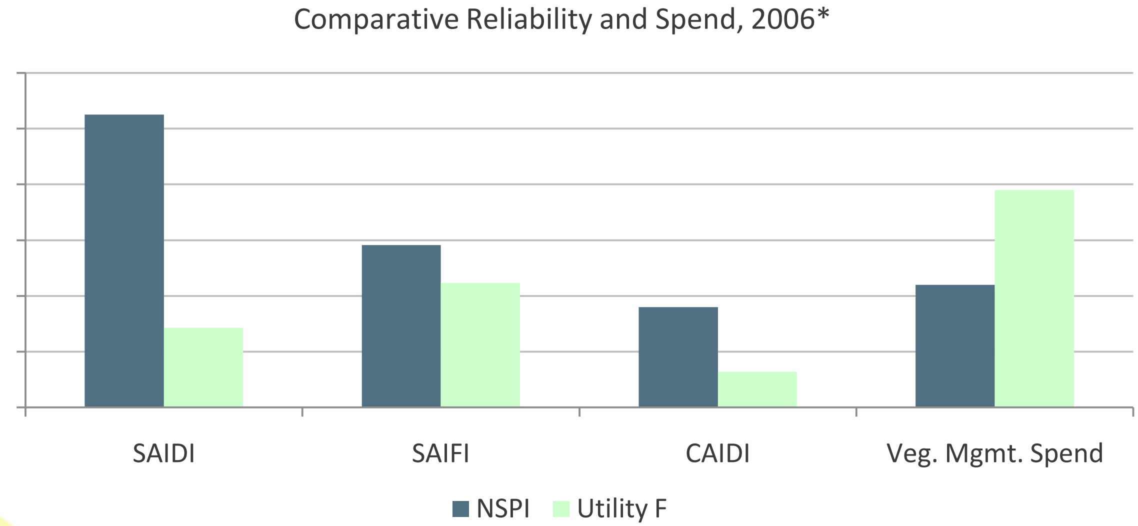


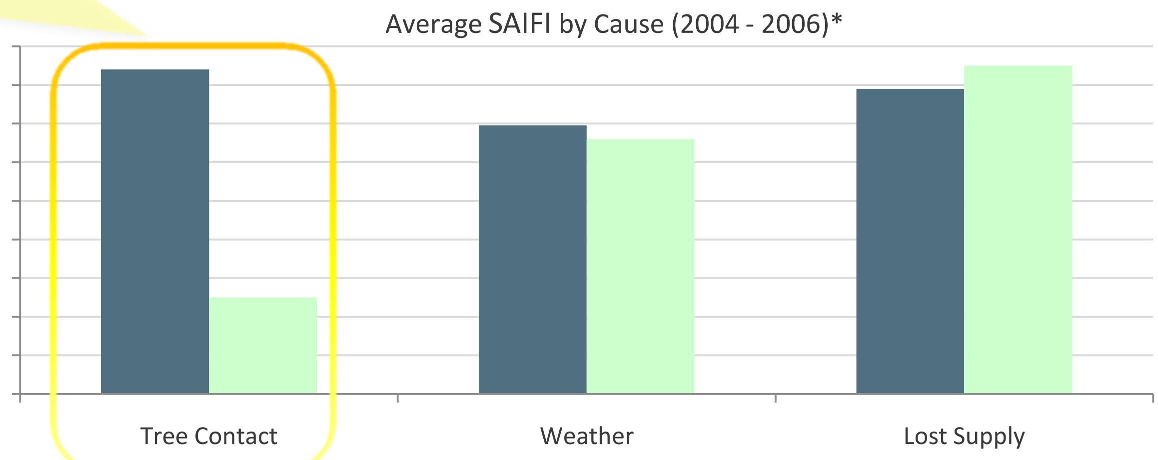

## Reliability Performance Measures (2007)




| | NSPI | Utility F | Utility D | Utility E |
|---|---|---|---|---|
| OM&G | $ 196M | Information Redacted | | |
| T&D km | 30,370km | | | |
| OM&G / T&D | 6,453 | 14,139 | 2,321 | 5,090 |
| SAIFI (2007) | 2.91 | Lower than NSPI | Lower than NSPI | Same as NSPI |

# Vegetation Mgmt.: Utility F spends almost twice as much as NSPI on veg. mgmt and significantly out-performs NSPI in key reliability measures




- Average SAIFI by cause demonstrates similar performance between Utility F and NSPI in most categories except for tree contact
- Tree contact discrepancy suggests that Utility F is performing better in its vegetation management program given NSPI's and Utility F's similarities

# Vegetation Mgmt.: Utility F and NSPI maintain similarly sized T&D assets and transmission line right-of-ways yet Utility F outperforms NSPI's reliability scores

- Utility F uses a work management system to plan, schedule, and track its vegetation management program
  - Annual work is planned by January 1
- Program is on a five, six, or seven year cycle depending on line voltage, conductor heights, and vegetation growth rates for the geographical area
  - Each year, Utility F maintains brush on ~1,000 km of transmission line rights-of-way
  - Buffer areas are managed to meet environmental concerns or construction permit conditions
- Utilizes slashing and mowing techniques with the use of hand tools as well as with wheel or track-mounted equipment
  - Herbicides are only used to control weeds located inside the yards of substations, terminals, dam sites, and fuel tank farms at generating stations

**Vegetation Management Profiles**

| | NSPI | Utility F |
|---|---|---|
| **% Outsourced vs. % In-House[1]** | 100:0 | 70:30[1] |
| **Distribution Lines (km)** | 25,195 | Information Redacted |
| **Transmission Lines (km)** | 5,175 | |
| **Rights-of-way (acres)** | 40,000 | |
| **Annual Cycle (years)** | 4 – 5 | 5 – 6 |
| **Primary Methods / Techniques** | Slashing, Mowing (~80%), Herbicides (~20%) | Slashing, Mowing (~95%), Herbicides (~5%) |
| **SAIFI** | 2.91 | Lower than NSPI* |
| **SAIDI** | 5.25 | Lower than NSPI* |
| **CAIDI** | 1.80 | Lower than NSPI* |

[1]*Based on approximate OM&G spend*

**Information Redacted**

*Utility F performs more of its vegetation management in-house at the same percentage of total OM&G spend*

# Vegetation Mgmt.: Utility F's prioritization / classification of vegetation management issues allows for the highest priority threats to be addressed within 24 hours

- Utility F completes an aerial inspection of all of its transmission lines annually and ground inspections on a five-year cycle
- During inspections, danger trees are assigned a priority classification (i.e., 1, 2, 3, or Emergency)
  - Prioritization determines speed at which vegetation management issues are addressed *(see graphic to right)*
- Upon identifying high priority vegetation management issues, work orders are created and then issued to either
  - Utility F's vegetation management group

  or
  - to hired contractors
- In most situations, Utility F's vegetation management group responds to the work order
  - By prioritizing, direct cost savings are realized through (1) prevention of immediate / short-term transmission disruptions and (2) by placing on hold non-immediate threats for the following year (i.e., labor savings)

Vegetation Management Priority Classification (Low → High)

**Priority 3**
- Least dangerous threats to transmission lines
- Recorded / processed for next year's cycle
- Removed during the **following year's maintenance cycle**

**Priority 2**
- Poses a short- to long-term risk to integrity of transmission system
- Removed **within one month** of identification

**Priority 1**
- High priority, posing great threat to transmission system (i.e., leaning trees)
- Removed **within 24 hours** of identification

**Emergency**
- Poses highest threat to transmission system (i.e., trees in threat of falling during heavy winds)
- **Removed almost immediately**; if not, within 24 hours

*Utility F's prioritization of vegetation management issues reduces transmission disruptions by addressing the highest threats to the system on a proactive basis; NSPI performs a prioritization assessment but reliability results have not measured up*

# Vegetation Mgmt.: Supplementing its vegetation management group with external contractors allows Utility F to effectively manage its transmission rights of way and operating costs

**Supervisor, Forestry and Vegetation Management**

**In-House Vegetation Management Program**

- Utility Specialist Certified Arborists
- Forest technicians
- Environmental inspectors
- Crew leaders
- Equipment operators
- Chainsaw operators

**External Vegetation Management Contractors**

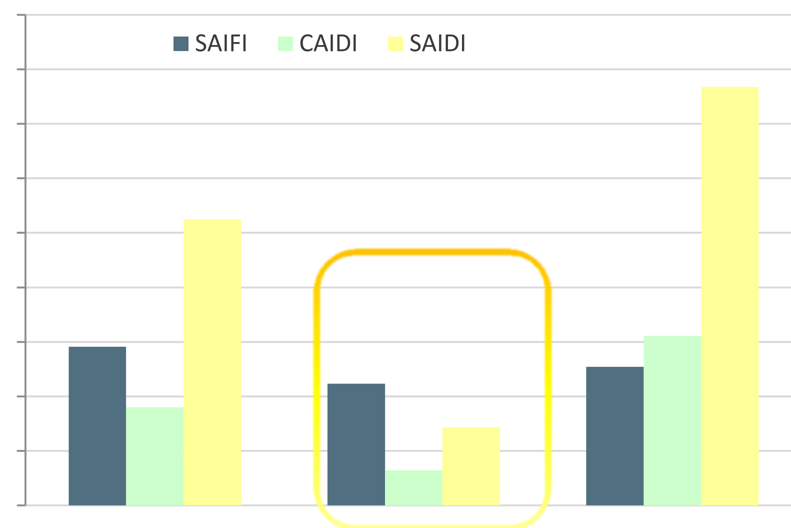
- Utility F uses its own staff (and cutting machinery) to meet most of its *planned* vegetation management goals
  - Utility F supplements in-house program with contractors to meet schedules and to address high priority / emergency priorities, when necessary
- Forestry and vegetation management program is staffed with approximately 20 employees
  - Forestry and Vegetation Management Supervisor manages in-house capability and external contractors

*Utility F's experienced in-house vegetation management program and centralized management of external contractors enables it to meet yearly schedules and goals*

# <u>Vegetation Mgmt.:</u> Utility F has reduced its vegetation mgmt. burden and improved its reliability measures by coupling its vegetation mgmt. program with the identification of T&D issues

- Utility F controls / reduces its vegetation management spend by (1) coupling its vegetation management program with the identification of T&D issues and (2) by negotiating alternate land use options
    1. In coordination with its hardware maintenance program, the vegetation management group monitors transmission equipment
        - Proactively identifies T&D asset pieces that should be maintained, upgraded and / or replaced (i.e., monitoring and replacing insulators, cross-arms, and poles on older lines)
    2. Utility F negotiates / discusses alternate land use options with landowners affected by rights-of-way to improve its vegetation management process
        - A secondary use agreement allows landowners to cultivate low growing plant species such as ornamental trees and blueberries on lands occupied by transmission lines
            - Ensures that vegetation remains below twelve feet
            - Allows landowners to profit from otherwise unused land
            - Improves the reliability of the transmission line

**Reliability Performance Measures (2007)***

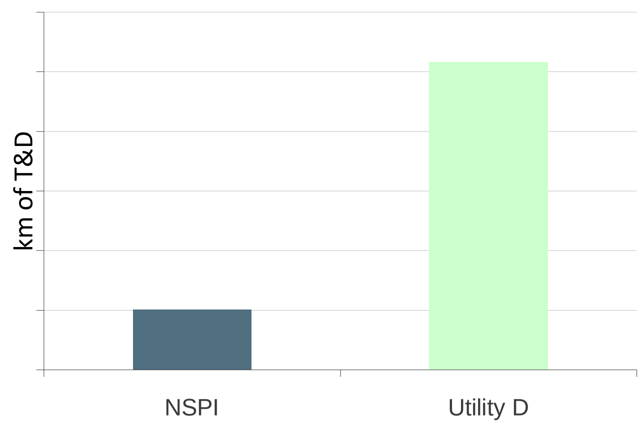


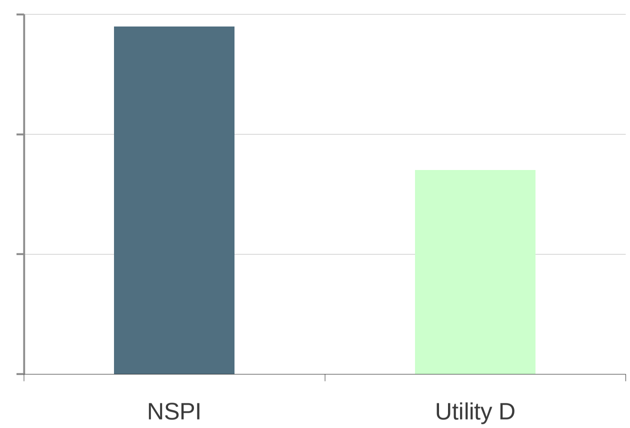

Utility F has significantly better reliability performance measures due to, in part, its pro-active vegetation management practices

*Utility F reduces the cost of maintaining its extensive network of T&D poles and improves its reliability measures through pro-active and supplemental initiatives; Again, NSPI performs a similar T&D identification program, but Utility F has demonstrated superior reliability scores*

# Vegetation Mgmt.: Utility D manages a much larger geographic area than NSPI with better reliability results

| | T&D Lines | Right of Way Clearance | SAIFI |
|---|---|---|---|
| NSPI | 30,370km | >10 meters | 2.9 |
| Utility D | Information Redacted | 10-70 meters | Lower than NSPI* |




*Utility D maintains a 10-70 meter clearance along more km than NSPI, but experiences a lower frequency of outages*

[1] Includes X km of underground distribution

# Vegetation Mgmt.: Utility D uses a long-term integrated vegetation management program to balance environmental responsibility and cost savings

**Seeded Vegetation**

- Seeds of low-growing native vegetation are often planted along T&D right-of-way
  - The Utility D Greenhouse plays an important role in this aspect of vegetation management
- Utility D is implementing a promotional campaign to encourage residents to plant trees / vegetation that won't interfere with power lines and may actually help manage unwanted vegetation

**Mechanical Management**

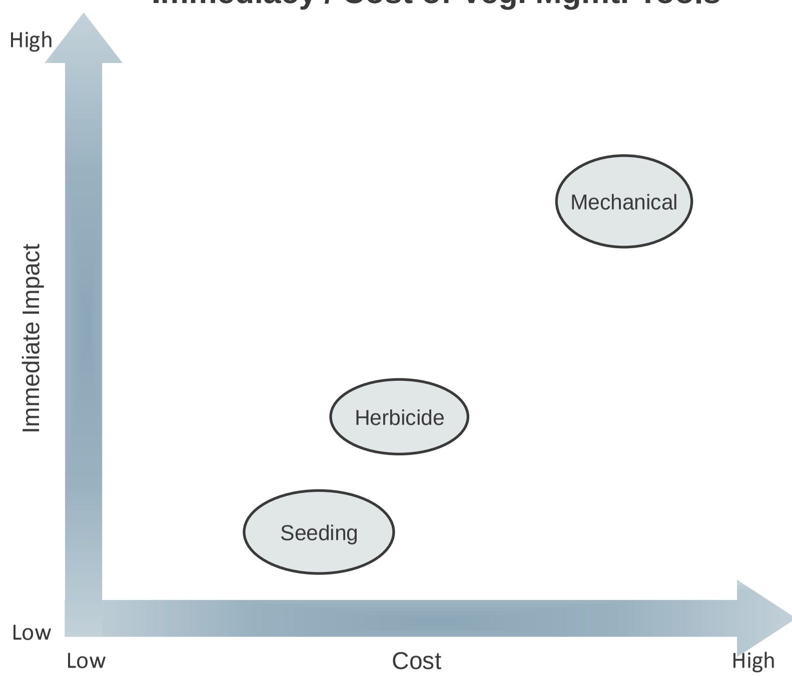
- Mechanical management provides immediate control of all vegetation, but often lacks long term durability
- Methods used by Utility D, include:
  - Brush mowing, mulching, tree trimming (both w/ special equipment and by hand), and slashing (hand-cutting using chain or brush saws)

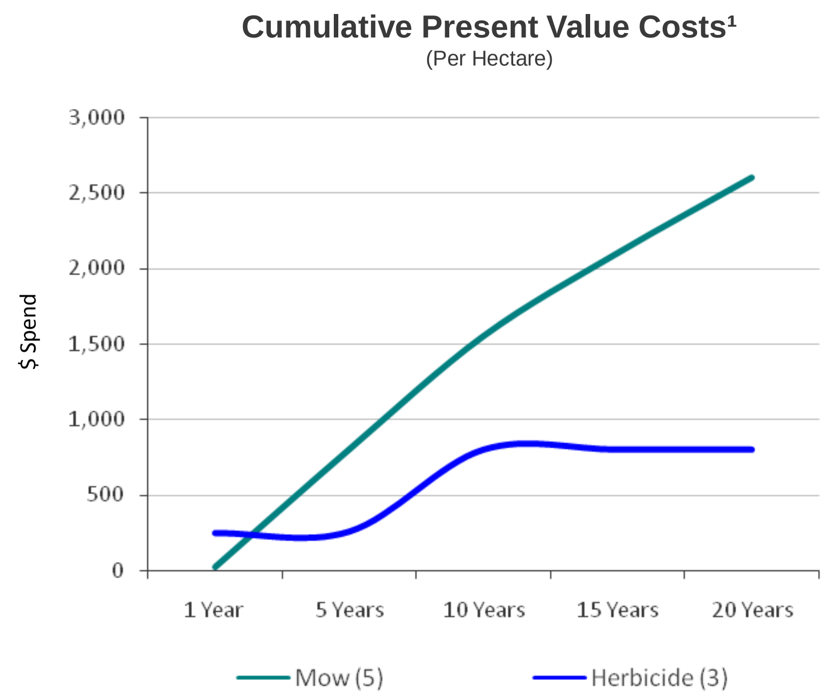
**Herbicides**

- The selective use of herbicides generates long-term vegetation management by encouraging vegetation conducive to maintaining clear rights-of-way
- Herbicide is applied one or two growing seasons after brush mowing
  - Followed up by selective applications on targeted trouble trees
- Utility D uses both Contractors and specially licensed Utility D personnel to apply herbicide
- All herbicides used by Utility D are regulated through the federal government's *Pest Control Products Act*

*Utility D uses three different tools in its integrated program: Mechanical Management, Seeded Vegetation & Herbicides*

# Vegetation Mgmt.: Utility D uses a mix of herbicides and mechanical methods to immediately enhance performance, while generating long term cost savings




*In the short term, Mechanical Management can be attractive, but over the longer term an integrated solution including herbicide treatments and seeded vegetation results in significant cost savings*

[1] Utility D Vegetation Management Study

# T&D Line Maintenance: Utility E implemented new proactive maintenance procedures which have reduced costs by 21% ($X M)*

## New Distribution & Maintenance Procedures

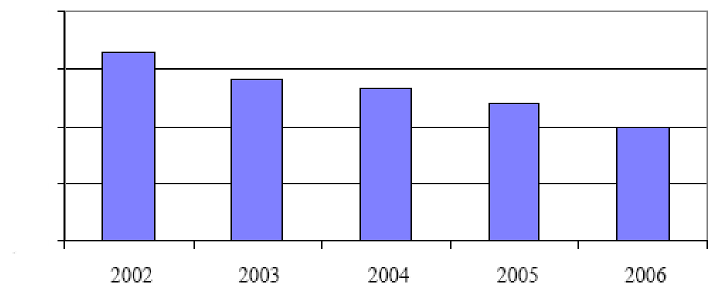
*Ground Inspection Frequency*
- Require one detailed ground inspection every 5 years for overhead primary distribution lines

*Ground Inspection – Components Assessed*
- Poles
- Conductors and insulators
- Cross-arms including hardware
- Transformers
- Anchors and guys

*Maintenance Priority Assignment*
- Inspection personnel assigns maintenance priority for each deficiency identified

| CLASSIFICATION | RESPONSE TIME |
|---|---|
| **Emergency** Immediate security of the line is at risk | Immediate |
| **Priority 1** Defects which if left could result in an interruption | One Month (approximately) |
| **Priority 2** Defects of less consequence | Within 12 months |
| **Priority 3** Defects of minor concern: no repairs necessary | Continue to monitor condition for possible upgrading of classification |

## Breakdown Maintenance Cost (000s)*




- One indication of improvement in maintenance programs is the cost of breakdown maintenance
  - **Breakdown maintenance costs decreased by 21% from 2002-2006**
- Unplanned nature of breakdown maintenance leads to increased costs particularly in overtime labor
  - **Overtime labor decreased by 23% from 2002-2006**

## Labor Costs (000s)

| Breakdown | 2002 | 2003 | 2004 | 2005 | 2006 | 2007F | 2008F |
|---|---|---|---|---|---|---|---|
| Regular and Standby | Information Redacted | | | | | | |
| Temporary | | | | | | | |
| Overtime | | | | | | | |
| Total Labour | | | | | | | |

*Maintenance performed in a planned manner through capital projects or preventive maintenance programs is usually less costly than maintenance performed after a breakdown has occurred*

# T&D Line Maintenance: Utility D uses an on-going preventative strategy to manage the costs associated with maintaining its network of wood T&D poles

- Instead of waiting until deterioration mandates total line replacements, Utility D selectively and regularly replaces portions of its lines' wood poles
  - For Utility D, regular replacements are more cost-effective and resource-efficient than complete line builds
- Utility D uses test data to target high value replacement segments

| | Wood Pole Replacement / Life Extension Program |
|---|---|
| Total Poles | Information Redacted |
| Annual Cost | |

Benefits of Regular Replacement / Life Extension Program

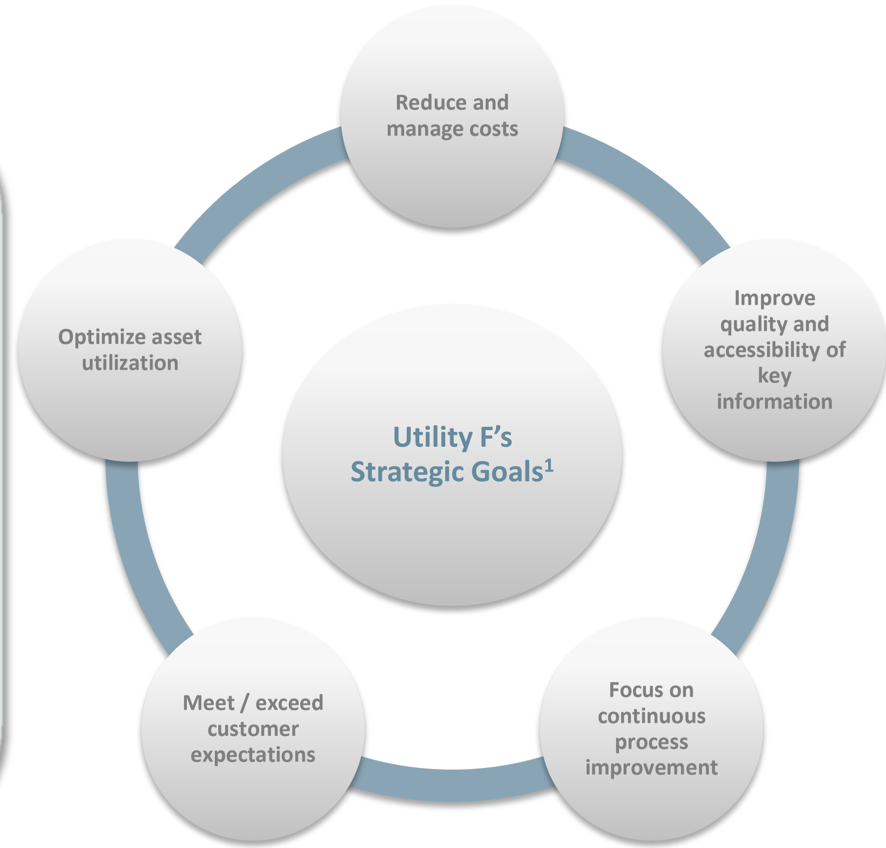
- Increased safety & system security
- Improved import / export capabilities
- Lower power quality issues
- Cost savings

*Utility D cuts the cost of maintaining its extensive network of wood T&D poles through an aggressive and regular life extension / replacement program*

[1]UtilityD typically budgets $10M for this program, but actual spend was $9M last year

# WMS: Utility F's implementation of an integrated WMS has enabled it to focus on its generation and distribution businesses, while meeting its strategic goals

- Utility F has made significant upgrades to its workforce management and customer service delivery systems over the past two years
- In the selection process, Utility F prioritized (1) functionality, (2) effort to implement and maintain, (3) total cost of ownership, and (4) ease of use
  - Selected SAP as the primary vendor for specific COPS and CS functions
  - While all vendors[2] offered similar functionality, SAP was least expensive to implement (i.e., all other vendors required interfaces, investment in licenses, incremental maintenance, and hardware)
- Utility F continues to rely on SAP as a vendor, implementing SAP software across various functions in order to create an efficient, integrated, and cost-effective system; for example:
  - Customer Service
    - SAP Customer Care Service (SAP CCS)
    - SAP Plant Maintenance (SAP PM)
  - Customer Operations
    - SAP Preventive Maintenance
    - SAP Computer Aided Dispatch (SAP CGI)




*Utility F's use of an integrated system allows it to focus on its key business of generating and distributing electricity, rather than the costly development of system interfaces and design to support its utility business*

[1]Actual Utility F strategic goals associated with WMS [2]Other vendors considered: Datrol, Indus, Synergen, Digital Inspections (Cascade), MRO (Maximo), Datastream, IVARA, Great Plains (Options Software)

# WMS: Utility F implemented its distribution and customer service WMS in a two-phased approach, in lieu of the original three phases, to realize ~$X M in one- time cost savings*

**Workforce Management System Implementation across Customer Operations and Customer Service**

**Phase I**
Non-detailing work orders (e.g., service and outage orders)

**Phase II**
Preventative maintenance work orders

**Phase III**
Work orders requiring engineering

Phase I:

- Completed within budget
- Improved work processes using mobile devices deployed to 80+ Customer Service Representatives, Meter Changers, Energy Advisors and Water Heater Maintenance Contractors

Phases II and III:

- Originally scoped for a three phases, Utility F implemented Phases II and III concurrently to reduce implementation costs and drive the momentum for change that existed in the organization
  - Reduction in implementation costs results from synergies and common work environment across the company (i.e., reduce costs associated with simultaneous operation of legacy and new workforce management systems)
- Similarly, Utility F recognized interdependence of business processes between customer operations and customer service and gains that were possible by considering simultaneous implementation
- In process of completing all final upgrades / process improvements

**Costs savings due to simultaneous Phase II and III implementation: ~$X M***

*Utility F expedited the implementation phases of its new WMS in order to achieve immediate functional synergies between COPS and Customer Service*

# WMS: With the introduction of its new WMS, Utility F is realizing ~$X M in cost savings per year in Customer Operations

**Workforce Management System Annual Savings - Customer Operations**

| Productivity / Cost Saving Improvement | Estimated Savings ($) / Year |
|---|---|
| Engineering work order processes (i.e., auto dispatch to the trucks, elimination of paper work orders , and work order completion at site) | Information Redacted |
| More accurate billing | |
| Material supply processes | |
| Financial recording and reporting processes | |
| Reduced material costs through best practice maintenance planning and inspection processes | |
| Consolidation of databases and standardization of processes | |
| Street Light Maintenance processes and increased Water Heater warranty claims recovery | |
| Operations, material handling, and vehicle usage through improved work planning processes | |
| Reduced application support costs through retirement of the legacy applications | |
| **Total** | |

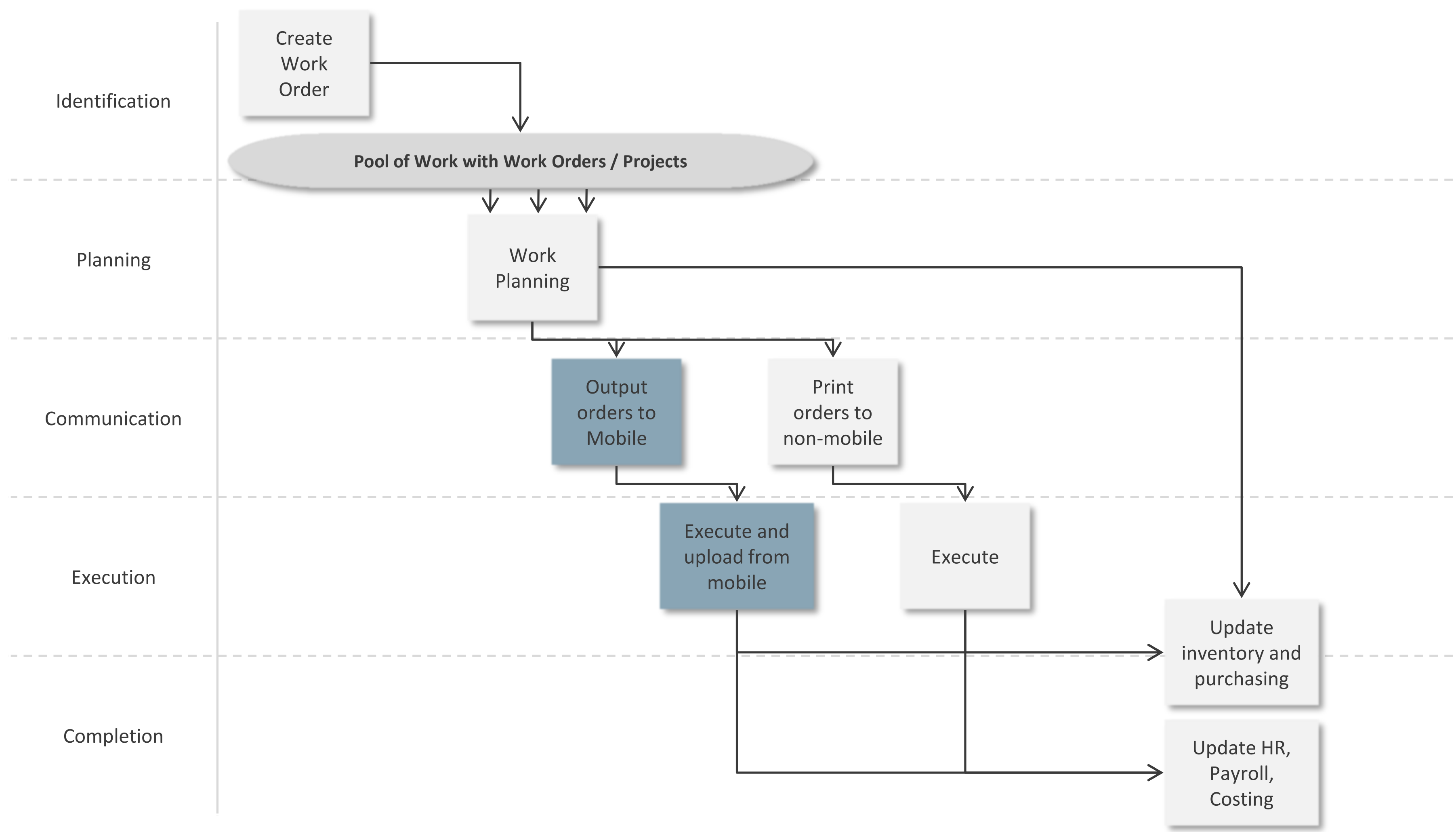
Example

| Material Supply Process Improvement | Details of Savings | Estimated Savings ($) / Year |
|---|---|---|
| Ability to order material based on Work content and hot line crew (i.e., specific crew material) | Information Redacted | |
| Eliminate storemen having open reservations | | |
| Reduce materials requirement planning list | | |
| Ability to order on demand material (i.e., avoid cost of delivery to site) | | |
| Returns to an exempt designation | | |
| Bar coding (i.e., entering serial numbers) | | |
| **Total** | | |

*Utility F is driving significant cost savings from 1) productivity improvements in the work order process 2) material cost reductions through best practice maintenance planning and inspection processes and 3) introduction of mobile-based system*

# WMS: Utility F implemented a mobile-based WMS to achieve savings of over $100,000 per year; NSPI has recently implemented a similar workflow in its plants

Simplified Workflow for Dual path Communication System



# WMS: Utility F's work management improvements are driving ~$X M in annual OM&G savings

**Customer Service Overview**

- Basic call center technology
- Limited investments made in past to support infrastructure
- Call center not positioned to keep pace with industry best practices
  - Lost opportunities to remove operational costs and enhance customer service delivery

**WMS Goals for Customer Service**

- Achieve cost reductions and increased customer satisfaction
- Control operating and capital spending
- Optimize process and use of assets
- Leverage technology to improve productivity

**Workforce Management System Annual Savings – Customer Service**

| Productivity / Cost Saving Improvement | Estimated Savings ($) / Year |
|---|---|
| Reuse of contract accounts and billing enhancements | Information Redacted |
| Reduction in Average Call Handle time | |
| Reduction in number of calls due to telephony self-service | |
| Deflection of calls to web self-service via telephone | |
| Increased success in outbound communications due to predictive dialer (i.e., collections) | |
| Other | |
| **Total** | |

- *Other cost savings result from simultaneous integration of Customer Operations and Customer Service work management systems (i.e., improved COPS response to outages via improved customer service reporting and tracking of incidents)*

Example

| Improved Outbound Communication (Collections) | Estimated Savings ($) / Year |
|---|---|
| • Collections make 260,000 collections calls of which only 20% (52,000) talk to a customer<br>• With management system improvements (i.e., a predictive dialer) collections will speak to double the number of customers (104,000), a 40% contact success rate | Information Redacted |
| **Total** | |

*Utility F is driving significant OM&G savings through self-service telephone options and a significant reduction in call volumes associated with the new WMS; NSPI is using predictive dialers in their systems – quantification of savings has not been provided*

# WMS: Utility F's payback period for customer operations and customer service WMS are approximately 6.3 and 6 years, respectively

## Workforce Management System Financial Payback

**Customer Operations**

Financial Payback

**Customer Service**

Financial Payback

**Information Redacted**

# WMS: Utility D's WMS has increased productivity by allowing for a greater percentage of planned vs. unplanned maintenance

Utility D has increased efficiency by:

- Increasing planned vs. unplanned work
  - Utility D believes that prior to implementation on average **50%** of work was planned and **50%** of that was completed
  - Today approx. 80% of work is planned
- Allowing for joint planning and scheduling between coordinators, planners, forepersons, stores, procurement, and engineers driving efficiencies
  - Each plant conducts weekly meetings where the WMS is accessed and displayed
- Prioritizing work orders so that critical work gets done, but that at the same time ensuring that routine maintenance is performed

| | Pre-WMS | Post-WMS |
|---|---|---|
| Planned Work % | 50% | 80% |
| No. Planned Work Orders / Year | N /A | 50,000 |

**Planned Work Orders as % of Total Work Orders**

**Information Redacted**

*In addition to higher productivity, a decrease in unplanned outages results in significant cost savings as unexpected outages cost between **$450,000** and **$700,000** a day*

*Utility D continues to cut costs and increase the productivity of its existing workforce*

# WMS: Utility D's WMS has brought dramatic increases in Plant Availability resulting in cumulative cost saving of $X M (through 2005)

- Utility D has seen strong increases in its plants' availability resulting in significant cost savings

| | Pre-WMS | Post-WMS |
|---|---|---|
| 5-Year Avg. EAF | 82.6% | 85.2% |

- Savings are even higher given that Utility D had projected a decline in EAF due to aging equipment / assets

**Coal Plant Equivalent Availability Factor (EAF)**

**Information Redacted**

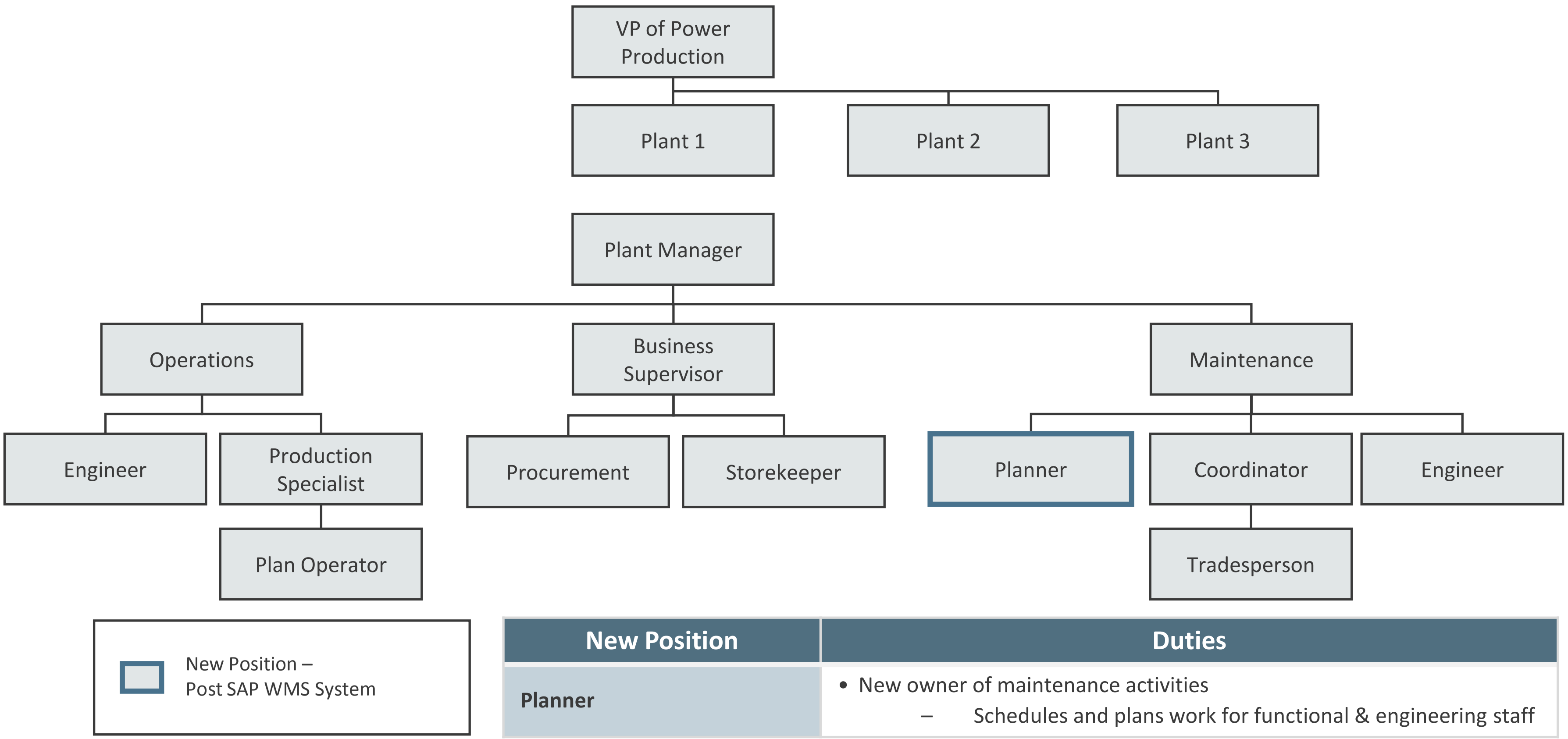
[1]Approximate Values; Source: Utility D 2006

**Benefits Realized from Coal Plant EAF**

**Information Redacted**

*Utility D's cost savings of **$X M** are the result of increases in the availability of its Coal Plants alone**

# WMS: Utility D complemented its SAP WMS with a redesign of its plant org. structure creating a new owner for operations, maintenance, and planning




| New Position | Duties |
|---|---|
| **Planner** | • New owner of maintenance activities<br>– Schedules and plans work for functional & engineering staff |

*Previously Coordinators, Engineers, and Tradespersons worked reactively responding to emergencies, under the new Planner organization work is planned and done proactively*

# WMS: In the future, Utility D hopes to cut the cost of skilled turnover through the knowledge capture function of its WMS

- Utility D faces an aging skilled workforce with a significant retirement bulge expected in the coming years
- Utility D believes it can use its WMS to capture knowledge from retiring workers to enable efficiencies when on-boarding new workers

| | Utility D Workforce |
|---|---|
| Tenure >20 Years | 50% |
| Retiring in the next 10 Years | 31% |
| Eligible for retirement in next 10 years | 67% |
| Avg. Age of Employee | 39.5 |
| % of Execs Retiring in 5-7 Years | 50% |

**Utility D WMS Knowledge Capture Overview**

**Information Redacted**

*Utility D hopes to more quickly ramp up junior employees through the knowledge & processes captured in its WMS*

