NEWFOUNDLAND POWER INC.

DIRECT TESTIMONY OF LARRY B. BROCKMAN

AUGUST 2001

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1. INTRODUCTION

Q. Please state your name and current position.

A. My name is Larry B. Brockman. I am a Managing Consultant with PA Consulting Group in Cambridge Massachusetts in their Energy and Economics practice. I currently specialize in regulatory assistance and analysis of wholesale energy markets. PA Consulting Group is a world-wide management consulting firm headquartered in London, England.

Q. Have you previously given evidence before this Board?

A. Yes. I have appeared as an expert witness before this Board on five previous occasions. I gave evidence on behalf of Newfoundland Power Inc. concerning cost of service, rate design and least cost planning in Newfoundland and Labrador Hydro's 1990 and 1992 general rate referral cases. In addition, I have appeared as an expert witness on behalf of Newfoundland Power in Hydro's 1992 generic cost of service proceeding and this Board's 1995 rural rate inquiry. I also appeared as an expert witness on cost of service and rate design in 1996 on behalf of Newfoundland Power.

Q. Please summarize your professional background

A. I have over 25 years of experience in the utility industry as a planner, regulator, ratemaker, educator, and consultant. From 1997, until I joined PA Consulting in 2000, I was the President of Brockman Consulting in Atlanta, Georgia, where I performed market studies and provided general regulatory assistance to electric utilities. From 1985 to 1997, I worked in the Consulting Department of Energy Management Associates, where I was a Vice President. In 1992, EMA became a division of EDS.

From 1981 until 1985, I was the Assistant Director of the Electric and Gas Department of the Florida Public Service Commission, which is the Florida equivalent to this Board. At the Florida Commission, I had responsibilities for supervising 48 employees engaged in all phases of electric and gas regulation. I was ultimately responsible for making recommendations to the commission on rate cases, power plant siting, conservation activities, automatic adjustment clauses, and various other public policy matters.

I have managed a wide variety of projects involving prices and profits in deregulated electricity markets, integrated resource planning, costing, ratemaking and general utility practice. I have reviewed and created least cost resource plans for Canadian and American clients. I have also participated in merger and acquisition studies, identifying and quantifying the potential planning and operational synergies. I was a co-developer and instructor for several courses on least cost planning and ratemaking offered across the U.S. by Public Utilities Reports and The Management Exchange. I received a Bachelor's Degree in Engineering from the University of Florida in 1973 and returned in 1977 to do post-graduate work in electrical engineering and regulatory economics.

From 1973 until 1977, I was a system planning engineer with Jacksonville Electric Authority, a municipal utility in Florida, where, I performed generation, transmission and distribution studies including evaluations of new generation, transmission lines, substations, feeder conversions and the like. I later worked for Gainesville Regional Utilities doing similar work and also performed cost of service and rate design studies.

A more complete resume of my qualifications is contained in Exhibit LBB-1.

Q. What is the purpose of your evidence in this proceeding?

A. My evidence in this proceeding will:

(1) provide an historical overview on the regulation of Hydro, since my involvement in its regulatory proceedings began in 1990;

(2) address Hydro's proposals on the Rate Stabilization Plan (RSP);

(3) address certain issues relating to Hydro's proposed test year forecast; and

(4) address issues arising from Hydro's proposed Cost of Service study, the Rural Rate Subsidy and rate designs.

2. REGULATORY OVERVIEW

Q. What historical perspectives on this case would you like to share with the Board that might be of some assistance in understanding the current case?

A. Much has changed with respect to this Board's regulation of Hydro since I began testifying as an expert before this Board in 1990.

In 1990, Hydro was a government owned utility subject only to limited jurisdiction by this Board. Responsibility for the recovery of the deficit associated with Hydro's rural service had recently been transferred to the ratepayers by government, and its magnitude was of great concern to Newfoundland Power. Hydro's revenue requirements were determined by the use of times-interest-earned calculation, as were the revenue requirements of most government-owned utilities. There were no uniform cost of service studies for all of Hydro's customer classes, and the rates for Industrials were not set by this Board. There were no public least-cost planning proceedings, and Hydro's capital expenditures were not regulated by this Board.

