P-886 ORIGINAL N-1(a)

Nova Scotia Utility and Review Board

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

- and -

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

RECEIVED
OCT 10 2006
Nova Scotia
Utility and Review Board

Notice of Application

- and -

Direct Evidence of NSPI

October 2006

REDACTED

NOVA SCOTIA UTILITY AND REVIEW BOARD

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

- and -

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

NOTICE OF APPLICATION

TO: The Nova Scotia Utility and Review Board

1. Nova Scotia Power Incorporated ("NSPI" or "the Company") is a public utility subject to regulation by the Nova Scotia Utility and Review Board ("the Board") and conducts its business in Nova Scotia where it is engaged in the generation, transmission and distribution of electrical power.

2. Above-the-line customer rates were last adjusted by Order of the Board effective March 10, 2006. Since that date there have been material changes in circumstances such that for the test year beginning in January 2007, unless above-the-line rates are re-adjusted, the Company will be unable to continue to provide the service expected by customers and will be unable to earn a just and reasonable return.

3. The Company therefore makes this Application for certain revisions to its rates, charges and regulations, effective April 1, 2007.

4. In support of this Application is filed the Direct Evidence of NSPI, which consists of the following:
   - 1.0 Introduction
   - 2.0 Fuel and Purchased Power
   - 3.0 Regulatory Amortization and Depreciation
   - 4.0 Operating, Maintenance and General
   - 5.0 Capital Structure and Financing
   - 6.0 Rate Base
   - 7.0 Load Forecast
   - 8.0 Cost of Service
   - 9.0 Revenue Forecast and Proposed Rates
   - 10.0 Miscellaneous Charges
   - 11.0 Outstanding Approvals and Deferrals
   - 12.0 A Final Word

5. The Direct Evidence also includes Appendices containing additional material supporting the Application.

6. There are several regulatory proceedings ongoing or anticipated in 2006 that could affect the NSPI revenue requirement. This Application does not take into account any additional spending (revenue requirement) that may result from these decisions by the UARB, or from additional directives that may be ordered by the UARB as a result of this Application. NSPI requests any additional spending, resulting from UARB decisions or directives be included in the 2007 Rate Decision and subsequently as part of the 2007 Compliance Filing.

7. On the evidence filed in support of this Application, NSPI asserts that the Order sought by the Application is in the public interest and in the interest of NSPI.

8. NSPI therefore seeks an Order, effective April 1, 2007, approving:

   a) The 2007 revenue requirement as set out in the Application so as to enable the Company to recover the reasonable costs of providing service to customers and to meet its financial obligations including provision for a just and reasonable return;

   b) The rates, charges and regulations as filed in this Application;

   c) Adjustments to the rates, charges and regulations as necessary to reflect decisions and directives in related proceedings, or as may be determined by the UARB in this Application;

   d) The return on common equity and return on rate base as set out in the Application.

9. Certain of the evidence filed in support of the Application is being filed with the request that the Board hold it in confidence and such evidence has been redacted from the copies of this Application that are being made publicly available. Specifically certain portions of Section 2.0 Fuel and Purchased Power, Section 6.0 Rate Base, Appendix A, Financial Tables and Appendix G, Cost of Service, have been redacted and filed in confidence with the Board.

10. The evidence sought to be filed in confidence relates to aspects of the Company's fuel and purchased power forecasts and expenses, including the Company's natural gas purchase contract; the purchase and use of heavy fuel oil; and the purchase and transportation of solid fuels. The public disclosure of this commercially and financially sensitive information will harm the Company and its customers by placing it at a material disadvantage in solicitations and negotiations with present and future suppliers. Additionally, some of the information is subject to confidentiality agreements with third parties.

11. Pursuant to the Board's practice in these matters, with the approval of the Board, the Company will immediately make available copies of the complete and un-redacted Application to any party who has a good faith interest in accessing the confidential information, who would not be otherwise conflicted, and who signs an agreement to maintain the confidentiality of the information.

12. NSPI also seeks Directions from the Board providing for:

    a) Pre-hearing procedures, including:

        i) Public Notice of this Application;

        ii) Approval of the request to file certain of the evidence in confidence as referred to in paragraphs 9, 10 and 11 herein;

        iii) Directions regarding the terms on which interested parties may have access to confidential information that may be sought by parties during the course of this proceeding;

        iv) Interventions and evidence from Intervenors;

        v) Information Requests;

        vi) A process for the establishment of an Issues List for the Hearing; and

        vii) A process for the expedient resolution of any pre-hearing procedural issues.

    b) Setting a date for the hearing of this Application in January of 2007 allowing sufficient time so that any Order arising out of this proceeding may be implemented effective April 1, 2007; and

    c) Such other matters as the Board deems fit.

DATED at Halifax Regional Municipality, in the Province of Nova Scotia this 10th day of October 2006.

NOVA SCOTIA POWER INCORPORATED

Per: _____

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President and Chief Executive Officer

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TABLE OF CONTENTS

1.0 INTRODUCTION 1

1.1 Fuel Expense Continues To Increase In 2007 2

1.2 This Application Recovers Costs Previously Approved By The UARB 2

1.3 NSPI Seeks No Change In 2007 For All Other Costs Other Than Pension 3

1.4 Replacement For Extra Large Industrial Interruptible Rate (ELIIR) 3

1.5 Working With Customers And Other Stakeholders 4

1.6 Requested Adjustment To Rates 5

2.0 FUEL AND PURCHASED POWER 6

2.1 Overview 6

2.2 Responding to the UARB 9

2.3 Energy Ventures Analysis Testimony 15

2.4 Fuel Testimony of NSPI 38

3.0 REGULATORY AMORTIZATION AND DEPRECIATION 65

3.1 Overview 65

3.2 Regulatory Amortizations 66

3.3 Revised Depreciation Rates 69

3.4 Additions to Plant 70

4.0 OPERATING, MAINTENANCE & GENERAL 71

4.1 Overview 71

4.2 Operating Efficiently 72

4.3 Operating Outlook 75

4.4 Operating Group Summary 75

4.5 Five Year OM&G Forecast 91

5.0 CAPITAL STRUCTURE AND FINANCING 94

5.1 Overview 94

5.2 Credit Ratings 95

5.3 Return on Equity: Compensation for the Equity Investor 100

5.4 Financing Outlook 101

5.5 Testimony of Dr. Roger A. Morin 107

6.0 RATE BASE 132

6.1 Overview 132

6.2 Details of Rate Base 132
7.0 LOAD FORECAST 140
7.1 Overview 140
7.2 Models 141
7.3 Economic Indicators 142
7.4 2007 Energy Forecast 144
7.5 2007 Peak Demand Forecast 153
8.0 COST OF SERVICE 157
8.1 Overview 157
8.2 New Rate Replacing ELIIR and 2P-RTP 158
8.3 Direct Expenses Associated with BMPC's "Additional Energy" 159
8.4 Cost of Serving the Unmetered Class 160
8.5 Summary 161
9.0 REVENUE FORECAST AND PROPOSED RATES 162
9.1 Overview 162
9.2 Below-The-Line Classes 164
9.3 Above-The-Line Classes 166
10.0 MISCELLANEOUS CHARGES 181
11.0 OUTSTANDING APPROVALS AND DEFERRALS 182
11.1 Pending UARB Review 182
11.2 Q1 Fuel Deferral 183
11.3 2P-RTP Deferral 184
12.0 A FINAL WORD 186

Appendices

Appendix A – Financial Tables
Appendix B – Operating, Maintenance and General Expenses
Appendix C – Operating Maintenance and General Expense 5 Year Forecast
Appendix D – Credit Rating Reports
Appendix E – Dr. Roger A. Morin Exhibits
Appendix F – Load Forecast Report
Appendix G – Cost of Service Study
Appendix H – Proposed Tariffs
Appendix I – Miscellaneous Charges
Appendix J – Proposed Regulation Changes

1.0 INTRODUCTION

Nova Scotia Power Inc. (NSPI) is applying for new electricity rates based on a test year beginning January 1, 2007. Two key factors bring about this request:

1. High fuel prices and increased volumes;
2. The recovery of expenses previously approved by the UARB.

In 2007 NSPI will maintain Operating, Maintenance and General (OM&G) expenses unchanged from its 2006 Compliance Filing (2006C) except to reflect increased pension expense. NSPI seeks no change in its return on equity or capital structure.

NSPI and its customers operate and live in a world of high and volatile commodity fuel prices. This is reflected in the cost of gasoline for the cars we drive, heating oil for our homes and higher prices generally for the goods and services we use every day. The cost to generate and distribute electricity is subject to the commodity costs of fuel.

Like other businesses, NSPI needs to recover its costs from customers and have an opportunity to earn a fair return. When increased input costs are not recovered from customers, or when recovery of necessary expenditures is delayed, the financial health of the utility can suffer. This is reflected in lower credit ratings, higher borrowing costs and greater difficulty attracting investment.

NSPI is currently experiencing a combination of influences that must be addressed in order to maintain the financial health of the Company. Input costs are increasing while the Company has been delayed in recovering expenses that have been approved and spent. The financial community has noticed these problems and NSPI's credit rating has been recently downgraded.

NSPI has been responsive to the directives of the UARB. NSPI manages all controllable costs effectively, which is reflected in this Application.

In this Application, NSPI seeks recovery of increased fuel costs, pension expense, and amortization of previously approved deferred costs. Approval of the requested rates for 2007 will help return the utility to strong financial health and reinforce a balanced, fair and principled approach to setting electricity rates in Nova Scotia.

1.1 Fuel Expense Continues To Increase In 2007

NSPI uses a combination of fuels to generate electricity. The fuel mix depends on global commodity prices within an overall framework that limits environmental emissions.

Consistent with other utilities, NSPI faces higher commodity costs for fuel. These fuels are used in generating approximately 90 percent of the electricity produced by NSPI. The increases in commodity costs for 2007 are not currently provided for in rates. Prices for all these fuels are driven by global market conditions. This Application includes a more detailed description of these global market conditions.

The Application also describes NSPI's management of fuel costs within the context of these volatile global markets. It describes NSPI's compliance with directives from the Board regarding fuel procurement contained in the 2006 Rate Decision.

The fuel forecast for 2007 is $498.7 million, or $68.5 million higher than the fuel amount currently provided for in rates.

1.2 This Application Recovers Costs Previously Approved By The UARB

The UARB previously directed recovery of Section 21 taxes already incurred (S21 taxes) be deferred until 2007, as well as recovery of taxes from the first quarter of 2005 already incurred (Q1 taxes). The third year of the depreciation phase-in settlement approved by the Board also begins in 2007. Each of these items is explained in detail, including the respective Board Orders.

Although recovery has been previously approved by the UARB, the Board's direction is required to now incorporate these three items into electricity rates.

1.3 NSPI Seeks No Change In 2007 For All Other Costs Other Than Pension

NSPI seeks no change in the 2007 revenue requirement for all other costs other than pension expenses. Also NSPI seeks no change to its return on equity.

NSPI's efforts to control costs and to deliver quality service are described in detail in this Application.

On June 21, 2006 Standard & Poor's rating agency (S&P) downgraded NSPI's credit ratings from BBB+ to BBB. NSPI is not requesting an increase in return on equity or capital structure, nor has the Company included any additional costs for 2007 associated with this downgrade. The credit rating downgrade will have long-term cost implications for NSPI and its customers as the Company re-finances existing debt, attempts to issue new capital or enters into new fuel procurement arrangements.

More detail on NSPI's capital structure is provided in this Application.

1.4 Replacement For Extra Large Industrial Interruptible Rate (ELIIR)

In the 2006 Rate Decision[1], the UARB directed NSPI to develop and file a new rate to be effective January 1, 2007 for the customers formerly served under the ELIIR rate. On September 28, 2006 the UARB released its Decision[2], providing the choice of two different rates.

Because of the timing and complexity of the ELIIR-2 Decision, this Rate Application has been prepared using a preliminary estimate of the ELIIR-2 rate. NSPI will not have certainty about the ELIIR-2 rate until the Compliance Filing has been approved and the

[1] NSPI 2006 Rate Case, UARB Decision, NSUARB – NSPI – P – 882, March 10, 2006, paragraph 715.
[2] NSPI 2006 ELIIR Replacement, UARB Decision NSUARB – NSPI – P – 883, September 28, 2006.

customers select their new rate. The ELIIR-2 rate, and the relevant portions of this Application, will be adjusted during this proceeding in order to reflect the rate(s) ultimately selected by the ELIIR-2 customers. This may affect the percentage rate increase for other customers; however, changes to the ELIIR-2 rate do not change NSPI's 2007 revenue requirement.

1.5 Working With Customers And Other Stakeholders

As a regulated cost-of-service utility, NSPI plans for the efficient use of power generation, transmission and distribution assets. These plans are based upon a 'test year' – a forecast of the future.

The Company must actively manage its costs in order to have the opportunity to earn its allowed rate of return under rates set by the regulator. A fair rate of return is a fundamental principle of rate-making and benefits all customers by allowing the Company to raise investment capital efficiently in equity and debt markets. A fair return is essential to providing customers with a reliable, safe and cost-effective system.

In this application process the Company provides information to stakeholders to identify and explain key issues. NSPI desires an application process that is efficient, collaborative and well managed. Where possible, the Company will look for opportunities to work with the Board and stakeholders to improve the pre-hearing and hearing processes. NSPI seeks the leadership of the UARB to keep the matters in issue realistic and focused and to keep the hearing productive and on topic. This will allow the Company and customers alike to receive a fair and timely decision from the Board.

1.6 Requested Adjustment To Rates

NSPI's revenue requirement in 2007 is $1,197.6 million, which reflects increased fuel costs and the recovery of previously approved but deferred tax and depreciation costs. Based on current rates, this results in an $81.3 million shortfall in electric revenue requirement from the Above-The-Line (ATL) and ELIIR-2 classes. This Application requests an average revenue increase of 7.5 percent for these customers.

Based upon the evidence regarding revenue, cost of fuel, taxes and depreciation and other items affecting the Company, NSPI has prepared a Financial Outlook for the 2007 test year. This Financial Outlook is attached as Appendix A.

NSPI requests new electricity rates effective April 1, 2007. Due to the timing of the ELIIR-2 proceeding and of this Application, NSPI is seeking UARB approval of deferred recovery of actual increased fuel costs experienced in the first quarter of 2007. A true-up relating to the ELIIR-2 real time pricing mechanism is also requested. There are other items pending UARB decision in separate filings that, if approved, will be incorporated in the revenue requirement of the Compliance Filing.

New rates for 2007 will recover increased fuel expenses driven by global market conditions, increased pension expense, and expenses previously approved but deferred by the UARB. All other expenses are maintained without change for 2007.

2.0 FUEL AND PURCHASED POWER

2.1 Overview

The increased cost of fuel commodities for NSPI in 2007 is one of the driving factors in this Rate Application.

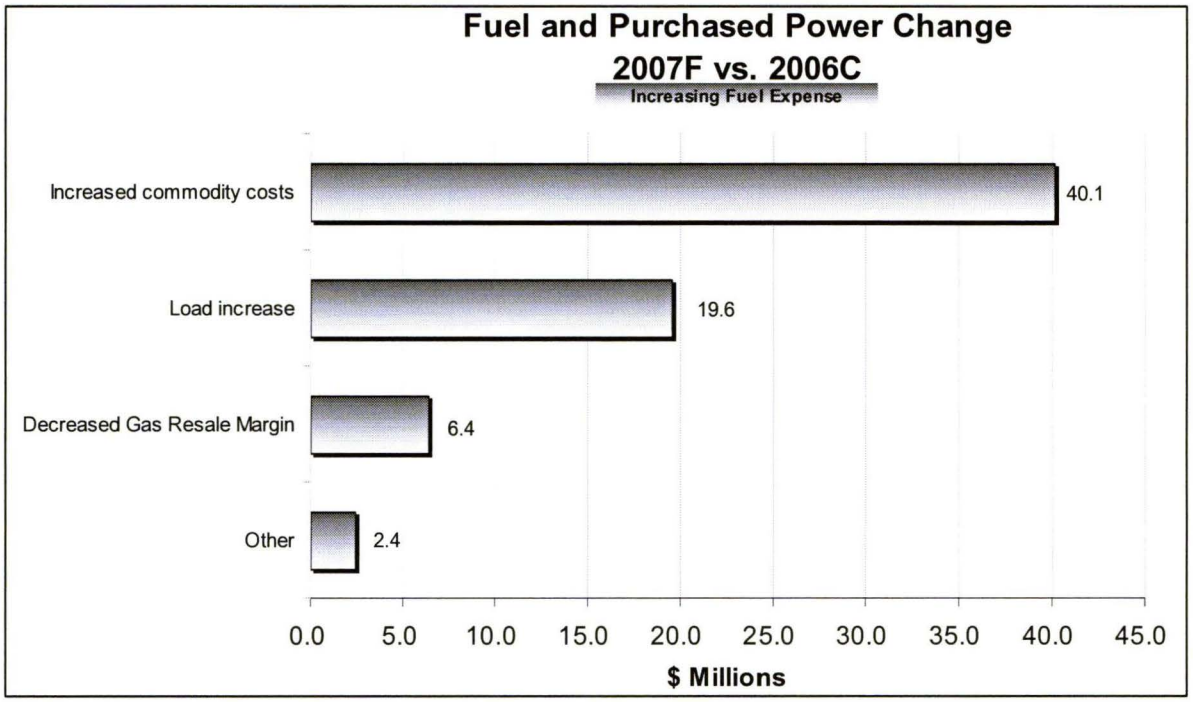
NSPI is responding diligently to the Board's directives from the 2006 Rate Decision. Updates on these activities are provided in Section 2.2 of the evidence.

The evidence of Energy Ventures Analysis Inc. (EVA) provides further context to market volatility and to NSPI's fuel procurement activities in Section 2.3. One of its principals, Emily Medine, provides fuel procurement expertise to NSPI.

NSPI's evidence with respect to the 2007 fuel and purchased power expense follows in Section 2.4. This section includes the Company's fuel procurement strategy, details on its fuel portfolio and NSPI's 2007 fuel forecast.

Current rates include fuel and purchased power expenses of $430.2 million. In 2007, these expenses are expected to be $498.7 million - $68.5 million higher than 2006C. The major components of this increased cost are shown in Figure 2.1. Each component is briefly described below and in more detail in Section 2.4.

Figure 2.1[3]



Increased Commodity Costs

Higher prices for oil, natural gas and solid fuels make up the majority of the increased commodity costs in the commodity pricing category. Heavy fuel oil (HFO) prices are the most significant contributor to this increase, adding [redacted] to total annual fuel costs.

NSPI's 2007 solid fuels cost recoverable from customers will be higher than 2006C primarily due to the expiration of the 2006 coal disallowance. While this reduced allowable fuel costs in 2006C by $15.7 million, it did not reduce NSPI's actual fuel costs.

The $40.1 million also reflects changes to the fuel mix and associated pricing, including higher import power and transportation costs.

[3]The variances depicted in the graph are calculated using standard accounting methodology for price and quantity variances. The quantity or "volume" variance ("Net Load Increase") is determined by taking the change in volume from 2006C to 2007 and multiplying by the original price. The price variance ("Increased Commodity Costs") reflects the change in price from 2006C to 2007 and the new quantity required.

Net Load Increase

In 2007, load is forecast to be 1 percent higher than in 2006C. The increased load results in a greater reliance on higher cost fuels such as oil and natural gas. This additional load adds $19.6 million to NSPI's overall fuel costs.

Decrease in Gas Resale Margin

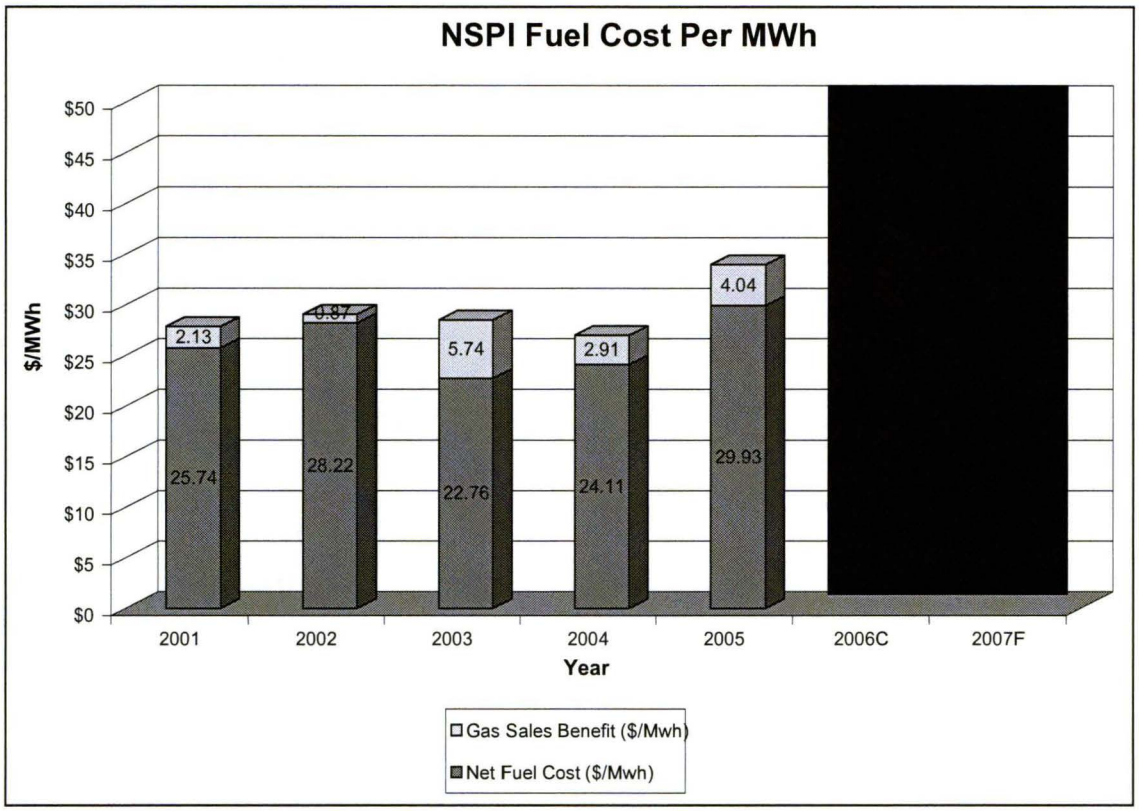
In 2007, there is an increase over 2006C in natural gas burn at Tufts Cove which results in a reduction in the amount of gas available to be sold. The increased gas burn results in a reduction of $6.4 million in 2007 in the natural gas resale margin, when compared to 2006C.

Other

[redacted] Offsetting this benefit are changes in generation equipment capacity and maintenance schedules, reduced hydro[4] as well as other miscellaneous variances. These are forecasted to increase fuel expenses by $2.4 million in 2007.

[4] The level of hydro generation forecast for 2007 is based on a 23-year long-term average.

Figure 2.2



As shown in Figure 2.2, the cumulative effect of the changes in fuel costs is a 15 percent increase in the fuel cost per megawatt hour of electricity produced over 2006C. Net fuel costs are forecast to increase from [redacted] in 2006C to [redacted] in 2007.

2.2 Responding to the UARB

NSPI has worked diligently to be responsive to the Board's fuel directives. The Company has listened to the Board and its customers and is addressing the issues brought forth in recent Rate Decisions.

On March 10, 2006 the Board issued its 2006 Rate Decision. In that Decision, the Board discussed fuel procurement and stated that it was:

> ...pleased with the dedication shown by NSPI towards improving its procedures in this very important area of NSPI's operations. The Board

> also notes that there appears to be general acceptance by the intervenors that NSPI has made significant improvements in the fuel procurement area...[5]

The Liberty Consulting Group ("Liberty") was engaged by the Board for the 2005 and 2006 Rate Proceedings and carried out reviews of NSPI's fuel procurement strategy, policies, procedures and contracts.

In Liberty's 2006 evidence, they noted significant progress and provided additional recommendations that were accepted by the Board:

> NSPI has made significant, positive change to its fuel portfolio strategy. The new strategy is clear, does away with the limitation of contract lengths, and provides for longer-term contracts with staggered expiration dates.[6]

NSPI continues to work with Liberty to improve its fuel procurement processes. The following section provides an update on the progress made on Liberty's recommendations regarding NSPI's procurement strategy, policies and procedures. As directed in the 2006 Rate Decision[7], NSPI filed a comprehensive status report with the Board on August 31st, 2006.

Planning

i. NSPI should immediately conduct an overall re-evaluation of its generating system to determine the optimum way of meeting new requirements for control of SO_2 emissions, as well as emissions of other pollutants of concern, from its generating plants.[8]

NSPI is undertaking an Integrated Resource Planning process that will fulfill the information requirement for this directive. This plan is being developed independent of this Rate Application.

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[5] NSPI 2006 Rate Case, UARB Decision, NSUARB – NSPI – P – 882, March 10, 2006, paragraph 44.
[6] NSPI 2006 Rate Case, Liberty Evidence, NSUARB – NSPI – P – 882, October 17, 2005, p. 29, Exhibit N-83.
[7] NSPI 2006 Rate Case, UARB Decision, NSUARB – NSPI – P – 882, March 10, 2006, paragraph 668.
[8] NSPI 2006 Rate Case, UARB Decision, NSUARB – NSPI – P – 882, March 10, 2006, paragraph 18.

Organization and Procedures

ii. NSPI should develop a more comprehensive set of fuel hedging policies and procedures that measure up to industry standards.[9]

NSPI has liaised with Liberty in regard to the recommendation to develop a more comprehensive set of fuel hedging policies. NSPI is working with its consultant Black & Veatch, to refine the objectives of the hedging policy. As the policy is developed it will be incorporated into NSPI's Fuel Procurement Policies and Procedures Manual.

iii. NSPI should continue to refine its own internal spreadsheet model for fuel procurement in order to bring it to a level of sophistication that permits evaluation of fuel-supply options and procurement decision-making on the basis of procuring that mix of fuels that will result in producing the lowest possible cost of electrical energy delivered to the bus-bar.[10]

NSPI is working to integrate the evaluation of the cost parameters through its combustion model in order to provide a fully evaluated cost to the bus-bar.

The following additional recommendations were made:

iv. develop a complete set of procedures for the procurement of purchased power;
v. continue to revise and refine the Fuel Procurement Policies and Procedures;
vi. continue to tighten the controls on the overall fuel procurement process.[11]

NSPI has developed the recommended set of procedures for the procurement of purchased power with the support and input from Board staff and Liberty. The new procedures incorporate the documentation requirements for the existing processes, procedures and control. The review and comments process with Liberty and the Board has provided NSPI with the ability to complete the detailed requirements of the directive.

[9] NSPI 2006 Rate Case, UARB Decision, NSUARB – NSPI – P – 882, March 10, 2006, paragraph 18.
[10] NSPI 2006 Rate Case, UARB Decision, NSUARB – NSPI – P – 882, March 10, 2006, paragraph 18.
[11] NSPI 2006 Rate Case, UARB Decision, NSUARB – NSPI – P – 882, March 10, 2006, paragraph 18.

NSPI, in consultation with Liberty, has addressed the comments in regard to revising and refining the Fuel Procurement Policies and Procedures.

NSPI has further developed its decision and approval recording processes on all fuel procurement functions. The format for the "Record of Procurement Approval and Decisions" document has been revised based upon Liberty input. NSPI is implementing the new documentation process to complete this recommendation.

Fuel Supply Portfolio

vii. continue to build the fuel supply portfolio so that the parameters currently set forth by NSPI in its Fuel Procurement Policies and Procedures are achieved by December 31, 2007.[12]

NSPI continues to build its portfolio with a target date of December 31, 2007 to meet the fuel portfolio guidelines. NSPI now has several multi-year contracts in place and continues to move closer to fulfilling the target percentage of contracted solid fuel required to meet these guidelines. Please refer to Figure 2.4 for more information on the status of NSPI's portfolio.

Affiliates

viii. NSPI should immediately bid on a fully competitive and arm's-length basis its sale of excess natural gas for a one-year term, and should arrange for and coordinate that bidding and the cancellation of the existing agreement with EES with all reasonable dispatch.[13]

NSPI has completed this directive.

ix. NSPI should also promptly conduct a complete and objective study of the net economic and other impacts of establishing an in-house capability to perform this sale function.[14]

[12] NSPI 2006 Rate Case, UARB Decision, NSUARB – NSPI – P – 882, March 10, 2006, paragraph 18.
[13] NSPI 2006 Rate Case, UARB Decision, NSUARB – NSPI – P – 882, March 10, 2006, paragraph 18.
[14] NSPI 2006 Rate Case, UARB Decision, NSUARB – NSPI – P – 882, March 10, 2006, paragraph 18.

NSPI has liaised with Liberty to develop terms of reference for a study to assess a method for selling excess natural gas. The study is proceeding and will be filed with the Board upon its completion.

x. There needs to be a comprehensive audit of affiliate transactions [15]

The Board directed Liberty to file a work plan by June 30, 2006 indicating that NSPI will be consulted and its opinion solicited. NSPI has provided input to the Board and has requested a meeting to discuss the scope of the work plan.

Fuel Procurement

In its 2005 Rate Decision, the UARB directed NSPI to obtain an in-house solid fuel expert[16]. NSPI has continued to work with an expert recruiting firm to obtain such an individual. This process has proven challenging due to location, size and nature of the utility. Further information is provided in Section 2.3.

In the 2006 Rate Decision, the Board requested quarterly reports on NSPI's progress in finding a suitable candidate[17]. As outlined in NSPI's July 31st quarterly report on this matter, NSPI continues to work to meet this directive.

[15] NSPI 2006 Rate Case, UARB Decision, NSUARB – NSPI – P – 882, March 10, 2006, paragraph 18.
[16] NSPI 2005 Rate Case, UARB Decision, NSUARB – NSPI – P – 881, March 31, 2005, paragraph 320.
[17] NSPI 2006 Rate Case, UARB Decision, NSUARB – NSPI – P – 882, March 10, 2006, paragraph 55.

Testimony of

Energy Ventures Analysis Inc.

1901 N. Moore Street, Suite 1200, Arlington, VA, 22209-1706

September, 2006

2.3 Energy Ventures Analysis Testimony

Energy Ventures Analysis, Inc. (EVA) has been engaged by Nova Scotia Power, Inc. (NSPI) to provide testimony in its 2007 Rate Application (2007 Application).

The 2007 Rate Application is driven in small measure by an increase in solid fuel costs on a dollar per megawatt hour basis. The greater proportion of increase is primarily driven by higher HFO costs, a decrease in the gas resale margin, an increase in the marginal cost of generation, and the expired fuel cost disallowance.

The components of solid fuel costs have changed with an increase in petroleum coke and domestic coal pricing and a decrease in low sulphur import coal costs. Accordingly, in this proceeding, EVA provides a brief review of all fuel markets (Section 2.3.1) followed by discussion of overall fuel price volatility (Section 2.3.2). Detailed testimony regarding NSPI's solid fuel procurement practices (Section 2.3.3) and NSPI's internal capabilities regarding the performance of its fuel procurement efforts (Section 2.3.4) are also reviewed. Finally, a brief discussion of the impact of credit rating on fuel purchase expense is provided (Section 2.3.5).

A number of utilities in North America have been forced to apply for rate increases in sequential years due to the unprecedented increases in fuel costs.

One example is the Tennessee Valley Authority (TVA). TVA is the largest public power company in the U.S., with 33 gigawatts of capacity. While not regulated by a utility commission, TVA operates pursuant to the TVA Act, which gives an independent board the sole responsibility for establishing rates. In July 2005, the TVA Board approved a 7.52 percent increase in firm wholesale electric rates largely related to increases in fuel and purchased power costs.[18] In

[18] http://www.tva.gov/news/releases/julsep05/budget.htm.

February 2006, the TVA Board approved another 9.95 percent increase in firm wholesale electric rates to cover natural gas and purchased power costs that were significantly higher than budgeted for 2006.[19] The increases were not larger because TVA generates 28 percent of its electricity from nuclear plants.

2.3.1 Fuel Market Outlook

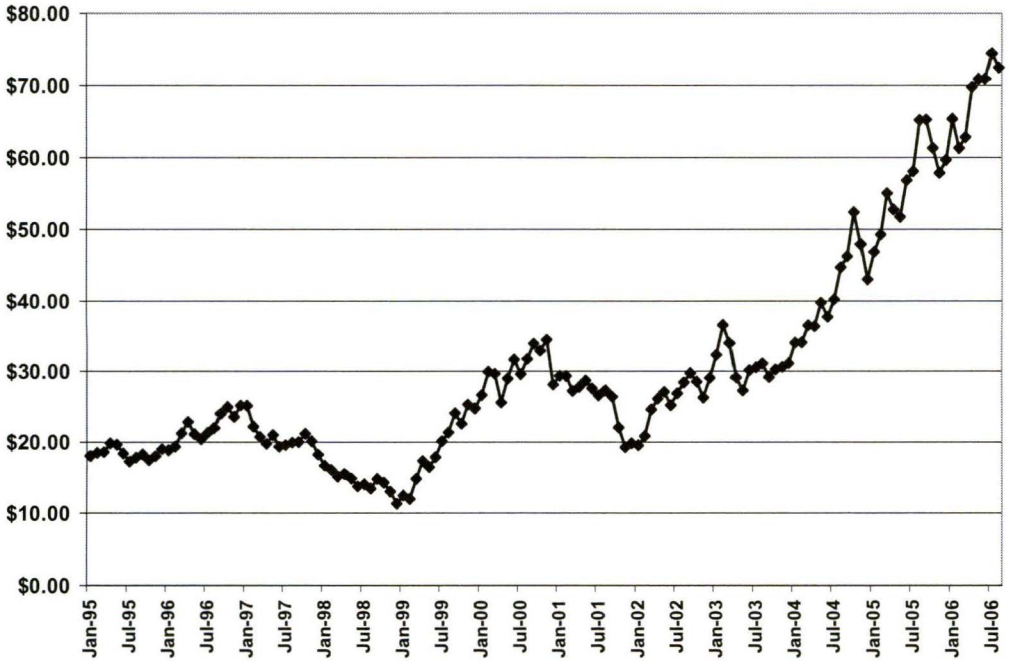
Petroleum Markets

World oil markets are at elevated levels, as shown in Figure 2.3.1. The high prices have been caused by strong demand, limited surplus capacity, potential or existing supply problems in Nigeria, Iran, Iraq, Venezuela and elsewhere, and weather, notably hurricane-related disruptions.

Figure 2.3.1

WEST TEXAS INTERMEDIATE PRICE (USD/BBL)

January 1995 - August 2006



[19] http://www.tva.gov/news/releases/janmar06/rate.htm.

Demand growth is expected to remain strong through 2007 despite some price-related conservation. As shown in Figure 2.3.2, demand growth is expected to be particularly strong in China, the U.S., and the other non-OECD countries.

Figure 2.3.2

GLOBAL PETROLEUM SUPPLY AND DEMAND (Million Barrels/Day)

	Year			Annual Change	
	2005	2006	2007	2006 v 2005	2007 v 2006
Demand [a]					
OECD					
U.S. (50 States)	20.7	20.8	21.3	0.5%	2.4%
U.S. Territories	0.4	0.4	0.4	0.0%	0.0%
Canada	2.3	2.3	2.3	0.0%	0.0%
Europe	15.6	15.6	15.7	0.0%	0.6%
Japan	5.4	5.4	5.5	0.0%	1.9%
Other OECD	5.3	5.4	5.5	1.9%	1.9%
Total OECD	**49.5**	**50.0**	**50.6**	**1.0%**	**1.2%**
Non-OECD					
Former Soviet Union	4.2	4.3	4.4	2.4%	2.3%
Europe	0.7	0.7	0.7	0.0%	0.0%
China	6.9	7.4	7.9	7.2%	6.8%
Other Asia	8.6	8.7	8.8	1.2%	1.1%
Other Non-OECD	14.0	14.6	15.1	4.3%	3.4%
Total Non-OECD	**34.4**	**35.6**	**36.9**	**3.5%**	**3.7%**
Total World Demand	**83.9**	**85.6**	**87.5**	**2.0%**	**2.2%**
Supply [b]					
OECD					
U.S. (50 States)	8.2	8.5	8.9	3.7%	4.7%
Canada	3.1	3.2	3.6	3.2%	12.5%
Mexico	3.8	3.8	3.7	0.0%	-2.6%
North Sea [c]	5.2	4.8	4.6	-7.7%	-4.2%
Other OECD	1.5	1.6	1.6	6.7%	0.0%
Total OECD	**21.8**	**21.9**	**22.4**	**0.5%**	**2.3%**
Non-OECD					
OPEC	33.9	34.0	35.1	0.3%	3.2%
Crude Oil Portion	30.0	29.8	30.5	-0.7%	2.3%
Former Soviet Union	11.7	12.1	12.5	3.4%	3.3%
China	3.7	3.8	3.7	2.7%	-2.6%
Other Non-OECD	12.8	13.2	13.8	3.1%	4.5%
Total Non-OECD	**62.2**	**63.1**	**65.1**	**1.4%**	**3.2%**
Total World Supply	**84.0**	**85.0**	**87.5**	**1.2%**	**2.9%**

Source: U.S. Department of Energy, June 2006, International Petroleum Supply and Demand, EVA

Supply growth is expected to occur from both OPEC and non-OPEC sources. Increases in Saudi Arabia and Iraq are expected to account for most of the near-term increases although production increases from Nigeria, Algeria, Libya, and the other OPEC nations are also expected to be significant. Non-OPEC

production increases are expected from the former Soviet Union, Brazil and Canada, plus the restoration of U.S. production in the Gulf.

The industry consensus is that world crude oil prices are expected to remain high in the near-term reflecting increases in demand, limited spare production capacity, and the geopolitical tensions in major oil-producing countries.

