BEFORE THE

NOVA SCOTIA UTILITY AND REVIEW BOARD

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

— and —

IN THE MATTER OF an Application of Nova Scotia Power Incorporated for approval of certain revisions to its Rates, Charges, and Regulations

EVIDENCE FILED BY JOHN STUTZ

On behalf of:

The Utility and Review Board Staff

March 25, 2002

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TABLE OF CONTENTS

List of Exhibits:

1. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John K. Stutz. My business address is the Tellus Institute (Tellus), 11 Arlington Street, Boston, Massachusetts 02116-3411. Until January 1, 1990, Tellus was known as Energy Systems Research Group, Inc. (ESRG).

Q. PLEASE DESCRIBE YOUR FIRM.

A. Tellus was formed in 1976. Our initial focus was on energy. Over the years, however, the scope of our work has grown. Today, in addition to energy, our work includes environmental policy, solid waste management, sustainable development and water resource planning.

Q. PLEASE DESCRIBE YOUR GENERAL BACKGROUND AND QUALIFICATIONS.

A. I am a vice president at Tellus where I have been employed since 1976. I have extensive experience with energy-related matters, particularly in the utility industry. I have appeared as an expert witness before FERC as well as Public Utility Commissions in 39 states, the District of Columbia, and three provinces in Canada. In total, I have appeared in 163 utility proceedings as shown in Exhibit JS-1. My articles and comments on utility-related subjects have been published in the *Public Utilities Fortnightly, The Electricity Journal*, and elsewhere. In addition to my energy-related activities, I work for the U.S. EPA, the OECD and various state agencies on issues related to solid waste management and the environment.

Q. PLEASE DESCRIBE YOUR BACKGROUND IN THE AREA OF ELECTRIC UTILITY RATEMAKING.

A. My first appearance as an expert witness on ratemaking was in 1979. Since then, I have presented testimony concerning a variety of rate-related topics including rate design, PURPA standards, marginal costs, embedded cost-of-service studies (COSS), fuel adjustment clauses, cogeneration-related rate issues, and the use of a future test year in utility proceedings. I have testified on rate-related issues in 95 proceedings involving electric, gas and telephone companies. Since the early 1980s, I have testified regularly on behalf of the Rhode Island Division of Public Utilities and Carriers on electric ratemaking issues, including all rate-related aspects of Rhode Island's transition to competition.

My writings on electric ratemaking are well known. My paper with Thomas Austin, "Embedded Cost-of-Service Studies—Issues in the Wake of PURPA," was published by the *Public Utilities Fortnightly* in 1983. It is cited, in the second edition of Bonbright's *Principles of Public Utility Rates*, as a source of information on electric ratemaking in general and COSS in particular. I was the lead author of "Aligning Rate Design Policies with Integrated Resource Planning," a white paper commissioned by NARUC and published in 1994. As NARUC's preface to this paper states, Tellus was selected to prepare this paper largely because of my expertise in both IRP and electric utility rate design.

Q. PLEASE DESCRIBE YOUR EXPERIENCE IN CANADA.

A. I first testified in Canada in 1982, in Prince Edward Island. My evidence dealt with System Planning and Rate Design. In 1989 I assisted Alberta Power

Company in developing a long-range forecast of energy requirements and peak demand for the Province of Alberta. In 1994, I was engaged by the Nova Scotia Utility and Review Board (UARB or the Board) to consult with Nova Scotia Power Incorporated (NSPI or the Company) concerning the results of my NARUC white paper and their applicability to rate designs for NSPI. This was followed by testimony in 1995 before the UARB on behalf of the UARB staff. In 1995, and again in 1996, I testified before the Ontario Energy Board on ratemaking and related issues. That work was sponsored by the Consumer Association of Canada. In 2001, I testified before the Board on behalf of the UARB staff, concerning NSPI's application to provide flexible, market-based, integrated energy solutions packages

Q. PLEASE DESCRIBE YOUR PROFESSIONAL ACTIVITIES BEFORE JOINING TELLUS.

A. I received a B.S. from the State University of New York at Stonybrook and a Ph.D. from Princeton University. Both degrees are in mathematics. I taught and did research at the Massachusetts Institute of Technology, the State University of New York at Albany, and Fordham University. At Fordham, I held the position of associate professor of mathematics and was co-director of the program in mathematics and economics. I left that position to join Tellus in 1976.

Q. WHAT IS THE PURPOSE OF YOUR EVIDENCE IN THIS PROCEEDING?

A. I am responding to evidence presented by NSPI and one of its witnesses, Mr. Jeff Watkins, concerning NSPI's application for approval of revisions to its rates, charges and regulations. Based on my evidence, I present a number of recommendations concerning NSPI's application.

Q. PLEASE EXPLAIN HOW YOUR EVIDENCE IS ORGANIZED.

A. The next section presents a summary of my evidence and recommendations. My detailed evidence is presented in the following four sections. These address Revenue Requirements, Cost-of-Service Studies, Rate Design and the Code of Conduct.