Today, the powers of this Board, with respect to the regulation of Hydro, have grown considerably. Hydro, while still governmentally-owned, is now a “fully regulated” utility requesting revenue requirements based on return-on-rate-base and return on common equity. We have much better cost of service studies for all of Hydro's rate classes.

I have testified at various times that:

(1) this Board should have regulatory oversight of Hydro's least-cost-planning and major capital spending;

(2) the rural subsidy should be allocated in a fair manner and minimized to the degree possible within a finite time schedule; and,

(3) Hydro’s rates to Newfoundland Power and the Industrials should be regulated on a comparable basis by this Board.

There has been progress on all of these items. In addition, I participated in the Board's 1993 generic cost of service proceeding, where we attempted to standardize the cost allocation procedures to be used in future cases. This Board has made rulings on how cost of service should be treated from that proceeding.

This Board now also has capital spending oversight with respect to Hydro. While there are exceptions, such as Granite Canal, this is also a positive change.

The issue of how the rural subsidy is to be spread between Hydro's customers has been largely decided by government -- the Industrial customers do not have to pay it. For the first time Hydro is proposing that the rural rate subsidy be collected from both Newfoundland Power and Hydro's Labrador Interconnected customers. While Hydro has proposed reducing the subsidy somewhat by eliminating preferential rates to fish plants and governmental facilities in rural areas, the rural rate deficit remains a substantial cost for Newfoundland Power's customers and will likely be so for the foreseeable future.

Newfoundland Power, the Industrials, Labrador Interconnected customers, and the Isolated Rural customers are now being treated in a uniform manner in Hydro's cost of service study, and rates for all will be set by this Board in one proceeding. This is an improvement over the situation in 1990, because it allows us to appreciate the effects of the decisions made for each of these groups on the others.

The major issues of cost allocation were decided by this Board following the 1993 generic cost of service hearing. We should not now have to re-try most of them again anytime soon.

Q. From your perspective, what remains to be done with respect to the progress of regulation of Newfoundland and Labrador Hydro?

A. Mr. Wells in his evidence, states that amendments to the *Public Utilities Act*, *the Electrical Control Act 1994*, and the *Hydro Corporation Act*, require Hydro to operate as a "fully regulated utility under the jurisdiction of the Public Utilities Board."

Newfoundland Power does not necessarily agree that this statement means Hydro has to have a rate of return equal to an investor-owned utility. There are several major things that remain to be done before Hydro can be treated as an investor-owned utility, whose owner just happens to be Government. First, the consumer cost of moving towards treating Hydro as an investor-owned utility could be potentially high and will require a phase in period. One important aspect of dealing with this issue will be the substantial rural rate subsidy and Hydro's plans with respect to it. In some sense, the rural rate subsidy could be considered a return on equity since Government (Hydro's shareholder) has decreed that it be collected in certain ways, and it bears no relationship to the cost of service. In fact, in October 1995, this Board reported to Government that the surcharge upon Hydro's customers was the equivalent of a hidden tax (Rural Rate Report, Oct. 10/95, p. 175).

Currently, the rural deficit of 26.2 million is allocated between Island Interconnected customers $22.9 million which is paid by Newfoundland Power's customers only and Labrador Interconnected customers 3.3 million (Exhibit JAB-1, Schedule 1.2.1). This results from a social policy directive of the Government with which Newfoundland

Power takes no issue. However, if Hydro expects to earn returns commensurate with investor-owned utilities, there must be recognition of the financial impact these "shareholder decisions" (by Government) have had.

If Hydro is to be treated the same as other regulated utilities it is worth examining the RSP and specifically Hydro's proposal to increase the cap on it. The present RSP protects Hydro's shareholders (Government) from the risk of changes in fuel costs, changes in hydraulic production, and changes in load. Since the vast majority of plant has been added to rate base by legislative fiat, other than the risk of their annual labor costs getting out of line, there is little risk left that the owner faces. While this has implications for the cost of capital, it also raises issues related to Hydro's regulatory inducement to be efficient.