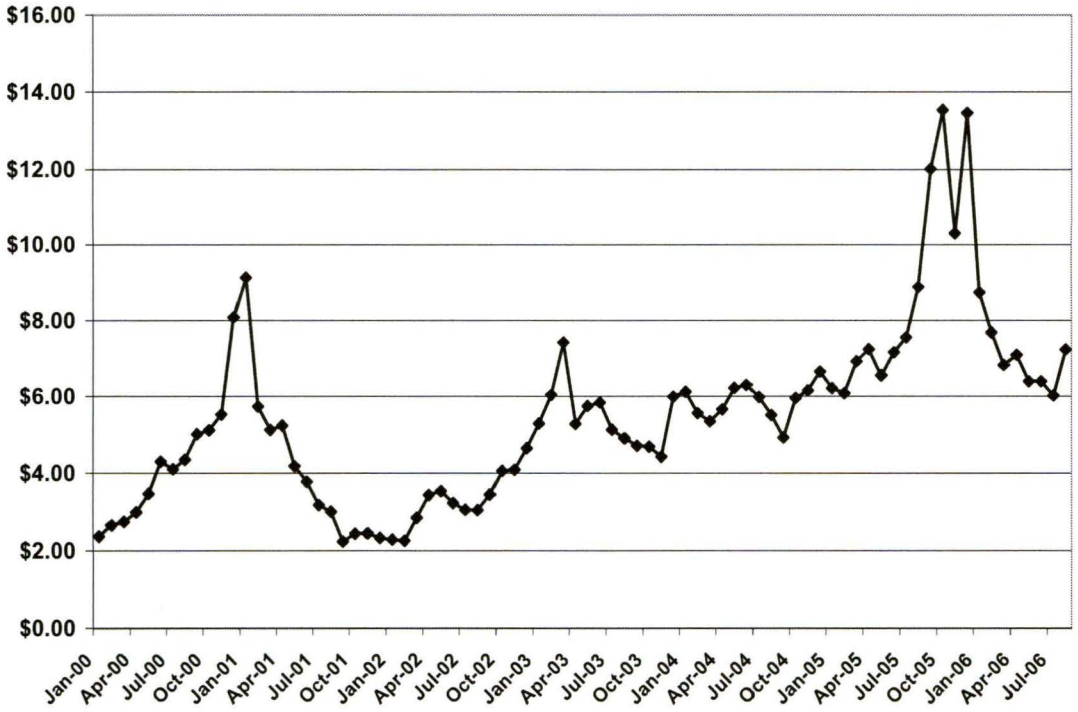
Natural Gas Markets

Natural gas pricing, like oil pricing, has been volatile. The active 2005 hurricane season combined with the disruption in production caused prices to spike to new record highs. As shown in Figure 2.3.3, prices since that time have fallen and while still high, are close to the top of the historical range. The decline is largely attributed to the unseasonably warm weather that resulted in high storage levels.

Figure 2.3.3

HENRY HUB NATURAL AVERAGE MONTHLY GAS PRICES (USD/MMBtu)

January 2000 - August 2006



The expectation is that natural gas prices will most likely revert to higher levels by next winter because of concerns about supply and continuing pressure from high oil market prices. Of course, any hurricane related disruption could cause prices to spike sooner.

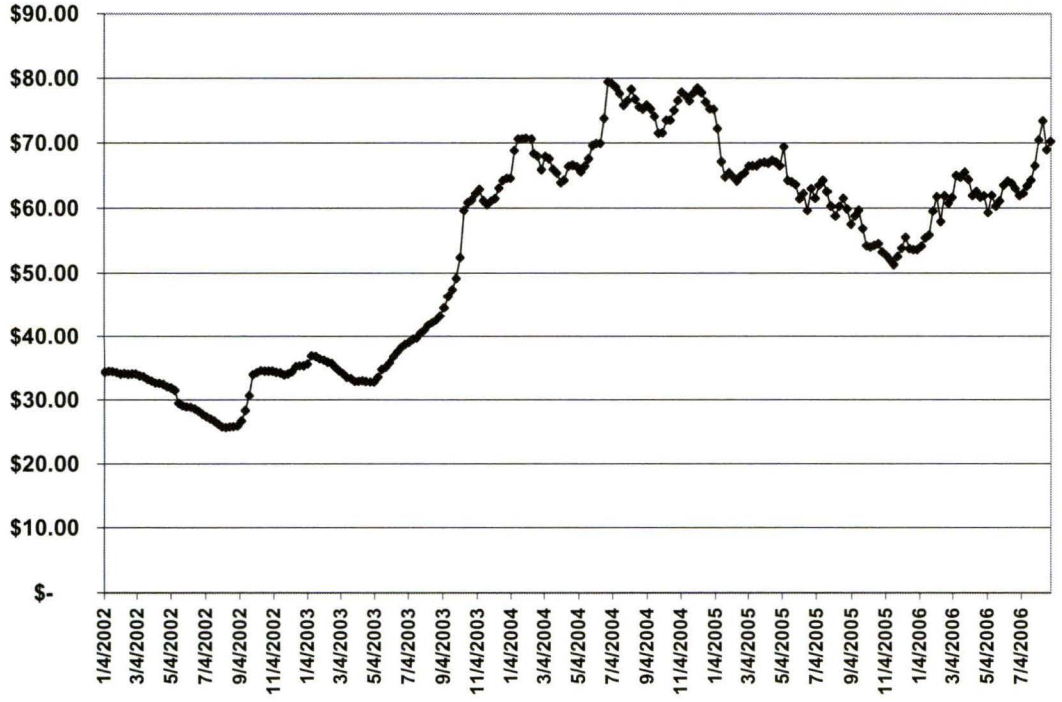
Coal Markets

Prompt[20] coal prices softened from the peak levels experienced in late 2003/early 2004 but did not return to the low levels experienced in 2002. In recent weeks, prompt coal prices have strengthened again in response to the hot summer in Europe and recent tightness in the freight market. As shown in Figure 2.3.4, pricing continues to be volatile with prices reacting in small increments to market events or even news of the day.

Figure 2.3.4

PROMPT API 2 PRICING (USD/Tonne ARA)

January 2002 - August 2006



[20] Deliveries within the next twelve weeks.

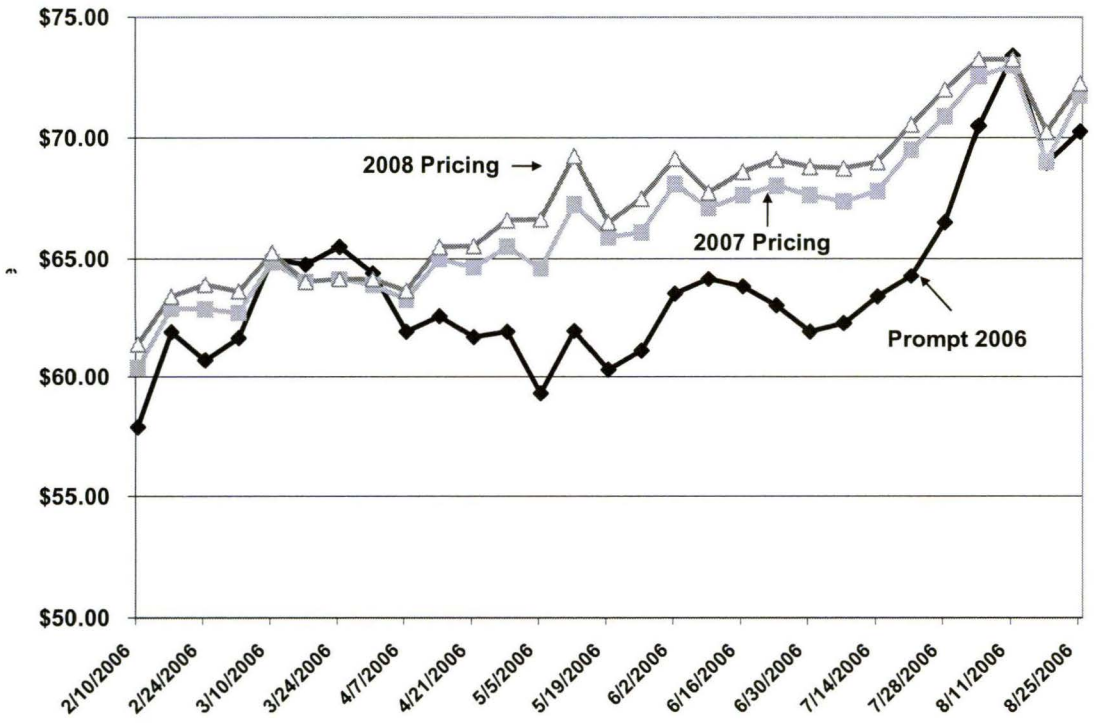
The softening in prompt coal prices in the second half of 2005 was expected by most analysts in response to the additional supply coming into the market that was developed in response to higher prices and profits. In Australia alone, five new mining projects came on line in the six months ending April 2006, most of which were developed for the export market. Despite the softness in prompt pricing in the first half of 2006, industry expectations in 2006 are for higher prices in 2007 and 2008 as shown in Figure 2.3.5. Between April and August 2006, the market was in what is referred to as *contango*, with future prices expected to be higher than current ones. When the market is in contango, producers are less willing to establish long-term contracts at current price levels. Generally, they will require either a higher levelized price or built in escalation.

Figure 2.3.5

PROMPT PRICING VERSUS THE FORWARD PRICE CURVES FOR API2

(USD/Tonne)

February 2006 - August 2006



The best way to describe the market is to say that it is uncertain. A wild card continues to be China, whose high economic growth triggered the initial run-up in prices in 2003. China's economic growth has slowed somewhat but is still expected to be strong. China's level of coal exports is difficult to predict but some experts expect thermal coal exports of 60 to 70 million tonnes and imports to exceed exports for metallurgical coal. Obviously, higher or lower exports could affect the global supply-demand balance and pricing.

China is not the only unknown. Labour could become a major issue in many of the exporting countries and could cause short-term disruptions. A month-long strike at the Drummond mine in Colombia has just ended. Elk Valley Coal in British Columbia narrowly averted a strike by agreeing to a 21.1 percent wage increase over a new five-year agreement plus retroactive wage increases of 9.1 percent. Labour unrest reflects the strong market prices for coal from which workers want to benefit. In the U.S., the United Mine Workers contract covering most of the eastern U.S. union coal production expires at the end of 2006 and could result in a disruption of production if a new agreement is not signed.

Petroleum Coke Markets

Petroleum coke (pet coke) is a by-product of the coking process that is used by some refineries in order to extract additional light oil. Pet coke has a high carbon content and low volatility and, if the sulphur content is higher than 2 percent, it is considered to be fuel grade. Its primary markets are cement kilns and power plants. The low volatility of pet coke limits its ability to be used in pulverized coal boilers because of flame stability and carbon carryover. Fluidized bed boilers do not have the same problems and can use pet coke for a higher percentage of their requirements.

As of 2004, there were 162 pet coking facilities in the world, 23 of which are located in the Gulf of Mexico. The Gulf region is the source of the pet coke

purchased by NSPI because of its location. Pet coke production in 2004 from these Gulf coast refineries was 29.1 million tonnes. Pet coke production has experienced substantial growth over the last few years with 3.7 million tonnes of new pet coke capacity in 2001, 0.7 million tonnes in 2002, 4.1 million tonnes in 2003, and 1.5 million tonnes in 2004.

The factors that are responsible for increasing pet coke supply include:

- Increased consumption of crude oil
- Declining quality of crude oil
- Shrinking markets for residual oil
- Increased heavy oil discounts

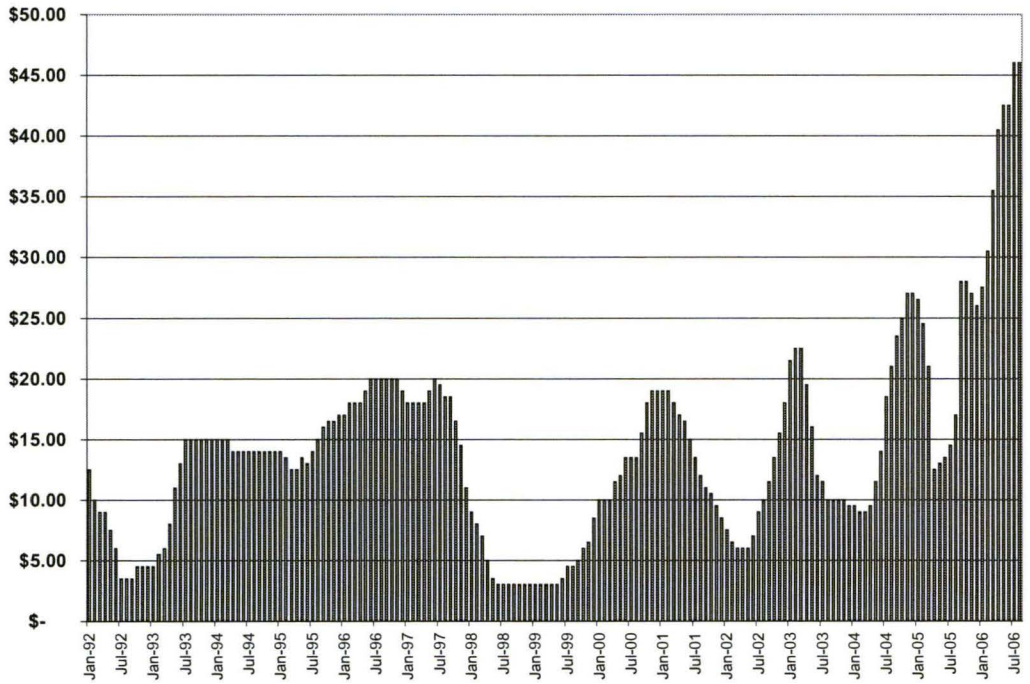
Pet coke supply is expected to continue its high growth due to the same factors.

As shown in Figure 2.3.6, pet coke prices are extremely volatile because as a by-product, its supply does not respond much to changes in price. The mechanism for pet coke prices is different from traditional commodities where there is typically a supply curve where increasing costs correspond to increasing demand. Because pet coke is a by-product, the supply costs for pet coke are very low. When there is an excess supply of pet coke, prices will drop to a floor price. Conversely, when there is a shortage of pet coke, prices will rise up to a ceiling price, which is generally set by the price of high sulphur coal.

Figure 2.3.6

PETROLEUM COKE PRICES (USD/Tonne)

January 1992 - August 2006



The price spike in late September 2005 was caused by Hurricanes Katrina and Rita shutting down Gulf coast pet coke supplies. The decline in prices in 2001 and 2003 was due to significant volumes of new pet coke capacity coming online in those years.

Most pet coke is sold through traders reflecting the by-product nature of this material. Because of the recent volatility in pet coke pricing, traders are reluctant to fix prices at levels that would have been considered reasonable two or three years ago. For future year purchases, traders are now tying the pet coke price to indices plus or minus a fixed amount.

The major factor influencing pet coke pricing in 2007 is weather (more specifically hurricanes). As demonstrated by Hurricanes Katrina and Rita, a hurricane can move the price from the floor to the ceiling virtually overnight. Other factors that either increase or decrease supply, such as refinery outages

and smaller/larger spreads between light and heavy fuel oil, also could have an effect but not likely to the same degree. There is some political risk with respect to supply as Venezuela produces about 15 percent of fuel grade pet coke in the Gulf. Any disruption in Venezuela could cause a price swing in the Gulf market.

2.3.2 Fuel Price Volatility

As expected, fuel price volatility continued into 2006. What was unexpected, however, was the magnitude of the price increases. Oil, natural gas, and petroleum coke all reached new highs over the last 14 months. The primary factors that are credited with the movements in the price for oil, natural gas, and petroleum coke are demand (for example China, India), geopolitical unrest,[21] and the residual impacts from the strong hurricane season in 2005, which curtailed production capacity in the Gulf of Mexico. More recently prices have softened but remain above historic levels.

Figures 2.3.7, 2.3.8, and 2.3.9 provide historical pricing for oil (West Texas Intermediate), natural gas (Henry Hub), and petroleum coke (average PACE < 50 HGI[22]), respectively, as they looked in May 2005 and as they look in August 2006. These comparisons demonstrate that what appeared to be close to record prices for oil, natural gas and petroleum coke in 2005, were in fact not. In July 2006, oil prices reached almost $75 USD per barrel. Natural gas prices were in double digits for four months. Petroleum coke prices spiked due to reduced supply resulting from hurricane-related losses and forecasts for another active hurricane season.

[21] Geopolitical unrest is tied to numerous matters including the war in Iraq, nuclear uncertainties in Iran, and civil unrest in Nigeria's Niger Delta. None of these factors are expected to be resolved in short-order.

[22] PACE Global Energy publishes pet coke prices for various qualities on a monthly basis. These numbers have become the industry standard for determining pet coke pricing. Sale offers are often priced in terms of the PACE index. The specific number referenced in this figure is the average price (that is, difference between bid and ask) for a less than 50 grind product, which is the stand product purchased by NSPI.

Figure 2.3.7

WEST TEXAS INTERMEDIATE (USD/Barrel)

January 2000 - August 2006

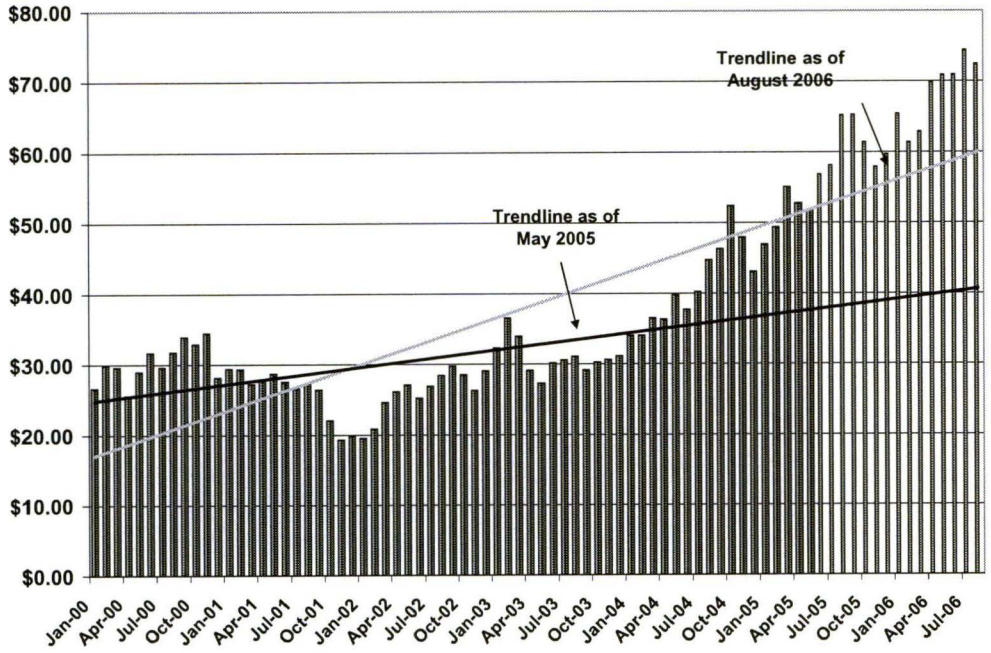


Figure 2.3.8

HENRY HUB NATURAL GAS PRICES (USD/MMBtu)

January 2000 - August 2006

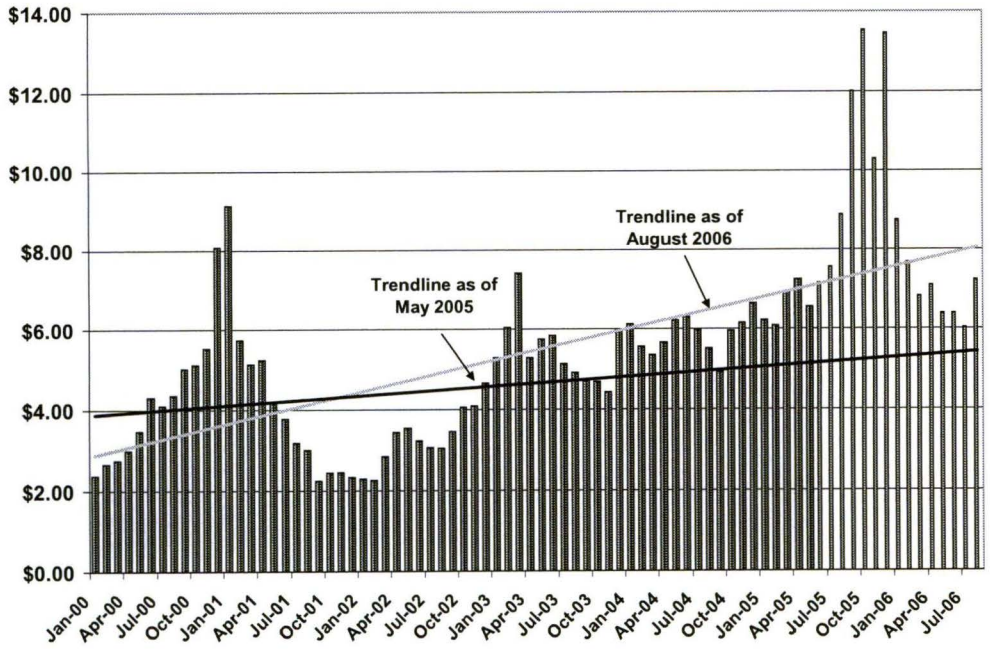
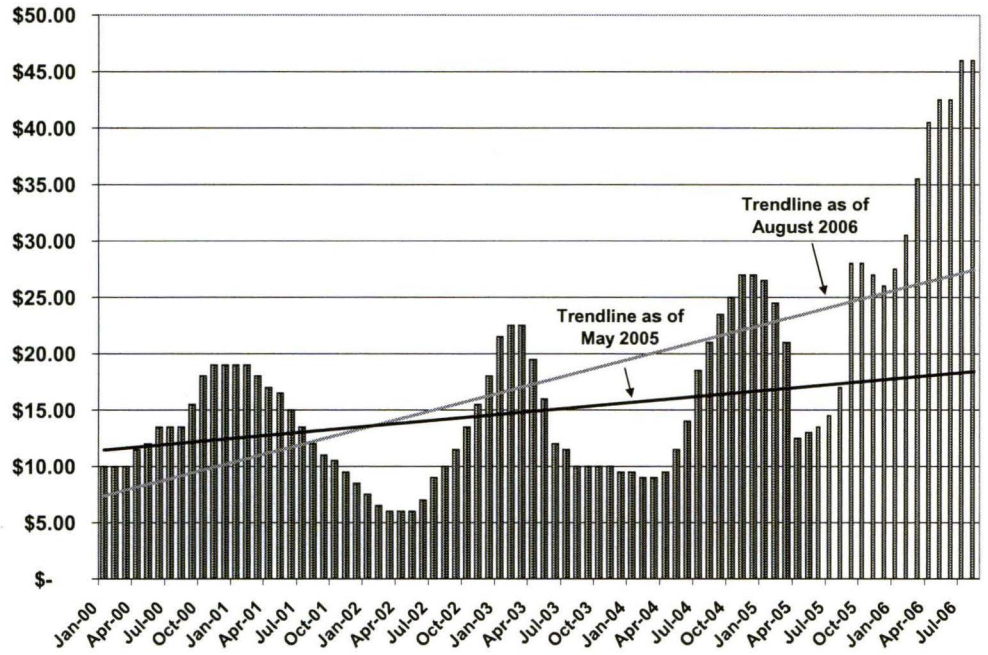


Figure 2.3.9

PETROLEUM COKE PRICES (USD/MMBtu)

January 2000 - August 2006



The degree of the price spikes over the last 15 months was largely unexpected even after the hurricane-related disruptions. In fact, the continued high oil prices confounded many analysts because the combination of high inventory levels and mild winter weather typically cause prices to fall. Natural gas prices, while still at the high end of the historic range, are back within the normal range of pricing.

The outlook for oil and gas prices in 2007 reflects recent volatility and high market prices. In the July 2007 Short-Term Outlook[23], the U.S. Department of Energy (DOE) projected that the monthly average West Texas Intermediate crude oil price would average $70 per barrel in both 2006 and 2007. In April 2006, the DOE acknowledged that it was substantially raising its forecast.[24]

[23] http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/july06.pdf. Note the Short-Term Outlook is revised monthly. It provides a monthly forecast for the current year plus one.
[24] http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/apr06.pdf.

DOE's July 2007 forecast for natural gas calls for an average spot price of more than $8 per million cubic feet, which is substantially higher than current levels.

DOE notes that its forecast does not assume any major disruptions due to hurricanes such as those experienced in 2005. In May 2006, the National Oceanic and Atmospheric Administration (NOAA) announced that it expected an active hurricane season in 2006. Specifically, NOAA's analysis suggests an 85 percent probability that the 2006 season is more active than normal and expects 13 to 16 named storms in the Atlantic. Obviously, any major disruption due to hurricane activity could cause oil, natural gas, and petroleum coke prices to spike once again.

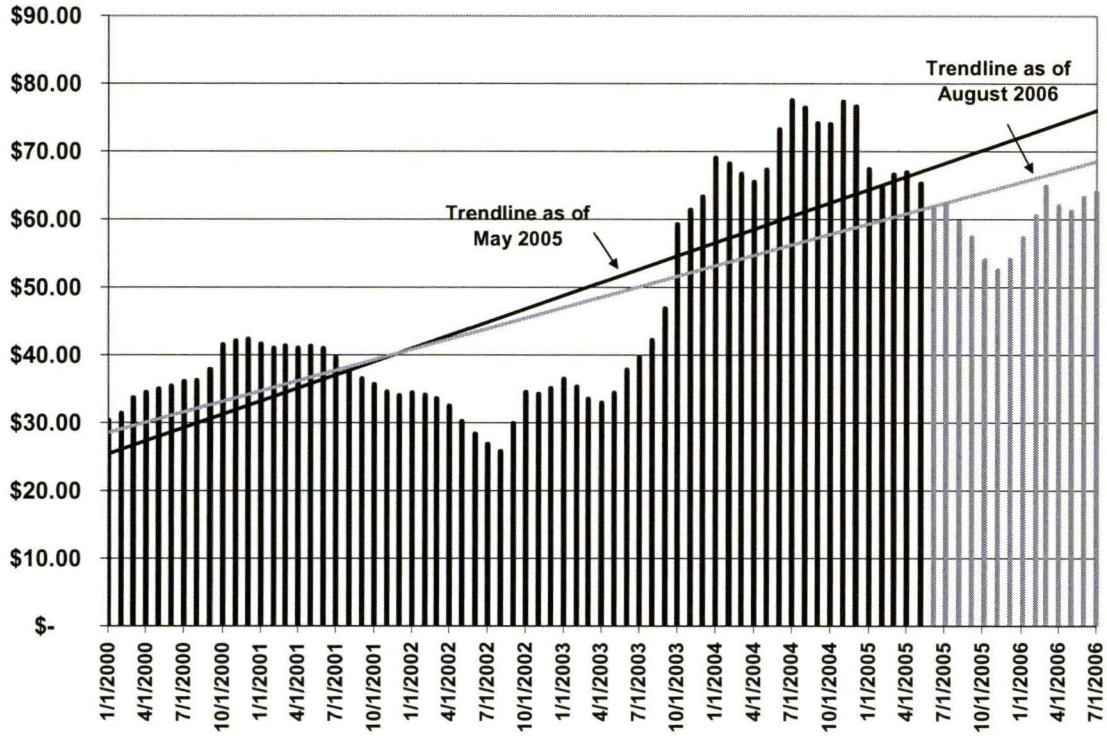
Unlike oil, natural gas and petroleum coke, coal prices did not spike over the last 15 months. Rather, as shown in Figure 2.3.10, international coal prices, as represented by API2[25], went through a mini-cycle with some softening through November 2005 and then strengthening thereafter. As measured by API2, year on year, there has been a slight decline in international coal prices.

[25] API2 is the average of the prompt price of a typical thermal coal delivered to Amsterdam, Antwerpt, and Rotterdam taken from two different publications.

Figure 2.3.10

INTERNATIONAL COAL PRICES ($/Tonne ARA)

January 2000 - August 2006



The short-term outlook for international coal prices is uncertain. The dip in the market during the fourth quarter of 2005 is believed to be tied to increased supply. The reason for the rebound in prices in the first half of 2006 is believed to be generally linked to European weather (both an unusually cold winter and warm summer) and stronger ocean freight mid-year.

The high prices over the last 18 months to two years have triggered an enormous amount of investment in coal producing capacity in Australia, Indonesia, Canada, Russia, and South America. The expectation of softening prices comes from an expected surplus in supply as this production hits the markets at a rate greater than demand growth. However, delays in getting new mines on line or supply disruptions in one or more countries could change the calculus quickly and eliminate the overhang. In addition, demand and

supply forecasts, particularly for China, could do the same. Again, the outlook is uncertain.

Fuel prices in 2006 are the best testament to the difficulty associated with forecasting fuel prices and the best argument for a portfolio procurement strategy. NSPI has worked towards a portfolio to help minimize market exposure in any one year, thus reducing fuel price volatility to consumers.

2.3.3 Utility Fuel Procurement Practices

EVA has conducted over 30 fuel procurement audits on behalf of regulators and/or consumer advocates, including two audits conducted in the last 12 months. On behalf of the Public Utilities Commission of Ohio, EVA conducted an audit of the fuel procurement practices of Cincinnati Gas & Electric. On behalf of the Consumer Advocate Division of the State of West Virginia, EVA conducted an audit of the fuel procurement practices of Appalachian Power. In addition, a number of utilities have engaged EVA over the last 12 months to provide independent reviews of their current procurement practices. EVA is aware of current utility practice with regard to fuel procurement activities and is able to evaluate NSPI's practice in the context of both the performance of other utilities and the regulatory environment.

The industry standard with respect to fuel procurement is portfolio strategy. Utilities use a combination of short, medium, and long-term agreements[26] with staggered terminations to balance risk and ensure security of supply.

This industry standard can be seen throughout North America. Recently, the Wisconsin Public Service Commission (WPSC) undertook a study of the fuel

[26] Definitions of long and medium term contracts vary in the industry. NSPI subscribes to the following definitions: Short: one year or less; Medium: between one and four years; Long: over four years.

procurement practices of the utilities it regulates. Utilities were asked to state what contracting or hedging strategies they deemed to be appropriate from the electric ratepayer perspective with respect to coal delivery or pricing issues. As shown below, the answers across the board speak to portfolio strategy.

- WPSC signs contracts of differing lengths and staggers the end dates of its contracts in accordance with an established policy. In this way, the amount of WPSC's requirements exposed to the market at any one time is limited. WPSC leaves approximately 10 percent of its requirements open for spot purchases each year to account for generation unpredictability. This type of disciplined hedging strategy is appropriate.[27] (**Wisconsin Public Service Corporation**)

- Due to the historically thinly traded coal financial instruments, WEPCO continues to emphasize improvements on the physical side of purchasing by having staggered coal supply expirations and where possible investing in plants to increase the ability to burn a variety of PRB[28] coals.[29] (**WE Energy**)

- WPL employs a strategy of entering into staggered term multi-year supply contracts. Staggering term expirations of contracts over a number of years has the effect of smoothing year-to-year pricing variations, which helps to make total costs, and correspondingly electric rates, more stable.[30] (**Wisconsin Power & Light**)

[27] http://psc.wi.gov/apps/erf_share/view/viewdoc.aspx?docid=53686.
[28] Powder River Basin.
[29] http://psc.wi.gov/apps/erf_share/view/viewdoc.aspx?docid=54044.
[30] http://psc.wi.gov/apps/erf_share/view/viewdoc.aspx?docid=53709.

- A balanced portfolio approach to coal procurement is likely to present the best hedging strategy. This would be comprised of longer-term (3-5 year) agreements, annual agreements, and Over-The-Counter purchases.[31] **(Xcel)**

This strategy is not limited to utilities in Wisconsin. Duke Power in its current fuel case in North Carolina provided testimony that it is pursuing a "comprehensive coal procurement strategy that reduces the risk of extreme price volatility that can be seen in the coal market. Aspects of the strategy include having the appropriate mix of contract and spot purchases, staggering contract expirations such that the Company is not in the position of replacing a significant percentage of contracts at any one time, and pursuing contract extension options that provide flexibility to extend terms with a price collar."[32] The Duke strategy also includes a test program in order to qualify coals from multiple mines and supply regions in order to limit Duke's exposure to market prices from a single region.

NSPI, like the Wisconsin utilities, Duke Power, and many other North American utilities, has adopted a portfolio strategy. NSPI is currently implementing commitments associated with achieving its baseline objectives such that it will have the basic components identified in its policies and procedures manual, that is, 30 to 50 percent long-term contract, 30 to 50 percent medium-term contract, and 0 to 20 percent spot/annual. NSPI continues to qualify many sources of supply such that it is not exposed to a single coal market for the bulk of its coal supplies.

The industry standard is to evaluate solid fuels on an evaluated delivered cost basis taking into account system operations as well as other

[31] http://psc.wi.gov/apps/erf_share/view/viewdoc.aspx?docid=53679.

[32] Duke Power's Application to adjust the fuel component of its electric rates filed March 3, 2006 before the North Carolina Utilities Commission (http://ncuc.commerce.state.nc.us/cgi-bin/webview/senddoc.pgm?dispfmt=&itype=Q&authorization=&parm2=OAAAAA96060B).

considerations, such as the credit-worthiness of suppliers and diversification of supply sources. This is consistent with the findings of Liberty Consulting, which noted in its recent audit of Kentucky Utilities and Louisville Gas & Electric that its experience over the last 15 years is "that electric utilities normally use a coal bid evaluation tool as part of the bid evaluation process in order to adjust the delivered price of coal," to "arrive at what is generally referred to as the 'evaluated cost of coal'. This 'evaluated cost of coal' then re-ranks the coal bids on the basis of which coals will result in the production of the lowest cost electrical energy."[33]

NSPI's evaluation process consists of a customized model that determines the suitability of the various coal offers for NSPI's plants as well as the relative costs associated with the acceptable fuels. NSPI also uses a spreadsheet model to rank the respective coals on an evaluated delivered price basis taking into account the commodity cost, ocean freight (where applicable), inland transportation costs and coal quality. The creditworthiness of the counter-parties is independently determined. In addition to the economic and financial evaluation, NSPI considers past performance of the potential supplier and the impact of each procurement on its policies regarding supply and supplier diversification.

The industry standard is to optimize procurements in order to minimize solid fuel expense. Utilities may be able to reduce fuel expenses through optimization of their fuel portfolios once commitments are made. The term "blend and extend" refers to a common utility practice of extending a fuel supply agreement in exchange for realizing prices closer to market. Recent market volatility has demonstrated that active management of even shorter-term agreements can yield positive results with respect to fuel procurement

[33] Focused Management Audit of the Fuel Procurement Functions of Kentucky Utilities and Louisville Gas & Electric, February 23, 2004.

costs. Such active management requires an acute awareness of market activity as well as continuous discussions with suppliers and other market participants. NSPI has demonstrated success in its active management of coal supply agreements. NSPI has been able to arbitrage portions of its commitments with favourable results.

The industry standard is to have a policies and procedures manual to guide fuel procurement efforts. EVA and Liberty Consulting in their respective engagements often note the importance of a comprehensive fuel procurement policies and procedures manual.[34] The ideal manual is one that provides clear guidelines while providing some flexibility to respond to market conditions.

NSPI's policy and procedures manual is equal to, and in many respects superior to, those found at other utilities in North America. As noted in EVA's audit of the fuel procurement practices of Appalachian Power, the fuel procurement manual of American Electric Power Service Corporation (AEPSC), one of the largest coal consumers in the US, is very general and contains no specifics with respect to its target portfolio or the manner by which fuel bids are to be evaluated.[35] AEPSC, which manages coal procurement for all of the AEP utilities, purchases almost 70 million tonnes per year. NSPI's manual, by contrast, contains specifics with respect to its portfolio standards, its commitment to rigorously evaluate fuel procurement offers, and its obligations to document fuel procurement decisions.

There is no specific industry standard with respect to how prices for test years are developed. Rather, similar to NSPI, most utilities use some combination of actual prices, forecasts, forward price curves, and bids to develop prices for budgetary purposes. NSPI's solid fuel budget is based upon a combination of actual commitments and a price forecast for uncommitted

[34] http://www.psc.state.ky.us/agencies/psc/hot_list/m_audit/ku_lge/kulge_foc_mgmt_021704.pdf, Page I-14., http://dis.puc.state.oh.us/CMPDFs/MK2VRIR@UPJQ54WB.pdf.
[35] http://www.cad.state.wv.us/051278EMedineDirect.pdf.

volumes. The price forecast is also applied to option tonnage to the extent that the price of the option tonnage is below the contract pricing. The price forecast for import solid fuel is a consensus forecast derived when appropriate from bids, consultant forecasts and where appropriate, forward price curves. The price forecast for HFO and natural gas is based upon the forward price curves. EVA finds that NSPI's approach is sound and yields budget forecasts that provide the best estimate of fuel prices at the time the budgets are prepared.

2.3.4 International Coal Expertise

NSPI was directed to seek an international coal expert as part of its procurement team. In response, NSPI engaged the services of the premier executive recruiter within the coal industry to find an international coal expert, who would be able and willing to join the NSPI procurement staff. Testimony was provided in 2005 as to NSPI's efforts in this regard. As referenced in a letter from this recruiter:

Some of the challenges in filling this position included:

1. Location - Nova Scotia is considered remote in the broader context of international coal markets where procurement individuals are located, that is London, Brisbane, and Houston.

2. Size of organization - The coal portfolio of Nova Scotia Power is small tonnage and considered a step backwards by many individuals with the appropriate credentials.

3. Regulatory environment - Many candidates come from a merchant environment and are uncomfortable with regulatory constraints.

4. Small pool of candidates - On a global basis, only about two dozen companies have individuals employed in a similar capacity to the needs of Nova Scotia Power. [36]

While these recruitment efforts are underway, NSPI has continued to participate in international coal markets and has been developing its internal capabilities to perform these activities. NSPI has committed to the further development and staffing of the fuel procurement function such that the capabilities of the group continue to be enhanced. The Manager of Solid Fuels now has sufficient experience and expertise in international coal markets such that, if his resume were presented by the recruitment firm, he would likely be considered a lead candidate.

2.3.5 Effect of Credit Rating on Fuel Purchase Expense

In recent history, there have been insolvencies of both buyers and sellers that have made the creditworthiness of counter-parties more important. Buyers and sellers are concerned about the ability of the counter-parties either to perform, or in the event of a breach, to pay damages. Further, as sale and purchase agreements are categorized as executory contracts, they can be rejected in bankruptcy.

In addition to evaluating the credit-worthiness of the counter-party when an agreement is made, provisions are often included that address changes in the credit rating during the term of the contract. Some coal companies want language that requires adequate assurances if there is a significant downgrade

[36] NSPI 2006 Rate Case, NSPI Undertaking U-50, NSUARB – NSPI – P-882, December 1, 2005.

in credit. For example, one coal company has the right in its Master Agreement to require a "credit enhancement" if the credit rating of a counter-party or a counter-party affiliate falls below investment grade. The credit enhancement might consist of letters of credit, compressed payment terms or cash on delivery. Further, if an adequate credit enhancement is not provided, the coal company can suspend future deliveries. Any credit enhancement will increase the cost to the buyer. Letters of credit, compressed payment terms or cash on or before delivery have quantifiable costs related to the time value and cost of money.