# WMS: Utility D expects to realize $2X M in cost-savings through its $X M investment in an integrated enterprise WMS and associated process improvements*

- In 1998, Utility D launched a corporate-wide initiative to review, redesign, and implement new operational and reporting processes
  - Project was originally intended to make Utility D more competitive in the face of expected deregulation
- Over time the project evolved into a major enterprise wide initiative that cost **$X M** to install and **$ X M** to operate for the first five years*
- Originally the WMS system was projected to realize benefits of **$X M** over five years*
  - This was revised down to $X M given difficulties in measuring certain, less tangible, benefits*

| | Cost |
|---|---|
| Initial Process Redesign and SAP Install | Information Redacted |
| Operating Cost (Five Years) | |
| Expected Benefit (Five Years) | |
| Realized Benefit (Sept. 2005) | |

**Cumulative Cost vs. Benefit**
(SAP WMS System)

Information Redacted

# WMS: Utility D's design and implementation of a WMS was a ten year iterative process requiring significant resources

**_1996-1997_**
**System Replacement Planning Project**
- Owned by CI&T w/ Fin., HR, MM, Prod., T&D
- PwC provided consulting support

**_April 1998_**
**Implementation**
- Deloitte provided consulting support
- Peak full time team

**_August 1999_**
**Launch**

**_March 2001_**
**Corporate Process Improvement**

**_May 2001_**
**Upgrade**

**_April 2004_**
**Contractor Invoicing**

**_Q2 2006_**
**Eng. Doc. Management**
**SAP Enterprise 2005**

| WMS Development Team | |
|---|---|
| Peak Team Size –Utility D Employees | 200 |
| Peak Team Size - Consultants | 40 |

*Utility D's experience serves as a guide that implementing a new integrated WMS can have positive impacts, but it is a long duration, resource consuming upgrade*

# Outsourcing: Utility D has kept IT costs constant through outsourcing and active process & program improvements

**Corporate IT (CI&T) Cost Saving Initiatives**

- Investing in technology that enables automated software upgrades
  - Utility D previously relied on manual installs by technicians
- Leveraging the SAP WMS tool to drive process improvements and increase efficiency
  - Utility D has been able to cut its Technician budget by **3 FTEs**
- Contracting / Outsourcing a significant portion of its CI&T workforce
  - Enables swifter response to technological change

| | 2001 | 2006 |
|---|---|---|
| $ Spend on CI&T | Information Redacted | |
| CI&T Spend as % of Revenue | 3.5% | 2.8% |

**Services Outsourced to EDS**

- Daily database administration and SAP system maintenance
- Operation and maintenance of province wide data network (more than 100 locations)
- Several customer service initiatives, including:
  - Building / maintaining the EnergyCheck audit application
  - Creating web-based customer submitted meter reading

*Utility D's IT strategies have saved **$X M** over expected costs in the past year alone**

²Source: UtilityD

# Recommendations: KA has identified several potential areas for cost savings in customer operations for NSPI; Potential savings is for identification only, NSPI would need to further evaluate identified practices to determine true potential

| Opportunity Area | Recommendation | Assumptions / Methodology | Potential Savings (Annual)[1] |
|---|---|---|---|
| **Vegetation Management** | • **Using an integrated proactive program incorporating mechanical methods, seeding, herbicides, and public information campaigns can cut costs over the long term**<br>– Integrated programs take longer to show effects, but cut costs in the long run<br>– Both Utility D and Utility F actively encourage the planting of low lying vegetation resulting in free long-term maintenance | • Potential savings based on a comparison of the cost of 100% mechanical methods vs. the cost of 50% mechanical & 50% herbicide mgmt over a 20 year period | **$ 0.5 –1 M / year** |
| **T&D Maintenance** | • **Using a regular prioritized life extension / replacement program for T&D assets can be cheaper over the long run than periodic total line replacements**<br>– Constant maintenance and targeted replacement of high risk assets results in fewer outages and a longer workable life span for T&D networks<br>– Utility D spends approx. $10M annually on wood pole life extensions / replacement, but estimates it saves money over the long term<br>– Utility E has cut breakdown maintenance costs by 20% over a four year period through new proactive T&D maintenance procedures | • Potential savings based on a 20% improvement in breakdown maintenance costs over a four year period<br>– Assumes a majority of breakdown maintenance costs are due to overtime<br>• Does not factor in potential economies of scale | **$ 1 M / year** |

[1]Potential Cost Savings calculated based on Kaiser's estimate of best case savings; Potential savings is TOTAL benefit but is not net of cost either upfront or ongoing

# Recommendations: KA has identified several potential areas for cost savings in customer operations for NSPI; Potential savings is for identification only, NSPI would need to further evaluate identified practices to determine true potential (continued)

| Opportunity Area | Recommendation | Assumptions / Methodology | Potential Savings (Annual)[1] |
|---|---|---|---|
| WMS | • **WMS implementation is a long-term, large scale project which can drive cost efficiencies, however it comes with significant risks and requires extensive resources even in a best case scenario**<br>• **WMS savings span Power Production, Customer Operations and Customer Service functions** | | |
| | • **Implementing an integrated WMS systems can drive cost savings by creating efficiencies in use of time, labor, materials, reduced application support of legacy systems, etc.**<br>– An effective COPs WMS realizes cost savings from productivity improvements in the work order process and in reduced material costs from maintenance planning and inspection processes<br>– Utility F is realizing ~1.0M in these improvements alone<br>– An effective Customer Service WMS reduces call volumes and call handle times, which reduces costs | • Assumes a COPS / Customer Service specific implementation at Utility F can be implemented at NSPI<br>• Potential savings based on savings for COPS and Customer Service at Utility F<br>• Potential Savings is TOTAL benefit and is NOT net of costs, either up front or ongoing | **$ 2 – 5 M / year** |
| | • **Creating and implementing an integrated enterprise WMS can drive greater productivity and availability resulting in significant cost savings, but requires significant capital outlays**<br>– A greater proportion of preventive / planned maintenance results in dramatic increases in a plant's EAF<br>– Utility D has seen cumulative cost savings of **$X** million from increases in availability of its coal plants alone<br>– A greater proportion of planned work also allows for a constant number of employees to get more done<br>– Utility D has increased the number of work orders it is able to process to 50,000 | • Assumes Benefits / Costs of Utility D's system would be roughly comparable for NSPI<br>• Potential cost savings based on expected benefit of Utility D's enterprise system<br>• Potential Savings is TOTAL benefit and is NOT net of costs, either up front or ongoing | **$ 10 – 15 M / year** |

[1]Potential Cost Savings calculated based on Kaiser's estimate of best case savings; Potential savings is TOTAL benefit but is not net of cost either upfront or ongoing

# Benchmarking Research


Baseline Comparison

Power Production

Customer Operations

Customer Service

Regulatory Affairs

Appendix

# Benchmark research has reviewed the following aspects of Customer Service and identified a number of opportunities

- High Level Comparison
- Customer Service Spend/Satisfaction
- Call Center
  - Cost-Saving Practices
  - Organization Design
  - Systems and Process Practices
  - KPIs
- Reliability Driving Satisfaction
- Meter Reading
- Customer Service In-sourcing
- Recommendations

**Primary and Best-in-Class Comparables**

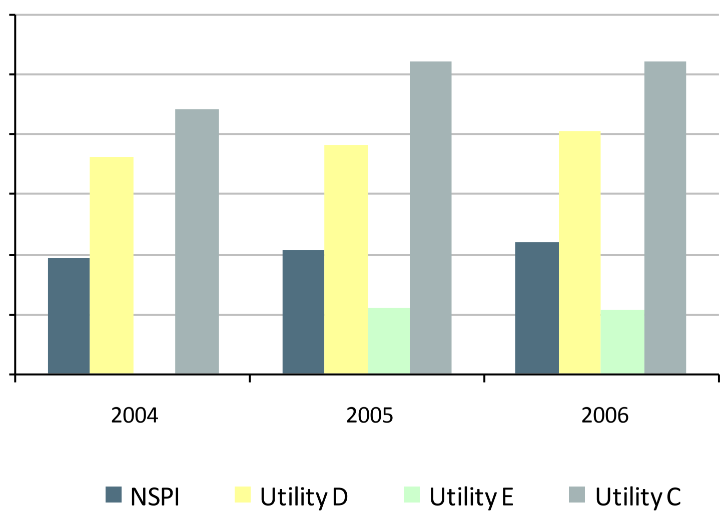
**Information Redacted**

# High Level Comparison: Customer Service Benchmarked Companies

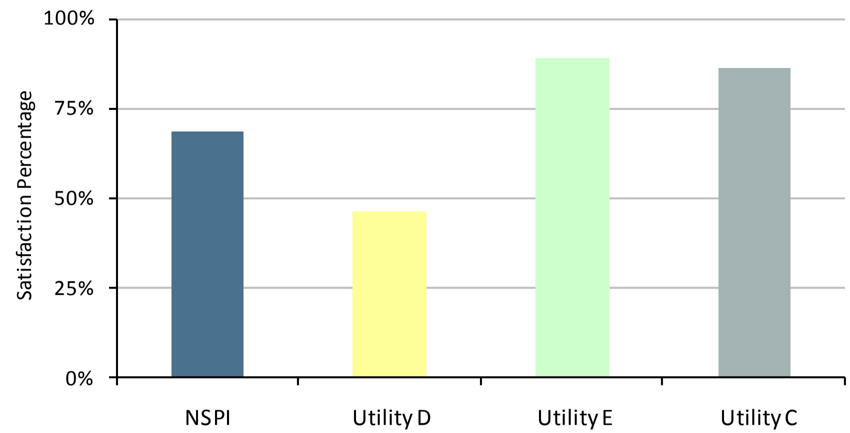
| | | Primary Comparables | | BIC Comparable |
|---|---|---|---|---|
| | NSPI | Utility C | Utility D | Utility E |
| Territory Served | Nova Scotia | Information Redacted | | |
| Customers | 465,424 | | | |
| Customers per Employee | 259 | 279 | 181 | 387 |
| Call Center Location | Halifax | Information Redacted | | |
| Outsourced vs. In-house | In-house | In-house | In-house | In-house |
| Automated Service | 24/7 | 24/7 | 24/7 | 24/7 |
| Hours of Operation | Monday – Friday 8am-8pm, Saturday 9am-5pm | Monday-Friday 7am-7pm plus emergency after hours service | Monday-Friday 8am-7pm, Saturday 8:30am-4pm | Monday-Saturday 8am-6pm |
| Industry Recognition | N / A | • Named the top customer service provider in the North American energy sector by Service Quality Management (SQM) Group Inc. for two years in a row<br>• Received an "Improvement Merit Award for First Call Resolution" for properly addressing customers' needs the first time they call | • Poor overall customer service, in the process of an aggressive redesign / strategic process development | • The J.D. Power and Associates 2007 Canadian Electric Utility Residential Customer Satisfaction Study (#1 Rankings for medium-sized utilities<br>• Canadian Information Productivity Award of Excellence winner for Customer Care. |

# High Level Comparison: NSPI falls in the mid-range of benchmarks in OM&G expenses per customer, but opportunities may exist for improved customer satisfaction

## Comparative OM&G Spend per Customer (2004-2006)[1]*




## Customer Satisfaction (%)



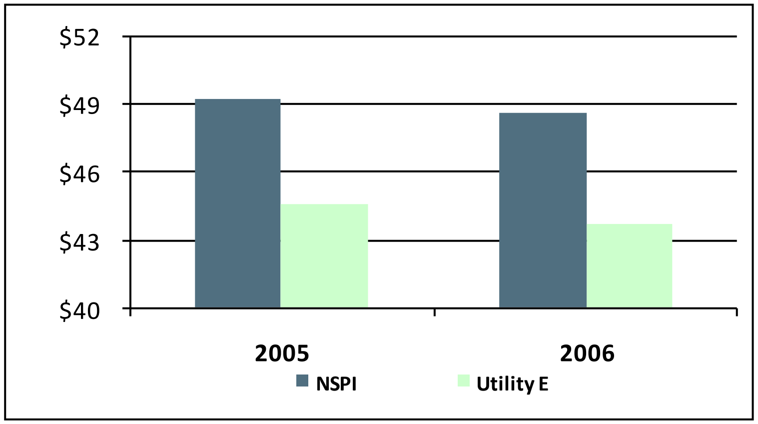

| | NSPI | Utility D | Utility E | Utility C |
|---|---|---|---|---|
| OM&G $ (2006) | $ 196M | | | |
| Customers | 465,424 | | Information Redacted | |
| OM&G $/ Customer | $421 | | | |
| Customer Satisfaction | 68.5%[1] | 46% | 89% | 86% |

[2]Holds number of customers stables for all 3 years in chart [3]Canadian customers only

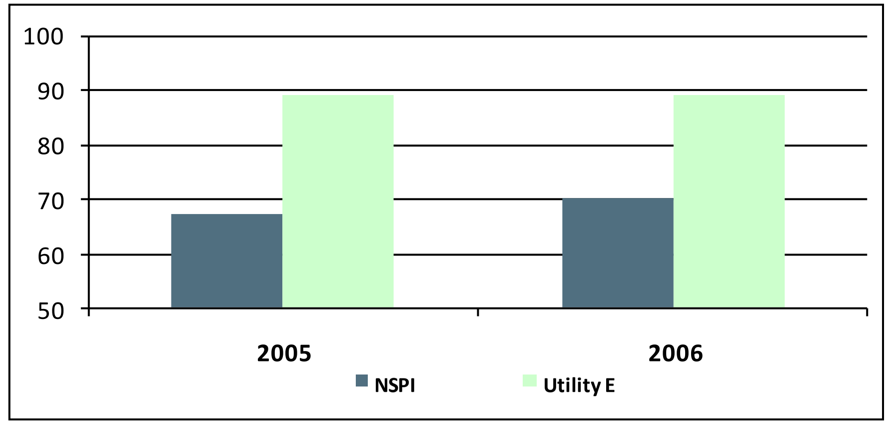
# Customer Service Spend/Satisfaction: Utility E spends less per customer on customer service, yet achieves better customer satisfaction statistics

*The J.D. Power and Associates 2007 Canadian Electric Utility Residential Customer Satisfaction Study ranked Utility E highest among Medium-sized utilities in satisfying residential electric utility customers*

## Customer Service Costs (per Customer)




## Customer Satisfaction Rankings




**Utility E**

- Utility E spend per customer is less despite NSPI's scale advantage
- Utility E includes some of NSPI's customer operations line items as part of customer service
- Utility E does not account for its meter reading or wiring inspection services in its customer service costs

**Utility E Customer Satisfaction**

- Customer satisfaction has averaged *89% since 2002*
- Conduct using surveys that asks customers to rate overall satisfaction level with the Company and its Customer Contact Center and field service on a scale of 1 to 10 with 1 being "not at all satisfied" and 10 being "fully satisfied"[1].

**NSPI Customer Satisfaction**

- Customer satisfaction has averaged *68.5% since 2005*
- Customer satisfaction is measured via telephone surveys conducted by a third party research company[2]
  - Calculated by taking the number of customers who rate NSPI as a 7, 8, 9, or 10 on a ten-point scale to the question "Using the same 10-point scale, how satisfied are you overall with Nova Scotia Power as your supplier of electricity?"

[1]Responses are averaged an weighted for Domestic and General Service customer classes

[2]Speaks to approximately 1,600 residential customers (400 per quarter) and 1,000 business customers (250 per quarter) annually

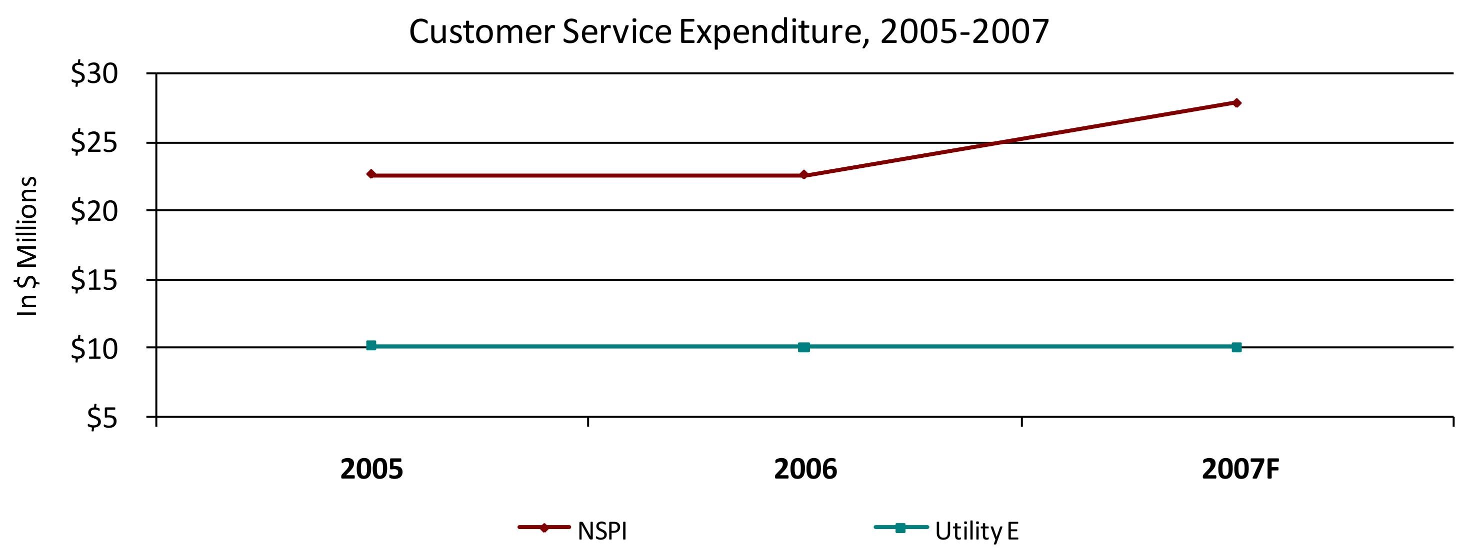
# Customer Service Spend/Satisfaction: Utility C's internal customer service scores higher on third-party satisfaction surveys

- Utility C commissions third-party research firms to issue customer satisfaction surveys via telephone
  - Surveys are administered to 600 customers to minimize statistical deviations and include questions developed by the Board
- Utility C assesses three major areas in its customer satisfaction surveys:
  1. Reliability performance, including service restoration after a power outage
  2. Performance and satisfaction with customer service
  3. Employees who are understanding, courteous, and informative
- Utility C's goal / minimum performance standard is to achieve >75% across most criteria

**Utility C Customer Satisfaction Survey Results (2007)**

| Satisfaction Measure | Residential | Farm / REA | Commercial | Total |
|---|---|---|---|---|
| **Reliability of electricity provided by Utility C** | 95% | 94% | 95% | **94%** |
| **Quality of electricity provided by Utility C** | 92% | 93% | 97% | **94%** |
| **Performance met or exceeded expectations** | 87% | 91% | 92% | **88%** |
| **Satisfaction with speed of service** (Base sample: customers who indicated they had experienced a power interruption in the last six months) | 87% | 92% | 83% | **87%** |
| **Experienced power quality problems in past six months** | 51% | 70% | 47% | **53%** |
| **Contacted Utility C to deal with the power quality problem** | 22% | 44% | 45% | **30%** |
| **Satisfaction with how Utility C dealt with the problem** (Base sample: customers who indicated they had contacted Utility C to address a power quality problem) | 78% | 97% | 81% | **84%** |
| **Overall satisfaction with Utility C** | **86%** | **86%** | **88%** | **86%** |

# Customer Service Spend/Satisfaction: NSPI's customer service costs have increased by over 20% since 2005 while Utility E's costs have remained flat




***Utility E has managed to control cost increases despite the following factors***

- *Over 13% increase in calls received at customer service center*
- *5% rise in amount of meter readings due to increase in customer accounts*
  - *From 2002 through 2008, the number of customers served by Utility E is increasing by an average of 1.1% per year*
- *22% increase in postage costs from 2002-2006*
  - *Company mails 12,000 items each day*
  - *Translates to $234,617 in added costs*

# Customer Service Spend/Satisfaction: Utility D is currently investing heavily in a service delivery renewal initiative to improve customer service and cut costs

## Initiative Goals

- Review and redesign metering, pricing, forecasting, planning, policy , and customer care processes
- Deliver and support a Web-based service channel for customer care
- Develop and resource the people required to support improvement activities
- Implement IT upgrades such as telephone management and online service, billing system replacement, automated meter reading, and interfaces with SAP
- Establish a corporate demand side management strategy (Customer energy efficiency program) and design / implement the support program infrastructure

**KPIs for Service Delivery Renewal Initiative[1]**

| | 2004 | 2005 | 2006 | 2007Target |
|---|---|---|---|---|
| SAIDI | Information Redacted | | | |
| SAIFI | | | | |
| Customer Satisfaction Indices (%) | 38% | 45% | 46% | 49% |
| Avg. Annual Rate Increases (%) | 5.65% | - | 4.9% | 4.3% |

*Utility D will spend **$ XM** dollars this year on the customer service delivery renewal initiative**

[1]Source: Utility D

# Customer Service Spend/Satisfaction: Utility D is reducing customer service costs by closing underutilized call / cashiering centers

- Utility D uses a decentralized network or regional customer service centers
- A number of Utility D cashier / call centers are underutilized
  - Utility D has recently undertaken a review of all its cashiering functions based on customer satisfaction and volume of customers served
- It has closed the 5 lowest scoring offices with the rationale that:
  - Foot traffic at other offices will rise making each remaining office more financially viable
  - Customer service numbers will improve with the elimination of the worst performers
  - Cost savings will be redirected into improved customer service training
  - Effect on collections will be negligible

| | 2001 | 2006 |
|---|---|---|
| No. Customer Service / Cashier Centers | Information Redacted | |
| No. Closed | TBD | 5 |

## Utility D Cashier / Call Centers

(Not to Scale - Draft)

**Information Redacted**

*Utility D has closed **5** offices in the past year*

# Call Center Cost-Savings Practices: On a per call basis, NSPI spends significantly more than Utility E

| Metric | NSPI | Utility E |
|---|---|---|
| Cost per Call | $4.82 | $3.11 |
| Cost per customer transaction using an Interactive Voice Response System (IVR) | N / A | $1.18 (35% of calls) |
| Cost per customer transaction on website | N / A | $0.10 |
| Cost-savings from ebills | $3.36 per customer | $7 per customer (11,000 customers in 2006) |
| Cost per meter read | $1.04 | $0.80 |
| Base call center system annual operating / maintenance costs | N / A | $65,000 |
| Annual operating expense of Outage Notification System | $725,000 (based on 600,000 calls) | $37,000[1] –Telephony Video Data- (on avg. over 100,000 calls annually since 2002) |

## ***Utility E Cost Savings***

- *Utility E has significantly reduced costs by encouraging use of its website, especially for simple transactions*
  - *Each time a customer chooses to visit the website instead of calling, Utility E saves between $1.08 – $3.01*
  - *Website was visited approximately 355,000 times by customers in 2006,*
    - *Increase of 174 percent since 2002*
  - *Approximately 42 percent of these visits were to review or change their account information*
    - *Eased burden on call center representatives and enabled them to focus on addressing more pressing matters*
- *Utility E saved $77k in 2006 by encouraging 11,000 customers to switch to ebills*
  - *($0.10 (paper and processing) plus $0.48 (postage) multiplied by 12 (months of bills) equals $6.96)*
  - *Utility E believes cost-savings associated with ebills will dramatically increase in the near future*
- *Utility E has increased its customer usage of IVR to 35% in 2006 from 20% in 1998 without sacrificing customer satisfaction*
  - *Utility E completed 190,000 calls using IVR in 2006, which saved $366,700 (assuming calls would have been handles by representatives)*

[1]Telephony Video Data

# Call Center Staffing Level: Utility E maintains high customer satisfaction despite serving more customers per call center FTE

| Metric | NSPI | Utility E | Utility Average[1] |
|---|---|---|---|
| Cost per Call | $4.82 | $3.11 | $5.20 |
| Ratio of call center FTEs to total customers | 1 to 4,519 customer (103 FTEs)[1] | 1 to 5,659 customers | N / A |
| Calls handled per agent per day | 47 | N/A | 53 |
| Length of calls | N / A | 3.20 minutes | N / A |
| Calls handled per agent per day | 47 | N/A | 53 |

## *Utility E's Efficiency Improvements*

- Utility E has reduced call center agents by 7 over past 4 -5 years
  - Despite more customers and increased services (e.g.. Handles 11,000 technical services calls in 2006)
- Utility E has significantly fewer call center agents per customer than NSPI (disparity is even bigger when NSPI's term labor employees are considered)
  - Utility E is likely able to manage this as a result of the popularity of its IVR and website among customers
- Investments in call center technology call center technology have increased efficiency of call center agents
  - Since 1999, the average length of calls has dropped from 4.09 minutes to 3.20 minutes

*Utility E has decreased its call center staff by 8 FTEs since 2001 despite receiving 35,000 more calls and expanding service capabilities per year by:*

- *Investing in time-saving call center technology*
- *Enhancing and promoting Internet services*
- *Encouraging and promoting Interactive Voice Response System*

[1]Ascent Group Report (2007)

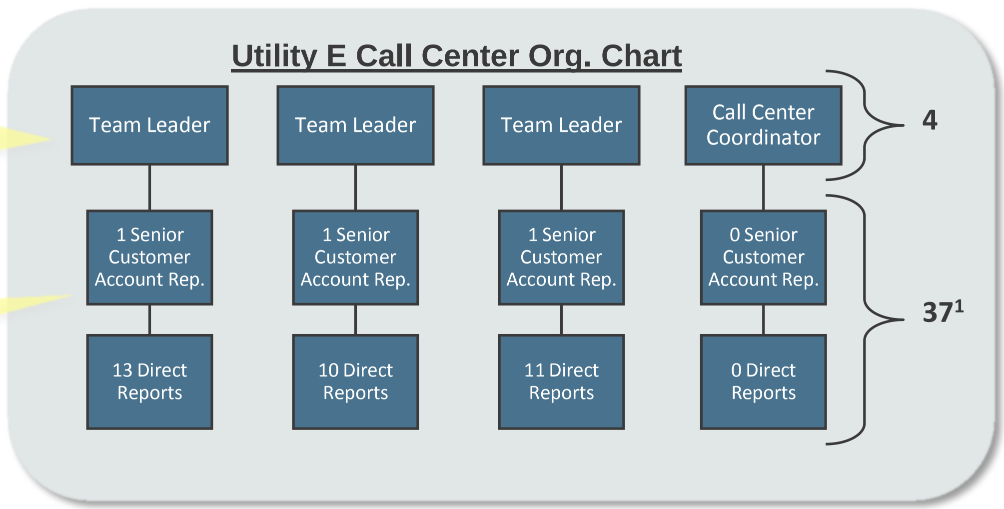
**Information Redacted**

# Call Center Org. Design: KA finds that NSPI has a higher span of control ratio within its call center compared to Utility E

| Metric | NSPI | Utility E |
|---|---|---|
| Span of Control (direct reports to supervisor level personnel) | 13 : 1 | 9 : 1 |


Focus on performance management, coaching

More complicated and time-consuming tasks escalated from agents on their team




[1]Includes term employees

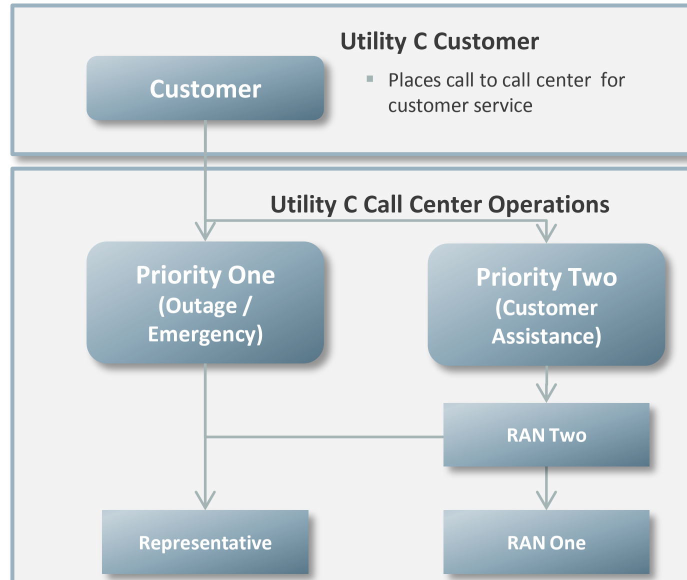
# Systems and Process Best Practices: Utility E's ability to retain call center employees is a key driver of customer satisfaction

| Strategies | Impact |
|---|---|
| **Technology Transformation** | • Adoption of cutting-edge telephone and PC integration, IVR applications, call routing, customer queuing and screen pops<br>– Transformed center into 2 4-hour multimedia center from 8-hour service center<br>– Telephony Video Data System has improved customer response rate during outages from 1% to more than 99%<br>– Calls are routed by up to 99 categories (e.g. residential customer, commercial customer or service inquiries)<br>- Enables key customer, special customer to be routed to more experienced agents |
| **Automation of Manual Process** | • Improved employee productivity by reducing / eliminating manual processes<br>– Time-saving desktop applications (e.g. billing calculator, consumption estimation program, literature request application)<br>– Automated customer forms (e.g. 'Application for Service', 'Returned Check', 'Request for Refund')<br>• Enhancing computer technology to enable employees to perform majority of tasks without needing to leave workstations |
| **Cross-Trained Agents** | • All contact center agents are trained to respond to all types of inbound inquiries and outbound credit management calls and<br>– Provided call center management team with maximum flexibility |
| **Low Staff Turnover** | • Call center has a low turnover rate<br>– Stability ensures that investment in in training is retained<br>– Results in more experienced reps.<br>- Leads to low average length of calls and decreased labor costs |

# Systems and Process Best Practices: Utility C's process of managing increased call loads during emergencies / outages has increased customer satisfaction levels, while off-setting the relationship between its two primary KPIs

- Utility C maintains **two phone queues** to accept customer calls: a **customer assistance queue** and an **emergency or outage queue**
  - After normal business hours, the emergency or outage queue covers both phone queues for customer calls
- The outage / emergency phone queue is treated as **priority one** calls and the customer assistance queue as **priority two**
- When outages occur, representatives are transferred from the customer assistance queue to the emergency queue
  - Supports increased volume requirements during normal business hours
- As there is no seasonal pattern to prepare for outage or emergency calls, Utility C **does not alter its staffing levels** to ensure service levels are met
- Furthermore, to off-set the relationship between its Call Answering Service Level and Abandoned Rate KPIs and to reduce the burden placed on representatives during outages/ emergencies, Utility C implemented the following solutions:
  - Automated messaging regarding details of power outages on the outage or emergency queue
    - An automated RAN (recorded announcements) installed in 2004 / 2005
    - While system has increased abandoned calls after customers hear a second or third RAN, the system still provides a higher level of customer service in notifying customers of power outage details

**Utility C's Emergency / Outage RAN System**




- A RAN is created in the emergency / outage queue for when customers do not receive a representative
- A second RAN is created in the customer assistance queue providing highlights of the power outage(s)
  - Heard by all waiting customer ~45 seconds after their call is received; after RAN, customers have the opportunity to hang up or wait for a representative

*Utility C's RAN system manages unexpected, increased call loads and improves call center performance*

# KPIs: NSPI lags behind Utility C and Utility E in a number of Call Center KPIs

| Metric | NSPI | Utility C | Utility E | Utility Average[1] |
|---|---|---|---|---|
| Average Speed to Answer (seconds) | 38 | 36 | 80% within 40 seconds | 56 |
| Cost per Call | $4.82 | 4.96[2] | $3.11 | $5.20 |
| **% Abandoned** | **6%** | **3.9%** | **1.8%** | **7%** |
| % agent availability | 68.6% | 83% | N/A | 73.4% |
| Absenteeism (days per year) | 7.8 | ~8 | N/A | 7.1 |
| Length of calls (key for Utility E) | 2.92 minutes (2007) | N / A | 3.20 minutes | N / A |
| Calls per Year / Customer (M) | ~4.3 | ~0.4 | N/A | 1.9 |

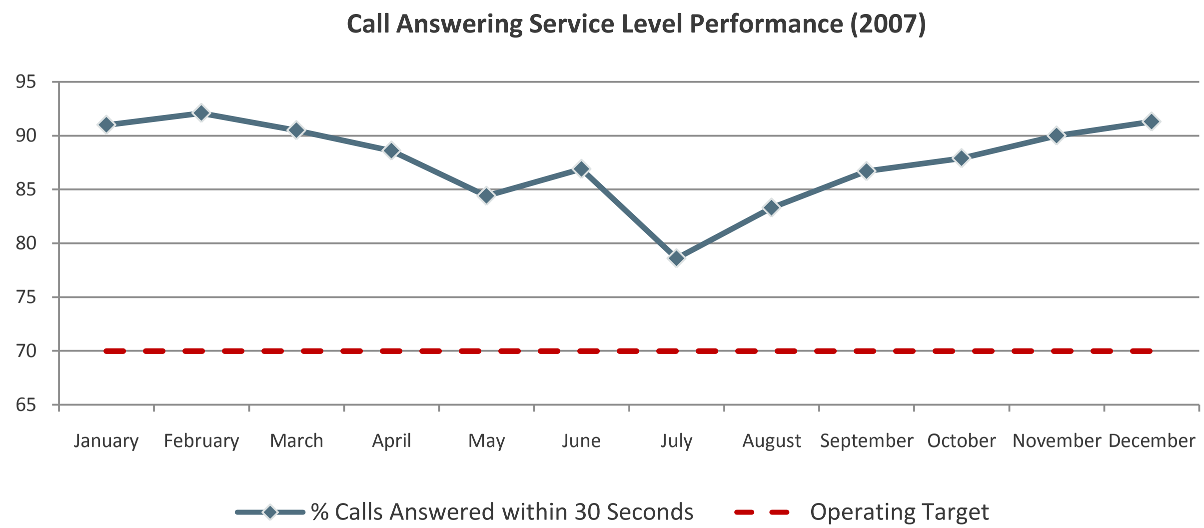
*When Utility E customers have been asked what the Company can do to improve telephone service, the responses have been to "answer right away" and "to have knowledgeable staff available to answer the calls"*

- *Cognos (with call center technology from Aspect) helped Utility E implement a new customer service system to increase speed and efficiency at which call center agents deal with service orders, billing and other requests*
- *Immediately provides call center agents with large volumes of easily accessible information*

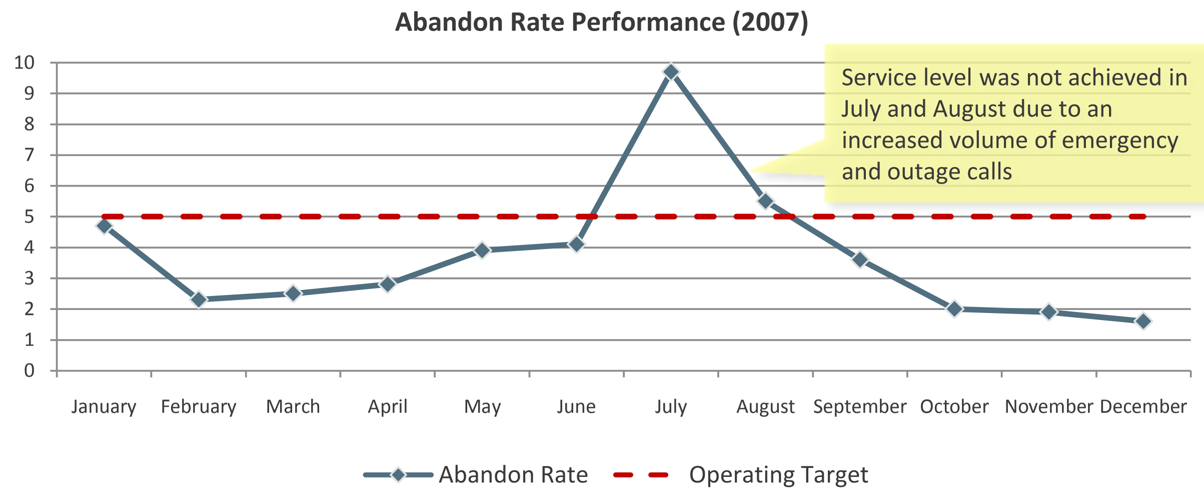
[1]Ascent Group Report (2007)

# KPIs: According to Utility C's primary customer service KPIs, Utility C is performing well above its monthly and annual operating targets

- **KPI:** Call Answering Service Level
- **Description:** Tracks percentage of attempted calls that, within 30 seconds, successfully reach a representative who is ready to accept or provide information
- **Calculation:** Monthly; (((calls answered + calls abandoned) – (calls answered after threshold + calls abandoned after threshold)) x 100) / (calls answered + calls abandoned))
- **Operating Target:** 70% of calls answered within 30 seconds
- **Annual Average:** 87.1%




- **KPI:** Abandon Rate
- **Description:** Tracks percentage of all attempted calls to reach a representative that are abandoned after being transferred from the IVR to the call center
- **Calculation:** Monthly; (number of calls abandoned) / (number of attempts to reach a representative)
- **Operating Target:** 5% or less
- **Annual Average:** 3.9%



# Other Satisfaction Drivers: Since 2002, Utility E customers have consistently ranked reliability of power as the most important attribute of service

### Frequency of Outages

- Since 2002, the frequency of outages experienced by customers has decreased by 39 percent

### Duration of Outages

- Since 2002, the duration of outages experienced by customers has decreased by 34 percent

**89% Customer Satisfaction**

### Key Investments

- Since 1999, Utility E has invested approximately $2 million per year, predominantly in rural areas, through its Distribution Reliability Initiative
  - From 2002 to 2006, rural distribution outages were, on average, 2 times greater than urban distribution outages (down from 2.6 times greater than urban distribution outages during previous 5-year period)

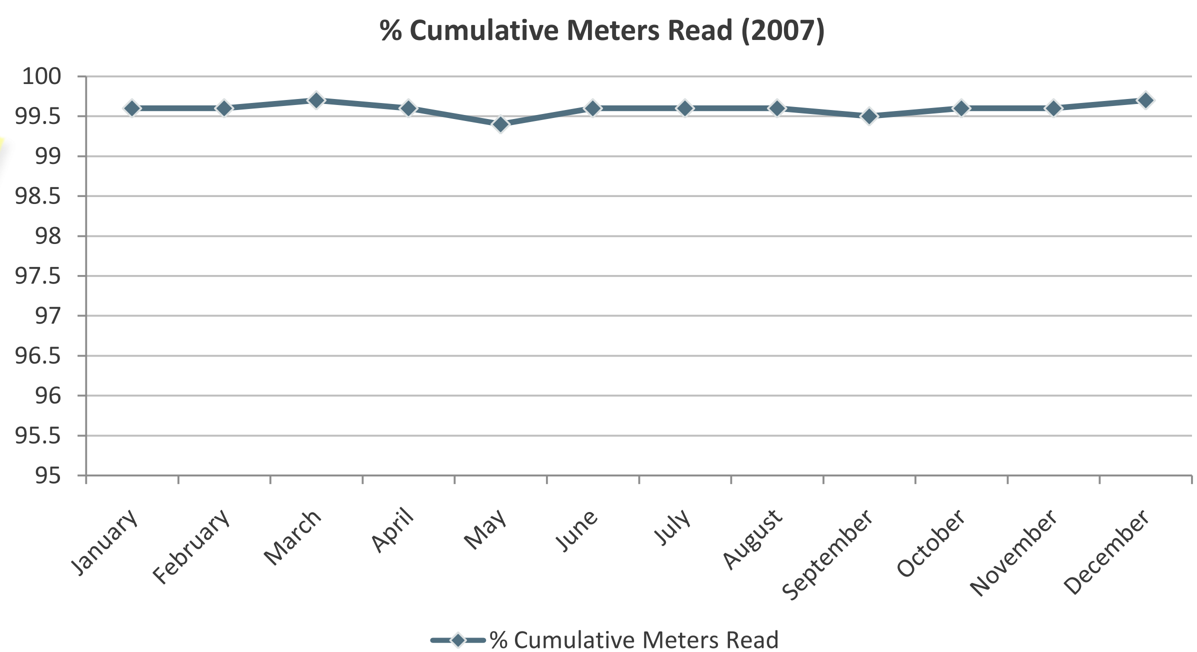
### KPIs / Performance Goals

- Utility E has a target to arrive at 85 percent of trouble calls within two hours of being contacted by a customer
  - Trouble calls include calls from customers reporting no power, part power, flickering lights, fluctuating voltage, blowing fuses or downed wires