3. THE RATE STABILIZATION PLAN

General

Q. Can you describe the RSP in simple terms?

A. The mechanics of the RSP works are conceptually illustrated in Exhibit LBB-2. Detailed monthly reporting can be found at the Response to Information Request IC-73 which illustrates the workings of the RSP for the months of January 1992 to June 2001.

The RSP takes any difference in costs that occur because of changes in hydraulic generation, thermal fuel costs, and sales to what were assumed in the last rate case and places them in a deferral account. The year-end rolling balance in this deferral account is then automatically applied to consumers' rates over a three year period. Interest is currently applied to the balance. Currently, there is a balance for the Industrial customers and the Retail customer, (Newfoundland Power). The purpose of the account is to smooth out the fluctuations in costs seen by customers in the rates they pay.

The account balance for the Retail customer is now capped at $50 million. Fuel costs in Hydro's rates are currently based on $12.50/bbl oil at Holyrood which was set in 1992.

The Principal Changes

Q. What are the principal changes Hydro is proposing to the RSP?

A. Hydro is proposing that the balance allowed in the account for the Retail customer be increased to $100 million from $50 million. In addition, Hydro is proposing that the cost of oil reflected in base rates be increased from $12.50/bbl to $20/bbl.

Increasing the RSP Cap for the Retail Plan

Q. Do you agree with Hydro's proposal to raise the Retail Customer's cap to 100 million?

A. No.

The RSP account allows Hydro to recover costs without coming to the Board for review, even when those costs change in a material way. This is because the deferral and flow-through are both now essentially automatic. Hydro does report to the Board on the amounts applied in the RSP, but there is limited regulatory oversight on adjustments which affect customer rates. With Hydro's request for a $100 million cap on the Retail part of the RSP, Hydro would be allowed to defer significant costs (JCR Schedule 1) and have them recovered from the customer automatically without any public scrutiny.

In my opinion, this amount (nearly 1/3 of Hydro's revenue requirement) is excessive and gives Hydro little or no incentive to operate efficiently. If the cap is raised, Hydro would have significantly less reason to come back to the Board to justify substantial cost increases, as a higher cap would allow Hydro the opportunity to avoid a general rate review for a longer time. In present circumstances, where Hydro has not had a rate case for 8 years, and proposes to migrate to commercial returns, it seems that greater, rather than lesser, regulatory oversight will be necessary than this proposed change implies.

My recommendation to avoid these types of consequences is that the Board leave the cap on the Retail Customer's portion of the RSP that can be automatically flowed through to consumers at $50 million, but allow Hydro to book up to $100 million into the account. If at any time the RSP balance goes over $50 million, Hydro can either decide to let its shareholders pay the cost (as a fully regulated utility might do), or it can apply to the Board for a hearing to justify increased cost recovery within the context of Hydro's total costs.

This proposal will provide Hydro with an increased incentive to be more efficient, but still allow the flexibility to be able to recover the full amount of its fuel costs.

The Industrial RSP

Q. Please comment upon the proposed changes to the Industrial RSP.

A. There is currently no cap on the Industrial RSP. In my opinion there should be a cap on automatic flow through, and it should be set at a reasonable level of annual revenues for the same reasons as the Retail RSP should be.

There is an additional danger in allowing the Industrial RSP to grow too large. There are only a handful of customers on the Industrial rate. If one of the larger industrial customers leaves the system, remaining customers might conceivably be left to pick up large deferred expenses in the RSP.

Hydro has proposed abandonment clauses to its Industrial contracts (see Schedule C to Hydro's Application, Article 15.04) which should help deal with some situations where a solvent Industrial customer has chosen to leave the system but the clause as proposed does not address the RSP. The Board may want to consider having Hydro amend the proposed abandonment clause to provide for recovery of an appropriate portion of the RSP balance from an Industrial customer that leaves the system. However, in situations where a customer cannot pay the abandonment charges (such as insolvency), significant risk to other customers will continue to exist.

