NEWFOUNDLAND POWER INC.

2nd SUPPLEMENTAL TESTIMONY OF

LARRY B. BROCKMAN

NOVEMBER 2001

TABLE OF CONTENTS

1. INTRODUCTION

Q. Please state your name and address.

A. My name is Larry Brockman. My address is 1 Memorial Drive, Suite 1600, Cambridge, Massachusetts.

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

A. The purpose of my additional evidence is to address new evidence provided by Hydro witness Mr. Henderson on the hydraulic production forecast for the test year, and to provide additional evidence I have gathered in regard to this issue.

In addition, I will address certain matters raised in the supplemental evidence of the Industrial Customers' witness Mr. Osler. Specifically, I will comment on the relative allocation of proposed rate increases, and on the allocation of generation demand costs.

2. HYDRO'S TEST YEAR HYDRAULIC GENERATION FORECAST

Q. Please comment on the methods used by Canadian utilities to forecast hydraulic production for use in ratemaking.

A. Mr. Henderson's supplemental evidence may have left the impression that there is a Canadian standard for the number of years of data and the methodology used to forecast test year hydraulic production. I do not believe there is any such standard.

Mr. Henderson stated that the acceptance of my recommendation of a 30-year moving average for test year hydraulic production would be "contrary to the accepted practices of other predominantly hydroelectric power producing utilities in Canada" (page 3, Supplemental Evidence of Robert Henderson).

Mr. Henderson sponsored responses from eight telephone contacts that said they used the full historical reliable record of inflows to determine forecast hydraulic production. However, Mr. Henderson admitted that the survey did not specifically query the companies on the methods they used to prepare hydraulic forecasts for ratemaking purposes (Transcript, October 9, 2001, page 27, lines 50-84).

Furthermore, two of the contacts are not utilities, and Hydro Quebec was contacted twice, which reduces the sample of Canadian utilities to five. These were B.C. Hydro, SaskPower, Manitoba Hydro, Ontario Power Generation, and Hydro Quebec.

In an attempt to determine the ratemaking practices accepted by the utilities' regulators, both Newfoundland Power staff and a member of my staff separately contacted the utilities that Mr. Henderson had surveyed. Unfortunately, in several instances the responses we obtained from the utilities were inconsistent. In other cases, the personnel contacted indicated they were not certain what methodology was approved for ratemaking purposes.

We also contacted Nova Scotia Power and New Brunswick Power, Canadian utilities with hydro capabilities that were not included in Mr. Henderson's survey.

According to its Rate Department, Nova Scotia Power bases its hydraulic production forecasts, both for business planning and ratemaking purposes, on data from the previous 5 years. Exhibit RH-5 shows that hydraulic production was only 8% of Nova Scotia Power's total generation in 2000. However, because shortfalls in hydraulic production are replaced by increasing thermal production, and because Nova Scotia Power does not have an RSP, a significant forecast error in hydraulic production can have a significant financial effect on the company. Hydro, on the other hand, is shielded by the RSP from the risk of immediate financial impacts from errors in their hydraulic production forecast.

New Brunswick Power reported using the median value, rather than the simple mean used by Hydro, for forecasting hydraulic production. We obtained from the New Brunswick Board of Commissioners of Public Utilities an excerpt from New Brunswick Power's evidence filed during their last general rate proceeding, in 1993. The evidence stated that "average water conditions are determined on the basis of a 35 year historical period, the computation of which is reviewed periodically." Exhibit RH-5 shows that New Brunswick Power produced 2,373 GWh of hydraulic production in 2000, comprising 16% of their total generation. At the time of their 1993 rate proceeding, New Brunswick Power had a Generation Equalization Account similar to the RSP; but it is my understanding that this account was eliminated in 1997.

Q. Please summarize what you conclude from Mr. Henderson's survey, the follow-up calls, and the information you reviewed?

A. From all of this information, I can discern no Canadian standard for either the number of years or the methodology used for forecasting hydraulic production for ratemaking purposes. Mr. Henderson stated that all of the utilities he contacted use all the reliable data available to them. However, from the information I have been able to obtain, it appears that the number of years of data used by each utility varies considerably.

Hydro uses the simple mean (or average) in developing their hydraulic production forecast; this cannot be viewed as an accepted standard. Other Canadian utilities use the median (Transcript, October 9, page 27, lines 46-49). Hydro's response to Request for Information NP-204 shows that the use of the median would increase Hydro's hydraulic production forecast for the test year; the result would be a reduction in revenue requirement of more than $1 million.