*Utility E has improved customer operations over the past several years which is reflected in its Customer Satisfaction scores*

# Meter Reading: Utility C maintains high levels of performance in meter reading and recently made investments to further improve its performance

- **KPI:** Percentage of Cumulative Meters with Readings less than or equal to 65 Days Old
- **Calculation:** Monthly; (number of cumulative meters with readings less than or equal to 65 days x 100) / (number of cumulative meter sites in Wire Owner's meter-reading responsibility as of the last day of the 2nd month)
- **Operating Target:** 100%
- **Annual Average (2007):** 99.6%




- *Utility C is close to meeting its operating target for the percentage of cumulative meters read*
  - *High performance levels are a result of Utility C 's investment in outside meters and related work management initiatives (see next slide)*
- *Discrepancies between Utility C operating target and annual average were due to:*
  - *Meters located in remote and isolated areas of Utility C's territory*
  - *Sites where customer has not given Utility C access*
  - *Sites where the power to the meter has been interrupted*

# Meter Reading: Utility C has moved inside meters to outside locations to realize operational improvements, cost savings, and higher levels of customer satisfaction

**Relative Time and Cost Comparison of Reading 100 Inside and Outside Meters[1]**

| Outside Meters | Meters | % Success | Meters Read | Successful Read: Time / Read (mins) | Successful Read: Cost / Read ($) | Attempt: Time / Attempt (mins) | Attempt: Cost / Attempt ($) | Total: Time (mins) | Total: Cost ($) |
|---|---|---|---|---|---|---|---|---|---|
| 1st Attempt | 100 | 95 | 95 | 0.65 | 0.27 | 0.55 | 0.23 | 61.80 | 26.80 |

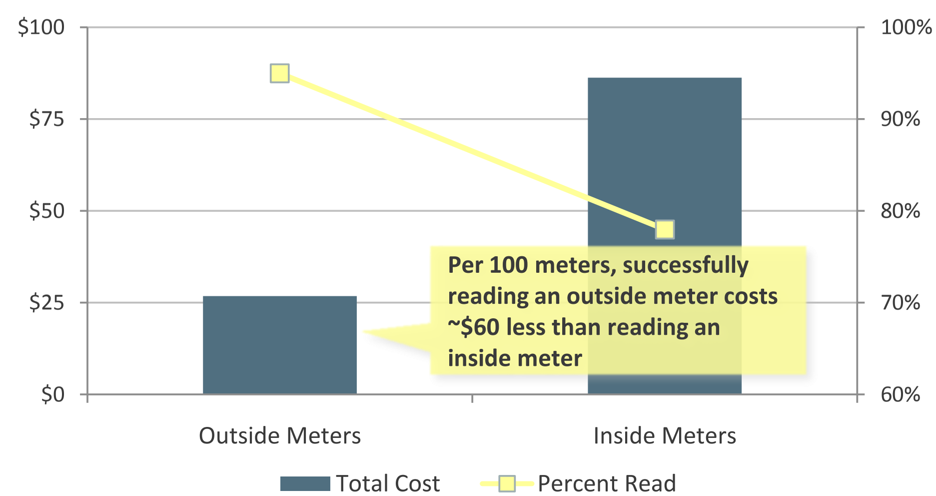
| Inside Meters | Meters | % Success | Meters Read | Successful Read: Time / Read (mins) | Successful Read: Cost / Read ($) | Attempt: Time / Attempt (mins) | Attempt: Cost / Attempt ($) | Total: Time (mins) | Total: Cost ($) |
|---|---|---|---|---|---|---|---|---|---|
| 1st Attempt | 100 | 55 | 55 | 1.83 | 0.75 | 0.55 | 0.23 | 125.40 | 51.60 |
| 2nd Attempt | 45 | 50 | 23 | 2.50 | 1.03 | 1.22 | 0.50 | 84.34 | 34.69 |

[1]*Based on historical experience of Utility C; assumes that additional attempts will be made on all unsuccessful inside meter reads**

- Utility C made significant metering improvements and investments from 2002 – 2005 to
  - Address customer concerns over billing accuracy
  - Achieve increased metering accuracy
  - Reduce OM&G costs
  - Drive higher levels of customer satisfaction by reducing communications with Utility C
- Most significant investment involved moving inside meters outside
  - Reduced the time to complete a read
  - Increased the success rate of a read
  - Reduced the number of special readings

**Information Redacted**

**Percent Read and Total Cost of Inside vs. Outside Meters**



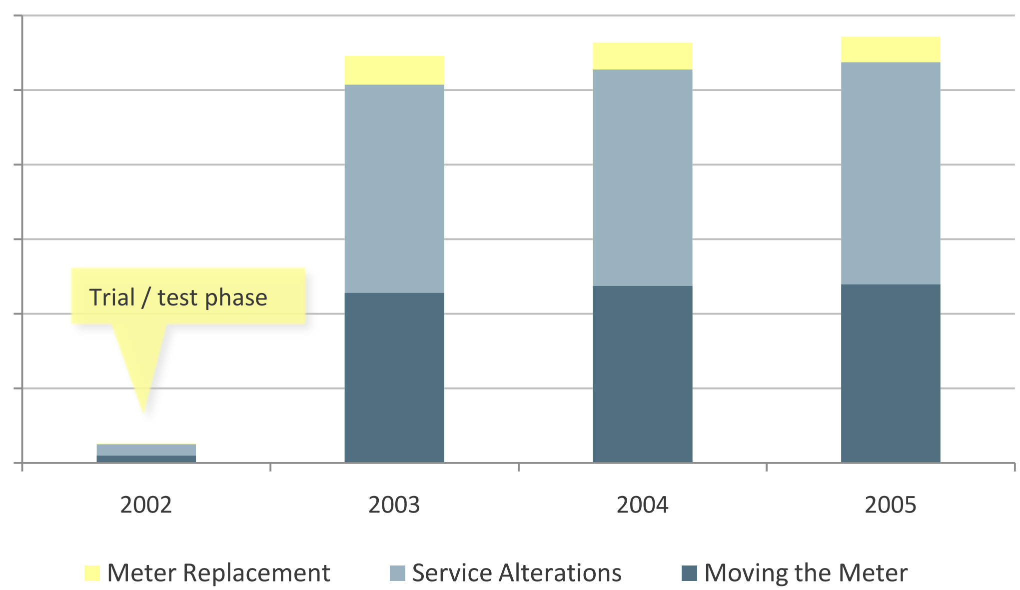
# Meter Reading: Moving meters outside will result in $X M in annual savings, with a financial payback in less than ten years*

- Utility C implemented the program over four years after determining that implementing the program over a time period of one or two years was logistically unmanageable
  - Three cost components were identified in transitioning from inside to outside meters
    - Moving and resetting the meter
    - Service alterations (i.e., alterations to allow the meter to be moved outside to an accessible location)
    - Replacement of some standard meters
- Lengthier implementation process
  - Provided the optimum use of resources
  - Allowed for the project to be properly managed
  - Reduced implementation costs

**Forecast Meter Reading Expenditures ($M)**

| | 2002 | 2003 | 2004 | 2005 |
|---|---|---|---|---|
| Moving the Meter | Information Redacted | | | |
| Service Alterations | | | | |
| Meter Replacement | | | | |
| Total | | | | |

**Forecast Meter Reading Expenditures ($M)***



# Meter Reading: In coordination with work management improvements, Utility C implemented a $7M system over three years to realize cost savings of ~$0.5M annually

## Overview

- In 2004, Utility C fully implemented a new $7M Computer Aided Dispatch (CAD) system to replace an outdated, proprietary radio network system with limited coverage

## Objectives

- Replace mobile data terminal (MDT) installed in service vehicles
- Expand coverage for electronic communications
- Eliminate paperwork
- Reduce costs
- Improve customer satisfaction

## Solution

- All 350 service technicians carry a Pocket PC equipped with a Wireless Card to communicate via the TELUS network
  - Service technicians receive work orders and all pertinent customer information directly on the Pocket PC
  - If additional information or information about another site is needed, the technician can request and receive it directly from the host, without intervention from a dispatcher
  - Technicians can also query each other while in the field
- Each Pocket PC runs a dispatching application developed by MDSI, which allows user-to-user and user-to-host communications
- Connections are secured through private, static IP addresses and a private network created by TELUS and Utility C

**Work Management / CAD Expenditures ($M)**

| | 2002 | 2003 | Total |
|---|---|---|---|
| Feasibility Study / Project Scope | Information Redacted | | |
| Installation & Interfaces | | | |
| Dispatch Software Package | | | |
| Infrastructure | | | |
| Server & Other Hardware | | | |
| PDA Software Development | | | |
| PDA Hardware | | | |
| Training | | | |
| Client Implementation Costs | | | |
| Total | | | |

Expenditures in 2004, for remaining implementation phases, took the total to **~$7M**

## Results

- Expanded coverage area from 2 to 3 percent to 99 percent of service territory
- Boosted efficiency of field staff through added functionality on Pocket PCs
- Saved money by using off-the-shelf Pocket PCs rather than laptops, which would have increased hardware costs by as much as four times
- Increased the number of service calls by 350 per day
- Decreased response time to customers, which has improved customer satisfaction
- Improved efficiencies result in lower operating costs by $0.5M annually

*"Having a Pocket PC allows technicians to take data into the customer's house. They can write down information and have the system validate it at the site rather than going back to the truck or back to the office … Furthermore, the reduced paperwork and improved organization will allow us to save potentially one to nine salaries a year."*

# Customer Service In-sourcing: Kaiser focused primarily on Utility C's customer service relationship with its former subsidiaries

## Overview / Structure of Utility C's Customer Service

**Information Redacted**

Utility C  three key areas of service include:
- Billing, call center, and customer care services
- Technology infrastructure, lifecycle management, network, server voice, and call center technologies
- Development, integration, maintenance and enhancement services of business applications

- Utility C provides in-house customer service support and billing services to its own utility business

**Information Redacted**

# Customer Service In-sourcing: Utility C is able to charge a premium for its services, which have been recognized by utilities and the CS industry as best-in-class

- As a bundled customer service package, Utility C's customer service is cited as providing better value than other outsourced vendors *(see table)*
  - "Outsourcing of Customer Services has a number of advantages … Vendors are driven to offer better services because the competitive marketplace forces them to achieve higher efficiencies across shared infrastructure and technology than utilities operating independently." – *Confidential Source*
- Utility C, as a result of experience and offering customer services to outside companies, has the ability to set and meet high performance standards due to:
  - Established facilities
  - Personnel and systems within a cost effective model
  - In-depth knowledge of the customers and market
  - Ability / willingness to invest in technologies to meet standards

**Pricing Ranges for Selected Services**

| Service Provided | Description | Other Vendors ($) | Utility C ($) |
|---|---|---|---|
| **Enrollment** | Per enrollment hour | 40 – 65 | 60 |
| **Back Office** | Per monthly service fee* | 1.50 – 2.50 | 2.20 |
| **Collections** | Per outbound hour | 40 – 65 | 55 |
| **Customer Care** | Per inbound hour | 40 – 65 | 60 |
| **Customer Care** | Per outbound hour | 40 – 65 | 60 |
| **Customer Care** | Per letter / e-mail hour | 40 – 65 | 44 |

**Notes:**
- Utility C provides bill generation and billing, presentation, payment processing, exceptions handling, and other special services; other vendors may not provide all services
- Pricing from other vendors represents services that are not identical to all of Utility C's services

*As a bundled customer service package, Utility C's customer service is cited as providing better value than other outsourced vendors and has established itself as a leading call center in North America*

# Recommendations: Kaiser has identified potential customer service cost savings and/or satisfaction improvement opportunities; Potential savings are for identification only, NSPI would need to further evaluate identified practices to determine true potential

| Opp. Area | Recommendation | Methodology / Assumptions | Potential Cost Savings (Annual)[1] |
|---|---|---|---|
| Call Center Operations | • **Encourage Website use for handing informational questions**<br>- Each time a customer visits the website instead of calling, Utility E saves between $1.08 - $3.01 | • Assumes that NSPI can increase the rate at which customers use Internet, as opposed to calling, by 20% by next year<br>• Assumes Internet transactions cost ten cents | **$1 M / year** |
| | • **Emphasize IVR systems to automate customer inquiries**<br>- Each time a customer is handled by IVR instead of a call center agent, Utility E saves $1.93 | • Assumes an increased rate of 35% by which customers use an IVR to conduct a transaction during a call versus a customer service representative<br>• Assumes cost per customer transaction of $1.18 using IVR | **$1 – 2 M / year** |
| Metering | • **Invest in moving inside meters outside to improve operational performance and reduce costs**<br>- Utility C is saving ~$60 for every 100 meters read after investments to move inside meters outside | • Assumes each NSPI customer has a meter<br>• 98% of meters are successfully read during bi-monthly reads as provided by NSPI<br>• 15% of NSPI's meters are located inside as provided by NSPI | **$0.5 -1M/ year** |

[1]Potential savings is TOTAL benefit but is not net of cost either upfront or ongoing

# Benchmarking Research

*Baseline Comparison*

*Power Production*

*Customer Service*

*Customer Operations*

*Regulatory Affairs*

# Benchmarking research has focused on comparables in the following areas of research

- OM&G Spend
- Org. Design
- Outsourcing
- KPIs
- Key Investments

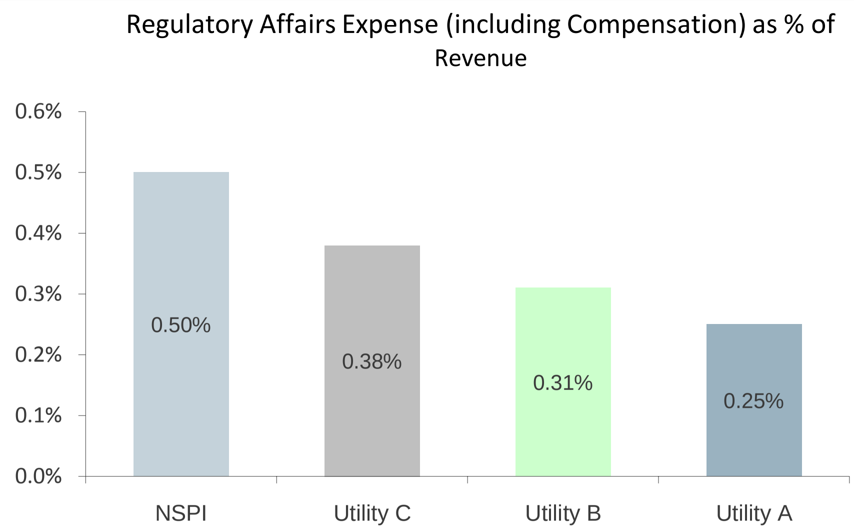
**Primary Comparables**

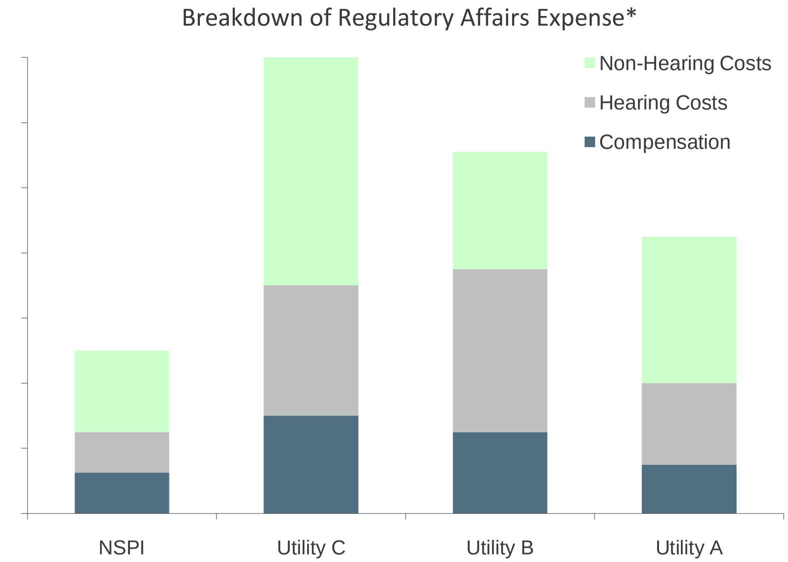
**Information Redacted**

# High Level Comparison: Kaiser performed benchmarking against 3 primary comparables for Regulatory Affairs

| | | *Primary Comparables* | | |
|---|---|---|---|---|
| | **NSPI** | **Utility C** | **Utility B** | **Utility A** |
| **Headquarters** | Halifax, Nova Scotia | Information Redacted | | |
| **Revenue** | $997.5M | | | |
| **OM&G Budget** | $200M | | | |
| **Plants** | 35 | | | |
| **Ownership Structure** | Investor owned; Subsidiary of Emera | Public Company | Government owned | Public Company |
| **Regulated by** | Nova Scotia Utility and Review Board | Information Redacted | | |
| **Regulatory Staff** | 15 | 20 | 16 | 10 |
| **Org. Structure** | Centralized | Centralized | Centralized | Centralized |
| **Time with Board** | High | High | High | Low |
| **Costs to Consumer or Shareholder** | Consumer | Mixed | Mixed | Shareholder |
| **Regulatory Expense** | $ 5M | $ 11M | $ 8.6M | $ 7M |

# OM&G Spend: NSPI spends more on regulatory affairs as a % of revenue than primary comparables due to its smaller scale

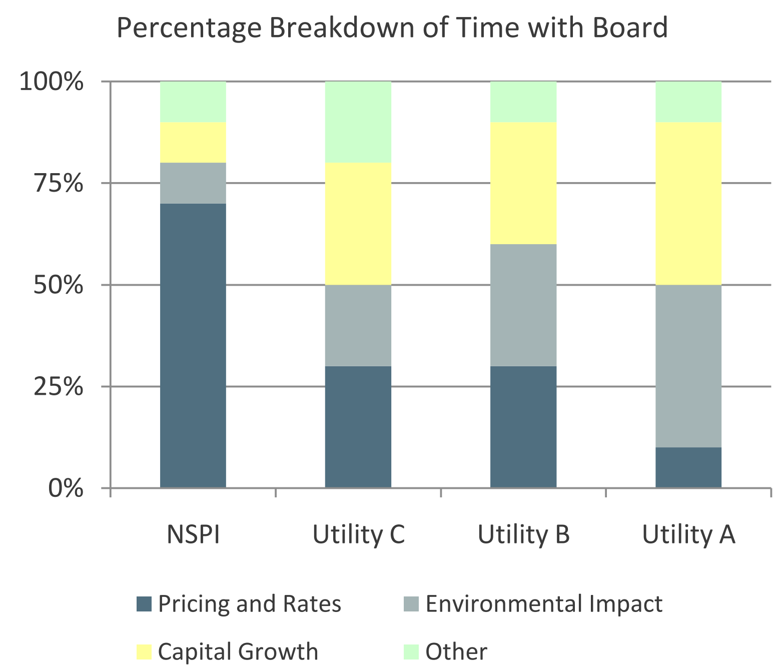



| | NSPI | Utility C | Utility B | Utility A |
|---|---|---|---|---|
| **Primary Expense Drivers** | • 40% of spend is on UARB consultants and counsel<br>• Extensive time spent in rate hearings | • Legal expenses, consulting expenses and intervenor groups associated with regulatory proceedings<br>• Capital projects associated with environmental and sustainability | • Legal expenses, consulting expenses and intervenor groups associated with regulatory proceedings | • Utility A is mostly a power generating business which has fewer regulatory requirements<br>• Capital projects involving land use and environmental concerns drive Utility A's regulatory costs |

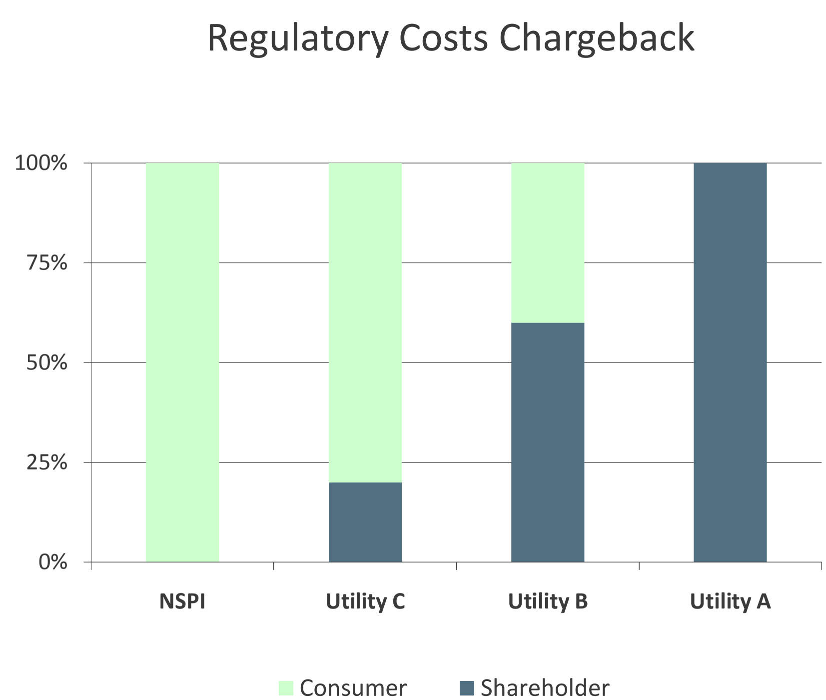
# OM&G Spend: Companies with diversified power generation, distribution and transmission business spend the most time with regulatory boards

| | Function | Regulated By | Amount of Time with Board |
|---|---|---|---|
| Nova Scotia Power | Power Generator, Distributor & Transmission | Nova Scotia Utility and Review Board | High |
| Utility C | Power Generator, Distributor & Transmission | Information Redacted | High |
| Utility B | Power Generator, Distributor & Transmission | | High |
| Utility A | Power Generator and Marketing | | Low |




*NSPI spends a greater percentage of time with the Board on its pricing and rate approvals as compared to competitors*

# OM&G Spend: Regulatory Expenses for transmission and distribution are typically charged to consumers and power generation to shareholders




- **Utility B** - More than half of Utility B's business is power generation with regulatory affairs expenses passed on to the shareholders
- **Utility C** - The majority of Utility C's business is distribution and transmission
  - Rates/prices continue to be regulated with regulatory charges passed on to consumers
  - Upgrades and expansions of distribution and transmission lines require approval from regulators and stakeholders
    - Charges are passed on to consumers
- **Utility A** - Power generation is not regulated by a board
  - Development of new power facilities require regulatory board approval
  - Costs are charged as overhead expenses

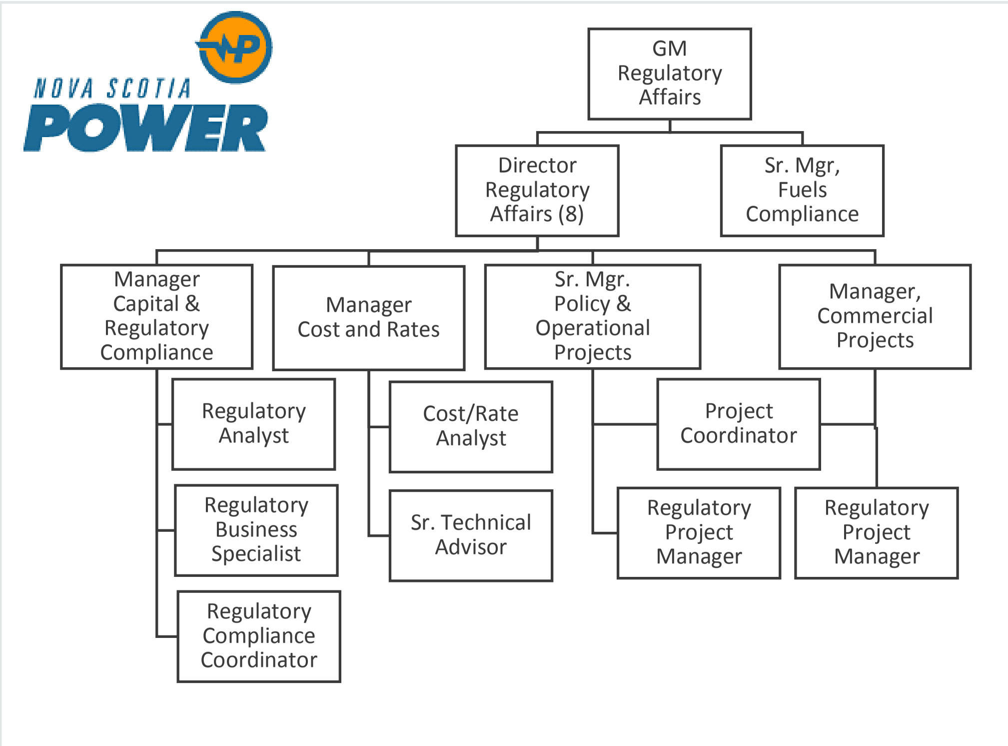
# Org. Design: Regulatory affairs departments are primarily small, centralized groups

| Company | Regulatory Affairs Staffing of Major Functions | | |
|---|---|---|---|
| | Org Structure | Staff | Areas of Responsibility |
| Nova Scotia Power | Centralized | | GM, Regulatory Affairs<br>1. Director, Regulatory Affairs and Rates |
| **Utility C** | Centralized | | EVP, Regulatory Utility C (Chief Compliance Officer)<br>1. VP, Utility C Pipeline and Gas<br>2. Director, Utility C Electric<br>3. Sr. Manager, Utility C Power |
| **Utility B** | Centralized | | SVP, Public & Government Affairs<br>1. VP, Commercial and Regulatory Affairs, Utility B Utilities<br>2. VP, Environmental and Regulatory Affairs<br>3. Chief Compliance Officer |
| **Utility A** | Centralized | | VP, Regulatory Affairs<br>1. Director, Regulatory Affairs<br>2. Eastern Regional Director, Regulatory and Legal Affairs |

## Key Findings

- To manage deregulated generation portion of utilities, many companies have re-organized and created new compliance and audit departments
  - Companies are emphasizing billing accuracy for customers and data accuracy for competitors operating in the space
- Utilities leverage cost efficiency in organizational structure
  - Recruit foreign workers
  - Utilize line managers in large power generation regulatory approvals for to receive buy-in from residents early

# Org. Design: NSPI's regulatory affairs group is large since it is involved in generation, transmission and distribution businesses




**Roles and Responsibilities**

**Regulatory Compliance, Legal and Special Projects:**
- UARB appeals
- UARB Directives
- FAM
- Relationships

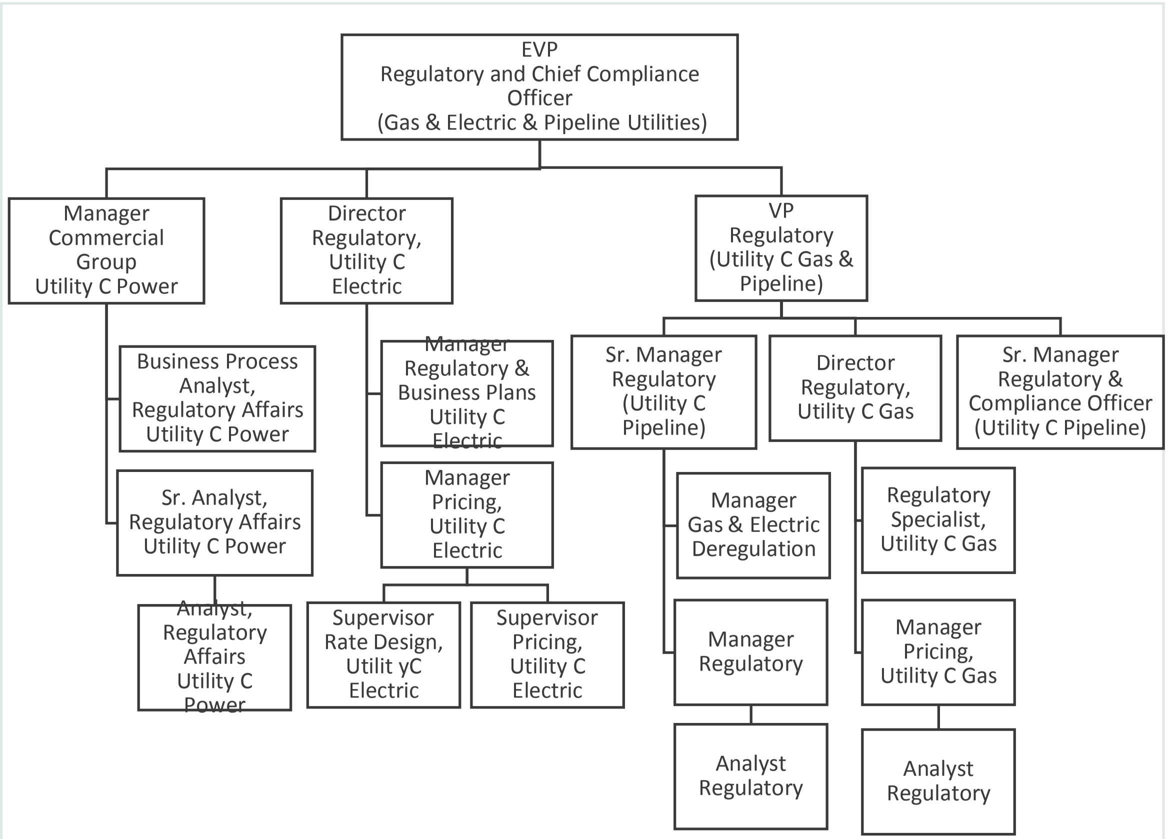
**Capital and Regulatory Compliance**
- Code of Conduct
- UARB Reporting and Directives
- Customer Complaint Management
- Capital (ACE, Power Production, Gen Planning and COPS capital)

**Costing and Rates (Tariffs and Cost of Service)**
- Rate Development
- OATT
- COSS
- Rate Analysis

**Policy and Operational Projects (Revenue and Sustainability)**
- Energy Efficiency and Conservation
- Rates Management, NERC
- Regulatory Policy
- Renewable, Cleaner & Greener
- Stakeholder Engagement

**Commercial Projects (Finance and Cost Recovery)**
- Rate Case Planning and Execution
- Cost Recovery
- Affiliate transactions
- Regulatory Assets
- Stakeholder Engagement

# Org. Design: Utility C's regulatory affairs group is divided into Power, Electric and Gas & Pipeline*




**Roles and Responsibilities***

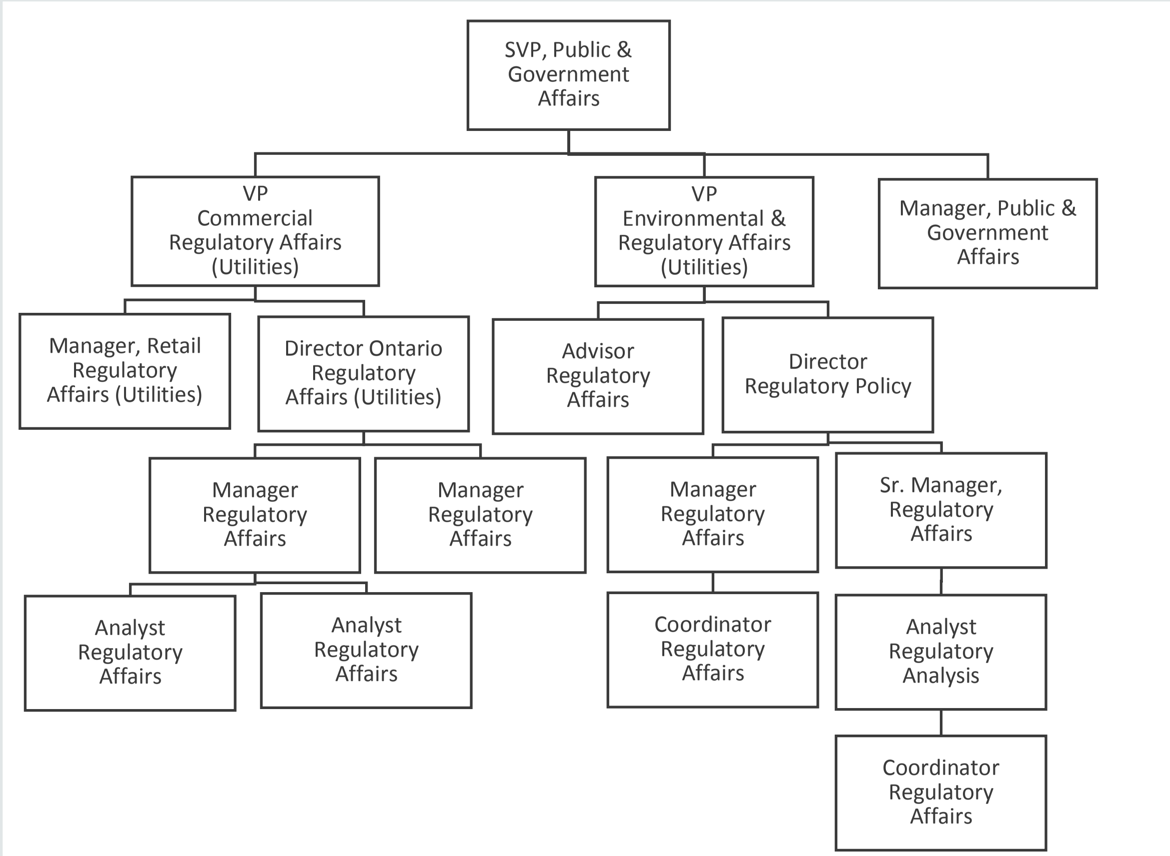
**EVP Regulatory Affairs**
- Chief Compliance Officer
- Additional compliance responsibilities created as a result of de-regulation

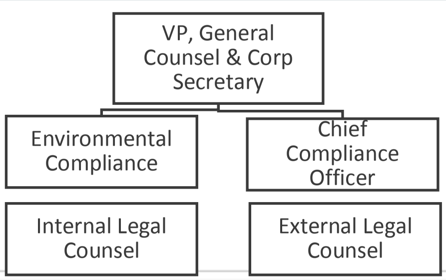
**Commercial Group, Utility C Power**
- Regulatory and commercial issues related to sustainability, climate change, greenhouse gases and air pollutants
- Market and regulatory reviews
- Strategy and information needs of department managers through the preparation of business-related analysis and research

**Regulatory Utility C Electric**
- Rate Development
- Rate Analysis
- Pricing

**Regulatory Utility C Gas & Pipeline**
- Energy Efficiency and Conservation
- Rates Management
- Pipeline distribution management, licensing and construction
- Regulatory Policy
- Pricing
- Regulatory Compliance including data and reporting accuracy and code of conduct

# Org. Design: The deregulation of Utility B's power generation business created new reg. affairs activities to monitor and ensure reg. compliance of client billing and data accuracy*



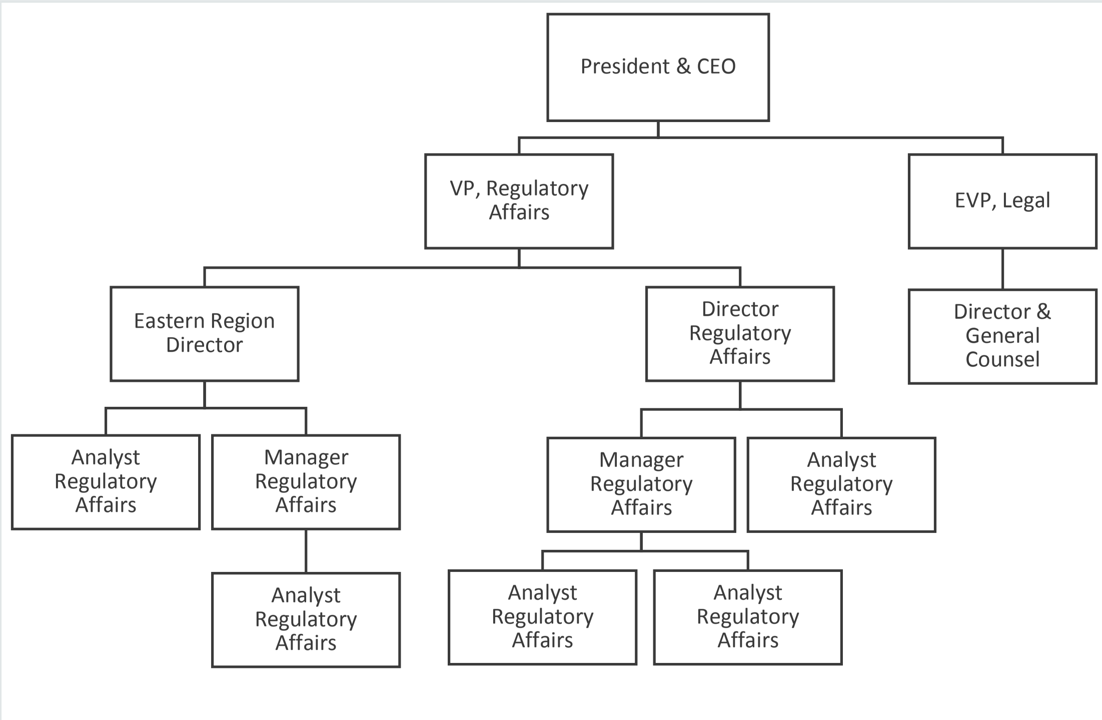

## Roles and Responsibilities

**Provincial Commercial Regulatory Affairs***
- Ensure the commercial performance of Power Generation
- Advise Utility B's business units on compliance and market evolution in Ontario
- Rate Development
- Rate Analysis
- Pricing

**Environmental & Regulatory Affairs**
- GHG projects
- Rate Development
- Rate Analysis
- Pricing

**Chief Compliance Officer**
- Position created as a result of de-regulation
- Corporation's ethics system
- Regulatory compliance
- CSOx sustainment activities
- Privacy obligations

# Org. Design: Utility A's power generation business operates outside the regulatory pricing approval process and, consequently, requires less regulatory affairs support




## Roles and Responsibilities

**Regulatory Affairs Eastern Region**
- Rate Development
- Rate Analysis
- Pricing

**Regulatory Affairs**
- Setting regulatory policy
- Regulatory strategy
- Develop a framework and strategy to minimize the environmental impact of its operations
- Negotiating settlements with stakeholders
- Manage federal, provincial and local environmental laws, regulations and guidelines concerning the generation and transmission of electrical and thermal energy and surface mining

**Line Expertise**
- Line managers used to supplement short term regulatory affairs activities
- Example: Director of wind resource planning for permitting sites to be compliant with local, provincial and federal requirements.