Increasing Fuel Costs in the RSP

Q. Please comment on Hydro's proposal to increase fuel costs.

A. Hydro has proposed to increase the fuel costs in the RSP from $12.50/bbl to $20/bbl. The $20/bbl price is below the current market price and, at current market prices, adoption of a $20/bbl price in base rates will result in further consumer price increases. Currently, Hydro is forecasting that an RSP increase of 6-7% (Wells, page 9) will occur on July 1st, 2002. It is important to note that this is in addition to whatever increase the Board determines appropriate as a result of this general rate review proceeding.

While an increase in fuel cost recovery in Hydro base rates is warranted, the overall magnitude of these recoveries ought not to be overlooked. Even with the forecast 6-7% increase on July 1st, 2002, Hydro is still forecasting large year-end balances in the Retail RSP until at least December 31st, 2004. The balances for 2003 and 2004 are set out below.

Year-End Retail RSP Balances
(Response to NP-50)

Year	$000,000
2003	62
2004	37

In the circumstances of this proceeding, Hydro's proposal to incorporate a $20/bbl fuel cost in base rates is a reasonable enough balance of the need to improve fuel cost recovery and provide rate stability. As well, in my opinion, the future consumer price increases which will flow from an understated price of oil should impact the timing of other regulatory developments for Hydro, including Hydro's migration to a capital structure and rate of return resembling that of an investor-owned utility.

4. TEST YEAR FORECAST

The Test Year Concept

Q. Please explain the test year concept as it is used in this case, and how it interacts with the cost of service.

A. The purpose of a test year is to establish values that will be used to determine revenue requirements and rates that will allow the utility the opportunity to earn its regulated rate of return for the years in which the rates will be in effect. The adequacy of a test year should be judged by how well it is likely to do this job.

The test year chosen by Hydro in this case is a fully-projected 2002, meaning all the data is forecast. This is in accordance with regulatory practice in Newfoundland.

Forecast Hydraulic Production

Q. Do you have any concerns with respect to Hydro's 2002 test year forecast?

A. Yes, I do.

My principal concern is the amount of generation that Hydro has projected to come from hydraulic generation versus the amount projected to come from thermal generation.

These amounts are shown in Mr. Henderson's Schedule V. Hydraulic generation in 1992 and 2000 was 4221.58 GWh and 5016.17 GWh, respectively. However, Hydro is projecting hydraulic generation in 2002 to be closer to the 1992 figures, at 4271.67 GWh which forecast for the 2002 test year seems low when compared to recent history. The following table shows the hydraulic generation for the years 1992-2000 from Hydro's Response to Information Request IC-100.

Actual
Hydraulic Generation
1992 – 2000
(Response to IC-100)

Year	**GWh**
1992	4,222.6
1993	4,440.0
1994	5,044.7
1995	4,393.6
1996	4,574.6
1997	4,629.5
1998	4,262.5
1999	4,802.6
2000	5,016.7
Average	**4,598.5**
Hydro Projection	4,271.7

The table plainly shows that hydraulic generation has been greater than the 4271.6 GWh assumed in the test year in 6 out of the 8 years shown. In fact, Hydro’s 2002 hydraulic generation forecast is 326.8 GWh less than the ***average*** from 1992 through 2000. In my opinion, therefore, Hydro's hydraulic forecast is unduly conservative.

In addition to the historical experience, there is a known event likely to occur in mid 2003 that will materially affect Hydro's energy forecast. That known event is Granite Canal hydraulic plant coming online. Granite Canal is projected to generate approximately 224 GWh per year (H.G. Budgell, Schedule 11). The present Hydro base rates have been in place for over 8 years. This fact alone makes consideration of planned events in the year following the test year reasonable in the circumstances.

Q. How is the cost of service sensitive to forecasts of hydraulic production?

A. The cost of service is sensitive to the forecast of hydraulic production in two direct ways. First, thermal generation is more expensive then hydraulic generation. Second, the amount of hydraulic power changes the relative allocation of generating plant between the customer classes.

In addition, the forecast of hydraulic production can also have a significant impact on future consumer rates through the operation of the RSP. This potential impact would be increased if the cap on the RSP is raised as proposed by Hydro. When considered in combination with the proposed changes to the RSP, the conservative 2002 test year hydraulic production forecast could result in the rates being set in this proceeding remaining in effect for a significant number of years.