NSPI, like other utilities, could be affected by the financial condition of its suppliers. Similarly, NSPI's own credit rating could affect the cost of its own fuel procurement.

2.3.6 Conclusions

- Volatility and high prices continue to characterize the fuel markets in which NSPI participates. As a result, fuel costs have trended upward and forecasts are more difficult to make.

- NSPI's fuel procurement practices are consistent with best industry practices. NSPI purchases its fuel using a portfolio approach which limits market, supply and supplier exposure in any one year; NSPI evaluates its fuel procurement decisions on a fully evaluated cost basis; and NSPI continually optimizes its procurements to insure minimum cost.

- NSPI has developed expertise in international fuel markets through experience, participation in industry forum, and selective use of industry experts. The recruitment of a seasoned executive is no longer necessary.

- The cost of fuel can be affected by both the credit-worthiness of both the buyer and the seller. NSPI's credit rating, as well as the credit rating of its parent, can affect the terms by which it is able to purchase coal.

2.4 Fuel Testimony of NSPI

Like all utilities and customers, NSPI is experiencing the effects of world market forces on its fuel costs. In 2007, NSPI is facing an increase in fuel costs of $68.5 million, 16 percent higher than in 2006C. NSPI's ability to recover its fuel costs is fundamental to the financial health of the utility and the reliability of the electricity system.

The Company concurs with and adopts the preceding evidence of Energy Ventures Analysis. This section outlines NSPI's mix of generating capacity and touches on market volatility. NSPI's Fuel Procurement Strategy and the fuel portfolio are discussed in detail. The fuel forecast methodology in general and the 2007 forecast in particular are described in detail, highlighting the following topics:

- Oil and Gas
- Solid Fuel
- Renewable Energy
- Foreign Exchange
- Effect of Load Growth on the Cost of Generation

2.4.1 NSPI's Fuel Procurement Strategy

NSPI has 2,283 megawatts (MW) of generating capacity. Coal-fired capacity makes up 54 percent; oil and natural gas fired facilities comprise another 29 percent while hydro, tidal and wind provide the 17 percent balance of the Company's total generating capacity.

Approximately 90 percent of NSPI's energy is produced from fuel-burning plants. Of this energy produced, solid fuel-fired generation accounts for approximately 73 percent; HFO, natural gas and light fuel oil (LFO) account for approximately 17 percent; hydro, tidal, wind generation and power purchases account for approximately 10 percent.

International fuel prices have experienced significant volatility over the past several years. The evidence of EVA provides a more extensive discussion of fuel market volatility.

The price of oil continues to be volatile and high by historical standards. Demand growth, the war in Iraq, and political unrest in the Middle East and elsewhere have caused the price of crude oil to reach record highs. The push and pull of investors in the commodity markets have added, and will continue to add, volatility to the prices paid by consumers.

Natural gas prices increased in 2005, largely due to weather-related disruptions. While prices have since fallen, they continue to be volatile in nature, the market being ever sensitive to demand, severe weather and storage positions.

Solid fuel accounts for the largest portion of NSPI's fuel budget. After reaching and sustaining all time highs in the second half of 2004, coal prices have been trading in a relatively narrow range over the last 12 months, although at prices significantly above historic levels. Pet coke prices reached new highs following the 2005 hurricane season and have stayed at elevated levels.

Fuel Portfolio

In support of the Board directive to develop a more comprehensive hedging program NSPI has undertaken a review of the objectives and goals of its fuel portfolio. The initial review has resulted in the restatement of the overall policy and goals for NSPI's fuel management.

NSPI has revised its Fuel Procurement Policy Statement as follows:

- NSPI will seek to procure and manage a reliable fuel supply with a diversified portfolio of fuel types, suppliers, contract terms, and pricing

structures that seeks to produce reliable energy for our customer, that is consistent with regulatory and environmental requirements.

- NSPI's fuel procurement and hedging activities will comply with NSPI's Code of Conduct.

- Hedging will be used to help stabilize fuel costs, recognizing market forces determine ultimate pricing.

The "Objective" section for NSPI's Fuel Procurement Policies has been renamed "Goals" and encompasses procurement, management and hedging price exposure for fuels as follows:

- NSPI will seek to procure a reliable supply of fuel on a system-wide evaluated cost basis for its generation fleet, utilizing a competitive procurement process to acquire fuel.

- NSPI will manage the procurement of fuel supplies and the implementation of a portfolio of procurement and financial hedging program which seek to provide a measure of fuel cost stability.

- NSPI will seek to dispatch and consume acquired fuel to yield the lowest cost while meeting all applicable policies, procedures, reliability, safety and environmental requirements.

The following describes the progress to date in the development of the portfolio by fuel type.

Oil and Natural Gas

NSPI burns HFO and/or natural gas at Tufts Cove. Tufts Cove Units 1, 2 and 3 are capable of burning both fuels while Units 4 and 5[37] burn only natural gas. The volume of HFO required in any year varies depending on two main factors. First, Tufts Cove is generally on the margin and its generation requirements are affected by changes in customer demand. Second, HFO is substituted with natural gas when it is economic to do so.

Since late 2002, NSPI has primarily been burning HFO in Tufts Cove Units 1, 2 and 3 and has been reselling the contracted natural gas that is not required in Units 4 and 5. However, with the increase in HFO prices in the last 12 months, natural gas has become a more economic fuel, reducing the quantities of HFO required. This situation could reverse if HFO prices fall and/or natural gas prices rise.

Oil

NSPI's HFO strategy is comprised of two parts; physical purchases and financial hedging. NSPI buys its HFO on a monthly basis, under a 12-month variable volume contract with pricing tied to a New York Harbour (NYH) market index. The variable volume allows NSPI to substitute HFO supplies when more favourable delivery terms can be found in the market or when gas is more economic to burn.

The physical supply of HFO and natural gas are both priced against market indices. This is designed, consistent with the Fuel Manual, to allow a hedging program to complement the future commodity and fixed prices. [redacted] NSPI has achieved this target for 2007.

[37] The LM6000 combustion turbine units.

Natural Gas

NSPI buys natural gas under [redacted] agreement with an existing supplier. Deliveries commenced on November 1, 2000. The contract represents 61,600 MMBtu per day of natural gas deliveries to NSPI.

On November 18, 2005 NSPI amended its agreement with its gas supplier covering the remaining period of the contract. The updated pricing provisions included in the agreement are reflected in the fuel expense calculations for 2007. The agreement is positive for both NSPI and its customers in terms of pricing as well as security of supply. NSPI's strategy is to optimize the value of this gas contract for the benefit of customers either by burning it or reselling it, according to operational and market conditions.

NSPI outlined in the 2006 Rate Hearing that an independent third party would be contracted to manage the sale of gas under the NSPI natural gas contract. NSPI issued a Request for Proposal (RFP) to secure an independent third party with the appropriate expertise. An RFP was issued to 13 bidders on November 2, 2005. Brant Energy, Inc. was selected from the short list of bidders to develop "Best in Class" processes with respect to natural gas re-sale solicitations and to design and manage the natural gas re-sale solicitation process, including award recommendations.

Brant Energy put in place a competitive RFP process for the sale of NSPI's natural gas for the period of April 1, 2006 to March 31, 2007. Brant Energy was responsible for managerial oversight of the process, evaluation of all RFP responses, and delivery of the RFP and award recommendation. The substantive content of the RFP was designed to obtain competitive bids that achieved the highest and most reliable price for the NSPI excess gas. The process developed provided a competitive environment that was transparent and fair to all bidders.

The winning bid was determined through an independent analysis performed by Brant and communicated to NSPI following the determination. Brant determined that the

Emera Energy Services (EES) bid achieved the highest competitive value for the excess NSPI gas supplies and minimized the potential for gas replacement cover cost.

Solid Fuel

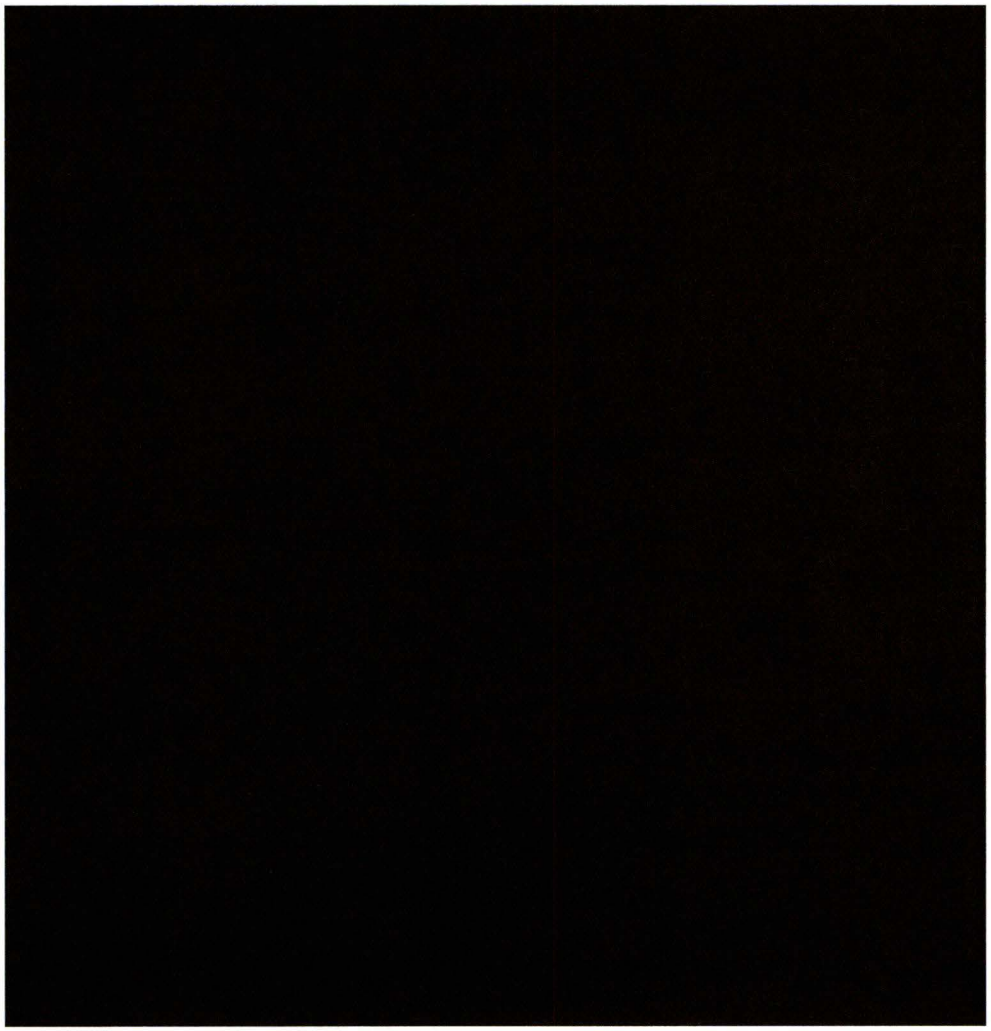
NSPI's solid fuel procurement policy is to procure and manage a reliable and reasonably priced supply of fuel on a system-wide evaluated cost basis for its generation fleet, which is consistent with regulatory and environmental requirements. NSPI's policy incorporates a portfolio approach to procurement

NSPI is on track to meet the December 31, 2007 goal of achieving contract commitments in line with its portfolio targets. As of September 6, 2006 NSPI has [redacted] of its forecasted 2007 procurement volumes of solid fuel requirements; [redacted] forecasted solid fuel requirements are under long-term contracts [redacted] are purchased under medium-term contracts. Figure 2.3 describes the portfolio position from 2006 to 2010 as well as the mix and length of contracts.

Figure 2.3

NSPI Solid Fuel Portfolio Table

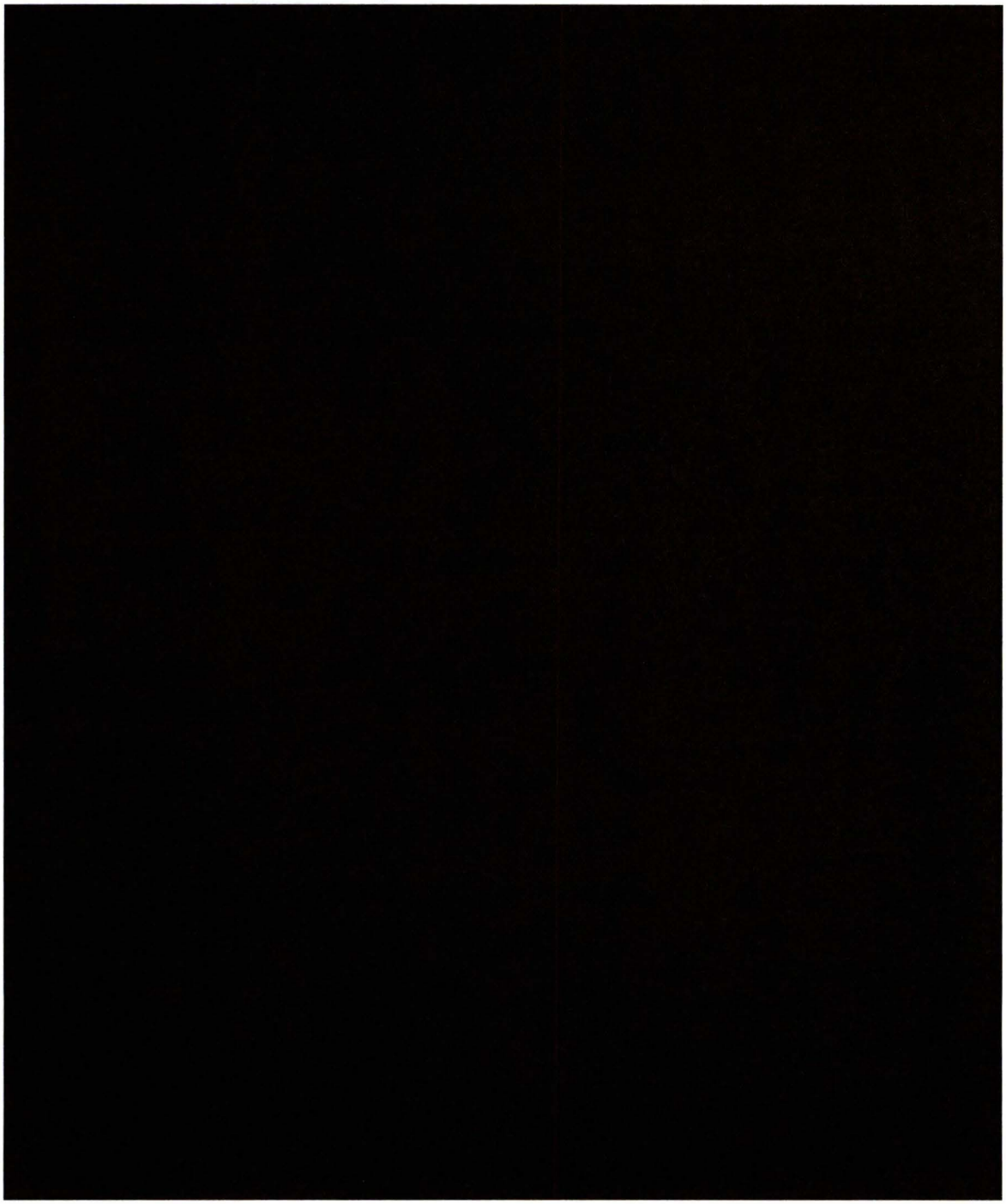
(in thousands of metric tonnes)



NSPI reviews its commitments on an on-going basis. Careful monitoring of NSPI's requirements and changing market conditions allows for the portfolio to be optimized. The contracts in which NSPI has engaged are summarized in Figure 2.4 and outlined in the following sections.

Figure 2.4 **Summary of Portfolio Status**

(in thousands of metric tonnes)



Long-Term Contracts

NSPI engages in long-term commitments for coals and pet coke that the Company will consume for four years or more.

NSPI [redacted] commitments for solid fuel as follows:

[redacted]

Medium-Term Contracts

[redacted]

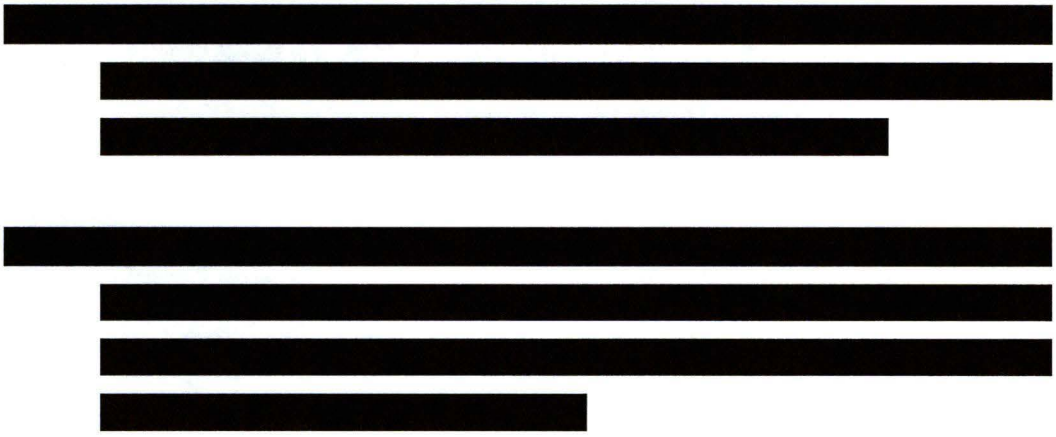
Short-Term Contracts

The balance of NSPI's solid fuel requirements is purchased on an annual or a short-term basis. This amount depends upon such factors as load and the relative cost of current market price versus long and medium-term contract prices, where permitted. The short-term commitments also include coal purchased for test burns and allow for management of sulphur emissions compliance.

Test Burn Program

NSPI maximizes competition among suppliers by qualifying multiple sources of supply. The test burn program allows NSPI to assess the potential for new fuel sources to be used in a specific plant or across the fleet of generators. Test burns are only conducted on coals that are determined through modeling to be suitable for NSPI combustors and that could be economically delivered to NSPI plants. The test burn results are used to assess the fully evaluated cost of a fuel for future purchase decisions.

Recent results from the test burn program are as follows:



[redacted]

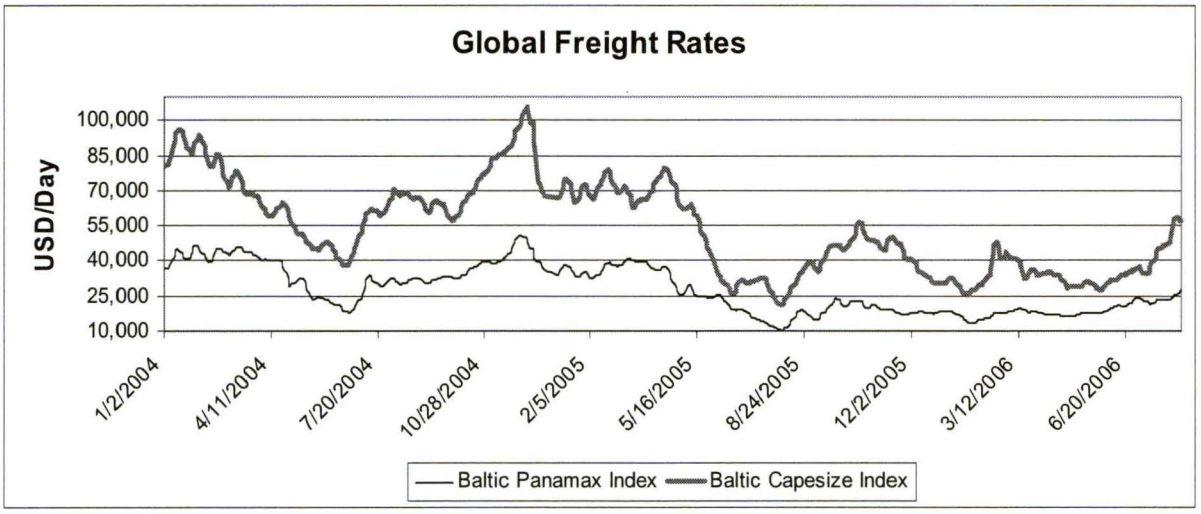
Transportation

Freight rates are determined by the type of vessel, the distance from the loadport and the market. NSPI receives solid fuel at two port facilities. The Point Tupper Marine Terminal (PTMT) successfully completed its first year of operation in 2006. It has the ability to handle bulker vessels that can economically deliver coal from a greater number of supply basins. The PTMT has enabled the economic testing program noted above due to its capabilities. The second facility, International Pier, is located in Sydney and can receive self-unloading vessels that typically originate along the eastern seaboard of North America and South America.

Freight rates have been extremely volatile over the past several years, as shown in Figure 2.5 which charts the Baltic Panamax Index (BPI) and the Baltic Cape Index (BCI)[38].

[38] Baltic Cape and Baltic Panamax Indices are widely accepted industry standards for freight pricing.

Figure 2.5



NSPI purchases most coal on a Free on Board (FOB) loadport basis and is therefore responsible for the procurement of ocean freight. Pet coke purchases are generally made on a delivered basis with the broker responsible for freight.

The type of freight required depends upon the origin of the fuel and its destination. As noted above, deliveries to International Pier are currently limited to belted self-unloaders. However, PTMT can accommodate most vessel types.

[redacted]

Point Tupper Marine Terminal

The Point Tupper Marine Terminal (PTMT) began commercial operation in January 2005 and with the commissioning of the E-Crane[39] mid year, had discharged the first gearless bulk vessel in August 2005. The PTMT has provided NSPI customers with two main sources of savings:

[39] An E-crane is a hydraulic crane used in unloading bulker type vessels that have no self unloading capacity. It is located on the unloading pier.

- Reduced freight rates and demurrage charges on belted self unloaders;
- Rail transportation costs from the port to the Point Tupper Generating Station have been eliminated.

The design of the PTMT affords NSPI the option of chartering gearless bulk vessels. The freight rates on bulk vessels are market driven whereas the rates on belted self unloaders generally operate on a return on investment basis and are less affected by the international markets. The option to take gearless bulk vessels introduces NSPI to a market in which freight rates are generally more competitive than belted self unloaders when the transport distance is beyond a few days.

Stemming from its ability to charter gearless bulk vessels, NSPI has gained access to several coal supply basins that were not previously an option due to the limitations on belted self unloading vessels. The ability to accept gearless bulk vessels has enabled NSPI to test several new solid fuels at Point Tupper. Testing these new solid fuels can benefit NSPI customers by increasing competition among coal suppliers. In recent coal solicitations NSPI has received bids from Russian, South African and Indonesian suppliers.

In the 2006 Rate Decision, the Board did not allow a capital charge for the PTMT as it was not in the rate base[40]. Following the Board's direction, there is no associated capital charge included in the 2007 Fuel Forecast. NSPI is continuing to evaluate whether the terminal should be sold or incorporated into NSPI's rate base. NSPI appreciates the Board's willingness to consider inclusion of the costs associated with capital recovery if and when NSPI makes an Application to the Board.

2.4.2 Fuels Forecast

Fuel costs include the cost of solid fuels, oil, natural gas and purchased power, offset by the net proceeds from export energy sales and the resale of natural gas.

[40] NSPI 2006 Rate Case, UARB Decision, NSUARB – NSPI – P – 882, March 10, 2006, paragraph 678.

The forecast is derived from generation models that indicate approximately 90 percent of NSPI's generation will be produced from fossil fuel-burning plants in 2007. This forecast also provides for NSPI's compliance with an annual emission cap of 108,750 tonnes of sulphur dioxide (SO_2).

Net electricity demand is forecast to increase by 111 GWh over 2006C. This load growth increases fuel costs by $19.6 million. On an average cost per MWh basis, net fuel costs are forecast to increase by 15 percent from 2006C, [redacted]

The recent credit downgrade by Standard and Poor's (S&P) has not been factored into the 2007 fuel costs. In the longer-term, NSPI expects higher costs due to the requirement for lines of credit and prepayment for commodities and services. Suppliers may be less willing to enter long-term contracts without exacting higher premiums. The downgrade will affect NSPI's fuel procurement requirements, but the exact ramifications on costs are as yet unknown.

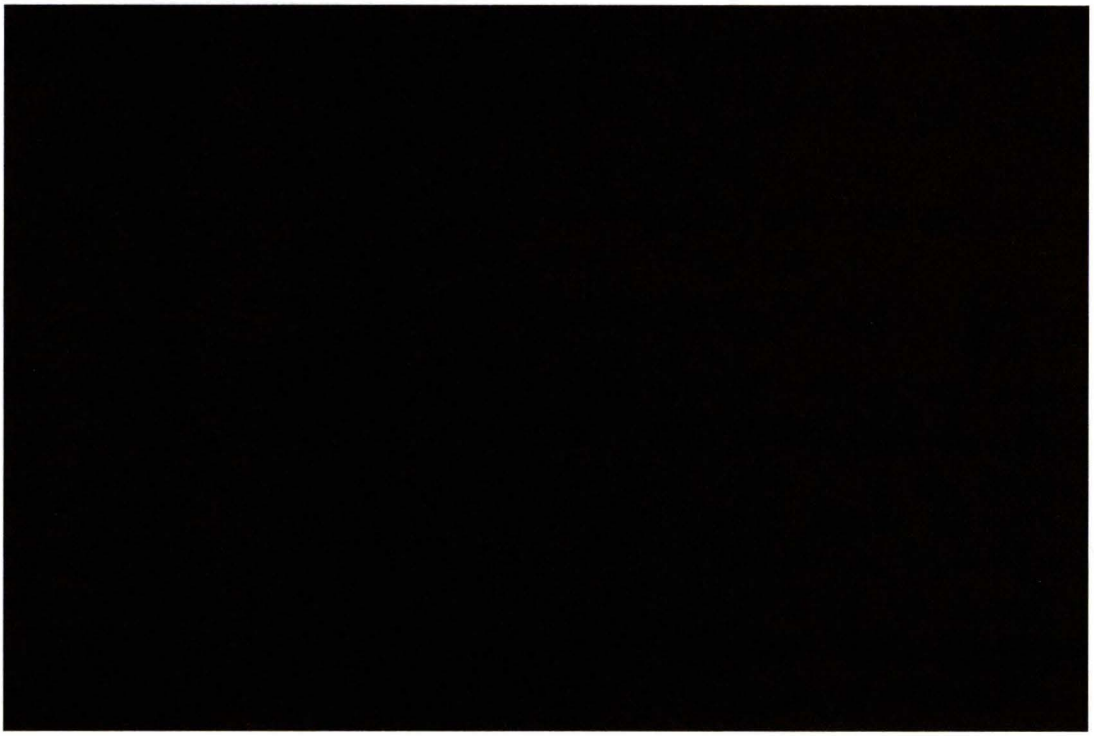
The following sections provide details on NSPI's 2007 fuel requirements, compared to 2006C. All commodity prices have been converted to Canadian dollars at an average exchange rate of $1.18 CAD for each U.S. dollar, as described in a later section.

Oil & Natural Gas Methodology

Figure 2.6 shows the 2007 over-the-counter[41] prices for oil and forwards for natural gas adjusted for delivery to Tufts Cove. As shown, the spread between natural gas and HFO is relatively narrow during summer months and widens during winter months. As the graph indicates, market gas prices are expected to remain above HFO prices in the winter months.

[41] Over-the-counter refers to solicitations from broker quotes for a commodity in the forecast period.

Figure 2.6



NSPI manages its exposure to changes in the market price of HFO through the use of swap and option contracts. The HFO price in the Application is forecast based upon over the counter quotes and in-place hedges.

The natural gas prices in this Application are produced using forward price curves[42] and in-place hedges. This methodology is consistent with that approved by the Board in the 2003 Generic Rate Case.

> The Board notes that there was no opposition to either NSPI's present method of including gas sales, based on forward curves, in its annual fuel

[42] A forward price curve refers to a trend in delivery prices decided upon by both buyer and seller for any given commodity.

budget or its proposed methodology for handling gas sales in the calculation of marginal costs. The Board approves both these methodologies as described.[43]

The key elements in calculating the natural gas margin are as follows:

- Estimate the volume of natural gas that will be available for resale after expected consumption;
- Estimate the amount of contract gas supply cuts that will be expected in the period;
- Determine the cost of gas NSPI will purchase as per the pricing terms of the gas purchase contract;
- Determine the selling price of the gas using market forward curves;
- Calculate the margin based on the monthly volume of gas available for resale multiplied by the expected selling price in the month less the forecast cost of the gas;
- Reduce the margin by transportation tolls that are incurred by NSPI as part of the natural gas sales program.

The methodology outlined above was presented and approved in the 2003 Generic Rate Case.

Oil Forecast

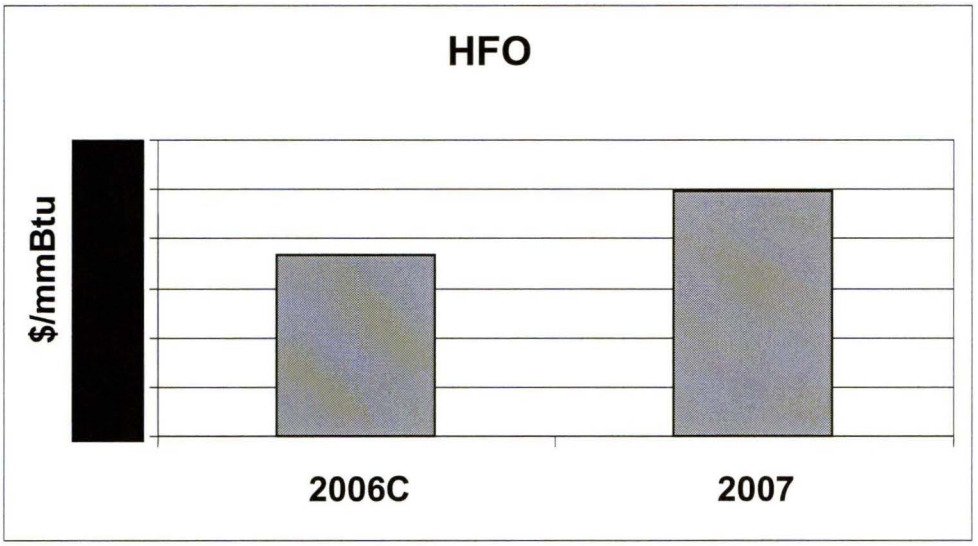
Given the relative forward market prices of each fuel, Tufts Cove is expected to burn HFO in the dual-fired steam boilers (Units 1-3) during the winter months and switch to gas for all of the summer months. 2006C vs. 2007 forecast has more [redacted] barrels of HFO displaced economically with natural gas.

[43] NSPI 2003 Generic Rate Proceeding, UARB Decision, NSUARB – NSPI P – 878, August 1, 2003, paragraph 51.

NSPI anticipates [redacted] in 2007 in Tufts Cove Units 1, 2 and 3 and as support fuel at its coal fired plants.

Figure 2.7 shows HFO costs for 2006C versus 2007. [redacted] This is an increase [redacted] the unit price of HFO.

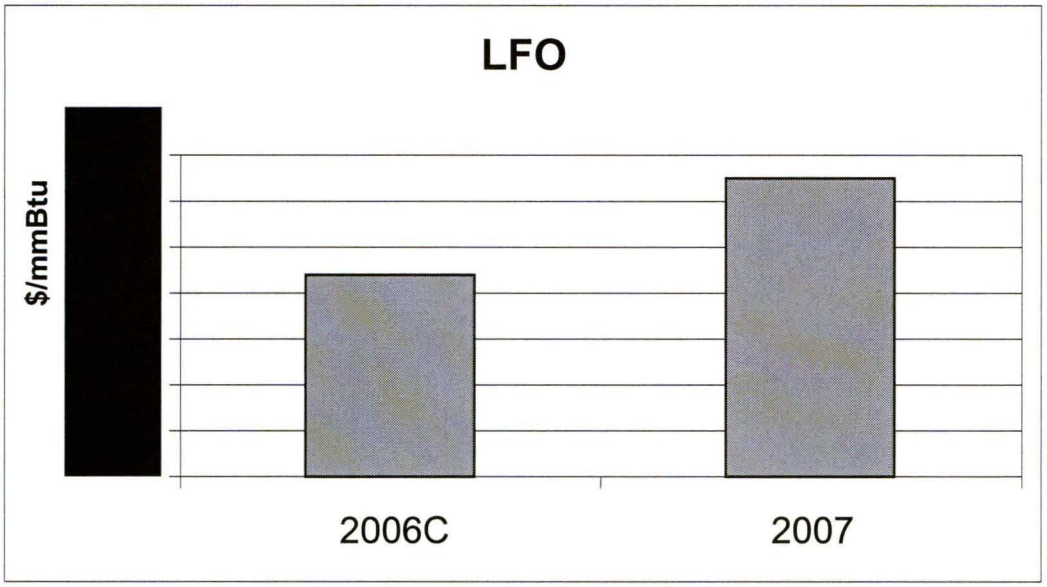
Figure 2.7



The Company expects to consume [redacted] LFO in 2007 as start-up fuel in its thermal units and consumption in the oil fired combustion turbines. The quantity of LFO forecast is higher than 2006C due to increased operation of NPSI's light fuel oil-fired combustion turbines, which is required to meet the load demand.

Figure 2.8 shows LFO price for 2006C versus 2007. The forecast price for light oil in 2007 [redacted] MMBtu. This [redacted] increase in the unit price of LFO costs.

Figure 2.8



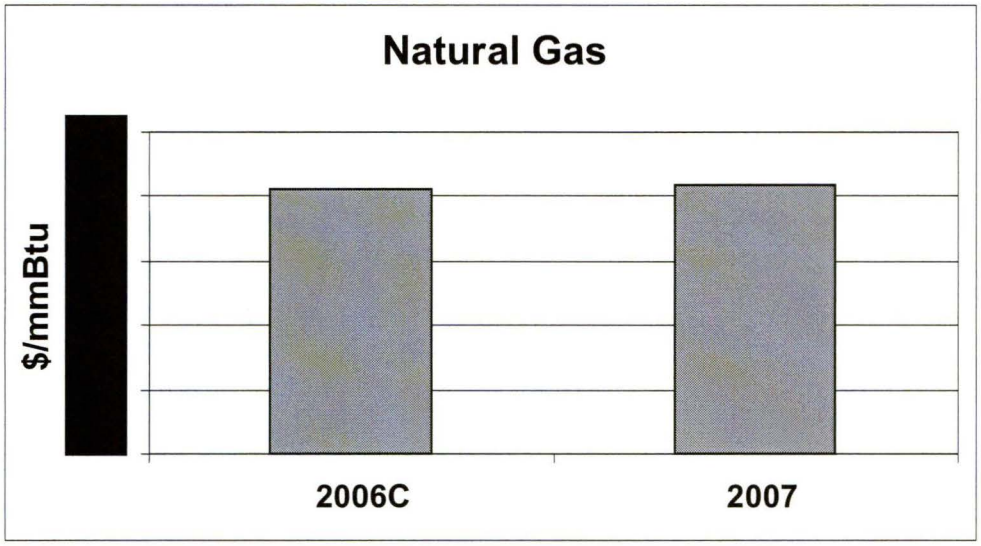
Natural Gas Forecast

With the price of HFO in a similar range to that of natural gas, the economics of burning natural gas during some of the summer months in Units 1, 2 and 3 at Tufts Cove is expected to be favourable. Gas is anticipated to be economically dispatched in the LM 6000 units at various times of the year. In 2007, the Company expects [redacted] of its contract volume of gas in the Tufts Cove Units [redacted].

Throughout 2006, NSPI has experienced some reduction in the supply of gas due to curtailments in supply from the Sable Offshore Energy Project (SOEP). NSPI's delivery forecast assumes [redacted].

Figure 2.9 shows the cost of natural gas in 2006C versus 2007. The average cost of natural gas consumed by the Company, including transportation charges to Tufts Cove, is forecast to [redacted]. On a unit cost basis, [redacted] than 2006C.

Figure 2.9



NSPI expects to continue its natural gas sales program and reduce overall fuel costs (after transportation charges) by [redacted]. This is a reduction over 2006C of $6.4 million.

Solid Fuels Forecast Methodology

In developing the solid fuel budget in this Application, solid fuels under contract were priced at contract levels while the uncommitted volumes were priced using market information and published forecasts. The optional volume on the contractual tonnage was priced at the lower of the contract or market levels.

At the time of the preparation of the 2007 fuel budget, Hill & Associates had not yet published its 2006 forecast. NSPI developed a consensus forecast for its solid fuels budget in 2007 based upon the following (where applicable):

- Contemporaneous bids
- Forward price curves

NSPI has reviewed the above information and developed a fuel price forecast that is representative of the various perspectives, rather than relying on one individual industry forecast. As was noted in the 2006 Rate Hearing:

> They [Utility Fuel Managers] should not build plans and strategies around a perceived single-point price or a narrow-band price estimate that ignores market uncertainty and volatility[44]

NSPI agrees that a consensus forecast is preferred to a single source and has endeavoured to take this approach, where possible. The forecast pricing for uncommitted volumes is outlined in Figure 2.10.

Figure 2.10

Uncommitted Volumes				
Commodity	**Volume (MT)**	**Sulphur Content (Wt., %)**	**Heat Content (Btu/Lbs)**	**Commodity($/ MT FOB)**
				CAD
Imports				
Low Sulphur Coal*	[redacted]	[redacted]	[redacted]	[redacted]
Mid Sulphur Coal*	[redacted]	[redacted]	[redacted]	[redacted]
High Sulphur Coal*	[redacted]	[redacted]	[redacted]	[redacted]
Petroleum Coke**	[redacted]	[redacted]	[redacted]	[redacted]

*FOB Load Port.
**Petroleum Coke pricing indicates delivered to the discharge port.

Solid Fuel Forecast

The majority of NSPI's generation comes from four plants fired by either coal or a blend of coal and petroleum coke.[45] Coal may come from either domestic or imported sources, but all petroleum coke is imported. The relationships of various fuel prices, in conjunction with their generation characteristics and demand, determine the mix of fuels. Figure 2.11 outlines the forecast mix of solid fuel blends for generation in 2007.

[44] NSPI 2006 Rate Case, Liberty Evidence, NSUARB – NSPI – P – 882, October 17, 2005, p. 19, Exhibit N-83.
[45] The plants are at Lingan, Point Aconi, Point Tupper and Trenton.