# Outsourcing: External contracts with a small number of approved companies reduces costs and improves service quality

| | Activities Outsourced | Outsourcing Strategy |
|---|---|---|
| Nova Scotia Power | • Legal Counsel<br>• Consulting firms<br>• Consumer Advocate | • External contractors are used to supplement shortage of staff at NSPI |
| Utility C | • Consultants<br>• Legal Counsel<br>• External auditors | • Outsource legal counsel to supplement and support current functions |
| Utility B | • Legal Counsel<br>• Consulting Firms<br>• Auditors | • Outsources services to support units that fall outside of the main service region<br>– Recently re-hired external contractors to ensure accuracy and quality compliance |
| Utility A | • Legal Counsel<br>• Human Resources<br>• Operations<br>• Desktop support<br>• Consulting | • Outsourcing is a key strategy used to offset the impact of deregulation by operating and maintain the traditional revenue stream<br>– Outsourcing creates / unlocks resources to focus on exploring new revenue streams<br>• Consulting activities are heavily outsourced at Utility A to support the needs of investment projects |

# KPIs: Deregulated companies focus on data accuracy for client billing, back-billing, and competitive pricing

| | KPI | Description |
|---|---|---|
| **Utility C** | • Full and Complete Regulatory reporting<br>– Goal: 100%<br>• Increase Accuracy of Client Billing<br>– Goal: 100% | • Full and complete reporting to regulatory agencies<br>– "We believe that full and complete reporting to regulatory agencies and to our shareowners as required reconstitutes a responsible and workable approach to the interests of disclosure." – Utility C |
| **Utility B** | • Increase Accuracy of Client Billing<br>– Goal: 100%<br>• Lower negative environmental emissions | • Effective processes for controlling the electricity procurement and regulated customer billing processes<br>• Atmospheric emissions, PCB management, internal energy efficiency, employee awareness and training, impacts on fish |
| **Utility A** | • Lower time and cost of public hearings<br>– Goal: < 7 days | • Systematically identify and address issues in advance of regulatory process. This helped bring the public hearing down to one week.<br>– "The key learning for us was the importance of building relationships and dealing with issues as best we could – early on in the process – rather than leaving them until the regulatory forum, which tends to be adversarial in nature." |

# <u>Investments:</u> Utility C and Utility B are incurring regulatory expenses as a result of large capital investments aimed at meeting future power demand

| | 2008 Investments | Objectives | Cost and Expected Results |
|---|---|---|---|
| Utility C | | | |
| Utility B | | | |

Information Redacted

# Investments: In addition to capital investments, reducing environmental risks to ensure environmental regulations compliance is a key driver of regulatory affairs spend

| | 2008 Investments | Objectives | Results and Expected ROI |
|---|---|---|---|
| Utility A | Information Redacted | | |

# In summary, NSPI rates favorably against their comparable group in OM&G expense, but has potential room to improve its operations which would result in reductions in OM&G, improvements in satisfaction and reliability

## Power Production

- **NSPI spends less on OM&G when adjusted for plant availability vs. comparables**
- **OM&G costs associated with power production has increased at a faster rate than comparables, similar to the pattern for overall OM&G**
  - Reallocation of head office cost is primary expense driver
- **NSPI's plants tend to have higher number of direct reports per employee than comparables**
  - Organizational change can enforce standardization and increased level of accountability in maintenance

## Customer Service

- **Spend per customer is in mid-range against comparables**
- **Customer satisfaction is low, in part due to number of outages**
  - Expenditure on emergency services are high due to number of outages
- **Call center has more supervisors for size of the staff vs. comparables, possibly demonstrating lower efficiency**

## Regulatory Affairs

- **NSPI is performing in line with comparables in regulatory affairs**
- **No significant recommendations were identified for regulatory affairs**

## Customer Operations

- **NSPI's expenditures on vegetation management and T&D maintenance are not in line with reliability results when compared**
  - NSPI is starting a new 5 year plan around veg. mgmt and T&D maintenance
- **NSPI lacks an integrated work management system and accompanying processes which affects customer operations, customer service and power production**
  - Lack of organizational standardization and accountability vs. comparables
  - Management should evaluate integrated WMS, to include implementation costs/time

# Appendix

*Glossary of Terms*

*List of Alternate WMS Vendors*

*Plant Reports*

*Customer Operations Observations*

*Customer Service Observations*

# Glossary of Acronyms

| Acronym | Meaning |
|---|---|
| BIC | Best in Class |
| CAGR | Compound Annual Growth Rate |
| OM&G | Operation Maintenance and General Expenditures |
| MWh/GWh | Megawatt-hour/Gigawatt-hour |
| T&D | Transmission and Distribution |
| WMS | Work Management System |
| SAIDI | System Average Interruption Duration Index |
| SAIFI | System Average Interruption Frequency Index |
| CAIDI | Customer Average Interruption Duration Index |
| | |

# WMS Vendors: In addition to the SAP system used by Utility D, Utility A and Utility F, a number of other potential solution providers exist

| Vendor | Website |
|---|---|
| **Ventyx (Indus)** | http://www1.ventyx.com/ |
| **Synergen** | http://www.synergen.com |
| **Digital Inspections (Cascade)** | http://digitalinspections.com/ |
| **MRO (Maximo) – Used by NSPI currently** | http://www.mro.com/corporate/assetmanagement/maximo-enterprise-suite/options.php |
| **Datastream** | http://www.datastream.net/ |
| **IVARA** | http://www.ivara.com/ |
| **Microsoft Great Plains** | http://www.microsoft.com/dynamics/gp/default.mspx |

# Plant Reports: Comparative OM&G Breakouts (2007F)

| | | Trenton | Point Tupper | Tufts Cove | Point Aconi | Lingan | Hydro | Comb. Turb. |
|---|---|---|---|---|---|---|---|---|
| Labor | 001 Regular Labor | | | | | | | |
| | 002 Overtime Labor | | | | | | | |
| | 004 Term Labor | | | | | | | |
| | 005 Loaned Op. Labor | | | | | | | |
| | 006 Borrowed Operating Labor | | | | | | | |
| | 007 Loaned Cap. Labor | | | | | | | |
| | 008 Labor Clearing | | | | | | | |
| | Total Labor | | | | | | | |
| Non-Labor | 010 Office Supplies | | | | | | | |
| | 011 Travel Expense | | | | | | | |
| | 012 Materials | | | | | | | |
| | 013 Contracts | | | | | | | |
| | 014 Overtime Meals | | | | | | | |
| | 015 Frt, Post & Delivery | | | | | | | |
| | 016 Tools & Equipment | | | | | | | |
| | 017 Chemicals | | | | | | | |
| | 018 Gases | | | | | | | |
| | 019 Water | | | | | | | |
| | 021 Telephones | | | | | | | |
| | 026 Sponsor & Other Donations | | | | | | | |
| | 028 Consulting | | | | | | | |
| | 029 Membership Dues | | | | | | | |
| | 030 Lubricants | | | | | | | |
| | 031 Fleet Fuel | | | | | | | |
| | 032 Subcrpt / Info. Software | | | | | | | |
| | 033 Rental and Maintenanc | | | | | | | |
| | 034 Appl. Software | | | | | | | |
| | 035 Comp.Hrdwr & Op.Sftwr | | | | | | | |
| | 037 Ext. Legal & Audit | | | | | | | |
| | 039 Donations | | | | | | | |
| | 041 Meals & Entertainment | | | | | | | |
| | 042 Employee Benefits | | | | | | | |
| | 044 Energy Use (Non-Elect) | | | | | | | |
| | 050 Rent | | | | | | | |
| | 051 Gen. Cost Recovery | | | | | | | |
| | 055 Warranty & Service Co. | | | | | | | |
| | 056 Training & Developmen | | | | | | | |
| | 058 Personal Equipment | | | | | | | |
| | 059 Severance Costs | | | | | | | |
| | 061 Write-offs | | | | | | | |
| | 065 By-product Sales | | | | | | | |
| | 066 Other Goods & Service | | | | | | | |
| | 083 Short-term interest | | | | | | | |
| | 189 Steam Sales | | | | | | | |
| | 190 Miscellaneous Revenue | | | | | | | |
| | Total Non Labor | | | | | | | |
| | TOTAL | | | | | | | |

Information Redacted

# Plant Reports: Point Aconi Generating Station Overview

**Plant**

Point Aconi, Thermal Production

**Plant Background**

**Information Redacted**


### Summary Review

- Point Aconi is a well-run facility
- In the course of its review:
  - Kaiser noted exemplary performance In Staffing  Practices, Safety (award winning safety record), Environmental
  - Potential recommendations are in the areas of: Operating KPIs, Environmental, Predictive and Preventative Maintenance and Work Management Processes

# Plant Reports: Point Aconi Organization Overview

## Staffing Practices

Information Redacted

## Performance – Availability / Efficiency / Capacity

Information Redacted

## Environmental

Information Redacted

# Plant Reports: Point Aconi Maintenance Programs

## Maintenance

Information Redacted

## Work Management Processes

Information Redacted

# Plant Reports: Point Aconi Organizational Chart

**Information Redacted**

# Plant Reports: Point Tupper Generating Station Overview

**Plant**

Point Tupper, Thermal Production

**Plant Background**

**Information Redacted**


**Summary Review**

- Point Tupper is a well-run facility
- In the course of its review:
  - Kaiser noted exemplary performance In Staffing Practices, Safety (highest priority KPI) and Environmental Processes
  - Potential recommendations are in the areas of: Operating KPIs, Environmental, Predictive and Preventative Maintenance and Work Management Processes

# Plant Reports: Point Tupper Organizational Observations

## Staffing

Information Redacted

## Performance – Availability / Efficiency / Capacity

Information Redacted

# Plant Reports: Point Tupper Maintenance Observations

## Environmental

## Maintenance

Information Redacted

# Plant Reports: Point Tupper Work Management Processes

## Maintenance (Cont.)

Information Redacted

## Work Management Process

Information Redacted

# Plant Reports: Point Tupper – Highlights of Predictive Maintenance Programs

Information Redacted

# Plant Reports: Point Tupper Organizational Chart

Information Redacted

# Plant Reports: Trenton Generating Station Overview

**Plant**

Trenton , Thermal Production


**Plant Background**

**Information Redacted**

**Summary Review**

- Trenton is a well-run facility
- In the course of its review:
  - Kaiser noted exemplary performance in Staffing Practices, Safety (tops in the NSPI system), Environmental Processes
  - Potential recommendations are in the areas of: Operating KPIs, Environmental, Maintenance) and Work Management Processes

# Plant Reports: Trenton Organization Overview

## Staffing

Information Redacted

## Safety

Information Redacted

## Performance – Availability / Efficiency / Capacity

Information Redacted

## Environmental

Information Redacted

# Plant Reports: Trenton Maintenance Observations

## Maintenance

Information Redacted

# Plant Reports: Trenton Work Management Processes

## Work Management Process

Information Redacted

# Plant Reports: Trenton Quadrant System for categorizing and assigning Maintenance Work

Information Redacted

# Plant Reports: Trenton – Highlights of Predictive and Preventative Maintenance Programs

**Information Redacted**

# Plant Reports: Trenton Organizational Chart

Information Redacted

# Plant Reports: Lingan Generating Station Overview

**Plant** Lingan, Thermal Production

**Plant Background**

**Information Redacted**


## Summary Review

- Lingan is a well-run facility
- In the course of its review:
  - Kaiser noted exemplary performance In Staffing Practices, Safety (award winning safety record)
  - Potential recommendations are in the areas of: Operating KPIs and Environmental Processes

# Plant Reports: Lingan Organization Observations

## Staffing

Information Redacted

## Safety

## Performance – Availability / Efficiency / Capacity

Information Redacted

# Plant Reports: Lingan Maintenance Observations

## Environmental

Information Redacted

## Maintenance

Information Redacted

# Plant Reports: Lingan Work Management Processes

## Work Management Process

Information Redacted

# Plant Reports: Lingan – Highlights of Predictive Management Programs

Information Redacted

# Plant Reports: Lingan Organizational Chart

**Information Redacted**

# Plant Reports: Tuft's Cove Generating Station Overview

**Plant**

Tuft's Cove, Thermal Production

**Plant Background**

**Information Redacted**


**Summary Review**

- Tuft's Cove is a well-run facility
- In the course of its review:
  - Kaiser noted exemplary performance in Environmental Practices
  - Potential recommendations are in the areas of: Operating KPIs, Environmental, Predictive and Preventative Maintenance and Work Management Processes

# Plant Reports: Tuft's Cove Organization Observations

## Staffing

Information Redacted

## Performance – Availability / Efficiency / Capacity

Information Redacted

## Environmental

Information Redacted

# Plant Reports: Tuft's Cove Maintenance Processes

## Safety

Information Redacted

## Maintenance

Information Redacted

# Plant Reports: Tuft’s Cove Work Management Processes

## Work Management Processes

Information Redacted

# Plant Reports: Tuft's Cove – Highlights of Predictive Maintenance Programs

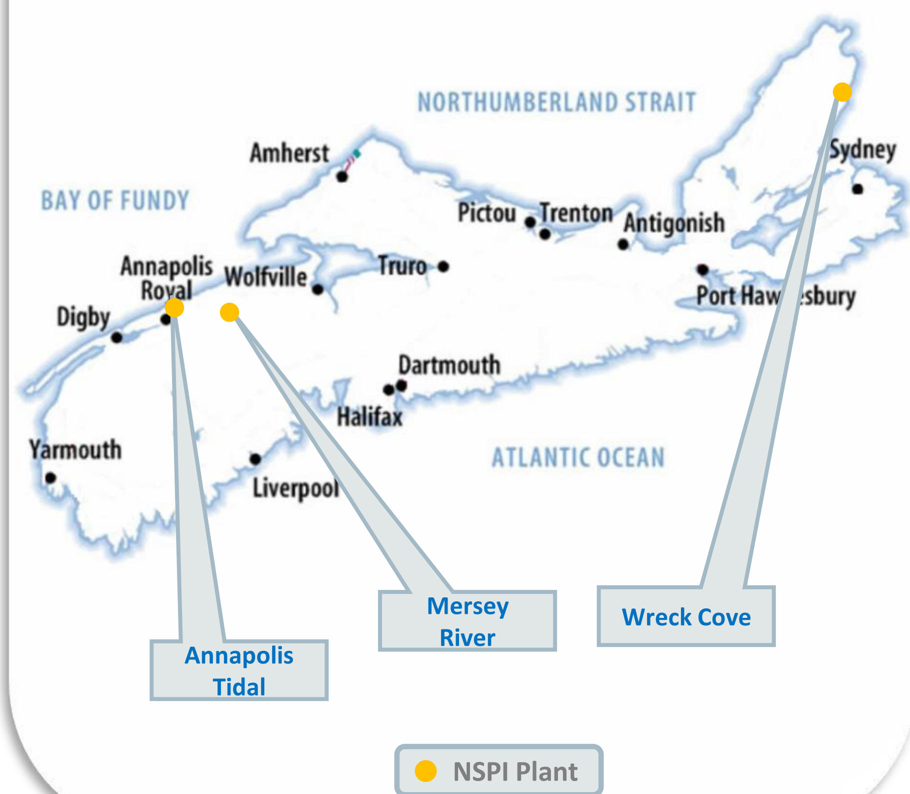
Information Redacted

# Plant Reports: Tuft's Cove Organizational Chart

Information Redacted

# Plant Reports: Hydro Stations including Annapolis Tidal Overview

| | |
|---|---|
| **Plant** | Annapolis Tidal, Hydro Production |
| **Plant Background** | **Information Redacted** |



# Plant Reports: Hydro Stations including Annapolis Tidal Organization Overview

## Staffing

Information Redacted

## Safety

## Performance – Availability / Efficiency / Capacity

Information Redacted

# Plant Reports: Hydro Stations including Annapolis Tidal Maintenance Procedures

## Environmental

Information Redacted

## Maintenance

Information Redacted

# **Plant Reports:** Hydro Stations including Annapolis Tidal Work Management Processes

## Work Management Process

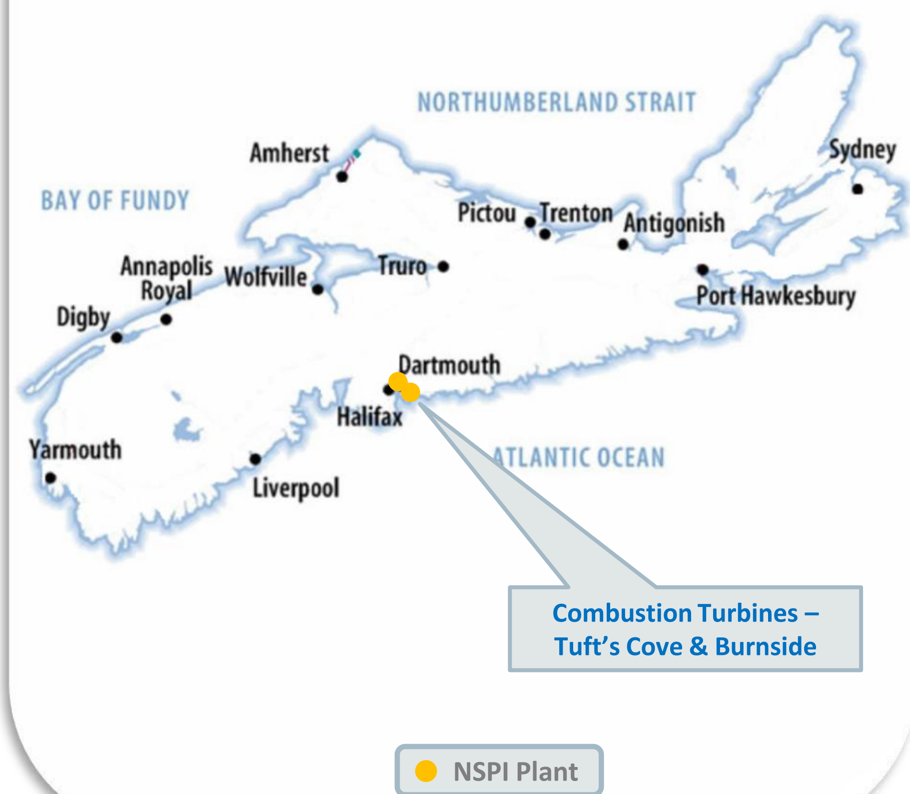
**Information Redacted**

# Plant Reports: Hydro Organizational Chart

Information Redacted

# Plant Reports: Combustion Turbines Overview

| | |
|---|---|
| **Plant** | Tuft's Cove and Burnside, Combustion Turbine |
| **Plant Background** | **Information Redacted** |



# Plant Reports: Combustion Turbines Organization Observations

**Staffing**

Information Redacted

**Safety**

Information Redacted

**Performance – Availability / Efficiency / Capacity**

Information Redacted

**Environmental**

Information Redacted

# Plant Reports: Combustion Turbines Maintenance Processes

## Maintenance

Information Redacted

## Work Management Process

Information Redacted

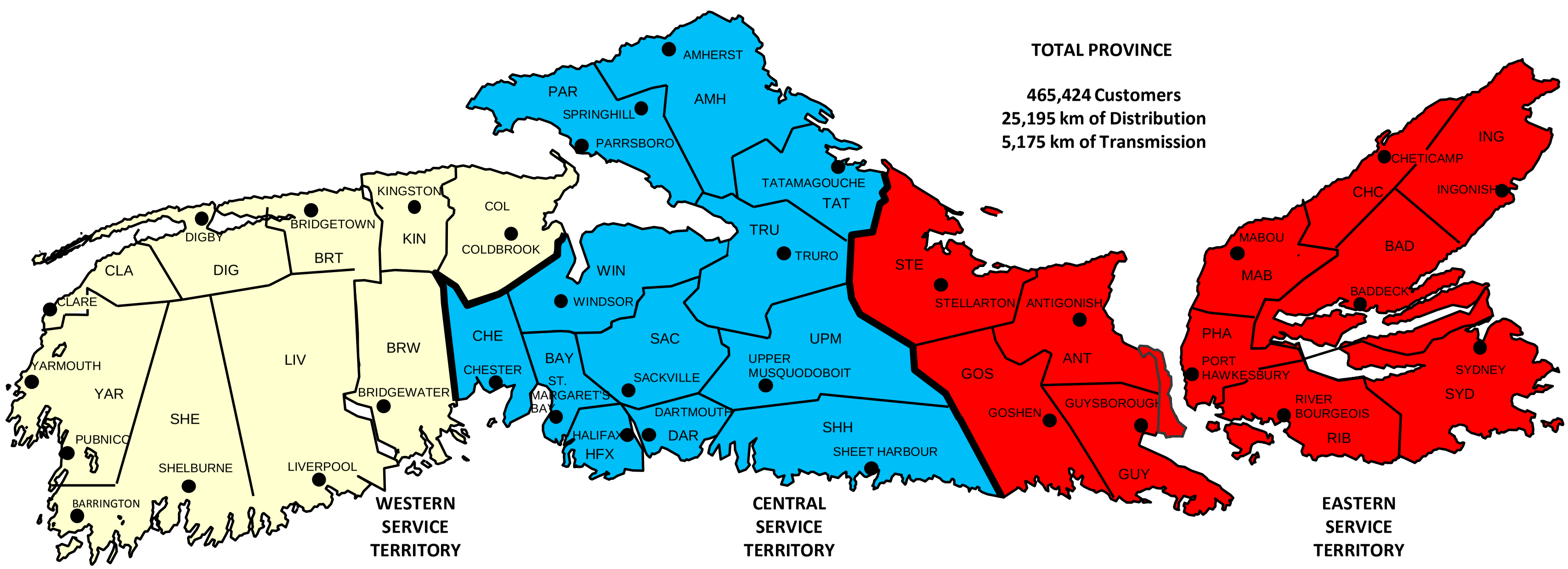
# Customer Operations: COPS covers 3 service territories and 35 depots has more than 522 employees and ~$19 million in OM&G Expenses

**Groups**

Lakeside, Customer Operations
Energy Control Center, Customer Operations

**Principal Activities**

Regional Operations
Control center Operations
T & D Asset Management
Work Force Management
Safety
Administration




**TOTAL PROVINCE**

**465,424 Customers**
**25,195 km of Distribution**
**5,175 km of Transmission**

**WESTERN SERVICE TERRITORY**

**Territory Headquarters: Bridgewater**

**101,477 Customers**
**7,419 km Distribution**
**1,520 km Transmission**

**CENTRAL SERVICE TERRITORY**

**Territory Headquarters Sackville**

**254,387 Customers**
**9,068 km Distribution**
**1,535 km Transmission**

**EASTERN SERVICE TERRITORY**

**Territory Headquarters Sydney**

**109,560 Customers**
**8,708 km Distribution**
**2,120 km Transmission**

# Customer Operations: Organizational Overview

| COPS Organization Chart | | | |
|---|---|---|---|
| Management | Classification | FTEs | Term |

Information Redacted

## Preliminary Recommendations

# Customer Operations: KPIs

## Staffing

Information Redacted

## Performance

Information Redacted

## Environmental

# Customer Operations: Asset and Work Management

## Asset Management of T&D

Information Redacted

## Work Management Process

Information Redacted

# Customer Operations: Work Planning

## Work Planning Process

Information Redacted

## Detailed work package design

Information Redacted

## Work Evaluation

Information Redacted

# Customer Operations: Vegetation Management

## Vegetation Management

Information Redacted

## Storm Center Management

Information Redacted

# Customer Service: NSPI's customer service includes more than 300 employees, ~$23 million in OM&G expenses serving the province from one Halifax location

## Overview

**Group**

Halifax, Customer Service

**Principal Activities**

- Retail and commercial billing, collections & payments
- Retail and commercial customer contact center
- Customer communications and quality assurance
- Meter reading and inspection
- WMS Project
- Conservation & Energy Efficiency

**Customer Service Organization**

| Management | Classification | FTEs | Term |
|---|---|---|---|

**Information Redacted**

# Customer Service: Organizational observations

## Staffing

Information Redacted

## Organizational Design

Information Redacted

## Safety

# Customer Service: Organizational observations (continued)

## Regional vs. Centralized Staffing Model

Information Redacted

## Outsourcing

Information Redacted

## Meter Reading

Information Redacted

# Customer Service: KPIs

## Key KPIs

Information Redacted

## Customer Satisfaction

Information Redacted

**Requirement:**

**Listing of all assets (by function) (length of transmission lines by voltage class, length of distribution lines by voltage, number of substation, et.)**

**Submission:**

Please refer to Attachment 1.

**Nova Scotia Power Inc.**

| | |
|---|---|
| 1 | **Steam** |
| 2 | Lingan 1 & 2 |
| 3 | Lingan 3 & 4 |
| 4 | Lingan Common |
| 5 | Point Aconi |
| 6 | Point Tupper |
| 7 | Trenton 5 |
| 8 | Trenton 6 |
| 9 | Trenton Common |
| 10 | Tufts Cove 1 |
| 11 | Tufts Cove 2 |
| 12 | Tufts Cove 3 |
| 13 | Tufts Cove Common |
| 14 | Point Tupper Marine Terminal |
| 15 | |
| 16 | **Hydro** |
| 17 | Wreck Cove - Unit One |
| 18 | Wreck Cove - Unit Two |
| 19 | Gisborne |
| 20 | Avon # One - Unit One |
| 21 | Avon # Two - Unit Two |
| 22 | Methals |
| 23 | Hollow Bridge |
| 24 | Lumsden |
| 25 | Hell's Gate - Unit One |
| 26 | Hell's Gate - Unit Two |
| 27 | White Rock |
| 28 | Nictaux |
| 29 | Paradise |
| 30 | Ridge |
| 31 | Fourth Lake |
| 32 | Sissiboo |
| 33 | Weymouth - Unit One |
| 34 | Weymouth - Unit Two |
| 35 | Tusket - Unit One |
| 36 | Tusket - Unit Two |
| 37 | Tusket - Unit Three |
| 38 | Gulch |
| 39 | Lequille |
| 40 | Annapolis |
| 41 | Mersey |
| 42 | Roseway - Unit One |
| 43 | Roseway - Unit Two |
| 44 | Harmony |
| 45 | Mill Lake - Unit One |
| 46 | Mill Lake - Unit Two |
| 47 | Sandy Lake - Unit One |
| 48 | Sandy Lake - Unit One |
| 49 | Tide Water - Unit One |
| 50 | Tide Water - Unit Two |
| 51 | Fall River |
| 52 | Malay Falls - Unit Four |
| 53 | Malay Falls - Unit Five |
| 54 | Malay Falls - Unit Six |
| 55 | Ruth Falls - Unit One |
| 56 | Ruth Falls - Unit Two |
| 57 | Ruth Falls - Unit Three |
| 58 | Dickie Brook - Unit One |
| 59 | Dickie Brook - Unit Two |
| 60 | |
| 61 | **Other Production Plant** |
| 62 | Burnside Gas Turbines |
| 63 | Tusket Gas Turbines |
| 64 | Victoria Junction Turbines |
| 65 | Tufts Cove 4 |
| 66 | Tufts Cove 5 |
| 67 | |
| 68 | **Wind Turbine** |
| 69 | Little Brook |
| 70 | Grand Etang |
| 71 | Nuttby Wind Farm |
| 72 | Pt. Tupper Wind Farm |
| 73 | Digby Wind Farm |
| 74 | |

Forecasts are compiled for purposes of this rate application and are not intended to be relied upon for other purposes.

| | Kms of Line (1) | Voltage |
|---|---|---|
| **Transmission** | 1,668 | 69kV |
| | 1,786 | 138kV |
| | 1,253 | 230kV |
| | 468 | 345kV |
| | 5,175 | |
| **Distribution** | 10,805 | 25KV |
| | 14,645 | 12KV |
| | 897 | 4KV |
| | 26,347 | |

Nova Scotia Power has approximately 230 substations associated with the Transmission & Distribution systems. Other assets associated with the Transmission and Distribution system include land rights, towers, poles and fixtures, transformers, meters and street lighting and signal systems.

**General Property**

Nova Scotia Power has general property including land rights, roads, bridges, structures and improvements, office furniture, computer hardware and software, transportation, tools, stores, shop, garage, communications, mining and other equipment.

**Requirement:**

**Test year Power Production unit maintenance schedule of all units including hydro, and tidal, submitted as a Gantt chart.**

**Submission:**

Please refer to Confidential Attachment 1.

**Requirement:**

**Breakdown of generating units by type showing in service date, net capacity, fuel type, heat rate, contribution to system peak, contribution towards annual energy (include IPP and purchased power).**

**Submission:**

Please refer to Partially Confidential Attachment 1.

**Standardized Filing Requirements for Fuel - Generating Units by Type**
**Year 2012**

| | Fuel Type | In Service Year | Net Operating Capacity (MW) | Net Avg. Heat Rate (Btu/kWh) | 2012 Annual Energy (GWh) |
|---|---|---|---|---|---|
| **Thermal Units** | | | | | |
| Tufts Cove 1 | Oil / Natural Gas | 1965 | 81 | [redacted] | 290 |
| Tufts Cove 2 | Oil / Natural Gas | 1972 | 93 | | 68 |
| Tufts Cove 3 | Oil / Natural Gas | 1976 | 147 | | 376 |
| Trenton 5 | Coal / Petcoke | 1969 | 150 | | 328 |
| Trenton 6 | Coal / Petcoke | 1991 | 157 | | 1145 |
| Pt. Tupper 2 | Coal / Petcoke | 1973 | 152 | | 1244 |
| | | Coal Conv. 1987 | | | |
| Lingan 1 | Coal / Petcoke | 1979 | 153 | | 1149 |
| Lingan 2 | Coal / Petcoke | 1980 | 153 | | 927 |
| Lingan 3 | Coal / Petcoke | 1983 | 158 | | 1119 |
| Lingan 4 | Coal / Petcoke | 1984 | 153 | | 1211 |
| Pt. Aconi 1 | Petcoke / Coal | 1994 | 171 | | 1305 |
| | | **Total Thermal** | **1568** | | **9162** |
| **Combustion Turbines** | | | | | |
| Tufts Cove 4 | Natural Gas | 2003 | 49 | [redacted] | |
| Tufts Cove 5 | Natural Gas | 2005 | 49 | | |
| Tufts Cove 6 | Natural Gas Combined Cycle | 2011 | 50 | | 999 |
| Tusket 1 | Light Oil | 1971 | 24 | | 1 |
| Burnside 1 | Light Oil | 1976 | 33 | | 6 |
| Burnside 2 | Light Oil | 1976 | 33 | | 4 |
| Burnside 3 | Light Oil | 1976 | 33 | | 3 |
| Burnside 4 | Light Oil | 1976 | 33 | | 0 |
| Victoria Junction 1 | Light Oil | 1976 | 33 | | 1 |
| Victoria Junction 2 | Light Oil | 1975 | 33 | | 1 |
| | | **Total CT's** | **371** | | **1015** |
| **Hydro and Wind Systems** | **Installed Capacity (MW)** | | **Firm Capacity (MW)** | | **Energy (GWh)** |
| Wreck Cove | | 1978 | 230 | | 301 |
| Annapolis Tidal | | 1984 | 3.7 | | 27 |
| Other Hydro | | | 163.5 | | 647 |
| Little Brook | 0.60 | | 0.2 | | 2 |
| Grand Etang | 0.66 | | 0.2 | | 2 |
| Digby | 30 | | 9.9 | | 107 |
| Nuttby Mountain | 45 | | 14.9 | | 140 |
| **Total Hydro/ Wind** | | | **422** | | **1226** |
| **Independent Power Producers** | **Installed Capacity (MW)** | | **Firm Capacity (MW)** | | **Energy (GWh)** |
| Independent Power Producers - Other | 36.8 | | 26.8 | Contract IPPs (pre 2001) | 198 |
| Independent Power Producers - Wind | 217.7 | | 71.8 | Renewables IPPs (post 2001) | 597 |
| **Imported Power** | | | | Import Purchases | 484 |
| **NS Power Total Firm Capacity (MW)** | | | **2460** | **Total Purchases** | **1279** |
| | | | | **Total Annual Energy** | **12681** |

| 2012 forecast breakdown of assets at the time of peak | |
|---|---|
| | |
| | MW |
| Peak (January, Monday, hour ending 19:00) | 2,308 |
| | |
| Thermal contribution | 1,613 |
| Hydro contribution | 378 |
| IPP contribution | 29 |
| Imports contribution | 288 |
| | |
| TOTAL | 2,308 |

Updated: 2010-12-31

**Requirement:**

**Physical, chemical specification sheets for all fuels.**

**Submission:**

Please refer to Attachment 1.

# TECHNICAL SPECIFICATION - LOW SULPHUR COAL

| Properties (As Received Basis) | Typical | Minimum | Maximum | Applicable ASTM Standard |
|---|---|---|---|---|
| Moisture | 7% | - | 9% | D3302 |
| Free Moisture | - | - | 3% | D3302 |
| Ash | 7% | - | 9% | D3172 |
| Sulphur | 0.65% | - | 1.10% | D3177 |
| Volatile Matter | 34% | 30% | - | D3175 |
| Calorific Value (Btu/lb.) | 11,300 | 10,800 | - | D5865 |
| Grindability (HGI) | 45-55 | 42 | 65 | D409 |
| Size (Topsize) | - | - | 2” x 0 | D4749 |
| Size (Fines < 0.5 mm) | - | - | 10% | D4749 |
| Mercury | | | | D6414-01 |

## TECHNICAL SPECIFICATION - PETROLEUM COKE

**Type: Delayed Petroleum Coke, Shot Coke Only**

| Properties (As Received Basis) | Typical | Minimum | Maximum | Applicable ASTM Standard |
|---|---|---|---|---|
| Moisture | 7% | - | 9% | D4931 |
| Free Moisture | - | - | 3% | - |
| Ash | 0.2% | - | 0.5% | D4422 |
| Sulphur | 4-6% | - | 6.5% | D1552 |
| Volatile Matter | 11% | 8% | - | D4421 |
| Calorific Value (Btu/lb.) | 14,000 | 13,900 | - | D5865 |
| Grindability (HGI) | 40 | 30 | 55 | D5003 |
| Size (Topsize) | - | - | 2" x 0 | D5709 |
| Size (Fines < 0.5 mm) | - | - | 12% | D5709 |
| Vanadium, ppm | 800 | - | 1200 | D5056 |
| Nickel, ppm | 100 | - | 500 | D5056 |

# TECHNICAL SPECIFICATION - MID SULPHUR COAL

| Properties (As Received Basis) | Typical | Minimum | Maximum | Applicable ASTM Standard |
|---|---|---|---|---|
| Moisture | 7% | - | 12% | D3302 |
| Free Moisture | - | - | 3% | D3302 |
| Ash | 7% | - | 12% | D3172 |
| Sulphur | 2.5% | - | 4.5% | D3177 |
| Volatile Matter | 35% | 30% | - | D3175 |
| Calorific Value (Btu/lb.) | | 11,000 | - | D5865 |
| Grindability (HGI) | 50-60 | 50 | 65 | D409 |
| Size (Topsize) | - | - | 2” x 0 | D4749 |
| Size (Fines < 0.5 mm) | - | - | 10% | D4749 |
| Chlorine | | | 1000 ppm | D4208-02 |
| Mercury | | | | D6414-01 |

*CONTRACT STANDARD*
**SPECIFICATION**

**NSPI Combustion Turbine**
**Distillate Specification for Product Delivered**
**March 1 – November 30**

| PROPERTY | MIN / MAX | ASTM TEST METHOD |
|---|---|---|
| Appearance | Clear and Bright | Visual |
| Density, kg/m3 | 0.881 max | D1298 |
| Distillation 90% Recovered | 360.0 max | D86 |
| Cloud Point, Degree C | Report (note 1) | D2500 |
| Pour Point, Degrees C | Report (note 1) | D97 |
| Viscosity @ 40 C, cst | 1.3 min – 3.6 max | D445 |
| Cetane Number | 40 min | D613 |
| Sulfur, wt % | 0.1 max | D1552 |
| Corrosion – Copper – 3 hrs @ 50 C | No. 1 max | D130 |
| Micro Carbon Residue 10% Bottoms % Mass | 0.2 max | D4530 |
| Flash, Degrees C | 40 min | D93 |
| Water and Sediment, Vol % | 0.05 max | D1796 |
| Ash, wt % | 0.01 max | D482 |
| Trace Metals, ppm by wt% | | D3605 |
| Vanadium | 0.2 max | |
| Sodium plus Potassium | 0.6 max | |
| Calcium | 2.0 max | |
| Lead | 0.1 max | |

**Notes**:

1. Operability of the fuel shall meet seasonal conditions. An operability schedule must be submitted with the tender.

Effective Date: May 1, 2003
Updated: November 1, 2009

*CONTRACT STANDARD*
**SPECIFICATION**

**NSPI Combustion Turbine**
**Distillate Specification for Product Delivered**
**December 1 – February 28**

| PROPERTY | MIN / MAX | ASTM TEST METHOD |
|---|---|---|
| Appearance | Clear and Bright | Visual |
| Density, kg/m3 | 0.850 max | D1298 |
| Distillation 90% Recovered | 290.0 max | D86 |
| Cloud Point, Degree C | -34 max | D2500 |
| Pour Point, Degrees C | Report | D97 |
| Viscosity @ 40 C, cst | 1.1 min – 1.8 max | D445 |
| Cetane Number | 40 min | D613 |
| Sulfur, wt % | 0.1 max | D1552 |
| Corrosion – Copper – 3 hrs @ 50 C | No. 1 max | D130 |
| Micro Carbon Residue 10% Bottoms % Mass | 0.1 max | D4530 |
| Flash, Degrees C | 40 min | D93 |
| Water and Sediment, Vol % | 0.05 max | D1796 |
| Ash, wt % | 0.01 max | D482 |
| Trace Metals, ppm by wt% | | D3605 |
| Vanadium | 0.2 max | |
| Sodium plus Potassium | 0.6 max | |
| Calcium | 2.0 max | |
| Lead | 0.1 max | |

Effective Date: May 1, 2003
Updated: November 1, 2009

## HFO QUALITY SPECIFICATION

| Property | Requirement | ASTM Test |
|---|---|---|
| Gravity, $^{0}$API- Apr 1 to Dec 31<br>Gravity, $^{0}$API- Jan 1 to Mar 31 | min. 9.0<br>min. 9.5 | D1298<br>D1298 |
| Saybolt Viscosity, Furol @ 50 $^{0}$C | min. 150<br>max. 300 | D445, D2161 |
| Flash Point, $^{0}$C ($^{0}$F) | min. 66 (150) | D93 |
| Sulphur, wt. % | max. 2.2 (or 1.0) | D4294 |
| Water by Distillation, vol. % | max. 1.0 | D95 |
| Compatibility, spot | max. 1 | D4740 |
| Hydrogen Sulphide, vol. ppm<br>*(The preceding seven Properties are referenced in Section 13.8 (a))* | 200 | Exxon AM-S90-003 |
| Gross Heat of Combustion, MMBtu/Bbl | 6.325 | D240 |
| Ash, wt. % | max. 0.10 | D482 |
| Sediment by Extraction, wt. % | max. 0.25 | D473 |
| Sediment by Hot Filtration, wt. % | max. 0.1 | D4870 |
| (1) Vanadium, wt. ppm | max. 300 | D5863A/B (1) |
| Sodium, wt. ppm | max. 50 | D5863B |
| Ashphaltenes, wt. % | max. 10 | IP143 |
| Pour Point, $^{0}$C ($^{0}$F) | max. 21 (70) | D97 |

Notes: 1)Test method ASTM-D-5863(B) will be used at discharge port to determine if discharge should be delayed while test method 5863(A) is performed. Test method ASTM-D-5863(A) will be used for pricing calculations at discharge port, and will be binding in the event of a dispute.

**Technical Specifications – Natural Gas**

Total Heating Value

(a) Natural gas received or delivered hereunder shall have a Total Heating Value below 36 $MJ/m^3$.

Composition

(a) Oxygen. The gas shall not have an uncombined oxygen content in excess of two-tenths (0.2) of one percent (1%) by volume, and both parties shall make every reasonable effort to keep the gas free from oxygen.

(b) Non-Hydrocarbon Gases. The gas shall not contain more than four percent (4%) by volume, of a combined total of non-hydrocarbon gases (including carbon dioxide and nitrogen); it being understood, however, that the total carbon dioxide content shall not exceed three percent (3%) by volume.

(c) Liquids. The gas shall be free of water and hydrocarbons in liquid form at the temperature and pressure at which the gas is received and delivered.

(d) Hydrogen Sulphide. The gas shall not contain more than six (6) milligrams of hydrogen sulphide per one (1) Cubic Meter.

(e) Total Sulphur. The gas shall not contain more than four-hundred and sixty (460) milligrams of total sulphur, excluding any mercaptan sulphur, per one (1) Cubic Meter.

(f) Temperature. The gas shall not have a temperature of more than forthy-nine degrees ($49^o$) Celsius.

(g) Water Vapor. The gas shall not contain in excess of eighty (80) milligrams of water vapor per one (1) Cubic Metre.

(h) Liquefiable Hydrocarbons. The gas shall not contain liquid hydrocarbons or hydrocarbons liquefiable at temperatures warmer than minus nine degrees (-9$^{o}$) Celsius and normal pipeline operating pressures of between 690 and 9930 kPag.

(i) Microbiological Agents. The gas shall not contain any microbiological organism, active bacteria or bacterial agent capable of contributing to or causing corrosion and/or operational and/or other problems.

**Requirement:**

**IPP contract details.**

**Submission:**

Please refer to Confidential Attachment 1.