2. SUMMARY AND RECOMMENDATIONS

Q. WHAT ARE THE KEY POINTS OF YOUR EVIDENCE?

A. The key points are listed below. For convenience they are grouped to correspond to the four sections of my evidence.

Revenue Requirements

- The increase in NSPI revenue requirements is driven primarily by a dramatic increase in imported coal costs, and by a dramatic decline in revenues from gas resale.
- NSPI's fuel costs for 2002 do not meet the basic requirement for test year data: they are not representative of the costs likely to be experienced when the rates set in this proceeding are in effect.
- NSPI's Revenue requirement includes 100 percent of incentive compensation. The Company has not justified an increase from the 50 percent allowed by the Board in the past.
- Demand Side Management (DSM) can be a cost-effective means of reducing growth. NSPI spent almost nothing on DSM in 2001.

Cost-of-Service Study

- Use of the minimum-size method to split distribution costs between demand and customer overstates customer costs, particularly for the Domestic class.

- With the exception of the use of the minimum-size method, the Company's COSS is reasonable.

Rate Design

- NSPI's customer charges do not have a reasonable cost basis. Raising them substantially would have inequitable impacts.
- Increasing demand charges more than energy charges inappropriately encourages load management rather than energy efficiency.
- NSPI may be purchasing much more interruptibility than it needs to maintain reliability without hard evidence that load will be interrupted when needed.
- Increasing interest in promoting energy efficiency and avoiding emissions, as well as the possible advent of competition, raise questions about the structure of the Industrial Expansion Interruptible rate.
- The adders included in the annually adjusted, real-time pricing rates inappropriately assigned fixed generation costs to only the on-peak period.

Code of Conduct

- Important developments related to the Code of Conduct are still in process. NSPI has not completed the Code guideline for fuels, nor has its first annual report to the Board been submitted or reviewed as yet.

Q. WHAT ARE YOUR RECOMMENDATIONS?

A. If rates are to be set based on a 2002 test year, the following adjustments to NSPI's fuel cost data for 2002 should be required:

- A 10 percent reduction in imported coal prices;
- A 15 percent margin on gas resale.

In addition, 50 percent of Incentive Compensation costs should be removed from the cost of operations, there should be no adjustment for actual January 2002 data, and NSPI should be required to file a new rate case during 2003 with a 2004 test year. If these adjustments cannot be made, NSPI's filing should be rejected.

If a 2002 test year is used, the following changes to NSPI's COSS and rate design should be made:

- Use of the minimum-size method for classifying distribution costs should be abandoned, and the affected costs classified as demand-related. Class revenue responsibility should be determined using the ratio of revenue to cost (R/C ratio) from the modified COSS.
- No change should be made in the current customer charges or interruptible credits. Any increases in class revenue requirements should be recovered through uniform, class-specific changes in energy and demand charges.
- NSPI Annually Adjusted rates for 2002 should be approved as proposed.

Subsequent to this proceeding, the Board should hold a hearing to consider changes in customer charges, credits for interruption, design of the Annually Adjusted rates, and other rate design issues. This hearing should be scheduled so that the Board can issue an order before the Annually Adjusted rates are updated for 2003.

Finally, the Board should not grant final Code approval until the guideline dealing with fuel has been developed and the first year report has been reviewed.

3. REVENUE REQUIREMENTS

Q. PLEASE DESCRIBE THE REVENUE INCREASE REQUESTED BY NSPI.

A. In 2001 NSPI had total revenues of $844.3 million. For 2002, NSPI proposes revenues of $936.0 million, an increase of $91.7 million. For 2002, absent any change, revenues would be $866.6 million. Thus, of the $91.7 million, $69.4 million is due to the proposed increase in rates and $22.3 million is due to underlying growth.

Q. WHAT REASONS DOES NSPI OFFER FOR AN INCREASE IN RATES?

A. On page 3 of its evidence NSPI offers three reasons for the increase:

- Because of the perception of increased business risk for electrical utilities, the Company wishes to strengthen its balance sheet.
- The Company relies on imported coal as its principal fuel and imported coal prices are high.
- The Company's US dollar requirements have risen sharply at a time when the Canadian dollar is at an all-time low.

On page 37 of its evidence, NSPI broadens the second point, citing dramatic increases in fuel costs as the cause for the increase.

Q. HAVE YOU ANALYZED THE FACTORS UNDERLYING THE REVENUE INCREASE?

A. Yes, I have. Exhibit JS-2 shows the differences in NSPI's cost of operation, taxes, preferred dividends, and earnings applicable to common shares, between

2001 and 2002. The cost of operation is divided into coal costs, net revenues from resale of gas, other fuel costs, and non-fuel items. The exhibit shows that the increase requested is due primarily to an increase of $35.5 million in coal costs and a decrease in resale revenues of $32 million. Coal costs include the cost of imported and domestic coal as well as the cost of coke, a lower-cost fuel that can replace some coal use. It is imported coal that accounts for the cost increase. Based on the data provided in NSPI's response to SEB-IR-2, between 2001 and 2002 NSPI's cost of imported coal rose by $75.4 million.

NSPI's request for increased revenues is driven primarily by the increase in imported coal costs and the decline in revenues from the resale of gas. As shown by NSPI's responses to NSUARB- IR-61 and 269, these changes create NSPI's need for US dollars. Changes related to NSPI's financial condition (i.e., preferred dividends and earnings available for common shares) account for only $9.1 million out of the increase of $91.7 million in required revenues.