Figure 2.11

Mix of Solid Fuel Blends for Generation

	2006C	2007
Import Coal	[redacted]	[redacted]
LS	[redacted]	[redacted]
MS	[redacted]	[redacted]
HS	[redacted]	[redacted]
Pet coke	[redacted]	[redacted]
Domestic	[redacted]	[redacted]
	100%	**100%**

The fuel mix outlined in the 2007 Application is such that all solid fuels will be imported except for some coal supplied domestically. Domestic coal accounts for [redacted] of NSPI's solid fuel requirements on a tonnage basis. Imports account for the balance.

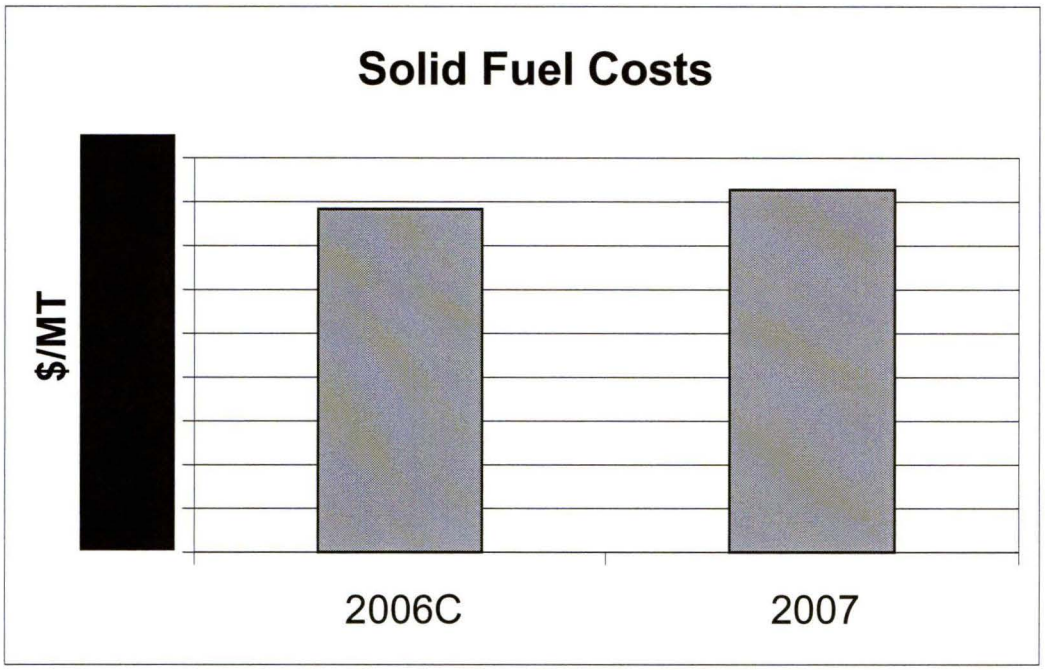
The import coal prices included in the 2006 Rate Application were based upon prices in early 2005. The international coal market has gone through a mini-cycle since then, dropping in the second half of 2005 only to rebound somewhat in 2006. The prices included in the 2007 Application are a combination of commitments made to date and a consensus forecast view comparing recent solicitations for 2007 fuel and comparison with forward curves.

Petroleum coke has generally been less expensive than coal. Its use is limited, however, by technical and environmental considerations. Prices of petroleum coke increased slightly for the 2007 Application versus 2006C. [redacted] NSPI's contract [redacted] providing savings to customers in this high cost market. The

uncommitted volumes are expected to be [redacted] petroleum coke.

As shown in Figure 2.12, the unit cost of solid fuel in 2007 has increased [redacted] over 2006C. This reflects the expiry of the 2006 coal disallowance.

Figure 2.12



Renewable Energy – Independent Power Producers

In the early 1990's, NSPI entered into long-term power purchase agreements (PPAs) with several independent power producers (IPPs). The power produced is through renewable type generation such as biomass, hydro and waste material. The waste burning generation contract ended with the Cape Breton Regional Municipal Waste Incinerator in 2005. The total capacity from these pre-2002 contracts totals about 26 MW and provides approximately 177 GWh annually.

In early 2005, Pubnico Point Wind Farm Inc. began full production under a long-term contract with NSPI from its 30.6 MW (approximately 100.9 GWh) wind farm at West Pubnico. At the end of 2005 NSPI had executed purchase power agreements with seven

wind developers, two biomass developers and one biogas developer. The 2007 forecast for this generation is 198.1 GWh. This is an increase from 2006C of 28.1 GWh.

Renewable Energy – NSPI

The renewable energy produced by NSPI comes from hydro, tidal and wind.

The level of hydro generation forecast for 2007 is based on a 23-year long-term average, consistent with the Board's Decision in 2002 Rate Decision where the Board stated the "longer-term data is preferable for purposes of hydro generation[46]". The use of this average, results in a production forecast of 964 GWh, which includes tidal energy at 30.8 GWh. NSPI's two wind turbines located at Grand Etang and Little Brook are forecasted to produce 2.7 GWh in 2007.

US Dollar Requirements and Exchange Rates

Most of NSPI's fuel requirement is purchased in U.S. dollars. The imported coal, petroleum coke, heavy fuel oil, natural gas and ocean freight are U.S. dollar denominated. The natural gas sales program provides a natural hedge against a portion of the Company's total currency exchange exposure[47] because the U.S. cash inflow from the sale of natural gas offsets some of the outflow required for fuel commodities; thereby lessening the net U.S. dollar requirement and NSPI's exposure to changes in the foreign exchange rate.

Exchange rates have improved since 2006 and NSPI has reflected lower foreign exchange rates in this Application. Offsetting the favourable effect of lower exchange rates is an increase in the amount of U.S. dollars NSPI requires in 2007, due to rising fuel costs.

NSPI hedges its U.S. dollar requirements based on known and forecast requirements. Similar to its fuel procurement policy, NSPI has expanded the horizon for foreign

[46] NSPI 2002 Rate Case, UARB Decision, NSUARB – NSPI – P – 875, October 23, 2002, paragraph 91
[47] Lower gas volumes reduce this natural hedge.

exchange hedging activity to four years and may extend further based on known requirements such as multi-year contracts. NSPI guidelines are to hedge 30-60 percent of each of the four forward years at any point in time. For the forward 12 month period, a maximum of 30 percent of the forecast USD requirement would remain open to allow for changes in the cash flow timing and volume of USD requirements. The hedged rates, and any related premiums, are factored into the budget rates for fuel.

The Company monitors foreign exchange markets and considers the views of economists and currency experts from both Canada and the U.S. Additional requirements are gradually locked up over time. A portion of the requirement is typically left "open" to allow for changes in the forecast volume and timing of the USD requirements. Although the amounts and timing of the "base" amount of fuel purchases are generally known, customer load and hence fuel requirements as well as natural gas sales volumes and amounts can vary depending on market conditions and positions taken by fuel management staff.

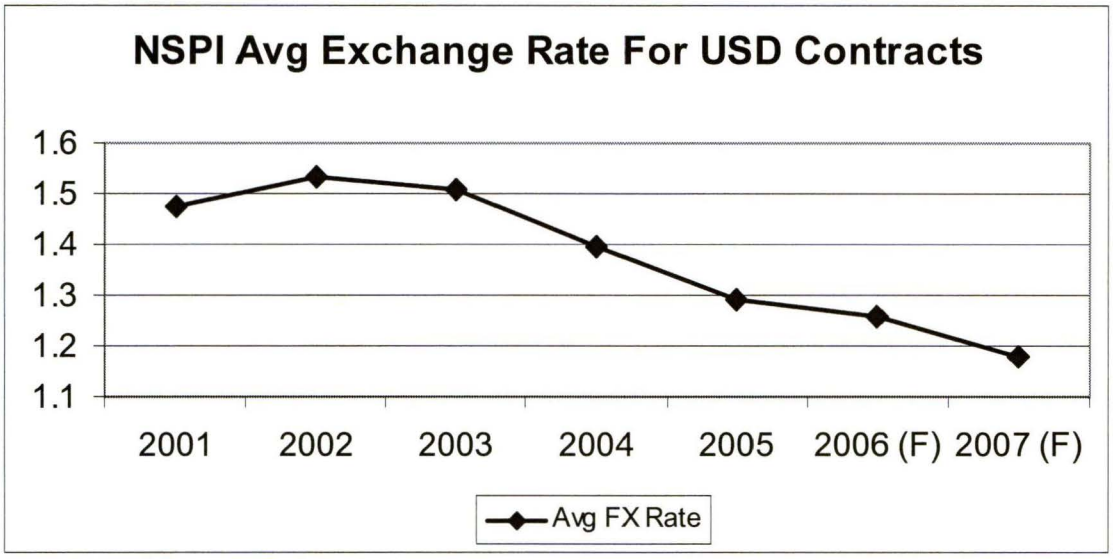
NSPI monitors and reports on its risk management strategies. This includes budgeted volumes of underlying positions not hedged and risk management strategies regarding revisions to the budget volume.

NSPI typically uses forward contracts to hedge its USD requirements for fuel. A forward contract is a commitment to purchase specific securities (in this case, U.S. dollars) at an agreed upon rate at specific date in the future.

Through its purchase of forward foreign exchange contracts, NSPI has approximately 70 percent of its 2007 U.S. dollar requirement at an average rate of $1.19 and has assumed a blended rate of $1.18 on all fuel costs in the 2007 Application. In 2007, NSPI anticipates that it will require approximately $376 USD million for fuel purchases.

Figure 2.13 shows the average exchange rates for USD contracts from 2001 to 2007.

Figure 2.13



Effect of Load Growth on Cost of Generation

As described in previous sections, the increase in fuel expenses for 2007 is primarily a function of changes in the price and mix of commodities to be used by NSPI. Load growth is a secondary factor contributing to the increase in fuel expense for NSPI in 2007. The 2007 total load is forecast to [redacted]. This is an increase [redacted] over 2006C.

NSPI expects to export surplus energy of 79 GWh in 2007 compared to 98 GWh in 2006C. Exports are lower due to limitations created by higher energy demand within the province. The cost of these 2007 export sales is estimated to [redacted] with a profit contribution [redacted] which reduces the overall revenue requirement, to the benefit of NSPI's customers.

In general, as the load increases, higher cost fuels are called upon to serve that new load, or "marginal"[48] load. In 2007, the marginal fuels are predominantly HFO, natural gas and LFO. Much of the incremental load in 2007 is being served by these fuels, supplemented by IPPs and Imports. Not only has the overall energy requirement

[48] Marginal refers to the next kWh that would need to be produced. The marginal cost is the cost that would be incurred to produce that next kWh.

increased, but peak demand has also grown, resulting in greater consumption of light oil by NSPI's combustion turbines.

The load increase [redacted] is expected to be served by an increase in production by the following sources, listed in order of greatest contribution to the generation mix:

- LFO
- Natural gas and HFO
- Independent Power Producers (IPPs)
- Imports

The mix of energy from the sources listed above results in a high weighted average cost of energy to serve the incremental load. Load growth has significantly increased the marginal cost of electricity and is responsible for a significant portion of overall fuel cost increases in 2007.

2.4.3 Summary

Currently 2006 customer rates include provision for fuel and purchased power expenses of $430.2 million. NSPI's net fuel costs for 2007 are forecasted to be $498.7 million. This is an increase of $68.5 million that needs to be recovered in rates.

The components of NSPI's increased fuel costs over 2006C are:

- Increases in the cost of oil, gas and solid fuels, including higher import power and transportation costs, equate to $40.1 million;

- Growth in load to be served by the utility, resulting in increased fuel consumption add an additional $19.6 million;

- A decrease in the gas resale margin results in increased natural gas burn which reduces the gas resale margin of $6.4 million;

- Other adjustments including contract assumptions, changes to generation equipment capacity factors and maintenance schedules, reduced hydro as well as other miscellaneous variances result in increased fuel costs of $2.4 million.

In 2007, average fuel costs per megawatt hour [redacted] above the levels in 2006C. The cost of generation is offset by natural gas resale margins, and is forecast [redacted] per megawatt hour in 2007. The effect of the June, 2006 S&P credit downgrade has not been factored in to 2007 fuel costs.

NSPI has been responsive to the Board's directives in the last two rate cases and is on track to meet its 2006 obligations. NSPI has developed its fuel portfolio targets and is on schedule to meet the requirements by December 2007.

The portfolio has limited, and will continue to limit NSPI's exposure to short-term market volatility. But the portfolio is affected by fuel commodity pricing in the mid to long-term. These increases are driven by world markets. Evidence of this is found in NSPI's forecast of 2007 fuel costs and supported by EVA's testimony.

3.0 REGULATORY AMORTIZATION AND DEPRECIATION

3.1 Overview

The UARB has previously approved each of the amortization and depreciation expenses sought to be included in the 2007 revenue requirement. These are all expenses that are properly recoverable in customer rates. It is necessary and prudent that recovery of these deferred expenses begin in 2007.

Regulatory amortization expenses will increase by $10.0 million to $16.2 million between 2006C and 2007. The increase results from:

- $14.5 million of amortization related to Section 21 taxes. The amortization schedule was developed using an eight year levelized approach as directed by the UARB in its 2005 Rate Decision[49].

- $1.7 million of amortization related to the deferral of income taxes applicable to Q1, 2005. NSPI's proposal is to start amortization in 2007 using an eight year levelized approach.

[redacted]

Depreciation expenses will increase by $7.3 million to $136.1 million between 2006C and 2007. The increase principally results from:

- $6.0 million related to the continued phase in of depreciation rate

[49] NSPI 2005 Rate Case, UARB Decision, NSUARB – NSPI – P – 881, March 31, 2005, paragraph 328.

adjustments. The 2007 test year revenue requirement is calculated based on the third year of the four year phase-in of depreciation rate adjustments approved by the Board in its Decision dated November 21, 2003.[50]

- $1.3 million related to capital additions.

3.2 Regulatory Amortizations

Regulatory amortizations are $16.2 million in 2007, an increase of $10.0 million over 2006C. This increase is due to the commencement of previously UARB approved amortizations of both Section 21 taxes and 2005 Q1 tax deferrals, [redacted]. Figure 3.1 provides a breakdown of these amortizations.

Figure 3.1

	2006C ($M)	2007 ($M)
Glace Bay amortization	[redacted]	-
S21 amortization	[redacted]	$14.5
Q1 2005 tax amortization	[redacted]	$1.7
Total	[redacted]	$16.2

Glace Bay Amortization

On July 28, 2003, the Board approved extending the write-off period for the Glace Bay Generating Station (GBGS) through to 2008, if necessary, with an annual minimum amortization of $6.2 million, commencing in 2003.

[50] NSPI 2003 Depreciation Rates Hearing, UARB Decision, NSUARB – NSPI – P – 879, November 21, 2003.

[redacted]

Section 21 Taxes Amortization

In the 2005 Rate Decision, the UARB approved the deferral of Section 21 taxes and stated:

> After considerable reflection, the Board finds that amortization of the s.21 taxes should be deferred for two years (2005 and 2006) and, commencing in 2007, amortization over an 8 year period should occur. The Board is satisfied that this approach is reasonable for ratepayers and NSPI, and complies with the regulatory principle of intergenerational equity. In addition, the Board agrees with Mr. Selecky's method of amortization in that a levelized revenue requirement over the 8 year period is appropriate.[51]

NSPI developed an amortization schedule for the Section 21 tax deferral in accordance with the UARB's directive.

Figure 3.2 shows an amortization of $14.5 million for Section 21 taxes in 2007. The tax effect of amortization of $8.9 million is the tax on revenue to recover the amortization expense. $14.8 million is the carrying cost of the deferred asset for a total of $38.2 million. The total cost of $38.2 million is held constant through the eight year amortization period in accordance with the levelized revenue requirement directed by the UARB.

[51] NSPI 2005 Rate Case, UARB Decision, NSUARB - NSPI-P-881, January 21, 2005, paragraph 200.

Figure 3.2

($M)	Amortization	Tax Effect of Amortization	Carrying Cost	Total
2007	$14.5	$8.9	$14.8	$38.2
2008	$15.5	$9.5	$13.2	$38.2
2009	$16.5	$10.2	$11.5	$38.2
2010	$17.6	$10.9	$9.7	$38.2
2011	$18.8	$11.6	$7.8	$38.2
2012	$20.0	$12.4	$5.8	$38.2
2013	$21.4	$13.2	$3.6	$38.2
2014	$22.8	$14.1	$1.3	$38.2

Accordingly, $14.5 million of amortization related to Section 21 has been included in the 2007 revenue requirement.

2005 Q1 Deferred Tax Amortization

The UARB approved the deferral of $16.7 million of taxes in Q1 of 2005, representing amounts associated with the deferral of taxes for the first quarter of 2005. In a letter dated June 12, 2006 the UARB stated:

> Accordingly, the Board hereby confirms the 2005 Q1 total deferred tax to be $16.73 million, as set out in the Board's letter of February 3, 2006.[52]

NSPI proposes the commencement of amortization for 2005 Q1 deferred taxes in 2007 and Figure 3.3 shows an amortization of $1.7 million in 2007. The tax effect of amortization of $1.0 million is the tax on revenue to recover the amortization expense. $1.6 million is the carrying cost of the deferred asset for a total of $4.3 million. The total cost of $4.3 million is held constant for the eight year amortization period in accordance with the levelized revenue requirement proposed in this Application.

[52] Letter from UARB dated June 12, 2006 re: NSPI Tax Deferral Request – (2005 Rate Application) – P881.

Accordingly, $1.7 million of amortization of the 2005 Q1 deferred taxes has been included in the 2007 revenue requirement.

Figure 3.3

($M)	Amortization	Tax Effect of Amortization	Carrying Cost	Total
2007	$1.7	$1.0	$1.6	$4.3
2008	$1.8	$1.1	$1.4	$4.3
2009	$1.9	$1.1	$1.3	$4.3
2010	$2.0	$1.2	$1.1	$4.3
2011	$2.1	$1.3	$0.9	$4.3
2012	$2.3	$1.4	$0.6	$4.3
2013	$2.4	$1.5	$0.4	$4.3
2014	$2.6	$1.6	$0.1	$4.3

The amortization of Section 21 and Q1 2005 deferred taxes discussed above is for a twelve month test year. NSPI is requesting that for the fiscal year 2007 the amortization of these deferred taxes commence on April 1, 2007, which is the requested effective date of rates. This request does not change the test year revenue requirement; however it does match the amortization expense with the recovery of these costs in rates.

3.3 Revised Depreciation Rates

In the 2002 Rate Decision, the UARB directed NSPI to retain an external depreciation consultant and file a depreciation study with the Board[53]. Pursuant to the Board's direction, the Company filed the Gannett Fleming Depreciation Study with the Board in April 2003. A stakeholder consultation process followed and subsequently a Settlement Agreement was reached with all Intervenors in the Depreciation Rate Hearing.

[53] NSPI 2002 Rate Case, UARB Decision, NSUARB – NSPI P – 875, October 23, 2002, paragraph 143.

The UARB approved the Settlement Agreement[54], and by Order dated December 23, 2003[55] directed an increase in depreciation rates for NSPI's depreciable property. As unanimously agreed upon by all parties, the Board directed that the increase in depreciation rates would be phased in over four years in equal instalments commencing January 1, 2004. In the 2005 Rate Decision the UARB deferred year two of the phase in by one additional year[56].

In its 2006 Rate Decision the UARB approved the resumption of the four year phase in of depreciation rates in the 2006 test year by including year two in rates[57].

The revenue requirement upon which this Application is based reflects a continuation of the four year phase in with year three of the Board-approved depreciation rates being used. This results in an increase of $6.0 million over 2006C.

3.4 Additions to Plant

Depreciation expenses will increase by $1.3 million as a result of various capital additions to plant in service through the Annual Capital Expenditure (ACE) Program, along with other capital expenditures approved each year by the Board.

The depreciable plant balance used in the Company's 2006 Compliance Filing has increased by approximately $70 million in this Application due to additions through the ACE Program.

[54] NSPI 2003 Depreciation Study, UARB Decision, NSUARB – NSPI P – 879, November 21, 2003, paragraph 22.
[55] NSPI 2003 Depreciation Study, UARB Order, NSUARB – NSPI P – 879, December 23, 2003.
[56] NSPI 2005 Rate Case, UARB Decision, NSUARB -NSPI-P-881, January 21, 2005, paragraph 333.
[57] NSPI 2006 Rate Case, UARB Decision, NSUARB - NSPI-P-882, March 10, 2006, paragraph 485.

4.0 OPERATING, MAINTENANCE & GENERAL

4.1 Overview

NSPI continues to control its Operating, Maintenance & General (OM&G) expenses. As a result, all 2007 costs remain unchanged as compared to the 2006 Compliance Filing costs of $197.5 million with the exception of additional pension expenses. Projected 2007 wage increases in both union and non-union groups are offset primarily by overhead capitalization adjustments (lowering OM&G costs) and staff reductions (lowering NSPI's overall labour costs) in order to keep OM&G costs consistent with the 2006 Compliance Filing. Total OM&G for the 2007 revenue requirement is $200.9 million, an increase of $3.3 million due to higher pension expenses.

OM&G expenses include labour and the various goods and services consumed in the generation, transmission and distribution of electricity.

Included in this section is a summary of projected OM&G expenditures in 2007 for the three main operating groups: Power Production, Customer Service and Customer Operations, along with each Corporate Support group. The Corporate Adjustment section describes the remainder of OM&G expenses.

- Customer Operations, Customer Service and Power Production OM&G costs will increase by $2.9 million or 2 percent in 2007 compared to 2006C.

- For Corporate Support groups, OM&G in 2007 will decrease by $1.2 million or 3.4 percent compared to 2006C.

- For Corporate Adjustments, OM&G in 2007 will increase by $1.6 million or 14 percent compared to 2006C.

The following sections compare 2007 OM&G to 2006 forecast (2006F), 2006 Compliance (2006C) and 2005 actual (2005A).

The anticipated OM&G expenses related to 2007 are included in the 2007 test year forecast. The OM&G requirement in the 2006 Compliance Filing reflects expenses included in rates as a result of the 2006 Rate Decision. The 2006 forecast depicts what NSPI expects to spend in the current year.

4.2 Operating Efficiently

In its 2006 Rate Decision, the Board requested an operations review to examine organizational efficiencies at NSPI. Specifically, the Board requested:

> ...that an operations review be carried out on NSPI's operation. The review shall encompass a detailed examination of NSPI's organization structure, its level of OM&G expenditures, and any other pertinent areas which may come to light, with a view to determining whether cost savings and operational efficiencies can be achieved. NSPI is directed to provide the terms of reference for the operations review and submit them to the Board for approval by May 31, 2006. The terms of reference shall also set out the procedures for identifying and selecting the firm or person who will perform the operations review.[58]

On May 31, 2006, NSPI submitted Terms of Reference to the Board building on a review previously undertaken and has requested the consultant to perform the following additional work:

- Review NSPI's organizational structure to determine its effectiveness;
- Provide an opinion as to whether OM&G expenses are at an appropriate level;
- Identify any cost savings/operational efficiencies that could be realized.

[58] NSPI 2006 Rate Case, UARB Decision, NSUARB – NSPI – P-882, March 10, 2006, paragraph 435.

The Board revised the Terms of Reference on July 21, 2006. This review is anticipated to be completed during 2007.

A detailed breakdown of OM&G expenses for the years 2005 through 2007 is provided in Appendix B. Variances over the period have been identified so that increases and decreases are readily apparent.

Cost Control Strategies

NSPI continues to control costs in all aspects of its business. The four primary strategies to control OM&G costs are as follows:

- Matching of resources to the work required;
- Ensuring that the most competitive sources are used to get the work done;
- Investing for the lowest long-term cost;
- Designing targets and tracking systems to achieve continuous improvement.

These strategies are on-going and are reflected in the 2007 test year.

NSPI continuously looks for ways to improve the efficiency of its business and provide greater transparency to the UARB and other stakeholders. As a result, significant reorganizations have been carried out over the past twelve months:

- A new Customer Service group has been established, consolidating activities such as: call centre, billing, credit and collections, customer communications, quality assurance, meter services, heating solutions, large customer management, load and revenue forecasting and conservation/energy efficiency programs.

The areas of responsibility outlined above were previously split between Customer Operations and Sales & Marketing. As a result of the consolidation, Customer Service now has responsibility for all customer care functions, enabling increased responsiveness to customer requirements and greater efficiency in dealing with customer related issues. Customer Operations will focus on all transmission and distribution related activity, including supporting functions.

To simplify the comparisons for 2005A, 2006C, 2006F and 2007, dollar transfers from one group to another are only referenced where partial budgets have been affected, for example, the $1.3 million transfer from Customer Operations and Information Technology to Customer Service. Where full budgets were transferred (for example Customer Service in its entirety removed from Customer Operations), adjustments were made to 2005 and 2006 numbers to enable comparisons.

- NSPI has recently implemented a number of organizational and governance changes designed to provide increased autonomy for NSPI and its affiliates and greater transparency of NSPI's costs. These include:

    - Appointment of John McLennan as Chair of NSPI's Board, effective May 15, 2006;

    - Appointment of Ralph Tedesco, former NSPI Chief Operating Officer, as NSPI President & Chief Executive Officer, reporting to the Chair of NSPI Board of Directors, effective May 15, 2006.

- Procurement, Information Technology, Human Resources and Finance groups now report directly to NSPI. Any work carried out for affiliated companies is billed based on the UARB approved cost allocation methodology.

4.3 Operating Outlook

The 2007 forecast includes increased spending due to wage increases for both union and non-union employees. NSPI's contract with its 1,146 unionized employees was signed on December 2, 2004 and is effective from April 1, 2003 until July 31, 2007. The increased labour costs associated with the agreement are reflected in the 2007 test year. These union and non-union wage increases, without any offsetting adjustments, would have required an increase in OM&G spending of $3.7 million or 1.9 percent in 2007 test year expenses. However, NSPI will achieve offsets to this increase in order to maintain the 2007 OM&G expenses at 2006C levels with the exception of increased pension expenses.

4.4 Operating Group Summary

Three business units, Power Production, Customer Operations and Customer Service represent approximately 76 percent of 2007 OM&G expenses. The remaining 24 percent of OM&G is comprised of corporate pension expenses, capital overhead contributions and Corporate Support groups.

4.4.1 Power Production

Figure 4.1

Power Production ($M)			
2005A	2006C	2006F	2007
$69.1	$74.9	[redacted]	$75.7

Figure 4.1 outlines Power Production OM&G expenditures associated with the operation and maintenance of the generation fleet, as well as general costs for fuel procurement and management.

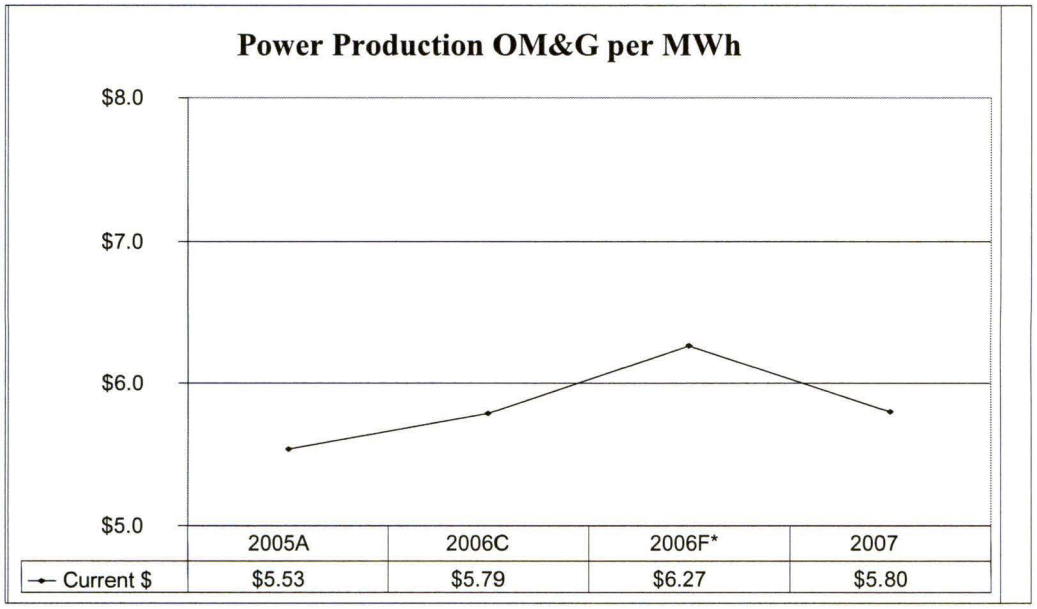
The Power Production business unit comprises 38 percent of the total OM&G expenses forecast for 2007. In 2007 these costs will increase by $800,000 over 2006C, an increase of 1%.

Cost Containment in Power Production

NSPI continues to control costs in Power Production while sustaining capacity factors, availability, reliability and performance at the same time as adding and upgrading generation. Power Production cost containment strategies are continuing to provide savings in 2007 and include life cycle management of machinery and labour management.

The Power Production OM&G requirement increase is $800,000 or 1 percent. Figure 4.2 shows that the cost per MWh will increase by only $0.01 over 2006C, including the effect of wage increases for union and non-union employees.

Figure 4.2



* Reflects reduced load due to a major customer not operating.

The factors driving the $800,000 increase in Power Production OM&G costs are outlined in Figure 4.3.

Figure 4.3

Cost	Amount ($M)
Union agreement and non-union labour increases	$1.6
Other (net of savings)	($0.8)
Total	**$0.8**

Union Agreement and Non-Union Labour Increases

The $1.6 million increase in Power Production OM&G costs since 2006C is a result of increased labour costs primarily due to the union agreement that was signed in December 2004. NSPI's compensation policy is to review market conditions annually and maintain salaries that are competitive with the market in order to attract and retain qualified personnel.

4.4.2 Customer Operations

Figure 4.4

Customer Operations ($M)			
2005A	2006C	2006F	2007
$51.3	$52.0	[redacted]	$52.3

NSPI's Customer Operations group provides services to residential, commercial and industrial customers across Nova Scotia. Customer Operations includes: Regional Operations (transmission and distribution field operating groups), Transmission and Distribution Assets (asset management – inspections, planning and engineering, fleet and vegetation management), the Ragged Lake Control Centre (System Operator function) and Administration. In the 2006 Rate Application, some Customer Service functions (e.g. call centre and billing) were also included in this group. Since that time, Customer

Service has been separated into its own operations group (see Section 4.2). Customer Operations costs are influenced by asset management needs, regulatory decisions, new customer growth and storm events.

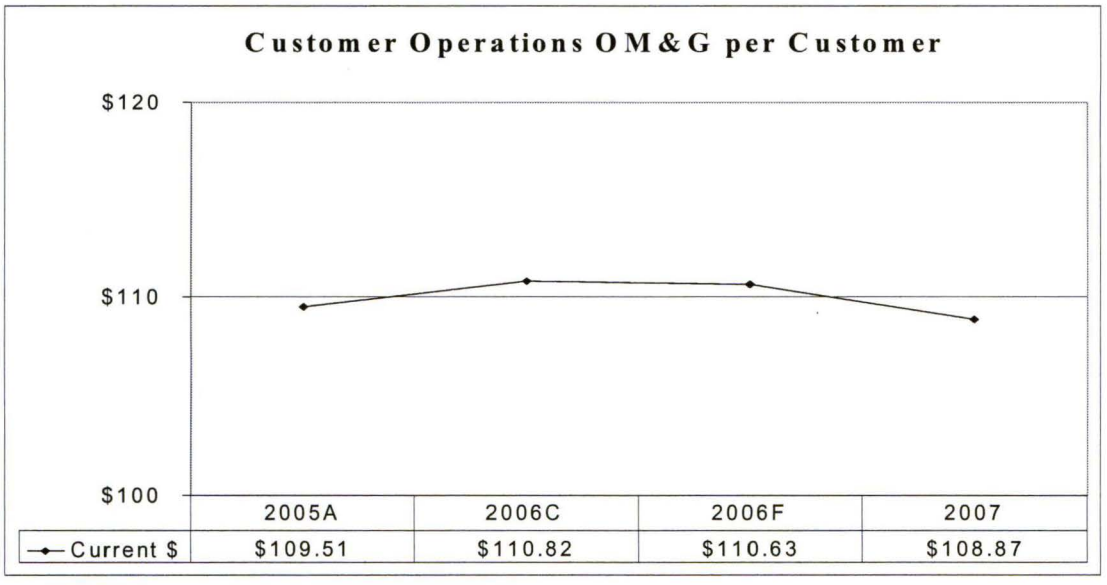
Customer Operations comprises 27 percent of the total OM&G expenses forecast for 2007. As shown in Figure 4.4, in 2007 these costs will increase by $300,000 over 2006C, an increase of 1%.

Cost Containment in Customer Operations

Customer Operations uses cost control strategies to ensure the business is run cost effectively. Overall OM&G expenses will increase in 2007 by $300,000 over 2006C, driven primarily by wage increases. This assumes no funding of new initiatives requested for 2007 and no further regulatory directives that increase costs.

Figure 4.5 below, shows that Customer Operations' cost per customer will decrease in 2007. While transfers out of Customer Operations have occurred in 2007, the cost per customer adjusted for these transfers of $700,000 is $110.32 which continues to be less than the 2006 forecast.

Figure 4.5



The factors driving the $300,000 increase in Customer Operations OM&G spending are outlined in Figure 4.6.

Figure 4.6

Cost	Amount ($M)
Union agreement and non-union labour increases	$1.0
Transfer to Customer Service	($0.7)
Total	**$0.3**

Union Agreement and Non-Union Labour Increases

Customer Operations OM&G spending will increase by $1.0 million in 2007 as a result of the union agreement and non-union increases.

Transfer to Customer Service

The internal reorganization outlined earlier in this section transferred costs associated with customer service functions (including the group's fleet fuel) from Customer Operations to Customer Service resulting in a decrease in costs in Customer Operations for 2007 of $700,000.

4.4.3 Customer Service

Figure 4.7

Customer Service ($M)			
2005A	2006C	2006F	2007
$22.7	$23.2	[redacted]	$25.0

NSPI's Customer Service group includes: call centre, billing, meter services, credit and collections, customer communications and quality assurance, all of which were formerly included in Customer Operations. It also includes heating solutions, large customer

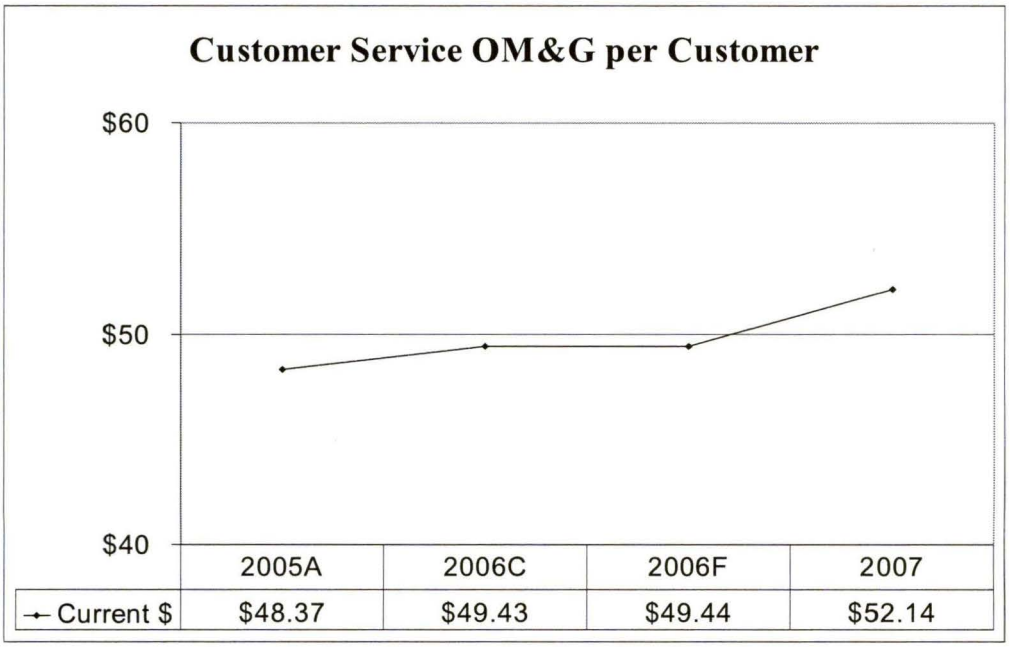
management, load and revenue forecasting and conservation/energy efficiency programs.

The Customer Service group comprises 13 percent of the total OM&G expenses forecast for 2007. In 2007 these costs will increase by $1.8 million over 2006C as outlined in Figure 4.7.

Cost Containment in Customer Service

Customer Service has continued to use cost control strategies to ensure the business is run cost effectively. Figure 4.8 below shows Customer Service costs per customer from 2005 to 2007.

Figure 4.8



While it appears the cost per customer has increased in 2007 over 2006F, with an adjustment for transfers of $1.3 million as indicated in Figure 4.9, the cost per customer in 2007 is actually $49.43 which is lower than the 2006F.

The factors driving the $1.8 million increase in Customer Service OM&G spending are outlined in Figure 4.9 below.

Figure 4.9

Cost	Amount ($M)
Union agreement and non-union labour increases	$0.5
Transfer from Customer Operations and Information Technology	$1.3
Total	**$1.8**

Union Agreement and Non-Union Labour Increases

Customer Service OM&G spending will increase in 2007 as a result of the union agreement that was signed in December 2004 as well as a non-union wage increase.

Transfer from Customer Operations and Information Technology

Due to reallocation of responsibilities and associated costs from other areas, Customer Service will see increased costs of $1.3 million. Transferred Customer Operations costs associated with Customer Service functions result in an increase in Customer Service costs of $700,000 for 2007. The Information Technology group in Corporate Support transferred $600,000 in costs associated with the Interactive Voice Response (IVR) system to Customer Service.

4.4.4 Corporate Support Groups

Figure 4.10

Corporate Support Groups ($M)			
2005A	2006C	2006F	2007
$35.5	$36.3	[redacted]	$35.1

NSPI's Corporate Support groups provide services such as regulatory compliance, accounting, internal controls, governance, administration, investor relations, human

resource management, stakeholder communications, procurement and information technology.

As outlined in Figure 4.10, NSPI's spending in its Corporate Support groups will decrease by $1.2 million in 2007 as compared to 2006C. This decrease contributes significantly to offset necessary increases in Power Production, Customer Operations and Customer Service.

Like other operating groups, Corporate Support groups work to control costs. Operational efficiencies, quality improvements, staffing levels, appropriate sourcing and investing for the lowest long-term cost are all considerations in determining business plan and resource allocations for the Corporate Support groups.