**Requirement:**

**Reliability Statistics for fossil fleet, and customer outage indices for NSPI and comparison to latest CEA all Canada values.**

**Submission:**

Please refer to Attachment 1.

| **Performance Factor:** | **Availability** | | | | | | |
|---|---|---|---|---|---|---|---|
| **Annual Hours:** | **8760** | **8784** | **8760** | **8760** | **8760** | **CEA** | **NERC** |
| **Year:** | **2007 (actual)** | **2008 (actual)** | **2009 (actual)** | **2010 (forecast)** | **2010 Actual** | **2001-2005** | **2001-2005** |
| **Plant** | | | | | | | |
| Pt. Aconi | 92.90% | 88.90% | 92.80% | 90.00% | 83.31% | | |
| Tufts Cove #1 | 87.90% | 79.60% | 54.00% | 92.00% | 92.99% | | |
| Tufts Cove #2 | 89.10% | 84.30% | 68.80% | 92.00% | 91.90% | | |
| Tufts Cove #3 | 82.50% | 72.80% | 74.30% | 87.00% | 69.25% | | |
| Tufts Cove #4 | | | | | 91.49% | | |
| Tufts Cove #5 | | | | | 72.54% | | |
| Tufts Cove #6 | | | | | n/a | | |
| PT. Tupper #2 | 98.90% | 89.90% | 90.30% | 96.00% | 93.55% | | |
| Trenton #5 | 90.90% | 94.50% | 65.80% | 89.00% | 62.01% | | |
| Trenton #6 | 91.40% | 87.30% | 93.00% | 98.00% | 79.08% | | |
| Lingan #1 | 96.20% | 80.70% | 96.90% | 92.00% | 80.95% | | |
| Lingan #2 | 89.60% | 93.50% | 90.30% | 90.00% | 91.19% | | |
| Lingan #3 | 94.60% | 93.80% | 88.70% | 94.00% | 96.02% | | |
| Lingan #4 | 91.70% | 80.10% | 86.00% | 90.00% | 94.42% | | |
| Fossil Fleet Availability | **91.40%** | **87.60%** | **82.30%** | **92.00%** | **84.52%** | **81.09%** | **87.64%** |

Definition: Availability is not a reported CEA measure. It is comparable to the Capability Factor CbF (%), which is the complement of the Incapability Factor. * CEA Availability is calculated here as (100% - ICbF).

**Customer Outage Indices**

| | NSPI All-In Data | | | CEA REGION 2 | | |
|---|---|---|---|---|---|---|
| | NSPI | NSPI | NSPI | CEA | CEA | CEA |
| Year | SAIFI | SAIDI | CAIDI | SAIFI | SAIDI | CAIDI |
| **2007** | 3.98 | 14.17 | 3.56 | 2.68 | 7.29 | 2.72 |
| **2008** | 4.15 | 11.29 | 2.72 | 2.76 | 8.56 | 3.10 |
| **2009** | 2.86 | 5.80 | 2.03 | 2.31 | 5.31 | 2.30 |
| **2010** | 4.36 | 17.67 | 4.06 | N/A | N/A | N/A |

**Requirement:**

**Numbers of customers by rate class.**

**Submission:**

Forecasted Average Number of Customers by rate class for 2012:

| Class | Number |
|---:|---:|
| Domestic | 446,692 |
| General | 35,269 |
| Industrial | 2,497 |
| Other | 9,457 |
| **Total** | **493,916** |

**Requirement:**

**Electronic link to latest Hydro Quebec report "Comparison of Electric Prices in Major North American Cities".**

**Submission:**

http://www.hydroquebec.com/publications/en/comparison_prices/pdf/comp_2010_en.pdf

**Requirement:**

**Presentations made by NSPI/Emera to Analysts and Bondholders, within the last year, on behalf of NSPI and Emera (to the extent NSPI is included in the Emera presentation) and copies of any reports NSPI has received from financial analysts or bondholders since the last rate filing.**

**Submission:**

Presentation to Bond Rating Agencies: Please refer to Confidential Attachment 1 for a presentation NSPI has made to Bond Rating Agencies in the last year.

Presentations to Investors: Please refer to Confidential Attachment 2 for two presentations made by NSPI and eight presentations made by Emera. Emera has additional presentations however the information related to NSPI is similar to the information in the nine Emera presentations provided.

Bond Rating Reports: Please refer to Confidential Attachment 3.

Reports from Equity Analysts: Please refer to Confidential Attachment 4.

**Requirement:**

**Most recent Emera Proxy statement.**

**Submission:**

Please refer to Attachment 1.

# EMERA INCORPORATED

## NOTICE OF ANNUAL MEETING OF COMMON SHAREHOLDERS WEDNESDAY, MAY 4, 2011

AND

## MANAGEMENT INFORMATION CIRCULAR

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Emera

## Notice of Annual Meeting

The annual meeting of the common shareholders of Emera Incorporated will be held at the Cunard Centre, 961 Marginal Road, Halifax, Nova Scotia on Wednesday, May 4, 2011 at 2:00 p.m. (Halifax time) for the purposes of:

1. Electing Directors to serve until the next annual meeting of shareholders;
2. Appointing Auditors;
3. Authorizing the Directors to establish the Auditors' fee; and
4. Transacting such other business as may properly come before the Meeting.

Common shareholders of record as of the close of business on Friday, March 18, 2011 are entitled to vote at and participate in the business of the Meeting.

By Order of the Board of Directors,

*"Stephen D. Aftanas"*
Stephen D. Aftanas
Corporate Secretary

Halifax, Nova Scotia, Canada
February 11, 2011

> As a shareholder, it is important that you vote. Common shareholders are encouraged to return their proxy as soon as possible. A postage-paid, pre-addressed envelope is provided. As an alternative, shareholders may choose to vote by telephone or the Internet as provided for on the proxy. Proxies must be received prior to the close of business on Tuesday, May 3, 2011.
>
> Should you have any questions or comments, you may contact Emera Incorporated by writing to the Corporate Secretary, Emera Incorporated, P.O. Box 910, Halifax, Nova Scotia B3J 2W5 or by calling 1-800-358-1995 from anywhere in North America or 428-6060 within the Halifax-Dartmouth area.

# Management Information Circular

Information as of March 14, 2011
(unless otherwise noted)

## Solicitation of Proxies

**This Management Information Circular (the "Circular") is furnished in connection with the solicitation of proxies by the Board of Directors and management of Emera Incorporated (the "Company" or "Emera") for use at the annual meeting (the "Meeting") of common shareholders (the "Shareholders") of the Company to be held on Wednesday, May 4, 2011 as set forth in the Notice of Annual Meeting (the "Notice").**

Enclosed with this Circular is a proxy. The solicitation of proxies will be primarily by mail although proxies may also be solicited by telephone, facsimile, in writing, or in person, by Directors, Officers, or other employees or agents of the Company.

The Company wishes to have as many Shareholders vote as possible and has retained Georgeson Shareholder Communication Canada Inc. as proxy solicitation agent to assist with the solicitation of votes from Shareholders. The proxy solicitation agent will monitor the number of Shareholders voting and will contact Shareholders in order to ensure that a maximum vote is achieved. The cost of this solicitation will be borne by the Company and is expected to be approximately $60,000.

## Appointment and Revocation of Proxies

The persons named in the enclosed proxy are John T. McLennan, Chair of the Board; and Christopher G. Huskilson, President and Chief Executive Officer, both of whom are Directors of the Company, and Stephen D. Aftanas who is Corporate Secretary of the Company.

In order for a proxy to be counted, it must be received prior to the close of business on Tuesday, May 3, 2011. For Canadian residents, a postage-paid, pre-addressed envelope is provided for this purpose. In order for your vote to be counted, you may:

vote by proxy via mail, the Internet or telephone;
**<u>or</u>**
attend the Meeting in person and submit your completed proxy;
**<u>or</u>**
attend the Meeting in person and vote by ballot.

Completion of a proxy gives discretionary authority to the proxyholder in respect of amendments to matters identified in the Notice and other matters that may properly come before the Meeting or any adjournment thereof. As of the date of this Circular, management of the Company knows of no such amendments or other matters to be presented for action at the Meeting.

If you appoint Mr. McLennan, Mr. Huskilson, or Mr. Aftanas as your proxyholder, they will vote, or withhold from voting, in accordance with your directions. **If you do not specify how you want your shares voted, they will vote "For" the:**

- **election of Directors named in this Circular;**
- **appointment of Ernst & Young LLP as Auditors; and**
- **authorization of the Directors to establish the Auditors' fee.**

They will vote in accordance with their best judgement if any other matters are properly brought before the Meeting.

**You may appoint any other person (who need not be a Shareholder) to represent you at the Meeting by inserting that person's name in the space provided on the accompanying proxy. The person whom you appoint is your proxyholder and must attend and vote at the Meeting in order for your vote to count.**

You may revoke your proxy by giving written notification addressed to Stephen D. Aftanas, Corporate Secretary, 18th Floor, Barrington Tower, Scotia Square, P.O. Box 910, Halifax, Nova Scotia B3J 2W5, not later than the last business day preceding the day of the Meeting or any postponement or adjournment thereof or with the Chair of the Meeting on the day of the Meeting or any postponement or adjournment thereof or in any other manner permitted by law. If a proxy is revoked and not replaced by the close of business on Tuesday, May 3, 2011, the shares represented by such revoked proxy will not be counted and can only be voted in person by you at the Meeting.

**Record Date and Voting of Shares**

The date for determining which Shareholders are entitled to receive the Notice is Friday, March 18, 2011. This is called the "Record Date". Only Shareholders of record at the close of business on the Record Date will be entitled to vote. Each common share owned as of the Record Date entitles the holder to one vote.

To the knowledge of the Directors and Officers, as of the date of this Circular, no person owned or exercised control over more than ten percent of the outstanding common shares of the Company and the only outstanding voting shares were 114,949,746 common shares.

**Beneficial (or Non-Registered) Shareholders**

If you have shares registered in your own name, you are a registered shareholder. If you do not hold shares in your own name, you are a beneficial or non-registered shareholder.

If your shares are listed in an account statement provided to you by a broker, then it is likely that those shares will not be registered in your name, but under the broker's name or under the name of an agent of the broker such as CDS Clearing and Depository Services Inc. or its nominee, the nominee for many Canadian brokerage firms.

There are two kinds of beneficial owners: (i) Objecting Beneficial Owners - those who object to their name being made known to the issuers of shares which they own and (ii) Non-Objecting Beneficial Owners - those who do not object to their name being made known to the issuers of the shares which they own.

Non-Objecting Beneficial Owners will receive a voting instruction form ("VIF") from Emera's registrar and transfer agent, Computershare Trust Company of Canada ("Computershare"). This is to be completed and returned to Computershare in the envelope provided. In addition, Computershare provides both telephone voting and Internet voting as described on the VIF.

Securities regulation requires brokers or agents to seek voting instructions from Objecting Beneficial Owners in advance of the Meeting. Objecting Beneficial Owners should be aware that brokers or agents can only vote shares if instructed to do so by the Objecting Beneficial Owner. Your broker or agent (or their agent Broadridge) will have provided you with a VIF or form of proxy for purposes of obtaining your voting instructions. Every broker has its own mailing procedures and provides instructions for voting. You must follow those instructions carefully to ensure your shares are voted at the Meeting. **If you are an Objecting Beneficial Owner receiving a voting instruction form or proxy from a broker or agent, you cannot use that proxy to vote in person at the Meeting. To vote your shares at the meeting, the voting instruction form or proxy must be returned to the broker well in advance of the Meeting. If you wish to attend and vote your shares in person at the Meeting, follow the instructions for doing so provided by your broker or agent.**

**Shareholder Proxy Materials**

These Shareholder proxy materials are being sent to both registered and non-registered owners of the Company's shares. If you are a non-registered shareholder, and the Company or its agent has sent these materials directly to you, your name and address and information about your holding of shares have been obtained in accordance with applicable securities regulatory requirements from the intermediary holding on your behalf.

**Restrictions on Share Ownership and Voting**

Common shares are the only voting shares at this time. Under Nova Scotia legislation that applies to Emera, no Shareholder may own or control, directly or indirectly, more than 15 percent of the outstanding voting shares. Shareholders who are not residents of Canada may not hold, in total, more than 25 percent of outstanding voting shares.

These restrictions may be enforced by limiting non-complying Shareholders' voting rights, dividend rights and transfer rights. Shareholders may be required, at any time, to furnish a statutory declaration to verify the number of shares held and/or residency in order to ensure compliance with these restrictions.

If you have any questions about share ownership and voting restrictions, please contact the Corporate Secretary.

### Business of the Meeting

All resolutions placed before the Meeting must be approved by a majority of the votes cast.

1. **Election of the Board of Directors:** The 12 nominees proposed for election as Directors at the 2011 Meeting are identified under the section of this Circular entitled “Director Nominees”. For more information about the nomination of Directors, see the section entitled “Nomination of Directors” in the Statement of Corporate Governance Practices later in this Circular.

   Except for James D. Eisenhauer, all nominees are currently Directors of the Company and have served as Directors from the dates set out under “Director Nominees” below. Each nominee has indicated his or her willingness to serve as a Director. Each Director elected at the Meeting will hold office until the next Annual Meeting of Shareholders.

   Mr. McLennan, Mr. Huskilson and Mr. Aftanas intend to vote "For" the 12 nominees unless instructed otherwise by shareholders in their proxy.

   Majority Voting Policy for Directors

   In February 2008, the Board of Directors adopted a Majority Voting Policy for Directors. For more information about this Policy, see the section entitled “Majority Voting for Election of Directors” in the Statement of Corporate Governance Practices later in this Circular.

2. **Appointment of Auditors:** The Audit Committee pre-approves all services to be supplied by auditors and has reviewed the performance of Ernst & Young, LLP, including its independence, relating to the audit. Mr. McLennan, Mr. Huskilson and Mr. Aftanas intend to vote "For" the re-appointment of Ernst & Young, LLP as auditors of the Company to hold office until the close of the next Annual Meeting of Shareholders, unless a Shareholder specifies their shares be withheld from voting.

   Ernst & Young, LLP have been auditors of the Company since 1998 and its predecessor company since 1991.

3. **Auditors' Fee**: The Company is incorporated under the Nova Scotia *Companies Act*. Shareholder approval of the authorization of Directors to establish the auditors’ fee is required pursuant to the Act. The fees paid to Ernst & Young, LLP for services provided to the Company and certain subsidiaries for 2010 were as follows:

| | |
|---|---|
| Audit Fees | $ 643,731 |
| Audit-Related Fees | 396,165 |
| Tax Fees | 177,107 |
| | $1,217,003 |

   Mr. McLennan, Mr. Huskilson and Mr. Aftanas intend to vote "For" the authorization of Directors to establish the auditors' fee for 2011, unless a Shareholder specifies their shares be voted "Against" such matter.

### Director Nominees

The following pages set out the names of the nominees proposed for election as Directors of Emera, together with brief biographical information about them, including age, municipality and country of residence, year first elected or appointed as a Director if applicable, principal occupation, education, skills and experience. The information about each Director nominee includes Committee memberships and meeting attendance. The membership of each Director nominee on other public company boards in the last five years is also described. There is information about the securities of Emera held by each nominee for the past three years, as well as a statement about their status under the Company’s share ownership guidelines for Directors.

The information below identifies the proposed nominees’ share and/or deferred share unit (DSU) ownership as of December 31, 2008, December 31, 2009 and December 31, 2010. The estimated value of their equity and DSUs holdings is based on the following:

- For the year ended 2010, the closing price of Emera’s common shares on December 31, 2010 of $31.35;
- For the year ended 2009, the closing price of Emera’s common shares on December 31, 2009 of $25.07;
- For the year ended 2008, the closing price of Emera’s common shares on December 31, 2008 of $22.20.

All nominees are required to meet share ownership guidelines, and the information below discusses each Director’s status under those guidelines. For further information on the non-employee Directors share ownership guidelines, see “Director Share Ownership Guidelines” in the Statement of Corporate Governance Practices. For further information on the share ownership guidelines for Mr. Huskilson, see the heading "Executive Share Ownership Requirements" in the Statement of Executive Compensation later in this Circular.

All nominees, except for Mr. Huskilson, are considered by the Board to be independent. For more information about Director independence, see the section entitled "Director Independence" in the Statement of Corporate Governance Practices later in the Circular.

The shaded boxes in the matrix below indicate the skills and experience on the part of the 12 Director nominees in eight categories important to the Company's business.

| **Skills and Experience** | Robert S. Briggs | Thomas W. Buchanan | Sylvia D. Chrominska | Gail Cook-Bennett | Allan L. Edgeworth | James D. Eisenhauer | Christopher G. Huskilson | John T. McLennan | Donald A. Pether | Andrea S. Rosen | Richard P. Sergel | M. Jacqueline Sheppard |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CEO/Senior Executive (1) | ■ | ■ | ■ | ■ | ■ | ■ | ■ | ■ | ■ | ■ | ■ | ■ |
| Governance/Other Directorships (2) | | ■ | ■ | ■ | ■ | ■ | ■ | ■ | ■ | ■ | ■ | ■ |
| Customer/Stakeholder (3) | ■ | ■ | ■ | ■ | ■ | ■ | ■ | ■ | ■ | | ■ | ■ |
| Energy Sector (4) | ■ | ■ | | | ■ | | ■ | | | | ■ | ■ |
| M&A/Growth Strategy (5) | | ■ | | ■ | ■ | | ■ | ■ | ■ | ■ | ■ | ■ |
| Compensation and Human Resources (6) | ■ | ■ | ■ | | ■ | | ■ | ■ | ■ | | ■ | ■ |
| Financial (7) | ■ | ■ | ■ | ■ | ■ | ■ | ■ | ■ | ■ | ■ | ■ | ■ |
| Legal and Regulatory (8) | ■ | ■ | ■ | ■ | ■ | | ■ | ■ | ■ | | ■ | ■ |

Notes:
(1) CEO or Senior Officer experience with large organization.
(2) Director of public company and/or significant governance role.
(3) Experience in managing stakeholders or represents customer group.
(4) Senior executive experience in the energy sector.
(5) Senior executive experience with mergers, acquisitions and/or business growth strategy.
(6) Understanding and experience with human resources issues and compensation policies.
(7) Senior financial executive experience.
(8) Legal or regulatory experience.

**Robert S. Briggs**
Age: 67
Carrabassett Valley,Maine,U.S.A.
Director Since: 2001
Independent

Mr. Briggs has been a Director of the Company since October 2001 and has been a member of the Audit Committee since April 2002.

Mr. Briggs was the President and Chief Executive Officer of Bangor Hydro Electric Company (Bangor Hydro) from January 1991 to October 2001 and was a Director of Bangor Hydro from 1985 to October 2001. From October 2001 to October 2006, Mr. Briggs was a Director of Nova Scotia Power Incorporated.

Mr. Briggs graduated from the University of New Hampshire with a BA and from the University of Maine School of Law with a JD.

Mr. Briggs has extensive experience in the electric utility industry, particularly in the State of Maine. His more than 20 year career in the regulated electric utility business, including with Bangor Hydro Electric Company, provided him with valuable experience in the regulated electric utility sector and senior executive experience.

**Skills and Experience**

- **CEO/Senior Executive**
- **Energy Sector**
- **Financial**
- **Customer/Stakeholder**
- **Compensation and Human Resources**
- **Legal and Regulatory**

| Board/Committee Membership | Attendance | Total % | Public Company Board Membership During Last Five Years |
|---|---|---|---|
| - Board Member | 9 of 9 | 100% | None |
| - Audit Committee Member | 6 of 6 | 100% | |

**Securities Held:**

| Year Ended | Common Shares | DSUs | Value of Shares and DSUs | Status under Share Ownership Guidelines |
|---|---|---|---|---|
| 2010 | 5250 | 1013 | $196,345 | Mr. Briggs owns shares and DSUs valued at 109% of the requirement under the Guidelines, therefore the Share Ownership Guidelines are met. |
| 2009 | 5250 | Nil | $131,617 | |
| 2008 | 5250 | Nil | $116,550 | |

**Thomas W. Buchanan, F.C.A.**
Age: 55
Calgary, Alberta
Director Since: 2009
Independent

Mr. Buchanan has been a Director of the Company since May 2009 and has been a member of the Audit Committee and the Nominating and Corporate Governance Committee since May 2009. He has been a member of the Technology and Development Committee since its inception in September, 2010.

Mr. Buchanan is Chairman and Chief Executive Officer of Charger Energy Corp., a private oil and gas company formed in October 2010. Prior thereto he was a Director, President and CEO of Provident Energy Trust, a diversified energy income trust with investments in upstream oil and gas production and natural gas liquids midstream services, from March 2001 to April 2010. Mr. Buchanan is currently a Director of Athabasca Oil Sands Corp., Hawk Exploration Ltd., Pace Oil and Gas Ltd. and Pembina Pipeline Corporation.

Mr. Buchanan is a Fellow of the Chartered Accountants. He graduated from the University of Calgary with a Bachelor of Commerce degree.

Mr. Buchanan's financial and accounting expertise complement his career as an entrepreneur and senior executive in the oil and gas industry. As Chief Executive Officer and Director of several companies, he has gained valuable capital markets and mergers and acquisitions experience, as well as insight into the energy industry.

**Skills and Experience**

- **CEO/Senior Executive**
- **Customer/Stakeholder**
- **M&A/Growth Strategy**
- **Financial**
- **Governance/Other Directorships**
- **Energy Sector**
- **Compensation and Human Resources**
- **Legal and Regulatory**

| Board/Committee Membership | Attendance | Total % | Public Company Board Membership During Last Five Years |
|---|---|---|---|
| - Board Member | 9 of 9 | 100% | Pembina Pipeline Corporation (August 2010 to present) |
| - Audit Committee Member | 5 of 6 | 83% | Pace Oil and Gas Ltd. (June 2010 to present) |
| - Nominating and Corporate Governance Committee Member | 6 of 6 | 100% | Athabasca Oil Sands Corp. (November 2006 to present) |
| - Technology and Development Committee | 2 of 2 | 100% | Hawk Exploration Ltd. (February 2009 to present) |
| | | | Churchill Energy Inc. (December 2005 to April 30, 2010) |
| | | | Provident Energy Trust (2001 to 2010) |
| | | | Hawk Energy Corp. (January 2003 to May 2006) |
| | | | Breitburn Energy Partners LP (October 2006 to June 2008) |

**Securities Held:**

| Year Ended | Common Shares | DSUs | Value of Shares and DSUs | Status under Share Ownership Guidelines |
|---|---|---|---|---|
| 2010 | Nil | 6708 | $210,296 | Mr. Buchanan owns DSUs valued at 116% of the requirement under the Guidelines, therefore the Share Ownership Guidelines are met. |
| 2009 | Nil | 2055 | $51,518 | |
| 2008 | N/A | N/A | | |

**Sylvia D. Chrominska**
Age: 59
Toronto, Ontario
Director Since: 2010
Independent

Ms. Chrominska was appointed a Director on September 24, 2010 and has been a member of the Management Resources and Compensation Committee since November 2010.

Ms. Chrominska is the Group Head of Global Human Resources and Communications for The Bank of Nova Scotia, where she has global responsibility for human resources, corporate communications, government relations, public policy and corporate social responsibility of the Scotiabank Group.

Ms. Chrominska graduated from the University of Western Ontario with an Honours Degree in Business Administration. She also serves on the Dean's Advisory Board at the Richard Ivey School of Business and on the Stratford Festival Board of Governors.

Ms. Chrominska's 30-year career in the banking sector has provided her with valuable skills and knowledge in financial and credit matters. In particular, the experience she has gained through her senior executive leadership role – with responsibilities encompassing human resources, corporate communications, media and government relations and corporate strategy for a complex, global business organization -- is a distinct asset.

**Skills and Experience**

- **CEO/Senior Executive**
- **Compensation and Human Resources**
- **Regulatory**
- **Governance**
- **Customer Stakeholder**
- **Financial**

| Board/Committee Membership | Attendance | Total % | Public Company Board Membership During Last Five Years |
|---|---|---|---|
| - Board Member | 4 of 4 | 100% | Dofasco Inc. (2000 to 2007) |
| - Management Resources and Compensation Committee | 2 of 2 | 100% | |

**Securities Held:**

| Year Ended | Common Shares | DSUs | Value of Shares and DSUs | Status under Share Ownership Guidelines |
|---|---|---|---|---|
| 2010 | 1,020 | 853 | $58,719 | Ms. Chrominska owns shares and DSUs valued at 32.6% of the requirement under the Guidelines. She has until September 2015 to meet the Share Ownership Guidelines. |
| 2009 | N/A | N/A | | |
| 2008 | N/A | N/A | | |

**Gail Cook-Bennett, C.M**
Age: 70
Toronto, Ontario
Director Since: 2004
Independent

Dr. Cook-Bennett has been a Director of the Company since November 2004. Since November 2004 she has been a member of the Nominating and Corporate Governance Committee and has been Committee Chair since May 2006. She was a member of the Audit Committee from May 2005 to May 2007. From November 2004 to October 2006, Dr. Cook-Bennett was a Director of Nova Scotia Power Incorporated.

Dr. Cook-Bennett is Chair of Manulife Financial, an insurance company which provides life insurance, group life and health insurance, long-term care services, pension products, annuities, and mutual funds in international markets. Prior to October 2008 she was Chair of the Canada Pension Plan Investment Board which has responsibility for investing Canada Pension Plan contributions.

Dr. Cook-Bennett holds a BA (Honours) from Carleton University and graduated from the University of Michigan with an M.A. and Ph.D. in Economics. She is a Fellow with the Institute of Corporate Directors.

Dr. Cook-Bennett brings to her role as a director of Emera, previous experience as a director of a regulated utility, Consumers Gas; oversight of risk as well as private equity and infrastructure acquisitions as Chair of the CPP Investment Board, and corporate board experience since 1978.

**Skills and Experience**

- **CEO/Senior Executive**
- **Customer/Stakeholder**
- **Financial**
- **Governance/Other Directorships**
- **M&A/Growth Strategy**
- **Legal and Regulatory**

| Board/Committee Membership | Attendance | Total % | Public Company Board Membership During Last Five Years |
|---|---|---|---|
| - Board Member | 8 of 9 | 88% | Manulife Financial Corporation (1978 to present) |
| - Nominating and Corporate Governance Committee Chair | 6 of 6 | 100% | Petro Canada (1991 to 2009) |

**Securities Held:**

| Year Ended | Common Shares | DSUs | Value of Shares and DSUs | Status under Share Ownership Guidelines |
|---|---|---|---|---|
| 2010 | 1,000 | 17,836 | $590,509 | Dr. Cook-Bennett owns shares and DSUs valued at 208% of the requirement under the Guidelines, therefore, Share Ownership Guidelines are met. |
| 2009 | 1,000 | 13,586 | $365,671 | |
| 2008 | 1,000 | 10,243 | $249,595 | |

**Allan L. Edgeworth**
Age: 60
Calgary, Alberta
Director Since: 2005
Independent

Mr. Edgeworth has been a Director of the Company since November 2005. He has been a member of the Management Resources and Compensation Committee since February 2006 and has been Committee Chair since May 2010. Mr. Edgeworth has been a member of the Audit Committee since April 2008 and, since September, 2010, has been a member of the Technology and Development Committee. He was a member of the Nominating and Corporate Governance Committee from May 2007 to April 2008. From November 2005 to October 2006, Mr. Edgeworth was a Director of Nova Scotia Power Incorporated.

Mr. Edgeworth is President of ALE Energy Inc. and is the former President and Chief Executive Officer of Alliance Pipeline. He is a Director of AltaGas Ltd. and Pembina Pipeline Corporation, and is a Commission Member and Director of the Alberta Securities Commission.

Mr. Edgeworth holds a Bachelor of Applied Science from the University of British Columbia in Geological Engineering and is a graduate of the Queen's Executive Program. He has also served on the boards of the Interstate National Gas Association of America, the Canadian Gas Association and is a past Chair of the Canadian Energy Pipeline Association.

Mr. Edgeworth's years of experience in the gas pipeline business brings an important industry perspective to Emera's Board. His role as chief executive officer and as a director of energy sector companies has provided him with valuable business acumen.

<u>Skills and Experience</u>

- **CEO/Senior Executive**
- **Customer/Stakeholder**
- **M&A/Growth Strategy**
- **Financial**
- **Governance/Other Directorships**
- **Energy Sector**
- **Compensation and Human Resources**
- **Legal and Regulatory**

| Board/Committee Membership | Attendance | Total % | Public Company Board Membership During Last Five Years |
|---|---|---|---|
| - Board Member | 9 of 9 | 100% | AltaGas Ltd. (previously AltaGas Income Trust) (March 2005 to present) |
| - Audit Committee Member | 6 of 6 | 100% | Pembina Pipeline Corporation (July 2006 to present) |
| - Management, Resources and Compensation Committee Member | 8 of 8 | 100% | |
| - Technology and Development Committee | 2 of 2 | 100% | |

**Securities Held:**

| Year Ended | Common Shares | DSUs | Value of Shares and DSUs | Status under Share Ownership Guidelines |
|---|---|---|---|---|
| 2010 | 1,000 | 18,467 | $610,291 | Mr. Edgeworth owns shares and DSUs valued at 339% of the requirement under the Guidelines, therefore, Share Ownership Guidelines are met. |
| 2009 | 1,000 | 14,476 | $387,983 | |
| 2008 | 1,000 | 11,922 | $286,868 | |

**James D. Eisenhauer, F.C.A.**
Age: 59
Lunenburg, Nova Scotia
Director Since: N/A
Independent

Mr. Eisenhauer is not presently a Director of the Company. He has been a Director of Emera's subsidiary, Nova Scotia Power Inc. since 2008. He is President and Chief Executive Officer of ABCO Group Limited, which has holdings in manufacturing and distribution activities. He is a Professional Engineer and a Fellow of the Institute of Chartered Accountants of Nova Scotia. Mr. Eisenhauer has been a member of the Board of Nova Scotia Business Inc. since 2005, and Chair since November, 2010. He is also a member of the Board of Composites Atlantic Limited since 1993 (and its predecessor Cellpack Aerospace since 1987) and is also on the Board of Atlantic Industries Limited and chairs its Audit Committee.

Mr. Eisenhauer holds a Bachelor of Science from Dalhousie University and Bachelor of Engineering (with distinction) from the Technical University of Nova Scotia.

Mr. Eisenhauer's professional knowledge and experience combined with his executive leadership in a manufacturing and distribution business are an asset. His leadership role in the Nova Scotia business community provides him with valuable stakeholder and governance skills and experience.

**<u>Skills and Experience</u>**

- **CEO/Senior Executive**
- **Customer/Stakeholder**
- **Governance/Other Directorships**
- **Financial**

| **Board/Committee Membership** | **Attendance** | **Total %** | **Public Company Board Membership During Last Five Years** |
|---|---|---|---|
| N/A | N/A | N/A | Nova Scotia Power Inc. (September, 2008 to present) |

**Securities Held:**

| Year Ended | Common Shares | DSUs | Value of Shares and DSUs | Status under Share Ownership Guidelines |
|---|---|---|---|---|
| 2010 | N/A | 5,175 | $162,236 | Mr. Eisenhauer owns DSUs valued at 90% of the requirement under the Guidelines. He will have until May, 2016 to meet the Share Ownership Guidelines. |
| 2009 | N/A | N/A | | |
| 2008 | N/A | N/A | | |

**Christopher G. Huskilson**
Age: 53
Wellington, Nova Scotia
Director Since: 2004
Not Independent

Mr. Huskilson has been a Director and the President and Chief Executive Officer of Emera since November 2004. He is Chair of the Technology and Development Committee. He is also Chair of Bangor Hydro Electric Company, a Director of Nova Scotia Power Incorporated and serves as the Chair or as a Director of a number of other Emera affiliated companies. Mr. Huskilson has held a number of positions within Nova Scotia Power Incorporated and its predecessor, Nova Scotia Power Corporation, since June 1980.

Mr. Huskilson holds a Bachelor of Science in Engineering and a Master of Science in Engineering from the University of New Brunswick.

Mr. Huskilson's decades of knowledge and experience in various roles with Emera's principal regulated electric utility subsidiary, Nova Scotia Power, allow him to provide leadership within Emera, and in the broader electricity industry, regionally, nationally and internationally.

**Skills and Experience**

- **CEO/Senior Executive**
- **Customer/Stakeholder**
- **M&A/Growth Strategy**
- **Financial**
- **Governance/Other Directorships**
- **Energy Sector**
- **Compensation and Human Resources**
- **Legal and Regulatory**

| Board/Committee Membership (1) | Attendance | Total % | Public Company Board Membership During Last Five Years |
|---|---|---|---|
| - Board Member | 9 of 9 | 100% | Nova Scotia Power Inc. (November, 2004 to present)<br>ICD Utilities Limited (September 2008 to present)<br>Algonquin Power and Utilities Corp. (July 2009 to present)<br>Saint Lucia Electricity Services Limited (January 2007 to February 2011) |

**Securities Held:**

| Year Ended | Common Shares | DSUs | Value of Shares and DSUs | Status under Share Ownership Guidelines |
|---|---|---|---|---|
| 2010 | 10,332 | 170,825 | $5,679,272 | Mr. Huskilson is subject to the Executive Share Ownership Requirements which require that he own shares and/or DSUs valued at 3 times his salary. He exceeds this requirement. |
| 2009 | 10,129 | 163,391 (vested and unvested) | $4,350,146 | |
| 2008 | 10,114 | 144,816 (vested and unvested) | $3,439,446 | |

Notes:

(1) Mr. Huskilson is not a member of any Committee, (except the Technology and Development Committee). However, as President and Chief Executive Officer he attends Committee meetings in a non-voting capacity. He did not participate in any portion of Board and/or Committee meetings that dealt with his role or performance.

**John T. McLennan**
Age: 65
Mahone Bay, Nova Scotia
Director Since: 2005
Independent

Mr. McLennan has been a Director of the Company since April 2005, and has been Chair of the Board of the Company since May 2009. He has been a Director of Nova Scotia Power Incorporated since April 2005 and was the Chair of the Board of Nova Scotia Power Incorporated from May 2006 to May 2009. Mr. McLennan was a member of the Management Resources and Compensation Committee and the Nominating and Corporate Governance Committee from April 2005 to May 2009 when he became Chair of the Board.

Mr. McLennan is the former Vice-Chair and Chief Executive Officer of Allstream Inc. (formerly AT&T Canada). He served as President and Chief Executive Officer of Bell Canada and Bell Mobility from 1990 to 1997, and is the former Chief Executive Officer of Cantel Inc. He currently sits on the Boards of Chorus Aviation Inc. and Amdocs Ltd.

Mr. McLennan holds a Bachelor of Science, Master of Science and Honorary Doctorate of Science degrees from Clarkson University in New York. He was Chancellor of Cape Breton University from 1996 to 2006 and received an Honorary Doctorate from Cape Breton University.

Mr. McLennan's extensive chief executive officer experience with complex organizations across a variety of industries provides him with valuable strategic insight and leadership capabilities. Through his membership on several public company boards he has gained extensive governance skills and business acumen.

**Skills and Experience**

- **CEO/Senior Executive**
- **Customer/Stakeholder**
- **Compensation and Human Resources**
- **Legal and Regulatory**
- **Governance/Other Directorships**
- **M&A/Growth Strategy**
- **Financial**

| Board/Committee Membership [1] | Attendance | Total % | Public Company Board Membership During Last Five Years |
|---|---|---|---|
| - Board Chair | 9 of 9 | 100% | Nova Scotia Power Inc. (April, 2005 to present) |
| - Audit Committee | 5 of 6 | 83% | Amdocs Limited (November 1999 to present) |
| - Management, Resources and Compensation Committee Member | 7 of 8 | 88% | Chorus Aviation Inc. (and its predecessor Jazz Air Income Fund and affiliate, Jazz Air Holding G.P. Inc.) (January 2006 to present) |
| - Nominating and Corporate Governance Committee | 6 of 6 | 100% | Ace Aviation Holdings Inc. (September, 2004 to June, 2008) |
| - Technology and Development Committee Member | 2 of 2 | 100% | Aeroplan Income Fund (June, 2005 to January, 2008) |
| | | | Air Canada (November, 2006 to January, 2008) |
| | | | Medisys Health Group (2002 to 2008) |
| | | | Manitoba Telecom Services Inc. (June, 2004 to May, 2007) |
| | | | Hummingbird Ltd. (1995 to October, 2006) |

**Securities Held:**

| Year | Common Shares | DSUs | Value of Shares and DSUs | Status under Share Ownership Guidelines |
|---|---|---|---|---|
| 2010 | 5,000 | 30,820 | $1,122,957 | Mr. McLennan owns shares and DSUs valued at 624% of the requirement under the Guidelines, therefore, Share Ownership Guidelines are met. |
| 2009 | 5,000 | 22,643 | $693,006 | |
| 2008 | 5,000 | 15,336 | $451,459 | |

Notes:
(1) As Chair of the Board, Mr. McLennan is not a member of any of Emera's Committees; however, he attends Committee meetings in a non-voting capacity. His attendance at meetings of these Committees is noted above.

**Donald A. Pether**
Age: 63
Dundas, Ontario
Director Since: 2008
Independent

Mr. Pether has been a Director of the Company since November 2008. He has been a member of the Management Resources and Compensation Committee and the Nominating and Corporate Governance Committee since May 2009.

Mr. Pether is the former Chair of the Board and Chief Executive Officer of Dofasco Inc. a Canadian steel producer. He is Chair of the Board of Governors for McMaster University, on the Council of Governors for the Art Gallery of Hamilton, and a Director of Primary Energy Recycling Corp. and Samuel, Son & Co. Ltd.

Mr. Pether has a Bachelor of Science from the University of Alberta and a Doctor of Laws (Hon) from McMaster University.

Mr. Pether's experience as a chief executive officer of a steel producer, which owned assets in the mining and automotive parts industry, and with employees in the U.S., Mexico and Canada, provided him with valuable business and stakeholder skills. His experience throughout his career with employee and labour relations, as well as with innovative manufacturing and maintenance processes, are an asset to the Board.

**Skills and Experience**

- **CEO/Senior Executive**
- **Customer/Stakeholder**
- **Compensation and Human Resources**
- **Legal and Regulatory**
- **Governance/Other Directorships**
- **M&A/Growth Strategy**
- **Financial**

| Board/Committee Membership | Attendance | Total % | Public Company Board Membership During Last Five Years |
|---|---|---|---|
| - Board Member | 7 of 9 | 77% | Primary Energy Recycling Corporation (April 2010 to present) |
| - Management, Resources and Compensation Committee Member | 7 of 8 | 88% | Samuel Manu-Tech Inc. (October 2007 to September 2010) |
| - Nominating and Corporate Governance Committee Member | 5 of 6 | 83% | Fording Canadian Coal Trust (March 2007 to October 2008) |
| | | | Dofasco Inc. (May 2003 to April 2007) |

**Securities Held:**

| Year Ended | Common Shares | DSUs | Value of Shares and DSUs | Status under Share Ownership Guidelines |
|---|---|---|---|---|
| 2010 | Nil | 6,032 | $189,103 | Mr. Pether owns DSUs valued at 105% of the requirement under the Guidelines, therefore the Share Ownership Guidelines are met. |
| 2009 | Nil | 1,939 | $ 48,610 | |
| 2008 | N/A | N/A | | |

**Andrea S. Rosen**
Age: 56
Toronto, Ontario
Director Since: 2007
Independent

Ms. Rosen has been a Director of the Company since January 2007 and has been a member of Emera's Audit Committee since May 2007. She was appointed Audit Committee Chair in April 2008.

Ms. Rosen is the former Vice-Chair, TD Bank Financial Group and President, TD Canada Trust from 2002 to 2005. Prior to this she was Executive Vice President of TD Commercial Banking and Vice Chair of TD Securities. She has experience in several investment banking roles, including with CIBC-Wood Gundy Securities, Inc. where she became Vice President and Director in 1996. Ms. Rosen is also a Director of Alberta Investment Management Corporation and Hiscox Ltd.

Ms. Rosen received her joint LL.B and M.B.A. from Osgoode Hall Law School, York University.

Ms. Rosen has over 20 years of experience in corporate finance and substantial executive experience. Her career in the investment and commercial banking industry has given her extensive financial and investment knowledge and experience.

**Skills and Experience**

- **CEO/Senior Executive**
- **Financial**
- **Governance/Other Directorships**
- **M&A/Growth Strategy**

| Board/Committee Membership | Attendance | Total % | Public Company Board Membership During Last Five Years |
|---|---|---|---|
| - Board Member | 8 of 9 | 88% | Hiscox Ltd. (October 2006 to present) |
| - Audit Committee Chair | 6 of 6 | 100% | |

**Securities Held:**

| Year Ended | Common Shares | DSUs | Value of Shares and DSUs | Status under Share Ownership Guidelines |
|---|---|---|---|---|
| 2010 | Nil | 14,167 | $444,136 | Ms. Rosen owns shares and DSUs valued at 247% of the requirement under the Guidelines, therefore Share Ownership Guidelines are met. |
| 2009 | Nil | 9,628 | $241,373 | |
| 2008 | Nil | 5,974 | $132,623 | |

Mr. Sergel was appointed a Director on September 24, 2010. He was appointed a member of the Audit Committee, the Nominating and Corporate Governance Committee, and the Technology and Development Committee in November 2010.