Q. DO YOU HAVE ANY COMMENTS ABOUT THE CHANGES IN NSPI'S FUEL COSTS?

A. Yes, I do. In responding to NSPI's request for increased revenues based on the use of 2002 as a test year, it is important for the Board to carefully consider the very dramatic changes in NSPI's fuel costs between 2001 and 2002, and the extremely high level of the 2002 costs compared to historical experience. To appreciate these points, a bit of statistical analysis is useful.

Current and historical data on NSPI's total fuel cost per MWH are shown in Exhibit JS-3. The mean and standard deviation of this data for the period 1996 to 2001 are 24.34 and .48. The small size of the standard deviation compared to the mean indicates that, while fuel cost varies annually, historically it has been close to the mean. In 2002 this changed dramatically. Distance from the mean is most appropriately measured in standard deviations. One expects most measurements to be within two or three standard deviations from the mean. For 2002, the fuel cost per MWH is more than **11 standard deviations** above the historical mean. Exhibit JS-3 also shows NSPI's annual imported coal prices. After varying between $2.24 and $2.51 per million Btus (MBtu), these prices spike to $3.14 in 2002. This is about **8 standard deviations** above the historical mean.

The changes related to the resale of gas are as dramatic as those for imported coal. Exhibit JS-4 summarizes the cost, sales revenues, margin and profit or loss on resale for 2000 and 2001, and for 2002 as shown in NSPI's original filing and in the revised filing. NSPI earned a profit of 55 percent on resale in 2000 and 60 percent in 2001. For 2002, NSPI originally anticipated a profit of 16 percent. In the revised filing, this was changed to a loss of about 1 percent.

The increase in NSPI's fuel costs is the result of what one might describe as a "perfect storm" scenario. In the book *The Perfect Storm*, a number of individually unusual developments all occurred at the same time, reinforcing each other to create a very unusual and terrible storm. In 2002, a dramatic increase in imported coal prices and equally dramatic decline in gas resale revenues come together, creating the financial equivalent of a perfect storm in NSPI fuel costs.

Q. WHAT QUESTION DOES THIS RAISE?

A. The question raised is quite fundamental: as filed, do NSPI's fuel costs for 2002 meet the basic requirements for test year data? In my view, the answer is "no."

Q. WHAT IS THE BASIS FOR YOUR POSITION?

A. As explained on page 3 of the *Electric Utility Cost Allocation Manual*, published by the National Association of Regulatory Commissioners, test year data should be representative of conditions during the period rates set on the basis of the test year are in effect. Rates set in this proceeding will be in effect for at most half of 2002. Their main impact will occur in 2003 and thereafter. NSPI's fuel costs for 2002, in the aggregate and for imported coal in particular, are far above historic levels. Revenues from resale are far below historical experience. Looking ahead, imported coal prices are expected to decline. Based on available evidence, revenues from resale can be expected to increase. In sum, NSPI's fuel cost data from 2002 are not representative of conditions in 2003 and beyond.

Q. HOW DO YOU RECOMMEND THAT THE BOARD RESPOND TO THE PROBLEMS WITH NSPI'S FUEL COSTS?

A. I recommend that the Board make the following adjustments to NSPI's data for 2002:

- Assume a 10 percent reduction in imported coal prices, reducing fuel costs by $19.7 million.
- Assume a 15 percent profit on gas resale, increasing revenues from resale by $2.9 million.

I also recommend that NSPI be required to file a new rate case during 2003 with a 2004 test year.

Q. WHY NOT SIMPLY REJECT NSPI'S FILING?

A. That would deny NSPI any rate relief for some time. My recommendation balances NSPI's legitimate need for rate relief and ratepayers' right to have rates based on "representative" data. However, if for some reason NSPI's fuel cost data cannot be modified as I have recommended, the best course of action would be to reject NSPI's application.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO IMPORTED COAL PRICES.

A. There is evidence showing that imported coal prices have declined and can be expected to decline further in the future. As shown in NSPI's response to SEB-IR-202, imported coal prices dropped significantly between June and September 2001. As indicated in the tables provided by NSPI in response to NSUARB-IR-43, the Company anticipates continuing reductions in the price of imported coal. These declines are summarized in Exhibit JS-5.

The spike in imported coal prices has created a unique situation. There has been little time since the spike to gauge exactly how the coal markets will behave in the next few years. My 10 percent reduction moves the price of imported coal one-third of the way back to its historic mean price. This is reasonable in light of the data in Exhibit JS-5.

Q. PLEASE DISCUSS YOUR ADJUSTMENT TO THE PROFIT ON GAS RESALE.

A. NSPI's admittedly limited historical experience shows that gas resale can produce handsome profits. Initially, NSPI expected to earn a margin of $4.9 million on resale in 2002. Even within NSPI's more pessimistic revised forecast, there are months where a profit is expected. NSPI's confidential response to NSUARB-IR-132 shows that NSPI anticipates a profit on a monthly basis late in 2002. Looking ahead to 2003, anticipated increases in economic growth in the US create the likelihood of better margins on resale because economic growth improves the market for gas and, as NSPI points out in its response to NSUARB-IR-65, the price NSPI receives for gas rises more quickly than the price it pays for gas when gas market prices increase.

It is simply not reasonable to assume that NSPI's resale revenues for 2002 are representative of what might occur in 2002. Based on the preceding discussion, I recommend assuming a profit of 15 percent, roughly the amount assumed by NSPI before its most recent adjustment. This percentage applied to the cost of gas for resale NSPI assumes for 2002 produces a margin of $2.9 million. Compared to NSPI's margins in 2000 and 2001, this is quite modest.