The $1.2 million decrease in spending in Corporate Support groups is a result of the transfer of costs to Customer Service and savings in each individual area. Overall savings in this area are partially offset by wage increases.

Figure 4.11 shows the main reasons for the decrease in Corporate Support OM&G spending.

Figure 4.11

Cost	Amount ($M)
Non-union labour increases	$0.5
Transfer of costs to Customer Service from Information Technology	($0.6)
Additional Savings	($1.1)
Total	**($1.2)**

These items are described in more detail in the following sections.

Executive Management

Figure 4.12

Executive Management ($M)			
2005A	2006C	2006F	2007
$2.3	$1.8	[redacted]	$1.6

As outlined in Figure 4.12, costs for Executive Management will decrease by $200,000 or 11 percent between 2006C and 2007, due to reduced labour and consulting costs.

The Executive group is responsible for providing corporate leadership and strategic direction. In prior Rate Applications, this group also included an allocation of the following Emera executives: Emera's CEO, CFO and VP of Human Resources. A time-tracking system ensured appropriate cost distribution between NSPI and other Emera companies, as directed by the Board in the 2002 Rate Case Order[59]. As a result of an organizational realignment, the above mentioned executives will no longer participate in NSPI's Executive group and, therefore, their costs will no longer be allocated to NSPI.

Labour costs are the largest of the expenditures in Executive Management. Other expenditures include industry membership dues, travel, consulting and other services driven by organization-wide or regulatory initiatives.

Human Resources

Figure 4.13

Human Resources ($M)			
2005A	2006C	2006F	2007
$3.2	$4.2	[redacted]	$3.7

[59] NSPI 2002 Rate Case, UARB Order, NSUARB – NSPI – P – 875, December 3, 2002.

Human Resources represents approximately 1.9 percent of projected 2007 OM&G expenses and is responsible for the development of strategies and management of human resources to support the execution of business plans. The Human Resources team supports NSPI in the areas of employee and industrial relations, training, apprenticeship, performance management, safety, pension, benefits and wellness administration, recruitment and policy. Human Resources is also responsible for recommending compensation levels for employees.

As outlined in Figure 4.13, costs for Human Resources will decrease by approximately $500,000 between 2006C and 2007 primarily as a result of reduction in staff and training requirements.

Human Resources continues to control costs through management of employee benefit programs. This is achieved by managing safety performance, implementing wellness programs to help reduce absenteeism and premiums, finding efficiencies in the administration of programs and continuation with participation of cost sharing for post retirement benefits.

Office of the Corporate Secretary & Office of General Counsel

Figure 4.14

Office of the Corporate Secretary & Office of General Counsel ($M)			
2005A	2006C	2006F	2007
$5.6	$5.6	[redacted]	$5.8

Office of the Corporate Secretary & Office of General Counsel include the functions of Corporate Secretarial Services, Legal Services and Insurance Risk Management Services; namely insurance and claim services.

Office of the Corporate Secretary & Office of General Counsel OM&G expenditures will increase by $200,000 in 2007 as shown in Figure 4.14. The increase of $200,000 is mainly due to increased insurance premiums.

Corporate Finance

Figure 4.15

Finance ($M)			
2005A	2006C	2006F	2007
$3.4	$4.0	[redacted]	$4.0

The Corporate finance function includes the activities of finance and accounting, tax, treasury, risk management and internal audit.

Costs in the Finance Department will remain flat compared to 2006C at $4.0 million as outlined in Figure 4.15. This ability to maintain stable costs in light of increasing labour expenses is attributed to a reduction in consulting fees due to changes in the new governance regulations required by the Canadian Securities Administrators (CSA).[60]

Investor and External Relations

Figure 4.16

Investor and External Relations ($M)			
2005A	2006C	2006F	2007
$1.4	$1.2	[redacted]	$1.4

[60] The proposed Multilateral Instrument, MI 52-111 has been withdrawn. An expanded MI 52-109 (Certification of Disclosure in Issuers' Annual and Interim Filings) now includes significant portions of the former MI 52-111; however, it has removed the requirement for external auditor confirmation attestation each year. http://www.csa-acvm.ca/html_CSA/news/06_07_internal_control.htm

Investor and External Relations include the functions of investor and government relations and public affairs. In prior rate cases, this group included Environment, which is now shown under the direction of Generation Development.

Investor and External Relations costs will be approximately $200,000 higher in 2007 over 2006C, as shown in Figure 4.16. Increased costs are due to the non-union labour increase and increased consulting costs, partially offset by a reduction in staff.

Regulatory Affairs

Figure 4.17

Regulatory Affairs ($M)			
2005A	2006C	2006F	2007
$4.6	$4.6	[redacted]	$5.1

Regulatory Affairs is responsible for matters relating to the regulation of the Company by the UARB and other energy regulators. The group's activities include regulatory liaison, compliance reporting, rate design and administration, code of conduct, presentation of the annual capital expenditure plan to the UARB and the management and presentation of all regulatory applications.

Regulatory Affairs represents 2.6 percent of forecast OM&G spending in 2007.

The significant expenses in the Regulatory Affairs group are consulting costs, UARB assessments and labour. Consulting costs include external consultants hired by NSPI and the UARB for regulatory proceedings and in compliance with regulatory orders.

In 2007, Regulatory Affairs OM&G costs will increase by $500,000 as compared to 2006C. An increase in consulting costs is partially offset by a decrease in external legal costs as a result of the increased staffing. This increase in staffing and consulting costs is primarily due to increased regulatory activity, hearings and UARB required studies.

Information Technology

Figure 4.18

Information Technology ($M)			
2005A	2006C	2006F	2007
$8.9	$8.7	[redacted]	$7.7

Information Technology costs will decrease by $1.0 million between 2006C and 2007, as shown in Figure 4.18. The Information Technology (IT) group provides equipment and related support and services to all areas of NSPI. A large portion of the decrease ($600,000) is due to a transfer of responsibility for, and costs associated with, the Interactive Voice Response (IVR) system to the Customer Service group. The remaining $400,000 decrease is mostly due to staff reductions from gained efficiencies and the IT group exercising cost control through standardization of software and vendor contract consolidation.

In mid-2003 the Company initiated a review of its Information Technology strategy to ensure that:

- Business needs were the basis for operating practices and technology selections;
- Maximum value was obtained for investments made;
- Services were effectively designed and delivered.

This strategy is now showing benefits by reducing overall costs in Information Technology, covering the costs of the non-union wage increases and achieving an additional $400,000 in annualized savings.

Facilities & Procurement

Figure 4.19

Facilities & Procurement ($M)			
2005A	2006C	2006F	2007
$6.1	$6.2	[redacted]	$5.7

Facilities & Procurement costs will decrease by $500,000 between 2006C and 2007, as shown in Figure 4.19. This is a result of staff reductions due to efficiency gains and recoveries from planned optimization of existing space. In addition to procurement of goods and services, this group provides:

- Full governance for all real estate acquisition and disposal decisions across the Company;
- Property management and facilities asset management;
- Overseeing of all critical NSPI building systems, including: HVAC, security and fire suppression.

4.4.5 Corporate Adjustments

Figure 4.20

Corporate Adjustments ($M)			
2005A	2006C	2006F	2007
$6.4	$11.1	[redacted]	$12.7

The remainder of OM&G costs represents corporate adjustments and credits for overhead costs that are allocated either to capital projects or to specific business unit OM&G accounts. In 2007 corporate adjustments will increase by $1.6 million over 2006C as shown in Figure 4.20. This is mainly due to a $3.2 million increase in pension expenses partially offset by applied overheads of $700,000 (which reduces the corporate

adjustment costs), resulting from increased capital spending and the net impact of lower payroll costs and corporate allocations of $900,000.

Corporate adjustments are expenses that are not assigned to a specific business unit or functional area. The primary components are certain payroll costs (including year-end payroll accrual, incentives and deferred severance), capital overhead contributions and a portion of pension expenses. Figure 4.21 summarizes the major components of Corporate Adjustments and Overheads.

Figure 4.21

Corporate Adjustments by Expense Type				
($ Millions)	**2005A**	**2006C**	**2006F**	**2007**
Payroll Costs	3.0	3.6	[redacted]	2.0
Pension	16.4	24.6	[redacted]	27.8
Applied Overheads	(12.1)	(14.8)	[redacted]	(15.5)
Corporate Allocations	(1.8)	(1.7)	[redacted]	(1.0)
Other	0.9	(0.6)	[redacted]	(0.6)
Total	$ 6.4	$11.1	[redacted]	$12.7

Pension Expenses

In the 2006 Rate Decision, the UARB approved the pension amount requested by NSPI based on a discount rate of 5.5 percent[61]. However, new discount rates are established on December 31st for the following year and the actual 2006 rate was set at 5.25 percent. As a result, NSPI's 2006 pension forecast increased from $29.8 million to $35.7 million.

Pension expenses will be $33.0 million in 2007 compared to $29.8 million in 2006C, an increase of $3.2 million. The increase to pension expenses resulted from the update of the return on asset assumption used in the 2007 pension calculation.

[61] NSPI 2006 Rate Case, UARB Decision, NSUARB – NSPI – P – 882, March 10, 2006, paragraph 407

Updated Return on Asset Assumption

In its pre-filed evidence in the 2006 Rate Decision, PricewaterhouseCoopers noted that the return on asset assumption and the discount rate were at the high end of reasonable ranges.

> ...major assumptions with respect to expected rate of return on assets and forecasted discount rate for liability valuation are at the high end of reasonable ranges...[62]

NSPI's actuary has also noted that the 7.5 percent return on asset assumption used in 2005 was high. Morneau Sobeco's (NSPI's actuary) "2005 Economic Assumptions for CICA 3461 Survey" indicates that the median asset return assumption used in reporting was 7.25 percent and the average asset return assumption was approximately 7.3 percent per annum. The general trend over the past few years has been a reduction in the asset return assumption. The survey indicates that less than half (42 percent) of the organizations surveyed used an asset return assumption of 7.5 percent per annum or higher. The 2006 Economic Assumption for CICA 3461 Survey has not been released but draft results show the asset return median of 7.23 percent and an average asset return of 7.17 percent. Accordingly, in this Application, NSPI has revised its return on asset assumption to 7.25 percent.

NSPI's actuary, Paul Chang of Morneau Sobeco, has provided the Company with the appropriate discount rate for CICA 3461 reporting purposes. Based on single "A" bonds, the current discount rate as of July 31, 2006 that would be used to determine CICA 3461 expenses for NSPI in 2007 is 5.50 percent. This discount rate assumption is consistent with the 5.50 percent used in 2006C.

With a change to the return on asset assumptions, the overall pension expense for 2007 has increased by $3.2 million. This results in the change to the OM&G revenue requirement for 2007.

[62] NSPI 2006 Rate Case, PWC Evidence, NSUARB – NSPI – P-882, March 10, 2006 Exhibit N-84, p. 13.

4.5 Five Year OM&G Forecast

In the 2006 Rate Decision, the UARB stated:

> ...PWC has recommended that future rate applications contain detailed five year forecasts of OM&G costs. The Board accepts this recommendation and directs NSPI to include detailed five year forecasts of OM&G costs in all future rate applications.[63]

In this Application, NSPI has included a detailed five year forecast of OM&G costs. Please see Appendix C.

Detailed multi-year forecasts of OM&G are inherently uncertain. A variety of factors can significantly affect specific OM&G costs from year to year, including: load growth, the extent and timing of plant maintenance, customer growth, changes in the regulatory environment, changes in pension expenses assumptions, fleet fuel costs, insurance cost increases or other market changes. NSPI's experience has been that any one of these can vary significantly from a given year to the next. The cost variance may then be further distorted in future year calculations.

As stated earlier, NSPI has diligently worked to keep the 2007 OM&G increase to a minimum with the only increase as a result of pension expenses. The OM&G requirement for 2008 is expected to require an increase to fund initiatives foregone in 2007 and anticipated in 2008.

Overall the five year forecast of OM&G costs shows continued cost increases. The costs and percentage increase over the five years are shown in Figure 4.22.

[63] NSPI 2006 Rate Case, UARB Decision, NSUARB – NSPI – P-882, March 10, 2006, paragraph 436.

Figure 4.22

	2007	2008	2009	2010	2011
OM&G costs	$200.9	$218.3	$223.9	$228.8	$233.5
Increase $	$3.3	$17.5	$5.6	$4.9	$4.7
Increase %	1.7%	8.7%	2.6%	2.2%	2.1%

In 2008 the increase over 2007 forecast is $17.5 million or an 8.7 percent increase. This increase consists of $11 million, or 5.5 percent, for potential new initiatives such as investments in vegetation management, succession planning, call centre third party overflow and various regulatory directive spending. The remaining $6 million, or 3.0 percent, is due to cost escalation.

The underlying assumptions in the five year OM&G forecast are:

- Wage increases for both union and non-union employees;
- Fleet fuel, travel expenses and freight – 6 percent increase per annum;
- Employee related expenses (other than labour) increase – 2 percent per annum;
- Communication expenses increase – 2 percent per annum;
- Pension costs - a decline in the years 2008 – 2011;
- Contract costs – actual escalations in the associated contracts, or estimates based on individual circumstances or 2 percent;
- Insurance costs – 10 percent annual escalation based on current insurance market;
- Corporate cost allocations – remaining consistent with the 2007 percentages;
- Vehicle and Administration overhead calculation - capital spend estimates laid out in the Annual Capital Expenditure plan;
- Property costs escalations – based on past experience rent cost escalation of 2.5 percent per annum and tax assessment increase of 3 percent per annum;

- Remaining property costs – 2 percent per annum;
- All other significant costs – 2 percent per annum;
- No unforeseen regulatory mandates.

Caution should be exercised as any change in forecast assumptions can have a material effect on the costs provided in this five year forecast as each year's costs are estimated based on previous years' estimates.

5.0 CAPITAL STRUCTURE AND FINANCING

5.1 Overview

On June 21, 2006 Standard & Poor's (S&P) downgraded NSPI's credit rating from BBB+ to BBB. As a result of this action, NSPI has the lowest credit rating of any regulated electric utility in Canada. This action comes after several years of continuous assessment regarding NSPI's cash flow and fuel commodity risk profile.

> The ratings action reflects an expectation that the company's historically weak cash flow metrics will not materially improve in the next several years given: no assurance of full recovery of fuel-related expense under the current regulatory framework; an evolving fuel procurement strategy; and upcoming challenges related to the approval, financing, and execution of several proposed capital projects.[64]

As NSPI stated in previous hearings, and as the Board recognized in its 2006 Rate Decision, NSPI's customers have a vested interest in a strong financial position for the utility.

> The Board recognizes that the interests of customers and shareholders of NSPI are not mutually exclusive. They both benefit from a financially sound utility.[65]

NSPI has not included extra costs associated with the downgrade in this Application as the full effect will be gradual. However, the downgrade will have long-term cost implications for NSPI and its customers as the company re-finances existing debt, attempts to issue new capital and enters into new fuel procurement arrangements.

Despite this, NSPI is not proposing at this time a change to the return on equity or the common equity ratio used for ratemaking purposes. Nevertheless, some background is helpful to provide context to NSPI's credit ratings and financial condition.

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[64] Standard & Poor's Research Update, "Emera Inc., Subsidiary Nova Scotia Power Inc. Ratings Lowered to 'BBB', Off Watch", June 21, 2006. See Appendix D, Attachment 1.
[65] NSPI 2006 Rate Case, UARB Decision, NSUARB – NSPI – P-882, March 10, 2006, paragraph 662.

A strong financial position ensures the Company will have access to the capital it needs at competitive rates, which helps reduce costs to customers. On an on-going basis, NSPI requires money from investors to re-finance existing loans as they mature. Future generation expansion and environmental investments will require significant capital that, if not readily accessible, could cause increased costs for Nova Scotia customers. The continued financial strength of the utility is an underlying requirement for the Company to be able to provide cost-effective, reliable service to customers.

In order to finance these requirements, NSPI obtains capital from two sources: debt investors and equity investors. If NSPI's returns are not competitive with other investments of comparable risk, investors will put their money elsewhere, with significant negative consequences for NSPI's customers.

> The Board understands the importance of ensuring that NSPI remain on a sound financial foundation as it heads into the future. The Company's ability to attract capital, access fuel markets and control costs must not be compromised.[66]

5.2 Credit Ratings

In the capital markets, a credit rating is an independent rating agency's opinion of the creditworthiness of a company – its ability to meet its obligations to its debt holders. It is the single most important factor influencing risk assessments of fixed income securities and bank credit terms. The higher the credit rating, the greater the perceived likelihood that the debt investors will receive their interest and principal payments as expected. As such, a company with a higher credit rating is a more attractive investment. Conversely, a lower credit rating can impact the ability of an issuer to access capital markets on a consistent basis, negatively impacting the cost and availability of both debt and credit.

Lower credit ratings reflect increased investor risk; therefore, investors expect to get paid more to provide funds to such an issuer. As well, some investors, such as pension funds and other institutional investors, are prohibited from investing in debt instruments below

[66] NSPI 2006 Rate Case, UARB Decision, NSUARB – NSPI – P-882, March 10, 2006, paragraph 665.

a certain rating. The lower the credit rating, the more stringent the terms will be, and the more restrictive the covenants on new issues will be. So the credit rating affects not only the cost of the debt, but also the amount and nature of capital that is available to the company.

Credit ratings are also used by entities involved in commodity sales and purchasing. Most entities require a certain minimum credit rating to grant credit when selling commodities to parties. If the party does not have an adequate credit rating, these entities require them to "post margin" or make a deposit with the seller to ensure payment. This increases the buyer's borrowing costs. When markets are tight, it is possible that buyers with lower credit ratings may not have physical or financial access to the commodities in question as the supply goes instead to companies with higher credit ratings. This is a situation that NSPI and its customers must avoid.

NSPI's Ratings

In recent years, NSPI has been under increasing credit rating pressure from two of the three agencies that rate NSPI's debt: S&P and Moody's. In 2005 both changed the outlook on NSPI's ratings from "stable" to "negative".[67]

> On July 5, 2005, the outlook on Emera and its subsidiary Nova Scotia Power Inc. (BBB+/Negative/--) was revised to negative from stable. Standard & Poor's stated at that time that regulatory developments could trigger another rating action, which could include a downgrade. The company's financial profile has been weakened by under-recovery of increasing fuel costs and the delayed and prolonged recovery of significant tax expense. Whether the ratings remain at their existing level of BBB+ with a negative outlook or move lower will depend largely on the outcome of the pending Nova Scotia Utility and Review Board rate determination, expected in the first half of 2006. Because NSPI contributes about 85 percent of Emera's cash flow, without solid potential for significant improvement in NSPI's credit metrics over the course of the next two to

[67] The Outlook associated with a credit rating provides the rating agency's opinion of the probable long-term direction of the issuer's credit rating. The outlook can be "positive, "stable" or "negative".
See Appendix D, Attachment 2; Moody's Investors Service, Rating Action, October 11, 2005.

three years and/or a reduction in NSPI's risk exposure to volatile fossil fuel costs, a downgrade is likely.[68]

Following the release of the 2006 Rate Decision in March, S&P placed NSPI on CreditWatch negative.[69] As noted previously, on June 21, 2006, S&P lowered its rating on NSPI citing ongoing concerns regarding cash flow and fuel cost recovery.

NSPI's credit ratings are at the lower end (that is less desirable) of those held by other Canadian electric utilities. NSPI's relative business risk profile is assessed to be higher than other regulated utilities, primarily due to the absence of a fuel adjustment mechanism or pass-through clause, which would ensure the recovery of volatile fuel costs. Figure 5.1 reflects S&P's business risk profile scores on a scale of 1 to 10 with 10 being the highest business risk.

Figure 5.1

Canadian Electric Utilities	Dominion Bond Rating Service (DBRS) Rating	S&P Rating	S&P Business Risk Profile	Moody's Rating
Altalink L.P	A/Stable	A-/Stable	2	Not rated
CU Inc.	A(high)/Stable	A/Stable	3	Not rated
ENMAX Corp.	A/Stable	A-/Stable	N/A	Not rated
EPCOR Utilities	A(low)/Stable	BBB+/Stable	N/A	Not rated
Maritime Electric	Not rated	BBB+/Stable	3	Not rated
Newfoundland Power	A/Stable	BBB+/Stable	3	Not rated
Nova Scotia Power	**A(low)/Stable**	**BBB/Stable**	**4**	**Baa1**

Accordingly, to compensate for this higher business risk profile and maintain a competitive credit rating, NSPI's financial profile – including its capital structure – should be stronger than that of other Canadian utilities. However, with the exception of

[68] Standard & Poor's, "Industry Report Card: Canadian Utility Sector", February 1, 2006. See Appendix D, Attachment 3.

[69] CreditWatch indicates that the rating agency is undertaking a 90 day evaluation of the company's circumstances to determine if the ratings should be confirmed or altered, either upward or downward. CreditWatch negative means that the rating will either be confirmed or lowered.

Altalink, which has a business risk profile of 2, NSPI's common equity component is actually lower than all of the other utilities listed above.

Although capital structure is important, credit rating agencies are more concerned about cash flow. Cash flow is the difference between cash coming into the Company and cash being paid out. Cash enables the Company to meet its commitments to debt holders. Of particular concern are funds from operations (FFO), which represent the net cash derived from the day-to-day running of the business before deducting outlays for capital expenditures. The prime financial ratios that rating agencies consider when performing credit assessments are FFO/debt and FFO/interest which measure the Company's ability to meet its debt and interest obligations with funds provided from day-to-day operations.

Over the past number of years, NSPI has been required to make substantial cash outlays. Regulatory decisions have deferred recovery of these cash outlays to future periods. (Refer, for example, to Section 3 for a discussion of the deferrals related to depreciation rates, Section 21 tax, and 2005 Q1 tax costs.) NSPI has also experienced rising fuel costs without full recovery in recent years, as a result of disallowances and higher than forecast fuel commodity costs. All of these factors weaken NSPI's day-to-day cash flow position.

Without a rate increase, NSPI's 2007 cash flow credit metrics fall in the range of BBB to BBB- according to guidelines provided by Standard & Poor's. With the proposed rate increase, NSPI's cash flow credit metrics will fall between BBB+ and BBB territory, as shown in Figure 5.2 and 5.3.

Figure 5.4

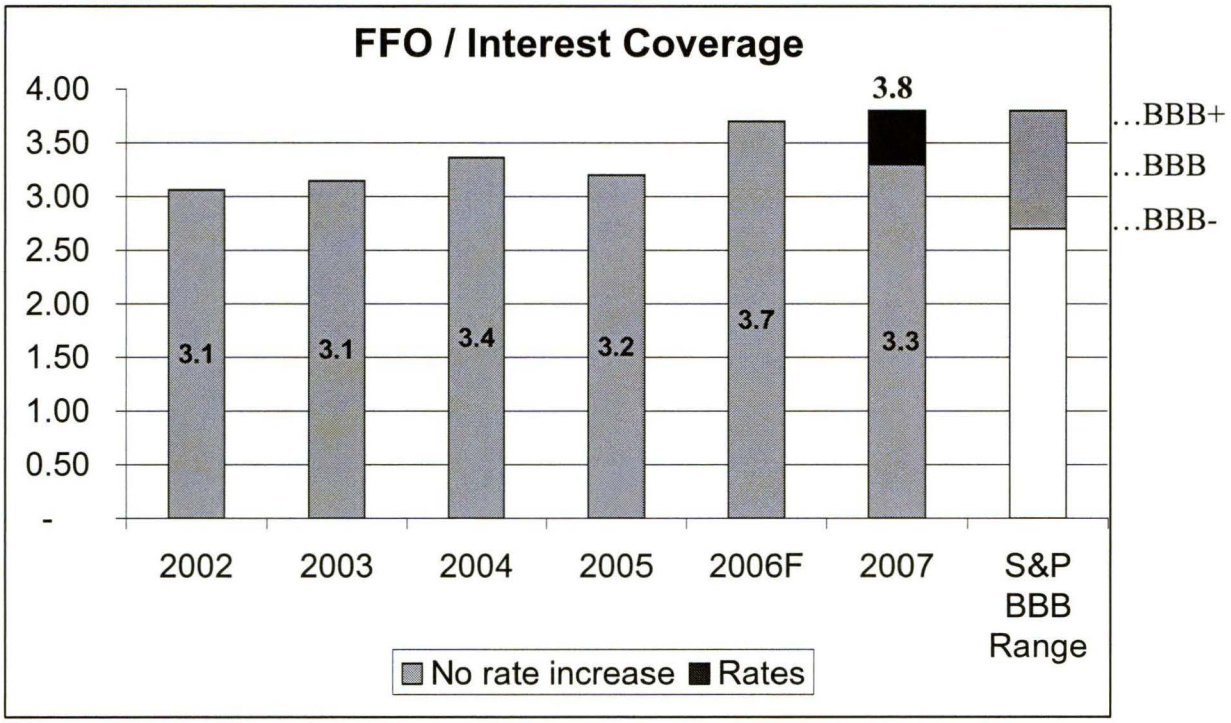
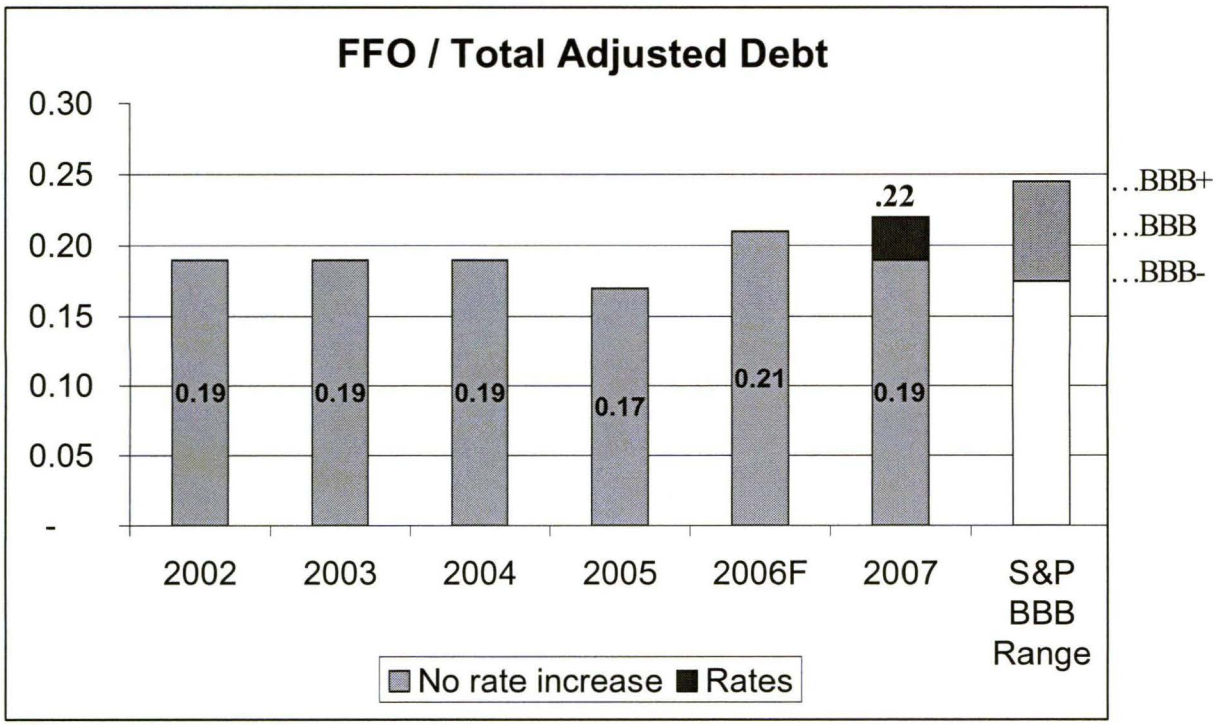


Figure 5.5



Without the rate increase that is requested in this Application in 2007, a further credit rating downgrade by S&P is a very real possibility.

> A negative rating action could result if the expected progress in the next two years toward improving NSPI's sustainable credit metrics and toward reducing cash flow exposure to uncertain costs recovery is not achieved.[70]

In summary, NSPI's current credit ratings are at the low end for Canadian utilities. It is critical to improve the Company's cash flow and fuel cost recovery situation in order to stabilize its credit ratings. This will ensure on-going access to capital and credit, which will enable NSPI to continue providing service at a reasonable cost. A reduced credit rating is difficult to restore. It eventually increases borrowing costs while reducing access to capital and availability of longer-terms, and will not enable NSPI to absorb any negative volatility in its financial performance. As well, a lower credit rating will eventually have an impact on NSPI's ability to procure commodities, particularly fuel, at competitive cost.

5.3 Return on Equity: Compensation for the Equity Investor

The return on equity earned by the Company is the compensation provided to the equity investor over the long-term. The return that can be earned by investors is assessed in terms of the risk of the investment compared to other alternatives.

The 2005 and 2006 Rate Decisions authorized a return on common equity of 9.55 percent on 37.5 percent common equity. Unlike pure transmission and distribution utilities, NSPI is subject to commodity and operating risks in its generation business, including fuel risk. Therefore, investors expect a fair return for NSPI to be higher than the allowed returns for utilities without this risk. NSPI's business risk profile is assessed by bond rating agencies and equity investors to be higher than that of other utilities.

[70] Standard & Poor's Research Update, "Emera Inc., Subsidiary Nova Scotia Power Inc. Ratings Lowered to 'BBB', Off Watch", June 21, 2006. See Appendix D, Attachment 1.

From an investor perspective, NSPI has the highest risk profile of all Canadian regulated electric utilities, but does not presently provide an expectation of a higher return. The comparisons with US utilities are poorer still. This is particularly relevant now with Canadian companies facing new competition in the financial markets from foreign issuers of debt and equity capital. The removal of the 30 percent cap on foreign investment in registered pension plans will affect access to capital markets for all Canadian securities issuers. Foreign utilities with higher returns and lower risk profiles than Canadian counterparts will be obvious choices for investors to make when investing in the utility sector.

Dr. Roger Morin provides evidence on NSPI's proposal to maintain its return on equity and capital structure at current levels in Section 5.5.

5.4 Financing Outlook

Financing costs reflect approximately 19 percent of NSPI's overall 2007 revenue requirement and represent the costs of providing returns to suppliers of capital including commercial paper investors, bondholders and preferred and common shareholders. As an asset intensive business, NSPI's financing costs are significant. Therefore, access to different types of financing that give the Company flexibility to take advantage of favourable financing options are fundamental to providing cost-effective service to customers.

Debt and Interest

NSPI uses a mix of fixed (that is, long-term) and floating rate (that is, short-term) debt in its capital structure. Long-term interest rates are normally higher and less volatile than shorter-term interest rates.

The Company's floating rate debt is obtained largely through its $400 million Commercial Paper (CP) Program. CP is short-term debt issued to investors with maturities of anywhere from a day to less than one year.

The predominant rating used by commercial paper investors in Canada is provided by the Dominion Bond Rating Service (DBRS). See Appendix D, Attachment 4 for the latest DBRS report on NSPI. NSPI's current rating of R1 (Low) is the minimum credit rating that allows an issuer to participate in this market without the requirement for a prospectus. CP is the lowest cost form of borrowing for NSPI. Participating in this market provides NSPI with flexibility in managing its cash flow, typically rolling over amounts between $5-10 million daily. Maintaining the current DBRS credit rating is imperative to have access to this efficient form of debt financing.

NSPI plans to participate extensively in the CP market throughout 2006 and 2007. The 2007 forecast monthly average short-term rate is 4.7 percent.

To issue long-term debt in the Canadian market, every issuer offering to sell securities to the public is required to file a prospectus with the provincial securities commissions of each province in which it expects the securities to be held. A prospectus is a legal document that describes the types of securities being offered for sale in the market. The prospectus provides all relevant information to potential investors so they may assess the quality of the investment, to determine if they want to participate in the offering. Rather than issuing a separate prospectus for every issue, some companies will file a "shelf-prospectus", which enables the company to issue up to a prescribed dollar amount of securities over a twenty-five month period.

NSPI has a shelf-prospectus in place, enabling it to issue up to $400 million in medium term notes (MTN)[71] from the period March 2005 to April 2007. The Company has issued $250 million during this time frame, leaving $150 million available to be issued under the prospectus. The issues are typically carried out through the Company's banking syndicate which includes five major Canadian banks who sell the debt to institutional investors such as pension plans, insurance companies and governments. Before the Company issues debt, it is required to confirm its credit ratings with the rating agencies in order for the issue to proceed.

[71] Medium Term Notes are long-term debt securities that in today's market can range from terms of two to thirty years.

Lower credit ratings attract fewer investors, and consequently lead to higher rates. In today's market, differences in credit spreads between BBB+ rated utilities and BBB rated utilities are between 15-35 basis points, depending on the term. In addition, lower credit ratings result in fewer options in available terms, that is, terms in excess of 10-years are not available for some entities with BBB ratings, increasing an issuer's re-financing risk.

NSPI has no new long-term debt issues included in the test year and has, therefore, not included any increased interest costs associated with the recent downgrade. Rating agencies look for sustained periods of improvement to upgrade ratings. NSPI's cash flow situation must be improved now to avoid higher costs in the future.

Preferred Equity

NSPI has $260 million of preferred equity in its capital structure. Preferred stock is a class of share capital that entitles the holder to a fixed dividend before any dividends are paid to common shareholders and to a stated dollar value in the event of liquidation. Preferred dividends for 2007 are consistent with previous applications.

In its credit assessment of NSPI, DBRS treats NSPI's preferred shares as 75 percent equity and 25 percent debt.[72] This serves to lessen the requirement for common equity in the capital structure by boosting credit metrics without the full cost of common equity -- the most costly form of financing.

Notably, as a result of S&P's recent rating action, NSPI's Preferred Share rating of BB+ is now below investment grade. Non-investment grade securities require high yields (that is high dividend rates) to be successfully marketed and/or attract limited investor interest because of the ineligibility for inclusion in investment portfolios.

On or after April 1, 2009, NSPI Preferred Series "C" shares are convertible into common equity of Emera at the option of the holder or can be redeemed at the option of NSPI. In

[72] The other rating agencies (S&P and Moody's) treat the preferred shares as debt equivalents.

either circumstance, NSPI will have a re-financing requirement. With a non-investment grade rating on preferred shares, this form of financing may be prohibitive from a cost and/or marketability perspective.

Without the option for preferred share issuance, the Company will be required to increase its common equity component in order to sustain its DBRS credit metrics. A thicker common equity component increases customer rates. This is another longer-term implication of the ratings downgrade.

Common Equity

In the 2002 Rate Decision the Board set rates using 35 percent common equity and said:

> The Board would indicate that it has no objection to NSPI increasing its actual equity ratio in the future to 40 percent. However, at any future rate hearing, the Board will determine what equity ratio is appropriate for ratemaking purpose.[73]

In the 2005 Rate Decision the Board approved an increase in NSPI's common equity to 37.5 percent for rate-making purposes, which was upheld in the 2006 Rate Decision. The Board said:

> The Board has considered the evidence concerning this matter and approves the proposed increase in the common equity ratio for ratemaking purposes from 35 percent to 37.5 percent. The Board is satisfied that the strengthening of the balance sheet in this way is desirable in the current economic climate. The Board notes that the majority of intervenors appear to be in favour of the proposed increase in the common equity thickness. [74]

The last time NSPI obtained common equity from the markets was late in 2002, following the 2002 Rate Decision. At that time, Emera issued common equity and injected one-half of the proceeds into NSPI to strengthen its balance sheet. Emera did

[73] NSPI 2002 Rate Case, UARB Decision, NSUARB – NSPI – P-875, October 23, 2002, paragraph 156.
[74] NSPI 2005 Rate Case, UARB Decision, NSUARB – NSPI – P-881, March 31, 2005, paragraph 166.

this to maintain NSPI's credit rating, which was under negative credit watch by DBRS.[75] Since that time, NSPI has maintained regulated common equity of at least 37.5 percent. However, adding more common equity now to NSPI's balance sheet, without the ability to earn an adequate return on the equity, will not improve NSPI's credit rating position and would weaken its attractiveness for equity investors.

Maintain Financial Strength

Without the rate increase requested in this Application, NSPI's weak cash flow position will persist. NSPI can expect to face difficulty in accessing reasonably priced capital in the financial markets and would expect increased fuel costs as suppliers build in premiums for additional credit risk. This inability to access affordable capital is in none of its stakeholders' interests, especially those of the Company's customers. Without access to capital and fuel commodities, NSPI could not operate, and Nova Scotians would cease to have a viable electric utility.

The long-term interests of customers and investors are best served by a utility that is financially strong. That will only occur if the Company recovers costs on a timely basis and has the opportunity to earn fair and reasonable returns.

[75] DBRS Press Release: Nova Scotia Power Inc. "Under Review with Negative Implications", October 30, 2002. See Appendix D, Attachments 5.

Testimony

OF

ROGER A. MORIN

FAIR RETURN ON COMMON EQUITY

FOR

NOVA SCOTIA POWER INC.

August 2006

5.5 Testimony of Dr. Roger A. Morin

PERSONAL INTRODUCTION

My name is Dr. Roger A. Morin. My permanent residence is in Atlanta, Georgia. I am Professor of Finance at the Robinson College of Business, Georgia State University and Professor of Finance for Regulated Industry at the Center for the Study of Regulated Industry at Georgia State University.

I hold a Bachelor of Engineering degree and an MBA in Finance from McGill University, Montreal, Canada. I received my Ph.D. in Finance and Econometrics at the Wharton School of Finance, University of Pennsylvania.

I have taught at University of Montreal's Hautes Etudes Commerciales, McGill University, the Wharton School of Finance at the University of Pennsylvania, Amos Tuck School of Business at Dartmouth College, Drexel University, and Georgia State University. In addition, I have developed and conducted numerous executive development programs for the University of Montreal, Hydro-Québec, Canadian Institute of Marketing, Investment Dealers Association of Canada, Financial Research Foundation of Canada, and Georgia State University. I was a faculty member of Advanced Management Research International, and I am currently a faculty member of The Management Exchange Inc., now known as Exnet, where I conduct frequent national executive-level education seminars throughout the United States and Canada. In the last twenty years, and throughout 2006, I am conducting regular national seminars on "Utility Cost of Capital", "Utility Capital Allocation", and "Alternative Regulatory Frameworks", which I have developed on behalf of The Management Exchange Inc. in conjunction with Public Utilities Reports Inc.

