APPENDIX A

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LEONARD R. CROOK, JR

EDUCATION

1972	MA, History, University of Memphis, Outstanding Graduate Student Award
1970	BA, History and Economics, with Honors in History, University of Memphis. Phi Alpha Theta National History Honor Society

EXPERIENCE

After a career with Federal Energy Regulatory Commission (FERC), Mr. Crook joined ICF in 1984 and is now a Vice President. He directs ICF's natural gas practice, specializing in natural gas market structure and operations, gas supply contracting, pipeline transportation issues, distribution costs and supply planning, LNG strategies, and climate change issues related to natural gas systems. He has authored a number of reports and made presentations on all aspects of the natural gas industry. Some of his principal areas of expertise are described below. Mr. Crook has a strong background in natural gas market structure and dynamics.

Gas Market Studies

- For a group of **New England electric and natural gas utilities**, Mr. Crook co directed a large study of the avoided costs of gas, oil, and power in the Northeast. The purpose of the study was to develop a consistent set of avoided cost estimates for use in demand side management program planning. Mr. Crook presented his findings before groups of utility managers, regulators, and public interest groups.
- Mr. Crook directed ICF's work on a quick turnaround project for the **Newfoundland and Labrador Department of Natural Resources** to study the opportunities for monetizing natural gas resources in the offshore fields. Mr. Crook presented the findings in St. John's to DNR staff.
- Mr. Crook led the preparation of a White Paper on LNG economic, contracting, market, and safety issues for the **National Association of Regulatory Utility Commissioners (NARUC)**. He has worked with the NARUC gas committee chairman and presented at the Mid-year conference. The paper will be published in the United States to present the state regulatory commissions' policies on LNG.
- Mr. Crook as part of a high level team of economists and gas industry executives, prepared a set of policy reviews and recommendations for restructuring the gas market in Ontario. The client is the **Ontario Energy Board**. Specifically, evaluated restructuring gas storage and gas system supply and the application of performance based ratemaking.
- Mr. Crook directs ICF's ongoing market analyses using the **North American Natural Gas Analysis System (NANGAS®)** a large linear program of the gas market in North America. It is one of the most sophisticated modeling systems used, with over 20,000 reservoirs modeled, the pipeline network, and gas demand by sector, region and competitive fuels. Under his direction NANGAS® has been used to analyze North American markets for many of the major production companies, potential LNG importers, pipelines, power companies, and the U.S. government (Department of Energy and Environmental Protection Agency). Mr. Crook has presented the results of the model at the **Energy Modeling Forum** for each of the last two years.
- Mr. Crook has recently completed a long term independent study of natural gas markets and commercial arrangements for The Amir of **Qatar** in anticipation of a major expansion of LNG imports to the U.S.. This work involved basic market modeling, market research, competitor research, and pricing and contracting strategies. Mr. Crook led separate briefings of our findings for the Foreign Minister and the Energy Minister.
- Mr. Crook has advised the **Government of the Bahamas** on developing tax and fee structures applicable to LNG terminals. This work involves both research into analogous fee regimes,

developing alternative structures and modeling potential revenues to identify those with the highest NPV to the government consistent with economic operation of the project. Mr. Crook provided independent reviews of contract documents and briefed the **Prime Minister** and the Cabinet.

- For a **Mitsubishi**, Mr. Crook has evaluated the competitive situation for LNG deliveries to the U.S. from different countries in the Atlantic LNG market zone. We evaluated the receiving capacity in the U.S. through 2015, LNG liquefaction capacities and plans, shipping availability, and costs along the value chain. ICF compared these estimates with our forecasts of ex-terminal gas prices in the U.S. to establish a merit order of imports.
- Mr. Crook directed an evaluation of the market for natural gas (including LNG) in eastern Canada and the northeastern U.S. for **Anadarko Petroleum**.
- Mr. Crook has assisted several other **LNG import project investor groups** (in the early 1990's) to understand the North American gas market dynamics and regulatory framework associated with importing LNG. Again, using NANGAS, we developed forecasts of future market conditions, with and without the LNG. These studies were supplemented by specific pipeline and gas contract assistance. We have briefed investor groups in Europe and South America on U.S. market and regulatory issues relevant to LNG.
- Mr. Crook has directed a due diligence review of the New York gas market in support of the **Iroquois Gas Transmission System's Eastchester Pipeline** extension into New York City. The analysis examined the outlook for gas consumption, pipeline competition, and long-distance electric transmission competition.
- Mr. Crook co-led ICF's analysis of the impact of bringing Alaskan natural gas into the U.S. market at specific locations and at specific quantities. This work was done on behalf of a consortium of the North Slope producers, led by **ExxonMobil**. It analyzed the impact on prices and flows across the North American gas network.
- Mr. Crook has directed ICF due diligence reviews of the **Portland Natural Gas Transmission System, Maritimes and Northeast Pipeline** and the **Pacific Gas Transmission Company**'s first major expansion. The work involved evaluating the market for gas, the availability of gas supply to support the project, and the outlook for competition from other pipelines and supply sources.

Gas Supply and Transportation Planning

- Mr. Crook led a valuation of an **Appalachian region gathering pipeline system**. The study evaluated the production potential in eastern Pennsylvania, the competing access to market for the production, and the value at market to estimate a value for the asset. The client in this case was a major pipeline company in the east.
- For **Portland General Electric**, Mr. Crook led a study of the gas supply options for the Beaver Power Plant, a large gas-fired facility. The analytic approach used ICF's Asset Optimization Model to analyze specific issue of concern to PGE – establishing the value of firm transportation, storage and a capacity call-back option.
- For **eCorp**, a storage developer, Mr. Crook participated in ICF's analysis of the Stagecoach Storage Facility in New York /Pennsylvania. This valuation examined the value of the facility as storage and for trading.
- For **Carolina Power and Light**, Mr. Crook helped to analyze the gas pipeline capacity and gas supply availability to support new gas-fired power plants in the CP&L service territory. Our analysis evaluated capacity availability on Transco, the possibility of extending the Southern Natural Pipeline, and other pipeline alternatives.
- For **Philadelphia Gas Works**, Mr. Crook directed an evaluation of the gas supply functions in the company, including using ICF's models to find the optimal mix of contracts, capacity, storage, and LNG; performing a management review of the gas supply department, reviewing peak day sendout

methodology, assessing; analyzing risk management options; and performing a preliminary engineering study of LNG plant upgrade options.

- For the **Philadelphia Gas Works,** Mr. Crook assisted in a procurement to outsource all of the gas supply functions for the distributor. Mr. Crook was brought into the process to review the RFP and make recommendations; develop evaluation criteria for selecting suppliers; review the bids; interview the finalists (Enron, Williams, Sempra, PECO, and TPC); make the final selection recommendations; and assist in negotiations.

- For **Niagara Mohawk Gas Company (NMGas)**, Mr. Crook directed an analysis of NMGas' contract supply portfolio to evaluate the reasonableness of costs and reliability of supply.

- For the **Defense Fuel Supply Center**, Mr. Crook has directed a major study of least cost gas supply strategies for California facilities. This analysis included an assessment of a wide array of gas supply, transportation, storage and fuel switching options. Using ICF's Gas Acquisition Strategy Model, the study analyzed alternative strategies under different pricing and demand assumptions.

- For **Southern California Edison Co.**, Mr. Crook helped develop a model to analyze gas purchasing decisions, focusing on storage.

- For a **New Jersey Natural Gas**, he analyzed alternative peaking supply options and developed a cost/benefit analysis of the available alternatives and their respective revenue requirements. Among the alternatives considered were hook-up moratorium, LNG, new storage, and pipeline supply.

Gas Supply Contracting and Due Diligence

- Mr. Crook has served as the principal gas consultant for over $4 billion of project financing for gas-fired cogeneration and independent power projects; advised clients on gas supply contracting, transportation and regulatory issues in the US and Canada. He worked closely with developers and bankers in finalizing project documents, and on occasion supporting negotiations with pipelines or suppliers. He has made presentations for loan syndication and financing club groups. Principal projects and lead banks include:

  Midland Cogeneration Venture (Michigan)—First Chicago, CitiBank
  Ave Fenix (Argentina)—NationsBank
  Encogen Four Partners (New York)—First Chicago
  Nevada Cogen Associates (Nevada)—Swiss Bank
  Encogen Northwest (Washington State)—First Chicago
  Hazleton (Pennsylvania)—ABN Amro
  Indeck Olean (New York)—CIBC
  Gordonsville (Virginia)—First Chicago, Norweb
  West Windsor (Ontario)—Citibank, Bank Nationale de Paris
  Panda Rosemary (Virginia/N.C.)—Energy Initiatives
  Project Orange (New York)—ABN Amro
  AG Energy (New York)—Swiss Bank
  PGT Expansion (Canada to California)—First Chicago
  Maritimes and Northeast Pipeline (Canada to New England)—CIBC, Toronto Dominion
  SkyGen Energy/Calpine IPPs: Hog Bayou (Alabama), Pine Bluff (Arkansas), Rockgen (Wisconsin), Broad River (South Carolina), Zion—Credit Suisse First Boston, DG Bank
  Ennis Power Project (Texas) – DG Bank
  Tuxpan Power Plants (Mexico) – Mitsubishi
  Rio Bravo Power Plants (Mexico) – International Finance Corporation, Societe Generale

- For the **Bonneville Power Administration,** Mr. Crook served as advisor on gas issues related to Bonneville's all-source-bidding program. He critiqued and advised BPA on its gas supply evaluation

criteria, assessed the reliability and costs of the proposed gas supply for gas-fired generation bids, assisted in negotiations with the winning bidder, and advised BPA on gas industry issues in general, particularly the potential impact of FERC Order 636.

- For **Oglethorpe Power Corporation,** Mr. Crook assisted the Corporation staff to develop its own bid for gas fired generating capacity in a solicitation.

Tariff and Rates Issues

- For the **City of Charlottesville Gas Department**, Mr. Crook performed a study of the interruptible service tariff in order to develop a revised tariff design and to implement a transportation-only service.
- Mr. Crook has assisted in the preparation of tariff case testimony before the **Federal Energy Regulatory Commission** and the **District of Columbia Public Utility Commission.** In the former case, he prepared a study to support a secondary market for pipeline capacity on the ANR pipeline system. In the latter, he assisted in preparation of marginal cost rate design for the Washington Gas Light Company.
- While a member of the FERC staff, Mr. Crook developed a Commission opinion on the application of socioeconomic impact costs to the Alaska Natural Gas Transportation System. Mr. Crook performed research, held hearings in Alaska, and performed the factual analysis on the issue of whether the pipeline rates should include additional costs associated with socioeconomic impacts on the Alaskan communities.
- Under a contract with the U.S. Agency for International Development, Mr. Crook prepared an analysis of the Natural Gas Sector in the **Czech Republic** as part of an overall assessment of privatization program. Mr. Crook reviewed alternatives for structuring the Czech gas industry. The report was submitted to AID and the Ministry for Economic Policy and Development for the Czech Republic.
- Under contract to USAID, Mr. Crook worked with the staff of the **Ceske Plynarenske Podniky (CPP)** to develop a program for applying long run marginal cost pricing principles to the development of rates for the gas distribution company in the Czech Republic. Mr. Crook met with CPP senior staff to review current pricing policies and rates procedures, briefed the CPP staff on alternative approaches to developing rates, and prepared a Long-Run Marginal Cost Briefing Paper for the CPP. Mr. Crook also developed a work plan for how the CPP could analyze its gas loads and develop information to support long run marginal cost based rates.

Natural Gas Industry Environmental Issues

- For the Environmental Protection Agency, Mr. Crook has directed ICF's support of the **Natural Gas STAR Program**, a cooperative gas industry/government program that identifies ways to reduce methane emissions from natural gas systems. Elements of this program include:
  - Marketing to gas companies to join the program
  - Working with gas companies to identify best management practices to reduce emissions, including the development of Lessons Learned Studies on cost effective emission reduction technologies and practices
  - Analyzing leak reduction reports
  - Developing and implementing computerized information systems for maintaining and analyzing leak reduction data by company and reporting data to EPA
- Mr. Crook led the development of the **national methane emissions inventory** from gas and oil systems. The inventory is an annual report to the United Nations on greenhouse gas emissions.
- Mr. Crook developed **gas industry marginal abatement** curves for reducing methane emissions. These are used to identify emission reductions achievable at various gas price and carbon price levels.

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Federal Energy Regulatory Commission **1972 - 1983**

Office of Pipeline Regulation (OPR) **1978 - 1983**

Served as an Industry Economist in Pipeline Certificates Division, managed environmental assessments (EAs) and environmental impact statements (EISs) for pipeline projects, curtailment plans and FERC rule makings; testified in FERC hearings on environmental matters; was given special assignments relating to the Alaska Natural Gas Transportation System (ANGTS), and as expert advisory staff to Commissioners Matthew Holden and Anthony Souza. Significant accomplishments included:

- Developed an environmental impact analytic approach for natural gas curtailment planning and applied that methodology in Florida for the Florida Gas Transmission Company's curtailment plan. We did air quality impact assessments for all of the counties in Florida as a result of curtailments under five alternative curtailment plan proposals. Testified in on the results.
- Developed and led a cost benefit analysis on Port Everglades of the effect of introducing a oil pipeline into Florida, then being sponsored by FGT. The analysis evaluated shipping under Jones Act tankers and barges, the effect on the port, and the effect on the local economy. Testified on the results.
- Researched and wrote a Commission policy statement on who should bear the socioeconomic impact costs in Alaska of the ANGTS. Conducted hearings in Alaska with Commissioner Souza, interacted with State agencies and social organizations.
- Developed the affirmative action and minority business enterprise plans for ANGTS, which under the Alaska Natural Gas Act required special MBE provisions. Coordinated the inputs of eight Federal Agencies, co-conducted hearings in Alaska (including one in Barrow), and successfully got the regulations implemented for FERC and the Office of the Federal Inspector. Received an outstanding performance award.

Office of Regulatory Analysis (Office of Economics) **1975 - 1978**

Served on the staff of the Commission's Advisor on Environmental Quality, an office created to implement the National Environmental Policy Act (NEPA); helped develop environmental regulations for the Commission; performed general policy and management analyses. Significant accomplishments included:

- Developed FERC (then Federal Power Commission) regulations under the National Historic Preservation Act.
- Assigned to the ANGTS economics analysis team, prepared the socioeconomic impact analysis for the FPC's EIS, testified in hearings, participated in preparing the *Recommendation to the President* and the *President's Report to Congress*.

Bureau of Power (Office of Hydroelectric Licensing) **1972 - 1975**

Served on Bureau of Power's environmental staff preparing environmental impact statements specializing in the economic and cultural resource impacts of hydroelectric projects. Also prepared FPC jurisdictional memoranda on dams across various rivers in New England, New York, and Michigan. Significant accomplishments included:

- Developed the first studies of the impact of power dams on historic and archeological resources and established FPC policies in this area in response to new legislation protecting cultural resources. Developed a primer for hydro license applicants on how to comply with this legislation.

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PUBLICATIONS and PRESENTATIONS

"Integrating World LNG Markets into North America: Issues and Challenges," 2006 Advanced Regulatory Studies Program, Institute of Public Utilities, Michigan State University. East Lansing, Michigan. June 7, 2006.

"Towards a World Gas Market, Recent Trends." Presented to the 2006 Winter Meeting of National Association of Regulatory Utility Commissioners, Washington, D.C., February 14, 2006.

"Towards a World Gas Market; Implications for the U.S." Presented to the 4th Annual Gas and Power Institute, University of Texas Law School, Houston. October 21, 2005.

"NARUC LNG Paper Highlights." Presented to the 2005 Summer Meeting of the National Association of Regulatory Utility Commissioners, Austin, Texas. July 25, 2006.

"Dawn Hub Market Dynamics" Presented to the NEGM/ANE Annual Customer/Supplier Conference. Cape Cod, Massachusetts. July 13, 2005.

"Towards a World Natural Gas Market, Observations along the Way" Presented to Ontario Energy Association. Toronto, Ontario, Canada. April 28, 2005.

"LNG at the Tipping Point," Infocast National LNG Conference. Houston, Texas. July 28, 2003

"How to Structure a Financeable Fuel Arrangement," Project Finance: The Tutorial, by Infocast. New York, New York, September 23, 2002

"Natural Gas and Climate Change," Presented to the Society of Gas Operators, New York, New York, October 28, 1999

"Buying Gas Today," presentation to Pennsylvania Association of County Commissioners meeting on "Getting the Most from Utility Competition;" Harrisburg, PA; May 7, 1997

"Becoming an Energy Services Company," Presentation to the IGT Energy Marketing Conference, Las Vegas, NV; Dec. 1996.

"Methane Emissions from Natural Gas Pipelines--Current Estimates, Technologies and Practices;" with M. Lang; presentation to International Energy Agency Conference: "Natural Gas Technologies: A Driving Force for Market Development;" Berlin, Germany, Sept. 1-4, 1996.

"Can Gas Compete on a Long Term Basis? The Implications of Power Industry Restructuring," Presentation at 14th CERI International Oil and Gas Markets Conference, Calgary, Sept., 1995

"Technologies Affecting Future Gas Demand," Institute of Gas Technology Conference; Chicago; 1995.

"Identifying Risks through Due Diligence and Analyzing Risk Significance: The Technical Perspective," Presentation at the INFOCAST Project Finance Tutorial; October, 1993 through 1995.

"Getting It Right: The Supply Side of Integrated Resource Planning," paper and presentation to the NARUC-DOE Integrated Resource Planning Conference in Kalispell, Montana; May, 1994.

"Gas Supply Strategies in the Post-Order 636 Environment," Presentation to the American Forest and Paper Association: Sept. 1993

"Integrated Resource Planning in Gas Utilities," Presentation to The National Regulatory Research Institute Seminars on The Energy Policy Act of 1992; Indianapolis and Portland, OR; June and July, 1993

"Making Sense of End-Use Gas Price Forecasts," Natural Gas, Nov. 1992.

"Environmental Policy and the Natural Gas Exploration and Production Industry," Natural Resources and the Environment, Spring, 1992.

"FERC Order 636," Two day seminar and presentation to staff of the Bonneville Power Administration; May, 1992.

"Preparing Bid and Evaluating Response to Competitive Solicitation for Power Projects: A Hands On Approach," a half day presentation to electric utility executives.

"Gas Supply Planning after the Bubble," with W. Hederman, Natural Gas, April 1989.

APPENDIX B

From: Paul Chang [mailto:pchang@morneausobeco.com]
Sent: Wednesday, January 17, 2007 10:18 AM
To: KEHOE, CLAUDETTE
Cc: BLUNDEN, GREG
Subject: NSPI's Projected 2007 Pension Expense

The December 31, 2006, 14 year duration, "A" rated bonds is at 5.25% Based on NSPI's methodology to determine the discount rate, this will be used to determine fiscal 2007 pension expense. I understand that management's asset return assumption will be changed to 7.25%, but all other assumptions for fiscal 2007 will be the same as for fiscal 2006 pension expense.

Based on a projection of the valuation using the Dec 31, 2005 membership data using the assumptions for fiscal 2007 noted above, NSPI's estimated pension expense for fiscal 2007 will be $36.00 million.

We expect to have an updated estimate of 2007 fiscal pension expense based on Dec 31, 2006 data in early February.

Regards,

Paul Chang
Morneau Sobeco, Halifax Office
Direct Line (902) 474 3239
General Line 902 429 8013

APPENDIX C

Rating Report

Nova Scotia Power Inc.

Report Date: August 23, 2006
Press Release: August 23, 2006
Previous Report: January 19, 2005

Nick Dinkha, CFA/Matthew Kolodzie, CFA
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ndinkha@dbrs.com

RATING

Rating	Trend	Rating Action	Debt Rated
A (low)	Stable	Confirmed	Unsecured Debentures & Medium-Term Notes
A (low)	Stable	Confirmed	Government guaranteed debt (issued prior to 06/30/93)
Pfd-2 (low)	Stable	Confirmed	Cumulative Preferred Shares
R-1 (low)	Stable	Confirmed	Commercial Paper

RATING HISTORY	Current	2005	2004	2003	2002	2001	2000
Long-Term Debt	A (low)	A (low)	A (low)	A (low)	A (low)	A (low)	A (low)
Preferred Shares	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)

RATING UPDATE

Nova Scotia Power Inc. (NSPI or the Company) continues to perform relatively well and is expected to benefit from the generally positive regulatory decision by the Nova Scotia Utility and Review Board (UARB), which was rendered on March 10, 2006. Although the Company's overall credit metrics were impacted in 2005 as a result of higher fuel costs incurred during that period, lower fuel expense, due to the temporary shutdown of a large industrial customer, and favourable settlement of a natural gas supply contract, helped these metrics recover for the 12 months ended June 30, 2006, and they should further improve with the UARB decision pertaining to NSPI's 2006 rate application (2006 RA). That decision provided for substantial recovery of the Company's 2006 projected fuel costs of $476 million. A portion of the 2006 projected fuel costs were adjusted for fuel costs incurred during 2003 and deemed by the UARB to have been 'imprudently incurred'. Dominion Bond Rating Service (DBRS) views the disallowance as not significant to the overall rating and the UARB's decision as generally favourable. The UARB also stated that there will be no further fuel-cost disallowances going forward and recognized the positive strides made by NSPI in improving its fuel procurement strategies, which should help to dampen the impact on price volatility and rates to customers.