Q. HOW DO YOUR ADJUSTMENTS AFFECT NSPI'S TOTAL FUEL COST?

A. NSPI's estimated total fuel cost for 2002 is $29.74 per MWh. Based on total system requirements of 11,928.2 GWH, my adjustment reduces NSPI's total fuel cost by $1.89, to $27.85. This adjusted figure is still **over seven standard deviations** above NSPI's average total fuel cost of $24.34 for the 1996 to 2001 period. It is $2.72 above NSPI's total fuel cost for 2001, the highest cost previous to 2002.

Q. ARE THERE OTHER CHANGES TO NSPI'S TEST YEAR DATA YOU RECOMMEND?

A. Yes, I recommend that NSPI use forecast rather than actual data for January 2002, and that only 50 percent of NSPI's cost of incentive compensation be allowed in the test year cost of operation.

Q. WHY DO YOU RECOMMEND USING FORECAST RATHER THAN ACTUAL DATA?

A. Actual January data are unrepresentative because the weather in January was much warmer than normal. As stated in NSPI's response to NSUARB-IR-342, heating degree days for January 2000 were 628, while normal is 702. As noted in NSPI's response to NSUARB-IR-241, the warm weather in January reduced sales substantially. If test year data are to be representative, they should reflect normal weather for January. NSPI's forecast data does that.

Q. PLEASE EXPLAIN YOUR TREATMENT OF NSPI'S INCENTIVE COMPENSATION COSTS.

A. In the past, the Board has allowed only 50 percent of these costs. NSPI states, in response to NSUARB-IR-72, that its incentive plans align individual activities with corporate objectives. As indicated in NSPI's response to NSUARB-IR-73, these corporation objectives include asset growth, which clearly benefits shareholders. As shown in the data provided in Exhibit JS-6, incentives are a growing part of NSPI's compensation to top management, which is likely to be knowledgeable about, and concerned with, shareholder interests. Taking all of these points into account, I recommend that the Board continue to allow only 50 percent of incentive compensation costs in NSPI's required revenues.

Q. DO YOU HAVE ANY COMMENTS ON NSPI'S SALES FORECAST?

A. Yes, I do. Growth is an important issue when one is considering test year revenues. Even without any increase in rates, NSPI's electric revenues will grow by $22.3 million between 2001 and 2002.

Exhibit JS-7 summarizes NSPI's data on net system requirements, annual peak demand, and sales to residential, commercial and industrial customers. The exhibit shows historical growth from 1996 to 2000, and forecast growth from 2000 to 2002. The forecast growth in system requirements and annual peak is less than historical experience. This reflects a dramatic drop in forecast growth in industrial sales, based primarily on survey results from industrial customers (see NSPI's response to NSUARB-IR-285). However, NSPI forecasts high residential and commercial sales growth compared to historical experience. With this in mind, it is appropriate to examine NSPI's Demand Side Management (DSM) programs.

As shown in the tables attached to NSPI's response to NSUARB-IR-162, NSPI has reduced its DSM expenditures on residential programs to near zero, and has not initiated any commercial DSM efforts. In light of the increasing concern about emissions and the emphasis on energy efficiency in the Provincial Energy Strategy, it would be appropriate for the Board to require NSPI to evaluate its options for new DSM efforts, particularly those that foster energy efficiency.

4. COST-OF-SERVICE STUDIES

Q. WHAT ROLE DO EMBEDDED COST-OF-SERVICE STUDIES (COSS) PLAY IN RATEMAKING?

A. Ratemaking begins with the revenues to be collected from all rate classes. The process involves setting of class revenue requirements and development of specific rates for each class. COSS assign costs to the various rate classes. This assignment provides part of the basis for setting class revenue requirements. COSS also provide unit costs that supply part of the basis for setting the charges in rates.

Q. PLEASE EXPLAIN YOUR APPROACH TO THE DEVELOPMENT OF COSS.

A. Bonbright's *Criteria of a Sound Rate Design,* reproduced in Exhibit JS-8 below, provides a useful and appropriate framework for ratemaking including the development of COSS. Bonbright's criteria include the following:

- Equity in the burden imposed on different customers.
- Efficiency, meaning that the "price signal" to the customer reflects the cost of consumption.

Ratemaking is generally shaped by considerations of equity and efficiency.

The development of a COSS involves choices about which analysts do not agree. It is tempting to think that there are **absolute right** choices, and that any other choices are therefore **absolutely wrong**. Such a perspective will inevitably distort any serious discussion of COSS. No COSS is perfect, or even nearly so.

The challenge is to develop a COSS which reflects causal relationships to the greatest extent possible. As I will explain, meeting this challenge is important in light of Bonbright's criteria.

Q. HOW IS AN EMBEDDED COSS ORGANIZED?

A. The major steps are functionalization, classification, and allocation. To begin, expenses and the costs associated with rate-based items are grouped into functional categories (generation, transmission, distribution, etc.). Next, costs in each of these functional categories are classified as being dependent upon customers' energy usage, their peak demands, or the number of customers served by the utility. Classification is performed by determining causal relationships. Of course, not all expense and rate-base items are easily classified. Finally, costs are allocated among the customer classes. This step is based on allocation factors which, directly or indirectly, reflect energy consumption, peak demand, or number of customers. The methods employed in allocation are quite straightforward in some instances, much less so in others. Here again, the principle of causality remains primary.