I have authored several books, monographs, and articles in academic scientific journals on the subject of finance. They have appeared in a variety of

journals, including The Journal of Finance, The Journal of Business Administration, International Management Review, and Public Utility Fortnightly. I published a widely-used treatise on regulatory finance, Utilities' Cost of Capital, Public Utilities Reports Inc., Arlington, Va. 1984. My second book, Regulatory Finance, a voluminous treatise on the application of finance to regulated utilities, was published in late 1994 by Public Utilities Reports Inc., Arlington, Va., and is widely used in the field of regulatory finance and economics. My latest book, The New Regulatory Finance, was published in 2006.

I served for three years as a consultant in computer applications in finance and investments for the Financial Research Institute of Canada. I was co-founder and director of the Canadian Finance Research Foundation. I have engaged in extensive consulting activities on behalf of numerous corporations and legal firms in matters of financial management and corporate litigation.

I have been a cost of capital witness before numerous federal, provincial, and state regulatory boards in both Canada and the U.S., including the Nova Scotia Utility and Review Board ("the Board"). In Canada at the federal level, I have appeared numerous times before the National Energy Board and the Canadian Radio-Television and Telecommunications Commission ("CRTC"). In the U.S. at the federal level, I have testified numerous times before the Federal Energy Regulatory Commission and the Federal Communications Commission. I have also appeared before some 50 regulatory bodies. I was, and continue to be, involved in several landmark proceedings involving the restructuring of the Canadian utility industry, notably in the field of the telecommunications industry on behalf of the CRTC, the natural gas pipeline industry on behalf of the National Energy Board, and the electric utility industry in the provinces of Quebec and New Brunswick. I was also, and continue to be, involved in several landmark proceedings involving the restructuring of the U.S. electric utility industry, notably in California, Pennsylvania, Mississippi, and Texas.

I was also a consultant on behalf of regulators as well, including this Board. I assisted the CRTC for four years in the fields of regulatory finance, applied economics and regulatory policy. I was a consultant for the Ontario Telephone Service Commission (OTSC) to establish procedures for determining the cost of capital for municipal, cooperative, and investor-owned telephone utilities regulated by the OTSC. I have frequently assisted regulatory commissions in matters of regulatory finance and cost of capital methodologies.

Purpose Of Memorandum

As part of its Application for 2007 rates, Nova Scotia Power Inc. ("NSPI", the "Company") is requesting to retain the 9.55 percent return on equity ("ROE") and the 37.5 percent common equity ratio authorized by the Nova Scotia Utility and Review Board ("UARB", the "Board") in the Decision issued on March 31, 2005[76]. I have been asked to provide an expert opinion on the fairness and reasonableness of the Company's proposal under current and prospective capital market conditions.

Summary

1) My assessment of NSPI's investment risk relative to other Canadian utilities is that business risk is above average, regulatory risk has increased slightly and lies slightly above that of other utilities, and financial risks have remained unchanged and are marginal relative to other utilities. The net result is that NSPI's total investment risk is above average relative to that of the energy utility industry in Canada. The inevitable consequence is that a higher allowed ROE and/or a stronger balance sheet are required to offset the Company's high business risk.

[76] 2005 Rate Case, UARB Decision, NSUARB – NSPI P – 881, March 31, 2005, paragraph 166

2) I conclude that the Company's deemed capital structure consisting of 37.5 percent common equity capital is very low given its above average business risk profile and given the deemed and actual capital structures of comparable electricity and gas distribution utilities. A capital structure consisting of 40 percent - 45 percent common equity capital would be more cost effective and reflective of the Company's high business risk.

3) I conclude that a fair and reasonable ROE for an average risk Canadian energy utility is in the range of 9.5 percent - 10.5 percent. In view of the fact that NSPI possesses above average business risk, I conclude that the upper portion of the range would be far more appropriate and reflective of the Company's business risk.

4) 2006 ROE awards for major investor-owned Canadian energy utilities average approximately 9.0 percent for the average typical Canadian utility and are expected to remain virtually unchanged or even increase slightly, given the actual behaviour and forecast level of interest rates. Because NSPI's risks exceed those of Canadian utilities, a higher ROE allowance is warranted. In order to reflect NSPI's weaker effective capital structure, the average allowed ROE of 9.0 percent would have to be adjusted upward by 60 basis points, raising the ROE from 9.0 percent to 9.6 percent. Alternatively, in order to equate NSPI's investment risk to that of the typical Canadian utility, a 40 percent - 45 percent common equity ratio would be required, versus the Company's deemed 37.5 percent.

Therefore, the Company's request to retain the authorized ROE of 9.55 percent is extremely conservative. I have reached this conclusion based on the changes in capital market conditions that have occurred since the Board's 2005 order and since the production of my own testimony in that proceeding.

Approach

On March 2005, the Board authorized a ROE of 9.55 percent, with a range of 9.3 percent - 9.8 percent, and a deemed common equity ratio of 37.5 percent. This decision was based on comprehensive expert evidence submitted by several cost of capital witnesses, including my own evidence. The witnesses' recommendations and conclusions were scrutinized and severely tested through the normal process of cross-examination and discovery. My ROE and capital structure recommendations in this memorandum are based on changes in capital market conditions that have occurred since the Board's 2005 Decision, the Company's relative investment risk, and the availability of comparable risk investment alternatives to investors.

This memorandum is organized in three (3) sections:

I. NSPI's Investment Risk
II. Capital Structure
III. Fair Rate of Return on Common Equity

I. NSPI's Investment Risk

It is convenient to disaggregate NSPI's risk into three broad components: business risk, regulatory risk, and financial risk. Business risk refers to the relative variability of operating profits induced by the external forces of demand for and supply of the firm's products, by the presence of fixed costs, by the extent of diversification or lack thereof of services, and by the character of regulation. Regulatory risk refers to the quality and consistency of regulation applied to a given utility and to the fairness and reasonableness of regulatory decisions. Financial risk refers to the additional variability of earnings induced by the

employment of fixed cost financing, that is, debt and preferred stock capital.

Relative to other Canadian energy utilities, NSPI possesses above average business risks, above average regulatory risk and average financial risks. The net result is that NSPI's overall risk substantially exceeds that of other Canadian energy utilities. Relative to Canadian electric utilities, NSPI is viewed as riskier principally because of its unique status as one of only two vertically integrated electric utility in Canada and the lack of a fuel adjustment clause. Relative to U.S. electric utilities, NSPI is viewed as riskier principally because of its weaker capital structure and financial indicators. It stands to reason that NSPI's allowed ROE and /or deemed common equity ratio should exceed those of its peers. These various risks are addressed in more details below.

Business Risk

To the extent that budgeted forecasts are made prior to regulatory determination of its rates, NSPI's principal source of business risk is forecasting risk. Potential deviations from expected profitability can occur due to unanticipated increases/decreases in costs, such as interest rates, inflation rates, exchange rates, and the price of coal, and due to unanticipated decreases/increases in revenues due to unforeseen economic cyclical variations and/or vagaries in weather, such as the devastating Hurricane Juan in 2003.

NSPI is selling electricity at regulated rates to customers whose energy demand is primarily dependent on the state of the economy (business cycle, work stoppages, factory closings, etc.) and the weather. With respect to economy-related risks, the business risks faced by the company relative to other Canadian utilities remain above average,

despite the improvement in the provincial economy in past years. The structural parameters of the province's economy remain fundamentally unchanged relative to the Canadian economy: a relatively weak regional economy, high unemployment and stagnant population growth.

The company continues to be vulnerable to lost revenues due to competition in the space and water heating markets from other energy sources, particularly from oil companies and eventually from natural gas. The availability of natural gas will likely present the most significant menace to the Company's revenue stream in the longer-term. Not only does this restrict its potential growth prospects, but the company's vulnerability is compounded by volatile fuel prices, notably coal. Cost-conscious industrial-commercial users with viable least-cost alternatives are prime targets for new cream-skimming competitors, to the extent that rates are not reflective of costs. There are potential incentives for some large volume users to bypass the network and/or to seek alternative energy providers to meet their energy requirements. Because large volume users represent a significant proportion of total revenues, the loss of this business could have serious long-term financial consequences.

With respect to weather-induced risk, NSPI operates in a relatively harsh climate with wide variations, imparting uncertainty to the revenue stream and exerting pressure on the physical assets. As a result of the variability induced by economic cycles and weather uncertainties, NSPI requires reasonable access to capital markets at all times. To illustrate, the ravaging Hurricane Juan of September 2003 and "White Juan" in early 2004, resulted in significant unexpected expenditures following the storms.

A key component of NSPI's business risk is the nature of its cost structure. If all production costs are variable, then operating income varies proportionately to sales variability. But, as is the case for NSPI, if a very large portion of costs are fixed and if there is very limited managerial manoeuvrability to reduce costs, operating income is far more volatile than sales. This magnification effect of fixed costs on the variability of operating income is known as "operating leverage" and is especially acute for NSPI.

Power Generation Risks

As one of only two publicly-traded investor-owned vertically integrated electric utilities in Canada[77] entrusted with the power generation function, NSPI necessarily faces higher business risks relative to its peers because the business risks faced by the power generation business exceed those of the transmission and distribution ("T&D") business. The electric utility industry has moved in the direction of more intense competition on the power generation side of the business; powerful buyers with many energy alternatives, including large industrial customers, result in a highly competitive market for electricity. Disintegrating entry barriers, intensifying rivalry among the rising number of competitors, more substitute products, and powerful buyers with many energy alternatives have resulted in a competitive energy production market in contrast to the T&D function that has remained largely monopolistic. Compounding the business risks of NSPI's power generation business are record-high and volatile fuel prices and potentially challenging environmental compliance requirements.

[77] The other company, FortisBC, faces far less business risk than NSPI because its generating plant is comprised of lower risk and lower cost hydroelectric facilities while NSPI's plant is largely coal and oil fired.

The investment community certainly believes that the power generation business has higher investment risks than the T&D business. In numerous articles discussing bond rating methods for electric companies, bond rating agencies have confirmed the view that fully-integrated electric operations which include generation exhibit higher risk profiles than T&D operations alone. To wit, the bond rating agencies have taken concrete steps to recognize the higher investment risks of the power generation business. Both Moody's and Standard and Poor's (S&P) report that fully integrated companies are expected to be capitalized with less leverage (less debt and more equity) than electric distribution operations in recognition of the lower business risks of the latter.

Bond rating agencies have taken concrete steps to recognize the higher investment risks of the power generation business and of NSPI in particular. For example, S&P reports in the aforementioned article regarding bond rating methodology for power companies worldwide that the median debt-to-capital ratio projected for "A" and "BBB"-rated electricity generators ranges from 35 percent to 45 percent. Whereas for transmission and distribution operations, S&P projects median debt-to-capital ratios of 55 percent and 65 percent for "A" and "BBB"-rated companies, respectively. The following table was taken in part from the article, which details S & P's financial medians:

	Total debt to Total Capital (%)	
	A	**BBB**
Transmission and Distribution Cos.	55	65
Generators	35	45
Vertically Integrated Cos.	45	56

The data in the table demonstrates that "A"-rated T&D companies have a projected median debt-to-total capital ratio of about 55 percent (which implies a total equity ratio of 45 percent). This capitalization ratio is much more highly leveraged than the level S&P projects for "A"-rated generators (65 percent equity, 35 percent debt). A similar trend applies to "BBB-rated" companies.

In a 2004 comprehensive study of the business risks of the utility industry, S&P assigned new business risk scores to utility and power companies to better reflect the relative business risk among companies in the sector. S&P has segmented the utility and power industry into the following sub-sectors reflective of their relative business risk:

1. Transmission and Distribution - Water, Gas, and Electric
2. Transmission Only - Electric, Gas, and Other
3. Integrated Electric, Gas, and Combination Utilities
4. Diversified Energy and Diversified Non-Energy
5. Energy Merchant/Developers/Trading and Marketing

Business risk scores are assigned on a 10-point scale (1 indicating low risk and 10 indicating high risk) based on the divergence of business risk. For example, the utility companies in the Transmission and Distribution category, without generation activities, have an average business risk score of 2.9, while the utility companies in the Integrated category, which includes power generation activities, have an average business score of 5.1. A similar pattern applies to bond ratings. As the power generation component of a utility's activities gains in importance, the credit score declines. I note that S&P has assigned a business risk score of 4, the highest among Canadian utilities except for TransAlta. The vast majority of investor-owned Canadian utilities are assigned scores of 2-3, and thus, have lower risks.

Examples of factors that increase the riskiness of NSPI's generation segment are increasingly stringent environmental and sitting restrictions, volatile fuel supply and transportation costs, and the ever-present concern regarding a regulatory finding of imprudent costs or operations. Because of the Company's predominantly fossil fuel-based generating capacity, a dominant element of business risk peculiar to NSPI is the potential environmental risks associated with changes in emission standards. Environmental compliance projects such as retrofit scrubbers and SCRs (that is, flue gas desulphurization and selective non-catalytic reduction facilities added to existing generating plants) are not only capital intensive, but they are also non-revenue producing in the sense that they are normally added based on requirements to serve existing customer loads and not new customer loads. They are also costly to operate, reduce the net generation from the plant and raise issues concerning efficiency of operations. Similarly, concerns are raised by other retrofit environmental compliance projects like cleaner replacement burners, equipment upgrades and emissions monitoring systems. Yet another special concern with environmental compliance projects is generally the scope and number of projects involved; they tend to produce numerous and staggered in-service dates that may be difficult to synchronize with base rate case proceedings.

Further accentuating NSPI's business risk relative to other energy utilities is the lack of a fuel adjustment clause increasing the Company's risk of not recovering its costs.

The investment community views all of these factors as contributing to the risk of NSPI's generation business. The net effect of all these business risk factors is that NSPI's business risks clearly exceed those of Canadian energy utilities. This is corroborated by the Company's bond ratings and business risk score that is the lowest (riskiest) among its

peers. I note that S&P has recently downgraded the Company's bonds to BBB from BBB+, one notch away from junk bond status.

I.2 Regulatory Risk

An important component of risk for utilities is "regulatory risk". On these grounds, regulatory treatment by the Board has been perceived by some investors as somewhat negative. Because rate decisions cannot be implemented retroactively, the Company's exposure to regulatory lag is substantial relative to other utilities. The problem of regulatory lag is well-known in the utility industry. Its presence makes it difficult to earn a reasonable rate of return, especially in an inflationary environment. Moreover, regulatory lag limits the pricing flexibility of the utility, and the company may be unable to respond to competitive pressures. Regulatory lag also creates mismatches between regulatory rates and supply-demand-costs so that prices are either too high or too low. Inefficient resource allocation and distorted consumer pricing signals may result. I believe the regulatory lag problem is more acute in the case of NSPI relative to other jurisdictions.

A salient element of regulatory risk peculiar to NSPI is the absence of a fuel adjustment clause ("FAC") in sharp contrast to the majority of North American utilities endowed with such a clause. The absence of such protection is factored into the Company's credit profile as a negative element, which in turn raises its cost of capital. To wit, the recent downgrade of the Company's bonds by S&P is attributed in part to the absence of a fuel recovery mechanism. In the absence of a FAC, NSPI's financial condition will continue to worsen, the probability of further credit downgrades increases, and its customers are at risk of having to pay higher rates due to access to capital being more expensive

for NSPI. I reiterate that the Company's bonds have been recently downgraded by S&P.

The absence of a FAC has substantial negative impact on the company's cost of debt and cost of common equity. With no provision for recovery of on-going fuel and purchased power costs, NSPI's risk, and therefore its cost of capital, is higher than that of its peers.

Therefore, in view of all these factors, I view NSPI's regulatory risks as above average at the present time, relative to other regulated utilities in Canada.

I.3 Financial Risk

Financial risk stems from the method used by the firm to finance its investments and is reflected in its capital structure. The greater the percentage of fixed charges to the total income of the company, the greater the financial risk. The use of fixed cost financing introduces additional variability into the pattern of net earnings over and above that already conferred by business risk.

With the movement towards a more global economy, rating agencies now assess companies using more global comparisons. Moody's and S&P both consider NSPI to have a relatively weak balance sheet and financial measures when compared to U.S. utilities. With NSPI's higher than average business risk, it is important for NSPI to at least maintain its current financial measures to continue with its current ratings.

The Company's deemed common equity ratio has improved significantly over the years and now stands at 37.5 percent. Comparisons of NSPI's capital structure and interest coverage ratios with those of Canadian utility companies indicate that NSPI's key financial risk ratios are at best

comparable to those of other energy utilities, despite the above average business risk factors discussed earlier. Moreover, when compared to industry peers in the United States, NSPI's leverage and cash flow coverages are much weaker than average. I further discuss NSPI's capital structure below.

The net result of this medley of risk factors is that NSPI possesses above average total investment risk relative to Canadian utilities. NSPI's business risks exceed those of other Canadian energy utilities, its regulatory risks slightly exceed those of comparable energy utilities, while financial risks are at best comparable to those of other Canadian utilities. NSPI's greater than average long-run business risks are not offset by the company's financial indicators, as further discussed below. NSPI's above average investment risk is corroborated by NSPI's bond rating of A(low) by DBRS, Baa1 by Moody's, and BBB by Standard & Poor's, while the majority of other Canadian utilities enjoy a superior bond rating. This is also corroborated by NSPI's business score of 4.0, the highest business risk rating for a regulated energy utility in Canada.

S&P's concerns with weak balance sheets, low allowed returns, and a renewed emphasis on business risk actually reinforce the conservative nature of the Company's ROE and capital structure requests. A regulatory decision weakening the Company's balance sheet and/or reducing allowed returns would not only be ill-advised but would certainly increase the probability of further downgrades.

Under present capital market circumstances, and given the investment community's concerns about overleveraged balance sheets and low allowed returns, it would be untimely and inopportune for the Board to weaken the Company's balance sheet. I urge the Board to opt for caution, prudency and financial stability of the Company at this time, at

a minimum retain the Company's currently allowed ROE and capital structure recommendations, and act in a manner conducive to alleviating the investment community's concerns with regard to overleveraged balance sheets and insufficient allowed returns.

II. Capital Structure

In order to establish the reasonableness of the Company's requested deemed capital structure consisting of 37.5 percent common equity capital, I have examined: 1) the common equity ratios imputed (deemed) by regulators, 2) actual capital structures of Canadian energy utilities, both investor-owned and government-owned, 3) actual capital structures of U.S. energy utilities, and 4) bond rating agency benchmarks.

Deemed Capital Structures

First, I note that following a long and protracted hearing, the National Energy Board recently raised the deemed common equity ratio from 30 percent to 36 percent for TransCanada pipeline. Because a vertically integrated electric utility is riskier than an energy transmission utility as discussed earlier, it stands to reason that a higher equity ratio is applicable to NSPI. Indeed, the Alberta board shortly followed suit after a prolonged generic hearing dealing with financial issues, and imputed common equity ratios ranging from 33 percent to 40 percent to the capital structure of gas distributors and electric utilities under its jurisdiction. Another development in recent years is the increased concern on the part of bond rating agencies with the relatively weak balance sheets of Canadian utilities, including NSPI.

As shown on Appendix E, Exhibit RAM-1, the average deemed common equity ratio for Canadian electric, gas distribution, and gas transmission

utilities is 38.0, 36.6, and 33.3 percent, respectively. The average ratio for all Canadian energy utilities is 36.3 percent. Focusing on the electric utilities group in the upper portion of Appendix E, Exhibit RAM-1, the average common equity ratio for the electric utilities group is 38.0 percent, which is higher than NSPI's deemed common equity ratio of 37.5 percent. Despite the fact that NSPI confronts higher business risk relative to its peers, the higher business risk is not offset by a higher deemed common equity ratio. Given that NSPI is a vertically integrated electric utility, focusing on the electric utilities group without the electric transmission utilities, the average common equity ratio for the remaining electricity distribution utilities is 40.0 percent, as shown on the table below, which again is higher than NSPI's deemed common equity ratio. Here again, NSPI's deemed common equity ratio is lower than the average of the major investor-owned electric utilities, all of which face lower business risk.

Company	% Common Equity
ATCO Electric Distribution	37.0%
ENMAX Distribution	39.0%
EPCOR Distribution	39.0%
Fortis Alberta	37.0%
Fortis BC	40.0%
Newfoundland Power	44.5%
Maritime Electric	40.0%
Average	**40.0%**

If we focus on those electric utilities that are most comparable to NSPI, namely, Fortis BC, Newfoundland Power, Maritime Electric, the average equity ratio is 41.5 percent, again higher than NSPI's.

I also note that in its generic Decision 2004-052, the AEUB approved a 37 percent common equity ratio for electricity distributors, which are less risky than NSPI on account of its power generation operations.

In sharp contrast to the deemed equity ratios in Canada, the deemed equity ratios of U.S. electric and gas utilities stand in the 47 percent - 48 percent range. U.S. utilities also enjoy substantially higher allowed returns on equity as evidenced by the average allowed return of approximately 9.5 percent in Canada versus 10.5 percent in the U.S.

Page 1 of Appendix E, Exhibit RAM-2 compiles the actual debt ratios for both publicly-owned and investor-owned Canadian electric utilities over the 2000-2004 time period as reported by DBRS in its February 2005 publication, "The Canadian Electricity Industry 2004." Page 2 of Exhibit RAM-2 displays the equity ratios, calculated as one minus the debt ratio for the same companies over the same period. The overall composite average equity ratio is 40.5 percent over the 2000-2004 period. The average is 47 percent for the investor-owned segment.

If we focus on the latest year's results Exhibit Appendix E, RAM-3 displays the equity ratios for 2004. The overall composite average equity ratio is 42.3 percent in 2004. The average is 46 percent - 47 percent for the investor-owned segment.

On the U.S. side of the border, as shown on Appendix E, Exhibit RAM-4 Pages 1-2, the average common equity ratio is 48.5 percent and 49.2 percent for investment-grade vertically integrated electric utilities and natural gas distributors, respectively.

It is reasonable to conclude from all these results that the Company's deemed common equity ratio of 37.5 percent is extremely low in view of

NSPI's higher business risk relative to its peers. One would normally expect the Company's high business risk to be offset by a stronger capital structure composed of more common equity capital.

S & P publishes financial benchmarks for regulated electric utilities. For integrated electric utilities with a business ranking of 4 (on a scale of 1 to 10 with 1 the least risky and 10 the most risky) as is the case for NSPI, the benchmarks for a single A rating, which I consider optimal for ratepayers, include a debt ratio in the range of 45 percent - 52 percent, that is, an equity ratio of 48 percent - 55 percent. The Company's deemed common equity ratio of 37.5 percent places the company well below the recommended target. The corresponding target range for a BBB rating, NSPI's actual bond rating, is 38 percent - 48 percent. Again, the company's 37.5 percent is insufficient as it is outside the target range for a BBB utility company and certainly not reflective of its high relative business risk.

III. FAIR RETURN ON COMMON EQUITY

According to the seminal risk premium principle, a fair and reasonable ROE is seen as the sum of the risk-free rate and a risk premium:

Return = Risk-free Rate + Risk Premium

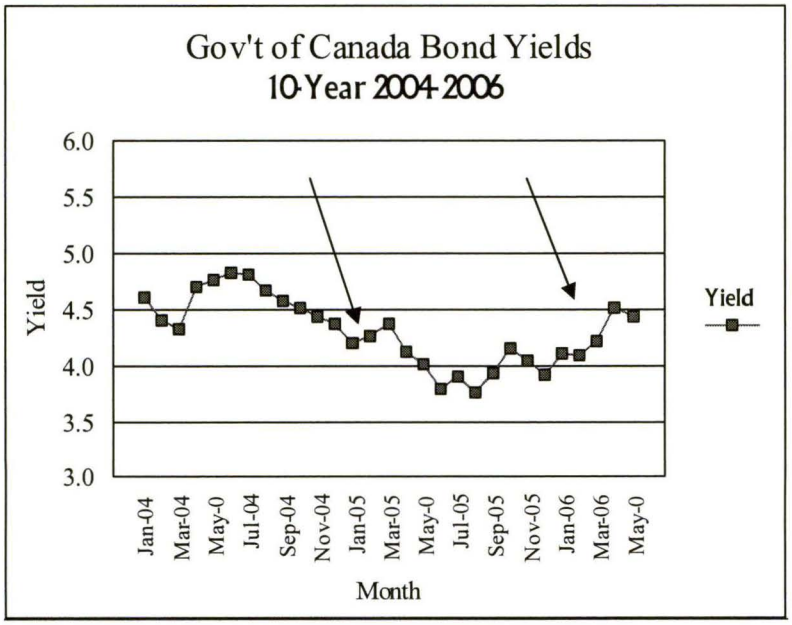
1 Risk-Free Rate

To assess whether NSPI's currently allowed ROE of 9.55 percent is reasonable, I examined the behaviour of both of these components since the Board issued its Decision in March 2005[78]. I also examined the currently allowed ROEs for Canadian utilities

[78] 2005 Rate Case, UARB Decision, NSUARB – NSPI P – 881, March 31, 2005.

compared to that of NSPI and evaluated the investment risk of NSPI relative to those companies in order to assess the reasonableness of the allowed ROE.

With regards to the risk-free component of return, I compared the level of interest rates when the Board issued its Decision in March 2005 with the current and prospective level of interest rates. As shown in the graph below, when the Board issued its Decision in March 2005, 10-year LTC bonds were yielding 4.4 percent. They are currently yielding 4.5 percent, and are expected to rise slightly. Therefore, from an interest rate perspective, there is certainly no valid reason to lower the allowed ROE, and if anything, it should be raised slightly.



As far as prospective interest rates are concerned, the May 2006 issue of Consensus Forecasts shows a LTC 10-year bond yield of 4.7 percent in twelve months time. Adding the historical spread of 30-40 basis points between 10-year and 30-year bond yields, the risk-free rate forecast is 5.0 percent. I note that the 4.7 percent

forecast is higher than the yield of 4.4 percent prevailing at the time of the Board's 2005 ROE Decision.

2 Risk Premium

With regard to the risk premium component of ROE, I compared my risk premium estimates presented to the Board in 2004 with current estimates. I found very little change. The table below compares the risk premium results obtained from the various cost of capital studies applied to various groups of Canadian and U.S. energy utilities in my 2004 testimony with current estimates:

STUDY	RISK PREMIUM	
	2004	2006
Capital Asset Pricing Model	4.4%	4.4%
Empirical Capital Asset Pricing Model	5.0%	4.9%
Electric Utility Industry Historical Risk Premium	5.6%	5.6%
Natural Gas Utility Industry Historical Risk Premium	5.7%	5.7%
Electric Utility Industry Prospective Risk Premium	5.0%	5.2%
Natural Gas Industry Prospective Risk Premium	5.4%	5.1%
Allowed Risk Premium Canada	5.2%	5.2%
Allowed Risk Premium US	5.2%	5.9%
AVERAGE	**5.2%**	**5.2%**
MEDIAN	**5.2%**	**5.2%**

The results are virtually unchanged. The average and median risk premium results are 5.2 percent in both 2004 and 2006. In light of the variability in those results, a risk premium in the range of 4.5 percent - 5.5 percent with a midpoint of 5.0 percent is

reasonable for the average risk Canadian utility in 2006, the same as my 2004 recommendation.

Using the forecast yields on 30-year long-term Canada (LTC) bonds of 5.0 percent from the May 2006 issue of Consensus Forecasts as an estimate of the risk-free rate, combined with a risk premium of 4.5 percent - 5.0 percent, a ROE of 9.5 percent - 10.5 percent is established and would be my recommendation for the average risk utility under normal rate proceeding circumstances in the absence of an automatic ROE adjustment formula. Of course, to the extent NSPI's risks exceed those of Canadian utilities, a ROE allowance in the upper portion of the range is warranted.

While my ROE recommendation request would stand at 9.5 percent - 10.5 percent under normal rate case circumstances, I would realistically expect a ROE allowance closer to the lower end of the range. My expectations are based on the results of ROE adjustment formulas presently in use by several Canadian jurisdictions, including the National Energy Board. 2006 ROE awards for major investor-owned Canadian energy utilities based on such formulas average approximately 9.0 percent for the average typical Canadian utility. Of course, to the extent NSPI's risks exceed those of Canadian utilities, a higher ROE allowance is warranted. Alternatively, in order to equate NSPI's investment risk to that of the typical Canadian utility, a 40 percent - 45 percent common equity ratio would be required, versus the Company's deemed 37.5 percent.

Financial theory provides a reasonable and consistent method of adjusting for the increased risk and return associated with higher debt levels (lower common equity ratios). The cost of equity for

a company with a weaker balance sheet, that is, less common equity capital, is higher because that company's effective leverage is higher than otherwise would be the case. It is a rudimentary tenet of basic finance that the greater the amount of financial risk borne by common shareholders, the greater the return required by shareholders in order to be compensated for the added financial risk imparted by the greater use of senior debt financing and/or debt equivalents. In other words, the greater the effective debt ratio, the greater the return required by equity investors.

Several researchers have studied the empirical relationship between the cost of capital and effective capital-structure changes. Comprehensive and rigorous empirical studies of the relationship between cost of capital and leverage for public utilities are summarized in Morin, Regulatory Finance, Public Utilities Report, Inc., Arlington, VA, 1994, Chapter 17.

The results of empirical studies and theoretical studies indicate that equity costs increase from as little as 34 to as much as 237 basis points when the debt ratio increases by ten percentage points. The average increase is 138 basis points from the theoretical studies and 76 basis points from the empirical studies, or a range of 7.6 to 13.8 basis points per one percentage point increase in the debt ratio. The more recent studies indicate that the upper end of that range is more indicative of the effect on equity costs.

Since the capital structure difference between NSPI's deemed common equity ratio of 37.5 percent and the 40 percent - 45 percent range consistent with its business risk amounts to 2.5

percent - 7.5 percent, the required upward adjustment to the cost of equity ranges from 7.6 to 13.8 basis points times 2.5 - 7.5, which equals 20 to 100 basis points. The midpoint of this range is about 60 basis points. Therefore, the allowed ROE of 9.5 percent would have to be adjusted upward by 60 basis points, raising the ROE from 9.5 percent to 10.1 percent, in order to reflect NSPI's weaker effective capital structure. Per force, the Company's request to retain the authorized ROE of 9.55 percent is extremely conservative.

If one speculates on allowed return estimates for 2007, the forecast 30-year Canada bonds of 5 percent suggests that allowed returns subject to formulaic adjustments will remain virtually unchanged or increase slightly, all else remaining constant. Therefore, the allowed prospective ROE of 9.0 percent would have to be adjusted upward by 60 basis points, raising the ROE from 9.0 percent to 9.6 percent, in order to reflect NSPI's weaker effective capital structure. Again, the Company's request to retain the authorized ROE of 9.55 percent is extremely moderate.

Relevance of International Comparisons

Consideration of the U.S. and world market results is certainly justified, and even more so since the Board's last ROE Decision, given the exponential increase in the degree of integration between the Canadian and U.S. capital markets in the last decades, as the barriers to entry in global capital markets have eroded. Canadian investors and analysts do compare U.S. equities with Canadian equities when making investment decisions.

A dramatic development of the last decade has been the integration of world financial markets into one global "supermarket". There is considerable evidence that national capital markets remain imperfectly integrated but are converging rapidly toward integration. Capital markets are far more integrated now than in the 1980s and 1990s. Transactions, diversification, and taxation barriers to investment in foreign securities by Canadian investors have eroded. It is now easier to purchase and sell shares traded on foreign exchanges. More shares of foreign companies are now interlisted on Canadian and US exchanges. The purchase of ADRs[79] (American Depository Receipts) and ADSs[80] (American Depository Shares) provides access to equity investments in foreign companies. A wide range of mutual funds with an international focus exists in Canada and the U.S. To illustrate, low-cost foreign index funds called "WEBS", an acronym for World Equity Benchmark Shares, eliminate some of the guesswork and costs of investing internationally. Each WEBS Index Series seeks to match the performance of a specific MSCI index.

The arguments for international investments are more powerful than ever, including superior performance, diversification, and the improvement of the risk/return trade-off. Diversification provides a substantial benefit of international investing. By spreading risks among different domestic equity markets, investors can achieve lower risks and/or improve investment returns.

[79] An ADR is a stock that trades in the United States but represents a specified number of shares; in a foreign corporation.
[80] ADS is the actual share trading; ADR is a bundle of ADSs.

Foreign content restrictions in Canada have been loosened considerably. Prior to February 2005, the level of foreign content permitted in RRSP portfolios had risen to 30 percent in Canada, which can effectively be increased to over 50 percent by investing the remaining 70 percent in shares of mutual funds which in turn have a foreign content of 30 percent. Now, with the most recent federal budget, the cap has been removed in its entirety. Cross-border access to capital by corporations is facilitated by the use of the multi-jurisdictional prospectus for new issues in North American capital markets, while international communications networks and equipment have facilitated the access to information on foreign securities. Global diversification is actively promoted by the investment community and by the investment academic literature.

In short, the integration and linkages between the U.S. and Canadian capital markets have greatly solidified in the last decade, and U.S. data are clearly relevant to both Canadian and U.S. investors. Given the escalating degree of integration of the U.S. and Canadian capital markets, regulators should be even more cognizant of the allowed returns and allowed equity ratios for U.S. utilities. Allowed ROEs on comparable risk U.S. utilities are far more attractive than those allowed Canadian utilities; on average, they are about 150 basis points higher, averaging about 10.5 percent, while allowed common equity ratios are close to 50 percent in contrast to the 40 percent allowed Canadian utilities. Once more, the Company's request to retain the authorized ROE of 9.55 percent and deemed equity ratio of 37.5 percent pales in comparison to such benchmarks.

6.0 RATE BASE

6.1 Overview

As directed by the UARB in the 2005 Rate Decision, NSPI determined its revenue requirement in the 2006 Rate Application based on a rate base methodology.[81]

Excepting adjustments to cash working capital (CWC), the Board accepted the calculations and assumptions used by NSPI to determine the rate base in the 2006 Rate Application. For this Application, the rate base methodology is maintained as described and accepted in the 2006 Rate Application with the exception of changes to the CWC allowance that are described in more detail in this section.

The average rate base for 2007 test year is $69.2 million lower than the 2006 Compliance Filing. The significant components are:

- Capital assets – decrease of $30 million
- Cash Working Capital – increase of $12 million
- Material and Supplies inventory – decrease of $3 million
- [redacted] – decrease of $16 million
- Deferred Charges & Credits – decrease of $32 million

6.2 Details of Rate Base

NSPI has, in the past, produced financial tables that started with the legal entity and made adjustments for unregulated activity to arrive at regulated financial statements. This approach is rather unusual as confirmed by NSPI expert witness Ms. Kathleen McShane during the 2006 Rate Hearing.

[81] NSPI 2005 Rate Case, UARB Decision, NSUARB – NSPI – P – 881, paragraph 158.

> This is a fairly unusual way of as far as Canadian utilities are concerned of presenting a regulatory balance sheet. Essentially what Nova Scotia Power does is present their statements in such a way that they tie them back to their corporate entity financial statements, which is relatively unusual.[82]

In addition, using a rate base methodology minimizes the relevance of unregulated activity in determining revenue requirement. In keeping with NSPI's efforts to provide clear and useful information, only the regulated financial statements have been produced for Appendix A.

Figure 6.1 below sets out the items included in NSPI's rate base for the 2007 test year, consistent with the items approved by the UARB in the 2006 Rate Decision.

Figure 6.1

Average Rate Base	2006C ($M)	2007 ($M)
Average capital assets	$2,390	$2,360
Average cash working capital allowance	$12	$24
Average materials and supplies inventory	$81	$78
[redacted]	$63	$47
Average deferred charges & credits	$295	$263
Total	**$2,841**	**$2,772**

Average Capital Assets

Average Capital Assets reflect NSPI's actual capital asset balances as of December 31, 2005. The Assets also include the 2006 Annual Capital Expenditure (ACE) Plan and the projected capital program for 2007, reduced by the accumulated depreciation and the depreciation expected to be taken in 2006-2007 in accordance with the UARB directives on the phasing in of new depreciation rates.[83] Average Capital Assets included in the

[82] NSPI 2006 Rate Case, Hearing Transcript, NSUARB – NSPI – P-882, November 22, 2005, Q.188, paragraph 961.
[83] See Appendix A, Table 14.

2007 test year rate base are valued at $2,360 million, a decrease of $30 million over 2006C.

Cash Working Capital Allowance

Cash working capital allowance (CWC) reflects the average amount of capital provided by investors above and beyond investments in plant and other separately identified rate base items. CWC investments bridge the gap between the time expenditures are made to provide service and the time payment is received for the service. This allowance is determined using a lead/lag study, which analyzes Company cash flows arising from its billing, paying and collecting procedures, with the goal of determining the average amount of working capital outstanding.[84]

As directed in the 2006 Rate Decision, NSPI has adjusted CWC for HST in this Application. The model calculates the payment lag for each type of expenditure. In its Decision, the Board stated:

> The Board believes this is a realistic manner of calculating the HST impact on CWC and, accordingly, accepts NSPI's calculation…[85]

Regarding the issue of lead/lag assumptions, the Board specifically identified three areas of concern: changes to NSPI's revenue lag, the lag for income taxes and the expense lag for labour. The Board stated that:

> The 2006 test year marks the first time that the determination of CWC allowance is relevant to the setting of rates.[86]

To address the previous concerns raised and to provide increased evidence to support its lead/lag assumptions, NSPI contracted Mr. John T. Browne, CA, of JT Browne Consulting to provide an appropriate methodology in determining lead/lag assumptions.

[84] See Appendix A, Table 17, which contains NSPI's calculations for working capital using the lead/lag methodology.
[85] NSPI 2006 Rate Case, UARB Decision, NSUARB – NSPI – P – 882, March 10, 2006, paragraph 263.
[86] NSPI 2006 Rate Case, UARB Decision, NSUARB – NSPI – P – 882, March 10, 2006, paragraph 308.

Mr. Browne was also responsible for reviewing NSPI's lead/lag calculations and providing an opinion on the appropriateness of the assumptions and calculations. At the time of this filing, Mr. Browne's report was not finalized. NSPI will be filing the report upon its completion as supplementary evidence.

When determining its 2007 CWC, NSPI included the following:

- Revenue lags as filed by NSPI in its 2006 Rate Application (42.1 days);
- All expense lags were maintained at the levels included in the 2006 Rate Decision;
- All expense categories were updated for the 2007 forecast;
- HST offset reduction to CWC was reduced to reflect the planned 1 percent reduction in the GST.

As a result of NSPI's methodology, the forecasted CWC at December 31, 2007 is $25.1[87] million, an increase of $12.6 million from the 2006 Rate Decision:

- $8.4 million as a result of increased revenue lag
- $4.2 million as a result of higher operating expenses (primarily fuel) and HST adjustment

Average CWC included in the 2007 test year rate base is $24 million, this is an increase of $12 million from 2006 compliance.