Overall, NSPI's ratings are supported by: (1) its regulated utility operations that generate stable cash flows that are typically sufficient to fund both capital expenditures and dividends; (2) a regulated capital structure, providing NSPI with the ability to earn on its equity component up to 40%; and (3) favourable load growth in Nova Scotia, which is expected to continue. The key limiting factor on the rating continues to be the lack of a fuel adjustment mechanism (FAM), which puts the Company at risk of full recovery of fuel costs on a timely basis, which could impact both earnings and cash flows.

RATING CONSIDERATIONS

Strengths

- Regulated operations contribute to earnings and cash flow stability
- Cash flow from operations are expected to remain sufficient to fund capital expenditures and dividends
- Geographic isolation and limited interconnections are effective barriers against external competitors
- Cleaner burning coal supply will reduce emissions in the short-term

Challenges

- Lack of a FAM/regulatory lag impacts earnings
- Earnings sensitive to weather and fuel costs
- High-cost generator/low population density of franchise
- Future competitive pressures from gas distribution network under development by Heritage Gas Limited
- Future environmental risks with coal-based generation plants and exposure to oil

FINANCIAL INFORMATION

	12 mos. ended	For the year ended December 31				
	June 30,2006	2005	2004	2003	2002	2001
Fixed-charges coverage (times)	2.52	2.10	2.43	2.35	1.99	1.94
Adjusted debt in capital structure (1)	57.2%	57.8%	56.7%	54.8%	56.0%	59.1%
Cash flow/adjust. total debt (times) (1)	14.3%	12.0%	14.6%	14.4%	14.4%	12.6%
Cash flow/capital expenditures (times)	2.63	2.63	1.66	2.32	2.16	1.89
EBIT (CAD millions)	284.9	234.3	291.8	303.5	251.0	258.8
Net income (after pfd. divs.) (CAD millions)	98.4	91.2	107.3	112.1	86.1	105.1
Cash flow from operations (CAD millions)	237.3	203.4	236.8	223.9	226.2	211.5

(1) Preferred shares treated as 30% debt equivalents.

THE COMPANY

NSPI is a fully integrated, regulated electricity utility that generates, transmits, and distributes electricity in the province of Nova Scotia. The Company is wholly owned by Emera Inc. (Emera), which is a diversified energy and energy-services holding company listed on the Toronto Stock Exchange.

AUTHORIZED COMMERCIAL PAPER AMOUNT Limited to $400 million.

Note:
All figures are in Canadian dollars unless otherwise noted.

Information comes from sources believed to be reliable, but we cannot guarantee that it, or opinions in this Report, are complete or accurate. This Report is not to be construed as an offering of any securities, and it may not be reproduced without our consent.

REGULATION

NSPI is regulated by the UARB under a cost-of-service methodology.

- Large industrial customers (approximately 15% of sales volumes) are subject to annually adjusted rates, which are adjusted based on an approved formula.
- Export sales (approximately 4% of sales volumes) are priced at the market.
- All remaining sales are subject to periodic rate adjustments following applications made to the UARB.
- In July 2005, the Company filed a general rate application for 2006 rates, the 2006 RA, and received a ruling by the UARB on March 10, 2006. Highlights include the following:
  - An average rate increase of 8.6%, although the Company requested a 13% average rate increase in their 2006 RA. The Company was previously granted an average rate increase of approximately 5.3%, effective April 1, 2005.
  - NSPI has committed to sourcing its fuel under a portfolio approach per the UARB's previous directions, making a solid effort to further its market intelligence on global fuel prices, and developing physical infrastructure to better access the global markets, such as the completion of the Point Tupper Marine Terminal (PTMT), which enables NSPI to access a greater number of global coal supply regions. The PTMT can accommodate larger coal-delivering vessels that typically have lower transportation rates per tonne.
  - Fuel costs, from 2002/2003, that the UARB deemed to be 'imprudently incurred' and, therefore, not recoverable effectively ended with the March 2006 UARB decision, which should lead to full-cost recovery in future rate decisions.
  - In addition the UARB recognized that NSPI has made positive strides in improving its fuel procurement strategies, which should help to dampen the impact on price volatility and hence, rates to customers. The UARB further recognized that the interests of both customers and shareholders of NSPI are tied and that balance between both stakeholders is necessary.
  - The return on equity (ROE) and deemed equity ratio established for setting rates are 9.55% and 37.5%, respectively (with the ability to earn their ROE on common equity of up to 40%). However, the ROE is allowed to move between the 9.3% to 9.8% range.
- Overall, the regulatory environment has improved over the past couple of years, largely due to the proactive steps taken by NSPI aimed at addressing the UARB's concerns through more openness and two-way communication.
  - DBRS is of the opinion that the recent UARB decision is favourable overall and consistent with the DBRS press release dated July 6, 2005, that confirmed the ratings of NSPI in light of their 2006 RA, based on the assumption of meaningful recovery of fuel costs for 2006.
  - The UARB also stated that, going forward, there are to be no further fuel-cost disallowances related to prior-period procurement practices (e.g., 2006 rates included a disallowance cost for actions taken in 2003 that were deemed by the regulator to be 'imprudently incurred'), putting the 'imprudence' test to rest. This cessation provides comfort for at least two reasons – (1) that the UARB feels that the Company is being prudent in its revised fuel procurement strategy; and (2) having a prudent fuel procurement strategy lends further strength to NSPI's argument for a FAM by giving comfort to the UARB that should such a mechanism be approved, then NSPI will be recovering prudently incurred costs from ratepayers.
  - DBRS is also encouraged that the UARB has not dismissed a FAM as a possibility for NSPI. NSPI must first receive approval from the UARB of its fuel procurement strategy. Once this strategy is approved by the UARB, a FAM is the next logical step.

ELECTRICITY MARKET COMPETITION IN NOVA SCOTIA

- In December 2001, the Nova Scotia government released *Seizing the Opportunity: Nova Scotia's Energy Strategy*, which outlined a plan to increase competition over a prudent timeframe. Key highlights of the strategy included (1) directing the UARB to authorize open-access transmission on NSPI facilities; and (2) introducing wholesale market competition by 2005, consisting of six municipal electric utilities representing 1.3% of NSPI's revenues.
- On September 23, 2004, the provincial government introduced the *Electricity Act* (2004) (the Act), which calls for more renewable sources of supply to be made available in the province. The Act is intended to implement particular components of the December 2001 government plan to increase competition and ensure a reliable, secure and environmentally responsible energy supply. Key elements of the Act are as follows:
  - By 2010, five percent of Nova Scotia's electricity supply must come from renewable-resource generating capacity that was built after 2001 and includes wind, hydroelectric power and biomass fuels.
  - That NSPI permits open access to other generators to NSPI's transmission system, which DBRS believes that NSPI will not have difficulty complying with.

RATING CONSIDERATIONS

Strengths

(1) Regulated operations provide a high degree of earnings and cash flow stability. Regulation also ensures the balance sheet remains stable, which currently reflects a 37.5% deemed equity. NSPI provides 97% of the generation, 99% of the transmission and 95% of the electricity distribution in the province.

(2) With a mature franchise and no need for significant additions to existing infrastructure, cash flow from operations is expected to continue to be sufficient to internally fund capital expenditure requirements and dividends over the foreseeable future.

(3) In spite of electricity rates among the highest in Canada, which could potentially attract competition, the Company's limited interconnection capacity and isolated geographic position provide an effective barrier to new market entrants. Neighbouring utilities in the U.S. Northeast have significantly higher electricity rates and are therefore not likely to export into NSPI's market. Hydro-Québec, the only potential Canadian competitor, has significantly lower electricity rates, but is more likely to export to U.S. markets where it could generate higher revenues. NSPI currently does not have direct export links to the United States and, instead, wheels power through New Brunswick into the U.S. area through the 300 MW interconnection it has with that province. NSPI has developed an open-access transmission tariff, consistent with provincial government policy to allow third parties to use NSPI's transmission system in an open and non-discriminatory manner.

(4) The Cape Breton Development Corporation (Devco), the coal mine that historically supplied NSPI, was shut down in 2000. NSPI has successfully tested a number of world coals that are low sulphur and is sourcing substantially all of its coal requirements from international suppliers, which provide cleaner-burning coal that should materially reduce emissions (SO_2). In April 2005, NSPI entered into its first multi-year contract, to 2009, to acquire low-sulphur import coal. The UARB deemed this contract to be a prudently-incurred fuel expense and all costs associated with this are recoverable. As to re-sourcing of coal from nearby Cape Breton (the Donkin mine), the final quality of that coal has yet to be determined. NSPI expects that the coal would be 'cleaned' by the developer to required emission standards, at no cost to NSPI.

Challenges

(1) In the absence of a FAM, the Company must apply to the regulator for recovery of fuel costs. Regulatory lag can have a material impact on earnings and cash flow, since rate decisions cannot be implemented retroactively.

(2) As earnings are sensitive to commodity prices, NSPI enters into short- to medium-term contracts to minimize this risk. All of NSPI's 2006 solid fuel requirement, and over 90% of its heavy fuel oil and natural gas requirements, are hedged. In addition, the Company has over 70% of its 2007 requirements, and between 25% and 40% of its 2008 and 2009 requirements hedged. However, a FAM would significantly reduce the risk of this aspect of the Company's business by enabling the Company to pass through fuel costs directly to the customer, rather than waiting to recover its fuel expenses through rate applications. NSPI earnings are also sensitive to weather, such that a 5% change in degree-days would impact net earnings by about $2.0 million. Further, during periods of poor hydrological conditions at its hydroelectric generating facilities, NSPI relies more heavily on higher-cost thermal facilities for generation.

(3) NSPI is a relatively high-cost investor-owned generator, at an all-in cost of 7.20 cents/KWh. As a taxable entity, NSPI passes through its taxes in rates, further widening the competitive gap between electricity and alternative sources of energy. As a result, these higher electricity rates make Nova Scotia an attractive market for potential competitors. However, while electricity prices may be high in Nova Scotia, they are typically lower than prices in the northeast United States; this should minimize competitive threats to NSPI. The currently high price of natural gas, the generators' use of higher-priced U.S. coal supplies and costly fuel-oil limits their competitiveness in NSPI's market.

(4) Competition will eventually affect NSPI on two fronts as follows: (a) The eventual increased availability of natural gas will be the most significant threat to the Company's sales volumes in the longer term, especially as an alternative to electric space heating and water heaters. However, the earnings impact should not be significant since (i) conversion of existing customers to natural gas is a gradual process, due to the high cost of conversion and long lead time for natural gas infrastructure to be built in the province, (as the province is situated primarily on granite, making excavation expensive); (ii) home heating and water heater sales account for only 20% of the residential electricity load, and (iii) time-of-use strategies help minimize load loss to industrial customers who may choose to use natural gas for self-generation of electricity. (b) While certain elements of competition have been introduced, full deregulation of the electricity market is expected to develop slowly.

(5) NSPI's generating capacity is 54% coal-based (approximately 76% of energy volume produced). The Company must manage potential environmental risks associated with changes in emission standards, such as the installation of expensive scrubbers on existing coal-based facilities. New emissions standards will come into force by 2009/2010. Although using cleaner-burning coal from international suppliers will help reduce emissions in the future, the Company has also discussed this with the UARB and both parties have agreed to compile more data as to best practices for emissions reduction – such as fuel switching (as the Company has done with the clean coal supply long-term contract), demand side management and renewable energy. This is being done to ensure that any costs incurred due to environmental compliance are recoverable.

EARNINGS AND OUTLOOK

Income Statement	12 mon. ended	For the year ended December 31				
(CAD millions)	June 30, 2006	2005	2004	2003	2002	2001
Net revenues (net of power purchased)	927.2	914.9	900.7	876.4	853.6	817.0
EBITDA	423.0	368.0	414.1	411.5	356.2	361.6
Depreciation and amortization	130.1	125.7	122.2	107.9	104.9	102.6
EBIT	292.9	242.3	291.9	303.6	251.3	259.0
Interest expense	94.7	94.0	98.4	107.4	108.9	111.7
Pre-tax income	181.9	133.3	179.8	187.0	125.4	131.0
Income taxes	71.6	45.5	59.2	57.8	15.7	13.9
Net Income Before Extras.	110.3	87.8	120.6	129.2	109.7	117.1
Extraordinary items (1)	(1.4)	(16.7)	-	4.0	13.4	-
Net income before preferreds (after extraordinary items)	111.7	104.5	120.6	125.2	96.3	117.1
Preferred dividends	13.3	13.3	13.3	13.1	10.2	12.0
Net Income Available to Common	98.4	91.2	107.3	112.1	86.1	105.1

(1) $4 million after-tax charge in Q3 2003 reflects restoration and repair costs associated with Hurricane Juan. For 2002, it relates to the one-time write-off of $13.4 million paid to the Cape Breton Development Corporation in 2001 to terminate a coal supply contract. For YE2005, represents $15.3 million in deferred taxes that were incurred between Jan, 1, 2005 and Apr. 1, 2005, but not reflected in rates. This amount is pending approval by the UARB, as well as recovery.

Summary

- Lower fuel costs during Q1 2006 helped in the recovery of credit metrics for the 12 months ended June 30, 2006.
  - This is the result of the favourable settlement of a natural gas supply contract, which was offset against a fuel expense the Company incurred during this period.
- Higher fuel costs during 2005 resulted in the lowest EBIT and net income in the last five years.
  - The UARB decision on the Company's 2005 rate application, rendered on March 31, 2005, denied about 10% of the Company's 2005 projected fuel costs, due to the perception that said costs were 'imprudently incurred'.
  - Furthermore, actual fuel costs during 2005 were higher than what was originally applied for in rates, so the proportion of recoverable fuel costs is actually lower than what was incurred. This highlights the nature of fuel risk to NSPI due to rapidly escalating prices.
- Also contributing to lower earnings during this period was the lower approved ROE for 2005, at 9.55%, compared with 10.15% in 2004.

Outlook

- As a stable, regulated business in a relatively mature market, NSPI's earnings are expected to remain relatively stable over the medium term, absent significant volatility in fuel prices.
  - The Company will benefit from further economic growth in the province.
- The recent 8.6% rate increase will allow NSPI to more fully recover their higher fuel costs, allowing the Company to earn within their allowed ROE in 2006.
- Key challenges over the medium term, which could continue to pressure earnings, are centred on the recovery of higher fuel costs. This was clearly the theme in the 2006 RA. Increasing global commodity prices have resulted in higher fuel costs for NSPI.
  - Full fuel-cost recovery will be reflected in an increase in earnings, as current figures are reflecting absorption of a portion of these costs by the Company.

FINANCIAL PROFILE

(CAD millions)	12 mos. ended June 30, 2006	2005	2004	2003	2002	2001
		For the year ended December 31				
EBITDA	415.0	360.0	414.0	411.4	355.9	361.4
Net income available to common	98.4	91.2	107.3	112.1	86.1	105.1
Depreciation and amortization	130.1	125.7	122.2	107.9	128.3	125.8
Other non-cash adjustments	8.8	(13.5)	7.3	3.9	11.8	(19.4)
Cash Flow From Operations	237.3	203.4	236.8	223.9	226.2	211.5
Capital expenditures	(90.3)	(100.4)	(142.5)	(96.7)	(104.6)	(111.8)
Common dividends	(75.0)	(91.0)	(153.1)	(70.0)	(84.4)	(161.2)
Free Cash Flow Before W/C Changes	72.0	12.0	(58.8)	57.2	37.2	(61.5)
Working capital changes	(72.6)	(73.5)	(7.9)	88.5	(7.9)	(66.1)
Free Cash Flow	(0.6)	(61.5)	(66.7)	145.7	29.3	(127.6)
Acq./divestitures						
Other financing activities	(2.9)	(5.7)	28.1	(31.0)	3.5	1.6
Cash flow before financing	(3.5)	(67.2)	(38.6)	114.7	32.8	(126.0)
Net change in long-term debt	25.5	70.7	38.6	5.0	(106.2)	46.7
Net change in preferred securities	-	-	-	-	-	10.9
Net change in equity financing	-	-	-	-	75.0	80.0
Pre-2003 income tax assessment (2)	-	-	-	(133.0)	-	-
Other financing activities	(21.8)	(3.5)	-	-	-	-
Change in Net Cash	22.0	0.0	0.0	(13.3)	1.6	11.6
Key Figures and Ratios						
% adj. debt in capital structure (1)	57.2%	57.8%	56.7%	54.8%	56.0%	59.1%
EBITDA interest coverage (times)	4.47	3.91	4.21	3.83	3.27	3.24
Fixed-charges coverage (times)	2.52	2.10	2.43	2.35	1.98	1.94
Cash flow/total adj. debt	14.3%	12.0%	14.6%	14.4%	14.4%	12.6%

(1) Preferred shares treated as 70% equity equivalents.

(2) NSPI has deposited this amount with the Canada Customs and Revenue Agency, and will begin amortizing this amount over eight years, commencing in 2007.

Summary

- Lower fuel costs during Q1 2006 resulted in higher earnings and cash flow from operations, which remained sufficient to fully fund capital expenditures and dividends.
  - Capital expenditures continue to be for system reliability and improvement.
  - NSPI pays dividends to its parent, Emera, such that NSPI's capital structure is maintained at a level that is consistent with regulatory requirements, which is up to 40% equity.
- The decline in cash flow from operations in 2005 resulted in weaker cash flow-to-debt and interest coverage ratios, which DBRS expects will improve somewhat in 2006 with the recent rate relief.
  - However, the general trend is that NSPI's credit metrics have shown material improvement over the past few years.

Outlook

- The Company's cash flow and coverage ratios are expected to continue to be sufficient to cover capital expenditures.
  - Annual capital expenditures will continue to be funded with internally generated cash flows as NSPI's mature market typically has no need for large investments in utility assets.
- In addition, the Company will continue to pay out dividends such that the equity portion of its capital structure is maintained in the 35% to 40% range.
- In a volatile fuel-cost environment, NSPI's key financial ratios will continue to be influenced by its ability to meaningfully recover fuel costs through the regulatory process.
- Beginning in 2007, and over an eight-year period, the Company will be recovering approximately $147 million in deferred taxes.
  - This will accrue to the Company's cash flow from operations and contribute to mitigating any free cash flow deficits.
- Overall, DBRS is of the opinion that the Company's cash flow and coverage ratios will continue to be maintained at levels sufficient to support the rating.

LONG-TERM DEBT MATURITIES AND BANK LINES

Bank Lines

NSPI has established the following short-term credit facilities:

- $400 million Commercial Paper program backed 100% with a line of credit, maturing June 28, 2007, which includes the standard provisions and covenants, including maintenance of ownership by Emera of 100% of the common equity shares and voting shares of the Borrower; maintenance of existence and conduct of business; no consolidation, liquidation or amalgamation, no change of control, debt/capitalization not greater than 65% and a consolidated net worth of $1.1 billion.
  - $182 million was utilized at December 31, 2005.
- $100 million operating line of credit (to June 30, 2008), of which $10 million was drawn at December 31, 2005.

DEBT MATURITY/PREFERRED SHARE REDEMPTION SCHEDULE

(as at December 31, 2005)

Unsecured Debentures (CAD millions)		Preferred Shares (CAD millions)		
Maturity	Principal	Redemption	Series C	Series D
Commercial Paper	182	On or after April 2009	125.0	-
2006	40.2	On or after October 2015	-	135.0
2007	0.20			
2008	115.2			
2009	125.2			
2010	100.1			
Subtotal	562.9			
Greater than 5 years	965			
Total	1,527.9			

Summary

- Long-term debt maturities over the next five years are manageable and well spread out.
- All preferred shares are redeemable at the Company's option.
  - The Series C and D preferred shares are treated as 70% equity equivalents (both are convertible at the holder's option into common shares of parent Emera after July 1, 2009, for the Series C preferred and after January 15, 2016, for the Series D preferred).
  - The Series C preferred shares are redeemable on or after April 1, 2009, at the option of NSPI.
  - The Series D preferred shares are redeemable on or after October 15, 2015, at the option of NSPI.
  - However, if the holder gives notice to exchange either series of preferred shares into Emera common equity, NSPI can give notice to either (1) redeem the preferred shares for cash; or (2) cause the holders of the preferred shares to sell on the exchange date (which is the respective redemption date noted above).
- The Company has a shelf prospectus enabling it to issue up to $400 million in medium-term notes between March 2005 and April 2007.
  - $150 million remains available under this shelf.
- The $40 million in long-term debt maturing in 2006 was extended, at the option of the debtholders, to April 2029 at an interest rate of 6.28%; the current interest rate is 5.20%. The Company assumed that this debt was extended in its 2006 RA, with such higher-interest costs being factored in their rate request.

