<u>IN THE MATTER OF</u> the *Electrical Power Control Act, 1994* (the "EPCA") and the *Public Utilities Act,* R.S.N. 1990, Chapter P-47 (the "Act") and their subordinate regulations; and

IN THE MATTER OF an Application by Newfoundland and Labrador Hydro ("Hydro") for approvals of: (1) Under Section 70 of the Act, changes in the rates to be charged for the Supply of power and energy to its Retail Customer, Newfoundland Power, its Rural Customers and its Industrial Customers; (2) Under Section 71 of the Act, its Rules and Regulations applicable to the supply of electricity to its Rural Customers; (3) Under Section 71 of the Act, the contracts setting out the terms and conditions applicable to the supply of electricity to its Industrial Customers; and (4) Under Section 41 of the Act, its 2002 Capital Budget.

<u>FINAL SUBMISSION OF INDUSTRIAL CUSTOMERS</u>

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I N D E X

PART 1:

INTRODUCTION

The Industrial Customers' in their opening statement, set forth the issues which the Board will need to address in making its final decision with respect to this matter. While the hearing process has been lengthy and the issues complex, it is clear that there are many contentious issues upon which the Board will have to decide, which have significant cost consequences for all of Hydro's customers.

Collectively, the Industrial Customers represent in excess of 16% of Hydro's annual sales. As a group, they employ close to 3,000 Newfoundlanders and their combined annual payroll is in the vicinity of $150,000,000.00. They are being asked, in 2002, to pay total costs in excess of $50,000,000.00.

The Industrial Customers are businesses. They sell their products in international markets in which they cannot, either individually or collectively, affect the price at which their product sells. They also compete within their own corporate groups for work and for capital dollars. Their ability to continue to create economic activity in this Province depends upon their ability to produce a product at a cost which allows them to be competitive in world markets. If the gap between their costs and the price dictated by the market does not produce a sufficient return on the investment by the shareholders of these companies, they cannot continue to operate. All of Hydro's Industrial Customers are bottom-line operations.

Continued reliability of Hydro's service is a vital part of what the Industrial Customers and others require. Interruption of electrical service is inconvenient to everyone, but to those who rely on power for industrial purposes, the consequences of an interruption can be devastating, involving both loss of product and to process, damage to equipment and long periods of down time to reset equipment, resulting in loss of production, loss of profit and damaged reputation in the market place. This fact needs to be considered in all of the discussion on cost reduction.

The issues before the Board can be classified into three categories:

1. Revenue requirement issues;
2. Cost of service issues;
3. Rate issues.

In addition, there are issues relating to the impact of legislative change and the issue of whether the Industrial Customers should, like every other major participant in this hearing, be entitled to recover their taxed costs.

The evidence of Melvin Dean and Jay Backus from Abitibi Consolidated Company of Canada underscores the potential negative impact of Hydro's proposed 17% increase in the cost of power purchased by the Industrial Customers.

In addition, the evidence that Hydro's proposed increases to the Industrial Customers will be approximately 17% while the net increase to Newfoundland Power's customers, after July 1, 2002, will be approximately 7%, indicates that there is much more to do in this rate hearing than analyze Hydro's proposed costs. As will be demonstrated herein, Hydro's reallocation of costs between its customers and policy changes, have shifted a disproportionate share of Hydro's revenue requirement to its Industrial Customers.

LEGISLATIVE FRAMEWORK

Since Hydro's last rate hearing in January, 1992, there have been several legislative changes affecting both Hydro and the Industrial Customers.

Section 3 of the **Electrical Power Control Act, 1994**[1] ("EPCA 1994") sets out the power policy of the Province. While there are several changes since 1992, two fundamental provisions remain unchanged. Sections 3(a)(i) and 3(a)(ii) provide:

> "3. It is declared to be the policy of the province that
>
> (a) the rates to be charged, either generally or under specific contracts, for the supply of power within the province
>
> (i) should be reasonable and not unjustly discriminatory,

[1] **Electrical Power Control Act, 1994** S Nfld. 1994, c. E-5.1 s. 3.

> (ii) should be established, wherever practicable, based on forecast costs for that supply of power for 1 or more years."[2]

Several provisions of the provincial power policy are new and have a bearing on this hearing. In particular, the EPCA 1994 now provides in section 3(b)(i) - (iii) as follows:

> "3. It is declared to be the policy of the province that
>
> (b) all sources and facilities for the production, transmission and distribution of power in the province should be managed and operated in a manner
>
> (i) that would result in the most efficient production, transmission and distribution of power,
>
> (ii) that would result in consumers in the province having equitable access to an adequate supply of power,
>
> (iii) that would result in power being delivered to consumers at the lowest possible cost consistent with reliable service."[3]

In other words, in looking at Hydro's plans, the Board must consider whether the proposals result in the most efficient production, transmission and distribution of power from all sources and facilities in the province. In addition, the management and operation of those sources and facilities

[2] ibid, s. 3(a)(i) & c(a)(ii).