Mr. Sergel is the former President and Chief Executive Officer of the North American Electric Reliability Corporation (NERC). He served as President and Chief Executive Officer of National Grid USA from 2000 to 2004. Prior to that he was President and Chief Executive Officer of the New England Electric System, where he held positions of increasing responsibility since 1979.
Mr. Sergel is presently a director of State Street Corporation. He also served on the boards of the Edison Electric Institute, the Consortium for Energy Efficiency, and the United Way of the Merrimac Valley.

Mr. Sergel holds a Bachelor of Science in mathematics from Florida State University, a Master of Science in applied mathematics from North Carolina State University, and a Master of Business Administration from the University of Miami.

Mr. Sergel's extensive career in the electricity sector in the United States has provided him with valuable industry and business skills and experience. His regulatory background is a distinct asset.

<u>Skills and Experience</u>

- **CEO/Senior Executive**
- **Customer/Stakeholder**
- **M&A/Growth Strategy**
- **Financial**
- **Governance/Other Directorships**
- **Energy Sector**
- **Compensation and Human Resources**
- **Legal and Regulatory**

| **Board/Committee Membership** | **Attendance** | **Total %** | **Public Company Board Membership During Last Five Years** |
|---|---|---|---|
| - Board member | 4 of 4 | 100% | State Street Corporation (February 2001 to present) |
| - Audit Committee Member | N/A | N/A | |
| - Nominating and Corporate Governance Committee Member | N/A | N/A | |

**Securities Held:**

| Year Ended | Common Shares | DSUs | Value of Shares and DSUs | Status under Share Ownership Guidelines |
|---|---|---|---|---|
| 2010 | Nil | 270 | $8,465 | Mr. Sergel owns DSUs valued at 5% of the requirement under the Guidelines. He has until September, 2015 to meet the Share Ownership Guidelines. |
| 2009 | N/A | N/A | | |
| 2008 | N/A | N/A | | |

**Richard P. Sergel**
Age: 61
Wellesley, Massachusetts
Director Since: 2010
Independent

**M. Jacqueline Sheppard**
Age: 55
Calgary, Alberta
Director Since: 2009
Independent

Ms. Sheppard has been a Director of the Company since February 2009. She has been a member of the Audit Committee and the Management Resources and Compensation Committee since May 2009, and of the Technology and Development Committee since its inception in September, 2010.

Ms. Sheppard is a Director and Chair of the Research and Development Corporation of the Province of Newfoundland and Labrador, a Provincial Crown Corporation. She is also a Director of Cairn Energy PLC, a publicly traded UK based international oil and gas producer and a Director of NWest Energy Inc., a publicly traded junior oil and gas company. Ms. Sheppard is a Director and founding shareholder of a private junior Canadian oil and gas corporation and a Director and founding shareholder of a private international oil and gas corporation focusing on the Middle East, North African and the Mediterranean area. She is the former Executive Vice President, Corporate and Legal of Talisman Energy Inc., a Canadian, publicly traded, international oil and gas producer.

Ms. Sheppard is a Rhodes Scholar, having received an Honours Jurisprudence, Bachelor of Laws degree (Honours) from McGill University in 1981, and a Bachelor of Arts degree from Memorial University of Newfoundland in 1977.

As a senior executive in the oil and gas industry, Ms. Sheppard played a leading role in Talisman's transformational growth from a Canadian domestic producer of approximately 50,000 barrels of oil equivalent to an international producer of over 500,000 barrels equivalent. She brings experience in corporate strategy, risk management, mergers and acquisitions, capital markets and investor relations. Global legal management, corporate governance and corporate responsibility were also areas of direct responsibility through these years of business expansion.

<u>**Skills and Experience**</u>

- **CEO/Senior Executive**
- **Customer/Stakeholder**
- **M&A/Growth Strategy**
- **Financial**
- **Governance/Other Directorships**
- **Energy Sector**
- **Compensation and Human Resources**
- **Legal and Regulatory**

| **Board/Committee Membership** | **Attendance** | **Total %** | **Public Company Board Membership During Last Five Years** |
|---|---|---|---|
| - Board Member | 9 of 9 | 100% | Cairn Energy PLC (May 2010 to present) |
| - Audit Committee Member | | | NWest Energy Inc. (July 2008 to present) |
| - Management, Resources and | 6 of 6 | 100% | |
| Compensation Committee Member | 8 of 8 | 100% | |
| - Technology and Development | | | |
| Committee Member | 2 of 2 | 100% | |

**Securities Held:**

| Year Ended | Common Shares | DSUs | Value of Shares and DSUs | Status under Share Ownership Guidelines |
|---|---|---|---|---|
| 2010 | Nil | 6,642 | $208,227 | Ms. Sheppard owns shares and DSUs valued at 116% of the requirement under the Guidelines, therefore the Share Ownership Guidelines are met. |
| 2009 | Nil | 2,010 | $50,390 | |
| 2008 | N/A | N/A | | |

## Compensation of Directors

The compensation of Directors is intended to be competitive and appropriate in order to attract highly skilled and experienced individuals to serve on Emera's Board, and to align their interests with shareholders. For more information about the determination of Director compensation, see the section entitled "Director Compensation" in the Statement of Corporate Governance Practices later in the Circular. Listed below are the annual compensation rates for independent Directors during 2010. These rates are not applicable to Mr. Huskilson, who was an employee of the Company, nor to Mr. G.A. Caines, who received an annual all-inclusive retainer as Chair of Nova Scotia Power Inc. The Company does not offer option-based awards, non-equity incentive plan participation, or participation in a Company pension plan to its Directors. Directors have the ability to elect to receive some or all of their cash compensation in the form of DSUs. In addition, $25,000 of the Directors' annual retainer is comprised of DSUs only. The Chair's annual retainer is comprised of $92,500 in DSUs and the remainder is cash.

The Annual Chair's Retainer is an all-inclusive fee, meaning the Chair of the Board receives no meeting fees or any other retainer. Effective September 24, 2010 the all-inclusive retainer of the Chair was increased to $185,000, an increase of $25,000, payable half in cash and half in DSUs. Additionally, effective September 24, 2010, the Chair is paid $35,000 cash for participation on the Board of Directors of Nova Scotia Power Inc.

| ANNUAL RETAINERS AND MEETING FEES | CASH AMOUNT | DSUs | TOTAL |
|---|---|---|---|
| Annual Chair's Retainer (1) | $127,500 | $92,500 | $220,000 |
| Annual Director Retainer | 35,000 | 25,000 | $60,000 |
| In-Person Meeting Fee | 1,750 | | |
| Telephone Meeting Fee | 1,250 | | |
| Travel Fee: (if one-way travel is 5 hours or more) | 1,750 | | |
| Travel Fee: (if one-way travel is at least 3 hours but less than 5 hours) | 875 | | |
| Annual Audit Committee Chair Retainer | 15,000 | | |
| Annual Audit Committee Member Retainer | 5,000 | | |
| Annual Management Resources and Compensation Committee Chair Retainer | 15,000 | | |
| Annual Management Resources and Compensation Committee Member Retainer | 3,000 | | |
| Annual Nominating and Corporate Governance Committee Chair Retainer | 8,000 | | |
| Annual Nominating and Corporate Governance Committee Member Retainer | 3,000 | | |

Notes:
(1) Includes $35,000 cash paid for participation on the Board of Nova Scotia Power Inc.

### Total Director Compensation in 2010

The following table sets out the total compensation earned by the Directors who served on Emera's Board during 2010 which is comprised of applicable retainers and fees for attendance at Board and Committee meetings for which a Director attended as a member or guest, briefing meetings, education sessions, and travel fees. Mr. Huskilson is not included in the table as his compensation for service as Emera's President and Chief Executive Officer is disclosed in the Statement of Executive Compensation. He does not receive any additional compensation for his services as a Director of Emera.

| Director | Fees Earned in 2010 (1) ($) | All Other Compensation ($) | Total ($) | Share Based Awards(2) ($) |
|---|---|---|---|---|
| R.S. Briggs | 98,930 | N/A | 98,930 | 31,772 |
| T.W. Buchanan | 112,500 | N/A | 112,500 | 145,878 |
| G.A. Caines (3) | N/A | 140,123 | 140,123 | 53,891 |
| S.D. Chrominska (4) | 26,242 | N/A | 26,242 | 26,772 |
| G. Cook-Bennett | 89,750 | N/A | 89,750 | 133,216 |
| A.L. Edgeworth | 119,923 | N/A | 119,923 | 125,102 |
| J.T. McLennan | 176,753 | N/A | 176,753 | 256,333 |
| D. A. Pether | 98,750 | N/A | 98,750 | 128,324 |
| A.S. Rosen | 101,250 | N/A | 101,250 | 142,305 |
| R.P. Sergel (4) | 31,898 | N/A | 31,898 | 8,485 |
| M.J. Sheppard | 112,000 | N/A | 112,000 | 145,231 |

Notes:
(1) The "Fees Earned in 2010" column is the amount of Directors' fees and includes the value of that portion of their retainer paid in DSUs. All Directors are paid in Canadian dollars.
(2) This column shows the value obtained when the number of DSUs awarded to each Director in 2010 in lieu of cash compensation, plus dividends earned on the DSUs in the form of additional DSUs, is multiplied by the December 31, 2010 Emera share closing price of $31.35.
(3) Mr. Caines is also the Chair of the Board of Nova Scotia Power Inc. ("NSPI") and is paid by NSPI for his services
(4) Ms. Chrominska and Mr. Sergel were appointed to the Board of Directors effective September 24, 2010.

All independent Directors are reimbursed for expenses incurred for attendance at Board, Committee, and Shareholders' Meetings and when on Company business. Directors are also eligible to receive accidental death and dismemberment (ADD) insurance coverage, the cost of which is paid by the Company.

### Directors Share Ownership Guidelines

In order to align the interests of Directors and shareholders, the Directors are subject to share ownership guidelines that require them to own common shares and/or deferred share units with a value of not less than $180,000 within a specified timeframe. For more information about the Director Share Ownership Guidelines see the section entitled "Director Share Ownership Guidelines" in the Statement of Corporate Governance Practice.

### Directors Deferred Share Unit Plan

Under the Directors deferred share unit plan (the "Plan"), independent Directors may elect to receive all or any portion of their compensation in deferred share units ("DSUs") in lieu of cash compensation. Directors' fees are paid on a quarterly basis and at the time of each quarterly payment, the applicable amount is converted to DSUs.

A DSU is a bookkeeping entry that has a value based upon the value of one Emera common share. When a dividend is paid on Emera's common shares, the Director's DSU account is credited with additional DSUs computed by dividing: (a) the amount obtained by multiplying the amount of the dividend declared and paid per common share by the number of DSUs recorded in the Director's account on the record date for the payment of such dividend, by (b) the market price of a common share as of the dividend payment date.

DSUs cannot be redeemed for cash until the Director leaves the Board. The cash redemption value of a DSU equals the market value of a common share at the time of redemption. DSUs are not shares, cannot be converted to shares, and do not carry voting rights.

In order to increase the Directors share based investment in the Company, effective January 1, 2010, independent Directors began receiving a portion of their annual retainer in grants of DSUs only. See “Director Compensation” in the Statement of Corporate Governance Practices in this Circular for more information about Director Compensation.

Independent Directors are not entitled to participate in any other compensation plan of the Company or in the Employee Common Share Purchase Plan.

**Committees of the Board of Directors**

The Board of Directors has three standing Committees and one Ad Hoc Committee to assist it in carrying out its duties. The standing Committees are:

- Audit;
- Management Resources and Compensation; and
- Nominating and Corporate Governance.

The Ad Hoc Committee is:

- Technology and Development.

For further information on the Committees, see the section entitled “Committees of the Board of Directors” in the Statement of Corporate Governance Practices later in this Circular.

**Certain Proceedings**

To the knowledge of the Company, none of the proposed nominees for election as Directors of the Company:

(a) are, as at the date of this Circular, or have been, within ten years before the date of this Circular, a Director, Chief Executive Officer or Chief Financial Officer of any company that:

  (i) was subject to a cease trade order, an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation that was in effect for a period of more than 30 consecutive days (an “Order”) that was issued while the proposed nominee was acting in the capacity as Director, chief executive officer or chief financial officer; or

  (ii) was subject to an Order that was issued after the proposed nominee ceased to be a Director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as Director, chief executive officer or chief financial officer,

(b) with the exception of Mr. McLennan as set forth below, are, as at the date of this Circular, or have been within ten years before the date of this Circular, a Director or executive officer of a company that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangements or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or

(c) have, within the ten years before the date of this Circular, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the proposed nominee.

Mr. McLennan was the Chief Executive Officer of AT&T Canada when AT&T Canada filed for protection under the *Companies’ Creditors Arrangement Act* on October 15, 2002.

## Statement of Executive Compensation

### Management Resources and Compensation Committee

The Management Resources and Compensation Committee of the Board of Directors (the "MRCC") determines the compensation for Emera's executive officers, and reviews, approves and oversees the administration of all of the Company's executive compensation plans and programs. The MRCC currently consists of, Allan L. Edgeworth (Chair), Donald A. Pether, M. Jacqueline Sheppard, and Sylvia D. Chrominska. All members of the MRCC are independent Directors.

The Board has assigned responsibility to the MRCC for reviewing overall compensation policies and for reviewing and recommending compensation for senior management of the Company.

The MRCC also has responsibility for assessing, on an annual basis, the performance of the President and Chief Executive Officer. The Board of Directors reviews the recommendations of the MRCC and approves compensation matters for senior management of the Company as well as on policy changes related to compensation.

For the purposes of compensation disclosure, the individuals listed in the 2010 "Summary Compensation Table" are the President and Chief Executive Officer, the Executive Vice-President and Chief Financial Officer and the next three most highly compensated executive officers of the Company, or its affiliated companies, as defined by Canadian securities legislation (the "Named Executive Officers").

### Succession Planning and Leadership Development

The MRCC also has responsibility for ensuring that there is an adequate succession planning process for senior management of the Company and its affiliates, and to review this process on an annual basis. At Emera, succession planning is a dynamic, ongoing process of systematically identifying, assessing and developing talent, leadership and skills, to ensure the Company's capacity to meet future strategic objectives and replenish critical organizational roles over time. On an annual basis, the senior management of Emera are required to review the performance of their team members and consider opportunities for growth and personal development. This activity also includes completing a vacancy forecast document and identifying possible internal successors as well as high potential performers. Where employees are considered potential successors, a mentor is assigned to oversee the alignment of the employees' personal development plan as well as training and educational opportunities. Should no internal candidate be identified, the Company confirms the need for a potential successor would be filled through external hiring.

As part of the succession planning process, the President and Chief Executive Officer annually provides a list of potential successors for his position to the MRCC. He identifies internal successors for each of the Named Executive Officers and senior management throughout the Company and its affiliates. The Committee members oversee management succession planning process and strategy. They consider emerging issues and risks, and report and make recommendations to the Board of Directors. To complement Emera's succession planning, the Company focuses on leadership development, including ensuring that challenging work assignments are offered, secondments to affiliates occur where appropriate, leadership development training occurs, and mentors are assigned where needed. Emera is committed to developing leaders at all levels in the Company and it has a comprehensive assessment process and framework to coordinate leadership development across the Company.

### Compensation Advisors

The MRCC retains the services of independent advisors as needed in order to assist in discharging its duties.

Since 2007, the MRCC has engaged Hugessen Consulting Inc. ("Hugessen") as its principal advisor to provide independent advice, compensation analysis and other information for compensation recommendations. Hugessen provides advice on the competitiveness and appropriateness of compensation practices and comparator groups for Emera and its affiliates. In addition, Hugessen provides advice to the MRCC on policy recommendations made by management, and also reviews and provides commentary on the Company's Statement of Executive Compensation. As of 2009, Hugessen has also been retained by the Company's Nominating and Corporate Governance

Committee to provide independent advice and compensation analysis regarding Directors compensation.

The MRCC has adopted a number of practices with regard to its executive compensation advisor:

- The MRCC annually reviews the advisor's performance and fees;
- With input from Company management and the advisor, the MRCC annually, or on an as-needed basis, determines the specific work to be undertaken by the advisor for the MRCC and the fees associated with this work;
- All services provided by the MRCC's advisor beyond its role in supporting the requirements of the MRCC require written pre-approval by the MRCC Chair outlining the scope of work and related fees. The MRCC does not approve any such work that, in its view, could compromise the advisor's independence in serving the MRCC;
- The work done and the fees paid by Emera to compensation advisors are disclosed annually in this Circular.

In addition to the MRCC's compensation advisor in 2010, Emera engaged the services of Towers Watson, Morneau Shepell (formerly Morneau Sobeco), and Mercer (Canada) Limited ("Mercer").

In 2010, Towers Watson was engaged to assist in compiling market information on senior management compensation for Emera relating to base salary, and short-term and long-term incentives. Towers Watson's scope of services included competitive reviews of executive compensation levels and information on industry trends.

In addition, Mercer conducted a review of Emera's Performance Share Unit ("PSU") plan (formerly called the Restricted Share Unit plan) and benchmarked the current plan design relative to market.

Also in 2010, Morneau Shepell completed actuarial analysis on Emera's long-term incentive plan and provided current data on the Executive Pension Plan.

The MRCC reviews information and recommendations provided by Hugessen, Towers Watson, Mercer, and Morneau Shepell, as it considers its decisions relevant to the objectives of the compensation program.

The table below summarizes the fees paid to all external compensation advisors in 2010:

| Advisor | All MRCC Work | All Other Work |
|---|---|---|
| Hugessen Consulting Inc | $96,654 | $11,965 (1) |
| Morneau Shepell | Nil | $69,517 |
| Towers Watson | Nil | $49,679 |
| Mercer (Canada) Limited | Nil | $14,162 |

Notes:
(1) Hugessen Consulting Inc. was retained by the Nominating and Corporate Governance committee in 2010 to review Directors compensation.

## Compensation Discussion and Analysis

This section discusses the elements of compensation for the five Named Executive Officers ("NEOs") in 2010 discussed in this circular; namely:

- Christopher G. Huskilson, President and Chief Executive Officer, Emera Inc.
- Nancy G. Tower, Executive Vice President and Chief Financial Officer, Emera Inc.
- Robert R. Bennett, President and Chief Executive Officer, Nova Scotia Power Inc.
- Wayne D. O'Connor, Chief Operating Officer, Emera Energy Inc.
- Wayne J. Crawley, President and Chief Executive Officer, ICD Utilities Limited

Objective of Compensation Program

The purpose of Emera's executive compensation program is to reward Emera's executives for sustained increases in shareholder value; to attract, retain and motivate highly qualified and high-performing executives; and align the interests of executives with the interests of Emera's shareholders.

Compensation Program Design

Emera's compensation program is designed to be competitive in relevant labour markets, include both short-term and long-term performance goals and link compensation to the Company's performance as measured by specific financial results.

**Market Competitiveness** – Emera's executive compensation program is designed to provide total target compensation on average at the median or 50th percentile of compensation paid by similar industries and similarly-sized companies. "Total Target Compensation" for senior management, including the Named Executive Officers, for these purposes, is comprised of:

- base salary,
- target annual incentive, and
- target long-term incentives linked to total shareholder value.

**Pay for Performance** – Emera's executive compensation philosophy is that a significant proportion of executive compensation must be at risk. The at risk components depend on achieving Company, business unit and individual performance objectives. These objectives are set forth in Scorecards ("Scorecards") that establish measurable financial, customer, asset and employee objectives that, if achieved, add value to the Company or its affiliates. Executives' performance against their Scorecard is measured and rated. The Executive must achieve a threshold level of performance for any payment against a particular objective, failing which there is no payment against such objective. Accordingly, incentive compensation plans and programs are designed to pay larger amounts for superior performance, and smaller amounts if target performance is not achieved. Generally, the higher the level of the responsibility, the greater the at risk compensation.

As part of the Board and its MRCC's oversight of the design and administration of the Company's executive compensation programs, the MRCC identifies and discusses design features or processes that may potentially represent conflicts of interest and/or inducements for unnecessary or excessive risk-taking by senior executives.

This includes annual reviews of the amount of total incentive relative to base salaries, the mix of short and long term incentives, the performance metrics and whether the goals are realistic or encourage excessive risk taking, and the use of other policies designed to mitigate risk such as vesting requirements, caps on payouts, deferral periods, and stock ownership guidelines. In addition, the MRCC utilizes various technical analyses including 'stress testing' and scenario analysis to evaluate the inherent risk and reward outcomes in the incentive compensation plans.

The MRCC also satisfies itself as to the adequacy of the information it receives, the independence of the review and reporting of financial results on which certain important compensation decisions (e.g., the amount of annual incentive to be paid) are based.

These existing safeguards notwithstanding in 2011, the MRCC and Board will continue to review the relationship between enterprise risk and the Company's executive compensation plans and policies to confirm they continue to be optimally aligned with shareholder interests while maintaining an acceptable level of risk exposure.

The following table shows the percentage weighting of each component of the Total Target Compensation for the Named Executive Officers. The compensation plan design for 2010 resulted in at least 50 percent of the Total Target Compensation to be at risk for the Named Executive Officers.

| Name | Base Salary (%) | Annual Incentive at Target (%) | Long Term Incentive at Target (%) | Total Pay at Risk (%) |
|---|---|---|---|---|
| C.G.Huskilson | 30 | 21 | 49 | 70 |
| N.G.Tower | 44 | 26 | 30 | 56 |
| R.R. Bennett | 50 | 20 | 30 | 50 |
| W.J.Crawley | 50 | 20 | 30 | 50 |
| W.D.O'Connor | 47 | 34 | 19 | 53 |

Management considers many factors when developing annual incentive and long term incentive design, including: current compensation trends; plan costs at payout; expected value to be delivered to participants; maximum payout values and causal analysis of minimum, target and maximum payouts.

Both annual incentive and long-term incentive plan designs are modeled using historical and prospective performance scenarios. This stress testing provides the MRCC with reasonable assurance that the plan payouts will be appropriate and aligned with shareholder and Company objectives. Analysis is also done every year to determine how actual payouts compare to expected payouts and whether the plan components require any changes.

The MRCC has, in its sole and absolute discretion, the ability to facilitate if required, changes to compensation incentive design results. The MRCC is able to, and has in the past, exercised its discretion to adjust compensation payout formulas to align with company results.

Benchmarking Data

Emera Management engages the services of a compensation consultant (Towers Watson) to compile market information on senior management compensation, including the Named Executive Officers, relating to base salary, short-term and long-term incentives. A complete benchmarking review takes place on an annual basis for Nova Scotia Power Inc. and every second year for Emera Inc. This scope of services includes competitive market reviews of senior executive compensation levels, review and observations of current executive compensation philosophy, policies and practices, and a review of pay and performance comparators.

The MRCC undertakes periodic reviews of compensation design and total compensation opportunities for the Named Executive Officers to ensure the programs are current and that they fairly compare for particular roles recognizing varying responsibility and scope of executive positions within Emera and its affiliates.

The MRCC reviews compensation data based on a comparator group of companies, primarily regulated utilities and other energy industry enterprises that approximate the size and scope of Emera. While the intention is to use a consistent list of comparators from year to year, the comparators used for compensation review are subject to some change each year due to (a) the availability of relevant pay data, (b) mergers and acquisitions, and (c) relevance of new comparators based on updated financial metrics.

Based on the benchmark data, the President and Chief Executive Officer recommends Total Target Compensation for each Named Executive Officer, excluding himself, to the MRCC. With respect to the President and Chief Executive Officer, the MRCC reviews benchmark data and other information regarding industry trends for positions of similar scope. Following this process, the MRCC makes recommendations for Total Target Compensation for all of the Named Executive Officers to the Board of Directors.

Two sources are used to gather market information about executive compensation and establish benchmark data for Emera and its affiliates:

(1) **Publicly-Disclosed Compensation Data (Applicable to President and Chief Executive Officer and Executive Vice President and Chief Financial Officer, Emera Inc. only**) – In 2010 Hugessen was retained by the MRCC to advise on the competitiveness and appropriateness of compensation programs (salary, annual and long term incentives, and pension) for the President and Chief Executive Officer and Executive Vice President and Chief Financial Officer at Emera Inc, using the pre-agreed proxy comparator group.

The following publicly-traded organizations were used as the primary comparator group for the purposes of the compensation benchmarking review as described above.

S&P / TSX Capped Utilities Index:

ATCO Ltd.
Atlantic Power Corporation
Brookfield Renewable Power Fund
Canadian Utilities Ltd.
Capital Power Income L.P.
Fortis Inc.
Just Energy Income Fund
Northland Power Income Fund
TransAlta Corp.

The following publicly-traded organizations were also used for the purposes of Emera's President and Chief Executive Officer and Executive Vice President and Chief Financial Officer compensation benchmarking as described above.

Energy Industry Comparables:

Enbridge Income Fund
Fort Chicago Energy Partners
Inter Pipeline Fund
Pembina Pipeline Corporation
Pengrowth Energy Trust
Precision Drilling Corporation
ShawCor Ltd.

The rationale for incorporating the energy industry is that senior talent can migrate between similar organizations (i.e. industry, scale, complexity) and the fact that Emera's strategic objectives include expansion into various energy-related sectors.

(2) **Survey Data** - Towers Watson's 2009 Executive Survey was used to benchmark compensation of the Named Executive Officers and other senior management using both a regulated sample (regulated utilities) and a select sample (a broader selection of survey participants), where data was available.

Broad Comparator Group:

Alberta Electric System Operator
Alliance Pipeline
AltaLink Management Ltd.
ATCO Electric
ATCO Ltd. and Canadian Utilities Ltd.
ATCO Power
Atomic Energy of Canada Ltd.
British Columbia Hydro and Power Authority
Bruce Power LP
Duke Energy/Spectra Energy
Enbridge Gas Distribution Inc.
Enbridge Inc.
ENMAX Corporation
EPCOR Utilities Inc.
FortisAlberta Inc.
Gaz Metropolitain Inc.
Hydro One
Hydro-Quebec
Imperial Oil Ltd.
Inter Pipeline Fund
New Brunswick Power Corporation
Newfoundland & Labrador Hydro Electric
Manitoba Hydro
Ontario Power Authority
Ontario Power Generation Inc.
SaskEnergy
SaskPower
Shell Canada Ltd.
Toronto Hydro
TransAlta Corporation
TransCanada Pipelines Ltd.

Compensation Process

Benchmarking data and other information regarding industry trends for positions of similar scope and responsibility are used to establish a base salary range for each position and a range for annual incentive and long-term incentive compensation for each position.

On an annual basis the President and Chief Executive Officer conducts performance assessments for each Named Executive Officer which can influence the annual salary adjustment recommendation for a Named Executive Officer.

Elements of Compensation

*Base Salary*

Base salaries for each Named Executive Officer are benchmarked against the median of the salaries paid for positions with similar responsibilities by comparator companies. The base salary for each Named Executive Officer is reviewed annually and reflects the degree of special skill and knowledge required for the position and the performance and contribution of the individual. Base salary is designed to be a component of Total Target Compensation and provides a threshold level of cash compensation for job performance that is not at risk in the same way as annual incentive compensation.

*Annual Incentive*

Annual incentive compensation is intended to link a portion of an employee's compensation to the achievement of predetermined levels of performance in support of corporate and business unit objectives ("Annual Incentive"). Those objectives are set forth in the Executive's Scorecard and designed to focus attention on short term goals that are intended to deliver value to customers and contribute to increased shareholder value in the longer term. Emera has adopted the Scorecard approach to translate corporate strategies into measurable incentive plan goals. Target payouts under the Scorecards are generally set as a percentage of salary and are benchmarked against the median for positions with similar responsibilities in comparator companies.

On the recommendation of the MRCC, the Board of Directors of Emera approved a scorecard setting forth corporate objectives and related threshold, target and stretch performance levels to be achieved in 2010 on which the Annual Incentive for the majority of Named Executive

Officers would be based. Payouts can range from 0 percent to 200 percent of target. Four of the five Named Executive Officers have their Annual Incentive calculated based on results achieved through Scorecard results. The Annual Incentive for Mr. W.D. O'Connor, however, is based on the year-end financial results of Emera Energy Inc. and based on an assessment of achievement of objectives, including financial results and progress on new business development, as well as asset management and human resource development.

2010 Emera Corporate Scorecard

The Scorecard for Emera is ("Emera Corporate Scorecard") developed and recommended by management for approval by the MRCC and the Emera Board of Directors at the beginning of each year. It is used to determine the Annual Incentive for Emera's President and Chief Executive Officer, Emera's Executive Vice President and Chief Financial Officer; and the President and Chief Executive Officer, ICD Utilities Limited.

The Emera Corporate Scorecard objectives are based on the Company's Business Plan for the year and establish threshold, target, and stretch performance standards for each objective.

Objectives on the 2010 Emera Corporate Scorecard included a 90 percent weighting for strengthening the financial position of the Company through generating growth as measured by:

- earnings per share; and
- cash flow per share

The corporate objective of maintaining and enhancing employee commitment and wellness received a 10 percent weighting on the Scorecard.

The MRCC determined that the President and Chief Executive Officer, Emera, Executive Vice President and Chief Financial Officer, Emera and President and Chief Executive Officer, ICD Utilities Limited achieved 137 percent of target performance pursuant to the 2010 Corporate Scorecard. The following table shows the elements of the Emera Corporate Scorecard for 2010.

| Emera Inc. Corporate Objective | Weighting | Target | Actual Result | Percentage Payout(1) |
|---|---|---|---|---|
| Earnings Per Share (2) | 60% | $1.70 | $1.76 (2) | 96 |
| Cash Flow Per Share | 30% | $2.99 | $2.96 | 21 |
| Employee Commitment and Wellness as Measured by the Annual Employee Survey(3) | 10% | Action plans implemented that would improve Employee Commitment and participation in Wellness screenings | Stretch | 20 |
| | 100% | | | Total = 137% |

Notes:
(1) Percentage payouts, below or above target for financial measures, are prorated on a scale between each level of performance.
(2) Earnings per share for the Company were $1.68, or $1.76 excluding mark-to-market adjustments for 2010. The mark-to-market accounting adjustment arises as a result of a contract between Brookfield Power and Bear Swamp Power Company (of which each of Emera and Brookfield holds a 50 percent interest). The contract fixes the price of power between Brookfield and Bear Swamp Power Company but it does not fall within the strict hedge accounting rules and therefore gets mark-to-market treatment. In 2010, as in prior years, earnings per share excludes the mark-to-market adjustment for incentive calculation purposes.
(3) Based on completing these objectives the Company would expect a statistically significant increase on the annual employee survey relating to these areas.

The table below shows Emera's trending for the period 2006 to 2010 of earnings per share and cash flow per share as of December 31.

| | 2006 ($) | 2007 ($) | 2008 ($) | 2009 ($) | 2010 ($) |
|---|---|---|---|---|---|
| Earnings Per Share(1) | 1.14 | 1.28 | 1.33 | 1.55 | 1.76 |
| Cash Flow Per Share | 2.83 | 3.28 | 2.84 | 2.94 | 2.96 |

Notes:
(1) Earnings Per Share numbers reflect results excluding mark-to-market adjustments.

Scorecard payouts on average over the last five years have been 36 percent over target. Earnings Per Share performance has trended upwards over the same period, meeting or exceeding the corporate targets since 2006 and increasing 54 percent over the five year period from 2006 to 2010.

2010 Nova Scotia Power Incorporated ("NSPI") Corporate Scorecard

The NSPI Corporate Scorecard is developed and recommended by NSPI management for approval by the NSPI Management Resources, Compensation, Environment, Safety & Security Committee ("MRCESSC") and the NSPI Board of Directors at the beginning of each year and receives final approval from the MRCC. It is used to determine the Annual Incentive for NSPI's President and Chief Executive Officer, one of the Named Executive Officers in 2010.

Objectives on the 2010 NSPI Corporate Scorecard included a 40 percent weighting for strengthening the financial position of NSPI by generating growth as measured by financial earnings and cash from operations. Reliability and reputation with the Customer received a 30 percent weighting. Asset management was weighted at 15 percent, People and Safety made up the balance at 7.5 percent each respectively.

On the recommendation of the NSPI MRCESSC, the MRCC determined that the Named Executive Officer of NSPI achieved an aggregate of 84.8 percent of target on all the objectives measured in the NSPI Corporate Scorecard in 2010. The following table shows the objectives of the NSPI Corporate Scorecard for 2010.

| Nova Scotia Power Inc. Corporate Objective | Weighting | Target | Actual Result | Percentage Payout |
|---|---|---|---|---|
| Safety | 7.5% | Lost Time Frequency is less than "Best ever NSPI performance" | Threshold not achieved | 0.0 |
| People – Attract, Retain and Develop the talent required | 7.5% | 10% improvement in Health Assessment baseline levels and 2010 Capital Plan resourcing plan complete | Target | 7.5 |
| Customer - Service Reliability (1)<br>(SAIFI x SAIDI) | 10% | Greater than 80% Customer Satisfaction Rating on reliability questions in the NSPI survey | Threshold not achieved | 0.0 |
| Customer - Customer Satisfaction Survey | 20% | Customer Satisfaction with service interactions | Threshold | 10.0 |
| Asset Management - Progress on Greener Cleaner Strategy | 15% | Asset Management Review conducted and recommendations implemented by year end. | Threshold not achieved | 0.0 |
| Financial - Earnings (1) | 30% | $108 million | $121 million | 60.0 |
| Financial - Cash From Operations (1) | 10% | $228 million | $221 million | 7.308 |
| | 100.0% | | **Total** | **84.8%** |

Notes:
(1) Actual results, below or above target, will be prorated on a scale between each level of performance.

2010 Emera Energy Incorporated Annual Incentive

Mr. W.D. O'Connor participates in Emera Energy Incorporated's annual incentive plan. Under the plan, Mr. O'Connor is allocated an annual incentive determined by the MRCC based on the year-end financial results of Emera Energy Inc. and based on an assessment of achievement of objectives, including financial results and progress on new business development, as well as asset management and human resource development.

Long-Term Incentive

In 2010, Mercer (Canada) Limited was engaged by Emera Inc. to review their Restricted Share Unit Plan relative to market. One of the recommendations as a result of this review was to rename this Long Term Incentive vehicle as a Performance Share Unit Plan (PSU Plan) due to the inclusion of both external relative and internal performance measures.

There are two components of long-term incentive compensation for the Named Executive Officers; namely, the PSU Plan and the Senior Management Stock Option Plan (the "Stock Option Plan"). More details about the PSU Plan and the Stock Option Plan are set forth below.

In 2010, the PSU Plan made up 50 percent of the target long-term incentive compensatory value for Mr. C.G. Huskilson and 75 percent of the target long-term incentive compensatory value for all other Named Executive Officers. In 2010, the Stock Option Plan made up 50 percent of the target long-term compensatory value for Mr. C.G. Huskilson and 25 percent of the target long-term incentive compensatory value for all other Named Executive Officers.

The number of performance share units ("PSUs") and stock options granted to the Named Executive Officers is determined based on competitive benchmarking data and the level of responsibility within the Company; generally, the level of grant increases with the level of responsibility. The MRCC is responsible for granting PSUs and stock options.

The PSUs and the stock options increase or decrease in value in proportion to the increase or decrease in the market price of Emera's common shares over the term of a particular grant.

The options granted to senior management are determined as a percentage of base salary in each year. The value of stock option grants are based on the Black-Scholes valuation methodology. The Black-Scholes value was determined to be equal to 12 percent of the closing share price of $23.94 as of February 16, 2010.

Previous grants of stock options and PSUs to senior management are taken into account when recommending new grants by considering a three year history on total compensation, which also includes long-term incentive (stock options and PSUs) and is reviewed for Named Executive Officers each year to ensure reasonable progression within the market.

Performance Share Unit Plan

The PSU Plan adopted by Emera is designed to retain and incent employee participants by allowing senior management and executives to participate in the long-term success of the Company.

In 2010, Mercer conducted a review of Emera's PSU Plan and benchmarked the current plan design relative to market. Their findings included that the use of performance share units as a long-term incentive vehicle is consistent with market practice as is the inclusion of both external relative and internal performance measures.

The PSU Plan provides for the establishment of performance based requirements by the MRCC. Under the PSU Plan, participants receive annual grants of Performance Share Units ("PSUs"). The PSU Plan pays monetary rewards based on a combination of financial measurements over a three-year performance period as established by the MRCC pursuant to the PSU Plan. For the 2010 grants, the MRCC established the following as the performance factors:

(a) Emera's total stock return relative to the total return of S&P/TSX Capped Utilities Total Return Index; and
(b) the average growth in Emera earnings per share.

In 2010 the initial grant value of a PSU was based on the average 50 trading-day share price on December 31, 2009 ($23.71) multiplied by a value ratio factor of 1.15. This PSU value ratio is a discounting factor to offset the additional value expected to be received through dividend reinvestment over the three-year period of the grant. An additional multiplier of 1.19 was also applied as a discount for expected share price appreciation. PSUs vest and are paid out at the end of a three-year performance period.

The number of PSUs granted to each employee participant is intended to pay 100 percent of the PSU target based incentive at the end of the three-year performance period if Emera achieves its financial objectives measured by the performance factors.

Performance Factor 1

Performance factor 1 is based on Emera's average three-year total stock return in excess of the average three year return of the S&P/TSX Capped Utilities Total Return Index as illustrated in the table below.

| Relative Annual Return to S&P/TSX Capped Utilities Total Return Index | Performance Factor |
|---|---|
| Less than -5% | 0.00 |
| -5% | 0.50 |
| 0% | 1.00 |
| 5% or more | 1.50 |

Performance Factor 2

Performance factor 2 is based on Emera's average annual growth in earnings per share. As well, dividends must be maintained at or higher than the December 31, 2009 levels. If dividends are reduced, Factor 2 will be deemed to be 0 regardless of the earnings per share growth as illustrated in the table below.

| Emera Average Three-Year Absolute Earnings per Share Growth (Compound Annual Growth Rate) | Performance Factor |
|---|---|
| Less than 4% | 0.00 |
| 4% | 0.50 |
| 6% | 1.00 |
| 8% or more | 1.50 |

The MRCC annually reviews the PSU Plan performance factors and in 2010 recommended a change to the second factor in light of Emera's strong performance in the market. For the 2010 grants, Performance factor 2 is based on an average three year Earnings Per Share growth range of 4 percent, 6 percent, and 8 percent rather than the range of 4 percent, 5 percent and 7 percent used for the 2008 and 2009 PSU grants.

The value of each performance factor will be interpolated on the basis of the actual relative returns. In addition, all annual average returns or percent over the three-year performance period will be determined on a compounded basis.

If targets are not met, there is the potential for no payouts. If targets are exceeded, payouts may be as much as, but not more than, two times the initial grant value.

The performance targets for the 2010 PSU awards are used for compensation purposes only and are not suitable for any other purpose. There is no assurance that any performance level will be met. The targets may also constitute forward-looking information. Forward-looking statements are based upon a number of assumptions and are subject to a number of known and unknown risks and uncertainties, any of which are beyond Emera's control, which could cause actual results to differ materially from the performance targets. Please see the cautionary statement in the 2010 Annual Report respecting risks and assumptions relevant to Emera's determination of performance targets for compensation purposes.

The amount payable to Named Executive Officers at the end of the three-year performance period is determined by:

(a) the number of PSUs held;
(b) the average 50 trading-day share price as at the end of the three-year performance period; and
(c) Emera's financial performance against the two equally-weighted performance factors over the three-year performance period.

If a participant leaves Emera's employment prior to the payout date and is under the age of 55 at the date of termination, the participant is not entitled to a payout for that particular grant of PSUs. An exception to this would be in the event of the death of a participant.

If, prior to the payout date a participant:

i) leaves Emera's employment between age 55 and 65 and does not work for, or on behalf of, one of Emera's competitors; or
ii) retires on or after age 65,

they will be eligible to receive a pro-rated portion of the payout for that particular grant based on the period during which they were employed by Emera during the three-year performance period. The payout will be made after the end of the three-year performance period.