OPERATING STATISTICS

		12 mos. ended	For the year ended December 31				
Electricty Sold		June 30, 2006	2005	2004	2003	2002	2001
Residential	34.4%	3,929.5	4,000	4,039	3,819	3,835.0	3,756.7
Commercial	25.8%	2,996.9	3,004	2,965	3,001	2,818.3	2,724.9
Industrial	36.1%	3,370.9	4,197	4,197	4,091	3,786.2	3,831.6
Other (including exports)	3.8%	633.4	436	473	595	786.3	592.6
Total (GWh sold)		10,930.7	11,636.7	11,673.2	11,506.4	11,225.8	10,905.8
Energy sales growth			-0.3%	1.4%	2.5%	2.9%	2.3%
Installed Generation Capacity							
Coal	54.2%	1,243	1,243	1,243	1,243	1,243	1,243
Hydro	17.2%	395	395	395	395	395	395
Dual fuel	15.3%	350	350	350	350	350	350
Oil	0.0%	0	0	0	0	0	0
Gas turbine	13.3%	304	304	304	254	204	204
Wind	0.0%	1	1	1	1	1	-
Installed capacity (megawatts)		2,293	2,293	2,293	2,243	2,193	2,192
Long-term IPP contracts (megawatts)			57	25	25	25	25
		12 mos. ended					
Energy generated – GWh		June 30, 2006					
Coal	76.3%	9,073.3	9,116	9,490	9,219	8,861.6	8,854.8
Natural gas	1.6%	239.3	194	97	120	1,578.7	1,129.1
Oil	13.2%	1,034.5	1,581	1,698	1,536	288.3	690.7
Hydro & wind	8.9%	1,013.4	1,062	889	1,080	1,024.6	692.2
Gross energy generated		11,360.5	11,953.5	12,174.0	11,953.6	11,753.2	11,366.8
Plus: purchases		392.3	529	391	375	277.6	279.4
Energy generated + purchased		11,752.8	12,482.8	12,564.9	12,328.8	12,030.8	11,646.2
Less: transmission losses & internal use		822.1	846	892	822	805.0	740.4
Total (GWh sold)		10,930.7	11,636.7	11,673.2	11,506.4	11,225.8	10,905.8
Energy lost/(energy gen. + purch.)		7.0%	6.8%	7.1%	6.7%	6.7%	6.4%
Export Interconnections (megawatts)							
New Brunswick Power		300	300	300	300	300	300
As % of installed capacity		13.1%	13.1%	13.1%	13.4%	13.7%	13.7%

Nova Scotia Power Inc.

Balance Sheet

(CAD millions)	June 30	As at December 31			June 30	As at December 31	
Assets	2006	2005	2004	**Liabilities & Equity**	2006	2005	2004
Cash	0.9	3.5	0.0	Short-term debt	39.0	5.4	4.7
Receivables	106.8	76.8	68.9	A/P + accr'd liab.	158.7	139.0	144.5
Inventories	87.5	45.5	41.6	L.t.d. due in one year	0.6	40.2	100.0
Prepaids + other	51.9	37.8	30.1	**Current Liabilities**	198.3	184.6	249.2
Current Assets	247.1	163.6	140.6	Def'd credits	80.3	76.0	73.6
Long-term receivable	10.2	23.3	13.9	Long-term debt	1,495.5	1,487.7	1,357.0
Net fixed assets	2,397.7	2,427.7	2,443.4	Preferred shares	260.0	260.0	260.0
Deferred expenses	444.0	446.9	394.9	Shareholders' equity	1,064.9	1,053.2	1,053.0
Total	3,099.0	3,061.5	2,992.8	**Total**	3,099.0	3,061.5	2,992.8

Ratio Analysis	12 mos. ended	For the year ended December 31						
Liquidity Ratios (1)	June 30, 2006	2005	2004	2003	2002	2001	2000	1999
Current ratio	1.20	0.92	0.67	0.66	0.66	0.60	0.46	0.46
Accumulated deprec./gross fixed assets	41.7%	40.6%	39.1%	38.3%	37.1%	35.8%	34.5%	33.1%
Cash flow/total adjusted debt (2)	14.3%	12.0%	14.6%	14.4%	14.4%	12.6%	14.8%	14.3%
Cash flow/capital expenditures (4)	2.63	2.03	1.66	2.32	2.16	1.89	1.98	2.07
Debt/EBITDA	3.93	4.60	3.91	3.77	4.41	4.63	4.38	4.42
Cash flow dividends/capital expenditures (4)	1.80	1.12	0.59	1.59	1.36	0.45	1.21	1.44
% debt in capital structure	54.5%	55.1%	54.0%	52.0%	53.2%	56.3%	56.3%	57.4%
% adjusted debt in capital structure (2)	57.2%	57.8%	56.7%	54.8%	56.0%	59.1%	59.0%	59.9%
% debt in capital structure (UARB) (3)	63.4%	64.0%	63.1%	61.2%	62.5%	65.5%	65.4%	65.8%
Average coupon on long-term debt	7.32%	7.32%	7.32%	7.32%	7.56%	7.59%	7.59%	7.58%
Deemed common equity	35%	37.5%	35%	35%	35%	35%	35%	35%
Common dividend payout (before extras.)	77.3%	122.1%	142.7%	60.3%	84.8%	153.4%	89.9%	70.0%
Coverage Ratios (5)								
EBIT interest coverage	3.09	2.58	2.97	2.83	2.31	2.32	2.29	2.28
EBITDA interest coverage	4.47	3.91	4.21	3.83	3.27	3.24	3.34	3.32
Fixed-charges coverage	2.52	2.10	2.43	2.35	1.99	1.94	1.97	1.93
Earnings Quality/Operating Efficiency								
Fuel costs/revenues	28.9%	33.8%	28.9%	27.6%	34.1%	33.2%	30.9%	30.4%
EBIT margin	29.6%	24.3%	31.2%	33.6%	28.6%	30.9%	31.1%	31.8%
Net margin (before extras. after pfd.)	10.1%	7.7%	11.5%	12.8%	11.4%	12.5%	12.7%	12.9%
Return on avg. equity (before extras.)	9.2%	7.1%	10.0%	10.8%	9.8%	10.9%	10.9%	11.1%
Approved ROE - mid-point	9.55%	9.55%	10.15%	10.15%	10.15%	10.75%	10.75%	10.75%
Customers/employee	n/a	289	283	262	248	226	227	229
Growth in customer base	n/a	1.0%	1.1%	0.9%	2.0%	0.8%	0.9%	0.8%
GWh sold/employee	n/a	7.2	7.1	6.6	6.1	5.5	5.5	5.4
Degree day deficiency (% normal)	n/a	93.6%	102.0%	-2.9%	97.1%	94.6%	92.2%	84.9%
Rate base ($ millions)	n/a	2,878	2,850	2,832	2,807	2,832	2,752	2,756
Growth in rate base	n/a	1.0%	0.6%	0.9%	-0.9%	2.9%	-0.1%	-1.0%

n/a - note certain figures are not able to be generated quarterly.

Self-Generation (Cost Structure) (6)^	(Cents per net generated kWh sold) (Tables may not add due to rounding)							
OM&A	1.83	1.69	1.57	1.63	1.61	1.47	1.51	1.44
Fuel	2.63	2.92	2.38	2.24	2.73	2.62	2.43	2.43
Variable costs	4.47	4.62	3.95	3.87	4.34	4.09	3.94	3.87
Government levies	0.38	0.36	0.35	0.30	0.20	0.19	0.17	0.16
Net interest expense	0.82	0.77	0.87	0.96	0.99	1.05	1.07	1.11
Total cash costs	5.67	5.75	5.17	5.13	5.53	5.33	5.18	5.14
Non-cash financial charges	0.15	0.13	0.12	0.08	0.16	0.15	0.15	0.16
Depreciation + amortizations	1.23	1.13	1.08	0.97	0.96	0.96	1.12	1.18
Total costs (excl. income taxes)	7.05	7.01	6.37	6.18	6.64	6.44	6.45	6.47

(1) Securitization sales added back to receivables and short-term debt for ratio calculations. (2) Preferred shares treated as 30%

(3) UARB treats preferred shares as 100% debt. (4) Capital expenditures net of customer contributions.

(5) EBIT includes interest income. Interest expense before capitalized interest, allowance for funds used during construction (AFUDC) and debt amortizations. Preferred dividends net of tax recovery. (6) Internally generated energy less energy used + lost, excludes power purchases. Transmissions losses apportioned relative to total energy supplied.

^ from Company's financial statements.

Income Statements (CAD millions)	12 mos. ended	For the year ended December 31				
Revenues	June 30, 2006	2005	2004	2003	2002	2001
Residential	423.6	411.4	402.9	375.9	371.0	362.1
Commercial	272.3	263.6	258.3	253.4	242.0	232.7
Industrial	201.2	235.1	222.5	218.5	203.0	197.3
Other	57.4	44.9	43.2	47.8	53.1	40.6
Gross electricity revenues	954.5	955.0	926.9	895.6	869.1	832.7
Other	9.0	8.0	7.2	9.0	7.4	5.9
Total revenues	963.5	963.0	934.1	904.6	876.5	838.6
Expenses						
Power purchases	36.3	48.1	33.4	28.2	22.9	21.6
Fuel	278.1	325.7	269.7	249.6	299.3	278.6
Operating, maintenance & general	193.7	188.8	177.5	182.0	176.4	156.8
Provincial grants and taxes	40.4	40.4	39.5	33.4	22.0	20.2
EBITDA	415.0	360.0	414.0	411.4	355.9	361.4
Depreciation	123.9	119.5	116.0	101.7	103.9	99.6
EBITA	291.1	240.5	298.0	309.7	252.0	261.8
Regulatory amortizations	6.2	6.2	6.2	6.2	1.0	3.0
EBIT	284.9	234.3	291.8	303.5	251.0	258.8
Total operating costs	678.6	728.7	642.3	601.1	625.5	579.8
Interest expense	94.7	94.0	98.4	107.4	108.9	111.7
Non-cash financing charges^	16.3	15.0	13.7	9.2	17.0	16.3
Other (income)/expense	(8.0)	(8.0)	(0.1)	(0.1)	(0.3)	(0.2)
Net interest expense	103.0	101.0	112.0	116.5	125.6	127.8
Pre-tax income	181.9	133.3	179.8	187.0	125.4	131.0
Income taxes	71.6	45.5	59.2	57.8	15.7	13.9
Net income before extras.	110.3	87.8	120.6	129.2	109.7	117.1
Extraordinary items (1)	*(1)*	*(16.7)*	*0*	4.0	13.4	0.0
Preferred div's net of tax recovery	13.3	13.3	13.3	13.1	10.2	12.0
Net income available to common sh'lders.	98.4	91.2	107.3	112.1	86.1	105.1

(1) Represents a $4 million after-tax charge at Q3 2003, reflecting restoration and repair costs associated with Hurricane Juan. For 2002 relates to the one-time write-off of $13.4 million paid to the Cape Breton Development Corporation in 2001 to terminate a coal supply contract. For YE2005, represents $15.3 million in deferred taxes that were incurred between Jan. 1, 2005 and Apr. 1, 2005, but not reflected in rates. This amount is pending approval by the UARB, as well as recovery.

^ Comprised primarily of defeasance costs - $13.2 million at YE2005, $15.1mm at YE2004, but includes forex gains/losses. Upon privatization in 1992, NSPI became responsible for about $1.1billion of defeasance securities held in trust. The excess of cost of the defeasance investments over the face value of the related debt is deferred on balance sheet and amortized over the life of the defeased debt.

STANDARD &POOR'S RatingsDirect

RESEARCH

Emera Inc.

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Major Rating Factors

Strengths:

- Monopoly service franchise for essential service
- Limited direct competition in generation
- Cost-of-service regulation that mitigates most operating risks

Weaknesses:

- Partial exposure to fuel price risk
- Intermediate financial profile
- Significant regulatory assets with delayed recovery prospects

Corporate Credit Rating
BBB/Stable/--

Rationale

The ratings on Emera Inc. and its subsidiary, Nova Scotia Power Inc. (NSPI; BBB/Stable/--), are based on the consolidated business and financial risk profile of the parent, Emera, which is itself based on the consolidated rating methodology of Standard & Poor's Ratings Services. The ratings reflect Emera's regulated cash flows from its utility operations. Offsetting these strengths are a moderate financial profile, the absence of a timely fuel cost recovery mechanism for NSPI, some exposure to higher risk activities (such as energy marketing), and a strategy for growth through acquisition.

Emera is a utility holding company based in Halifax, N.S. The ratings on Emera are supported by the average business risk profile of regulated NSPI and the above-average business profile of its Maine-based subsidiary, Bangor Hydro-Electric Co. (BHEC; unrated). Together, these regulated utilities generate approximately 90% of Emera's cash flow and represent a similar percentage of its assets. NSPI is a vertically integrated electric utility, accounting for about 75% of consolidated assets and 80% of Emera's funds from operations (FFO). NSPI benefits from its monopoly position as the principal electricity supplier in the Province of Nova Scotia (A+/Stable/A-1+). BHEC provides low-risk transmission and distribution services to about 115,000 customers in southeastern Maine.

Supportive, cost-of-service regulation underpins Emera's regulated cash flows at both NSPI and BHEC. Furthermore, regulated utility customers provide a solid revenue base. Organic growth opportunities, however, are limited in the mature markets of Nova Scotia and Maine, with typically a 1% increase in the number of customers per year. About 70% of Emera's regulated sales revenues are derived from its diversified residential and commercial customer base, providing a backdrop of stability for Emera's regulated cash flows. In the past five years, Nova Scotia's economy has been generally in line with the Canadian national average annual growth rate, with real GDP growth averaging 3.5% per year. The strength of the province's economy, however, is largely dependent on the performance of the U.S. and Canadian economies and on conditions prevailing in offshore oil and gas development and exploration.

Emera's financial profile is satisfactory for the ratings. On a consolidated basis, adjusted FFO interest coverage for the past 12 months is around 3.0x. FFO-to-average total debt is about 17%, while total debt-to-total capital is about 53%. There has been low volatility in these measures, and earnings are reasonably

predictable. We have some concerns, however, with new projects that might be undertaken and could pressure the company's leverage measures (Emera recently announced its intention to invest around C$350 million in a pipeline to transport natural gas from a liquefied natural gas (LNG) facility in New Brunswick).

Emera continues to face significant risk regarding the timeliness and certainty of the recovery of NSPI's fuel and other costs. NSPI's cash flows are exposed to variances between fuel costs forecast for purposes of setting the utility's regulated rates, and actual fuel costs incurred. There is no regulatory mechanism by which these variances can be recovered from customers. This weakness in the regulatory regime acts as a primary constraint on Emera's rating.

Although Emera's involvement in unregulated business activities represents a relatively small contribution to overall cash flows, these higher risk activities marginally weaken the company's overall business profile.

Liquidity
Standard & Poor's views Emera's liquidity as adequate, given the company's expected cash flow generation, its available bank facilities, and its ability to access capital markets through its existing MTN shelf programs at both the holding and operating company levels.

- On a consolidated basis, expected FFO in 2006 should be sufficient to meet expected capital expenditures and dividend payments.
- Emera has access to C$600 million in credit facilities, of which C$411 million remained available as of Sept. 30, 2006, as well as through an undrawn C$300 million MTN shelf that expires in April 2007. Emera's consolidated LOCs meet the company's operating needs and provide liquidity support to Emera's proprietary trading activities.
- At the subsidiary level, NSPI has an additional C$400 million bank facility that backstops its C$400 million CP program, of which C$128 million was outstanding as of Sept. 30, 2006. At the end of third-quarter 2006 (Sept. 30), NSPI had issued C$12 million in LOC from its C$100 million operating facility.
- BHEC has access to US$70 million in credit facilities of which US$40 million remained available as of Sept. 30, 2006.

Outlook

The stable outlook on Emera and its subsidiary, NSPI, reflects an expectation that the company's key credit metrics will continue to improve marginally in the next few years. Although considered unlikely, a negative outlook or rating action could result if Emera does not continue to exhibit stable operating performance or if leverage levels increased materially as a result of new investments. A positive rating action would require further, sustainable improvement in key cash flow credit metrics or a material decrease in the company's overall business risk.

Business Description

Emera is a utility holding company based in Halifax, N.S. The primary subsidiaries of Emera are:

- NSPI: NSPI provides electricity generation, transmission and distribution to Nova Scotia. The company is a regulated monopoly. NSPI has about C$3 billion in assets and contributed net income of C$91 million to Emera's consolidated results in 2005.
- BHE: BHE is an electricity transmission and distribution company operating in eastern Maine. BHE operations are regulated. The company contributed net income of C$15 million to Emera's consolidated income in 2005.

Emera's other investments include a joint venture in Bear Swamp, a 600-MW pumped storage hydroelectric facility in northern Massachusetts, as well as a 12.9% interest in the Maritimes and Northeast Pipeline, and wholly owned Emera Energy Services, which manages assets on behalf of third parties and provides related services. Emera recently announced plans to invest approximately C$350 million in a New Brunswick pipeline that seeks to deliver natural gas from a LNG facility in New Brunswick to the U.S.

portion of the Maritimes and Northeast pipeline at the Canada-U.S. border. BHEC has begun construction of a new US$110 million, 345-kilovolt transmission line connecting eastern Maine and New Brunswick.

Business Risk Profile

Regulation: regime presents some issues
Cost-of-service regulation supports Emera's business risk profile. Nevertheless, the specific regulation that applies to NSPI is viewed as somewhat less favorable than other regulatory regimes.

- There is an absence of a regulatory mechanism by which fuel cost variances can be mitigated after the fact. This exposes NSPI to volatility in fuel (particularly coal and natural gas) markets.
- Rate stability, a key regulatory objective of the Nova Scotia Utility and Review Board (UARB), presents a further risk to the utility's financial profile and cash flow and appears to be a determining factor in the UARB's 2005 NSPI rate decision. The deferral of an already approved recovery of C$150 million in taxes is an example of the cash flow impact of measures taken by the regulator to manage electricity rate increases.

For the purpose of ratemaking, the UARB allows for a ROE of 9.55% on a deemed equity layer of 37.5%. The regulation, however, allows NSPI to earn 9.3%-9.8% return on an equity layer of up to 40%. Although NSPI's electricity rates must be approved by UARB, the utility is not subject to annual regulatory reviews. Regulated cash flows from BHEC are supported by regulation administered by the Maine Public Utilities Commission. Almost 30% of BHEC's electricity rates relates to stranded cost recovery, highlighting a supportive regulatory regime. Distribution rates are set based on an ROE of 11% but the utility is allowed to earn 5%-17% ROE. BHEC's distribution rates also have a built-in average annual rate reduction of 2.5% per year from 2003-2008, a pressure on the utility's profitability.

BHEC benefits from supportive regulation from both of its U.S. regulators. The Federal Energy Regulatory Commission (FERC) regulates BHEC's transmission activities and the Maine Public Utilities Commission regulates its distribution and stranded cost recovery activities. BHEC's transmission service is allowed an ROE of 11.4% on existing and 12.4% on new transmission assets; the FERC regulated transmission tariff is automatically adjusted by the utility annually, based on a formula, and without a rate hearing. The distribution business benefits from supportive performance based regulation; BHEC is allowed to earn a ROE of 5%-17% and enjoys a 50-50 sharing mechanism outside of the band. Furthermore, the distribution utility is not exposed to the risks associated with standard offer obligations and is allowed to earn a 10% return on the recovery on its stranded costs.

Markets: mature with modest growth prospects
Emera's revenue base is relatively stable and faces no material customer concentration risk. Although both NSPI and BHEC have some limited exposure to the pulp and paper sector, they serve predominantly residential customers in mature markets with modest growth. NSPI's top 10 customers represent less than 20% of net revenues and include government-related entities as well as some less stable industrial customers.

The main risks to Nova Scotia's economy and Emera's revenue base remain the health of the U.S. economy and other Canadian provinces, the province's principal trading partners. Nova Scotia's economy is dependent on trade, with more than 50% of its GDP directly attributed to the export of goods and services to these partners.