An illustration of the impact of average hydraulic production (1992-2000) and the effects of Granite Canal on revenue requirements follows. In this Table I have relied on Response to Information Request NP-141 which indicates that the increase in consumer rates for each 100 GWh of underestimated hydraulic production is in the order of $3.3 million.

Proforma Reduction in 2002 Revenue Requirements
From Variations in Test Year Production Assumptions
(Response to NP-141)

Variation	GWh	$000,000
Use Average 1992-2000 Hydraulic Production	326.8	10.8
Include Granite Canal Production	224.0	7.4
Totals	**550.8**	**18.2**

Interaction with the RSP

Q. Would the RSP take care of any inaccuracies between hydraulic and thermal generation assumed in the test year?

A. Yes, it would. However, there is the issue of consumer impact for the Board to consider.

Hydro is proposing a rate increase for January 1, 2002 with a further increase on July 1, 2002 as a result of the RSP. The conservative hydraulic production forecast has the effect of adding to the overall impact on consumers in this six month period.

So there is an issue of timing here. The RSP provides for interest to compensate Hydro for timing differences between when costs are incurred and when they are collected from consumers. The overall effect is that Hydro recovers all of its fuel and carrying charges thereby fully insulating it from shocks in fuel price, hydraulic production variation and system load.

Q. Do you have any other comments on the RSP?

A. Finally, given the size of RSP increases forecast by Hydro, RSP mechanics are becoming more important. Currently, the calculations are done after the actual loads and generation are known, but the process of allocating the amounts is not very transparent. The numbers are run back through the cost of service study and the final results reported. It is difficult to track this calculation after-the-fact. Hydro is now proposing that they simply be allocated based on relative energy use, which would remedy this to some extent.

Hydro should be required to file with the Board all calculations (including allocations) as part of routine reporting.

5. COST OF SERVICE, RURAL RATE SUBSIDY & RATE DESIGN

Cost of Service Studies Generally

Q. What is the purpose of a cost of service study?

A. Cost of service studies serve several purposes. The 1992 NARUC Electric Utility Cost Allocation Manual (page 12) gives the following purposes for cost of service studies:

(1) To attribute costs to different categories of customers based on how those customers cause costs to be incurred;

(2) To determine how costs will be recovered from customers within each customer class;

(3) To calculate costs of individual types of service based on the costs each service requires the utility to expend;

(4) To determine the revenue requirement for the monopoly services offered by a utility operating in both monopoly and competitive markets; and

(5) To separate costs between different regulatory jurisdictions.

Q. What types of cost of service studies are recognized in the industry?

A. There are two major types of cost of service studies. One is called an embedded cost of service study, which deals with the costs of existing utility plant and operating expenses. The other type, marginal cost of service studies deal with the future costs of meeting additional electric energy and demand requirements.

Q. How are cost of service studies used?

A. The use of cost of service studies to allocate revenue responsibility derives from the generally accepted principles of good rate design. James Bonbright was one of the first to codify these principles in his classic book, *Principles of Public Utility Rates*. Bonbright's principles which relate to cost of service studies are:

(1) Effectiveness in yielding total revenue requirements;

(2) Fairness in the apportionment of total costs of service among the different ratepayers; and

(3) Static efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:

(a) in the control of the total amounts of service supplied by the Company; and

(b) in the control of the relative uses of alternative types of service by ratepayers (on-peak versus off-peak service or higher quality versus lower quality service).

Embedded cost of service studies are done primarily to achieve the goal of fairness, and to avoid undue discrimination in the apportionment of revenue responsibility to rate classes and to individual customers within these classes. Fairness in allocating revenues between individual customers within each class is accomplished by the proper setting of demand, energy and customer charges within those classes. Marginal cost of service studies are performed primarily to assist in designing rates that are economically efficient. The cost of service methods under investigation in this proceeding are embedded methods and are therefore primarily aimed at achieving fairness.