Materials and Supplies Inventory

Fuel and supplies inventory is based on the projected monthly average for 2007, consistent with the methodology used in the 2006 Rate Application. It consists primarily of coal and oil inventory as well as transformers and cabling to support the transmission and distribution system.

[87] See Appendix A, Table 17

Average materials and supply inventory included in the 2007 test year rate base is $78 million.[88] This is a decrease of $3 million from 2006 Compliance.

[redacted]

Deferred Charges and Credits

NSPI's methodology for calculating deferred charges and credits is consistent with the 2006 Rate Application. NSPI's approach was confirmed by the UARB in the 2006 Rate Decision where all components of the deferred charges and credits were included in the rate base calculation in NSPI's Compliance Filing.

Deferred charges reflect amounts that the Company has paid as part of the operation of the utility that have not yet been reflected in expenses and accordingly, have not been reflected in customer rates. Such items are used and useful for a number of reasons. For example, deferred charges include costs incurred to fund the pension plan, which is part of employee compensation, and costs incurred to execute debt transactions that are required to operate the business or pay past taxes on behalf of customers. A fair return on the assets compensates investors for the use of these funds.

[88] See Appendix A, Table 16.

The average deferred charges and credits for the 2007 test year are $263 million, a decrease of $32 million over 2006C. NSPI's deferred charges and credits are outlined in Figure 6.2.

Figure 6.2

Deferred Charges & Credits	2006 Average ($M)	2007 Average ($M)
Defeasance & Finance Charges	$161	$148
Section 21 and 2005 Q1 taxes	$147	$156
Prepaid Pension Asset	$51	$39
Asset Retirement Obligations	$(67)	$(77)
Other	$3	$(3)
Total	**$295**	**$263**

The amounts included in rate base reflect a simple year-end average, consistent with the methodology approved by the Board in previous cases. The $32 million reduction is primarily a result of defeasance amortizations reductions of $13 million, the addition of 2005 Q1 tax deferral net of amortizations of $9 million, pension asset reduction of $12 million and asset retirement obligation increases of $10 million.

Further explanation of these assets is described below.

Defeasance and Finance Charges

Defeasance costs are included in average rate base as approved in the 2006 Rate Decision. The reduction of $13 million in the average is due to amortizations on the defeasance deferred charges. These deferred amounts are being amortized over the life of the new debt in accordance with UARB Rate Decision NSPI P-863 in 1993[89].

[89] 1993 Rate Case, UARB Decision, NSUARB – NSPI – P – 863, p. 18.

Section 21 and 2005 Q1 Taxes

In the 2006 Rate Decision, the Board approved the inclusion of the Section 21 taxes in rate base. In this Application, the amortization of these taxes is included as directed by the Board in its 2005 Rate Decision:

> The Board finds that amortization of the s.21 taxes should be deferred for 2005 and 2006 and, in 2007, amortization over an 8 year period should commence.[90]

The UARB previously approved the deferral of $16.7 million of taxes in Q1 of 2005 representing amounts associated with the deferral of taxes in the first quarter of 2005. This Application includes the amortization of the deferral to commence in 2007 over a levelized eight year period similar to Section 21 tax deferral. As a result, the average deferred balance for taxes has increased $9 million due to the addition of Q1 tax deferral partially offset by the commencement of the amortization of Section 21 taxes and Q1 2005 tax amortization over eight years.

Prepaid Pension Asset

For the 2007 test year, NSPI forecasts pension funding at the minimum required amount of $23.7 million, while pension expenses are forecast to be $33.0 million.

Asset Retirement Obligations (ARO)

As part of the Depreciation Settlement reached in 2003, NSPI adopted the ARO methodology as proposed by Canadian Institute of Chartered Accountants, Handbook Section 3110 beginning in 2004. Under this methodology, an entity will recognize a liability for the fair value of its obligation to decommission a site when the obligation arises. At that time, a corresponding asset retirement cost is added to the carrying amount of the related asset. In subsequent periods, the amount of the liability is adjusted

[90] NSPI 2005 Rate Case, UARB Decision, NSUARB – NSPI – P-881, March 31, 2005, paragraph 327.

to reflect the passage of time with the change in the liability charged to depreciation expenses.

The average ARO amount deducted from NSPI's average rate base in 2007 is $77 million, an increase of $10 million over 2006C. This increase is in keeping with the Depreciation Settlement reached in 2003.

7.0 LOAD FORECAST

7.1 Overview

Peak demand and customer energy requirements have a significant effect on the costs associated with running NSPI. Growth in peak demand can affect fixed costs over the long-term, while growth in electric energy consumption drives up variable operating costs – especially fuel. As such, the electric load forecast, which provides an outlook on the energy and peak demand needs by month, is an essential part of determining future costs.

In addition, information from the forecast is used to allocate both fixed and variable costs by customer class in the cost-of-service model. Two key factors determine the required rate increase for each ATL class – the cost by class allocation outlined above, and the goal that, whenever possible, rate revenues recover within 5 percent of allocated costs.

Highlights of the 2006 forecast include:

- In-province electric energy sales, which have grown at an average annual rate of 1.9 percent over the past five years, are forecast to grow by 1.9 percent annually on average from actual 2005 results to 2015.

- 2007 residential sector sales are forecast to increase by 2.9 percent over 2006 projections, while commercial sector sales are expected to increase by 2.1 percent. 2006 industrial sector sales have been reduced by the temporary shutdown of a large paper mill. However NSPI's forecast assumes the mill will return to normal operation for 2007. With the effect of this closure removed, underlying growth in the industrial sector is forecast at 1.9 percent for 2007. The total in-province electricity requirement, including losses, is forecast to be 12,981 GWh in 2007. This represents a 12.1 percent increase over the 2006 forecast (adjusted for Q1

2006 actuals without weather normalization) of 11,580 GWh. Full details are provided in the 2006 Load Forecast Report, provided in Appendix F.

- Peak demand for the winter of 2006/2007 is forecast to be 2,256 MW, up from the 2,143 MW experienced in the winter of 2004/2005. In 2005/2006, warm weather conditions and industrial shutdowns saw a system peak of just 2,029 MW.

The load forecast is prepared using "billed" rather than "accrued" sales history. Due to the fact that many meters are read bi-monthly rather than monthly, actual month or year end consumption (accrued) is calculated using actual billed data and other parameters. The use of billed sales provides a longer-term historical time series on which to base forecast models. Accrued sales are shown in Table 7 of NSPI's financial tables in Appendix A. The revenue forecast is discussed separately in Section 9.0.

Electric load grows as new customers are added to the system. It grows as existing customers add electrical appliances or equipment, tempered somewhat by the fact that new equipment tends to be more energy efficient. It grows (or shrinks) with changes to the ownership and/or usage of certain end-uses such as space heating equipment that may be subject to competition from alternative fuel sources such as heating oil. The effect of weather conditions on the use of space heating equipment can also create significant variations in electric load. As a result, electric load growth tends to be tied to economic growth.

The following sections provide an overview of the development of the current load forecast.

7.2 Models

NSPI's load forecast is prepared using surveys, econometric and end-use models and assumptions regarding the economic, demographic and technological environment over the forecast period. The total demand for electricity is modeled by residential,

commercial and industrial sectors, plus exports and the losses associated with supplying load.

NSPI's forecasting procedures, which have been discussed in earlier proceedings, are modified and updated as appropriate. Alternate econometric model structures are tested and the models are updated where such changes improve the model structure and enhance or maintain accuracy. Current procedures are described in the 2006 Load Forecast Report (Appendix F).

Figure 7.1, which lists the annual forecast and actual in-province load, shows that the models have generally performed well. 2005 results show a decrease in overall load due to warmer than normal weather and the reduced industrial load associated with a plant shutdown in December. The actual econometric model equations and regression statistics are shown in the Load Forecast Report.

Figure 7.1

NSPI Energy Forecast Accuracy - unadjusted for weather effects				
Year	**Forecast GWh**	**Actual GWh**	**Variance GWh**	**% Variance**
1998	10,474	10,336	138	1.3
1999	10,669	10,870	(202)	(1.9)
2000	11,043	11,240	(197)	(1.8)
2001	11,439	11,303	136	1.2
2002	11,704	11,501	203	1.7
2003	11,833	12,009	(176)	(1.5)
2004	12,289	12,388	(99)	(0.8)
2005	12,663	12,338	325	2.6

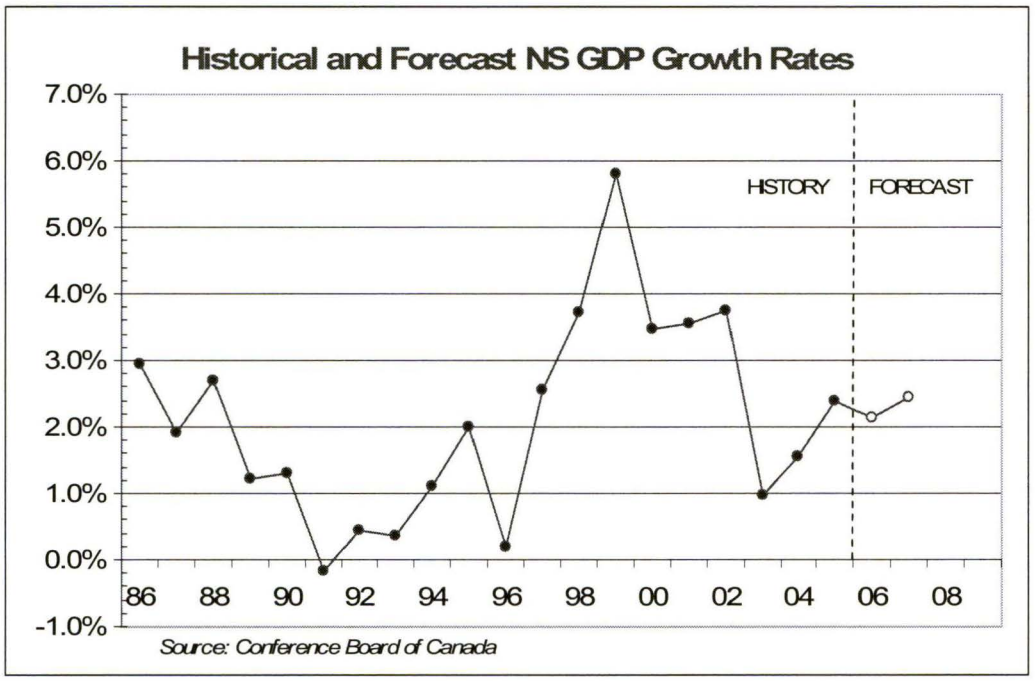
7.3 Economic Indicators

Economic indicators such as Gross Domestic Product (GDP) are primary inputs to the load forecast models. Historical trends show that electricity load growth and economic growth are closely related. The most significant economic indicator used in commercial and industrial sector load forecast models is the provincial GDP, or the total value of all

goods and services produced within the province. The Nova Scotia economic indicators and demographic data for 2007 are drawn from the Conference Board of Canada's economic forecast.

Historical and projected GDP growth rates are provided in Figure 7.2. For 2006 and 2007, the Nova Scotia GDP is forecast to grow by 2.2 percent and 2.5 percent, respectively. Provincial economic growth will be led by the service sector and primarily by continued momentum in retail sales.

Figure 7.2



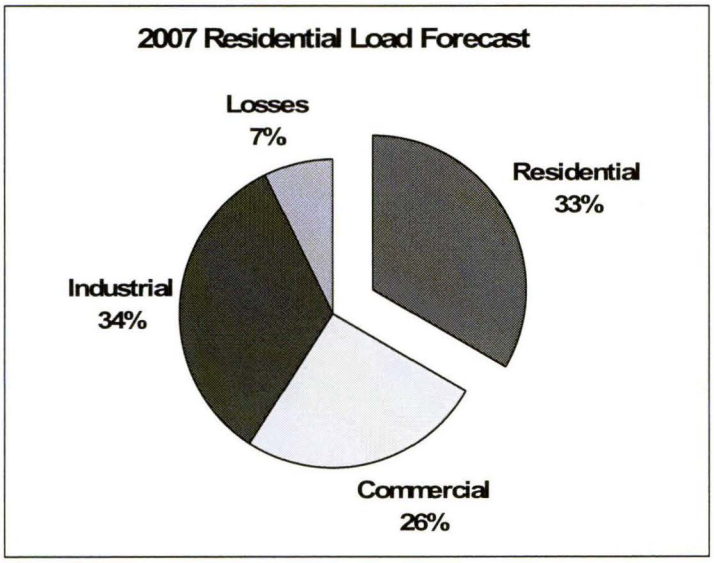
Inflation is expected to remain steady, with Consumer Price Index growth for Nova Scotia projected to be 2.2 percent for 2006 and 1.7 percent for 2007. Real personal disposable income is expected to increase by 2.2 percent in 2006 and 2.0 percent in 2007, after averaging 1.1 percent annual growth over the past five years. Retail sales are expected to grow at 3.8 percent for 2006 and 3.7 percent for 2007, similar to the average of 3.6 percent over the last five years. Housing starts were 4,775 in 2005 and, with borrowing costs expected to increase, are expected to decrease to 3,000 in 2007.

7.4 2007 Energy Forecast

7.4.1 Residential Sector

The residential sector is comprised of year-round and seasonal households, non-commercial farm use and the residential customers served by municipal utilities. In 2007, residential sales are expected to make up 33 percent of in-province energy requirements, as shown in Figure 7.3.

Figure 7.3



The residential forecast model is an end-use/econometric hybrid. The end-use model incorporates changes to household appliance loads based on appliance average use, maturity rates, efficiency improvements, market saturation and growth in the number of customers. The electric heating customer count is also used in conjunction with the anticipated heating degree-day estimate for the year to determine loads related to space heating.

The end-use modeling also includes detailed analyses of electric space heating and water heating loads, including market penetration rates based on the price ratio of electricity and heating oil. For the 2007 test year, the end-use model forecasts that approximately 33 percent of Nova Scotia residential customers will use electric space heating

equipment, up from 30 percent in 2005 and 31 percent for 2006. For 2007, 57 percent will use electric water heating, up slightly from estimated 55 percent in 2005 and 56 percent for 2006. NSPI's space and water heat market share models take electricity and competing fuel oil prices into account and so are affected by recent and forecast price changes.

Retail sales are the main economic indicator used in the residential econometric model. Retail sales represent the cumulative total value of all retail sales in the province, as measured in millions of dollars. Strong growth is expected to be maintained from 3.8 percent in 2005 to 3.8 percent in 2006 and 3.7 percent in 2007.

The historical forecast accuracy for this sector, with no adjustment for weather effects, is shown in Figure 7.4.

Figure 7.4

Residential Sector Forecast Accuracy			
Year	**Forecast GWh**	**Actual GWh**	**% Variance**
1998	3,672	3,524	4.0
1999	3,606	3,512	2.6
2000	3,636	3,672	(1.0)
2001	3,776	3,741	0.9
2002	3,904	3,829	1.9
2003	3,958	4,011	(1.3)
2004	4,107	4,114	(0.2)
2005	4,201	4,114	2.1

The residential sector load has grown at an average annual rate of 2.3 percent over the past five years. Annual energy and growth rates modeled for this sector are indicated in Figure 7.5.

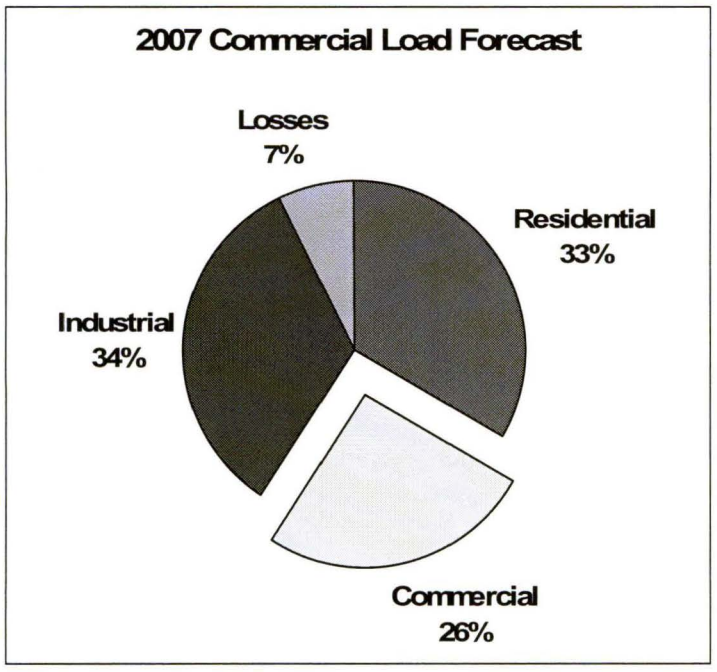
Figure 7.5

Residential Sector		
Year	**GWh**	**% growth yr/yr**
1998	3,524	(2.0)
1999	3,512	(0.4)
2000	3,672	4.6
2001	3,741	1.9
2002	3,829	2.3
2003	4,011	4.7
2004	4,114	2.6
2005	4,114	0.0
2006F	4,203	2.2
2007	4,327	2.9

7.4.2 Commercial Sector

The commercial sector includes restaurants, theatres, retail stores, banks, office buildings, malls, schools and street and traffic lights, etc. 2006 commercial sales are expected to make up 26 percent of in-province energy requirement, as shown in Figure 7.6.

Figure 7.6



The load forecast for this sector is developed using an econometric model that relates commercial customer consumption to GDP, disposable income, residential sector load growth and prior commercial load levels. Large firms with commercial operations in Nova Scotia, as well as institutions such as universities and hospitals, depend heavily on both the strength of the provincial economy and the level of government expenditures. These customers on the Large General rate are surveyed, forecast individually and reconciled to the commercial sector forecast.

The historical forecast accuracy for this sector, without adjustment for weather effects, is shown in Figure 7.7

Figure 7.7

Commercial Sector Forecast Accuracy			
Year	**Forecast GWh**	**Actual GWh**	**% Variance**
1998	2,771	2,702	2.5
1999	2,794	2,767	1.0
2000	2,871	2,829	1.4
2001	2,951	2,959	(0.3)
2002	3,075	2,996	2.6
2003	3,091	3,091	0.0
2004	3,197	3,188	0.3
2005	3,255	3,223	1.0

Figure 7.8 shows commercial sector load growth since 1998. Growth in this sector has averaged 2.6 percent over the past five years and, driven by continued strong wholesale and retail trade activity, is expected to grow by 1.6 percent in 2006 and 2.1 percent in 2007.

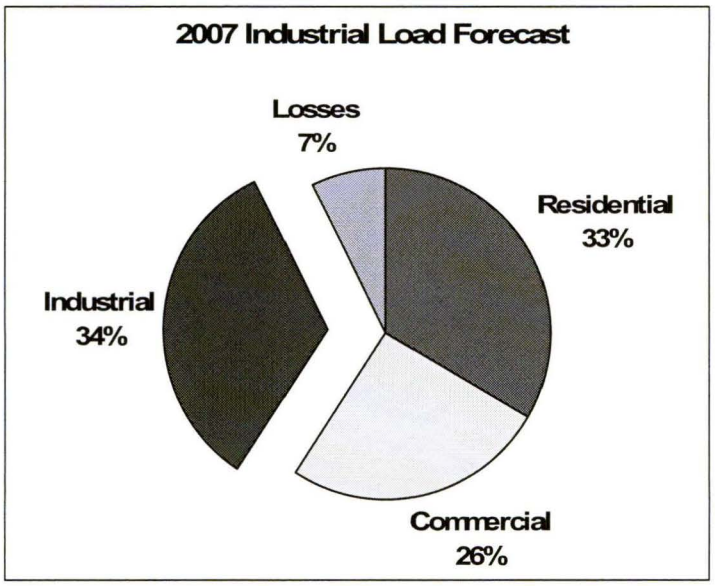
Figure 7.8

Commercial Sector		
Year	**GWh**	**% Growth yr/yr**
1998	2,702	(0.8)
1999	2,767	2.4
2000	2,829	2.3
2001	2,959	4.6
2002	2,996	1.3
2003	3,091	3.1
2004	3,188	3.1
2005	3,223	1.1
2006F	3,275	1.6
2007	3,345	2.1

7.4.3 Industrial Sector

The industrial sector includes customers who manufacture finished goods, or who process material to produce a product of higher value. This includes fish plants, pulp and paper mills, mines, tire manufacturers, furniture and clothing manufacturers, etc. In 2007, industrial sales are expected to make up 34 percent of in-province energy requirements, as shown in Figure 7.9.

Figure 7.9



The load forecast for this sector is developed using a combination of econometric modeling and large customer load surveys. Econometric models for small and medium industrial classes relate electricity consumption to GDP. For the large industrial classes, which exert a substantial impact on overall load, surveys provide an effective and comprehensive basis for the large customer forecast. Comprised of relatively few customers and spanning a variety of industries, large customers can be heavily influenced by factors external to Nova Scotia including foreign exchange rates and international demand for their particular exports such as newsprint or tires. Large customer surveys effectively capture this information and are therefore used to provide the basis for the large customer forecast. Plant or production changes within this large customer group add significantly to the uncertainty of the load forecast.

This method of forecasting accounts for economic conditions, changes in technology and end-uses, planned production changes, shutdowns and changes in the electric intensity of processes.

The historical forecast accuracy for this sector is shown in Figure 7.10. Industrial sales are relatively insensitive to weather, and therefore no normalization is required.

Figure 7.10

Industrial Sector Forecast Accuracy			
Year	**Forecast GWh**	**Actual GWh**	**% Variance**
1998	3,297	3,442	(4.4)
1999	3,497	3,872	(10.7)
2000	3,806	3,930	(3.3)
2001	4,020	3,873	3.7
2002	4,008	3,799	5.2
2003	3,899	4,046	(3.8)
2004	4,120	4,212	(2.2)
2005	4,339	4,215	2.9

Figure 7.11 shows load growth from 1998 to 2005. While industrial load growth tends to fluctuate significantly, it has averaged 1.4 percent per year over the last five years. Growth in this sector is driven largely by expansions at individual large customer sites and is offset by any business closures that may occur.

Figure 7.11

Industrial Sector		
Year	**GWh**	**% growth Yr/Yr**
1998	3,442	20.1
1999	3,872	12.5
2000	3,930	1.5
2001	3,873	(1.5)
2002	3,799	(1.9)
2003	4,046	6.5
2004	4,212	4.1
2005	4,215	0.1
2006F	3,362	(20.2)
2007	4,388	30.5

Major plant expansions contributed to substantial growth rates in 2003-2004; however, no large production additions are expected in 2006-2007 thereby tempering growth in this sector. The large swings in load growth for 2006-2007 are due to the temporary shutdown and restart of a large industrial customer. The forecast industrial sector load for the 2007 test year is 4,388 GWh, or 1.9 percent above the level for 2006, normalized for the effects of the shutdown.

7.4.4 Exports

Whenever economically feasible, NSPI sells energy to customers outside Nova Scotia, generally during the summer periods of lower in-province demand. The margin on these sales contributes to our annual fixed costs, thereby reducing the revenue requirement to in-province customers.

The forecast for export sales depends upon commodity prices, market demand for electricity, solid fuel plant utilization levels, plant dispatch constraints to meet emissions caps and foreign exchange rates.

2007 exports are expected to be lower than in recent years, primarily due to environmental constraints around emissions and higher in-province demand. In order to achieve reduced emissions, changes in plant dispatch and fuel mix are required. This increases the cost of producing electricity, making it less attractive in the export market. As shown in Figure 7.12, the current export forecast for 2007 is for sales of 76.2 GWh with associated losses of 2.4 GWh, for a total export requirement of 78.6 GWh, which is the total used for rate-making purposes.

Figure 7.12

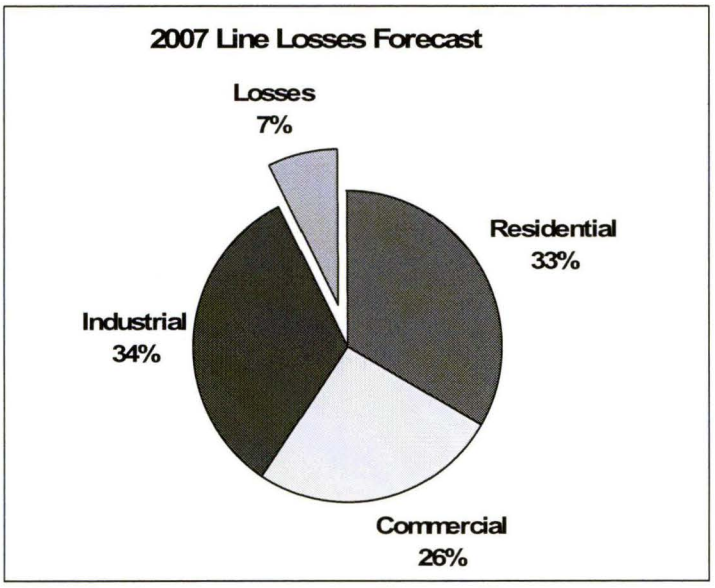
Export Sales		
Year	**GWh**	**% growth Yr/Yr**
1998	151	(52.8)
1999	185	22.6
2000	170	(8.1)
2001	304	79.0
2002	489	61.0
2003	301	(38.5)
2004	167	(44.6)
2005	136	(18.6)
2006F	180	31.8
2007	76	(56.3)

7.4.5 Line Losses

The percentage of energy lost in delivery varies according to volume, delivery voltage, temperature, line impedance, etc. Losses are estimated for both the transmission and distribution levels of the grid. Transmission losses are estimated using historical data from the Supervisory Control and Data Acquisition (SCADA) system and are based on the generation and transmission configuration. Transmission losses (69kV and above)

are forecast at an average of 2.9 percent of the total in-province load. Based on historical estimates, distribution losses are forecast at 6.4 percent of distribution sales, or 4.1 percent of in-province load. Overall, NSPI total system losses incurred on accrued energy sales are currently forecast at 899 GWh, or 7.0 percent of the 2007 in-province energy requirement as shown in Figure 7.13.

Figure 7.13



7.4.6 Total Requirement

The total energy requirement is the sum of the residential, commercial and industrial sectors as well as export sales and associated losses. Total requirement growth has averaged 1.8 percent per year from 2000-2005. It is modeled to drop by 4.4 percent for 2006 and rebound to 9.5 percent in 2007, due to the effects of the temporary large industrial plant shutdown. The underlying growth rate is 1.3 percent when the effects of the shutdown are removed from the growth calculation. The total energy requirement for the 2007 test year is 13,059 GWh as shown in Figure 7.14.

Figure 7.14

Total Requirement		
Year	**GWh**	**% growth**
1998	10,506	2.0
1999	11,079	5.5
2000	11,432	3.2
2001	11,646	1.9
2002	12,031	3.3
2003	12,329	2.5
2004	12,565	1.9
2005	12,483	(0.6)
2006F	11,935	(4.4)
2007	13,059	9.4

7.5 2007 Peak Demand Forecast

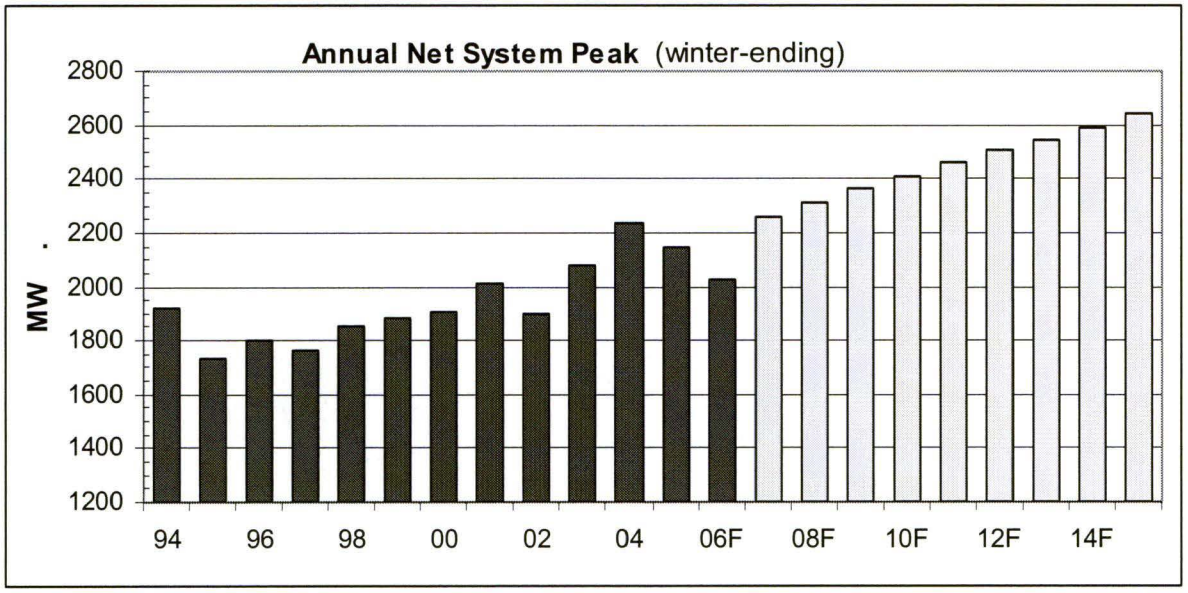
7.5.1 System Peak

System peak is defined as the highest single hourly average demand experienced in a calendar year. It includes both firm and interruptible load. The system peak forecast is used for operations and generation planning, and is also used for cost allocation purposes. Accurate peak forecasting relies on predicting a number of customer behaviours and weather effects.

With the exception of large customer classes, monthly and annual Net System Peaks are computed using forecast monthly energies and historical coincident load factors for each of the rate classes. For large customers, individual demand contributions to system peak are assessed based on recent history and/or new customer-specific information. Monthly peak loss percentages are applied to each monthly sales peak to produce losses by class and are then summed to produce the total peak demand forecast.

Over the longer-term, Net System Peak is forecast to increase from 2,143 MW in 2005 to 2,639 MW in 2015, which represents an average annual growth rate of 2.1 percent as show in Figure 7.15.

Figure 7.15



The actual hourly peak demand during 2005 was 2,143 MW and it occurred in January. This was 95 MW lower than the record previously experienced in January of 2004 (2,238 MW) and was due to the effects of differences in temperature and large customer behaviour. January 2005 did not have the sustained cold temperatures of the previous year.

2006 also has had lower peaks than forecast. The winter of 2006 was mild and, compounded with the reduced industrial load due to a large industrial shutdown, the actual peak was also lower than 2004.

The forecast peak for 2007 is 2,256 MW, based on an assumption of normal temperatures (30 year average) and industrial customers maintaining typical load. As the most likely case, this value is used for ratemaking purposes.

7.5.2 Non-Firm Coincident Peak

Certain industrial customers who meet specific criteria may contract to have their electricity supply interrupted on short notice in order to meet any necessary emergency peak reductions required to maintain system stability. Electric load under rates that allows for such conditions is considered "non-firm." There are several classes of non-firm rates: the "Interruptible" rider of the Large Industrial rate; the "Generation Replacement and Load Following" rate; the Additional Energy portion of Bowater Mersey Paper Company's (BMPC) demand; and the "ELIIR". Although the ELIIR is to be replaced, the new proposed rate is also non-firm.

An effective measure of the level of non-firm load is the amount of electricity available to be interrupted at the time of the maximum load on the system. Non-firm coincident peaks are typically in the range of 400 MW. The non-firm coincident peaks through the winter of 2006 were considerably lower than usual because the largest of the 27 customers on these rates was shutdown.

Non-firm coincident peak demand is forecast explicitly by customer. The customers who currently take non-firm service are expected to continue with this service. Therefore, non-firm coincident peak is forecast to remain at its current level assuming there are no major changes made to the rate's availability or requirements over the forecast period.

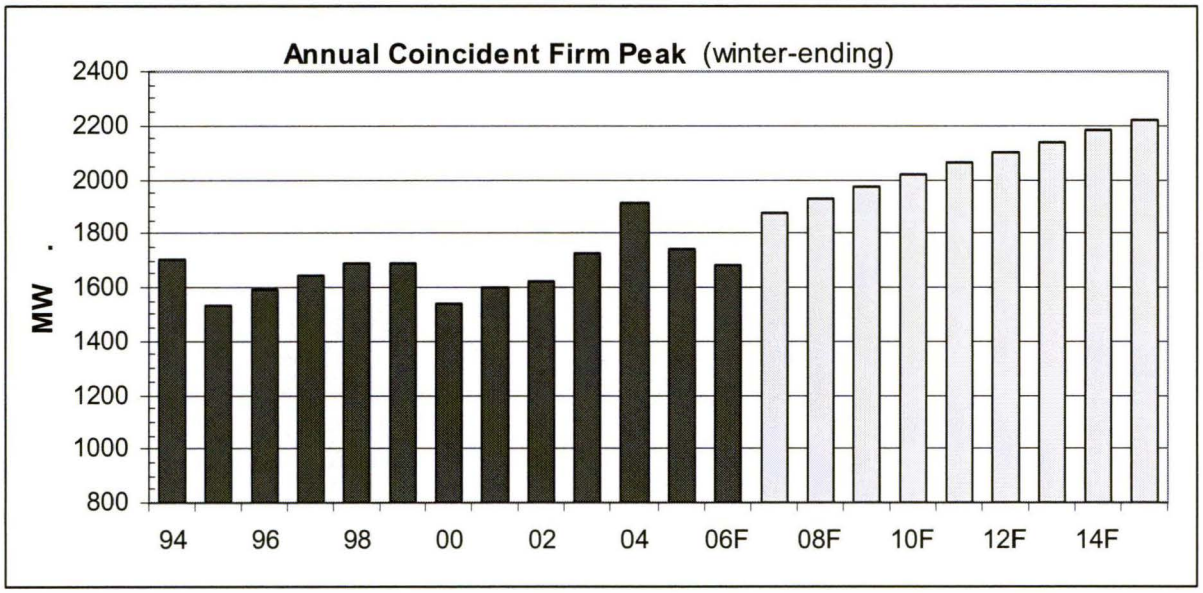
7.5.3 Total Coincident Firm Peak

Total Coincident Firm Peak is the demand at the time of NSPI's system peak that is attributable to all firm (non-interruptible) classes (for example residential, small general, etc.), but excludes the non-firm customer classes mentioned in the previous section. Since the customer classes with electric space heating loads are within this group, the firm peak varies substantially with weather.

The firm peak forecast is an important part of system planning. As required by the Northeast Power Coordinating Council and the NS-NB Interconnection Agreement, NSPI

is required to maintain a minimum planning reserve margin equal to 20 percent of its firm system load. The criterion states that the utility must plan its resources in such a manner that the probability of disconnecting non-interruptible customers due to a resource deficiency, will be no more than once in ten years, on average.

Figure 7.16



The coincident firm peak in January 2005 was 1,751 MW and only reached 1,683 MW in February 2006 due to mild winter temperatures. It is forecast at 1,875 MW for 2007, with the expectation of normal winter temperatures. For 2015, the coincident firm peak is forecast to be 2,224 MW for an average annual growth rate of 2.2 percent over the forecast period as shown in Figure 7.16.

8.0 COST OF SERVICE

8.1 Overview

In the development of new rates, revenue-to-cost ratios are an important consideration. These are determined using NSPI's Cost of Service Study (COSS) which the Company has prepared for the 2007 test year. This study is based on financial tables presented in Appendix A and prepared in accordance with the methodology approved by the Board. The Cost of Service Study is attached as Appendix G. Exhibit 1 of Appendix G presents class revenue-to-cost ratios under current and proposed rates.

In response to various UARB directives from the 2006 Rate Decision, the following changes have been made to NSPI's COSS:

- The COSS methodology has been updated to show average rate base, consistent with return on investment calculations shown on Table 1, Line 22 of NSPI's Financial Tables (Appendix A).

- A replacement rate for ELIIR is being developed as directed by the UARB in its September 28, 2006 Decision.[91] While this rate is considered a BTL rate for operational purposes, it is to be treated as ATL for costing purposes. The COSS has been modified to include this new class as well as methodology to split transmission-related costs associated with 138,000 volts and higher from other transmission and distribution costs.

- The direct expenses associated with serving the Additional Energy portion of BMPC load (as defined by the Mersey Agreement) have been corrected, from a marginal cost basis, to the same cost basis that is used for Interruptible Rider load. This approach is required to be consistent with

[91] NSPI 2006 ELIIR Replacement Hearing, UARB Decision, NSUARB – NSPI – P – 883.

Bowater's choice as to how Additional Energy is to be priced, and is the same as that presented in the prior ELIIR Replacement discussions.

- The costs associated with serving the Unmetered class were reviewed as ordered by the Board, resulting in changes to the costs allocated to this class as well as the COSS C-3 weighting allocator used to allocate customer service related costs.

- A review was conducted to update the capital and maintenance costs associated with supplying and maintaining street lights. This review concluded that changes were required to the capital and maintenance components of the various street light rates. Changes to these components, combined with a rebalancing of the "power and energy" component of the rates, reduce the overall revenue from the Unmetered class in 2007.

8.2 New Rate Replacing ELIIR and 2P-RTP

In its March 10, 2006 Rate Decision, the UARB directed NSPI to consult with its customers and by June 30, 2006, submit a new rate to replace the ELIIR, for use in 2007.

> It is clear to the Board that ELIIR is not working as it was originally intended to by both NSPI and SEB... Therefore, the Board will hold a separate hearing in 2006 to consider a replacement for ELIIR, which will become effective January 1, 2007. The Board directs NSPI to file an application for a new rate to replace ELIIR, after consultation with its customers, no later than June 30, 2006.[92]

After consultation with StoraEnso Port Hawkesbury Ltd. and Bowater Mersey Paper Company (jointly "SEB"), Dr. John Stutz and other stakeholders, NSPI filed the

[92] NSPI 2006 Rate Case, UARB Decision, NSUARB – NSPI – P – 882, March 10, 2006, paragraph 570.

proposed ELIIR replacement rate on June 28, 2006. Hearings were held to review this matter on September 5th to 8th, and the Board issued a Decision on September 28, 2006[93].

The Board directed NSPI to develop two specific rates and to prepare a Compliance Filing for their approval. For purposes of this Application, NSPI has followed the UARB's direction in using the COSS to determine ELIIR-2 costs, applied a 15 percent premium for priority supply Interruptibility, and applied a 95 percent R/C ratio in determining the ELIIR-2 revenue.