Operations
The profitability and competitiveness of Emera's operating companies are dependent in part on the ability to maintain good operational performance in a cost-effective manner. NSPI's generating resources have achieved improving availability in the past five years (see table 1) while keeping its operating costs (excluding fuel expense) relatively flat during the same period. Asset performance is within range of current industry performance of similar assets.

Table 1

Emera Inc.--Generation Asset Performance

	2005	2004	2003	2002	2001
Thermal capacity utilization (%)	78	82	78	77	77
Generating capacity availaiblity (%)	90	92	91	91	91
Cost of fuel and purchased power (mil. C$)	374	303	278	336	302

NSPI's generation portfolio, although reliant on coal-fired facilities, benefits mildly from diversification within its predominantly fossil fuel-fired generation assets (see tables 2 and 3). The utility maintains sufficient capacity plus reserves to meet its obligations to supply the provincial load.

Table 2

Emera Inc.--Generation Portfolio

Fuel Type	MW	% of total
Coal	1,243	54
Dual-fueled (oil or gas)	350	15
Gas	323	14
Hydro	395	17
Wind turbines	1	0
Total installed capacity	2,312	100
Other factors		
Long-term power purchase contracts	32	
Interconnection with other markets (N.B. Power)	300	
Peak demand	2,143	
Peak demand/available capacity (%)	109	

Table 3

Emera Inc.--Annual Energy Production By Fuel Type

(%)	2005	2004	2003	2002	2001
Coal	63	65	62	61	73
Oil	11	12	10	2	6
Natural gas	1	1	1	11	9
Hydro	7	7	8	8	6
Wind	0	0	0	0	0
Purchases	18	16	18	19	6

Historically, Emera has managed its cash flow exposure to significant fuel price risk by hedging more than half of its forecast fuel requirement out about 12-18 months. The company is targeting to hedge about 30%-50% of its coal requirements out two to four years. A nonregulated marine terminal built by Emera in 2004 mitigates fuel price risk somewhat. The terminal provides improved access to better quality, lower sulfur coal, and cheaper freight.

The reliability of NSPI's electricity transmission and distribution operations is typically within industry benchmarks but deteriorated to below industry average in 2004 (see table 4). System performance suffered during a severe winter storm in 2004. Although the utility received significant criticism from customers, an independent study concluded that NSPI had been maintaining its system adequately. Reliability of BHEC's wires operations is monitored by regulators and remains in line with industry benchmarks.

Table 4

Nova Scotia Power Inc.--Reliability*

Reliability measures	2005	2004	2003	2002	2001
System Average Interruption Frequency Index (SAIFI; interruptions per year)	3.54	3.79	2.85	2.62	2.48

CEA region 2 composite SAIFI	2.46	2.3	2.8	2.56	2.67
System Average Interruption Duration Index (SAIDI; minutes)	620	1,105	343	368	243
CEA region 2 composite SAIDI	391	317	222	291	263

*Reliability measures exclude 2003 Hurricane Juan outages. Figures reported for CEA Region 2 in 2003 reflect northeast Aug. 14 blackout. CEA--Canadian Electrical Association.

Emera's capital spending should be about C$200 million per year in 2006. The bulk of this capital spending will be directed at maintenance of NSPI's existing assets and the growth of BHE's regulated transmission asset base. In 2008 and beyond, NSPI potentially will face the need to spend significant capital on environmental controls (subject to regulatory approval) and new generation capacity.

Electricity generation costs could hurt competitiveness

Emera's transmission and distribution activities are monopolies and do not face direct competition. Nevertheless, expected increases to NSPI's cost to generate electricity could put pressure on NSPI's future cost competitiveness relative to independent power producers and neighboring utilities. Furthermore, about 20% of NSPI's current residential load is electric space heating that is exposed to competition from oil and wood heating.

By the end of the decade, Emera could face competition from more cost-efficient generators. Current expectations are that NSPI will be allowed to participate if a competitive bidding process is implemented for the construction of new generation capacity in Nova Scotia. If successful, the new assets would remain under cost-of-service regulation and become part of NSPI's rate base. New capacity is not likely required in Nova Scotia in the next few years.

Market restructuring in Nova Scotia is not a concern from a ratings perspective. The provincial government, after many years of study, has opened a very limited wholesale electricity commodity market. Wholesale competition in electricity was introduced in 2005 for six small to medium municipalities that represent less than 2% of NSPI's revenue base. Broader restructuring is not on the immediate horizon.

Financial Policy

The company's targeted debt-to-total capitalization is 50%-55%. The holding company structure is constrained by the 55% total debt (excluding preferred shares) to capital at its key subsidiary NSPI allowed by regulatory directives. The company manages its debt maturities such that the average is not less than 10 years. Emera's dividend typically represents a payout ratio of about 70%, although in 2002, the payout was 100%.

Accounting

Emera reports its financial statements in accordance with Canadian GAAP. Emera's statements received an unqualified opinion by independent auditor, Ernst and Young LLP, in the most recent annual audited period (December 2005). No material changes to Canadian GAAP or the accounting policies adopted by Emera that would materially alter the company's financial statements as presented are expected.

In calculating Emera's key credit metrics, we have presented NSPI's preferred shares as equity. The deferrable preferred dividend payments, however, are not considered to be overly flexible and are considered a somewhat fixed obligation from an analytical perspective. Hence, in its ratings determination, Standard & Poor's considers the impact of the payment of preferred dividends on cash flow interest coverage ratios.

Financial Profile

Steady profitability; less stable cash flow

Profitability and cash flow protection at Emera are largely a function of the capital structure and returns provided by NSPI's regulatory regime. Accordingly, in the past four years, Emera's net profits have been reasonably stable, at around C$120 million per year. Our ratings continue to factor in this level of profitability over the next few years. Variances in profitability would most likely be induced by changes in allowed returns on equity or by cost disallowances.

Operating cash flow has been somewhat less stable given working capital volatility. Nevertheless, operating cash flows have been persistently above net income given the large proportion of non-cash expenses; depreciation runs at about C$150 million per year. On average, operating cash flows are typically sufficient to fund dividends (C$110 million per year) and capital expenditures that run modestly above depreciation expense.

Capital structure and liability management

Emera's total debt (excluding preferred stock)-to-total capital as of Sept. 30, 2006, was 53%, which is consistent with the company's financial policies. As operating cash flows are typically sufficient to fund capital expenditures, there is little pressure on debt levels. Nevertheless, the company has announced its intention to invest in a natural gas pipeline for about C$350 million. The company has not disclosed its financing proposals for this project.

Ratings Detail (As Of 21-Dec-2006)*

Emera Inc.	
Corporate Credit Rating	BBB/Stable/--
Corporate Credit Ratings History	
21-Jun-2006	BBB/Stable/--
10-Mar-2006	BBB+/Watch Neg/--
05-Jul-2005	BBB+/Negative/--
19-Aug-2003	BBB+/Stable/--
05-Mar-2003	BBB+/Watch Neg/--
21-Dec-2001	BBB+/Stable/--
Financial Risk Profile	Intermediate
Related Entities	
Nova Scotia Power Inc.	
Issuer Credit Rating	BBB/Stable/--
Commercial Paper	
Canadian National Scale Commercial Paper Rating	A-2(Cdn)
Preferred Stock	
Local Currency	BB+
Canadian Preferred Stock Rating	P-3(High)/Stable
Senior Unsecured	
Local Currency	BBB

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

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Moody's Investors Service

Global Credit Research
Credit Opinion
22 DEC 2006

Credit Opinion: Emera Inc.

Emera Inc.

Halifax, Nova Scotia, Canada

Ratings

Category	Moody's Rating
Outlook	Negative
Senior Unsecured Shelf -Dom Curr	(P)Baa2
Nova Scotia Power Inc.	
Outlook	Negative
Issuer Rating	Baa1
Senior Unsecured -Dom Curr	Baa1
Commercial Paper -Dom Curr	P-2
ST Issuer Rating	P-2

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Key Indicators

Emera Inc.

	[1]LTM	2005	2004	2003	2002
(CFO Pre-W/C + Interest) / Interest Expense	**2.9x**	**2.8x**	**2.9x**	**2.8x**	**2.5x**
(CFO Pre-W/C) / Debt	**13.4%**	**11.7%**	**12.9%**	**12.8%**	**11.4%**
(CFO Pre-W/C - Dividends) / Debt	**9.2%**	**7.6%**	**8.9%**	**8.9%**	**7.6%**
(CFO Pre-W/C - Dividends) / Capex	**146.3%**	**140.1%**	**138.5%**	**173.5%**	**158.7%**
Debt / Book Capitalization	**66.7%**	**67.6%**	**66.8%**	**67.6%**	**62.6%**
EBITA Margin %	**36.6%**	**28.1%**	**32.1%**	**29.0%**	**22.3%**

[1] Twelve months as at September 30, 2006

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Company Profile

Emera (EMA) is a relatively small utility/energy services holding company with total assets of approximately $4 billion. Historically, management's growth strategy has focused on the regions in relatively close proximity to EMA's home market of Nova Scotia but its geographic focus is expected to broaden as it considers options for deploying the cash generated by its core regulated electric utility subsidiaries. Sectorally, EMA has focused on developing or acquiring energy infrastructure assets that are similar or complementary to its core electric utility business and that generate regulated or low-risk unregulated returns. EMA's largest subsidiary, Nova Scotia Power Inc (NSP), with assets of $3.1 billion, is a vertically integrated regulated electric utility serving the Province of Nova Scotia. EMA also owns 100% of Bangor Hydro-Electric (BHE), a regulated transmission and distribution utility with assets of $581.9 million, which operates in the State of Maine. Together, these two regulated electric utility subsidiaries represent over 90% of EMA's consolidated total assets as well as its net income.

The company's other investments include an approximate 13% interest in the Maritimes & Northeast Pipeline. Together with its joint venture partner, Brookfield Power Corporation, EMA owns the 600 MW Bear Swamp

pumped storage hydro electric facility in northern Massachusetts. EMA also operates Emera Energy Services, a company that manages energy assets on behalf of and provides energy management services to third parties. Emera Energy Services' risk management policies require the company to operate with very little exposure to commodity price and volume risks. EMA is seeking regulatory approval to develop the Brunswick Pipeline, a 145 km, $350 million natural gas pipeline which will connect the proposed Canaport LNG regassification facility in St. John, New Brunswick with the Maritimes & Northeast Pipeline at the Canada-US border. Should EMA be successful in obtaining regulatory approvals for the Brunswick Pipeline, an affiliate of Duke Energy will permit, construct and may operate the pipeline on behalf of EMA. Duke Energy is the operator of the Maritimes & Northeast Pipeline in which EMA is an equity investor.

Emera's regulated electric utility subsidiaries face little restructuring risk since no further significant electricity restructuring is expected in Nova Scotia or Maine in the medium term. The limited competition permitted in Nova Scotia's generation market is not expected to have any material adverse impact on NSP due to the small size of the contestable market, the relative geographic isolation and low growth of the Nova Scotia market and its limited interconnections with adjacent markets.

NSP is predominantly a coal/pet coke burning utility and is currently exposed to significant fuel price risk. While solid fuel-fired generation makes up only 54% of NSP's total capacity of 2,283 MW, solid fuel-fired generation represents 73% of NSP's energy production. Other fossil fuels, predominantly heavy fuel oil and natural gas, account for a further 17% of energy output with the balance of energy production (10%) coming from a combination of hydro, wind, tidal and power purchase arrangements. While NSP is regulated by the Nova Scotia Utility and Review Board (UARB) on a cost-of-service basis, the company does not have the benefit of a fuel cost pass-through mechanism. In recent rate orders, the UARB has been critical of NSP's fuel procurement practices, has ordered the company to make changes to its fuel procurement policies, procedures and staffing and has disallowed the recovery of significant fuel-related expenditures. Those cost disallowances, together with the deferred recovery of certain expenditures, predominantly Section 21 taxes and increased depreciation, have contributed to the weak cash flow metrics at both NSP and EMA. While NSP has made some progress in implementing the changes required by the UARB, several initiatives are still ongoing and are unlikely to be fully resolved prior to receipt of the UARB's decision on NSP's October, 2006 rate application. In that application, NSP requested an average rate increase of 7.5%, much of it relating to fuel cost increases. Moody's foresees a risk that the UARB might not grant the full amount of NSP's requested rate increase given i) the magnitude of the request; ii) the UARB's recent history of approving less than full fuel cost recovery; and iii) the fact that while the UARB, in its March 10, 2006 Decision, recognized the effort expended by NSP in implementing many improvements in its fuel procurement procedures, the UARB noted that a number of deficiencies still remain and directed NSP to implement the balance of the recommended changes as soon as possible.

Rating Rationale

NSP's financial metrics, including ratios of FFO/Debt of approximately 12% and FFO/Interest of less than 3.0x, are weak for a Baa1-rated regulated electric utility at the high end of the low business risk category under Moody's global rating methodology for electric utility companies. As a cost-of-service regulated electric utility operating in Canada, where Moody's considers the supportiveness of the regulatory and business environment to be relatively high, and an entity that has no unregulated operations, NSP naturally falls into the low overall business risk category. However, given NSP's challenging relationship with its regulator, including disallowance of certain fuel costs and uncertain timing of recovery of certain other costs, and the low probability of obtaining a fuel cost pass-through mechanism in the near-term, Moody's considers NSP's overall business risk to be at the high end of the low risk category. NSP's financial metrics are weaker than those of other integrated electric utility operating companies in the Baa1 category such as Newfoundland Power, Cleco Power LLC and Idaho Power Company.

The Baa2 senior unsecured rating of EMA is based largely on the credit strength of its subsidiary, NSP (Baa1 and Prime-2 (Baa)). NSP comprises over 77% of assets and approximately 80% of net income on a consolidated basis. It also reflects the fact that EMA's other principal subsidiary, BHE (not rated), is a self-financing regulated monopoly T&D utility. Together NSP and BHE represent in excess of 90% of Emera's consolidated net income and assets. EMA's rating also reflects the fact that, unlike NSP, EMA is involved in unregulated business activities (primarily Emera Energy Services and Bear Swamp) although unregulated activities typically represent approximately 5% or less of consolidated cash flow. EMA's rating also reflects the company's relatively weak financial profile compared to global integrated utility holdco peers in the Baa2 rating category. EMA's rating reflects the structural subordination of EMA's debt to approximately $1.6 billion of debt at its operating subsidiaries as well as the risk that potential acquisitions could alter EMA's financial or business risk profile.

Rating Outlook

The rating outlook for both EMA and NSPI is negative reflecting the weakness of the companies' financial profiles due to NSP's inability to fully recover its fuel costs through rate increases. The negative outlook also reflects Moody's concern that there may not be the regulatory or political appetite to address NSP's fuel price risk exposure either through periodic rate applications or the adoption of a fuel price pass-through mechanism. Moody's also expects that potential increases in capital expenditure requirements at NSP in the near and medium term could cause NSP to be free cash flow negative on average over the next few years.

What Could Change the Rating - Up

While considered unlikely in the short term, some combination of the following could lead to a consideration of a ratings upgrade:

Sustainable improvement in Emera's consolidated credit metrics (FFO Interest Coverage approaching 4x and FFO/Debt in the range of 20%)

Adoption of an automatic fuel price pass-through mechanism at NSP

What Could Change the Rating - Down

Emera's inability to maintain sustainable consolidated credit metrics commensurate with the rating category and the company's risk profile (FFO Interest Coverage of about 3x and FFO/Debt in the mid teens)

Failure to receive timely and balanced regulatory decisions

Inability to manage NSP's fuel price risk

Increased reliance on short-term or floating rate debt

Any acquisition or development that materially alters Emera's business/financial profile

Rating Factors

Emera Inc.

Select Key Ratios for Global Regulated Electric Utilities

Rating	Aa	Aa	A	A	Baa	Baa	Ba	Ba
Level of Business Risk	Medium	Low	Medium	Low	Medium	Low	Medium	Low
CFO pre-W/C to Interest (x) [1]	>6	>5	3.5-6.0	3.0-5.7	2.7-5.0	2-4.0	<2.5	<2
CFO pre-W/C to Debt (%) [1]	>30	>22	22-30	12-22	13-25	5-13	<13	<5
CFO pre-W/C - Dividends to Debt (%) [1]	>25	>20	13-25	9-20	8-20	3-10	<10	<3
Total Debt to Book Capitalization (%)	<40	<50	40-60	50-70	50-70	60-75	>60	>70

[1] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items

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This credit rating opinion has been prepared without taking into account any of your objectives, financial situation or needs. You should, before acting on the opinion, consider the appropriateness of the opinion having regard to your own objectives, financial situation and needs.

APPENDIX D

No.	Region	State Code	US State or Canadian Province	2005 (1) Total no. of Utilities that provide power to industrial customers	2005 (1) Ind. Customers	Census data from the first 10 months of 2006 (2) MWh Sales to Ind. Sector	Revenues from Ind. sector ('000 of $)	Regional Average Cost (cents/KWh)	State Average (Cents per KWh)	Dr. Rosenberg's sample Number of utilities	Ave Cost at 75% load factor bfr Adj. For the pending rate case increase (US cents/KWh)	Var from Average State costs
	Canada	NS	Nova Scotia (2006 test year)						5.36 (3)	1	5.23	-2%
1	New England	CT	Connecticut	8	5,486	4,148	$490	10.84	11.81			
2	New England	ME	Maine	4	45	2,592	$217	10.84	8.36			
3	New England	MA	Massachusetts	44	14,266	8,137	$906	10.84	11.14			
4	New England	NH	New Hampshire	9	3,184	1,795	$216	10.84	12.03			
5	New England	RI	Rhode Island	3	2,480	992	$119	10.84	12.05			
6	New England	VT	Vermont	19	367	1,354	$113	10.84	8.36			
7	Middle Atlantic	NJ	New Jersey	8	13,047	8,652	$814	7.43	9.41			
8	Middle Atlantic	NY	New York	50	6,355	16,704	$1,448	7.43	8.67			
9	Middle Atlantic	PA	Pennsylvania	43	27,381	40,379	$2,622	7.43	6.49			
10	East North Central	IL	Illinois	54	5,921	37,813	$1,779	5.38	4.71			
11	East North Central	IN	Indiana	88	19,057	41,675	$2,077	5.38	4.99	2	3.79	-24%
12	East North Central	MI	Michigan	49	12,860	28,425	$1,770	5.38	6.23			
13	East North Central	OH	Ohio	102	20,268	47,982	$2,646	5.38	5.52			
14	East North Central	WI	Wisconsin	89	7,145	21,206	$1,249	5.38	5.89			
15	West North Central	IA	Iowa	105	5,941	15,573	$773	4.95	4.97	3	3.30	-34%
16	West North Central	KS	Kansas	79	17,001	9,383	$499	4.95	5.31			
17	West North Central	MN	Minnesota	118	8,266	18,806	$983	4.95	5.23			
18	West North Central	MO	Missouri	90	10,591	15,363	$721	4.95	4.70	3	3.57	-24%
19	West North Central	NE	Nebraska	96	37,130	7,534	$344	4.95	4.57			
20	West North Central	ND	North Dakota	25	2,328	2,748	$118	4.95	4.30			
21	West North Central	SD	South Dakota	38	2,317	1,685	$82	4.95	4.89			
22	South Atlantic	DE	Delaware	9	569	2,615	$133	5.59	5.09			
23	South Atlantic	DC	District of Columbia	2	(44)	245	$22	5.59	8.96			
24	South Atlantic	FL	Florida	34	29,672	16,546	$1,265	5.59	7.65			
25	South Atlantic	GA	Georgia	75	15,361	29,577	$1,601	5.59	5.41	1	5.62	4%
26	South Atlantic	MD	Maryland	8	10,354	7,586	$816	5.59	10.76			
27	South Atlantic	NC	North Carolina	65	10,976	24,855	$1,308	5.59	5.26	2	4.52	-14%
28	South Atlantic	SC	South Carolina	34	4,786	26,810	$1,270	5.59	4.74	3	4.16	-12%
29	South Atlantic	VA	Virginia	30	5,196	15,906	$743	5.59	4.67	2		
30	South Atlantic	WV	West Virginia	5	11,618	11,556	$426	5.59	3.69	2	3.46	-6%
31	East South Central	AL	Alabama	56	8,721	30,826	$1,529	4.90	4.96	1	4.51	-9%
32	East South Central	KY	Kentucky	52	6,627	36,110	$1,481	4.90	4.10	3	3.73	-9%
33	East South Central	MS	Mississippi	48	7,748	13,060	$782	4.90	5.99			
34	East South Central	TN	Tennessee	85	1,993	27,659	$1,481	4.90	5.36	2	3.72	-31%
35	West South Central	AR	Arkansas	32	31,364	14,889	$788	7.16	5.30	3	4.43	-16%
36	West South Central	LA	Louisiana	29	18,161	22,806	$1,599	7.16	7.01	1	4.52	-36%
37	West South Central	OK	Oklahoma	65	17,683	12,191	$680	7.16	5.58			
38	West South Central	TX	Texas	122	113,943	79,185	$6,176	7.16	7.80	3	4.41	-44%
39	Mountain	AZ	Arizona	33	8,097	9,685	$566	5.55	5.85			
40	Mountain	CO	Colorado	42	12,835	10,181	$612	5.55	6.01			
41	Mountain	ID	Idaho	23	25,259	7,800	$289	5.55	3.71	2	3.20	-14%
42	Mountain	MT	Montana	26	4,528	4,000	$194	5.55	4.85			
43	Mountain	NV	Nevada	13	3,350	11,401	$910	5.55	7.98			
44	Mountain	NM	New Mexico	24	4,030	5,570	$313	5.55	5.63			
45	Mountain	UT	Utah	28	8,986	6,809	$296	5.55	4.35	1	4.46	2%
46	Mountain	WY	Wyoming	23	8,651	6,936	$282	5.55	4.06	1	3.75	-8%
47	Pacific Contiguous	CA	California	39	78,970	41,027	$3,931	7.45	9.58			
48	Pacific Contiguous	OR	Oregon	36	21,729	10,673	$476	7.45	4.46			
49	Pacific Contiguous	WA	Washington	44	24,689	18,059	$788	7.45	4.36	1	3.20	-27%
50	Pacific Noncontiguous	AK	Alaska	25	1,123	1,012	$119	16.67	11.77			
51	Pacific Noncontiguous	HI	Hawaii	4	684	3,244	$590	16.67	18.20			
	U.S. Total		U.S. Total	2,224	713,609	841,766	$51,458		6.11	36		

(1) Table 8. Class of Ownership, Number of Bundled Ultimate Consumers, Revenue, Sales, and Average Retail Price for the Industrial Sector by State Utility, 2005 (EIA)

(2) Source:Table 5.6.B. Average Retail Price of Electricity to Ultimate Customers by End-Use Sector, by State, Year-to-Date through October 2006 and 2005

(3) Average cost to NSPI industrial customersas per test year data per 2006C. Used same exchange rate $ 1.15 CND = $1.00 U.S as in Dr. Rosenberg's comparison.