Q. HOW DO COSS TREAT COST CAUSATION?

A. In a COSS, cost causation is based on **relative use**. Customers are assigned the costs associated with the share of utility services and equipment used to serve them.

Q. DOES RELATIVE USE REFLECT COST CAUSATION?

A. Yes, it does. Over the long run, utilities construct, maintain, and operate facilities and provide services matched as closely as possible to their customers' demand and usage.

Q. IS RELATIVE USE CONSISTENT WITH BONBRIGHT'S CRITERIA?

A. Yes. In particular, reliance on relative use reflects and fosters efficiency and equity. Assigning customers costs based on relative use facilitates the design of rates which send customers current "price signals" concerning the cost associated with their presence on the system, as well as their demand and consumption. While economists may object because these price signals reflect average rather than marginal costs, regulators often find them to be consistent with the notion of efficient consumption described in the eighth of Bonbright's criteria. Assigning customers responsibility for the cost of the services and facilities they use is, on its face, equitable.

Q. DO NSPI'S METHODS FOR ALLOCATING COSTS REASONABLY REFLECT RELATIVE USE?

A. For generation and transmission costs, the Company's methods reflect relative use in a reasonable fashion. However, for distribution-level costs there is an issue. Distribution costs include costs associated with the poles, wires, and other equipment that make up the physical distribution system. In NSPI's COSS, many of these costs are classified as demand- and customer-related. This creates a requirement to separate the costs for poles, wires, and other equipment into customer- and demand-related components.

Q. DO YOU SUPPORT THE DIVISION OF DISTRIBUTION COSTS INTO CUSTOMER AND DEMAND COMPONENTS?

A. No, I do not. Instead, I recommend that all distribution costs which are not directly customer related be classified as demand.

Q. PLEASE EXPLAIN THE BASIS FOR YOUR POSITION.

A. Customers must be served through a system of sufficient capacity to meet their demands. Distribution systems are engineered to meet customers' current or anticipated demand. Demand clearly causes distribution costs to be incurred. The other basic cause is "geography," that is distribution of customers within the service territory. Number of customers is a poor proxy for geography.

Q. HOW DOES NSPI DETERMINE THE CUSTOMER COMPONENT OF DISTRIBUTION SYSTEM COST?

A. The customer component of distribution system cost is obtained by estimating the cost of a **hypothetical distribution system** which connects all customers to the grid. NSPI uses the minimum-size method, in which the hypothetical system is constructed using components (i.e., poles, wires etc.) of the smallest actual size.

Q. WHY IS THE MINIMUM-SIZE METHOD PROBLEMATIC?

A. The minimum-size method assigns to all customers a share of the cost of a hypothetical distribution system which has real load-carrying capacity. It also assigns demand costs based on every kW of customer demand. The effect is to "double count" the demand which could be met by the minimum-sized system. This double counting inflates the cost assigned to Domestic customers, each of whom has a relatively low level of demand.

Q. ARE YOU AWARE THAT THE BOARD HAS APPROVED THE USE OF THE MINIMUM-SIZE METHOD IN THE PAST?

A. I am aware of that fact. I hope past approval will not preclude the Board giving my evidence due consideration. However, if the Board decides to continue to rely on the minimum-size method, the Board should recognize that use of this method will overstate customer costs, particularly for the Domestic class.

Q. HOW ARE THE RESULTS OF THE COSS USED?

A. The results of the COSS have two uses. First, they provide the costs that enter into the determination of ratio of revenue to cost (R/C ratio). In the past, the Board has ordered that class revenue responsibility be set so that the R/C ratio is within the range of .95 to 1.05. Second, the COSS is the source of unit customer, demand and energy costs that can be used in ratemaking. I will address the use of the unit costs in the next section of my testimony.

The R/C ratios proposed by NSPI are shown in Exhibit JS-9. With the revenue responsibility proposed by NSPI, the R/C ratios are all in the .95 to 1.05 range, and generally move in the direction of an R/C ratio of 1.0. Thus, on their face, the R/C ratios appear reasonable. However, because of NSPI's use of the minimum-size method, the cost assigned to the Domestic class is overstated, and that of the other classes receiving distribution-level service is understated. If the Board decides to accept my recommendations on the minimum-size system, the COSS should be rerun and the class revenue requirements set so that the .95-1.05 range is preserved and progress toward 1.0 is made. If, on the other hand, the Board continues to approve use of the minimum-size system, it should bear in mind that cost applicable to the Domestic class is overstated, and so its true R/C ratio is understated.

Q. DOES ACCEPTANCE OR REJECTION OF THE MINIMUM-SIZE SYSTEM NEED TO BE ADDRESSED IN THIS PROCEEDING?

A. No. As explained in the next section of my testimony, there are a number of ratemaking issues that should be addressed in a separate proceeding. The Board could generally rely on the accepted method here, and include reconsideration of the minimum-size system as part of that hearing.