Bonbright's principle of fairness in cost apportionment and the NARUC principle of attributing costs based upon causality are inextricably inter-twined. In fact, the principle of causality is almost universally claimed in attempts to justify various cost of service methodologies as fair. The causality principle states that costs should be assigned according to load and customer characteristics that cause the costs to go up or down.

Q. Please describe how an embedded cost of service study is performed.

A. There are three main steps involved in performing an embedded cost of service study:

(1) functionalization;

(2) classification; and,

(3) allocation.

Each step is a process of sub-dividing the utility's overall costs into smaller and smaller portions, each associated with specific customer classes and load characteristics that cause the costs to occur.

Q. Please describe the functionalization step.

A. Functionalization is the process of deciding what purpose (or utility function) a utility investment or expenditure serves. Common examples of utility functions are production, transmission, and distribution. As an example of functionalization, consider the cost of fuel burned at a power plant and the cost of carrying the investment in that plant. These costs would be functionalized as production. Functionalization helps identify how the costs of providing service to various customers change when the load characteristics of those customers change. The functionalization of Hydro's costs can be seen in Exhibit JAB-1, page 28, for example.

The costs assigned to the major utility functional categories are often broken down further into sub-categories associated with individual customers or groups of customers. For example, if a transmission line was built just to serve a specific group of customers, the costs of that line should be functionalized as transmission whose function is to serve only that group of customers. This promotes fairness by ensuring that the cost of that line will eventually be assigned only to that group of customers. Exhibit JAB-1, page 28, indicates $1,638,134 of specifically assigned revenue requirements for Island Interconnected customers.

Q. Please describe the classification step.

A. Classification is a process of deciding what customer characteristics cause each functionalized cost to increase or decrease as customer load characteristics change. Costs are usually classified as increasing or decreasing because of changes in customer demand, energy or number of customers on the system. The table below shows some commonly accepted ways of classifying the major functional categories:

	Costs Classified as		
Functional Category	**Demand**	**Energy**	**Customer**
Production	yes	yes	no
Transmission	yes	yes	no
Distribution	yes	no	yes

In the classification stage, we must decide not only whether a cost is related to demand, energy or number of customers, but we must also assign percentages for those functions which may be related to more than one of these causal factors.

Even a simple table such as this one can be controversial when we discuss classification, because there is no universally agreed upon method for classifying production, transmission, or distribution related costs. A summary of the classifications used by Hydro for their operating and maintenance expense is shown on Exhibit JAB-1, page 34. The rate base is classified on page 37 of the same exhibit.

Q. Please describe the allocation step.

A. In the allocation step, the previously functionalized and classified costs are allocated to the individual customer classes. Allocation to the classes is usually done in proportion to each classes' share of the demand, energy or number of customers depending on how the cost was classified in the prior step. This is best illustrated by an example.

Suppose a utility spent $50 in a year to provide a generating plant to serve two customer classes. After investigation of the utility's accounting books, it was found that $25 was spent at the power plant for fuel and $25 was associated with carrying the investment in the power plant. The first $25 cost would be functionalized as production-fuel, and the second $25 cost would be functionalized as production-carrying costs.

Next, suppose that consultation with the planners and operators of the plant revealed that the costs of fuel increase primarily as more energy from the plant is used, but one-half of the investment in the plant was spent due to the amount of energy it produced, and the other one-half of the investment in the plant was based on the demand placed on the system. Applying the principle of causality, the $25 production-fuel costs would be classified as energy related, $12.50 of the production carrying charges on the plant as demand related, and the $12.50 of the carrying charges as energy related, for totals of $37.50 energy related and $12.50 demand related costs.

To perform the allocation step it must first be determined how much demand and energy requirement each of the classes places on the system. Suppose in this example that Class 1 places two-thirds the total demand on the system, but uses only one-half the total energy from the plant (Class 1 has a lower load factor than Class 2). Two-thirds of the $12.50 demand related carrying charges on the plant would be allocated to Class 1, because that would be their share of the total demand. (The principle of causality would suggest that they caused two-thirds of the demand costs). Also, one-half of the $37.50 energy related costs would be allocated to Class 1 because that is their share of the total energy used from the plant. The basis of the allocations of costs to all the Island Interconnected classes is shown on Exhibit JAB-1, page 38.