If a participant dies prior to the payout date, their named beneficiary will be eligible to receive a pro-rated portion of the payout based on the period during which they were employed during the three-year performance period for that particular grant. The payout will be made after the end of the three-year performance period.

*Senior Management Stock Option Plan*

The administration of the Senior Management Stock Option Plan (the "Stock Option Plan") has been delegated to the MRCC by the Board of Directors. Under the Stock Option Plan, the MRCC is responsible for designating, based on Management's recommendation, which employees of the Company and its affiliates will be eligible to participate in the Stock Option Plan. All of the Named Executive Officers are participants in the Stock Option Plan and have received stock options in 2010 as a part of their long-term incentive.

Options are currently designed to deliver a percentage of the long-term incentive opportunity for senior management, including the Named Executive Officers, and have been retained to recognize their importance as a component of competitive executive compensation and to preserve a long-term focus. The level of grant increases with the level of responsibility.

Options are granted to selected employees of the Company and its affiliates and may be exercised for up to a maximum of ten years. All options granted to date are exercisable on a graduated basis with up to 25 percent of the 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 employee loses all rights thereunder. The holder of an option has no rights as a shareholder until the option is exercised and shares have been issued. The price at which stock options may be exercised is the closing market price of the Company's common shares on the Toronto Stock Exchange on the last business day on which such shares were traded immediately preceding the effective date of the grant of an option.

Unless the term of an option has expired, options may be exercised within the 24 months following the date of retirement or termination for other than just cause, and within six months following the date of termination for just cause, resignation, or death.

The maximum percentage of shares under all security-based compensation (including the Stock Option Plan) issuable to insiders of the Company at any time is ten percent of the issued and outstanding shares of the Company.

The maximum number of shares to be optioned to any one person under the Stock Option Plan is five percent of the issued and outstanding shares of the Company at the date of the grant of the option.

The number of shares issued to insiders, within any one-year period, under all security-based compensation arrangements, will not exceed ten percent of the issued and outstanding shares of the Company.

Under the Stock Option Plan, options may be granted in respect of authorized and unissued common shares of the Company, to a maximum of 6,700,000 shares, or approximately 5.8% of the total issued and outstanding common shares of the Company as of the date of this Circular.(1) 2,909,275 shares (approximately 2.5% of the total issued and outstanding common shares of the Company) have been issued under the Stock Option Plan since its inception, and 2,340,803 shares (approximately 2.0% of the total issued and outstanding common shares of the Company) are issuable under actual grants of options. Under the Plan, options remain available to be granted in respect of 1,449,922 shares (approximately 1.3% of the total issued and outstanding common shares of the Company).

Notes:

(1) The prescribed information in this paragraph is as of the date of the Circular, March 14, 2011. Prescribed information about the Stock Option Plan is also contained in the table later in this Circular under the heading "Shares Authorized for Issuance Under Equity-Based Compensation Plans" which is as of December 31, 2010, the end of the Company's most recently completed financial year.

The table below summarizes certain ratios regarding the Stock Option Plan, namely dilution, burn rate and overhang as defined in the table and measured as a percentage of the total number of shares outstanding as of December 31, 2010, 2009 and 2008.

| | Dec. 31 2010 | Dec. 31 2009 | Dec. 31 2008 |
|---|---|---|---|
| **Dilution** *(total number of options outstanding divided by total number of shares outstanding)* | 1.87% | 1.84% | 1.96% |
| **Burn Rate** *(total number of options granted in a fiscal year, minus expired options, divided by the total number of shares outstanding)* | 0.34% | 0.33% | 0.21% |
| **Overhang** *(total shares available for issuance plus options outstanding, divided by the total number of shares outstanding)* | 5.20% | 5.50% | 5.93% |

Stock options issued under the Stock Option Plan are non-assignable other than by Will or pursuant to the laws of succession.

The Board of Directors of the Company may amend or discontinue the Stock Option Plan by resolution at any time; provided, however, that no such amendment:

- results in any extension of the term of a stock option benefitting an optionee; or
- results in any reduction to the exercise price of a stock option benefitting an optionee; or
- increases the maximum number of shares that may be optioned under the Stock Option Plan;
- change the manner of determining the option price; or
- without the consent of the optionee, alter or impair any stock option previously granted to an optionee under the Stock Option Plan.

Any amendment to the Stock Option Plan may be subject to the approval of regulatory authorities, including the listing requirements of the Toronto Stock Exchange and other stock exchanges and may require shareholder approval.

In 2010, the Company provided no financial assistance to participants under the Stock Option Plan to facilitate the purchase of shares under the Plan.

<u>Other Executive Benefits</u>

The Company provided executives with additional benefits in accordance with the compensation program objectives and for the purpose of retention and motivation. As part of their compensation, the Named Executive Officers are eligible to receive:

- Life and Accidental Death and Dismemberment (ADD) Insurance coverage of five times annual base salary to a maximum of $1,000,000 ($1,500,000 for the President and Chief Executive Officer);
- supplementary retirement plan contributions for amounts beyond the allowable Canada Revenue Agency pension limits; annual income tax return preparation in conjunction with retirement planning;
- monthly parking;
- monthly car allowance plus mileage, as applicable; and
- an annual wellness/fitness allowance for a recreational and/or social club.

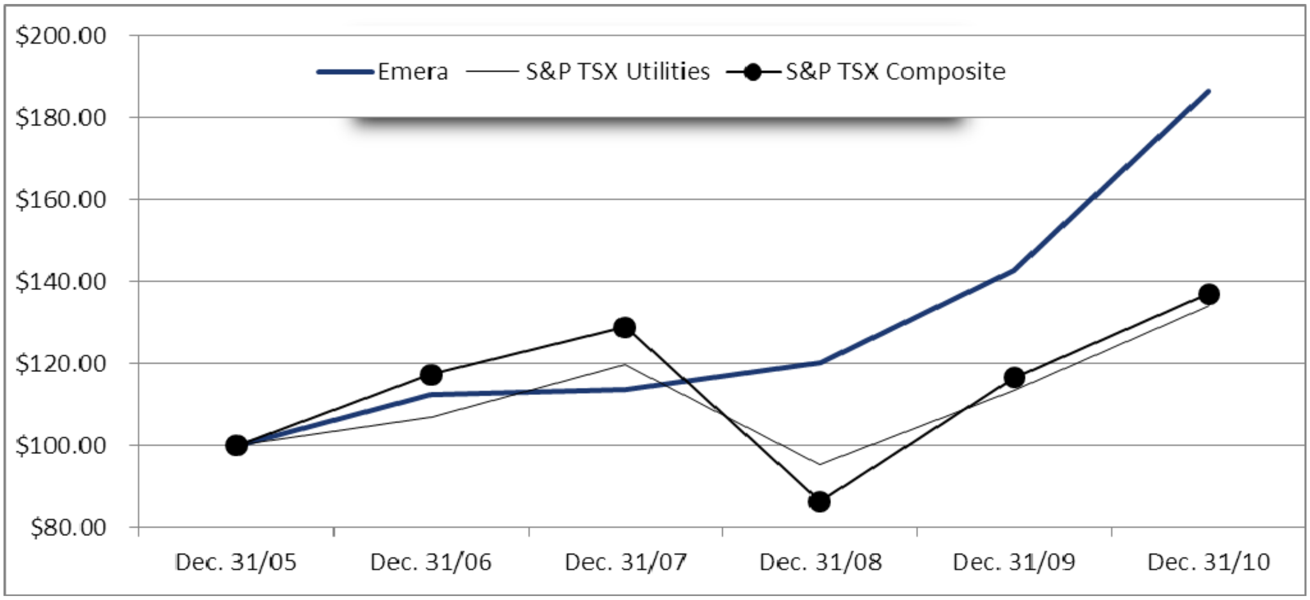
Some of these items are considered as taxable benefits and are reported in the Summary Compensation Table for the Named Executive Officers.

All retired employees are eligible to continue basic life and accident insurance as well as extended health coverage.

**Performance Graph**

The following performance graph compares the Company's cumulative total shareholder return (assuming an investment of $100 and reinvestment of dividends) for its shares with that of the S&P TSX Utilities Index and the S&P TSX Composite Index.

**Cumulative Total Return on $100 Investment**
**December 31, 2005 to December 31, 2010**




| | Dec. 31/05 | Dec. 31/06 | Dec. 31/07 | Dec. 31/08 | Dec. 31/09 | Dec. 31/10 |
|---|---|---|---|---|---|---|
| Emera | $100.00 | $112.31 | $113.53 | $120.28 | $142.57 | $186.48 |
| S&P TSX Utilities | 100.00 | 107.01 | 119.73 | 95.23 | 113.33 | 134.17 |
| S&P TSX Composite | 100.00 | 117.26 | 128.79 | 86.28 | 116.53 | 137.05 |

From 2005 to 2010, total annual salary and annual incentive for the top five Named Executive Officers increased by 46.8 percent. The cumulative total shareholder return for Emera during the same period was 86.5 percent. The chart above shows the steady growth of Emera during the past five years from 2005 to 2010, which has exceeded market comparators (52.3 percent more than the S&P TSX Utilities Index and 49.4 percent more than the S&P TSX Composite Index) and delivered total shareholder returns of more than 86 percent. During the same period, total annual salaries and annual incentives for the top five Named Executive Officers who have led this significant performance increased 46.8 percent.

Total shareholder return for Emera from 2009 to 2010 was 31 percent. During the same period, total annual salary and annual incentive for the President and Chief Executive Officer, Emera increased 14 percent.

The total annual salary, annual incentive and long-term Performance Share Unit payouts earned in 2010 for the Named Executive Officers totaled $5,558,307 which represents 2.9 percent of the Company's net earnings applicable to common shares of $191,100,000 for the period ended December 31, 2010.

### Summary Compensation Table

| Name and Principal Position | Year | Salary (1) ($) | Share Based Awards (2) ($) | Option Based Awards (3) ($) | Non-equity Incentive Plan Compensation: Annual Incentive Plans (4) (5) (6) ($) | Subtotal ($) | Pension Value (7) ($) | All Other Compensation (8) ($) | Total Compensation ($) |
|---|---|---|---|---|---|---|---|---|---|
| C.G. Huskilson President & Chief Executive Officer Emera Inc. | 2010 | 625,000 | 500,034 | 500,038 | 849,375 | 2,474,447 | 471,000 | 23,741 | 2,969,188 |
| | 2009 | 649,038 | 421,820 | 421,931 | 693,750 | 2,186,539 | 249,000 | 20,438 | 2,455,977 |
| | 2008 | 623,076 | 632,813 | 210,938 | 468,750 | 1,935,577 | 427,000 | 24,491 | 2,387,068 |
| N.G. Tower Executive Vice President & Chief Financial Officer Emera Inc. and Nova Scotia Power Inc. | 2010 | 349,231 | 183,878 | 61,131 | 287,700 | 881,940 | 187,000 | 15,355 | 1,084,295 |
| | 2009 | 321,385 | 162,795 | 54,216 | 316,600 | 854,996 | 85,000 | 16,866 | 956,862 |
| | 2008 | 299,423 | 157,500 | 52,500 | 187,500 | 696,923 | 115,000 | 16,452 | 828,375 |
| R.R. Bennett President & Chief Executive Officer Nova Scotia Power Inc. | 2010 | 349,519 | 157,480 | 52,521 | 168,720 | 728,240 | 187,000 | 18,972 | 934,212 |
| | 2009 | 336,692 | 146,309 | 48,694 | 195,240 | 726,935 | 286,000 | 24,260 | 1,037,195 |
| | 2008 | 274,487 | 416,256 | 24,375 | 113,026 | 828,144 | 444,000 | 19,946 | 1,292,090 |
| W.D. O'Connor Chief Operating Officer Emera Energy Inc. | 2010 | 275,000 | 82,441 | 27,552 | 357,000 | 741,993 | 24,750 | 13,240 | 779,983 |
| | 2009 | 274,539 | 82,385 | 27,610 | 345,000 | 729,534 | 24,750 | 11,921 | 766,205 |
| | 2008 | 234,078 | 40,000 | 50,000 | 255,000 | 579,078 | 15,600 | 62,031 | 656,709 |
| W.J. Crawley President & Chief Executive Officer ICD Utilities Limited | 2010 | 250,000 | 112,411 | 137,597 | 90,413 | 590,421 | 1,000 | 15,668 | 607,089 |
| | 2009 | 247,230 | 108,102 | 35,893 | 100,333 | 491,558 | 84,000 | 18,978 | 594,536 |
| | 2008 | 240,000 | 107,878 | 36,112 | 120,000 | 503,990 | 10,000 | 15,834 | 529,824 |

Notes:

(1) Salary information is based on actual earnings.

(2) Includes DSU special awards and PSU grants. It does not reflect DSU's received in lieu of cash bonuses. See 'Deferred Share Unit Plan' for further details. The initial value of a PSU was based on the average 50 trading-day share price on December 31, 2009 (23.71) multiplied by a value ratio factor of 1.15, and a share appreciation factor of 1.19 resulting in an expected value of a PSU to be $32.47.

(3) The value of stock option grants is based on the Black-Scholes valuation methodology. Stock options granted to the Named Executive Officers in 2010 were based on the Black-Scholes value which was determined to be equal to 12 percent of the closing share price of $23.94 as of February 16, 2010. The option based award for Mr. W.J. Crawley includes an additional grant of stock options with an intended award value of $100,000 in recognition of results achieved on ICD Utilities Ltd.'s growth and investment plan in 2010. This additional grant was calculated based on the closing share price of $31.02 as of November 10, 2010.

(4) In 2010 Mr. C.G. Huskilson, Ms. N.G. Tower, and Mr. W.J. Crawley participated in the Emera Corporate Scorecard which included specific financial targets of earnings per share (60 percent), cash flow per share (30 percent), and leadership of people (10 percent). In 2010 earnings per share were $1.76 (excluding a mark-to-market adjustment for 2010) which was over target or 96 percent; cash flow per share was slightly below target at $2.96 or 21 percent; and the leadership measure achieved stretch and paid out at 20 percent. Based on these year-end results, it was determined by the MRCC that the Named Executive Officers for Emera achieved 137 percent of target on the Emera Corporate Scorecard.

In 2010 Mr. R.R. Bennett participated in the Nova Scotia Power Inc. Corporate Scorecard which included specific financial targets of financial earnings and free cash flow (40 percent), service reliability and customer satisfaction (30 percent), asset management (15 percent), safety excellence (7.5 percent), and leadership of people (7.5 percent). Based on year-end results, it was determined by the MRCC that Mr. Bennett achieved 84.8 percent of target on the Nova Scotia Power Inc. Corporate Scorecard.

The annual incentive for the Named Executive Officer for Emera Energy Inc., Mr. W.D. O'Connor, is based on the year-end financial results of Emera Energy Inc. and based on an assessment of achievement of objectives, including progress on new business development and human resource development. (See the section entitled "Annual Incentive" earlier in this Circular for more information about the Emera Corporate Scorecard and the NSPI Corporate Scorecard.)

(5) The non-equity incentive plan compensation reflects amounts earned within the 2010 performance year and paid in 2011. Mr. C.G. Huskilson elected not to receive any of his 2010 annual incentive in DSUs. Ms. N.G. Tower elected to receive 50 percent of her 2010 annual incentive ($143,850) in DSUs. Mr. R.R. Bennett elected to receive 50 percent of his 2010 annual incentive ($59,360) in DSUs. Mr. W.D. O'Connor elected to receive 50 percent of his 2010 annual incentive ($178,500) in DSUs. Mr. W.J. Crawley elected to receive 50 percent of his 2010 Emera annual incentive ($28,542) in DSUs.

(6) The 2010 non-equity incentive plan compensation for Mr. C.G. Huskilson includes a lump sum amount of $250,000 in recognition of outstanding growth and capturing business development opportunities. The 2010 non-equity incentive plan compensation for Mr. R.R. Bennett includes a bonus amount of $50,000 for execution of clean air strategy and development of new projects. The 2010 non-equity incentive plan compensation for Mr. W.J. Crawley includes an amount of $33,330 based on results achieved on ICD Utilities Limited's growth and investment plan.

(7) Further information concerning pension values can be found in the section entitled "Pension Plan Benefits".

(8) As part of their compensation, the Named Executive Officers are eligible to receive Life and Accidental Death and Dismemberment (ADD) Insurance coverage of five times annual base salary to a maximum of $1,000,000 ($1,500,000 for the President and Chief Executive Officer); supplementary retirement plan contributions for amounts beyond the allowable Canada Revenue Agency pension limits; annual income tax return preparation in conjunction with retirement planning; monthly parking; monthly car allowance plus mileage, as applicable; and an annual wellness/fitness allowance. These items are included in the All Other Compensation column and some of these items are considered taxable benefits. Mr. Bennett's All Other Compensation includes an amount of $556 that reflects the taxable benefit on an interest-free loan. The costs of the benefits are based on the costs incurred by the Company except in the case of the interest-free loan to Mr. Bennett which is based on an imputed interest rate of 4.0 percent per annum.

## Outstanding Share-Based Awards and Option-Based Awards

The following table describes all option-based and share-based awards outstanding as of December 31, 2010 for each Named Executive Officer.

| | Option-based Awards (1) (Stock Options) | | | | Share-based Awards (Restricted Share Units (RSUs) and Deferred Share Units (DSUs)) | |
|---|---|---|---|---|---|---|
| Name | Number of Securities Underlying Unexercised Options (#) | Option Exercise Price ($) | Option Expiration Date | Value of Unexercised in-the-money Options ($) (2) | Number of Shares or Units of Shares That Have Not Vested (#) (3) | Market or Payout Value of Share-Based Awards That Have Not Vested ($) (4) |
| C.G. Huskilson | 26,400 | 24.63 | June 5, 2020 | 177,408 | 77,072 | 2,416,207 |
| | 147,000 | 23.94 | February 16, 2020 | 1,089,270 | | |
| | 168,100 | 21.99 | February 12, 2019 | 1,573,416 | | |
| | 79,500 | 21.58 | February 14, 2018 | 776,715 | | |
| | 163,800 | 20.42 | March 8, 2017 | 1,790,334 | | |
| | 172,900 | 19.88 | March 16, 2016 | 1,983,163 | | |
| | 160,200 | 19.50 | February 9, 2015 | 1,898,370 | | |
| | 90,000 | 17.79 | February 5, 2014 | 1,220,400 | | |
| | 69,000 | 15.73 | February 5, 2013 | 1,077,780 | | |
| N.G. Tower | 21,300 | 23.94 | February 16, 2020 | 157,833 | 13,426 | 420,905 |
| | 21,600 | 21.99 | February 12, 2019 | 202,176 | | |
| | 21,500 | 21.58 | February 14, 2018 | 210,055 | | |
| | 42,100 | 20.42 | March 8, 2017 | 460,153 | | |
| | 30,500 | 19.88 | March 16, 2016 | 349,835 | | |
| | 19,600 | 19.50 | February 9, 2015 | 232,260 | | |
| | 14,400 | 17.79 | February 5, 2014 | 195,264 | | |
| | 9,000 | 15.73 | February 5, 2013 | 140,580 | | |
| | 4,750 | 17.55 | October 27, 2012 | 65,550 | | |
| R.R. Bennett | 18,300 | 23.94 | February 16, 2020 | 135,603 | 23,437 | 734,750 |
| | 19,400 | 21.99 | February 12, 2019 | 181,584 | | |
| | 10,000 | 21.58 | February 14, 2018 | 97,700 | | |
| | 12,600 | 20.42 | March 8, 2017 | 137,718 | | |
| | 14,100 | 19.88 | March 16, 2016 | 161,727 | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| W.D. O'Connor | 9,600 | 23.94 | February 16, 2020 | 71,136 | 6,453 | 202,302 |
| | 8,250 | 21.99 | February 12, 2019 | 77,962 | | |
| | 16,350 | 22.59 | June 1, 2018 | 143,226 | | |
| W.J. Crawley | 27,778 | 31.02 | November 9, 2020 | 9,167 | 8,603 | 269,704 |
| | 13,100 | 23.94 | February 16, 2020 | 97,071 | | |
| | 14,300 | 21.99 | February 12, 2019 | 133,848 | | |
| | 14,800 | 21.58 | February 14, 2018 | 144,596 | | |
| | 30,400 | 20.42 | March 8, 2017 | 332,272 | | |
| | 15,750 | 19.88 | March 16, 2016 | 180,652 | | |

Notes:
(1) Option-based awards include both vested and unvested options.
(2) The value of all unexercised option-based awards was calculated using a December 31, 2010 closing share price of $31.35.
(3) Unvested share-based awards include initial Performance Share Unit (PSU) and Deferred Share Unit (DSU) grants and any additional PSUs and DSUs from dividend reinvestment as of December 31, 2010.
(4) Share-based awards values were calculated based on an assumed performance factor of 1 and a December 31, 2010 closing share price of $31.35.

### Incentive Plan Awards – Value Vested or Earned During the Year

The following table describes the value of all option-based awards, share-based awards, and non-equity incentives that vested or were earned during 2010 for each Named Executive Officer.

| Name | Option-based awards Value vested during 2010 (1) ($) | Share-based awards (Performance Share Units (PSUs) and Deferred Share Units (DSUs)) Value vested during 2010 (2)(3) ($) | Non-equity incentive plan compensation - Value earned during the year (4) ($) |
|---|---|---|---|
| C.G.Huskilson | 482,772 | 1,549,707 | 849,375 |
| N.G. Tower | 97,526 | 428,329 | 287,700 |
| R.R. Bennett | 43,629 | 229,593 | 168,720 |
| W.D. O'Connor | 16,742 | 77,366 | 357,000 |
| W.J. Crawley | 80,524 | 208,662 | 90,413 |

Notes:
(1) Represents the aggregate dollar value that would have been realized if the options under the option-based award had been exercised on the vesting (eligibility) date in 2010.
(2) This dollar amount represents the payout of 2008 PSU grants based on the performance factors established in 2008. In 2010, the value of share-based awards vested during the year reflects performance factors based on Emera's relative performance versus the S&P/TSX Capped Utilities Total Return Index and Emera Inc.'s average annual growth in Earnings per Share. The payout at the end of the three-year performance period is calculated based on vested PSUs x Performance Factors x Period Ended Share Price. The overall performance factor was 1.50. The average share price during the last fifty trading days of 2010 was $31.19.
(3) This dollar amount includes the value of DSUs vested in 2010, including additional DSUs from dividend reinvestments, and calculated at a December 31, 2010 closing share price of $31.35. In 2010 for Mr. C.G. Huskilson this amount equaled $325,475. For Ms N.G. Tower this amount equaled $123,613 and for Mr. R.R. Bennett this amount equaled $88,219.
(4) This dollar amount represents the 2010 incentive payout as previously discussed in the Summary Compensation Table.

### Aggregated Option Exercises during 2010 and 2010 Option Values

The following table summarizes for each of the Named Executive Officers the number of common shares acquired pursuant to the exercise of stock options during the fiscal year ended December, 31, 2010, if any; the aggregate value realized upon exercise, if any; and the number of common shares covered by unexercised options under the Stock Option Plan as at December 31, 2010. Aggregate value realized upon exercise, if any, is the difference between the fair market value of the common shares on the exercise date and the exercise or base price of the option. Value of unexercised in-the-money options at fiscal year-end, if any, is the difference between the exercise or base price of the options and the fair market value of the common shares on December 31, 2010 which was $31.35.

| Name | Securities Acquired on Exercise (#) | Aggregate Value Realized ($) | Unexercised Options at December 31, 2010 Exercisable (#) | Unexercisable (#) | Value of Unexercised In-the-Money Options at December 31, 2010 Exercisable ($) | Unexercisable ($) |
|---|---|---|---|---|---|---|
| C.G. Huskilson | 87,500 | 1,371,790 | 696,725 | 380,175 | 8,304,174 | 3,282,681 |
| N.G. Tower | Nil | N/A | 125,975 | 58,775 | 1,484,175 | 529,531 |
| R.R. Bennett | Nil | N/A | 33,400 | 41,000 | 359,261 | 355,070 |
| W.D. O'Connor | 6,000 | 55,530 | 6,550 | 27,650 | 57,378 | 234,946 |
| W.J. Crawley | 38,700 | 445,902 | 49,525 | 66,603 | 535,616 | 361,990 |

**Pension Plan Benefits**

The Named Executive Officers are members of the corporate pension plan and participate in either a defined benefit basis or a defined contribution basis.

Defined Benefit

The following table shows years of credited service, estimated pension amounts, and changes to accrued obligations from January 1, 2010 to December 31, 2010 for the Named Executive Officers who participate in the corporate pension plan on a defined benefit basis.

| Name | Number of Years Credited Service (#) | Annual Benefits Payable At Year End(1) ($) | At Age 65 ($) | Accrued Obligation at Start of Year ($) | Compensatory Change(2) ($) | Non-Compensatory Change ($) | Accrued Obligation at Year End ($) |
|---|---|---|---|---|---|---|---|
| C.G. Huskilson | 30.58 | 472,000 | 540,000 | 6,536,000 | 471,000 | 1,657,000 | 8,664,000 |
| N.G. Tower | 13.33 | 98,000 | 195,000 | 1,105,000 | 187,000 | 343,000 | 1,635,000 |
| R.R. Bennett | 22.67 | 141,000 | 218,000 | 1,761,000 | 187,000 | 678,000 | 2,626,000 |
| W.J. Crawley | 20.4 | 111,000 | 190,000 | 1,260,673 | 1,000 | 491,327 | 1,753,000 |

Notes:

(1) Not eligible for immediate pension at year-end, amount shown is the amount payable starting at age 65 if Named Executive Officer terminated employment at December 31, 2010.

(2) Reflects change in accrued benefit obligation related to a) the employer cost of the additional pension service earned during 2010 and b) changes in pensionable earnings different than what was assumed.

(3) The compensatory figure for Mr. C.G. Huskilson takes into consideration the understanding reached with the Board of Directors in 2010 which allows him to convert his pension entitlement from the Supplementary Retirement Plan ("SERP") to a commuted value at termination regardless of his age. This is a one-time impact on the compensatory figure. The amount assumes that he would convert 50 percent of his SERP pension to a commuted value at a discount rate 1 percent lower than accounting discount rates. There was no plan amendment as a result of this agreement.

The defined benefit component of the plan entitles members to pension benefits based on two percent of the average of the four highest years' earnings (base salary plus up to 50 percent of target short term incentive) multiplied by each year of credited service to a maximum of 35 years credited service. Upon reaching age 65, pension benefits under the pension plan are reduced to reflect commencement of payments under the Canada Pension Plan (CPP). In addition, the Named Executive Officers are eligible to have portions of their annual incentive included in pensionable earnings.

The pension is payable upon the earlier of age 60 or age 55, provided that age and years of service add to at least 85. A member may also retire on a reduced formula if the member has attained age 55, but does not qualify for the rule of 85.

Members of the defined benefit component of the plan contribute 5.4 percent of eligible earnings up to the year's maximum pensionable earnings ("YMPE") under the Canada Pension Plan, and seven percent of earnings between the YMPE and the amount on which pension benefits may be earned under a registered pension plan as permitted by the *Income Tax Act,* (Canada).

Spousal benefits are paid on the death of a member at the rate of 60 percent of regular pension benefits. The pension plan is indexed to the consumer price index to a maximum of six percent per annum.

Due to Canada Revenue Agency's limitations on the maximum pension benefit which may be paid under the pension plan, a portion of the pension earned after January 1, 1992 is provided under the terms of a Supplementary Employee Retirement Plan which is secured by a letter of credit deposited in a retirement compensation trust.

The accrued pension obligation is calculated following the method prescribed by the Canadian Institute of Chartered Accountants and is based on management's best estimate of future events that affect the cost of pensions, including assumptions about future salary adjustments and annual incentive award.

Defined Contribution

The following table shows accumulated value, estimated pension amounts, and changes to accrued obligations from January 1, 2010 to December 31, 2010 for the Named Executive Officer who participates in the corporate pension plan on a defined contribution basis.

| Name | Accumulated Value at Start of Year ($) | Compensatory ($) | Non-Compensatory ($) | Accumulated Value at Year End ($) |
|---|---|---|---|---|
| W.D. O'Connor | 129,500 | 24,750 | 23,250 | 177,500 |

The defined contribution component of the plan is a registered pension plan regulated by the *Income Tax Act* and the *Nova Scotia Pension Benefits Act*. Accordingly, contributions are deductible for income tax purposes.

The Company contributes a base amount to the participant's account each pay period. The amount is expressed as a percentage of eligible earnings. Plan participants can also make contributions to the defined contribution component with the Company matching a portion of these contributions. Canada Revenue Agency limits apply.

Upon ending active employment with the Company at any age between 55 and 65, plan participants may start receiving retirement income through the purchase of a life annuity or by converting their account to a Life Income Fund (LIF).

The defined contribution component of the plan is administered on behalf of the Company by a major Canadian insurance company which acts in accordance with the provisions of the defined contribution component of the plan, the *Income Tax Act*, and the *Nova Scotia Pension Benefits Act.*

Mr. O'Connor participates in the defined contribution component of the plan. Under the terms of the defined contribution component, Mr. O'Connor and the Company each contribute six percent of his base salary into the registered pension plan up to the total amount permitted under the *Income Tax Act*. For 2010 Mr. O'Connor and the Company each contributed $11,225. In addition, the Company maintains an account for any Company contributions which would be made in the absence of the *Income Tax Act* limits. For 2010, the additional Company contribution was $13,525.

### Deferred Share Unit Plan ("DSU Plan")

Emera has a DSU Plan for executives and senior management and each Named Executive Officer is a participant.

A Deferred Share Unit ("DSU") is a bookkeeping entry that has a value based upon the value of one common share of the Company. Each DSU earns dividend equivalents in the form of additional DSUs. DSUs are not paid out until such time as the participant is no longer employed by the Company or any of its affiliates. When redeemed, the value of a participant's DSUs is equivalent to the fair market value of an equal number of common shares of the Company.

Prior to the start of each financial year, the Named Executive Officers provide elections respecting the portion of their upcoming Annual Incentive, if any, which is to be allocated to DSUs. When the Annual Incentive is paid to the Named Executive Officers, the amount elected is allocated to DSUs rather than paid in cash. Each DSU has a value equal to the market price of a Company common share.

The table below identifies the amount of annual incentive for 2010 which each Named Executive Officer elected to receive as DSUs.

| Name | Percentage of 2010 Annual Incentive Elected to Deferred Share Units (%) | Dollar Amount of 2010 Annual Incentive Elected to Deferred Share Units ($) |
|---|---|---|
| C.G. Huskilson | 0 | Nil |
| N.G. Tower | 50 | 143,850 |
| R.R. Bennett | 50 | 59,360 |
| W.D. O'Connor | 50 | 178,500 |
| W.J. Crawley | 50 | 28,542 |

When a dividend is paid on Emera's common shares, each participant's DSU account is allocated additional DSUs equal in value to the dividend paid on an equivalent number of Emera common shares.

Following resignation, termination of employment or retirement, and on a date selected by the participant not later than December 15 of the next calendar year after resignation, 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. The after-tax amount is paid to the participant. If a participant is a U.S. taxpayer, payment shall be made six months following the termination date.

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

### Executive Share Ownership Requirements

To align the interests of senior management with the interests of shareholders, share ownership guidelines were introduced for designated Executive Officers in 2003. The guidelines, which must be achieved within five years of becoming a designated Executive Officer, are as follows:

| | |
|---|---|
| President and Chief Executive Officer, Emera | 3.0 times salary |
| President and Chief Executive Officer, Nova Scotia Power Inc. & Bangor Hydro Electric Co. | 2.0 times salary |
| Chief Operating Officers and Executive Vice Presidents (1) | 1.5 times salary |
| Vice Presidents | 1.0 times salary |

Share ownership is based on the number of shares owned by an individual, plus Deferred Share Units (DSUs) which may be acquired pursuant to the Company's DSU Plan. DSUs are considered share equivalents.

The DSU Plan is intended to facilitate achievement of share ownership guidelines without diluting the shareholder base. DSUs are an income deferral mechanism only, and therefore there are no performance targets attributable to DSUs.

Under the DSU Plan, each participant may elect to defer all or a percentage of the annual incentive award in the form of DSUs until the applicable guidelines are met.

The share and/or share equivalent ownership for those Named Executive Officers governed by the ownership guidelines are set out below. The estimated value is based on the closing price of Emera's common shares on December 31, 2010 of $31.35. All Named Executive Officers have met or exceeded their share ownership requirements.

Notes:
(1) W.J. Crawley has been determined to be equivalent to Chief Operating Officer and Executive Vice President in his capacity as President and Chief Executive Officer, ICD Utilities Limited.

| Named Executive Officer | Shares/Share Equivalents [(1)] (#) | Estimated Value ($) | Multiple of Base Salary |
|---|---|---|---|
| C.G. Huskilson | 181,157 | 5,679,272 | 9.1 |
| N.G. Tower | 39,961 | 1,252,777 | 3.6 |
| R.R. Bennett | 27,131 | 850,557 | 2.4 |
| W.D. O'Connor | 24,399 | 764,909 | 2.8 |
| W.J. Crawley | 15,224 | 477,272 | 1.9 |

Notes:

(1) Includes vested and not yet vested DSUs calculated at a December 31, 2010 closing share price of $31.35.

### Termination and Change of Control Benefits

The following table provides the estimated amounts of incremental payments, payables and benefits to which each Named Executive Officer would be entitled under various plans and arrangements, assuming retirement, resignation, termination without cause, termination for cause, and separation from the Company in circumstances of a change of control, assuming the triggering event took place on December 31, 2010.

| Name | Termination Scenario[(1)] | Cash Severance ($) | Short Term Incentive ($) | Performance Share Units (PSUs) ($) | Deferred Share Units (DSUs) ($) | Stock Options ($) | Continuation of Benefits (Present Value) [(2)] ($) | Total ($) |
|---|---|---|---|---|---|---|---|---|
| C.G. Huskilson | Retirement/Resignation | | | | | | | |
| | Termination for Cause | | | | | | | |
| | Not for Cause | 1,250,000 | 875,000 | | 1,301,903 | | 40,000 | 3,466,903 |
| | Control Change | 1,250,000 | 875,000 | 1,114,304 | 1,301,903 | | 40,000 | 4,581,207 |
| N.G. Tower | Retirement/Resignation | | | | | | | |
| | Termination for Cause | | | | | | | |
| | Not for Cause | 350,000 | 210,000 | 218,729 | | | 16,200 | 794,929 |
| | Control Change | 350,000 | 210,000 | 420,905 | | | | 980,905 |
| R.R. Bennett | Retirement/Resignation | | | | | | | |
| | Termination for Cause | | | | | | | |
| | Not for Cause | 350,000 | 140,000 | 193,962 | 364,318 | | 15,000 | 1,063,280 |
| | Control Change | 350,000 | 140,000 | 370,432 | 364,318 | | | 1,224,750 |
| | Retirement/Resignation | | | | | | | |
| W.D. O'Connor | Termination for Cause | | | | | | | |
| | Not for Cause | 275,000 | 357,000 | | | | | 632,000 |
| | Control Change | | | | | | | |
| | Retirement/Resignation | | | | | | | |
| W.J. Crawley | Termination for Cause | | | | | | | |
| | Not for Cause | | | | | | | |
| | Control Change | | | | | | | |

Notes:

(1) Change of Control scenarios also assume all unvested PSUs would become payable in full and are valued based on an assumed performance factor of 1 and a year-end closing price of $31.35. Change of control scenarios also assume all DSUs would vest and are valued based on a year-end closing share price of $31.35.

(2) Continuation of benefits reflects amounts for car allowance and health and dental benefits.

The following is a summary of termination and change of control benefits afforded to each Named Executive Officer under his or her employment contract.

**C.G. Huskilson, President and Chief Executive Officer, Emera**

If Mr. Huskilson resigns his position he will be entitled to all compensation and benefits up to the effective date of resignation.

If Mr. Huskilson is terminated for cause, he will not be entitled to compensation upon or following such termination.

If he is terminated without cause, he shall be entitled to 24 months' compensation based upon annual salary, annual incentive at target, and car allowance in effect at the time, salary to termination date, any accrued but unused vacation time, health, dental and other such benefits for 12 months.

If there is a change of control of the ownership of the Company, such that any one party acquires 50 percent or more of voting securities and there is a substantial reduction in responsibilities or scope of authority, Mr. Huskilson may elect within three months following such substantial reduction in responsibilities or scope of authority to terminate employment and receive 24 months' compensation and 12 months of benefits.

Under any termination of employment by the Company, or as a result of death, all entitlement to Deferred Share Units (DSUs) previously granted in May 2006, which have not yet been vested at the date of such termination, or death shall vest immediately.

Mr. Huskilson becomes eligible to retire with an unreduced pension on June 30, 2012. He has agreed to advise the Company at least one year in advance of any proposed retirement. Information regarding pension entitlement is contained in the section entitled "Pension Plan Benefits".

Under all scenarios, unless otherwise noted, Mr. Huskilson shall be entitled to payments associated with PSUs, DSUs, and Stock Options according to the terms and conditions of the plans.

**N.G. Tower, Executive Vice-President and Chief Financial Officer, Emera Inc. and Nova Scotia Power Inc.**

If Ms. Tower resigns her position she will be entitled to compensation and benefits up to the effective date of resignation.

If Ms. Tower is terminated for cause, she will not be entitled to compensation upon or following such termination.

In the event of termination without cause, she is entitled to a lump sum equal to 12 months' compensation based upon annual salary, annual incentive at target, and car allowance in effect at the time, salary to termination date, any accrued but unused vacation time, health, dental and other such benefits for 12 months or until she obtains new employment benefit coverage.

Any unvested Performance Share Units (PSUs) held at the date of termination will be prorated.

If there is a change of control of the ownership of the Company, such that any one party acquires 50 percent or more of voting securities and there is a substantial reduction in responsibilities or scope of authority, Ms. Tower may elect, within three months following such substantial reduction in responsibilities or scope of authority, to terminate employment and receive 12 months' compensation calculated on the basis of her annual salary and target bonus then in effect.

Ms. Tower becomes eligible to retire with an unreduced pension on March 31, 2019. Information regarding pension entitlement is contained in the section entitled "Pension Plan Benefits".

Under all scenarios, unless otherwise noted, Ms. Tower shall be entitled to payments associated with PSUs, DSUs, and Stock Options according to the terms and conditions of the plans.

**R.R. Bennett, President and Chief Executive Officer, Nova Scotia Power Inc.**

If Mr. Bennett resigns his position he will be entitled to compensation and benefits up to the effective date of resignation.

If Mr. Bennett is terminated for cause, he will not be entitled to compensation upon or following such termination.

In the event of termination without cause, he is entitled to a lump sum equal to 12 months' compensation based upon annual salary, annual target bonus and car allowance in effect at the time, salary to termination date, any accrued but unused vacation time, health, dental and other such benefits for 12 months.

In addition, if Mr. Bennett is terminated without cause any special Deferred Share Unit grants received in 2008 will vest immediately.

Any unvested Performance Share Units (PSUs) held at the date of termination will be prorated.

If there is a change of control of the ownership of the Company, such that any one party acquires 50 percent or more of voting securities and there is a substantial reduction in responsibilities or scope of authority, Mr. Bennett may elect, within three months following such substantial reduction in responsibilities or scope or authority, to terminate employment and receive 12 months' compensation calculated on the basis of his annual salary and target bonus then in effect.

Mr. Bennett becomes eligible to retire with an unreduced pension on October 31, 2017. Information regarding pension entitlement is contained in the section entitled "Pension Plan Benefits".

Under all scenarios, unless otherwise noted, he shall be entitled to payments associated with PSUs, DSUs, and Stock Options according to the terms and conditions of the plans.

**W.D. O'Connor, Chief Operating Officer, Emera Energy Inc.**

If Mr. O'Connor resigns his position he will be entitled to compensation and benefits up to the effective date of resignation.

If Mr. O'Connor is terminated for cause, he will not be entitled to compensation upon or following such termination.

Mr. O'Connor's employment contract does not contain change of control provisions.

In the event of termination without cause, he is entitled to a lump sum equal to 12 months' compensation based upon annual salary in effect at the time, annual salary to termination date, and any accrued but unused vacation time.

Mr. O'Connor becomes eligible to retire in 2020. Information regarding pension entitlement is contained in the section entitled "Pension Plan Benefits".

Under all scenarios he shall be entitled to payments associated with PSUs, DSUs, and Stock Options according to the terms and conditions of the plans.