[3] ibid, s. 3(b)(i), (ii), (iii).

in the province should result in power being delivered to consumers, including the Industrial Customers,[4] at the lowest possible cost consistent with reliable service.

As will be discussed in the part of this submission dealing with Capital Structure and rate of return, the power policy of the province insofar as it relates to the profit which Hydro is entitled to include in its rates, has also changed.

Section 3(c) of the EPCA, as it existed prior to 1994, (the "old EPCA") provided:

> "It is declared to be the policy of the province that the rates to be charged, either generally or under specific contracts, for the supply of power within the province
>
> (c) should provide sufficient revenue to the supplier of the power to enable it
>
> (ii) in the case of the hydro corporation, to recover the cost of service provided by it and a margin of profit sufficient to achieve and maintain a sound financial position
>
> so that it is able to achieve and maintain a sound credit rating in the financial markets of the world."[5]

The EPCA, 1994 now provides with respect to Hydro's profit as follows:

> "3. It is declared to be the power policy of the province that

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[4]ibid, s. 2(c) "'Consumer' means a person purchasing power from a retailer for the use of that person & not for resale."

[5]**Electrical Power Control Act**, RS Nfld. 1990 c. E-5

> (a) the rates to be charged, either generally or under specific contracts, for the supply of power within the province
>
> (iii) should provide sufficient revenue to the producer or retailer of the power to enable it to earn a just and reasonable return as construed under the **Public Utilities Act** so that it is able to achieve and maintain a sound credit rating in the financial markets of the world."[6]

The only change effected in 1994 was the deletion of the words "in the case of the hydro corporation, to recover the cost of service provided by it and a margin of profit sufficient to achieve and maintain a sound financial position" and the substitution of the words "to earn a just and reasonable return as construed under the **Public Utilities Act**".

In both provisions, the guiding principle is that the rate of return enable Hydro to achieve and maintain a sound credit rating in world financial markets.

Further guidance is found in Section 80(1) of the **Public Utilities Act** which provides:

> "80(1) A public utility is entitled to earn annually a just and reasonable return as determined by the board on the rate base as fixed by the board for each type or kind of service supplied by the public utility . . ."[7]

This tells us that the return to be set by the Board is the just and reasonable return on rate base which will enable Hydro to achieve and maintain a sound credit rating in world financial markets

[6]**EPCA, 1994**, supra, s. 3(a)(iii).

[7]**Public Utilities Act**, RS Nfld. 1990, c. P-47, s. 80(1).

as provided in s. 3(a)(iii) of the EPCA, 1994 while resulting in rates "at the lowest possible cost consistent with reliable service" as required by s. 3(b)(iii) of the EPCA, 1994.

An additional change to the legislative framework is the change in the Board's jurisdiction over Hydro and its rates.

At the time of the 1992 hearing, section 21 of the **Hydro Corporation Act** provided that, notwithstanding the **Public Utilities Act**, the Board "has no jurisdiction over the corporation."[8] Section 21 of the **Hydro Corporation Act** was repealed in 1995.[9]

In 1992, the Board's jurisdiction over Hydro was found in Sections 8 - 17 of the old EPCA. These sections required that Hydro refer proposals for rates to be charged to its rural and retailer customers to the Board for investigation and a public hearing. However, the Board's report was not binding on Hydro and required the final approval of the Lieutenant-Governor in Council.[10]

In 1992, the only provision relating to Industrial Customers was Section 17(2) of the old EPCA which provided:

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[8] **Hydro Corporation Act**, R.S. Nfld. 1990, c. H-16, s. 21.

[9] **Hydro Corporation (Amendment) Act**, S. Nfld. 1995 c. 37, section 7.

[10] **EPCA** R.S. Nfld. 1990 c. E-5, s. 8 - 17.

> "17(2) Where the hydro corporation supplies power to a user who is neither a retailer nor a rural customer, the hydro corporation shall use its best endeavors to obtain for that power the rates or a class of rates that would be compatible with the power policy declared by section 3."[11]

Clearly this provision entitled Industrial Customers to rates which were reasonable and not unjustly discriminatory and based on forecast costs.[12] It also required that the profit incorporated in industrial rates be on the same basis as that in the rural and retailer customer rates.[13]

The provisions of the old EPCA were repealed with the enactment of the **EPCA 1994.**[14]

The result of the above is that, effective December 21, 1995 the Board had full authority with respect to Hydro's rates, including its industrial rates, subject to specific provisions to the contrary.