Q. Please explain a little more about the history of cost of service in Newfoundland as you have observed it, and how we got to where we are today.

A. As previously discussed, cost of service is always a controversial topic, because reasonable people often disagree on how it should be calculated and allocated. Because the topic is controversial, and because we don't want to argue it in every case, it is not uncommon for a Board to have a generic hearing where the major cost of service issues are decided on generic basis, and then used in cases without having to re-hear the arguments every time. This was the theory behind the Board's 1992 Generic Cost of Service proceeding. They heard the arguments and provided their decision, which is contained in the 1993 Report to the Board on Cost of Service. A summary of that Report and my assessment of Hydro's compliance with it is contained in Exhibit LBB-3.

Hydro's Treatment of Cost of Service

Q. Please address the way Hydro has complied with the Report in the way they allocated demand related production plant.

A. The 1993 Board Report recommended that Hydro file a study of generation plant demand allocators. Hydro addresses this issue in Mr. Brickhill's evidence. Mr Brickhill says that Hydro did a study of loss of load hours (LOLH) and that he chose the 2 CP allocator because two months of the year contributed most of the loss of load hours, and because it was more stable.

Q. Do you agree with Mr. Brickhill's conclusions on this issue?

A. No. While I do not doubt that two of the peak months contribute most to the loss of load hours, the peak tends to occur in different months in different years. Using only two months can lead to erroneous conclusions, depending on the test year chosen. This can easily be seen from the Response to Information Request NP-157, where the monthly peak for the years between 1986 and 2000 occurred in the months of December four times, January three times, February five times and March three times. In my opinion, choosing only two months for the cost allocator is thus too unstable. Which two months would you choose?

The study Hydro filed to support the 2 CP allocator used a normalized load shape derived from 1990-1994 load shapes. These years stand out as having peak months only in January and February, compared to other years in Response to Information Request NP-157. Had other years been chosen, the LOLH of other months would have been higher, since LOLH is very sensitive to load levels. The table on page 3 of Response to Information Request NP-156 indicates that LOLH was twice as high in December as it was in February. It was almost three times as high in December as it was in January.

Calculating the demand allocator using more months leads to more stability, not less. Mr Brickhill's table (Schedule 11) seems to bear this out, since the variance on the allocator is highest with the 2 CP and lowest with the 4 CP. Mr. Brickhill at page 8 of his evidence states, "One test of a cost allocation method is variation in results over time. All other things begin equal, a method that produces significant variation over time should be avoided." Since the 2 CP seems to be so sensitive to what years we choose in Newfoundland, it is my opinion that the 2 CP should be avoided by that reasoning and that the 4 CP would be a more stable allocator.

Hydro should use a 4 CP allocator calculated on the basis of historical data.

The Rural Rate Subsidy

Q. Have you reviewed Hydro's treatment of the rural rate subsidy in this case, and what are your conclusions concerning it?

A. Yes. I have reviewed Hydro's treatment of the rural rate subsidy in this case. I have reached several conclusions concerning that issue:

?? Hydro has appropriately stated that it is their goal to minimize the subsidy to the extent practical;

?? Hydro has made some movement towards eliminating the subsidy in this case. In particular, they are proposing to charge the Government accounts in the isolated areas at their cost of service;

?? However, the progress at eliminating the rural rate subsidy is painfully slow.

Mr. Hamilton's evidence contains the following summary of the revenue/cost ratios of Hydro's retail customers but excluding Newfoundland Power and the Industrial Customers from the cost of service study.

	Island Interconnected	**Isolated Systems**	**L'Anse au Loup**	**Labrador Interconnected**
Domestic	0.72	0.16	0.37	0.75
GS 0-10 kW	1.00	-	0.52	1.06
GS 10-100 kW	1.08	-	0.53	2.24
GS 110-1000 kW	1.24	-	1.24	3.06
GS over 1000 kVA	0.87	-	-	3.44
GS Diesel	-	0.28	-	-
Street Lighting	1.10	0.36	0.77	1.13
System	0.83	0.21	0.44	1.20

Since Hydro proposes that Newfoundland Power and the Island Industrial's revenue requirements are derived exactly from the cost of service study (Hamilton, page 4), their revenue/cost ratios are by definition 1.0.