5. RATE DESIGN

Q. PLEASE BRIEFLY DESCRIBE NSPI'S RATES.

A. NSPI has two groups of rates. First there are what NSPI refers to as the **Existing Rates**. These are the Domestic, General, and Industrial rates for which class revenue requirements and individual rate components (i.e., customer demand and energy charges) are set in a base rate case. In addition, there are five **Annually Adjusted rates** that will be addressed in this proceeding as well.

Q. WHAT CHANGES DOES NSPI PROPOSE IN THE EXISTING RATES?

A. NSPI proposes substantial changes in the Existing Rates. Customer and demand charges are increased much more than energy charges. Where there are two block energy charges, the initial block charge is increased much more than the run-out block. Exhibit JS-10 summarizes these changes. Sheet 1 shows current and proposed charges side by side. Sheet 2 shows the changes proposed and the associated customer impacts. In addition to the changes shown in the exhibit, NSPI proposes to redesign the Domestic time-of-use rate, and to reduce the Interruptible Rider credit. I will discuss these separately.

Q. HOW DO THE CHANGES PROPOSED BY NSPI IMPACT CUSTOMERS?

A. For those classes that have a customer charge (i.e., Domestic and Small General), and for those classes in which there are demand charges as well as a wide variation in customer load factor (i.e., Small General as well as Small and Large Industrial), the changes proposed by NSPI amplify the impact of the underlying increases in class revenue requirements, creating a wide variation in customer impacts.

Q. WHAT PRINCIPLE GUIDES NSPI'S REDESIGN OF THE EXISTING RATES?

A. NSPI's rate redesign is guided by its belief that efficient pricing results if run-out block energy charges are set as close as possible to marginal energy costs. NSPI sets customers and demand charges as required to meet that goal while limiting the range of customer impacts.

Q. IS THERE ANY PROBLEM WITH NSPI'S RATE DESIGN APPROACH?

A. Yes, the basic problem is a lack of balance:

- NSPI's selective use of customer charges forces some customers to pay for more than a fair share of customer costs while charging others far less.
- Raising demand charges more than energy charges sends customers a price signal that load management is more important than the pursuit of energy efficiency. For NSPI, the opposite may in fact be the case.

Q. HOW DOES THE USE OF CUSTOMER CHARGES AFFECT THE PRICE A CUSTOMER PAYS FOR ELECTRICITY?

A. The use of customer charges raises the price to customers who use a small amount of electricity, and lowers it to those who use a large amount. This point is illustrated in Exhibit JS-11, using data for the Domestic class. The exhibit shows the average price per kWh of 200, 500, and 1,000 kWh under the current domestic rate and under NSPI's proposed rate. As the results in the exhibit show, NSPI's proposed redesign of the Domestic rate increases the "quantity discount" that is built into NSPI's current rate.

Q. ARE NSPI'S CUSTOMER CHARGES COST-BASED?

A. No, they are not. As I mentioned in the preceding section, NSPI's COSS provides unit customer, demand, and energy-related costs by rate class. Exhibit JS-12 compares NSPI's customer costs and customer charges. The exhibit provides data on four rate classes: Domestic and Small General, for which NSPI currently has monthly customer charges; and General and Large Industrial, for which there are currently no customer charges. For each rate class the exhibit shows the total customer costs as determined by NSPI, the number of customers, the monthly customer cost (i.e., the total customer costs divided by 12 times the number of customers), and the current and proposed customer charges.

The data in Exhibit JS-12 show the NSPI's proposed customer charge for the Small General class collects more than 100 percent of the customer costs. Because of NSPI's use of the minimum-size method in the COSS, customer costs for the domestic class are overstated. Thus, the NSPI's proposed customer charge for that class will over-collect customer costs as well. The General and Large Industrial classes have larger total customer costs and much larger monthly customer costs than the Small General class, but have no customer charges.

Q. WHAT ABOUT NSPI'S PROPOSAL TO INCREASE THE CUSTOMER CHARGE FOR THE DOMESTIC TIME-OF-USE RATES?

A. Exhibit JS-13 provides a comparison of NSPI's current and proposed versions of the Domestic time-of-use rate. NSPI proposes increasing customer charges substantially, from $18.25 to $26.10 per month. The per-kWh charges for the off-peak and shoulder periods also increase, while the on-peak charge remains the same. The result of these changes is to make the rate much less attractive.

Q. WHY DO NSPI'S PROPOSED CHARGES MAKE THE DOMESTIC TIME-OF-USE RATE LESS ATTRACTIVE?

A. The Domestic time-of-use rate is voluntary. Customers will adopt it if they can save money be shifting usage from higher-cost to lower-cost periods. Such shifts need to be sufficient to pay for the customer's incremental fixed cost due to the higher customer charge than the non-time-of-use rate available to the customer. NSPI's proposal raises the customer's incremental fixed cost by $7.85 per month. It also reduces the difference between the on-peak and shoulder or off-peak charges. This reduces the benefit of shifting usage out of the peak period.

Q. IS THE DESIGN OF THE DOMESTIC TIME-OF-USE RATE CONSISTENT WITH NSPI'S OTHER TIME-OF-USE RATES?

A. No. The Domestic time-of-use rate has a substantial customer charge. None of NSPI's other time-of-use rates have any customer charge at all.