Table #2 US census statistics for selected utilities and states from 2005 (1)

Utility	State	Region	Ownership	Census statistics of Utilities from dr. Rosenberg's Sample: Industrial Customers	Industrial Sales	Industrial Revenues	Cents per Kwh	Combined Census Statistics of all utilities from a given US state: Industrial Sales	Industrial Revenues	Cents per Kwh	Variance in average cost of power to industrial customers between sampled utilities and state average.
Indiana Michigan Power Co	IN	East North Central	Investor Owned	4,151	7,018,591	$294,935	4.20	48,944,355	$2,164,797	4.42	-5%
PSI Energy Inc (Presently Duke Energy)	IN	East North Central	Investor Owned	2,907	11,639,028	$486,231	4.18	48,944,355	$2,164,797	4.42	-6%
Alabama Power Co	AL	East South Central	Investor Owned	5,407	23,355,787	$1,065,576	4.56	36,278,765	$1,641,194	4.52	1%
Kentucky Power Co	KY	East South Central	Investor Owned	1,457	3,342,619	$127,676	3.82	43,180,694	$1,557,049	3.61	6%
Kentucky Utilities Co	KY	East South Central	Investor Owned	1,911	6,004,038	$245,293	4.09	43,180,694	$1,557,049	3.61	13%
Louisville Gas & Electric Co	KY	East South Central	Investor Owned	398	3,076,790	$127,876	4.16	43,180,694	$1,557,049	3.61	15%
Tennessee Valley Authority	TN	East South Central	Federal	37	8,798,897	$325,342	3.70	32,011,816	$1,572,205	4.91	-25%
Kingsport Power Co	TN	East South Central	Investor Owned	185	943,018	$32,698	3.47	32,011,816	$1,572,205	4.91	-29%
Avista Corp	ID	Mountain	Investor Owned	502	1,267,808	$52,507	4.14	8,636,444	$337,435	3.91	6%
PacifiCorp (Presently Rocky Mountain Power)	ID	Mountain	Investor Owned	5,436	2,184,262	$75,266	3.45	8,636,444	$337,435	3.91	-12%
PacifiCorp (Presently Rocky Mountain Power)	UT	Mountain	Investor Owned	8,283	7,094,794	$284,706	4.01	7,988,772	$338,766	4.24	-5%
PacifiCorp (Presently Rocky Mountain Power)	WY	Mountain	Investor Owned	2,714	5,771,890	$223,510	3.87	8,007,142	$319,485	3.99	-3%
PacifiCorp (Presently Rocky Mountain Power)	WA	Pacific Contiguous	Investor Owned	5,868	1,229,730	$56,173	4.57	20,174,298	$833,603	4.13	11%
Georgia Power Co	GA	South Atlantic	Investor Owned	7,674	25,027,371	$1,351,731	5.40	34,601,792	$1,826,756	5.28	2%
Duke Energy Corporation	NC	South Atlantic	Investor Owned	5,650	15,097,219	$702,575	4.65	30,101,279	$1,516,421	5.04	-8%
Progress Energy Carolinas Inc	NC	South Atlantic	Investor Owned	3,590	9,450,295	$518,354	5.49	30,101,279	$1,516,421	5.04	9%
Duke Energy Corporation	SC	South Atlantic	Investor Owned	1,819	10,279,050	$389,907	3.79	32,080,455	$1,459,564	4.55	-17%
Progress Energy Carolinas Inc	SC	South Atlantic	Investor Owned	773	3,243,126	$167,877	5.18	32,080,455	$1,459,564	4.55	14%
South Carolina Electric & Gas Co	SC	South Atlantic	Investor Owned	877	6,651,036	$327,684	4.93	32,080,455	$1,459,564	4.55	8%
Appalachian Power Co	VA	South Atlantic	Investor Owned	1,985	5,784,516	$197,125	3.41	19,202,549	$855,528	4.46	-24%
Virginia Electric & Power Co	VA	South Atlantic	Investor Owned	585	8,621,448	$401,660	4.66	19,202,549	$855,528	4.46	5%
Appalachian Power Co	WV	South Atlantic	Investor Owned	2,406	4,504,844	$166,355	3.69	11,290,074	$434,785	3.85	-4%
Monongahela Power Co	WV	South Atlantic	Investor Owned	7,161	4,667,768	$190,235	4.08	11,290,074	$434,785	3.85	6%
MidAmerican Energy Co (North, South and East)	IA	West North Central	Investor Owned	1,199	6,903,223	$279,901	4.05	17,915,187	$817,783	4.56	-11%
Aquila Inc	MO	West North Central	Investor Owned	276	1,309,091	$55,971	4.28	16,849,266	$765,368	4.54	-6%
Kansas City Power & Light Co	MO	West North Central	Investor Owned	1,162	1,718,826	$77,967	4.54	16,849,266	$765,368	4.54	0%
Union Electric Co	MO	West North Central	Investor Owned	6,434	8,346,469	$358,766	4.30	16,849,266	$765,368	4.54	-5%
Empire District Electric Co	AR	West South Central	Investor Owned	9	75,948	$3,811	5.02	17,554,806	$832,493	4.74	6%
Entergy Arkansas Inc	AR	West South Central	Investor Owned	22,318	7,333,641	$361,877	4.93	17,554,806	$832,493	4.74	4%
Southwestern Electric Power Co	AR	West South Central	Investor Owned	837	1,740,775	$81,433	4.68	17,554,806	$832,493	4.74	-1%
Southwestern Electric Power Co	LA	West South Central	Investor Owned	1,927	930,754	$46,873	5.04	27,031,224	$1,813,941	6.71	-25%
El Paso Electric Company	TX	West South Central	Investor Owned	51	1,058,705	$79,009	7.46	92,972,718	$6,654,998	7.16	4%
Southwestern Electric Power Co	TX	West South Central	Investor Owned	4,389	2,883,860	$135,466	4.70	92,972,718	$6,654,998	7.16	-34%
Southwestern Public Service Co	TX	West South Central	Investor Owned	161	6,626,393	$312,600	4.72	92,972,718	$6,654,998	7.16	-34%
Total				110,539	213,981,610	$9,604,966	4.49	1,060,284,031	$55,162,286	5.20	-14%

(1) Source: Table 8. Class of Ownership, Number of Bundled Ultimate Consumers, Revenue, Sales, and Average Retail Price for the Industrial Sector by State, Utility, 2005 (EIA)

APPENDIX E

FILE COPY

Nova Scotia Utility and Review Board

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December 15, 2006

By Fax: 428-6011 & Regular Mail

Mr. Dan Muldoon
General Manager
Customer Operations
Nova Scotia Power Inc.
PO Box 910, Scotia Square
Halifax, Nova Scotia B3J 2W5

Dear Mr. Muldoon:

NSPI Request for Approval of Distribution System Vegetation Management Program
November Power Outage Review Decision Reports P-401.32

The Board has reviewed NSPI's distribution management report dated September 29, 2006, and its letter of November 14, 2006 with regard to approval of the cost of implementing the proposed Distribution System Vegetation Management program. As NSPI notes in the above-noted report, this matter was referred to in the Board's decision dated March 10, 2006 (P-882), on NSPI's 2005 general rate application. In that decision, the Board deferred the inclusion of the requested $3.6 million increase in spending on the program from NSPI's test year revenue requirement pending an evaluation of Liberty's report with respect to this matter.

The Board fully recognizes the importance of the implementation of this program and remains very concerned about the frequency and duration of power outages, particularly in view of the public input received during the 2005 power outage review public hearing. As the September 29, 2006 report filed by NSPI states:

> Vegetation encroachment is confirmed as the single largest cause of electric service interruptions. During periods of severe weather, vegetation conflict accounts for almost 35% of customer outages. A material increase to funding of distribution system vegetation management is necessary to further improve customer reliability and to "storm-harden" the distribution system. NSPI experience during recent large-scale outage events confirms that our customers want this.

NSPI states that its request for Board approval of this project is on the basis that the expenditure of $3.6 million can be recovered in customer rates. However, in view of the fact that NSPI's October 10, 2006 general rate application does not include this cost in its test year revenue requirement, approval of this project, on the basis set out by NSPI, would result in a corresponding increase to the 2007 test year revenue requirement. This was clearly a foreseeable expenditure which NSPI could have provided for in its filing. As NSPI is aware, the issue concerning revisions to the revenue requirement filed by NSPI in its rate application has been raised by a number of intervenors in the upcoming rate hearing and was one of the matters heard by the Board at the preliminary hearing on December 7, 2006. In the Board's direction to the parties, issued on December 8, 2006, the reference to the revenue requirement states:

> Confirmation of Revenue Request
>
> NSPI confirmed that the revenue request being applied for was the revenue request filed with its evidence of October 10, 2006. It has not been amended and will not be amended by NSPI.

The Board is certainly prepared to approve this important and necessary program should NSPI wish to proceed on the basis that ongoing annual costs associated with this project would be included in future rate applications. The matter will be explored further in the upcoming rate hearing.

Yours truly,

Nancy McNeil
Regulatory Affairs Officer/Clerk

cc. Bob Boutilier, Director, Regulatory Affairs By Fax: 428-6542
Eric Ferguson, Manager, Regulatory Affairs By Fax: 428-6542

FILE COPY

NOVA SCOTIA POWER
An Emera Company

November 14, 2006

Ms. Nancy McNeil
Regulatory Affairs Officer/Clerk
Nova Scotia Utility and Review Board
1601 Lower Water Street, 3rd Floor
Halifax, NS B3J 3P6

Dear Ms. McNeil:

Re: November Power Outage Decision Reports-Distribution System Vegetation Management Spending

The Board's letter dated, October 26, 2006, provided a copy of the report prepared by Board consultant, the Liberty Consulting Group (Liberty, the Consultant) concerning NSPI's proposed Distribution System vegetation management spending. The Board's letter requested NSPI's comments on the Liberty report as well as responses to two additional questions issued by the Board. This letter provides NSPI's response to the Liberty report and the Board's questions.

Liberty Report

The Liberty report contains the following conclusions and recommendations:

Liberty Conclusions

"1. NSPI based its proposed vegetation management program for the distribution system on reasonable assumptions. The well-planned program appears to maximize the benefits to customers for the requested level of spending.

2. NSPI's proposed vegetation management program for the distribution system should result in improvements in reliability but may not resolve customer dissatisfaction issues."

Liberty Recommendations

"1. Require that NSPI justify the portion of the vegetation management budget related to customer-requested work and hazard trees.

2. Approve the requested level of annual spending of at least $7 million, assuming a satisfactory justification in response to item #1 directly above.

3. If does not already do so, require that NSPI use the approved funding only on distribution vegetation management, and require that NSPI report annually on the work completed compared to planned work."

NSPI Comment

NSPI accepts Liberty's conclusions. We are encouraged by and in agreement with the Consultant's finding that NSPI's proposed Distribution System Vegetation Management Program is well-planned and should maximize benefits to customers for the requested level of spending.

With respect to Liberty's recommendations, NSPI's response to Recommendation 1 is provided in Attachment 1. Recommendations 2 and 3 remain subject to the Board's approval of the additional funding necessary to execute the expanded Distribution System Vegetation Management Program.

NSPI's responses to the Board's two questions are provided in Attachment 2.

Should you have any further questions please feel free to contact me.

Yours truly,

Dan Muldoon
General Manager, Customer Operations

c: Ralph Tedesco
Bob Boutilier
Eric Ferguson
Rene Gallant
File

Attachment 1

Customer Requested Work and Hazard Trees Cost Justification

The NSPI filing dated September 29, 2006 included funding of approximately $1 million to address Customer Requested Work and Hazard Trees. Each of these elements is discussed below.

Customer Requested Work Program (CRW)

NSPI's Customer Requested Work Program is directed at addressing safety issues associated with vegetation in proximity to power lines.

NSPI typically receives between three thousand and four thousand calls per year from customers concerned with vegetation encroachment to power lines, on or near their property. In response NSPI has established a process to assess these requests and ensure that where safety concerns exist, these are addressed in a timely manner. Typically approximately half of customer calls require the dispatch of a NSPI crew.

The number of calls requiring crew dispatch and the associated cost of this for 2004, 2005 and 2006 year-to-date is presented in the table below. Recent experience indicates this activity is increasing. For the purposes of the vegetation submission an annual cost of $900,000 was assumed.

Year	Jobs Completed	Expenditure
2006	1616 YTD	$776,929
2005	1434	645, 986
2004	1940	628, 049

Large Hazard Tree Program (LHT)

The large hazard tree program targets large trees, near NSPI plant that have died or are dying. The objective of the program is to remove the tress before they fall apart. The classic example of this in our region is American White Elm, which have been damaged by Dutch Elm Disease (see Figure 1 on the following page).



Figure 1 - Dead American Elm tree being removed from over a three phase distribution line in the Annapolis Valley

When these trees begin to fall apart they shed large limbs that weigh hundreds of pounds. If the falling debris makes contact with NSPI plant, outages may result and significant damage can occur.

The table below provides NSPI costs for this program for 2004 and 2005. For the purpose of the annual distribution system vegetation management spend, $100 thousand has been forecast.

Year	Expenditure
2005	$104,943
2004	126,616

Summary

Customer requested work and hazard trees account for approximately $1 million annually in utility cost. This work is customer-specific and largely unaffected by the scope of work undertaken in the balance of the Distribution System Vegetation Management Program. Annual variances in this spend will occur. However NSPI commits that these will be absorbed in the reactive and proactive segments of the overall vegetation program. Therefore the $1 million estimate is reasonable for budget purposes.

Attachment 2

Question 1

The report's financial estimates are based on a unit price per span for trimming of $325 per span. What is the breakdown or origin of this unit price?

Response

The forecast unit price figure is based on actual costs for the period 2003-2005. The following table presents the actual annual vegetation cost and spans-addressed information.

Year	Distribution System Vegetation Management Cost	Spans Addressed	Average Cost/Span
2003	$4,844,840	14,953	$324
2004	4,030,026	11,289	357
2005	3,149,501	9,935	317
Average	$4,008,122	12,048	$332

While the mix of vegetation work will change among periods and across regions, for budget purposes a system average figure of $325/span is reasonable.

Question 2

What are the anticipated roles of NSPI's linemen, scopers, foresters, and contract tree-trimmers in the proposed program?

Response

NSPI contracts out the vast majority of tree work. NSPI's linemen and regular scopers will have a limited role in the proposed program. Their activities will be limited to trimming associated with capital jobs which require some maintenance on existing rights-of-way.

NSPI's foresters and forest technicians will be responsible for detailed plan development, job scoping and inventory collection. As well, this group will be responsible for safety and environmental, financial and operational management of the program and individual jobs. NSPI's forestry team will also be responsible for interaction with customers, municipalities and government departments as required to address issues arising from proposed or completed work.

Contract tree trimmers will complete all the work identified within the program. The contractor will be responsible to supply all machinery and equipment required, as well as provide direct supervision of individual jobs.

Nova Scotia Utility and Review Board

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October 26, 2006

By Fax Only: 428-6542

Mr. Eric Ferguson
Manager, Regulatory Affairs
Nova Scotia Power Inc.
14th Floor, Barrington Tower
P. O. Box 910, Scotia Square
Halifax, NS B3J 2W5

Dear Mr. Ferguson:

November Power Outage Review Decision Reports - NSPI Distribution System Vegetation Management Spending - P-401.32

Enclosed is a copy of Liberty Consulting Group's comments on the above-noted report. Please provide the Board with NSPI's comments on this report, as well as responses to the following questions:

1. The report's financial estimates are based on a unit price per span for trimming of $325 per span. What is the breakdown or origin of this unit price?

2. What are the anticipated roles of NSPI's linemen, scopers, foresters, and contract tree-trimmers in the proposed program?

Yours truly,

Nancy McNeil
Regulatory Affairs Officer/Clerk

c.c. S. Bruce Outhouse, Q.C., Board Counsel Fax: 429-7347
Robert Stright, The Liberty Consulting Group Fax: (717) 270-0555

DRAFT

THE
LIBERTY
CONSULTING GROUP
65 Main Street, P.O. Box 1237
Quentin, PA 17083
717-270-4500

October 20,
2006

Mr. George Smith
Director of Technical Analysis
Nova Scotia Utility and Review Board
1601 Lower Water St., Suite 300
Halifax, Nova Scotia B3J3S3

Dear George:

In its March 10, 2006, decision, the Nova Scotia Utility and Review Board (UARB) deferred the approval of a requested increase in expenditures for vegetation management of the distribution system until Nova Scotia Power Inc. (NSPI) could respond to a Liberty report, make estimates of reduced outage and repair costs that may result from the increase, and justify the level of expenditures requested. On September 29, 2006, NSPI filed with the UARB a report addressing this subject. This letter responds to your request that Liberty evaluate the NSPI report and provides a summary of the results of that review to you.

Liberty concluded:

1. NSPI based its proposed vegetation management program for the distribution system on reasonable assumptions. The well-planned program appears to maximize the benefits to customers for the requested level of spending.
2. NSPI's proposed vegetation management program for the distribution system should result in improvements in reliability but may not resolve customer dissatisfaction issues.

Liberty recommends that the UARB:

1. Require that NSPI justify the portion of the vegetation management budget related to customer-requested work and hazard trees.
2. Approve the requested level of annual spending of at least $7 million, assuming a satisfactory justification in response to item #1 directly above.
3. If does not already do so, require that NSPI use the approved funding only on distribution vegetation management, and require that NSPI report annually on the work completed compared to planned work.

The following summary of Liberty's analysis of the NSPI report provides either support for the above conclusions and recommendations or highlights Liberty's observations for the UARB's information.

Liberty's distribution system report of November 2005 suggested that NSPI use a cyclical vegetation management program. While acknowledging the benefits of a cyclical approach, NSPI states that such a program would cost significantly more than the one it proposes. Liberty agrees that a cyclical program would have higher annual costs, but that those expenditures would result in:

1 More resistance to the effects of storms (i.e., more "storm hardening") because of greater average vegetation clearance.
2 Improved reliability for rural, low-density customers.
3 Greater resistance to momentary outages.

Nevertheless, Liberty agrees that, for the suggested level of annual expenditures, NSPI's proposed approach maximizes the benefits to customers.

NSPI's approach contains three parts—a proactive portion with annual expenditures of about $4.3 million, a reactive portion with first year budget of about $1.7 million, and a third portion that includes customer-requested work and hazard trees that apparently is about $1.2 million. NSPI's report did not provide any information that would support the expenditure proposed for this third part.