The legislative scheme effective December 21, 1995 contained several transitional provisions which are also relevant in this hearing as set forth in Sections 17, 18 and 19 of the **Hydro**

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[11]ibid s. 17(2).

[12]ibid s. 3(a) (i) & (ii).

[13]ibid s. 3(c).

[14]EPCA, 1994, supra, s. 35.

Corporation Act, as amended.[15] The most important provisions in this regard provide that Hydro shall

1. Adopt and maintain the rate stabilization plan of the corporation on the basis reflected in the audited financial statements of the corporation for the year ended December 31, 1994 until the Board of Commissioners of Public Utilities otherwise orders under the **Public Utilities Act** (Section 17).[16]

2. For all purposes of the **Public Utilities Act**, the expenses chargeable to the operating account by the corporation shall include all amounts paid by the corporation for non-utility generation totaling approximately 38 megawatts under agreements entered into with up to 4 persons that submitted proposals under the corporation's Request for Proposals, which expenses shall be considered to be reasonable and prudent and properly chargeable to operating account for all purposes of the **Public Utilities Act**, including subsection 80(2) of that Act (Sections 17(3)(c) and 17(4)).[17]

3. The rates, tolls and charges for, and the rules applicable to each kind of service provided or supplied directly or indirectly to the corporation immediately prior to January 19, 1996 shall apply to the same kind of service so provided or supplied by the corporation until

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[15]**Hydro Corporation (Amendment) Act**, S. Nfld. 1995 c. 37, s. 7.

[16]ibid

[17]ibid

altered under the **Public Utilities Act** and, notwithstanding that Act, no alteration shall have retroactive effect on those rates, tolls or charges or increases, including by providing for refunds or credits to customers. (Section 17(5)).[18]

4. The capital budget of Hydro for the period ending December 31, 1996 and any other construction work in progress as approved by the board of directors of Hydro, shall be considered to be approved by the Board under section 41 of the **Public Utilities Act** and for all purposes of that Act, in respect of Hydro (Section 17(6)).[19]

5. Until the Board approves the rules and regulations which relate to Hydro's service under s. 71 of the **Public Utilities Act**, a supply contract between Hydro and its customer is deemed to provide that Hydro "is not liable for damages in respect of any delay, interruption or other partial or complete failure in that supply where those damages are caused by something which is beyond the reasonable control of Hydro". (Section 17(7)).[20]

6. The Lieutenant-Governor in Council can direct the Board with respect to policies and procedures to be implemented respecting rate structures of public utilities under the **Public Utilities Act** including:

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[18]ibid

[19]ibid and Proclamation bringing Act into force, Nfld. Regulation 1/96 dated January 19, 1996.

[20]ibid, Section 17(6), as amended.

(a) direction on the setting and subsidization of rural rates,

(b) the fixing of a debt-equity ratio for Hydro,

(c) the phase-in, over a period of years of a rate of return determination for Hydro.[21]

7. Where the Board believes that a rate or charge is unreasonable or unjustly discriminatory, or that a reasonable service is not provided, the Board may investigate, of its own motion, with or without notice.[22]

PART 2: COST OF SERVICE ISSUES

COST OF SERVICE METHODOLOGY - GENERAL

One issue raised, in particular, by the evidence of the Board's cost of service methodology expert, Dr. John Wilson, is the extent to which the components of the cost of service methodology approved by the Board in 1993 is open for discussion.

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[21] **EPCA, 1994**, supra s. 5.1 as amended.

[22] **Public Utilities (Amendment) Act**, S. Nfld. 1998, c. 29, s. 14.

In its 1993 Report on Hydro's cost of service methodology, the Board recommended that the new cost of service methodology be adopted by Hydro for the purpose of its next rate referral.[23] This hearing is the first rate referral since the 1993 cost of service methodology was approved by the Board. Thus, the 1993 cost of service methodology has yet to be implemented by Hydro.

Part 3 of the 1993 Board Report contains very few interim recommendations. The only interim recommendations are as follows:

1. <u>Recommendation 8</u>: that a 1 CP allocator be approved for interim use in the island inter-connected system and that Hydro present to the Board at the time of its next rate hearing an analysis of the relationship between load factor and system reserve requirement, together with a recommendation regarding the number of peaks on which the CP allocator for generation demand costs should be based;

2. <u>Recommendation 14</u>: that Hydro examine the practicality of attributing system energy losses to rate classes on a time-differentiated basis and report its conclusions as to both practicability and impact on allocated costs at the time of its next rate referral;

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[23] 1993 Board Report, page 77.