Q. Do you believe it is necessary for Hydro to use the same number of years and the same method for calculating hydraulic production for ratemaking purposes as they use for planning and operations?

A. No.

I see no reason to link ratemaking, planning, and operations in that way. In fact, I see good reasons not to. Hydraulic systems are usually planned to meet energy requirements in the driest years. This is a reliability consideration that ensures continuous supply during years of drought. It is prudent to be more conservative in planning hydraulic systems than in forecasting production for ratemaking purposes, because the effects of occasionally being wrong in ratemaking are reversible (particularly with the existence of an RSP), while the effects of being wrong in planning are more severe.

For this reason, Hydro already uses a different hydraulic forecast methodology for system planning than for operations planning. Hydro's forecast of annual hydraulic firm energy production for system planning purposes is more conservative than their forecast of hydraulic production for operating purposes.

The purpose of a test year forecast is to approximate the financial conditions that will occur in the test year, so that rates can be set to recover the resulting revenue requirement. The estimation of expected generation in the test year is, to some degree, a judgment call. While it is unlikely that a forecast of the test year hydrology will be precise, the use of the median, rather than the simple mean as proposed by Hydro, would at least give an expectation of being high half the time and low half the time.

Q. Please comment on the possible impact on system operations of using a 30-year average to determine the hydraulic production forecast for setting rates.

A. Under cross-examination by Counsel for Newfoundland Power, Mr. Henderson testified that any impact would come from price elasticity effects, and he acknowledged that it would be small (Transcript, October 10, page 6, lines 50-51).

Other than this minimal impact, Hydro has offered no evidence to indicate that the use of a 30-year moving average would negatively affect the operation of the power system.

3. RELATIVE ALLOCATION OF PROPOSED INCREASES

Q. What are your comments on the relative allocation of proposed increases as addressed by Mr. Osler?

A. The proposed increases for Newfoundland Power and the Industrial Customers have been determined based on the results of the 2002 Cost of Service Study. Hydro's approach in making these determinations is consistent with their past practice in regulatory proceedings before this Board.

Mr. Osler indicated in his evidence that he expected the proposed rate increase to Newfoundland Power to be higher than that proposed for Industrial Customers. However, Mr. Osler appears to have overlooked the fact that the Industrial Customers have received several decreases in rates relative to Newfoundland Power since 1992.

Exhibit LBB-5, based on information provided in Hydro's response to Request for Information NP-24, shows the increases in the base rates of Newfoundland Power and Industrial Customers from 1992 to present (excluding rate changes resulting from annual RSP adjustments and the HST adjustment that occurred in 1997). As the exhibit shows, Newfoundland Power's base rate has not changed since 1992. Hydro is now proposing to increase the base rate to Newfoundland Power by 6.4% to bring it in line with the results of the current cost-of-service study.

The Industrial Customers, on the other hand, have had 3 decreases in base rates since 1992: a 6% decrease in 1993, a 2.3% decrease in 1994 and a 10.7% decrease in 2000. The cumulative effect of these rate decreases is that the current base rates for Industrial Customers are 18% lower than the base rates set in 1992. The proposed increase for 2002 for Industrial Customers is 10.0%. If the proposed increase is approved, the base rates for Industrial Customers will be only 90.2% of the base rates set in 1992. By comparison, the base rate proposed for Newfoundland Power is 106.4% of the base rate established in 1992.

The relative spread between the base rates proposed to be charged to Newfoundland Power and the Industrial Customers has thus widened by 16.2% since 1992. Mr. Osler was correct that the spread between the rates for Industrial Customers and Newfoundland Power should have widened since 1992, and with the downward rate adjustments for Industrial Customers since 1992, this is in fact what has transpired.

Q. Are there any other significant items that help explain the relative allocation of proposed increases?

A. Yes.

The cost of No. 6 fuel, which is classified as an energy cost in the cost-of-service study, has increased significantly since the last cost-of-service study was approved for setting rates in 1992.

Because they have a higher load factor, the Industrial Customers are allocated a higher percentage of system energy costs than of system demand costs (approximately 23% and 15% respectively); while Newfoundland Power is allocated a higher proportion of demand costs than of energy costs (approximately 78% and 71% respectively). These percentages are taken from Exhibit JAB-1, Rev. 2, page 38 of 94.