Q. WHAT CONCLUSIONS DO YOU DRAW BASED ON THE RESULTS OF YOUR ANALYSIS?

A. It is inequitable and inappropriate to collect (or over-collect) customer costs from some classes through customer charges, while at the same time exempting other classes from any customer charges at all. The Board should decide whether, as a matter of policy, NSPI should have separate customer charges. If the customer charges are to be used, they should be designed to collect a specified set of costs—such as hook-up, metering and billing—which are clearly customer-related. If all customers pay charges designed to recover the same set of costs, the charges are equitable.

Q. DO YOU SUPPORT THE USE OF LARGE CUSTOMER CHARGES?

A. No, I do not. I favor **usage-sensitive pricing**, which emphasizes charges based on usage (i.e., kVA or kWh charges) and limits the use of customer charges, or dispenses with them altogether as NSPI does in most of its rates.

Q. WHY IS USAGE-SENSITIVE PRICING APPROPRIATE?

A. Usage-sensitive pricing fosters efficient use of energy and load management. Any charge will draw the customer's attention to the cost of electricity. However, unlike a charge per kWh or kVA, a customer charge does not provide any opportunity for increased savings on the part of a customer who invests in more efficient equipment or changes consumption patterns. Increasing the customer charge sends the customer a simple "price signal": ignore usage and just pay your increasing bill. This may adversely affect customer investment in conservation or load management.

The customer charge also affects the price signal sent by the entire rate. By creating an average price that declines as consumption increases, NSPI's Domestic rate encourages consumption. The same is true of the Small General rate, which has a customer charge and declining block energy charges.

Q. PLEASE DISCUSS NSPI'S DECISION TO INCREASE DEMAND CHARGES MORE THAN ENERGY CHARGES.

A. The issue this decision raises is one of balance. Increasing demand charges more than energy charges fosters load management more than efficient energy use. In fact, the opposite may be appropriate for NSPI

NSPI has a substantial reserve margin. There is no pressing need to avoid capacity additions. As stated in NSPI's response to NSUARB-IR-331, generation additions anticipated through 2005 reflect policy objectives and improved generation efficiency, not the need to meet peak demand. Looking ahead, NSPI faces increasingly strict emission standards. Efficient energy use can lower generation and so reduce emissions. Further, the recently released *Provincial Energy Strategy* stresses increasing the efficiency of energy use. Thus, there may be policy reasons to provide price signals that give additional emphasis to energy efficiency.

Q. PLEASE DESCRIBE NSPI'S PROPOSED CHANGE TO THE INTERRUPTIBLE CREDIT.

A. NSPI has proposed reducing the interruptible credit from $3.43 per kVA to $3.08. The calculation of the current and proposed credits is summarized in Exhibit JS-14. As shown there, the calculation begins with the annual value of avoided capacity. The proposed credit is based on a 183-MW combustion turbine, rather than the 50-MW unit used to develop the current credit. The value of avoided capacity is multiplied by the interruptible load coincident with the system peak to obtain the value of the interruptible load, and then divided by total, demand-related billing determinants for a year, to obtain the unit credit. The change in the credit is the result of two major but offsetting changes—the drop in annual value and the drop in billing determinants.

Q. DO YOU HAVE ANY COMMENTS ON THE INTERRUPTIBLE CREDIT?

A. Yes, I do. NSPI's calculation, particularly matching the size of the avoided resource to the size of the interruptible load, may be reasonable. However, stepping back from the details of the calculation, it is not clear that the credit is justified.

Between 1998 and 2001, $38.3 million in interruptible credits were paid to customers willing to be interrupted. (See NSPI's response to NSUARB-IR-277.) However, as indicated in NSPI's response to NSUARB-IR-94, no interruptible customers have ever been interrupted. Thus, hard evidence that interruptibility will be there when NSPI needs it is lacking.

NSPI pays customers willing to be interrupted because their willingness to be interrupted increases NSPI's reserve margin. Since 1996 NSPI's reserve margin has been 35 percent or above, much more than the 20 percent required to meet reliability standards. It is forecast to remain at 35 percent in 2002. (See NSPI's response to NSUARB-IR-286.) Thus, NSPI could substantially reduce its purchases of interruptibility while maintaining the reserve margin required to meet its reliability standards. On the other hand, tests may show that 1 MW interruptibility is not sufficiently firm to justify the deferral of 1.2 MW of generating capacity (the assumption underlying the development of the current and proposed credits). If so, the current amount of interruptibility may be justified but a lower credit may be in order.

Looking ahead, the Board may wish to consider whether paying a lower credit, limiting the amount of interruptible load or requiring "test" interruptions is appropriate.

Q. IN LIGHT OF THE ISSUES YOU HAVE RAISED, HOW DO YOU RECOMMEND THAT EXISTING RATES BE REDESIGNED?

A. I recommend that existing rates be redesigned as follows:

- No change should be made in the current customer charges or interruptible credits.
- Any increases in class revenue requirements should be recovered through uniform, class-specific changes in energy and demand charges.

In my view, it is likely more appropriate to decrease the customer charges than to increase them. Changes related to the interruptibility credits may also be warranted. However, to avoid rushing the consideration of what could be important changes in these charges, I recommend deferring their consideration. Thus, I recommend that, subsequent to this proceeding, the Board hold a hearing to consider changes in the customer charges and credits for interruption.