Possibly less significant but noteworthy observations on the NSPI report are:

1 NSPI performed its analysis in constant-year dollars (i.e., no inflation adjustment).
2 The program does not address the potential issue of trimming refusals, which may increase with the implementation of added proactive trimming.
3 The report does not mention either customer education or a budget contingency.
4 The report correctly notes the relatively small savings gained from a reduction in interruption restoration and the fact that the program's benefits primarily and simply result from improved reliability.
5 In the proactive portion of its program, NSPI will address 70 percent of the total number of customers affected in the first year. Over half of the expenditures over the five years will be in the Western region. These and similar observations regarding the proposed program support the view that it has been well planned and consistent with Liberty's observations of the need for increased attention to vegetation management.

If you have any questions on this matter, please contact me.

Sincerely,
Robert Stright
Principal

APPENDIX F

Average Credit Provided by ELI 2P-RTP Three-Tiered Credit Mechanism

The average percentage (of marginal cost) that SEB is credited, based on the three tiered credit mechanism of the ELI 2P-RTP rate, exceeds 95%. This is in contrast with the 77% that Dr. Stutz suggested was appropriate during his testimony in the ELIIR-2 Hearing.

This is because the vast majority of actual load reductions by SEB fall into the first tier, which is credited at 100% of marginal cost. Based on actual hourly load data for 2005, the historical deviations fall into the three tiers as shown in the following table.

Tier	**StoraEnso**		**Bowater**	
	MW in tier	% of annual decrement energy	MW in tier	% of annual decrement energy
Tier 1 (@100% of MC[1])	75 MW	82 %	30 MW	93 %
Tier 2 (@80% or SEC[2])	30 MW	10 %	10 MW	6 %
Tier 3 (@60% or SEC)	Balance (~95 MW)	8 %	Balance (~2 MW)	1%

Based on the above 2005 data, the load-weighted average percent of marginal cost has been calculated at **95** percent for StoraEnso and **98** percent for Bowater.

The actual figures for December 2006 shown in the table below indicate that even higher percentages are credited at full marginal cost.

Tier	**StoraEnso**		**Bowater**	
	MW in tier	% of annual decrement energy	MW in tier	% of annual decrement energy
Tier 1 (@100% of MC)	75 MW	92 %	30 MW	99.99 %
Tier 2 (@80% or SEC)	30 MW	5 %	10 MW	.01 %
Tier 3 (@60% or SEC)	Balance (~95 MW)	3 %	Balance (~2 MW)	0%

[1] Marginal Cost
[2] Standard Energy Charge of the ELI 2P-RTP Tariff

APPENDIX G

APPENDIX A (REVISED)

ANALYSIS OF WEIGHTING FACTOR FOR C-3 CUSTOMER ALLOCATOR

APPENDIX A - TABLE 1 (REVISED)

UNMETERED SERVICE CLASS
ANALYSIS OF ALLOCATED CUSTOMER-RELATED EXPENSES

	2006 Compliance Filing				
	Total ($000)	Total - Incl. Corp. O/H ($000)	Corp. O/H Rate	Cust. Costs assigned to Unmetered Class ($000)	Cust. Costs assigned to Unmetered Class (%)
Customer Costs Assigned to Unmetered Class:					
Current COSS Methodology					
Billing Services (including Corp. O/H)	$3,272	$5,456	66.75%	$424	7.8%
Call Centre (including Corp. O/H)	6,230	10,389	66.76%	808	7.8%
Cust. Serv. H/O (including Corp. O/H)	3,034	5,060	66.78%	393	7.8%
Total (using a Weighting Factor of 5)				$1,625	
Proposed COSS Methodology					
Billing Services (including Corp. O/H)	$3,272	$5,456	66.75%	$165	3.0%
Call Centre (including Corp. O/H)	6,230	10,389	66.76%	175	1.7%
Cust. Serv. H/O (including Corp. O/H)	3,034	5,060	66.78%	0	0.0%
Total Revised Assignment				$341	
Revised Weighting Factor				**1.05**	

APPENDIX A - TABLE 2 (REVISED)

BILLING SERVICES OPERATIONS

Rate Class	Total Accts	% of Accounts	Meter Reading Processing	Billing	Inquiries	Large Accts requiring manual effort	Unmetered Accts with more than 10 lights & LED TCL Conversions	Total FTEs	% of FTEs	Labour Budget allocated by Rate Class	Total Accts	% of Accounts	Other Budget allocated by Rate Class
			2.5 FTE	**7.25 FTE**	**2.75**	**1.5 FTE**	**1.0 FTE**			**$0.6 Million**			**$2.0 million**
Residential	415,831	89.90%	2.28	6.52	2.47			11.27	75.17%	451,002	415,831	89.89%	1,797,846
Tou	3,296	0.71%	0.02	0.05	0.02			0.09	0.60%	3,576	3,296	0.71%	14,250
General (Rate 10)	22,391	4.84%	0.12	0.35	0.13			0.61	4.05%	24,282	22,391	4.84%	96,808
General Demand (Rate 11)	11,103	2.40%	0.06	0.17	0.07			0.30	2.01%	12,042	11,103	2.40%	48,004
Industrial (Rate 21 & 22)	2,419	0.52%	0.01	0.04	0.01			0.07	0.44%	2,622	2,419	0.52%	10,459
Unmetered	7,491	1.62%	0.00	0.12	0.04		1.00	1.16	7.75%	46,476	7,491	1.62%	32,387
Sub-Total	462,531	100.00%	2.50	7.25	2.75								
LCB/LCCB	57		0.00	0.00	0.00	1.50		1.50	10.00%	60,000	57	0.01%	246
Total	462,588		2.50	7.25	2.75	1.50	1.00	15.00	100.00%	600,000			2,000,000
FTE			2.50	7.25	2.75	1.50	1.00						
										$600,000	**462,588**	**100.00%**	**$2,000,000**

Billing Services Weighting Factor Calculation
= (Unmetered Billing Services Costs / Total Billing Services Costs) / (Total Unmetered Accounts / Total NSPI Accounts)
= (($46,476 + $32,387) / $2,600,000) / (7,491 / 462,531)

Weighting Factor **1.87**

APPENDIX A - TABLE 3

CALL CENTRE OPERATIONS

Group	Calls	Budget 2006	Cost Per Call	Total Cost	%
Outage	116,565			$782,043	10%
Residential	400,097			2,684,280	36%
Commercial	66,861			448,575	6%
Collections	453,439			3,042,155	41%
Wiring Permit	41,650			279,433	4%
Web Contacts	36,095			242,164	3%
Total Contacts 2005	**1,114,707**	**$ 7,478,650**	**$ 6.71**	**$7,478,650**	
Unmetered Service Calls	16,343		$ 6.71	109,646	1.47%
Unmetered Service Web Contacts	2,438		$ 6.71	16,357	0.22%
Total Unmetered Service Transactions	**18,781**		**$ 6.71**	**$126,003**	**1.68%**

Call Centre Weighting Factor Calculation

= (Unmetered Call Centre Costs / Total Call Centre Costs) / (Total Unmetered Accounts / Total NSPI Accounts)

= ($126,003 / $7,478,650) / (7,491 / 462,531)

Weighting Factor **1.04**

Assumptions/Notes:

Uses 2005 Call/transaction volumes

Uses 2006 budget

Cost/call based on inbound contacts plus outbound collections calls (excludes technology satisfied)

Unmetered Services transactions are a subset of total 2005 contacts and are based on activity codes entered by CSRs.

EXHIBIT 10

NOVA SCOTIA POWER INC.

REVENUE TO EXPENSE COMPARISON (REVISED)

FOR THE YEAR ENDING DECEMBER 31, 2007

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL DMD.RELATED EXPENSES	(2) TOTAL ENG.RELATED EXPENSES	(3) UNIT COST ENG.RELATED (C / kW.h)	(4) TOTAL CUST.RELATED EXPENSES	(5) TOTAL OPER. EXPENSES	(6) TOTAL RATE REVENUE	(7) % REVENUE TO EXPENSES
(1) DOMESTIC	$154,267	$304,041	7.14	$71,970	$530,279	$524,839	98.97
(2) SMALL GENERAL	8,832	17,175	7.10	3,937	29,944	30,167	100.74
(3) GENERAL	65,741	169,619	6.84	5,315	240,675	252,840	105.05
(4) LARGE GENERAL	7,320	28,536	6.77	226	36,083	35,773	99.14
(5) SMALL INDUSTRIAL	5,817	17,227	6.80	1,303	24,347	24,680	101.37
(6) MEDIUM INDUSTRIAL	9,871	39,637	6.77	574	50,081	50,228	100.29
(7) LARGE INDUSTRIAL	2,916	71,628	6.64	625	75,170	74,536	99.16
(8) EXTRA LI INTERR. - 2	(1,510)	132,546	6.38	463	131,500	124,906	94.99
(9) MUNICIPAL	3,412	13,162	6.71	144	16,718	16,574	99.14
(10) UNMETERED	14,828	7,968	7.09	1,109	23,904	24,158	101.06
(11) SUB-TOTAL	$271,494	$801,541	6.85	$85,665	1,158,701	1,158,701	100.00
(12) DIRECT EXP./ REV					16,051	19,514	N/A
(13) RETURN ON DIRECT EXP.					3,464	0	N/A
(14) TOTAL					$1,178,215	$1,178,215	100.00

APPENDIX H

Curriculum vitae

Bruce Smith
Department of Mathematics and Statistics
Dalhousie University, Halifax, N.S., B3H 3J5

Education

B.Sc. (Animal Biology), 1975, University of Calgary.

B.Sc. (Statistics), 1979, University of Calgary.

M.Sc. (Statistics), 1982, University of Calgary.
Thesis title: *Random properties of sea ice*

Ph.D. (Biostatistics) 1988, University of California (Berkeley).
Thesis title: *The neurophysiological quantal hypothesis.*

Employment History

1. Professor, Department of Mathematics and Statistics, Dalhousie University, July, 2005.
2. Associate professor, Department of Mathematics and Statistics, Dalhousie University. June,1996 - June, 2005.
3. Assistant professor, Department of Mathematics, Statistics and Computing Science, Dalhousie University. July,1988 - May, 1996.
4. Assistant professor, Department of Mathematics and Statistics, University of Victoria. January,1994 - June,1995.
5. Post-doctoral fellow, Department of Statistics, University of Toronto. January,1988 - May,1988.
6. Part time sessional lecturer, Department of Computing Science, University of Calgary, January, 1981 - August, 1981.
7. Statistical consultant, Department of Academic Computing Services, University of Calgary. November, 1978 - June,1984.

Research Contributions
In referreed journals

1. Downing, M., Louden, L, Halperin, B.A., Scott, H., Smith, B. and Halperin, S.A. (2006) Prenatal screening for HIV in Nova Scotia: survey of postpartum women and audit of current prenatal screening practices. *Can. J. Infect. Dis. Med. Microbiol.*, **17**, 224-228.

2. Halperin, S.A., Sweet, L., Baxendale, D., Neatby, A, Rykers, P., Smith, B., Zelman, B., Maus, D., Lavigne, P, and Decker, M. (2006) How soon after a prior tetanus-diphtheria vaccincation can one give adult formulation tetanus-diphtheria-acellular pertussis vaccine? *Ped. Inf. Dis. J.*, **25**, 195-200.

3. Qin, Y.S. and Smith, B. (2006) The likelihood ratio test for homogeneity in bivariate normal mixtures. *J. Multivar. Anal.*, **97**, 474-491.

4. Langley, J.M., Halperin, McNeil, S., Smith, Jones, T., Burt, D., Mallett, C.P., Lowell, G.H. and Fries, L. (2006) Safety and immunogenicity of a Proteosome^{TM}-trivalent inactivated influenza vaccine, given nasally to healthy adults. *Vaccine* **24**, 1601-1608.

5. Xie, C., Singh, R.S., Smith, B. and Lu, X. (2005) Generalized separation theorems for singular values of a matrix and their applications in canonical correlation analysis. *Probability and Mathematical Statistics*, **25**, 223-229.

6. Youden, L., Downing, M., Halperin, B., Scott, H., Smith, B. and Halperin, S. (2005) Group B Streptococcal testing during pregnancy: survey of postpartum women and audit of current prenatal screening practices. *J. Obstet. and Gyn.*, **27(12)**, 1006-1012.

7. Halperin, S.A., Smith, B. Clarke, K., Treanor, J., Mabrouk, T. and Germain, M. (2005) Phase I, Randomized, Controlled Trial to Study the Reactogenicity and Immunogenicity of a Nasal, Inactivated Trivalent Influenza virus Vaccine in Healthy Adults. *Human Vaccines* **1**, 37-42.

8. Halperin, S.A., Dobson, S., McNeil, S., Langley, J.M., Smith, McCall-Sani, R., Levitt, D., van Nest, G., Genevois, D., and Eiden, J. (2005) Comparison of the safety and immunodeficienty of hepatitis B virus surface antigen co-administered with an immunostimulatory phosphorothioate oligonucleotide and a licensed hepatitis V vaccine in healthy young adults. *Vaccine* **24**, 20-26.

9. McNeil, S.A., Halperin, S.A. Langley, J.M., Smith, B. Warren, A, Sharratt, G.P., Baxendale, D.M., Reddish, M.A., Hu, M.C., Stroop, S.D., Linden, J., Fries, L.F., Vink, P.E., and Dale, J.D. (2005) Safety and immunogenicity of 26-valent Group A *Streptococcus* vaccine in healthy adult volunteers. *Clinical Infectious Diseases*, **41**.

10. Geelhoed, M., Boerrigter, A.O, Camfield, P., Geerts, A., Arts, W., Smith, B. and Camfield, C. (2005) The accuracy of outcome prediction models for childhood-onset epilepsy. *Epilepsia*, **46**, 1526-1532.

11. Geelhoed, M., Boerrigter, A.O, Camfield, P., Geerts, A., Arts, W., Smith, B. and Camfield, C. (2005) The accuracy of outcome prediction models for childhood-onset epilepsy. *Epilepsia*, **46**, 1526-1532.

12. Qin, Y.S. and Smith, B. (2005) The likelihood ratio test for homogeneity in bivariate normal mixtures. *J. Multivar. Anal.*,

13. Smith, B. (2004) Sealevel characteristics in the Bay of Fundy/Gulf of Maine. *EnvironMetrics*, **14**, 745-756.

14. Qin, Y.S. and Smith, B. (2004) The likelihood ratio test for homogeneity in normal mixtures in the presence of a structural parameter. *Stat. Sinica*, **14**, 1165-1177.

15. Langley, J.M., Halperin, S.A., Boucher, F.D. and Smith, B. (2004) Azithromycin is as effective as and better tolerated then erythromycin estolate for the treatment of perussis. *Pediatrics*, **114**, 96-101.

16. Butler, K., Field, C., Herbinger, C.M. and Smith, B. (2004) Accuracy, efficiency and robustness of four algorithms allowing full sibship reconstruction from DNA marker data. *Molec. Ecol.*, **13** (6), 1589-1600.

17. Halperin, S.A., Smith, B., Nolan, C., Shay, J. and Kralovec, J. (2003) Safety and immunoenhancing effect of a *Chlorella*-derived dietary supplement in healthy adults undergoing influenza vaccination: randomized, double-blind, placebo-controlled trial. *Can. Med. Assoc. J.*, **169**, 111-117.

18. Mikelova, L.K., Halperin, S.A, Scheifele, D., Smith, B. Ford-Jones, E., Vaudry, W., Jadavi, T., Law, B. Moore, D. (2003) Predictors of death in infants hospitalized with pertussis: a case-control study of 16 pertussis deaths in Canada. *Journal of Pediatrics*, **143**, 576-581.

19. Speers, R.A, Rogers, P. and Smith, B. (2003) Non-linear modelling of industrial brewing fermentations. *J. Inst. Brewing*, **109**, 229-235.

20. Langley, J.M., LeBlanc, J.C.C., Wang, E.E.L., and Smith, B. (2003) Increasing incidence of hospitalization for bronchiolitis in Canadian children 1980-97. *J. Infectious Diseases*, **188**, 1764-1767.

21. Sinha, S.K., Field, C.A. and Smith, B. (2003) Robust estimation of nonlinear regression with autogressive errors. *Stat. Prob. Lett.*, **63**, 49-59.

22. Langley, J.M., Halperin, S.A., and Smith, B. (2003) A pilot study to quantify parental anxiety associated with enrollment of an infant and toddler immunization in a phase III vaccine trial. *Vaccine*, **21**, 3863-3866.

23. Halperin, S.A., Scheifele, D., Mills, E., Guasparini, R., Humphreys, G., Barreto, L, and Smith, B. (2003) Nature, evolution, and appraisal of adverse events and antibody response associated with the fifth consecutive dose of a five component acellular pertussis-based combination vaccine. *Vaccine* **21** 2298-2306.

24. Halperin, S.A., van Nest, G., Smith, B., Abtahi, S., Wiley, H. and Eiden, J.J. (2003) A phase I study of the safety and immunogenicity of recombinant hepatitis B surface antigen co-administered with and immunostimulatory phosphorothioate oligonucleotide adjuvant. *Vaccine* **21**, 2461-2467.

25. Halperin, B.A., Halperin, S.A., McGrath, P., Smith, B., and Houston, T. (2002) Use of lidocaine-prilocaine patch to decrease intramuscular injection pain does not adversely affect the antibody response to diphtheria-tetanus-acellular pertussis-inactivated poliovirus-Haemophilus influenzae type b conjugate and hepatitis B vaccines in infants from birth to six months of age. *Pediatr. Infec. Dis. J.* **21**, 399-405.

26. Halperin, S.A., McDonald, J., Samson, L, Danzig, L, Santos, G., Izu, A., Smith, B., and MacDonald, N. (2002) Simultaneous administration of meningococcal C conjugate vaccine and diphtheria-tetanus-acellular pertussis-inactivated poliovirus-*Haemophilus influenzae* type b conjugate vaccine in children: a randomized double-blind study. *Clin. Invest. Med.* **25**, 243-251.

27. Halperin, S.A., Smith, B., Mabouk, T. Germain, M, Trepanier, P, Hassell, T., Treanor, J, Gauthier, R., and Mills, E.L. (2002) Safety and immunogenicity of a trivalent, inactivated, mammalian cell culture-derived influenza vaccine in health adults, seniors, and children. *Vaccine*, **20**, 1240-1247.

28. Smith, B., Herbinger, C. and Merry, H.R. (2001) Accurate partition of individuals into full sib families from genetic data without parental information. *Genetics*, **158**, 1329-1338.

29. Thompson, K.,R., Dowd, M.G., Lu, Y. and Smith, B. (2000) Oceanographic Data Assimilation and Regression Analysis. *EnvironMetrics* **10**, 183-196.

30. Miyaoka, E., Kajikawa, M. and Smith, B. (2000) Analysis of binary cross-over data with generalized linear transition models. *Journal of the Japan Statistical Society*, **30**, 17-26.

31. Halperin SA, Smith B, Russell M, Hasselback P, Guasparini R, Skowronski D, Meekison W, Parker R, Lavigne P and Barreto L. (2000) An adult formulation of a five-component acellular pertussis vaccine combined with diphtheria and tetanus toxoids is safe and immunogenic in adolescents and adults. *Vaccine* **18**, 1312-1319.

32. Halperin SA, McGrath P, Smith B, Houston T. (2000) Lidocaine-prilocaine patch decreases the pain associated with the subcutaneous administration of measles-mumps-rubella vaccine but does not adversely affect the antibody response. *J. Pediatr.*, **136**, (6), 789-794.

33. Halperin SA, Smith B, Russell M, Scheifele D, Mills E, Hasselback P, Pim C, Meekison W, Parker R, Lavigne P, and Barreto L. (2000) An adult formulation of a five-component acellular pertussis vaccine combined with diphtheria and tetanus toxoids and inactivated poliovirus vaccine is safe and immunogenic in adolescents and adults. *Pediatr. Infect. Dis. J.* **19**, 276-283.

34. Smith, B. and Miyaoka, E. (1999) Frequency domain identification of harbour seiches. *EnvironMetrics* **10**, 575-587.

35. X. Z. Yuan, B. Smith and S. Lou (1998) Fixed point and coincidence theorems for set-valued mappings in topological vector spaces with some applications. *Nonlinear Analysis*, **32 2**, 133-149.

36. Wirrell, E.C., Camfield, C., Camfield, P., Dooley, J., Gordon, K. and Smith, B. (1997) Long-term psychosocial outcome in typical absence arthritis. *Arch. Pediatr. Adolesc. Med.*, **151**, 152-158.

37. Clements, J.C. and Smith, B.R. (1996) Numerical modeling of the excitatory postsynaptic current at the crayfish neuromuscular junction. *CAMS Quarterly* , **4**, 157-173.

38. Islam, M.N., O'Shaughnessy, C.D., Smith, B. (1996) A random graph model for the final-size distribution of household infections. *Stat. in Med.*, **15**, 837-843.