3. Recommendation 19: that Hydro's proposed classification of distribution cost be accepted for interim use and that Hydro prepare a revised study of distribution cost for presentation to the Board at the time of its next rate referral;

4. Recommendation 21: that subject to the provisions of Recommendation 19, Hydro's proposed methodology be approved for the Labrador inter-connected and rural isolated systems.[24]

On October 27, 2000, in Board Order P. U. 25 (2000-2001) the Board dealt specifically with the extent to which the 1993 cost of service methodology would be open for change in this hearing.[25]

The order specifically provides that the hearing will be based upon the 1993 cost of service methodology approved by the Board. In addition, in the recitals to the order, it specifically states that the parties present, namely, Hydro, the Industrial Customers, Newfoundland Power and Board counsel, then Randy Pelletier, were consulted about and agreed that this rate referral would be conducted on that basis.[26]

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[24]ibid, pages 74 to 77.

[25]Board Order P. U. 25 (2000-2001)

[26] Ibid, pages 3 & 4 and Transcript, October 11, 2000 Pre-Hearing Conference

The Industrial Customers submit that to the extent that Dr. Wilson's testimony proposes changes to the cost of service methodology in relation to issues which were not "interim" in the Board's 1993 Report, the evidence is not relevant to the issues before the Board and this hearing and should be disregarded.

COMMON PLANT

Assigning the costs of generation, transmission and distribution to the various customer classes is one of the critical elements of applying the Cost of Service Methodology.

For the purpose of determining which plant is "Common" and which should be specifically assigned, Hydro has adopted a well recognized definition of common plant, namely

> "Common Plant" is defined as plant that is of substantial benefit to two or more firm customers, costs for common plant are assigned to all customers of the system."[27]

However, as indicated by Mr. Budgell, Hydro has developed "rules" or guidelines for the interpretation of the term "substantial benefit" in the definition of Common Plant.[28] These rules have evolved over the years as will be discussed. The Industrial Customers submit that, in their

[27]Pre-filed Evidence, H. Budgell, May 31, 2001, page 16

[28]ibid, page 16, lines 26-30 and page 17, lines 1-16.

present form, these rules represent an unreasonable interpretation of the definition of Common Plant.

Each of the cost of service experts was asked to address the meaning of “substantial benefit to two or more customers”.

Each agreed that “substantial benefit” is a benefit which is more than minor or incidental.

Mr. Brickhill, Hydro’s cost of service expert, testified that Hydro’s definition of Common Plant which is utilized in other jurisdictions. Mr. Brickhill testified that a substantial benefit is a material benefit and that it should be more than speculative.[29]

Mr. Brockman also agreed that a generally accepted definition of Common Plant is plant which is of substantial benefit to two or more firm customers.[30] Mr. Brockman also agreed that the overriding principle which the Board has tried to establish is that there be “substantial benefit”.[31]

[29]Transcript, November 27, 2001, page 7, lines 50 to 65.

[30]Transcript, December 3, 2001, page 40, lines 72 to 87.

[31]ibid, page 41, lines 19 to 25.

Mr. Bowman, for the Consumer Advocate, also agreed on cross-examination that an appropriate definition of Common Plant is plant which provides a substantial benefit to two or more customers. Mr. Bowman defined substantial as more than average.[32]

Dr. Wilson, the Board's cost of service expert, agreed. He testified that the definition of Common Plant as plant that is of substantial benefit to two or more customers, is a fairly well recognized definition of Common Plant. He also indicated that there are many instances where direct assignments are made even though more than one customer is served off a particular facility. He would not object to a direct assignment of a line that served two customers simply because it was serving two or more customers. Dr. Wilson testified that if those were the only two customers being served, it would make more sense to assign that and divide it between those two customers than to allocate it as a common cost element.[33]

Mr. Drazen, on December 12, 2001, agreed that the proposed definition of Common Plant as plant which provides substantial benefit to two or more customers is a fairly common definition of Common Plant. However, he agreed with one change, "that it's used or required to be used to serve them." Mr. Drazen also indicated that the word benefit can lead to problems in assigning

[32]Transcript, December 6, 2001, page 15, lines 16 to 32.