However, at the time of this Application, ELIIR-2 has not been finalized, and the customers have not selected their rates. Revisions resulting from the Board's pending Order regarding ELIIR-2 will be reflected in a future filing during this proceeding.

8.3 Direct Expenses Associated with BMPC's "Additional Energy"

In the process of determining the appropriate costs of serving each rate class, the COSS assigns direct expenses associated with serving BTL classes.

One of the BTL classes is the Generation Replacement Load Following (GRLF) class. Until 2004, this class was also used as the price BMPC paid for the Additional Energy portion of their load. This portion of their load, and the manner in which it is to be priced, is included in the Mersey System Agreement. In 2004, following a hearing on the matter, the UARB ruled that the Agreement permitted BMPC to choose one of either:

- The GRLF rate (more specifically the Load Following (LF), portion of that rate)
- The Interruptible Rider of the Large Industrial rate

Since 2004, BMPC has selected the Interruptible Rider, which provides them with lower energy costs.

[93] NSPI 2006 ELIIR Replacement Hearing, UARB Decision, NSUARB – NSPI – P – 883.

In order to appropriately reconcile costs with revenues for BTL rates, in this COSS the direct expenses associated with serving the Additional Energy portion of BMPC's load have been corrected from a marginal cost basis (that would have been assigned using GRLF) to be the same cost basis that is used for Interruptible Rider load. This reduced the fuel costs assigned to BTL Mersey Additional Energy by $5.2 million. This approach is required to be consistent with Bowater's choice as to how Additional Energy is to be priced.

8.4 Cost of Serving the Unmetered Class

In its 2006 Rate Decision[94], the UARB also directed NSPI to review the cost of serving the Unmetered Class, specifically with respect to:

- The "C-3 factor", which is used to allocate certain customer-service-related costs;
- Street light assets included in unmetered rate base;
- An updated street light cost study.

Full details of these three items were provided in a separate report entitled "2006 Unmetered Class Cost of Service Review and Street Lighting Study Report" filed with the UARB on July 31, 2006.

The updated study shows that the capital and "power and energy" cost components that form these rates should be reduced and that the maintenance component should be increased, prior to the adjustment required to recover 2007 costs. The capital and maintenance portion of street light revenue for 2007 has been calculated using the capital and maintenance rate components resulting from the study. The power and energy component of street light rates and all other unmetered rates is set based on the Miscellaneous Small Loads rate, which has been increased by the general rate increase percentage for 2007.

[94] NSPI 2006 Rate Case, UARB Decision, NSUARB – NSPI – P – 882, March 10, 2006, paragraph 598.

As a result of the updated cost study, the costs are determined using the COSS, and the revenues are determined by applying the new rate components as set by the street lighting study. The Unmetered revenue-to-cost ratio is a result of these figures.

8.5 Summary

The COSS methodology remains the same as previously approved by the Board. Changes in structure are as follows:

- The COSS methodology now uses average rate base rather than year-end;
- There has been a modification to the ATL class structure due to the inclusion of the ELIIR replacement class (ELIIR-2), which is also costed according to the COSS;
- The costs associated with transmission at 138,000 volts and above have been accounted for separately from other transmission costs to facilitate appropriate cost allocation to ELIIR-2;
- The direct costs assigned to BMPC's Additional Energy load have been corrected to reconcile to the price applied to the load;
- The customer service costs allocated to the Unmetered class have been reduced due to the removal of some cost centers previously included, as well as a reduction in the C-3 weighting factor.

9.0 REVENUE FORECAST AND PROPOSED RATES

9.1 Overview

From a cost-of-service methodology perspective, NSPI's customers fall into two broad categories, BTL and ATL. The revenue forecast to be received from BTL rates, which are adjusted annually with the exception of ELIIR-2, is calculated before determining the adjustment required to the ATL rates.

The cost increases described in preceding sections of this Application, which drive the revenue requirement increases for ATL classes, also result in required increases to BTL rates. BTL rates, also referred to as Annually Adjusted Rates (AARs), are rates normally recalculated and set annually based on pre-approved formulae and methodology. In 2006 however, based on the March 10, 2006 UARB Rate Decision, the ELIIR and Two Part - Real Time Pricing (2P-RTP) rates were set in a different fashion. In that same Decision, the Board also ordered that a cost-based replacement rate for ELIIR be filed for use in 2007.

Following a Hearing in this matter, the UARB issued a Decision on September 28, 2006[95]. The Decision stipulates that ELIIR-2 is to be a BTL rate, but for costing purposes it is treated as an ATL rate. As a result, pending further adjustments, the rate is considered to be an ATL rate for purposes of this Application.

There are several steps performed to calculate the proposed ATL revenue increase:

- Determine any total revenue shortfall from 2007 revenue requirement if no rates were to increase, other than the BTL GRLF rate, based on the forecast average marginal cost of energy in 2007;

[95] NSPI 2006 ELIIR Replacement Hearing, UARB Decision, NSUARB – NSPI – P – 883.

- Calculate the increase required to ATL rates, and specifically the increase in the Large Industrial Interruptible Rider;

- Apply the increase in the Interruptible Rider to the Mersey Additional Energy rate (another BTL rate), and recalculate the total expected BTL revenue;

- Calculate the resultant average ATL rate increase required;

- Apply this average increase to the Miscellaneous Charges as required, and to the "power and energy" component of the unmetered street light rates. This determines the Miscellaneous and the Unmetered Class revenues;

- Determine the revenue increases required from each ATL class, with the exception of the ELIIR-2 class (which has been set using a 95 percent R/C ratio for this Application) and the Unmetered class (which had already been determined in the previous step), taking into consideration the resulting revenue-to-cost ratios.

With ELIIR-2 sales priced at a 95 percent R/C ratio and treated as an ATL class, for purposes of this filing, and the Mersey Additional Revenue priced at the *current* Large Industrial Interruptible rate, the BTL classes are expected to produce revenue of $18.7 million.

Total in-province electric and miscellaneous revenues, priced at the current rates with the exception of the GRLF class, are expected to be $1,115.1 million. This represents an expected revenue increase of approximately 1 percent over the $1,106.6 million revenue requirement approved for 2006C. The increase in revenue is attributable to increased sales in 2007. Compared to the 2007 revenue requirement of $1,197.6 million, this would represent a revenue shortfall of $82.5 million prior to accounting for a required increase in Mersey Additional Energy revenue.

The Mersey Additional Energy portion of BMPC's rate is a BTL rate. As selected by the customer and permitted by the Mersey Agreement, this rate is priced at the ATL Large Industrial Interruptible Rider rate, requiring iterative calculations. An increase in the Interruptible Rider rate results in an increase to the BTL Additional Energy rate. The required revenue increase to the Mersey Additional Energy rate is $0.8 million, which increases BTL revenue from $18.7 million to $19.5 million. This increases the $1,115.1 million in expected total revenues to $1,115.9 million before the other required increases in ATL and miscellaneous charges are calculated.

The total revenue requirement for 2007, reflective of the revenue required from all proposed rates and fees (including Miscellaneous and Export revenues) is $1,197.6 million. Compared to the $1,115.9 million stated above, this results in an $81.7 million shortfall in revenue from the current miscellaneous and ATL electric revenue classes. As a result NSPI is seeking an average increase in rates of 7.5 percent to be applied to these revenue categories.

Each of these categories is described in detail in the following sections.

9.2 Below-The-Line Classes

These rates are normally prepared in the fall of each year and are submitted to the UARB for approval to be applied in the subsequent year.

As a result of the UARB's 2006 Rate Decision issued March 10, 2006, the ELIIR and 2P-RTP rates were not set as defined by the previously approved tariffs. The Board ordered them replaced for 2007.

The Board Decision in this matter was issued on September 28, 2006, but the final rate forms and levels will not be known until after the Board approves a Compliance Filing. NSPI has used the UARB's methodology in determining the ELIIR-2 revenue for 2007. Adjustments that may be required as a result of the Board's final Order on ELIIR-2 will be reflected in subsequent filings during the course of this proceeding.

Total sales to remaining BTL classes are forecast to be 379.7 GWh or approximately 3.1 percent of total in-province sales in 2007. Based on a UARB Order in October 2004, at the customer's option, the Additional Energy portion of Bowater Mersey's energy may be priced at the Large Industrial Interruptible rate or the Load Following Rate. This energy is priced at the Large Industrial Interruptible rate for 2007.

This means that changes to the Large Industrial Interruptible Rate that result from adjustments to the ATL rates also affect the BTL revenue, and a secondary adjustment is required to finalize the rates. The final forecast revenue from BTL sales, based on proposed rates, is $19.5 million or 1.6 percent of total revenues. BTL revenues are forecast at the individual customer level.

1.1.1 Generation Replacement and Load Following Rate (GRLF)

The Generation Replacement and Load Following (GRLF) rate is designed to provide both load following and back up service to large customers who own their own generation or otherwise qualify for the rate.

For 2006, energy sales under this rate are forecast at 11.8 GWh.

GRLF revenue is determined by applying the relevant rate components to the Load Following (LF) and Generation Replacement (GR) portions of the kWh sales projected for each customer. The LF rate is based on the expected average decremental cost of serving 25 MW of load in the 2007 test year, plus a $5/MWh adder. The GR rate is the sum of a $5/MWh adder and the actual marginal costs for the period of time under which the customer's generation is out of service. The rates are estimated based on the assumption of no exports being present on the system.

The proposed Load Following rate for 2007 is 10.82 cents/kWh.

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9.2.2 Real Time Pricing (RTP)/Load Shifting Rate

In recent years, NSPI has offered two RTP rates; One-Part and Two-Part RTP. 2P-RTP was only available to customers also using ELIIR. The Board's September 28th Decision directs NSPI to revise the 2P-RTP rate for use as an alternative to the former ELIIR rate[96].

The 1P-RTP rate has been little-used since 2003 and no sales are forecast under this rate for 2007.

9.2.3 Mersey System Rate

This rate is based on the Mersey Agreement. The rate is forecast based on budgeted costs used for billing throughout the year, and is adjusted at year-end with a thirteenth bill or credit, depending upon the difference between actual and budgeted costs.

A portion of energy sold under the Mersey Agreement includes "Additional Energy". The agreement permits the customer, in advance of each rate year, to select the GRLF rate or the Large Industrial Interruptible Rider price for this load. For 2007, revenue has been calculated assuming the use of the Interruptible Rider price.

9.3 Above-The-Line Classes

Rates for the ATL classes are allocated based on the forecast embedded cost of service for each class and are designed to provide revenues that will recover those costs within a range of plus or minus 5 percent of cost. NSPI's Cost of Service Study defining costs by class is attached to this Application as Appendix G. Unlike Annually Adjusted Rates, ATL rates are changed only through revenue requirement proceedings. Virtually all of NSPI's customers, with the exception of a few large industrial loads, are billed under ATL rates.

[96] NSPI 2006 ELIIR Replacement Hearing, UARB Decision, NSUARB – NSPI – P – 883, paragraph 143.

The forecast total revenue requirement in 2007 is $1,197.6 million dollars. Subtracting $19.5 million dollars in revenue forecast from BTL classes, $8.5 million dollars in revenue expected to be received from export sales, and $10.8 million dollars in revenue expected from miscellaneous charges (based on proposed fee changes), yields the revenue to be collected from ATL classes, namely $1,158.7 million dollars.

Under current rates the expected ATL revenue would be $1,077.4 million dollars, leaving a shortfall of $81.3 million dollars. This $81.3 million is the remaining increase required to ATL revenue after accounting for increases in Miscellaneous and Mersey Additional Energy. This $81.3 million dollar shortfall translates into an average increase in ATL rates of 7.5 percent.

The following sections discuss proposed changes to the ATL rates, as well as the expected revenue and revenue-to-cost ratios for each class. In allocating revenue responsibilities among rate classes, NSPI has followed a process intended to fairly and equitably recover costs from all classes. All classes have been brought within the prescribed 95-105 band. The classes with lower revenue to cost ratios experience higher revenue increases.

9.3.1 Revenue to Cost Ratios and Proposed Changes to the Above-The-Line Rates

Figure 9.1 compares projected costs to expected revenues priced at *current* rates, with the exception of exports and the GRLF class. This comparison shows a revenue shortfall of $82.5 million in 2007. This is before any increase is applied to the Mersey Additional Energy rate or miscellaneous revenues.

Figure 9.1

	R/C Ratio	% Revenue Increase	Revenue $ M
ABOVE-THE-LINE CLASSES			
Residential	**90.8%**	**0.0%**	**$481.6**
Commercial			
Small General	93.7%	0.0%	$28.1
General Demand	101.4%	0.0%	$244.3
Large General	90.9%	0.0%	$32.9
Total Commercial	**99.4%**	**0.0%**	**$305.3**
Industrial			
Small Industrial	94.3%	0.0%	$23.0
Medium Industrial	93.3%	0.0%	$46.8
Large Industrial	91.5%	0.0%	$68.9
ELIIR-2	85.4%	0.0%	$112.4
Total Industrial	**89.2%**	**0.0%**	**$251.1**
Other			
Municipal	89.7%	0.0%	$15.0
Unmetered	100.7%	0.0%	$24.4
Total Other	**96.2%**	**0.0%**	**$39.4**
Total Above-the-line classes	**92.9%**	**0.0%**	**$1,077.4**
Below-the-line		**0.0%**	**$18.7**
Exports		**0.0%**	**$8.5**
Miscellaneous		**0.0%**	**$10.5**
Total Revenue		**0.0%**	**$1,115.1**
Revenue Requirement		**0.0%**	**$1,197.6**
Revenue Shortfall			**($82.5)**

The $82.5 million shortfall between revenue collected under current rate and the revenue required in 2007 would result in an across the board increase of 7.6 percent if the increase in revenue requirement were spread using the same percentage for all ATL classes.

As described in Section 8.0, the Unmetered class revenue is largely pre-determined by the updated street light study which results in an overall unmetered class revenue decrease of 0.9 percent. This reflects the Board-ordered review of the costs of serving this class. As ordered, NSPI filed a report on the updated costs of serving the Unmetered

Class on July 31, 2006. Revised capital and maintenance cost components for individual street lighting types determine the non-energy components of these rates. The Miscellaneous Small Loads rate was used to determine the power and energy portion of the rates. As a result, the revenue from this class is specifically determined for 2007 and the rates have not been further adjusted using the revenue allocation procedure used for other classes.

For the purpose of presenting the revenue associated with the pending replacement rate(s) for ELIIR, NSPI used 2007 costs, a 15 percent increase in interruptible credit, and a 95 percent R/C ratio. The ELIIR-2 rate is then excluded from the revenue allocation process applied to all the other ATL classes.

This means that the average increase required for all remaining ATL classes is 7.3 percent. The resulting revenues and revenue-to-cost ratios for 2007 are as shown in Figure 9.2.

Figure 9.2

	R/C Ratio	% Revenue Increase	Proposed Revenue
ABOVE-THE-LINE CLASSES			
Residential	**97.6%**	**7.3%**	**$516.9**
Commercial			
Small General	100.7%	7.3%	$30.2
General Demand	108.9%	7.3%	$262.3
Large General	97.7%	7.3%	$35.3
Total Commercial	**106.8%**	**7.3%**	**$327.7**
Industrial			
Small Industrial	101.3%	7.3%	$24.7
Medium Industrial	100.2%	7.3%	$50.2
Large Industrial	98.4%	7.3%	$74.0
ELIIR-2	95.0%	11.1%	$124.9
Total Industrial	**97.4%**	**9.0%**	**$273.8**
Other			
Municipal	96.4%	7.3%	$16.1
Unmetered	99.9%	(0.9)%	$24.2
Total Other	**98.4%**	**2.3%**	**$40.3**
Total Above-the-line classes	**100.0%**	**7.6%**	**$1,158.8**
Below-the-line		**3.9%**	**$19.4**
Exports		**0.0%**	**$8.5**
Miscellaneous		**3.5%**	**$10.8**
Total Revenue		**7.4%**	**$1,197.6**
Revenue Requirement		**0.0%**	**$1,197.6**
Revenue Shortfall			**$0.0**

As previously stated, the goal for rate-making purposes is to set rates that will provide sufficient revenues to keep each of the revenue-to-cost ratios between 95 and 105 percent.

Figure 9.2 shows that a simple across-the-board increase of 7.3 percent (with the exception of the Unmetered and ELIIR-2 classes) would put the General class outside of this range.

NSPI used a process of adjusting this 7.3 percent increase by rate class, such that all classes were brought within the allowable band, while at the same time providing sufficient revenue to meet the revenue requirement.

The process used is as follows:

1. First, the General rate class increase was reduced from 8.7 percent to 3.5 percent in order to reduce the revenue-to-cost ratio to the maximum-allowable 105.0 percent, down from 108.9 percent. Making only this change reduces the revenue from the General class, producing a revenue shortfall of $9.4 million as shown in Figure 9.3.

Figure 9.3

	R/C Ratio	% Revenue Increase	Proposed Revenue
ABOVE-THE-LINE CLASSES			
Residential	**97.6%**	**7.3%**	**$516.9**
Commercial			
Small General	100.7%	7.3%	$30.2
General Demand	105.0%	3.5%	$252.9
Large General	97.7%	7.3%	$35.3
Total Commercial	**103.7%**	**4.3%**	**$318.3**
Industrial			
Small Industrial	101.3%	7.3%	$24.7
Medium Industrial	100.2%	7.3%	$50.2
Large Industrial	98.4%	7.3%	$74.0
ELIIR-2	95.0%	11.1%	$124.9
Total Industrial	**97.4%**	**9.0%**	**$273.8**
Other			
Municipal	96.4%	7.3%	$16.1
Unmetered	99.9%	(0.9)%	$24.2
Total Other	**98.4%**	**2.3%**	**$40.3**
Total Above-the-line classes	**99.2%**	**6.7%**	**$1,149.3**
Below-the-line		**3.9%**	**$19.4**
Exports		**0.0%**	**$8.5**
Miscellaneous		**3.5%**	**$10.8**
Total Revenue		**6.6%**	**$1,188.1**
Revenue Requirement		**0.0%**	**$1,197.6**
Revenue Shortfall			**($9.4)**

2. To eliminate the $9.4 million shortfall, revenues from four classes with the lowest revenue to cost ratios; Municipal, Large General, Large Industrial and Residential were increased such that their revenue to cost ratios were set equally at 99.1 percent. As Figure 9.4 shows, the 99.1 percent ratio is the lowest of all ATL rate classes except for the ELIIR-2 class.

Figure 9.4

	R/C Ratio	% Revenue Increase	Proposed Revenue
ABOVE-THE-LINE CLASSES			
Residential	**99.1%**	**9.0%**	**$524.8**
Commercial			
Small General	100.7%	7.3%	$30.2
General Demand	105.0%	3.5%	$252.8
Large General	99.1%	8.9%	$35.8
Total Commercial	**103.9%**	**4.4%**	**$318.8**
Industrial			
Small Industrial	101.3%	7.3%	$24.7
Medium Industrial	100.2%	7.3%	$50.2
Large Industrial	99.1%	8.1%	$74.5
ELIIR-2	95.0%	11.1%	$124.9
Total Industrial	**97.6%**	**9.3%**	**$274.3**
Other			
Municipal	99.1%	10.4%	$16.6
Unmetered	99.9%	(0.9)%	$24.2
Total Other	**99.6%**	**3.4%**	**$40.7**
Total Above-the-line classes	**100.0%**	**7.5%**	**$1,158.7**
Below-the-line		**4.3%**	**$19.5**
Exports		**0.0%**	**$8.5**
Miscellaneous		**3.5%**	**$10.8**
Total Revenue		**7.4%**	**$1,197.6**
Revenue Requirement		**0.0%**	**$1,197.6**
Revenue Shortfall			**$0.0**

9.3.2 Rate Design

Electric rates generally comprise:

- Demand charges ($/kVA or kW);
- Energy charges (cents/kWh);
- Customer charges ($/month).

From a pure rate design perspective, demand charges are generally intended to recover the fixed costs of providing electric service. The energy charge is intended to recover the costs that vary with the amount of energy required and the customer charge is intended to recover the costs associated with customer-related costs. Due to historical revisions to the rates resulting from Hearings, NSPI's rate components are not currently set purely in this fashion. The total revenue produced from the application of these individual rate components is designed to provide recovery of the revenue requirement.

NSPI is not, at this time, proposing to adjust customer charges (in those classes that actually employ such charges, that is, Residential, Residential time-of-day, Small General, and ELIIR-2 classes). In addition, the Company is not proposing to change the other components of individual class rates (that is, demand and energy charges) by differing amounts. Instead, whatever change is required to the class revenue (as described in the section on Class Revenues above) to bring it within the 95-105 percent band has been applied to all individual rate components.

This means that the energy charges and demand charges will all increase by the same percentage as the revenue required from the class. As a result, except for those rates where the customer's resultant electricity costs are affected by transformer ownership or interruptible demand credits (which are not proposed to change), all customers within each rate class will see the same percentage increase in costs, provided there has been no change in their usage characteristics.

Aside from the recently approved 15 percent increase in interruptible credit to the ELIIR-2 class, no change is proposed to the method of calculating, or to the value assigned to the existing interruptible demand credit or the transformer ownership credit. With the interruptible credit and transformer ownership credit unchanged, and an increase only to the other energy and demand components of the rates, the overall effect of the rate increase will differ among customers in those classes that employ these items.

Figure 9.5 shows the current and proposed rates by rate component.

The replacement rate(s) for ELIIR are still under development and have not been included at this time.

Figure 9.5 PROPOSED INCREASES BY RATE COMPONENT

RESIDENTIAL TARIFFS					
Domestic Service Rate		**units**	**Current Rate**	**Proposed Rate**	**% change**
Customer Charge		$/mo	10.83	10.83	0.0%
Energy Charge		¢/kWh	10.13	11.16	10.2%
Domestic Service TOD Rate					
Customer Charge		$/mo	18.82	18.82	0.0%
December, January & Feb: energy charge					
	on-peak	¢/kWh	14.560	16.01	10.0%
	shoulder	¢/kWh	10.130	11.16	10.2%
	off-peak	¢/kWh	5.065	5.580	10.2%
Other months: energy charge					
	on-peak	¢/kWh	10.13	11.160	10.2%
	off-peak	¢/kWh	5.065	5.580	10.2%
COMMERCIAL TARIFFS					
Small General Rate		**units**	**Current Rate**	**Proposed Rate**	**% change**
Customer Charge		$/mo	12.65	12.65	0.0%
Energy Charge, block 1 (first 200 kWhs)		¢/kWh	11.21	12.15	8.4%
Energy Charge, block 2		¢/kWh	9.86	10.69	8.4%
General Rate					
Demand Charge		$/kW	8.10	8.38	3.5%
Energy Charge, block 1 (first 200kWh * demand)		¢/kWh	8.60	8.90	3.5%
Energy Charge, block 2		¢/kWh	6.08	6.29	3.5%
Transformer Ownership Credit		¢/kVA	32.00	32.00	0.0%
Large General Rate					
Demand Charge (Ratcheted)		$/kVA	9.61	10.46	8.8%
Energy Charge		¢/kWh	5.71	6.21	8.8%
Transformer Ownership Credit		¢/kVA	32.00	32.00	0.0%
INDUSTRIAL TARIFFS					
Small Industrial Rate		**units**	**Current Rate**	**Proposed Rate**	**% change**
Demand Charge		$/kVA	5.63	6.04	7.3%
Energy Charge, block 1 (first 200 kWhs * demand)		¢/kWh	7.33	7.87	7.4%
Energy Charge, block 2		¢/kWh	5.59	6.00	7.3%
Transformer Ownership Credit		¢/kVA	32.00	32.00	0.0%
Medium Industrial Rate					
Demand Charge		$/kVA	9.05	9.71	7.3%
Energy Charge		¢/kWh	5.21	5.59	7.3%
Transformer Ownership Credit		¢/kVA	32.00	32.00	0.0%

Large Industrial Rate				
Demand Charge (Ratcheted)	$/kVA	8.74	9.38	7.3%
Energy Charge	¢/kWh	5.25	5.64	7.4%
Transformer Ownership Credit	¢/kVA	(32.00)	(32.00)	0.0%
Interruptible Credit	$/kVA	(3.43)	(3.43)	0.0%

MUNICIPAL TARIFFS

Municipal Rate	**units**	**Current Rate**	**Proposed Rate**	**% change**
Demand Charge (Ratcheted)	$/kVA	8.96	9.89	10.4%
Energy Charge	¢/kWh	5.38	5.94	10.4%
Transformer Ownership Credit	$/kVA	32.00	32.00	0.0%

OTHER TARIFFS

Outdoor Recreational Light Rate	**units**	**Current Rate**	**Proposed Rate**	**% change**
Energy Charge	¢/kWh	10.96	11.78	7.5%
Miscellaneous Small Loads Rate				
Demand Charge	$/kW	8.41	9.04	7.5%
Energy Charge, block 1 (first 200kWh * demand)	¢/kWh	9.56	10.28	7.5%
Energy Charge, block 2	¢/kWh	6.32	6.79	7.4%

Note: Increases in *rate components* shown above may differ from the average *revenue increases* shown in previous tables. For average revenue increases by customer class see table 9.4.

Residential Rate Classes Revenue Forecasts

NSPI has two residential rate classes, the Domestic Class and the Domestic Time of Day Class. The Domestic Class represents over 99 percent of all residential customers. The Domestic Time of Day Class accounts for the remaining 1 percent of residential customers and is designed for customers who use electrical thermal storage (ETS) or other approved off-peak operational systems for space heating. Both classes have customer and energy charges, which recover required revenue without employing demand charges, which are generally uneconomic to implement in this class. The Domestic Class charges remain constant throughout the year whereas the energy charges of the Domestic Time of Day Class vary by season and time of day.

The revenue forecast for this class is calculated by multiplying the proposed rate components from Figure 9.5 by the relevant billing determinants forecast for each month of the year. The customer charge is applied to the anticipated total number of customers in each month. The energy charges are applied to total kWh consumption broken down by appropriate time periods in each month for the Domestic Time of Day class.

Commercial Rate Classes Revenue Forecasts

Commercial revenues are collected from three rate classes: Small General, General and Large General. The Small General rate has a customer charge and a two-block energy charge, which again collects all required revenue without employing a demand charge.

The General rate has a two-block energy charge and a demand charge but no customer charge. The Large General rate consists of a single energy charge and a single demand charge.

The revenue forecast for the Small General and General classes is calculated by multiplying the proposed rate components from Figure 9.5 by the relevant billing determinants of each class. The Small General revenues are determined by applying the customer charge to an anticipated total number of customers in each month and adding to this the products of energy charges and kWh consumption falling into each of the two energy blocks.

The General class revenues are determined in a similar way (except that there is no customer charge) and a demand charge is applied to the sum of the non-coincident demands, as measured in kilowatts (kW), projected for each month.

Large General class revenue is forecast at the individual customer level. Each customer's forecast energy and peak demand for the month is used with the applicable rate and discount for transformer ownership, if applicable. The demand is metered in kilovolt amperes (kVA) to capture any reactive power effects that may be present in large commercial consumption. The monthly demand charge is based upon a ratcheted demand, that is, the highest demand level from the previous December, January, February, or the month being forecast.

Industrial Rate Classes Revenue Forecasts

Revenues from industrial customers are collected under both ATL and BTL rate classes. The BTL classes have been discussed in a separate section because revenues in these classes are a function of pre-approved pricing methodologies rather than set unit prices.

There are now four industrial rate classes that fall into the ATL category:

- Small Industrial Class
- Medium Industrial Class
- Large Industrial Class with an interruptible rider option
- Extra Large Industrial Interruptible – 2 Class (and/or the revised 2P-RTP both for costing and revenue allocation purposes in this Application)

Revenue requirements for all but the ELIIR-2 class are collected by employing energy and demand components, but no customer charge. Due to the costs associated with operating an economic interruption mechanism and other customer-related costs, the ELIIR-2 employs a customer charge. Demand is metered in kVA to capture reactive power effects often present in industrial consumption.

The Small Industrial rate structure is the same as that of the commercial General class with the exception of the unit of measurement of non-coincident demands (kVA rather than kW).

The Medium and Large Industrial rates have single energy and demand charges. The Interruptible Rider, offered under the Large Industrial and ELIIR-2 classes, is provided through a demand credit (applied per kVA of billed demand). This credit is a reduction in the customer's demand charge provided in exchange for the customer providing NSPI interruptible load.

The revenue forecasts for the Small and Medium Industrial Classes are calculated by multiplying the proposed rate components from Figure 9.5 by the relevant billing determinants of each class. The energy charges are applied to the monthly energy in each block. Demand charges are multiplied by the sum of the non-coincident kVA demands projected for each month.

Large Industrial and ELIIR-2 customer loads are forecast at the individual customer level. The revenue forecast accounts for such items as ratcheted demand and the Interruptible Rider credit.

Municipal Class

The Municipal Class revenue is forecast based on multiplying the proposed rate components from Figure 9.5 by the determinants forecast for each individual municipal utility.

Unmetered

Unmetered class revenue is made up of revenue from a variety of lighting types including street lights and miscellaneous small loads. Street light rates comprise capital, maintenance and "power and energy" components. The 2007 capital and maintenance components have been determined using costs updated in 2006. The "power and energy" component costs of all the unmetered rates are set using the Miscellaneous Small Loads rate.

The new unmetered service rates in Figure 9.6 have been added to the Proposed Tariffs section in Appendix H.

Figure 9.6

Description	Rate Code	kWh/month	$/month
High Pressure Sodium (100W) Continuous Operation	126	99	$19.20
Metallic Additive (150W)	143	67	$14.39
Fluorescent 4x48" (440W)	216	166	$24.77

Miscellaneous Revenue

Miscellaneous Revenue is derived from fees not directly tied to the consumption of electricity, but rather to the recovery of various customer service-related costs that are provided to individual customers as required, rather than to all customers every year. Miscellaneous revenue is forecast using the forecast demand for the various services and the fees approved for each type of service. Details on the various fees and services are provided in Section 10.0.

10.0 MISCELLANEOUS CHARGES

NSPI offers a variety of services to customers as part of its obligation to provide low-cost, reliable electricity to Nova Scotians. Charges for these services are set out in Appendix J (Schedule of Charges) of the Regulations approved by the Board for NSPI. Periodically, the Company reviews these charges in light of changes in service delivery, cost structures and technological advances.

NSPI is requesting the application of the average general rate of increase for ATL rates to miscellaneous charges. This is the same approach that was approved in the 2006 Rate Case.

As shown in table format in Appendix I, the application of the average general rate of increase for ATL rates to miscellaneous charges brings the rates closer to the costs of providing the services.

There are three charges where the application of the average general rate of increase for ATL rates would have exceeded the cost to deliver the service. These rates were therefore held at the actual cost and have been highlighted in Appendix I.

The aggregate effect of the proposed changes is to increase the Company's miscellaneous revenue by approximately $369,000. This additional revenue in turn reduces the overall revenue required from ATL customers.

The proposed Regulation changes that would give effect to the proposed changes above are provided in Appendix J.

11.0 OUTSTANDING APPROVALS AND DEFERRALS

11.1 Pending UARB Review

NSPI has several regulatory proceedings scheduled for 2006. This Application does not incorporate any additional spending (revenue requirement) that may result from these decisions by the UARB.

Decisions that require additional spending will increase NSPI's revenue requirement. NSPI proposes that these amounts, if any, be included in the Board's 2007 Rate Decision and subsequently as part of the 2007 Compliance Filing. These potential decisions include:

- Any changes to NSPI's proposed rates as filed in the 2007 Rate Application, or as a result of the Avon Valley et al Appeal of the 2006 Rate Decision. Whether in the case of the ELIIR-2 Decision or adjustments to other customer classes, any rate changes must be rebalanced over remaining rates to recover NSPI's entire approved revenue requirement.

- The UARB Order to review NSPI's Demand Side Management (DSM) plan. For the 2007 Rate Application, NSPI has not included additional funding for DSM. Outcomes of this process will be reflected in the 2007 Compliance Filing should incremental costs be directed by the UARB.

- As part of the Board's ongoing Storm Hearing process, the UARB is considering NSPI's proposed increase to annual Distribution System vegetation management spending. In this 2007 Rate Application, NSPI has not changed the proposed vegetation management funding level from that approved by the Board in the 2006 Rate Decision. Once a Board Decision about vegetation management is issued, changes in spending will be reflected in the 2007 Compliance Filing.

- The third-party call overflow recommendation resulting from the Storm Hearing. This 2007 Rate Application does not presume a solution. Any incremental costs of a UARB approved solution will be reflected in the 2007 Compliance Filing.

- The design and implementation of a relay testing program associated with the 69 kV and 138 kV systems. NSPI is currently designing the relay testing program in accordance with the Storm Hearing Directive. Additional spending to complete the program will be reflected in the 2007 Compliance Filing.

11.2 Q1 Fuel Deferral

In this Application, NSPI seeks new rates effective April 1, 2007. With a filing in early October, 2006 the hearing processes will not enable new rates to be effective January 1, 2007. As a result, NSPI will operate in the first quarter of 2007 when customer load and fuel cost are at their peaks without the appropriate recovery of prudently incurred costs. NSPI estimates this cost to be $18.3 million based on the 2007 fuel forecast. NSPI seeks only to recover actual fuel costs, a recoverable cost of doing business, based on actual costs incurred. The actual costs may be higher or lower than this estimate.

Failure to recover these costs will have a significant detrimental financial effect on NSPI in 2007. The increased fuel expense, not presently incorporated in rates and faced by the utility in 2007, without corresponding revenues from customers is a material and immediate concern. The recent downgrade by S&P underscores this concern.

NSPI has appropriately delayed filing this Application. The 2006 Rate Case Decision was released on March 10, 2006 and required time for analysis. Several directives required immediate attention by NSPI, most notably the replacement of the Extra Large Industrial Interruptible Rate. With the formal portion of the ELIIR-2 Proceeding now complete and a decision available, it is now clear a major customer will continue

operating. It is now appropriate to place the 2007 General Rate Application before the Board.

NSPI requests the Board direct the deferral of increased 2007 fuel expense, that is approved for recovery by the Board but otherwise unfunded, for the first quarter of 2007. This requested deferral will ensure NSPI has a reasonable opportunity to achieve its allowed return and provides NSPI an earnings opportunity consistent with that before the Board for the 2007 Test Year.

As was the case with the 2005 tax deferral approved by the Board, 2007 Q1 fuel expense will be fully recovered in an amount determined and approved by the Board. NSPI requests that the approved amount be recovered over a maximum twelve month period commencing in 2008.

11.3 2P-RTP Deferral

The UARB Decision in the ELIIR-2 proceeding (P-883) offers the option of a new Two Part Real Time Pricing rate (2P-RTP) to customers in the ELIIR-2 customer class. A key issue in the proceeding was that using marginal costs to price decrements and increments from a flat Customer Base Line would not match the fuel savings or increased costs related to the load shifting. The Board has attempted to alleviate that risk by establishing a limitation of 20 percent of the customer's total annual energy taking, a step pricing mechanism for decrements, and charging for increments at marginal cost[97].

In establishing these limitations, the Board confirmed that the intention of the 2P-RTP mechanism is to ensure that the utility is kept whole, in that the cost saving should match the customer credit for decrements, and the cost increases should match the amount of the increment charge. The Board commented:

[97] NSUARB-NSPI-P-883 2006 NSUARB 97, ELIIR-2 Decision, page 51, paragraph 146.

> "The debits and credits for load shifting are intended to be cost neutral to other parties and so should not factor into setting the revenue requirement for ATL customers."[98]

Experience with the 2P-RTP rate will demonstrate whether the limitations on the marginal pricing mechanism will alleviate the risk that the cost of generation will exceed the credits and debits relating to customer load shifting. If the protections are inadequate, NSPI will not recover the fuel expense needed to serve the ELIIR-2 load. Given that the intent of the 2P-RTP is to match the credits and debits to actual fuel expense, such an outcome would violate a key operational premise of the new rate.

Therefore, NSPI requests the Board direct a true-up of fuel expense that is not recovered due to the operation of the 2P-RTP rate. This would be fuel expense that is approved for recovery by the Board but otherwise unfunded. This may occur due to unintended operation of the 2P-RTP rate in terms of the failure to match actual fuel costs to load shifting credits and debits. NSPI will monitor the operation of the 2P-RTP rate and report to customers and the Board the actual results relating to fuel expenses. At the end of the calendar year the amount of the loss, if any, will be recovered from 2P-RTP customers.

The 2P-RTP rate mechanism is predicated upon cost savings to NSPI being equal to the cost savings to the customers. Therefore, NSPI anticipates no opposition to this request. This true-up will ensure NSPI has a reasonable opportunity to achieve its allowed return and provides NSPI an earnings opportunity consistent with that before the Board for the 2007 Test Year. NSPI requests that the approved amount be recovered within 30 days from the ELIIR-2 customers. NSPI seeks only to recover the actual costs of fuel, from those customers served by the rate, using this true-up mechanism.

[98] NSUARB-NSPI-P-883 2006 NSUARB 97, ELIIR-2 Decision, page 53, paragraph 148.

12.0 A FINAL WORD

In this proceeding, the UARB will determine the increase in NSPI's revenue requirement for the 2007 test year.

Volatile fuel prices and increasing fuel costs are an unfortunate reality – a reality witnessed first-hand by Nova Scotians at the fuel pumps, and on their home heating bills. However, rising fuel prices are not the only costs NSPI must contend with as it strives to build a reliable, financially healthy business. Providing a reliable electricity system requires adequate investment, and the timely recovery of previously paid expenses.

As a cost of service regulated utility with an obligation to serve, NSPI has a right both to recover its expenses, and the opportunity to earn a fair return on its investment. The basis of this Application is straightforward. NSPI seeks the recovery of increased fuel and pension expenses, and of costs that were previously approved by the Board.

NSPI intends, with the support of the Board, to work with customers and other stakeholders during this process. A constructive attitude from NSPI and stakeholders, and management of the process by the Board, can achieve a result that will benefit all Nova Scotians.

Based upon this Application and the evidence contained herein, NSPI seeks an Order, effective April 1, 2007, approving:

a) The 2007 revenue requirement as set out in the Application so as to enable the Company to recover the reasonable costs of providing service to customers and to meet its financial obligations including provision for a just and reasonable return;

b) The rates, charges and regulations as filed in this Application;

c) Adjustments to rates, charges or regulations as necessary to reflect decisions and directives in NSPI related proceedings, or as may be determined by the UARB in this Application; and

d) The return on common equity and return on rate base as set out in the Application.

The rate adjustments described in this Application are fair to both customers and the Company.