The end result is that approximately 69% of the costs assigned to the Industrial Customers are energy-related, as compared to Newfoundland Power, whose total assigned costs are 56% energy-related. These percentages are derived from Exhibit JAB-1 Rev. 2, page 16 of 94.

Because energy costs make up a larger percentage of the total costs for Industrial Customers, an increase in the cost of No. 6 fuel will have a greater impact on them than on Newfoundland Power. Conversely, if the cost of No. 6 fuel declines, the Industrial Customers will benefit more than Newfoundland Power.

The price of oil has plummeted recently, due to continued weakness in the economy and OPEC's apparent inability to maintain production caps. If oil prices continue to drop, it is conceivable that the required increases to Industrial Customers will be less than proposed. Incidentally, this could also result in a circumstance where Hydro might rethink their proposal to raise the retail RSP cap.

4. ALLOCATION OF GENERATION DEMAND COSTS

Q. Do you agree with Mr. Osler's recommendation that the Board use a 1 CP demand allocator for generation demand costs.

A. No.

Mr. Osler, at page 17, line 25 of his supplementary evidence, says that "there is likely benefit to retaining the current 1 CP allocator" for the allocation of generation demand costs. It is true that the single highest actual peak on the system determines the amount of actual generation capacity called upon in that year. However, a single peak per year is not what determines the timing of generation additions under Hydro's LOLH planning criteria.

Q. Please explain why the single highest peak is not what determines the timing of generation additions under an LOLH planning criteria.

A. There are two general indicators that utilities use to determine when new generation capacity needs to be added to the system. The first, and the most simple, indicator is reserve margin. In reserve margin planning, the generation utility maintains a target reserve of generation capacity in excess of its actual capacity requirements. When load growth reduces the reserve margin, additional capacity is added to restore the margin.

The other indicator commonly used in capacity planning is Loss of Load Hours (LOLH). LOLH is the forecast of the expected number of hours during the year when there is insufficient generation available to serve the load.

A software package calculates, for each hour of the year, the probability of losing load as a result of load requirements exceeding generation. The probabilities for each hour are summed to obtain the annual number. For example, if 7,760 hours during the year have a zero probability of loss of load, and the remaining 1000 hours have a 1% probability, the LOLH for the year would be 10 hours (7,760 × 0% + 1000 hours × 1%).

In reality, there is some probability that load will exceed generation during each hour of the year. For example, a number of generating units could fail simultaneously. For hours when load is low, the probability of losing load is also low; while peak load hours have much higher probabilities of loss of load. However, all hours contribute something to the annual LOLH. According to Hydro witness Mr. Budgell, Hydro plans to add new capacity when the cumulative LOLH exceeds 2.8 hours per year (Evidence of Hubert Budgell, page 8).

Hydro's evidence in this proceeding indicates that approximately 60% of the Loss of Load Hours are attributable to hours in the month of February. The month of January is responsible for another 23%. The months of December and March contribute another 16.4%. These figures are based on Hydro's 2002 LOLH study, found in the response to Request for Information CA-19. Each of these months is important in planning the addition of generation; although some are more important than others. In reality, loads that occur in months other than February have a higher causality than this simple study indicates because, historically, many peaks have occurred in months other than February.

In other words, over 40% of the causality of adding generation capacity is attributable to months other than February. Hydro is unable to predict in which month the peak, and therefore the highest LOLH, will occur. Consequently, the 1 CP method cannot accurately capture causality, or a fair allocation of generation demand related costs, for Hydro. Causality can most effectively be captured using the Multiple CP method of demand cost allocation.

Q. Does this conclude your evidence?

A. Yes.

Comparative Increases in Rates for Newfoundland Power and Industrial Customer
1992 to Present

	Industrial Customers		Newfoundland Power	
Year	**% Rate Change**	**% of 1992 Rates**	**% Rate Change**	**% of 1992 Rates**
1992	0.0%	100.0%	0.0%	100.0%
1993	-6.0%	94.0%	0.0%	100.0%
1994	-2.3%	91.8%	0.0%	100.0%
1995	0.0%	91.8%	0.0%	100.0%
1996	0.0%	91.8%	0.0%	100.0%
1997	0.0%	91.8%	0.0%	100.0%
1998	0.0%	91.8%	0.0%	100.0%
1999	0.0%	91.8%	0.0%	100.0%
2000	-10.7%	82.0%	0.0%	100.0%
2001	0.0%	82.0%	0.0%	100.0%
2002 Proposed	10.0%	**90.2%**	6.4%	**106.4%**
	Relative change			**16.2%**