**W.J. Crawley, President and Chief Executive Officer, ICD Utilities Limited**

If Mr. Crawley resigns his position he will be entitled to compensation and benefits up to the effective date of resignation.

If Mr. Crawley is terminated for cause, he will not be entitled to compensation upon or following such termination.

Mr. Crawley's employment contract does not contain change of control provisions.

In the event of termination without cause, Mr. Crawley would be paid in accordance with common law.

Mr. Crawley becomes eligible to retire with an unreduced pension on December 31, 2018. Information regarding pension entitlement is contained in the section entitled "Pension Plan Benefits".

Under all scenarios, unless otherwise noted, he shall be entitled to payments associated with PSUs, DSUs, and Stock Options according to the terms and conditions of the plans.

**Shares Authorized for Issuance Under Equity-Based Compensation Plans**

The following table shows shares authorized for issuance under the Senior Management Stock Option Plan and the Employee Common Share Purchase Plan as of December 31, 2010. There are no equity-based compensation plans that were not approved by Shareholders.

| Plan Category | (A) Number of shares to be issued upon exercise of outstanding options | (B) Weighted-average exercise price of outstanding options | (C) Number of shares available for future issuance under equity compensation plans (excluding column (A)) |
|---|---|---|---|
| Equity-based compensation plans approved by shareholders | | | |
| - Senior Management Stock Option Plan | 2,146,078 | $21.02 | 1,664,822 |
| - Employee Common Share Purchase Plan | N/A | N/A | 442,444 |
| Total | 2,146,078 | $21.02 | 2,107,266 |

### Aggregate Indebtedness of Directors and Executive Officers and Indebtedness Under Securities Purchase or Other Programs

The Company does not have a program that allows for the provision of loans to Directors or Officers, and the Company is not intending to initiate such a program. In addition, there is no program to allow loans or indebtedness under any share purchase program.

As of the date of this Circular there was no indebtedness of the Directors to the Company.

As of the date of this Circular, except for routine indebtedness, there is no indebtedness of Executive Officers and other employees to Emera or its subsidiaries.[1]

### Material Transactions

During the year, insiders of the Company and its affiliates, including Directors, Executive Officers, proposed nominee Directors or their associates or corporations they controlled, did not have any material interest, direct or indirect, in any transaction or in any proposed transaction that has materially affected or will materially affect the Company.

### Management Contracts

There are no functions of management which are performed by a person or company other than the Directors, Executive Officers or other employees of the Company.

### Directors' and Officers' Insurance

The Company's Articles of Association provide for the indemnification of Directors and Officers against liability incurred by them in the proper performance of their duties as Directors and Officers of the Company.

The Company purchases Directors' and Officers' insurance coverage. This coverage provides protection for Directors and Officers in cases where they incur a liability as a result of their activities as a Director or Officer of the Company. For the year ending December 31, 2011 this insurance provides for a maximum coverage of $100,000,000 per claim and in the aggregate. The premium for this insurance is approximately $370,000.

### Audit Committee Information

For information regarding Emera's Audit Committee, including its Charter, composition, relevant education and experience of its members, Audit Committee oversight, policies and procedures for the approval of non-audit services and auditors' service fees, please refer to Emera's Annual Information Form available on SEDAR at www.SEDAR.com or by contacting the Corporate Secretary of the Company.

Notes:
(1) As applicable to Emera, "routine indebtedness" includes: (i) loans made on terms no more favourable than loans to employees generally, for which the amount remaining unpaid does not exceed $50,000; (ii) loans to full-time employees, fully secured against their residence and not exceeding their annual salary; and (iii) loans for purchases on usual trade terms, or for ordinary travel or expense advances, or similar reasons, with repayment arrangements in accordance with usual commercial practice.

# Statement of Corporate Governance Practices

Emera and its Board of Directors are committed to high standards of corporate governance because we believe they are fundamental to achieving strong corporate performance and generating long-term shareholder value.

The Board regularly reviews corporate governance to ensure industry best practices are observed and to continually improve governance and disclosure.

The Board of Directors' Nominating and Corporate Governance Committee annually reviews the Company's Corporate Governance Practices and, where appropriate, the Committee recommends revisions to those Practices.

## 1. Board of Directors

### Director Independence

All Emera Directors are independent from management, except Christopher G. Huskilson, who is the President and Chief Executive Officer of the Company. To be considered independent, a Director must be independent as defined under applicable Canadian securities laws and, in particular, must be free of any direct or indirect material relationship which could, in the view of the Board of Directors, be reasonably expected to interfere with the Director's independent judgment. Use of the term "independent" in relation to a Director in this Circular shall refer to the foregoing meaning of that term. None of the independent Directors receive remuneration from Emera other than Directors' retainers, fees or retainers for service as Chair of the Board or Chair of a Committee. Mr. J.D. Eisenhauer receives a retainer and meeting fees from Emera's subsidiary, Nova Scotia Power Inc. (NSPI).

To assure the Board's independence, the Company's Articles of Association provide that no more than two Directors may be employees of the Company or of a subsidiary or affiliate of the Company. Christopher G. Huskilson, as President and Chief Executive Officer of the Company, is the only Director employed by the Company.

## 2. Board of Directors Charter

The Board of Directors believes that clear accountabilities lead to the best governance and, therefore, maintains a Charter for the Board. In November 2010 the Board of Directors adopted a revised Charter which is attached to this Circular as Appendix "A".

Under the Charter, the Board is responsible for overseeing the management of the business of the Company and for providing stewardship and governance to ensure the viability and growth of its business.

The Charter emphasizes the duties and responsibilities of the Board in matters of independence and integrity, strategic planning, risk responsibility, leadership and succession, financial reporting, corporate communications and public disclosure, and corporate governance.

### Strategic Planning

Pursuant to the Board of Directors Charter the shaping of the Company's strategy is one of the primary roles of the Board. Directors participate in the development of the corporate strategy which determines the annual and longer-term objectives for the Company. The Directors regularly evaluate progress made in pursuing that strategy.

The President and Chief Executive Officer, in collaboration with Executive Officers and the Board of Directors, develops a strategic plan which is presented to the Directors at a mid-year strategic retreat for approval.

### Risk Management

Under the Board of Directors Charter, the responsibility of the Board to oversee risk is articulated. The Charter provides that the Board shall oversee the implementation by management of appropriate systems to identify, report, and manage the principal risks of Emera's business. It requires the Board to consider the Company's risk tolerance. The Board will also review Emera's annual insurance program and uninsured exposure and its business continuity and disaster recovery plans. The Board is to receive regular updates on the status of risk management activities and initiatives. Finally, under the Charter the Board has a duty to approve and monitor processes that provide reasonable assurance of compliance with applicable legal and regulatory requirements.

### Directors Meet without Management

There were 32 Board and Committee meetings during 2010. At each Board and Committee meeting as a matter of course, an opportunity is provided for an in-camera session at which management is not present and, if necessary, the

President and Chief Executive Officer (who is the only non-independent member of the Board) is also excluded. In 2010, the Board met without management at a portion of each regularly scheduled Board meeting, being five separate occasions. On two of those occasions, the Board also met without the President and Chief Executive Officer being present. In 2010, the members of the Audit Committee met without management for a portion of five of the Committee meetings, including the four regularly scheduled quarterly meetings at which the Company's annual and interim financial statements and management's discussion and analysis are reviewed.

The Board has adopted a practice of holding evening sessions before the day of a formal Board Meeting. As required and at least once a year, the independent Directors conduct such an evening session to the exclusion of all management including the President and Chief Executive Officer.

**Independent Chair**

The Chair of the Board, Mr. John T. McLennan, is an independent Director. The Articles of Association of the Company mandate that the Chair of the Board and the Chief Executive Officer must be separate individuals.

**Chair of the Board of Directors Mandate**

Pursuant to the Chair of the Board of Directors Mandate, the Chair is responsible to lead the Board to fulfill its duties effectively, efficiently and independent of management. The Chair ensures Board and Shareholder meetings function effectively, provides leadership of the Board and its Committees and provides advice and counsel to Directors and the Chief Executive Officer. The Chair participates in the recruitment of Directors and the assessment of their performance.

The Chair of the Board of Directors Mandate is attached to this Circular as Appendix B.

**Directors' Membership on Other Public Company Boards**

Emera monitors the participation of Directors on other company's boards to ensure a balance of time is available to attend to Emera's governance needs. Many of the Company's Directors do serve as Directors of other reporting issuers. Details of these positions for each Director are set forth in their biographies earlier in this Circular. Membership on other public company boards is generally viewed positively by Emera in that it provides a Director with additional perspective and insight that is beneficial in performing their duties for the Company. Each of the Directors is required to ensure these other positions do not negatively impact their ability to perform as Directors of the Company.

The biographies of Director nominees earlier in the Circular describe the public company board memberships during the last five years. Mr. Edgeworth and Mr. Buchanan are both members of the board of Pembina Pipeline Corporation, however, this common board membership is not considered to impair the ability of these Directors to exercise independent judgment as members of our Board.

**Board Size**

The Articles of Association provide that the number of Directors on the Company's Board must not be less than eight and not more than fifteen.

**Majority Voting for Election of Directors**

The confidence of shareholders in the actions of the Board and management are important, and in order to provide a mechanism for shareholders to express that confidence in each Director, the Board adopted a Majority Voting Policy for Directors in February 2008. The Policy states:

> *Should a Director nominee, in an uncontested election at a meeting of shareholders of Emera whereby Directors are to be elected, receive a majority of "withheld" votes for his or her election as a Director, the individual shall submit his or her resignation to the Board for consideration promptly following such shareholders' meeting. The votes determining such action shall be those votes validly voted by proxy and those votes validly voted in person at such shareholders' meeting.*

The Directors who received a majority "for" vote at the shareholders' meeting shall consider whether or not to accept the resignation submitted by a Director that received a majority of "withheld" votes for his or her election as a Director. If there are less than three such Directors, the entire Board shall consider whether or not to accept the resignation.

A news release disclosing the Board's determination shall be issued within 90 days following the date of the shareholders' meeting. If the resignation is rejected by the Board, the news release shall include the reasons for rejecting the resignation.

## 3. Position Descriptions

### Chair of the Board

The Chair of the Board has a Mandate that is reviewed by the Nominating and Corporate Governance Committee on an annual basis (see Appendix B to this Circular). The most recent revisions to this Mandate were approved in February, 2011.

### Committee Chairs

All of the Committees have Charters which set out duties and responsibilities. It is the responsibility of each Committee Chair to ensure that the Committee carries out its duties and responsibilities. The various Committees review their Charters on an annual basis.

### Position Description for CEO

The roles and responsibilities of the President and Chief Executive Officer are contained in his employment contract and in the Articles of Association which provide that he is chief executive for the Company. The President and Chief Executive Officer's employment contract is negotiated by the Management Resources and Compensation Committee and is approved by the Board of Directors.

## 4. Orientation of Directors and Continuing Education

The Board and management believe that for new Directors to be effective in their roles they must be knowledgeable about the Company, its strategy, strengths and challenges. As well, effectiveness is enhanced as the new Directors form a collegial working relationship with other members of the Board in order to best bring their skills and knowledge to the operation of the Board.

New Directors to the Emera Board of Directors receive an orientation to the Company that familiarizes them with the businesses, investments and key personnel of the Company and allows them to effectively integrate with other Board members.

### Orientation Process

The following are the elements of the orientation process.

Key documents of the business are provided. These include the following:

(a) the most recent annual and interim management's discussion & analysis and financial statements; most recent management information circular and annual information form:
(b) the Board and Committee Charters;
(c) the most recent strategic plan and business plan;
(d) a guide to the Company's management structure;
(e) insider trading guidelines;
(f) the Emera Group of Companies Standards for Business Conduct;
(g) recent minutes of the meetings of the Board and Committees.

An orientation session is attended by the President and Chief Executive Officer, the Chief Financial Officer and such other Executive Officers or leaders of key subsidiaries as the President deems appropriate. The Chair also attends the orientation meetings with the new Directors. Existing Directors are encouraged to attend.

The orientation session is designed to provide a forum for new Directors to meet senior management and become familiar with their areas of responsibility. It also covers such topics as: the Company's structure, operations and assets; its strategy; the human resources of the Company; and the operation of the Board and related governance processes at the Company. It also includes a tour of certain sites and facilities of the Company's business.

The most recent orientation session conducted was in the summer of 2010 in preparation for Ms. Chrominska and Mr. Sergel joining the Board of Directors in September 2010.

### Continuing Education for Directors

The oversight function of Directors is enhanced when they are well informed about the Company's businesses and its industry. Management continually seeks opportunities to update, educate and inform the Directors in areas they request or that management determines are relevant to issues facing the Company.

### Management Reports

The Board and Committees receive briefing reports and material from management in advance of all meetings. Regular communications are provided to the Directors between meetings to provide updates on developments that might affect Emera's business and that of its subsidiaries.

The Board is also provided with opportunities to make site visits to operational facilities to assist Directors to more fully understand the business.

**Directors Updates and Briefings**

Communications between the Board and management occur apart from regularly scheduled Board and Committee meetings in the form of oral and written briefings or specially-called meetings which update Directors on business, operational or technical matters relevant to the Emera group of companies.

From time to time the Board receives specialized presentations from external parties and management on various matters of significance to the Company.

Directors participated in education sessions and received education materials about specific topics in 2010 as follows:

**Continuing Education for Directors**

| Education Presentations | Date | Participants |
|---|---|---|
| Presentation by external advisor to the Management Resources and Compensation Committee about the Company's executive compensation program in relation to the Canadian Coalition for Good Governance 2009 Pay for Performance Principles. | February 2010 | Management Resources and Compensation Committee (MRCC) |
| Presentation on new accounting standards related to financial instrument disclosures and related items. | February 2010 | Audit Committee |
| Annual Presentation on Environmental Oversight for Directors, including a review of the Company's Environmental Governance Structure and review of the 2009 Annual Environmental Report | May 2010 | Board |
| Presentation on the Fuel Adjustment Mechanism of the Company's subsidiary, Nova Scotia Power Inc. | May 2010 | Audit Committee |
| Presentation on market research on utilities, power and pipelines by external expert and energy industry update at Board Strategy meeting. | June 2010 | Board |
| Enterprise risk presentation, including a review of the strategic risks facing the Company, mitigation strategies, management responsibility, and oversight responsibility of the Board and Board Committees, and the report of an external consultant on the results of a risk assessment survey. | September 2010 | Board |
| Executive Compensation presentation including the purpose and design of the Company's executive compensation program, the role of the MRCC in relation to the executive compensation program, the role of the MRCC's independent advisor and the role of advisors engaged by the Company. | September 2010 | Board |
| Presentation by external advisor to the MRCC on Say on Pay and other Shareholder Initiatives. | September 2010 | MRCC |
| Directors' Education Session on United States Generally Accepted Accounting Principles (US GAAP) and the Company's transition to US GAAP, including registration with the U.S. Securities and Exchange Commission. | October 2010 (with an additional session held in November 2010) | Board |

**Guideline for Directors' Attendance at Education Sessions**

The Board of Directors adopted a guideline in 2008 for Directors' attendance at education sessions conducted by external organizations. The purpose of the guideline is to encourage Directors to participate in education sessions from time to time that are directly related to the business of the Company and the performance of their duties as a Director of the Company. The guideline provides that Directors are entitled to reimbursement for related out-of-pocket expenses incurred in attending an education session, including conference registration fees, and to compensation for attendance at approved education sessions at the rate per day equivalent to the current compensation for Directors' attendance at a Board or Committee meeting. Independent Directors who wish to attend an education session are required to request the approval of the Chair of the Board of Directors to attend a particular education session and receive compensation in accordance with the guideline.

**Board Dinners with High Potential Employees**

The Board of Directors holds an annual dinner to which are invited members of the Company's senior management that have been identified as having a high potential to be promoted to senior executive positions. The annual dinner with high potential employees supports and promotes the Company's executive succession planning and is a valuable part of the Board's continuing education about those succession plans. Directors provide feedback to management about the high potential employees they meet at such dinners which is incorporated into the ongoing succession planning.

**5. <u>Ethical Business Conduct</u>**

The Board recognizes the importance of establishing and promoting integrity and ethical business practices throughout the Company. The Board encourages and promotes a culture of ethical business conduct.

**Corporate Disclosure Policy**

The Board has approved a formal Corporate Disclosure Policy. The purpose of the Disclosure Policy is to ensure that communications to investors and potential investors are timely, factual and accurate, and that the information is disseminated in accordance with all applicable legal and regulatory requirements to the investing public, analysts, and the media.

**Standards for Business Conduct**

The Board has adopted a written code entitled The Emera Group of Companies Standards for Business Conduct (Standards for Business Conduct) for all Directors, Officers, and employees. Directors, Officers and employees are required to annually sign an acknowledgement that they have reviewed and understand the Standards of Business Conduct. The document is available on Emera's website at www.emera.com or a copy may be obtained by contacting the Executive Vice-President Human Resources, Emera Inc., P.O. Box 910, Halifax, Nova Scotia B3J 2W5.

The Company has also adopted a protocol entitled Procedures for the Reporting of Irregularities and Dishonesty (otherwise commonly referred to as a whistleblower's policy). Reports under the Standards for Business Conduct and Procedures for the Reporting of Irregularities and Dishonesty are addressed by the Company, and on a quarterly basis the Internal Audit department informs the Audit Committee of all reports and their status. The Company has established a confidential business conduct helpline hosted by an external service provider called "The Ethics Hotline", which is available to employees to report allegations of conduct not in compliance with the Standards for Business Conduct.

**No Material Change Report**

There has been no material change report filed that pertains to any conduct of a Director or Executive Officer that constitutes a departure from the Standards of Business Conduct.

**Conflicts of Interest**

Under the Company's Articles of Association, Directors are required to declare any interest which they may have in a matter before the Board. In any matter requiring approval of the Board, a Director is prohibited by the Articles from voting in respect of the matter in which the Director is interested.

The Directors have also instituted a policy which requires them to submit their resignation as a Director if there is a significant change in their principal occupation. The resignation is then reviewed by the Board to determine if the circumstances warrant acceptance of the resignation. This practice ensures that the change of principal occupation does not result in a conflict-of-interest situation for the Director and ensuring that the Director is able to continue to make their contributions to the Board or maintain the skills which resulted in that person initially becoming a member of the Board.

## 6. Nomination of Directors

Under Emera's Articles of Association, the Nominating and Corporate Governance Committee is responsible for providing the Company with a list of nominees for election as Directors to be included in the Company's Management Information Circular prior to each annual meeting of shareholders of the Company. Pursuant to the Articles, the Committee creates and reviews the criteria for selecting Directors by assessing the personal qualities, business experience, and qualifications of current Directors. The Committee also assesses the Company's ongoing needs and circumstances, geographical representation and the overall experience of the Board. The Committee considers the background, skills and experience desired for Directors in view of the Company's strategy and activities, and provides a plan for the recruitment of nominees who can provide those characteristics. Director nominees must, in the opinion of the Committee, be able to contribute to the broad range of issues with which the Directors must deal and who are able to devote the time necessary to prepare for and attend meetings of the Board and Committees of the Board to which they may be appointed.

The Committee uses the services of a search consulting firm in order to assist it in identifying suitable Director candidates. Potential Director candidates are interviewed by the Chair of the Board, the Committee Chair, and the President and Chief Executive Officer, and in most cases by additional Directors. Reference checks and background checks may also be carried out on potential Director candidates.

Under the Company's Articles, the list of Director nominees must include the President and Chief Executive Officer. It may include one other senior executive of the Company, as determined by the Committee, but the President and Chief Executive Officer is the only Executive of the Company nominated for election at the annual shareholders meeting on May 4, 2011.

Director nominees must not have reached 70 years of age, except in certain exceptional circumstances. The Committee may determine and recommend that an individual be permitted to serve as a Director beyond age 70 because of the individual's contribution and skills. Such determination will be made annually. One of the Directors nominated for election (Dr. Cook-Bennett) will be age 70 at the time of the shareholders' meeting on May 4, 2011, and the Committee has determined and recommended to the Board of Directors that because of her unique and valuable contribution, she should continue to serve as a Director.

In 2010, the Nominating and Corporate Governance Committee anticipated the expected turnover of Directors in advance of their retirement from the Board and implemented an effective succession plan that included creating overlap between new Directors and retiring ones.

Under a Corporate Governance Practice adopted in 1994, the Committee must also provide that no fewer than 25 percent of the members of the Board of Directors are female. The list of Director nominees for the annual shareholders' meeting on May 4, 2011 includes 4 females out of 12 Director nominees, or 33 ⅓ percent.

## 7. Compensation

### Executive Compensation

The Board of Directors determines the compensation for the Company's senior executives, including the Officers of the Company, on the recommendation of the Management Resources and Compensation Committee. See the section of this Circular entitled "Compensation Discussion & Analysis" above with respect to compensation of the Company's Named Executive Officers.

### Director Compensation

The Company is committed to attracting highly skilled and experienced Directors to serve on its Board and, therefore, strives to maintain appropriate and competitive compensation for Directors.

The Board of Directors determines the compensation for the Company's Directors on the recommendation of the Nominating and Corporate Governance Committee.

The Nominating and Corporate Governance Committee annually reviews the compensation of the Directors to ensure the form of compensation is appropriate. In doing so, the Committee carries out a review of the compensation practices of Canadian publicly-traded companies similar to Emera's operations and size and ensures the Directors are appropriately compensated for the responsibilities and risks involved in being a Director. The review is based upon publicly available information concerning Director's compensation, public surveys and comparison of compensation of Directors of publicly-traded companies in Canada.

**Director Share Ownership Guidelines**

The share ownership guidelines for Directors of the Company effective January 1, 2010 make it mandatory that all Directors must each own three times the total cash and equity-based annual Board retainer for Directors, equal to $180,000. Under these guidelines, each Director must own Emera shares or DSUs, or a combination of the two, worth $180,000 by the earlier of either September 2013 (in accordance with the September 2008 amendment of the guidelines) or within five years of the appointment date of a new Director.

Details of each Director's share and DSU ownership, and status under the share ownership guidelines, is shown in each nominee Director's biography earlier in this Circular.

**Directors Are Increasing Their Share/DSU Ownership Over Time**

The Directors increase their share based ownership by at least $25,000 per annum. The Board of Directors believes that the share ownership guidelines for Directors and the payment of a mandatory $25,000 portion of Director compensation in DSUs only contributes to the alignment of the interests of Directors with those of shareholders. DSUs are only payable on retirement from the Board.

## 8. Committees of the Board of Directors

The Board is committed to effective and efficient operation in carrying out its oversight responsibilities. As such, it strongly supports the work of its three standing Committees to which certain functions are delegated as set forth in written charters. They are:

- the Audit Committee;
- the Management Resources and Compensation Committee; and
- the Nominating and Corporate Governance Committee.

In September 2010, the Board established the Technology and Development Committee as an ad hoc Committee of the Board, Chaired by the Company's President and Chief Executive Officer. Its primary purpose is to assist the Board in evaluating opportunities for the Company in the area of strategic development, particularly related to identification and evaluation of new lines of business and new technologies, and making recommendations to the Board as appropriate.

In consultation with the Chair of the Board, the Board and its Committees may retain outside advisors at the Company's expense as they deem necessary.

**Audit Committee**

The Audit Committee of the Board of Directors assists the Board in discharging its oversight responsibilities concerning the integrity of Emera's financial statements, its internal control systems, the internal audit and assurance process, the external audit process and its compliance with legal and regulatory requirements.

The Committee is comprised of independent Directors only, who are financially literate, none of whom may be employees of Emera, or employees of any affiliate of Emera. The Committee shall be responsible for reviewing and recommending to the Board for approval the annual and interim financial statements and all related management's discussion and analysis.

The Committee evaluates and recommends to the Board the external auditor and the compensation of such external auditor. Once appointed, the external auditor shall report directly to the Committee, and the Committee oversees the work of the external auditor concerning the preparation or issuance of the auditor's report or the performance of other audit, review or attest services for Emera. The Committee reviews management controls and processes concerning the administration of investment activities, financial reporting, and funding of the pension plans.

The Company's internal auditor also reports directly to the Audit Committee, and the Committee oversees the appointment, replacement, or termination of the internal auditor.

**Nominating and Corporate Governance Committee**

The Nominating and Corporate Governance Committee assists the Board with a variety of matters relating to corporate governance. These include the responsibility for providing the Company with a list of nominees for election as Directors to be included in the Company's Management Information Circular prior to each annual meeting of shareholders of the Company (for more information about the nomination of

Directors see section 6 of this Statement, above, entitled *Nomination of Directors*). The Committee consists of independent Directors only, selected by the Board. The Articles of Association of the Company provide that the Chair of the Board may not be a member of the Committee.

The Committee is responsible for assessing on an annual basis the effectiveness of the Board, individual Directors, and its various committees. The assessment of the Chair of the Board is conducted by the Committee.

The Nominating and Corporate Governance Committee is responsible for developing and communicating the Company's approach to corporate governance issues, and reviews and approves Emera's disclosure of corporate governance practices. The Committee keeps abreast of best governance practices in the industry and continually evaluates the governance practices of Emera. It reviews any disclosure of the Company's corporate governance practices in accordance with applicable rules and regulations.

The Nominating and Corporate Governance Committee oversees the orientation of new Directors. This list of orientation activities is reviewed each time that a new Director joins the Board, and updated as required.

Other duties and responsibilities of the Committee include: (a) assisting the Board and its Committees in determining Committee composition, as well as reviewing the mandate of each Committee for submission to the Board; (b) making recommendations to the Board on all components of non-employee Director compensation including the Board Chair and Committee Chairs; (c) ensuring procedures are in place to assist the Board in obtaining information necessary to carry out its duties and ensuring the Board has access to executive management; and (d) reviewing the Company's Standards for Business Conduct.

**Management Resources and Compensation Committee**

The Management Resources and Compensation Committee is comprised of independent Directors only. The Company's Articles of Association require that the Chair of the Board not be a member of the Committee. The Committee reviews overall compensation, including salary and benefit policies and recommends such policies to the Board of Directors.

It reviews corporate goals and objectives relevant to the corporate strategy and recommends such goals and objectives to the Board of Directors. The Committee ensures that an assessment of the President's performance in relation to these goals and objectives, is completed. It makes recommendations to the Board of Directors relating to the President's compensation level, participation in incentive-compensation plans, and equity-based plans based on the Committee's evaluation. It makes recommendations about senior management compensation, incentive-compensation plans, and equity-based plans. It approves grants of stock options, performance share units (PSUs) (previously referred to as restricted share units or RSUs) and deferred share units (DSUs) in accordance with the provisions of the respective plans. It reviews executive compensation disclosure prior to the Company releasing such information to the public.

It recommends executive officer appointments to the Board of Directors for approval. It ensures there is an adequate succession planning process for senior management and other potential senior management candidates of the Company and its affiliates and actively participates in that process with a review conducted on an annual basis. It reviews share ownership guidelines for Executive Officers. It ensures there are appropriate labour relation strategies in place and regularly reviews management's direction and decisions made in support of effectual labour and employee relations.

9. **<u>Board and Director Performance Assessments</u>**

The Board recognizes the value of regularly assessing its effectiveness in order to find ways to improve its performance and the performance of the Chair, individual Directors, and the Board Committees. In February 2009, the Board of Directors adopted a guideline for the performance of assessments of the effectiveness of the Board of Directors, its Committees, and assessment of the Chair of the Board.

**Assessment Process**

Under the guideline, each year the Nominating and Corporate Governance Committee determines the process by which Director performance assessments will be conducted. The process may include the use of questionnaires, one-on-one interviews with Directors by the Board Chair or such other process as the Committee determines appropriate. A report on the assessment is provided to the Board of Directors. Issues arising from the assessment are identified, an action plan developed and progress monitored by the Nominating and Corporate Governance Committee.

**2010 Board/Director Performance Assessment**

In December 2010, the Chair of the Board interviewed each external Emera Director as part of the 2010 Board and Director Performance Assessment. A series of questions was sent to each Director in advance for their consideration on a number of themes, including:

*Assessment of the Board:* the Directors were asked to assess the effectiveness of the operation of the Board of Directors and suggest improvements.

*Assessment of the Board Committees:* the Directors were asked to assess the effectiveness of the operation of the Committees.

*Self-Assessment and Peer Assessment:* the Directors were asked to assess their own performance as Directors, including what might make them more effective as Directors, and comment on the performance of their peer Directors on the Board.

The assessment of the Chair of the Board was conducted in a meeting of all Directors that was led by the Chair of the Nominating and Corporate Governance which excluded the Board Chair.

The Nominating and Corporate Governance Committee received the findings and the results of the 2010 Board and Director Performance Assessment. The Chair worked to develop an action plan based on those findings where necessary. That action plan was shared with the Board, and progress on the action plan will be reported to the Committee and the Board from time to time.

**Communications with Directors**

Shareholders may communicate with the Chair of the Board or other independent Directors as a group by mailing (by regular mail or other means of delivery) to the corporate head office at 18th Floor, 1894 Barrington Street, Barrington Tower, Halifax, N.S., B3J 2A8, in a sealed envelope marked “Private and Confidential – Attention Chair of the Board of Directors of Emera Incorporated”.

**Additional Information**

Additional information relating to the Company may be found on SEDAR at www.sedar.com. The Company's financial information is contained in its comparative financial statements and management’s discussion and analysis for the financial year ended December 31, 2010.

For copies of the Company’s financial statements and management’s discussion and analysis, you may also contact the Office of the Corporate Secretary at 1894 Barrington Street, Suite 1800, Barrington Tower, P.O. Box 910, Halifax, Nova Scotia, B3J 2W5. Telephone: (902) 428-6096; Facsimile: (902) 428-6171.

Appendix A

**EMERA INCORPORATED**
**BOARD OF DIRECTORS CHARTER**

The fundamental responsibility of the Board of Directors (the “Board”) is to provide stewardship and governance to Emera Incorporated (“Emera”) to ensure the viability of the Company by overseeing management of the business.

In addition to the powers set out in Emera’s Articles of Association, the Board shall have the following duties and responsibilities.

## Independence and Integrity

The Board shall be comprised of a majority of “independent directors” as defined from time to time under applicable legislation and the rules of any stock exchange on which Emera’s securities are listed for trading.

The Chair shall be an “independent director” as defined above.

The Board shall review and approve standards for ethical business conduct for employees, officer and directors of Emera and its subsidiaries and affiliates and a procedure for monitoring compliance with such code throughout the Company.

The Board shall satisfy itself as to the integrity of the Chief Executive Officer and executive officers and the creation of an integrity-based culture throughout the Company.

The Board shall, through its oversight of management, continue to foster an organization which operates in an environmentally responsible manner.

## Strategic Planning

The Board shall provide oversight and guidance on the strategic issues facing Emera.

The Board shall oversee a strategic planning process resulting in a strategic plan which shall be approved on an annual basis and will take into account, among other things, the opportunities and risks of the business.

The Board shall regularly consider Emera’s strategy, evaluate progress made in pursuing that strategy, and consider any adjustments to the strategy that may be required from time to time.

The Board shall review and approve the Company’s financial objectives, plans and actions, including significant capital allocations and expenditures.

The Board shall review and approve all material acquisitions, dispositions, projects, business plans, and budgets.

## Risk Responsibility

The Board shall oversee the implementation by management of appropriate systems to identify, report, and manage the principal risks of Emera’s business. The Board will consider Emera’s risk tolerance. The Board will also review Emera’s annual insurance program and uninsured exposure and Emera’s business continuity and disaster recovery plans.

The Board shall receive regular updates on the status of risk management activities and initiatives.

The Board shall approve and monitor processes that provide reasonable assurance of compliance with applicable legal and regulatory requirements.

**Leadership and Succession**

The Board shall oversee policies and practices to enable the Company to attract, develop and retain the human resources required by the Company to meet its business objectives.

The Board shall appoint executive officers and delegate the necessary authority for the conduct of the business.

The Board shall establish annual performance expectations and corporate goals and objectives for the Chief Executive Officer and monitor progress against those expectations.

The Board shall evaluate the performance, and, following a review of recommendations from the Management Resources and Compensation Committee, approve compensation for executive officers.

The Board shall oversee the succession planning program for the Chief Executive Officer and other key executive positions from time to time.

**Financial**

The Board shall oversee the financial reporting and disclosure obligations imposed on the Company by laws, regulations, rules, policies and other applicable requirements.

The Board will review the financial performance of the Company and declare dividends as appropriate.

The Board shall approve for release to the public as necessary the Company's financial statements, management's discussion and analysis (MD&A) and earnings releases prepared by management and oversee the Company's compliance with applicable audit, accounting and reporting requirements.

The Board shall review the quality and integrity of Emera's internal controls and management information systems.

**Corporate Communications and Public Disclosure**

The Board shall review and approve a formal corporate disclosure policy and oversee policies and processes for accurate, timely and appropriate public disclosure.

The Board shall oversee systems for receiving feedback from stakeholders and monitor such feedback received by the Company.

**Governance Responsibility**

The Board is responsible for overseeing the Company's corporate governance policies and practices and shall maintain a set of corporate governance practices that are specifically appropriate to the Company.

Pursuant to the Articles, the directors shall appoint one of the directors as Chair of the Board and such director shall not be an employee of Emera or any of its affiliates or subsidiaries.

The Board shall establish appropriate structures and procedures to allow the Board to function independently of management and in the interests of the Company and its shareholders.

The Board, in carrying out its mandate, shall appoint committees of the Board and delegate certain functions to those committees, each of which shall have its own written charter. Notwithstanding such delegation, the Board retains its oversight function and ultimate responsibility for these delegated functions.

The Board shall oversee a process for the selection of qualified individuals for board nomination, and shall approve selection criteria for identifying director candidates taking into account the competencies and skills the Board as a whole should possess.

The Board shall undertake regular evaluation of the Board, the Chair of the Board, the Board committees and individual Directors.

The Board shall undertake regular evaluation of Directors' compensation.

The Board shall review this Charter annually to ensure it appropriately reflects the Board's stewardship responsibilities.

Appendix B

## EMERA INCORPORATED
## CHAIR OF THE BOARD OF DIRECTORS
## MANDATE

### Responsibility

The fundamental responsibility of the Chair of the Board of Directors (the "Chair") of the Company is to lead the Board to fulfil its duties effectively, efficiently and independent of Management. The Chair provides leadership to the Board in reviewing and deciding upon matters which exert major influence on the manner in which the Company's business is conducted and ensure effective operation of the Board. The Chair acts in a general advisory capacity to the President and Chief Executive Officer and other officers in all matters concerning the interests and management of the Company.

### Independence

The Chair shall be an independent Director in accordance with the Company's Articles of Association and applicable legislation.

Specifically, the Chair shall perform the duties as required in the Company's Articles of Association and shall:

### Meetings

1. Oversee the discharge by the Board in an efficient and effective manner the Board's obligations and responsibilities including those relating to corporate governance matters.

2. Preside at, determine that a quorum is present to conduct business, and manage Board meetings and shareholder meetings.

3. Plan and organize the activities of the Board in consultation with the Chief Executive Officer and Corporate Secretary and with Committee Chairs and individual directors as necessary.

4. Oversee the distribution of information to the Board to support decision making in manageable form and sufficiently in advance of the meeting to allow adequate lead time for effective study and discussion of business under consideration.

5. Review and provide input to meeting agendas and ensure sufficient time during Board meetings to fully discuss agenda items.

### Leadership

6. Counsel collectively and individually with members of the Board, utilizing their capacities to the fullest extent necessary to optimize the effectiveness of the Board and its Committees.

7. Oversee and monitor Committees' work to see that delegated Committee functions are carried out and reported to the Board.

8. Provide the Board, Committees and individual Directors with leadership to assist them in their duties and responsibilities, and actively participate in the selection of Committee members and Committee Chairs. The Chair shall actively oversee the succession planning for Committee Chairs.

9. Provide advice, counsel and mentorship to individual Directors, to assist them to improve performance or, when appropriate, to transition them from the Board.

Board Management Relationship

10. Manage and clarify the boundaries between Board and Management responsibilities while fostering a constructive and professional working relationship.

11. Facilitate effective communication between Directors and Management, both inside and outside of Board meetings.

12. Oversee the Board's independence from Management and ensure that the independent Directors have adequate and regularly scheduled opportunities to meet to discuss issues without Management present.

13. Act as the principal liaison between the Board and management working closely with the Chief Executive Officer with a view to ensuring that management strategies, plans and performance are clearly represented to the Board.

Director Recruitment, Retention, Education

14. With the Nominating and Corporate Governance Committee, actively participate in the recruitment and retention of Directors, and oversee appropriate processes to determine that the Board of Directors has the requisite skill sets needed by the Company.

15. Support the orientation of new Directors and the continuing education of existing Directors.

Assessment/Evaluation

16. In conjunction with the Board's Nominating and Corporate Governance Committee, support and assist in the conduct of an annual assessment of the effectiveness of the overall Board and its members.

17. Assess, in conjunction with the Management Resources and Compensation Committee, the performance of the Chief Executive Officer and provide input with respect to compensation and succession.

Other

18. At the request of the Chief Executive Officer, or where appropriate, represent the Board at official functions and meetings with major shareholder groups and other stakeholder groups.

19. Carry out any other appropriate duties and responsibilities assigned by the Board.

**Requirement:**

**Applicable emissions targets legislated and compliance accomplished for past year and current year, and how compliance is planned for the test year and five years into the future.**

**Submission:**

NSPI is required to manage air emissions within annual limits regulated by Nova Scotia Environment.

For 2011, the cap on annual air emissions for sulphur dioxide ($SO_2$) is 72,500 tonnes. The cap for annual emissions of nitrogen oxides ($NO_x$) is 21,365 tonnes. The cap on annual emissions of mercury was originally 65 kg; however, an announcement by the Provincial Government in July, 2010 extended the 65 kg emission cap until 2014. The 2011 mercury emission allowance has now been set at 100 kg. Additionally 2010-2011 marks the first Compliance Period for which NSPI is required to meet an emission limit for greenhouse gas (GHG) with a limit of 19.22 million MT. Based on the 2010 GHG emission total of 9,250,254 tonnes and an emission credit of 580,000 tonnes, the 2011 GHG emission limit will be 10,549,746 $CO_{2eq}$ tonnes. NSPI manages its actual air emissions by purchasing and combusting specific quality fuels, increasing production from renewable energy sources, procuring power from other sources (imported power and Independent Power Producers) and in some cases by installing emission control equipment.

In addition to these fleet-wide caps, each generating facility operates within a permit which requires ground level ambient air quality to be maintained, plume visibility to be within limits and, in some cases, specific emission standards to be met. This is accomplished by maintaining the plant equipment in good working order and operating the plant within the specified limits.

In 2006, the first Low $NO_x$ Combustion Firing System (LNCFS) was installed, at Lingan 3. In 2007, two additional units (Lingan 2 and 4) were fitted with LNCFS. In 2008, three additional units were fitted with LNCFS. The seven LNCFS units installed will enable NSPI to continue to meet the $NO_x$ emission cap of 21,365 tonnes up to 2015.

In late 2009 NSPI installed mercury abatement equipment on seven of its solid fuel generating units to aid in meeting the reduced mercury cap. The mercury abatement equipment consists of front-end chemical additives applied to the fuel prior to combustion and activated carbon injection (ACI) upstream of the particulate control device. The mercury abatement equipment has been tested with the solid fuel units using different fuel blends to characterize retention of mercury in ash. The capital addition of a baghouse at Trenton 5 in 2009 provides necessary fuel flexibility as well as improved mercury capture.

The cap for the $SO_2$ will remain at 72,500 tonnes until 2015. The greenhouse gas emission limit will be 18,500,000 tonnes in the 2012-2013 Compliance Period. For 2010-2014 these caps will be met primarily by purchasing specific quality fuel, continuing to add renewable energy and managing the load through energy conservation and efficiency programs.

**Requirement:**

**Quantities and classes of shares, and price as of filing.**

**Submission:**

<u>NSPI</u>

As of December 31, 2010 NSPI had 112.2 million issued and outstanding common shares. The shares are not publicly traded.

As of December 31, 2010 NSPI had 5.4 million 5.9 percent Series D First Preferred Share Units.

As of March 16, 2011 the Series D preferred shares were trading at $28.20.

<u>Emera</u>

As of December 31, 2010 Emera had 114.6 million issued and outstanding common shares. As of April 29, 2011 the shares were trading at $31.50.