39. Camfield, P., Gordon, K., Camfield, C., Tibbles, J., Dooley, J. and Smith, B. (1995) Results are rarely the same if repeated within 6 months in childhood epilepsy. *Can. J. Neurol. Sci.* **22**, number 4, 297-300.

40. Field, C. and Smith, B. (1994) Robust estimation - a weighted maximum likelihood approach. *Bull. Int. Stat. Rev.*, **62**, number 3, 405-424.

41. Smith, B. and Field, C. (1993) Variance estimation for quadratic statistics. *J. Time. Ser. Anal* 14, 381-395.

42. Smith, B. (1993) Mixture estimation and the neurophysiological quantal hypothesis. *Biometrics* **49**, 643-651.

43. Camfield, C., Camfield, P., Gordon, K., Smith, B., and Dooley, J. (1993) Outcome of childhood epilepsy: a population-based study with a simple predictive scoring system for those treated with medication. *Journal of Pediatrics*, **122**, 861-868.

44. Camfield, C., Camfield, P., Smith, B., Gordon, K., and Dooley, J. (1993) Biologic factors as predictors of social outcome of epilepsy in intellectually normal children: a population-based study. *Journal of Pediatrics*, **122**, 869-873.

45. Smith, B.R., Wojtowicz, J.M. and Atwood, H.L. (1991) Maximum likelihood estimation of non-uniform transmitter release probabilities at the crayfish neuromuscular junction. *J. Theoret. Biol.* **150**, 457-472.

46. De Braekeleer, M., and Smith, B.R. (1988) Two methods for measuring the non-randomness of chromosome abnormalities. *Ann. Hum. Genet.* **52**, 63-67.

47. Bruvold, W., and Smith, B.R. (1988) Developing and assessing a model of residential water conservation. *Water Res. B.* **24**, 661-669.

48. De Braekeleer, M., Smith, B.R., and Lin, C.C. (1985) Fragile sites and structural rearrangements in cancer. *Human Genetics* **69**, 112-116.

49. Enns, E.G., Smith, B.R., and Ehlers, P.F. (1984) Hitting spheres with straight-line motion or Brownian motion. *J. Appl. Prob.* **21**, 70-79.

50. Enns, E.G., and Smith, B.R. (1984) Optimal platform strength in the presence of moving ice. *Ocean Engineering* **11**, 239-244.

Refereed conference proceedings

38. Smith, B. and Field, C. (2001) Symbolic cumulant calculations for frequency domain time series. *Statistics and Computing* **11**, 435-442.

39. Wojtowicz, J.M., Smith, B.R., and Atwood, H.L. (1991) Activity-dependent recruitment of silent synapses. *Ann. N.Y. Acad. Sci.* **627**, 169-179.

Non-refereed contributions

40. Field, C., and Smith, B. (2002) Discussion of the evaluation of a candidate genetic locus in a genome scan of complex disease. *Can. J. Stat.* **30**, 167-169.

Submitted

Qin, Y.S. and Smith, B. The likelihood ratio test for homogeneity in bivariate normal mixtures. revision submitted to *J. Mult. Anal.*

Invited presentations - past 6 years

1. Smith, B. Exceedance Point Processes, with Application to Estimation of Extreme Sea Levels. Fields Institute workshop on "The Point of Point Processes", University of Ottawa, February, 2004.

2. Smith, B. Changing tides in the Bay of Fundy/Gulf of Maine. RSS/IMS Joint Meeting, Banff, 2002.

3. Smith, B. Symbolic computation for frequency domain time series. IMS/ASA Joint Meeting, Baltimore, 1999.

4. Smith, B. and Field, C. Symbolic computation for frequency domain time series. CRM workshop on symbolic computation, Montreal, 1997.

5. Smith, B. Frequency domain analysis of harbour seiches. CRM workshop on Time Series Analysis, Montreal, 1998.

6. Smith, B. Frequency domain analysis of harbour seiches. CRM workshop on Time Series Analysis, SSC Conference, Regina, 1999.

7. Smith, B. Robust frequency domain estimation, SSC conference, Fredericton, 1997.

Research Support

Operating grants

	Amount	Years	Source	% Funds Available
B.Smith	22K PA	2004-2009	NSERC Discovery	100
B.Smith	16.25K PA	1999-2003	NSERC Operating	100
B.Smith	10K PA	1995-1998	NSERC Operating	100
B.Smith	10K PA	1992-1994	NSERC Operating	100
B.Smith	12K PA	1989-1991	NSERC Operating	100

Jointly held

	Amount	Years	Source	% Funds Available
C.Herbinger+3 others	119K PA	2004-2008	Atlantic Innovation Fund	4
F.Doolittle+5 others	1.5M PA	2001-2005	Genome Atlantic	0
S.Bull+7 others	157K PA	1999-2005	NSERC NCE	3
C.Field+3 others	102K PA	1996-1998	NSERC Collaborative	0

Equipment grants

	Amount	Years	Source
C.Field+5 others	63268	2004	NSERC RTI
C.Field+3 others	70476	2001	NSERC Equipment
C.Field+3 others	17163	1999	NSERC Equipment
B.Smith+4 others	10855	1997	NSERC Equipment
C.Field+3 others	12605	1994	NSERC Equipment

Graduate and undergraduate supervision

Name	Years	Degree	Position
T.Ikeda	01-02	M.Sc.	Ph.D. student, Hokkaido University
T.Ikeda	00-01	B.Sc.	
A.Webber	00-01	B.Sc.	M.Sc. student, University of Victoria
J.Loredo-Osti	96-99	Ph.D.	PDF, McGill University
C.Xie	98-99	M.Sc.	Assistant Prof., McMaster University
F.Desalegne	97-98	M.Sc.	Ph.D. student, UofT
G.Yuan	96-97	M.Sc.	Risk Analyst, KPMG, Dallas
J.Sweet	95-97	M.Sc.	Statistical analyst, Province of PEI
H.Merry	95-97	M.Sc.	Statistical analyst, CTRC, Dalhousie
P.Felx	96-97	B.Sc.	
D.McNeil	95-96	M.Sc. (incomplete)	Analyst, Statistics Canada
L.McNabb	92-93	B.Sc.	Statistical consultant, Yellowknife
J.Grant	90-91	M.Sc.	actuarial student, Maritime Life
W.Blanchard	89-90	B.Sc.	Statistical consultant, Dalhousie
G.Jean	89-90	M.Sc.	Statistical analyst, Quebec

Students jointly supervised

Name	Years	Degree	Position
M.Yang	01-02	M.Sc.	
S.Sinha	98-00	Ph.D.	Assistant Prof., U.Winnipeg
O.Golubeva	97-99	M.Sc.	Statistical analyst, Harvard U.
E.O'Neill	2002-2004	M.Sc.	Statistical analyst, New Zealand
S.Weerasinghe	1988-1993	Ph.D.	Ass.Prof, CH&E, Dalhousie
J.Roy	94-95	M.Sc.	lecturer,U de Moncton a Shippigan

Currently jointly supervised

Name	Years	Degree
Bo Lin	2001-2004	Ph.D.

Other supervision

Prof. Y.Qin of the University of Guangxi worked with me as a Mitacs PDF from July 01 through March 03.

External Ph.D. examiner for

Name	Year	University
Patrick Chareka	1995	University of New Brunswick
Alfred Benn	1998	University of Western Ontario
Ying Liu	2000	University of Toronto
Zeny Feng	2004	University of Waterloo

Administration

1. Director of the Division of Statistics (July 2001 - present)
2. Statistics Graduate Co-Ordinator (Sept 1995- June 2001)
3. NSERC Grant Selection Committee 14 (Statistical Sciences), member 2001-2003.
4. Associate Editor, Canadian Journal of Statistics, 1994-1997, 2004-2006.
5. Atlantic Association for Research in the Mathematical Sciences, member of Scientific Review Panel, 2002-present.
6. Atlantic Association for Research in the Mathematical Sciences, board member 2001-2002.
7. Canadian Journal of Statistics Awards Committee, member 1995-1997.

Conferences Organized

1. Program Chair, Statistical Society of Canada Annual Meeting, Hamilton, June, 2002.
2. Joint organizer of workshop entitled "Point Processes - Theory and Applications", Banff International Research Center, June, 2003.
3. Organized invited, contributed and data analysis sessions at several annual SSC conferences.

Other Service

Grant reviewer for NSERC, FCAR, NSF. Reviewer for CJS, JASA, Annals of Statistics, J.Multivariate Analysis, Molecular Ecology, American Statistician, Can.J.Fisheries and Aquatic Sciences, Communications in Statistics.

APPENDIX I

CURRICULUM VITAE

Reginald John Kulperger

May 2006

Contents

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1 Biographical Data

- ADDRESS: 10 Gretna Green, London, Ontario N6G 1X1
- PHONE: 519-471-1333 (home) 519-661-3627(office)
- E-MAIL: kulperger@stats.uwo.ca

- DATE OF BIRTH: February 10, 1951
- PLACE OF BIRTH: Brantford, Ontario, Canada

EDUCATION:

Degree	University	Department	Year
B.Math.	Waterloo	Mathematics	1974
M.Math.	Waterloo	Statistics	1975
Ph.D.	Carleton	Mathematics	1978

THESES TITLES:

Degree	Title	Supervisor	Year
Masters:	A stochastic model of urban mobility	M. E. Thompson	1975
Ph.D.:	Statistical inference for a simple branching diffusion process	D. A. Dawson	1978

HONOURS: NATO Fellow 1979–80.

TENURE GRANTED: 1 July, 1986

EMPLOYMENT HISTORY:

From	To	Employer	Position
1977		Health and Welfare Canada	Contract Statistician
1978	1980	U California at Berkeley	One-year NSERC Postdoctoral Fellow and one-year NATO Postdoctoral Fellow
1979	Sept/Dec	U California at Berkeley	Visiting Lecturer
1980	1982	McMaster University	Assistant Professor
1982	1986	U of Western Ontario	Assistant Professor
1986	1998	U of Western Ontario	Associate Professor
1998	present	U of Western Ontario	Professor

2 Teaching

Course Development

1. Stat 450/535. When I first arrived at UWO, this course was taught as a classical first graduate course in probability. Given the type of fourth year honours and masters' students that we had and were aiming at, this did not seem appropriate. I changed the course instead to a first course in asymptotic methods in statistics. Specifically it now studies the law of large numbers and the central limit theorem, and how to adapt these tools to the study of the large sample approximations of estimators.

2. Stat 420/520. I have been involved in developing the new course Stat420, financial models, first given by me in September 1996. It discusses the terminology and underlying statistical principles of financial option derivatives. The choice of material, type of text and philosophy of the course are all part of the choices for such a new course. Much time and effort are required for this, and will evolve over the few years. There are very few other such courses offered at present (1995) in North America.

3. Joint Graduate Program in Financial Modeling. I have been involved from the start of this initiative. In several meetings with John Knight, Graduate Chair, Economics, we have mapped out a set of courses for students from either a statistics or economics and mathematics background in order to complete the MSc or PhD in financial modeling. The next stage will be formal application to the University for the implementation of the program.

COURSES TAUGHT:

UNDERGRADUATE COURSES:

Course	Description / frequency
450	Probability Theory. Convergence, some statistical applications. 1984–94, 1998. Given yearly, 1982–95, 98
452	Stochastic processes. Markov chains, renewal theory Given several times 1983–95, 1999
135	Introductory Statistics. A non-calculus based introduction. Given 4 times, 1982–86.
255	Introductory Statistics. Calculus based, honours course. Given twice, 1986–88
241	Introductory statistics for engineers. One semester. 1989–92 (twice per year), 1994–95
359	honours regression 1996
420	financial models, 1996, 98, 2001
421	advanced financial models, 1999, 2002, 2003
357	Probability, 1999–
358	Inference, 2000–2001
712b	Reading course on financial topics for Jason Goss. Jan 1997.
530	Statistical Inference, 2002–

I have also taught courses in elementary calculus and ordinary differential equations. In addition I have given the following graduate courses, graduate seminars and reading courses.

GRADUATE COURSES:

1. Measure theory and probability, 1989, 1992
2. Inference for stochastic processes
3. Point processes (on R) and martingales
4. log linear models
5. Interacting particle systems, 1991.
6. Data analysis, for student D. Rylett, 1985.
7. Ion channel modelling, for student T. Leung, 1987.
8. Point processes, based on Miller and Snyder, 2nd edition, 1993
9. Theory of point Processes, based Daley and Vere–Jones, 1993
10. Asymptotics of Experiments and Contiguity, based on LeCam and Yang, September 1994.
11. Bootstrap and Edgeworth Expansions, based on P. Hall, January 1995.
12. Stochastic Differential Equations, based on Shreve and Karaztas, 2nd edition. Sept 1995.
13. Weak Convergence, based on van der Vaart and Wellner, Sept 1996.
14. Stochastic differential equations, based on Oksendal, 5th edition. September 1998.
15. Stat 708a: Bootstrap and Edgeworth Expansions, based on P. Hall, September 1999. We are also using symbolic computations to understand the algebraic calculations.
16. Stat 722 : Spectral methods in time series, Jan 2001. Based on M. B. Priestly, Spectral analysis and Time Series: Volume 1.

GRADUATE EXAMINING COMMITTEES - Examiner

1. Departmental Ph.D. thesis examiner, V. K. Jandhyala, December 1985.
2. Departmental Ph.D. thesis examiner, T. S. Kheoh, July 1986.
3. Extra-departmental Ph.D. thesis examiner, Paul Rilestone, Economics, August, 1987.
4. Extra-departmental M.Sc. thesis examiner, M. Gleica, Geology, July, 1988.
5. Departmental Ph.D. thesis examiner, K. Lawry, March, 1990
6. Extra-departmental Ph.D. thesis examiner, Y. Fan, Economics, April, 1990.
7. Extra-departmental M.Sc. thesis examiner, N. Blackman, Epidemiology and Biostatistics. Supervisor J. Koval. July, 1991.

8. External examiner, Ph.D. thesis, Ge Mai Chen, Department of Mathematics and Statistics, Simon Fraser University, August, 1991.

9. Extra departmental examiner, M.Sc. thesis, C. Zhang, Department of Applied Mathematics. Supervisor K. De'Bell. September 1992.

10. Extra departmental examiner, Ph.D. thesis, Paul St. Pierre, Department of Chemistry. Supervisor N. Petersen. December 1992.

11. Departmental Ph.D. thesis examiner, Benoit Quenneville, September 1993.

12. External examiner, PhD thesis, Tamuka Kaseke, Department of Statistics, University of Waterloo, October, 1994.

13. Extra departmental examiner, Ph.D. thesis, George Jiang, Department of Economics. Supervisor John Knight. May 1996.

14. Extra departmental examiner, Ph.D. thesis, Sultan Sial, Department of Applied Mathematics. Supervisor Turab Lookman. January, 1997.

15. Extra departmental examiner, Ph.D. thesis, Jun Yu, Department of Economics. Supervisor John Knight. September 1998.

16. Departmental Ph.D. thesis examiner, Steve Drekic, supervisor Dave Stanford. August 1999.

17. Extra departmental examiner, Ph.D. thesis, Fuchan Li, Department of Economics. Supervisor John Knight. September 1999.

18. Extra departmental examiner, Ph.D. thesis, Tieling Chen, Department of Mathematics. Supervisor Gord Sinnamon. September 2000.

19. External examiner, PhD thesis, Fuping Huang, Department of Mathematics and Statistics, University of Guelph. Supervisors: E. M. Carter and R. S. Singh. May 23, 2001.

20. External examiner, PhD thesis, Rong Zhu, Department of Statistics, University of Brisitsh Columbia. Supervisor: H. Joe, 2001.

21. External examiner, PhD thesis, Andrei Volodin, Department of Mathematics and Statistics, University of Regina. Supervisor: E. Ahmed. July, 2002.

22. Departmental Ph.D. thesis examiner, X. Li, Supervisor : D. Murdoch, September 2002.

23. proposed External Ph.D. thesis examiner, University of Ottawa. Yuri Dranev, Supervisor Andre Dabrowski. U of Ottawa proposes a list of three names, one of which is then choosen. Exam March 2004.

24. Departmental Ph.D. thesis examiner, Wayne Horn, Supervisor : D. Stanford, September 2004.

25. External examiner, PhD thesis, Daniel Serban, Department of Mathematics and Statistics, University of Alberta. Supervisor: E. Gombay. March, 2005.

GRADUATE EXAMINING COMMITTEES - Chair

1. Ph.D. exam, D. A. Robertson, Business Administration, March 1987.
2. Ph.D. exam, Chuanyi Zhang, Mathematics, 10 August, 1992.
3. several others not listed.
4. PhD exam, Songhui Zhu, Applied Mathematics. Advisor Pei Yu. July 2001.

TEACHING WORKSHOPS, ETC.

- PACTL 1984. U.W.O., September, 1984.
- Session on voice projection with M. Dow, Althouse. September 1984.
- PACTL 1986. U.W.O., September, 1986.
- PACTL 1990. Session on super calculators for engineering courses. August, 1990.

GRADUATE SUPERVISION

PhD Students

Student	Year	Thesis Title
1. Braun, W. John	1992	Statistical inference for an interacting particle system.
2. Benn, Alfred	1996	A Poisson driven stationary process model in spectroscopy.
3. Kawczak, Janusz	1999	Weak Convergence of a Certain Class of Residual Empirical Processes
4. Andreou, Pantelis	1999	A regression residual process.
5. Watteel-Sprague, Gena	1994–2000	Investigations in Financial Time Series: Model Selection, Option Pricing, and Density Estimation
6. Alex Badescu	2003 - present	Topics in mathematical finance
7. Doug Woolford	2004 - present	Jointly supervised with Dave Stanford. Topics in stochastic modelling with applications to forestry.

Master's Students : with MSc project

1. Kopp, Steve	1984	Finding the best set of independent variables in regression analysis.
2. Leung, Tom	1987	A review of the bootstrapping method.
3. Benn, Alfred	1991	Some statistical properties of fluorescence correlation spectroscopy.
4. Andreou, Pantelis	1992	AR Residual EDF Process Simulation.
5. Chekmas, Lubov	1998	Statistics of ultrasound.
6. Rhim, Don	1999	Approximating stochastic DE's and option prices.
7. Yan, Lin	2000	Monte Carlo study of EDF processes for ARCH(1) residuals.
8. Ahemd, Rashid	2001	Kolmogorov-Smirnov goodness of fit test based on residuals of ARCH(1)
9. Wang, Peng	2001	Discrete Time Option Pricing : Markov Process and Bootstrap
10. Wei Zhang	2002	Penalized estimation for ARCH(1) process with Gaussian noise.
11. Alex Badescu	2002	Inference for diffusion processes
12. Qin Hu	2003	Model Effect on Value at Risk

NSERC Undergraduate Summer Research Students

Student	Year	Project
1. Bai, Fan	2000	Smoothing Methods and Passive Sonar Data Analysis
2. Woolford, Doug	2001	Estimation of Option Pricing for ARCH(1) Models
3. Alek Hunchak	2002	Forest fire models
4. Tova Miadovic	2003	Data analysis of lightning strikes in Ontario

3 Research

Publications

Refereed Journals

1 R. Kulperger, "Parametric estimation for a simple branching diffusion process', *Journal of Multivariate Analysis*, 9, pp. 101–115, (1979).

2 R. Kulperger, "Brillinger type mixing conditions for simple branching diffusion processes", *Stochastic Processes and Their Applications*, 9, 55–66, (1979).

3 P. Guttorp and R. Kulperger, "Criticality conditions for some random environment processes", *Stochastic Processes and Their Applications*, 11, 207–12, (1981).

4 R. Kulperger and A. C. Singh, "On random grouping in goodness of fit tests of discrete distributions", *Journal of Statistical Planning and Inference*, 7, 109–115, (1982).

5 R. Kulperger and P. Guttorp, "Statistical inference for some Volterra population processes in random environment", *Canadian Journal of Statistics*, 12, 289–302, (1984).

6 P. Guttorp, R. Kulperger and R. Lockhart, "A coupling proof of weak convergence", *Journal of Applied Probability*, 22, 447–453, (1985).

7 R. Kulperger, "On an optimality property of Whittle's Gaussian estimate of the parameter of the spectrum of a time series". *Journal of Time Series Analysis*, 6, 253–259, (1985).

8 R. Kulperger, "On the residuals of autoregressive processes and polynomial regression". *Stoch. Processes and Their Applications*, 21, 107–118, (1985).

9 R. Kulperger, "Parametric estimation for simple branching diffusion processes, II". *Journal of Multivariate Analysis*, 18, 225–241, (1986).

10 R. Kulperger, Some remarks on regression with autoregressive errors and their residual processes. *Journal of Applied Probability*, 24, 668-678, (1987).