Q. WHAT CUSTOMER IMPACTS WOULD ACCOMPANY YOUR RATE DESIGN PROPOSALS?

A. For the two rate classes with customer charges, my proposal would provide less than average increases for small customers and greater than average increases for large customers. This would somewhat reduce the quantity discount built into NSPI's current Domestic and Small General rates. However, for large customers, the impacts would not be dramatically greater than under NSPI's proposal. For Domestic customers using 1,000 kWh per month, NSPI's proposal would produce $102.10 per month, compared to $102.70 under my proposal. For Small General customers using 1,000 kWh per month, NSPI's and my proposals would produce $104.21 and 108.86, respectively. (See Exhibit JS-15 for the calculation of these amounts.) These amounts are based on NSPI's proposed revenue requirements. With my adjustments to required revenues, the differences would be lower.

For all of the rate classes except Domestic and Small General, my proposal increases all charges by the same percentage. Thus, apart from the effect of the interruptible credits, all customer increases would be the same as the increase in their class revenue responsibility.

Q. PLEASE DESCRIBE NSPI'S PROPOSED CHANGES IN THE ANNUALLY ADJUSTED RATES.

A. NSPI has five rates that are adjusted on an annual basis, based on methodologies. approved by the Board. These rates are the Generation Replacement and Load Following (GRLF) rate, the Industrial Expansion Interruptible (IEI) rate, and the Distribution, High Voltage and Extra High Voltage Real Time Pricing (RTP) rates. Exhibit JS-16 shows NSPI'S current and proposed changes for the GRLF and IEI rates. For the three RTP rates, the charge is NSPI's actual hourly marginal energy cost plus an adder. Exhibit JS-16 shows the current and proposed adders.

As shown in the exhibit, NSPI has proposed large changes to all of the Annually Adjusted rates. As explained in NSPI's responses to NSUARB-IR-182 to 186, these changes result from NSPI's application of the Board approved methodologies for setting the charges in these rates.

Q. DO YOU HAVE ANY COMMENTS ABOUT THE ANNUALLY ADJUSTED RATES?

A. Yes, I do. My comments concern the basic structure of the rates, not NSPI-specific calculations. They focus on IEI and RTP rates. With respect to the IEI rate, I have three comments:

- Under certain circumstances, the IEI rate can be "locked in" for a 10-year term. Given the possible introduction of competition, this may not be appropriate.
- The IEI rate provides baseload energy to certain new or expanding industrial loads. Such arrangements may deserve reconsideration in light of increasing concerns about environmental emissions.
- Given the emphasis on energy efficiency in the Provincial Energy Strategy, it may be appropriate to add some requirement that energy received under this rate will be used efficiently.

Turning to the RTP rates, I have two comments:

- The RTP rates have no customer charges. This differs markedly from the domestic time-of-use rate which has a substantial customer charge.
- As NSPI states in its response to NSUARB-IR-185, fixed costs associated with generation are only included in the on-peak adder. This is inconsistent with the way in which the Board has required NSPI to allocate generation costs in the COSS. There generation costs are allocated, in part, on the basis of energy use, on and off peak.

Q. IN LIGHT OF THESE COMMENTS, HOW DO YOU RECOMMEND THAT THE BOARD DEAL WITH THE ANNUALLY ADJUSTED RATES?

A. I recommend that the Board approve the rates as proposed by NSPI, and that the Board include review of the Annually Adjusted rates as part of the separate rate design hearing I proposed earlier in my evidence. I recommend that the hearing be scheduled so that a Board decision is available before the Annually Adjusted rates are set for 2003.

6. CODE OF CONDUCT

Q. PLEASE SUMMARIZE THE SITUATION WITH RESPECT TO NSPI'S CODE OF CONDUCT.

A. Currently NSPI has a Code of Conduct (COC) in place that has initial Board approval. That COC, contained in Appendix 5 of NSPI's evidence, provides a framework for utility/affiliate interactions including various transactions. In its evidence, NSPI has requested final approval of the Code.

Q. DOES NSPI CURRENTLY HAVE TRANSACTIONS WITH AFFILIATES?

A. Yes, it does. For example, as indicated in NSPI's response to NSUARB-IR-205 and 206, 501845 N.B. Inc. is an affiliate from which NSPI purchased 75 percent of its new transformers in 2001.

Q. HAS NSPI FILED A REPORT ON THE CODE OF CONDUCT WITH THE BOARD AS YET?

A. No. As indicated in NSPI's response to NSUARB-IR-100, NSPI's first report is not due at the Board until April 30, 2002.

Q. ARE DEVELOPMENTS RELEVANT TO THE COC CURRENTLY UNDERWAY?

A. Yes. NSPI is in the process of developing a new relationship with its affiliation, Emera Energy, related to the acquisition of fuels for NSPI. Given the size and importance of NSPI's expenditures for fuel, this is an important development.

Q. ARE GUIDELINES DEALING WITH THE APPLICATION OF THE COC IN THE FUELS AREA COMPLETE?

A. No, as indicated in NSPI's responses to NSUARB-IR-69, Guideline 9 covering this area will be developed once the "new relationship" has been clearly defined.

Q. WOULD IT BE APPROPRIATE FOR THE BOARD TO GRANT FINAL APPROVAL BEFORE THE GUIDELINE DEALING WITH FUEL HAS BEEN DEVELOPED AND THE FIRST YEAR REPORT HAS BEEN REVIEWED?

A. No.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does.