The table illustrates several areas where the rates could be improved. First, the isolated systems and L'Anse au Loup Domestic rates remain very far below cost. Some of this is dictated by government decree setting the first blocks of service (below 700 kWh) to Newfoundland Power's rates. Consumption over 700 kWh is not subject to this decree. This promotes inefficient use of electricity in these areas, especially since the marginal cost of serving them is much higher than the costs reflected in this table. The L'Anse au Loup GS 0-10 kW rate is also too low, with the same consequence.

The Labrador Interconnected GS classes above 10 kVA are all being served at far above costs. In the long run, this should also be normalized.

Finally, Isolated Diesel and Isolated Street Lighting classes are too far below cost. The long-run goal should be to reach more reasonable targets, as Mr. Hamilton has said.

I have testified previously before this Board on the importance of minimizing these subsidies. The following table from Paul Hamilton's evidence in this case shows Hydro's long-term targets for the ratio of rates versus costs for customers on the isolated island system:

Domestic	20%
General Service	45%
Government Agencies	100%
Street Lighting	50%

I see no economically justifiable reason for having a long term goal of serving any class of customer at 20%-50% of their cost of service. I recommend that Hydro be required to implement a plan with the Board to begin eliminating these subsidies within the next 5 years. In fact, the Board ordered in its July 29, 1996 "Referral by the Lieutenant Governor in Council Concerning Rural Electric Service" that "preferential rates be phased out. The phase out period should be five years." However, Hydro responded in Response to Information Request NP-151 that it could not change rates without a hearing (rate case), and that this was the first time it had financial reasons to seek one.

Hydro's apparent inability to change rate structure between major rate referrals underlies the importance of the previous discussion on limiting Hydro's proposed changes to the RSP cap which would postpone Hydro's need for review of rates and its potential effect on regulatory control.

Rate Design

Q. What issues do you wish to raise concerning the rate designs Hydro has proposed in this case?

A. Mr. Osmond at page 7 of his evidence, gives the following rate design goals for Hydro: (1) Rate charged to Newfoundland Power and Island Industrials are to be based on the cost of service; (2) Customers in the same class served from the same system, Island or Labrador Interconnected, should pay the same rates; (3) Domestic customers, in Isolated Rural Systems, should pay the Island Interconnected domestic rate for their lifeline block of energy (700 kWh/month); and, (4) Hydro will use certain design measures to reduce the rural deficit.

These goals are appropriate, although a little more speed at achieving the last one would be desirable, from Newfoundland Power's standpoint, although Hydro feels the rate impacts of such a move would be too harsh at this time. A positive first step is the elimination of subsidies to Government departments.

I have examined the rate designs Hydro has submitted and for the most part do not take issue with them, given Hydro's goals above. I should point out that I have not done an exhaustive review of all of Hydro's rate designs, such as the one we did in Newfoundland Power's last rate case.

Demand Energy Rate

Q. You have previously given evidence that Hydro should serve Newfoundland Power on a combined demand/energy rate. Why are you not recommending that in this case?

A. On a number of occasions since the issue first arose, Hydro and Newfoundland Power have attempted, without success, to craft a rate that was acceptable to both companies. While a demand-energy rate is generally desirable in many circumstances, a demand energy rate would have a tendency to create volatility in the earnings of both Hydro and Newfoundland Power from year to year. Because this increased business risk ultimately would be reflected in the utilities' cost of capital, and tends to put upward pressure on consumer rates, measures would be required to moderate this effect. The appropriate means to accomplish this would be a further modification of the existing rate stabilization mechanisms, which would run counter to the desired impact of the new rate structure.

The other alternative would be to expose electricity consumers to greater variability in their rates. In light of past experience, it is anticipated that public reaction to increased variability in electricity rates would be overwhelmingly negative.

Q. Does this conclude your evidence?

A. Yes.