11 R. Kulperger, "Central limit theorem with three moment conditions: an example of the truncation method." *Canadian Applied Mathematics Notes*, 12, 44–50, December, 1987.

12 R. Kulperger, "A monte-carlo approximation of the distribution of the maximum of various Brownian bridges", *Communications in Statistics*, Theory and Methods, 17, 4389–4397 (1988)

13 R. Kulperger and B.L.S. Prakasa Rao. "Bootstrapping a finite state Markov chain", *Sankhya A*, 51, 178–91 (1989).

14 R. Kulperger, "Estimating non-linear shifts in stationary mixing processes in the two sample case", *Pakistan Journal of Statistics A*, 5, 175–188 (1989).

15 R. Kulperger, "On the distribution of the maximum of Brownian bridges with application to regression with correlated errors." *Journal of Statistical Computations and Simulation*, 34, 97–106 (1990).

16 S. E. Ahmed and R. Kulperger. "Asymptotic confidence intervals from a preliminary test estimator", *Environmetrics*, 1, 295–303 (1990).

17 D. R. Bellhouse and R. Kulperger, "Computer generated simple random samples." *Communications in Statistics: Simulation and Computation*, 20, 539–50 (1991).

18 W. J. Braun and R. Kulperger, "Interacting particle systems as cell growth models: Can they be identified? *The Western Journal of Graduate Research*, 3, 106–115. (1991).

19 R. Kulperger and S. E. Ahmed. "A bootstrap theorem for a preliminary test estimator." *Communications in Statistics: Theory and Methods*, 21, 2071–82. (1992).

20 W. J. Braun and R. Kulperger, "Differential equations for the moments of counts for an interacting particle system." *Journal of Mathematical Biology.*, 31, 199–214 (1993).

21 J. Braun and R. Kulperger, "Data analytic implementation of an interacting particle system for tumor growth modeling." *Pakistan Journal of Statistics*, 11, 123–36 (1995).

22 A. Benn and R. Kulperger, "Statistical inference for a Poisson process model of scanning fluorescence correlation spectroscopy." *Environmetrics*, 7, 167–83 (1996).

23 R. J. Kulperger. Bootstrapping EDF processes from AR fitting. *Communications in Statistics: Computation and Simulation*, 25, 657–70 (1996).

24 A. Benn and R. Kulperger. Image Correlation Spectroscopy. *Canadian Journal of Statistics*, 25, 215–31 (1997).

25 R. J. Kulperger. On a Property of the Finite Fourier Partial Sums Process. *Probability and Statistics Letters*, 35, 101–7 (1997).

26 W. J. Braun and R. J. Kulperger. A Fourier method for bootstrapping time series. *Communications in Statistics: Theory and Methods*, 26, 1329–36 (1997).

27 R. J. Kulperger and R. A. Lockhart. Tests of Independence in Time Series. *Journal of Time Series Analysis*, 19, 165–85 (1998).

28 A. Benn and R. Kulperger. A Remark on a Fourier Bounding Method of Proof for Convergence of Sums of Periodograms. *Annals of the Institute of Statistical Mathematics*, 50, 187–202 (1998).

29 W. J. Braun and R. Kulperger. A Bootstrap for Point Processes. *Journal of Simulation and Computational Statistics*, 60, 129–55 (1998).

30 R. Kulperger. Higher order cumulants and interference for a class of filtered Poisson processes. *Austrian Journal of Statistics*, 27, 59–71 (1998).

31 A. Benn and R. Kulperger. Using parallel computing for data analysis. *Statistics and Computing*, 8, 309–18 (1998).

32 R. Kulperger. Countable State Markov Process Bootstrap. *Statistical Planning and Inference*, 76, 19–29 (1999).

33 Ahmed, S. E. and R. J. Kulperger. Simultaneous improved estimation of the means of exponential distributions. *Far East Journal of Theoretical Statistics*, 4, 297–318 (2000).

34 Kilani Ghoudi, Reg Kulperger and Bruno Remillard. A nonparametric test of serial independence for time series and residuals. *Journal of Multivariate Analysis*, 79, 191–218 (2001).

35 Reg Kulperger and Gena Watteel-Sprague. Discrete Time Option Pricing : Model Sensitivity. *Derivatives Use, Trading and Regulation*, 7, 206–222 (2001).

36 W. J. Braun and R. J. Kulperger. Estimating parameters in a tumor growth interacting particle system : the continuity of moments. *Pak. J. Statist.*, special issue in honour of S. Ejaz Ahmed, 18, 149–64 (2002).

37 W. John Braun and Reg J. Kulperger. Re-Colouring the Intensity-Based Bootstrap for Point Processes. *Communications in Statistics: Simulation and Computation*, 32, 475-488 (2003).

38 R. N. Watteel and R. J. Kulperger. Estimation of the Kolmogorov canonical meansure for infinitely divisible distributions. *Journal of Simulation and Computational Statistics*, 73, 525-542 (2003).

39 Zengjing Chen, Reg Kulperger and Long Jiang. Jensen's Inequality for g-Expectation, Part 1, Comptes Rendus Mathematique, 337, 625-730 (2003); Part II, Comptes Rendus Mathematique, 337, 797-800 (2003).

40 Chen, Z., Kulperger, R., and Wei, G. A comonotonic theorem of BSDEs and its applications. *Stoch. Proc. and Their Applic.*, 115, 41-54 (2005).

41 R. Kulperger and H. Yu. High Moment Partial Sum Processes of Residuals in GARCH Models and their Applications. *Ann. Statist.*, 33, 2395-2422

42 J. Kawczak, R. Kulperger, H. Yu. The Empirical Distribution Function of Residuals from a Stationary ARCH Process. to appear *Ann. Institute of Statist. Math.*, accepted January, 2005.

43 Z. Chen and R. Kulperger. A Stochastic Competing Species Model and Ergodicity. *Journal of Applied Probability*, 42, 738-753.

44 Z. Chen and R. Kulperger. Inequalities for Upper and Lower Probabilities. To appear in *Statistics and Probability Letters*, accepted February, 2005.

45 Z. Chen and R. Kulperger. Minimax pricing and Choquet pricing. To appear in *Insurance Mathematics and Economics*, accepted December 2005.

46 D. Boychuk, W. J. Braun, R. J. Kulperger, Z. L. Krougly, D. A. Stanford. A Stochastic Model for Forest Fire Growth. Under revision, *INFOR*, August 2006.

Invited Discussions in a Refereed Journal and Invited Contributions to An Encyclopdia

47 Invited discussion of papers by R. Pyke and by D. McLeish, *Canadian Journal of Statistics,* 12, 283–85, (1984).

48 Reg Kulperger and Hao Yu. Parallel Computing. In *Environmetrics Encylcopia,* vol 3, 1529-34, (2001).

Submitted or In Preparation

49 Zengjing Chen, Kun He and Reg Kulperger. g-Expectations and Related Risk Measures. Submitted February 2005.

50 Zengjing Chen and Reg Kulperger. N competing species population dynamics. In preperation, 2005.

51 Zengjing Chen and Reg Kulperger. Relations between risk and nonlinear expectations. In preparation, 2005.

52 Zinovi Krougly, Reg Kulperger and Dave Stanford. Fire Spread Lattice Model. Submitted to conference with proceedings. St Petersberg, Russia, 2005.

Refereed Conference Proceedings

53 R. Kulperger, "Testing for nonlinear shifts in stationary ϕ-mixing processes", In *Time Series Methods in Hydrosciences,* ed. A. El-Sharraawi and S. Esterby, Elsevier Pub. Co., 37–44 (1982).

54 R. Kulperger, "Residuals from regression with dependent errors". *Statistical Aspects of Water Quality Monitoring, Developments in Water Sciences,* **27,** 318–325, ed. A. El-Sharaawi, *et al.* (1986).

55 R. Kulperger, "Central limit theorems for cluster point processes". *Festschrift in Honour of V. M. Joshi, Applied Probability and Sampling Theory Volume,* 131–139, ed. I. B. MacNeill and G. J. Umphrey, (1987).

56 R. Kulperger, "On generating functions, convergence in distribution and the continuity theorem." In the "Proceedings of the First Islamic Conference on Statistics," (1989).

57 W. J. Braun, R. Kulperger and T. Lookman. "Identification of an interacting two type particle system." In "Stochastic Modelling in Biology," edited by P. Tautu, p401–411. World Scientific Publishing Co., New York. (1990).

58 R. Kulperger. A regression residual process. ICAMPS Proceedings, 741–57. Edited by B. Syszkowicz. (1998).

59 R. Kulperger. SDE Estimation: Effects of Misspecified Diffusion Functions. In Stochastic Models, Canadian Mathematical Society Conference Proceedings, Volume 26, Edited by Luis G. Gorostiza and B. Gail Ivanoff, pp 283–97, (2000).

60 Reg Kulperger. Stochastic Finance: Discrete Time Processes and Risk Neutral Pricing. *Asymptotics Methods in Stochastics*, a conference in honour of the 70th birthday of Miklos Csorgo. *Fields Institute Communications*, 44, 431-446 (2004).

RESEARCH INTERESTS Stochastic processes, Asymptotic methods in statistics, Statistical inference for stochastic processes, Applied probability, Probability Theory

MEMBERSHIPS IN ACADEMIC SOCIETIES

1. Institute of Mathematical Statistics, since 1974
2. Statistical Society of Canada, since 1981
3. Bernoulli Society, since 1985

4 Invited Lectures and Grants

INVITED CONTRIBUTIONS AT CONFERENCES, WORKSHOPS, ETC.

1 Workshop on Stochastic Analysis, Carleton University, June 1978.

2 Annual Winter Meeting of the Canadian Math. Congress, at University of Ottawa, December 1979.

3 Statist. Soc. Can., annual meeting. Invited discussant of papers by R. Pyke and by D. McLeish, at U.B.C., June 1983.

4 With P.D.M. Macdonald. The use of stochastic processes in data analysis. At the Joint Statistical Meetings, SSC session, 15–18 August, 1983, Toronto.

5 Regression with dependent errors. Workshop on Statistical Methods in the Hydrosciences, Burlington, October 1985.

6 Estimation of Moment Intensities for Poisson Cluster Processes, Heidelberg, West Germany, August 1988.

7 A bootstrap theorem for a preliminary test estimator, Statistics Day, University of Regina, April, 1990.

8 with W. J. Braun, Interacting particle system (cellular automata) models for cell growth, Statistical Society of Canada Annual Meeting, Edmonton, June 1992.

9 Empirical processes and residuals. Workshop on Empirical Processes, Carleton University, Ottawa, August 1992.

10 with Gena Watteel, Discrete time financial modeling. Workshop on Financial Mathematics, Carleton University, September 1996.

11 A regression residual process. International Conference on Asymptotic Methods in Probability and Statistics (ICAMPS), Ottawa. July 1997.

12 Correlation Spectroscopy. Eighth Environmetrics Meeting, Innsbruck, Austria, August, 1997.

13 SDE Estimation: Effects of misspecified diffusions. Conference in honour of Donald Dawson. June 1998.

14 (with Hao Yu) Nonlinear time series. SSC Annual Meeting, June 2001.

15 (with John Braun and Dave Stanford). A lattice forest fire model project. Special session sponsored by CORS. SSC Annual Meeting, June 2002.

16 Discrete time option pricing. Conference in honour of Miklos Csorgo's 70-th birthday. Ottawa, June 2002.

17 (with Zengjing Chen). Stochastic competing species processes. Applied Probability Session. SSC Annual Meeting, June 2003.

18 GARCH residual processes. Conference in honour of David Brillinger's 65-th birthday. Organized by Peter Guttorp and Bruce Smith. Banff Mathematics Reseach Institute, June 2003.

19 Mathematical Finance Meeting, Graz, Austria, May 2004. Organized by I. Berkes, and L. Horvath

SOME RECENT COLLOQUIUM LECTURES

1. Stochastic Competing Species and Prey Predator Models. IMS/CRM Colloquium Series, at UQAM, September 30, 2005.
2. Stochastic Competing Species Processes. Shandong University, Jinan, China. November 29, 2005.
3. GARCH Residual Processes. Shandong University, Jinan, China. December 2, 2005.
4. Stochastic Competing Species Processes. Beijing Norma University, Beijing, China. December 5, 2005.

RESEARCH GRANT INFORMATION

Operating and Individual Grants

Year	Grantor	Amount per year	Title of Project
1981–84	NSERC	\$3,650	Estimation and data analysis for point processes and branching processes
1984–87	NSERC	\$7,400	Inference for stochastic processes and time series
1987–90	NSERC	\$12,200	Inference for stochastic processes and time series
1988	NSERC	\$ 1,076	Bilateral grant - travel to Germany
1988	DFG[a]	7,500 DM	3 month visit to Heidelberg
1990–93	NSERC	\$12,460	Inference for stochastic processes
1993–97	NSERC	\$11,500	Inference for stochastic processes
1997–2001	NSERC	\$15,000	Inference for stochastic processes
		\$16,500	(adjusted for 1998–99)
		\$17,325	(adjusted for 1999–2000)
2001–5	NSERC	\$20,000	Inference for stochastic processes.

[a]DFG = Deutsche Forschungs Gemeinschaft

Co-investigator Grants

Year	Grantor	Amount	Principle Investigator	Type of Grant
1983–86	NSERC	\$95,400	I.B. MacNeill	Infrastructure
1983–84	NSERC	\$108,000	I.B. MacNeill	Major Equipment
1984–85	NSERC	\$14,884	I.B. MacNeill	Equipment
1985–86	NSERC	\$5,500	I.B. MacNeill	Conference
1987–88	NSERC	\$24,000	I.B. MacNeill	Equipment
1991	NSERC	\$40,400	D.R. Bellhouse	Equipment
1993	NSERC	\$50,500	A. I. McLeod	Equipment
1996	NSERC	\$29,081	A. I. McLeod	Equipment
1997	NSERC	\$55,879	H. Yu	Equipment
1998	NSERC	\$10,697	H. Yu	Equipment
1999	NSERC	\$26,424	D. Murdoch	Equipment
2000	NSERC	\$29,148	H. Yu	Equipment
2000–03	UWO-ADF	\$32,300	D. R. Bellhouse	ADF

5 General Contributions

ADMINISTRATIVE, COMMITTEE AND ASSOCIATION ACTIVITY

Administrative

Graduate Chair, Dept of Statist.	1992–97
Faculty Liaison to StatLab	1992–94
Associate Chair	2004–5

Internal Committees — Department

Committee	Year
Grad Statist (McMaster)	1980–82
Statistics Seminar (McMaster)	1981–82
Colloquium	1983–85, 86–87
Library	1983–88
Graduate Affairs	1984–88, 89–90 , 91–97, 2000-01
Appointment	1987–88, 1990–92, 1993–97, 1998–2002, 2003-04
Promotion and Tenure	1987–88, 1990–92, 1993–94, 96–97, 98-99, 2003-04
Undergraduate Affairs	1990–91
Computing	1992–94, 2001-04
Workload	2000-03

Internal Committees — Science and Graduate Studies

Chairman's Selection Department of Statistics	1985–86
Chairman's Selection Department of Statistics	1991–92
UWO NSERC Student Awards Committee	1994–96
Faculty of Science Grievance Committee	1995-96
Faculty of Science Grievance Tribunal, Member	May–June 1995
Faculty of Graduate Studies Grievance Committee	1995
Chairman's Selection Department of Statistics	1996–97
Faculty of Science Promotion and Tenure	1998–2000
Chairman's Selection Department of Statistics	1999, 2003
Faculty Grad Studies Ad-hoc Committee for failed PhD Thesis	1999
Promotion and Tenure, Statistics	2003-4
Promotion and Tenure, Mathematics	2003-4

External and Other Committees

Committee	Position	Year
Organizational Committee International Time Series and Hydrology Meeting	Member	1981
Organizing Committee of Festschrift in honour of V.M. Joshi, and organizer of the session on Applied Probability and Stochastic Processes		1984–85
Pierre Robillard Committee SSC thesis award committee	Member	1991
Ontario Graduate Scholarship Awards		1992-94
Ad-hoc committee of IMS-SSC for E.L. Scott Memorial Prize	Member	1991–95
Statistical Society of Canada, Ontario Board Representative		1998-2000
Session Organizer (with J Braun) at the SSC Annual Meeting		1999
Canadian Journal of Statistics Awards Committee for Best Paper	Member	1999
Canadian Journal of Statistics Awards Committee for Best Paper	Chair	2000
Southern Ontario Regional Assocation (SORA), SSC and ASA Chapter	Secretary	1997–99
SORA , SSC and ASA Chapter	Secretary	1997–99
SORA, SSC and ASA Chapter	President	2000
SORA, SSC and ASA Chapter	Treasurer	2003-4
SSC Awards Committee	2003-4	
ESSO Mathematics Education Foundation (UWO)	Member, Board of Directors	2003-5

Referee and Editorial Work

I have been a referee of papers for the following journals, about 60 papers: Canadian Math. Bull., Time Series and Hydrology Proceedings, Communications in Statistics (several), Aequationе Mathematicae, Journal of Multivariate Analysis, Journal of Statistical Planning and Inference, Canadian Journal of Statistics (several times), Journal of Time Series Analysis, Joshi Proceedings, American Statistician, Journal of the American Statistical Association, Stoch Processes and Their Applications (several times), Journal of Statistical Research, American Statistician, Annals of Statistics (a few times), Environmetrics, Malaysian Journal of Statistics, Bernoulli (a few times), Statistical Computing and Data Analysis

In addition I have been an NSERC referee for about 30 applications.

I have been a referee for the Ontario PREA (Premiers Research Excellence Award).

I have organized or co-organized 6 invited paper sessions at conferences and workshops. Also I have chaired several contributed paper sessions at SSC and IMS meetings.

OTHER

Invited to be Full Research Member of the Laboratory for Research in Statistics and Probability (LRSP), Carleton University and the University of Ottawa. Invitation dated September 12, 2003.

APPENDIX J

Report #: DOE/EIA-0640(2005)
Release date July 2006
Next release date: February 2007

Annual Energy Outlook Evaluation, 2005

Table 1. Comparison of Absolute Percent Difference Between *AEO* Reference Case Projections and Realized Outcomes

Variable	Average Absolute Percent Difference					
	AEO82 to AEO2000	*AEO82 to AEO2001*	*AEO82 to AEO2002*	*AEO82 to AEO2003*	*AEO82 to AEO2004*	*AEO82 to AEO2005*
Consumption and Emissions						
Total Energy Consumption	2.0	2.1	2.1	2.1	2.2	2.2
Total Petroleum Consumption	3.0	3.1	3.1	3.0	2.9	2.9
Total Natural Gas Consumption	7.1	7.1	6.7	6.4	6.4	6.4
Total Coal Consumption	3.3	3.5	3.6	3.7	3.9	3.9
Total Electricity Sales	2.0	2.3	2.3	2.3	2.4	2.4
Total Carbon Dioxide Emissions	3.1	3.3	3.2	3.1	3.1	3.0
Production						
Crude Oil Production	4.5	4.5	4.5	4.6	4.6	4.7
Natural Gas Production	4.6	4.6	4.4	4.5	4.7	4.9
Coal Production	3.5	3.8	3.7	3.8	4.1	4.2
Imports and Exports						
Petroleum Net Imports	8.3	7.7	7.3	7.1	6.8	6.5
Natural Gas Net Imports	15.9	16.1	15.8	15.4	15.2	14.9
Prices and Economic Variables						
World Oil Prices	68.4	65.5	62.4	59.3	56.4	54.2
Natural Gas Wellhead Prices	82.4	78.6	74.3	70.4	67.5	64.9
Coal Prices to Electric Generating Plants*	46.5	49.8	49.1	48.4	47.7	47.0
Average Electricity Prices	18.6	20.1	19.8	19.6	19.6	19.5
Gross Domestic Product	5.7	5.9	5.8	5.6	5.5	5.4
Energy Intensity	5.8	6.1	6.0	5.8	5.7	5.7

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Source: Statistics in Table 1 are a summary of the calculations in Tables 2 through 18. The data in Tables 2 through 18 are based on the 1982 through 2004 *Annual Energy Outlook* projections. Historical data are taken from the *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, September 2005) and the *Monthly Energy Review November 2005,* DOE/EIA-0035(2005/11) (Washington, DC, November 2005).

Note: Projections of carbon dioxide emissions began in *AEO93* and were first evaluated in 2000. Revisions to historical carbon emissions are reflected in this edition. Evaluation of energy intensity projections began in 2003.

*Coal prices to electric generating plants are not published in the *Annual Energy Review*. Beginning in *AEO2003*, EIA electric generating projections incorporated combined heat and power (CHP) electricity generation in electricity generating plants. Prior to *AEO2003*, coal price projections reflected data collected, estimated, and reported to electric utilities and excluded CHP power generation.

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