[33]Transcript, December 6, 2001, page 44, lines 38 to 56.

costs. He gave the example that if his neighbor puts up a fence to keep his dog in, he may benefit from that. However, Mr. Drazen indicated that he didn't think he should have to pay for it.[34]

This is consistent with the test applied by Mr. Osler in looking at the reasonableness of Hydro's assignment of certain plant as common.[35]

This is the context in which the Board must assess the reasonableness of Hydro's "rules" and the reasonableness of Hydro's proposed assignments of plant to "common".

A. <u>The Rules</u>

The "rules" or guidelines developed by Hydro with respect to assignment of plant are set out in the pre-filed evidence of Hubert Budgell as follows:

> "The following facilities have been assigned as Common Plant:
>
> (a) all of Hydro's production facilities (hydraulic, thermal, gas turbine and diesel);
>
> (b) all of Hydro's transmission and terminal station plant, 66 kV and above, that is of substantial benefit to two or more customers;
>
> (c) all of Hydro's transmission and terminal station plant whose sole function is the interconnection of a generating facility with the system. Transmission and terminal plant in this category have their costs classified on the same basis as the generation that it interconnects; and

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[34] Transcript, December 12, 2001, page 10, lines 60 to 73.

[35] Pre-filed Supplementary Testimony of C. F. Osler, September 12, 2001, pages 47 to 49.

(d) all of Hydro's transmission and terminal station plant that connects a single customer and remote generation or voltage support equipment, that is of substantial benefit to all customers on the grid. For the purposes of this guideline if, under any normal operating scenario, the output of remote generation can be delivered to the 230 kV grid (i.e. in excess of radio load), then the remote generation is considered to be of substantial benefit to all customers and as such the transmission and terminals plant connecting it to the grid would be assigned common.

Specifically Assigned Plant is defined is plant that is of benefit to only one customer. Costs for specifically assigned plant are assigned directly to the benefitting customer."[36]

Mr. Budgell testified that the issue for the Board in terms of assignment is whether there is a substantial benefit to one or more customers. He also agreed that the threshold test for substantial benefit should be the same regardless of the asset. He agreed that you don't change the definition of substantial depending on the asset. He further agreed that the word "substantial" needs to be defined in any event.[37]

Mr. Budgell testified that these are the rules or guidelines that have been adopted by Hydro or which Hydro would like to adopt in its interpretation of the definition of Common Plant.[38]

Mr. Budgell testified that the proposed rules for interpretation of the definition of Common Plant were developed by him in collaboration with two individuals from the transmission planning

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[36]Pre-filed Testimony of H. G. Budgell filed May 31, 2001, pages 16 and 17.

[37]Transcript, November 8, 2001, lines 61 to 89.

[38]Transcript, November 7, 2001, page 1, lines 77 to 90.

section and, in the early stages, someone from the customer services department. They examined previous Board decisions, discussed the rules themselves and developed them. They did not have any discussions with or have any consultants' reports on what appropriate principles would be. They did not check with other utilities in Canada to find out what principles those utilities applied on their systems. However, once the proposed principles or rules were developed they were used by the Hydro parties associated with this hearing in preparation for the hearing, including Hydro's legal counsel.[39]

In its 1996 Report, at page 3, the Board found:

> "The Board recommends that both generation assets and the 138 kV transmission line on the Great Northern Peninsula be assigned on a provisional basis as being of common benefit to all interconnected customers and that sub-transmission costs for lines whose voltage is below 138 kV be specifically assigned. The Board further recommends re-examination of these cost assignment decisions ***and the rules for cost assignment*** at a future hearing."[40] (Emphasis added)

Mr. Budgell testified that the rules contained in his pre-filed testimony in this matter are not the same as those before the Board at the time of its 1992 rate hearing. Those rules are found in his 1992 pre-filed testimony, which was entered as Consent No. 6 in this matter.[41]

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[39]Transcript, November 7, 2001, page 15.

[40]IC 126, 1996 Board Report, page 33.

[41]Consent No. 6, page 13/14.

Hydro’s proposed rule (a) is the same as that which Hydro proposed in 1992 and is one of the rules which the Board, in its 1996 Report, presumably wished to have re-examined at a future hearing.

With respect to rule (a), the Industrial Customers would agree that most of Hydro’s production facilities would have been constructed for and operated for the benefit of all of its island inter-connected customers. However, the Industrial Customers do not agree that “all” of Hydro’s production facilities necessarily are of substantial benefit to two or more firm customers. The Industrial Customers submit that proposed rule (a) does not correspond to the definition of Common Plant adopted by Hydro and by the Board in previous hearings, since it does not express the qualification that the production facilities classified as common would have to be of substantial benefit to two or more customers.

Hydro’s proposed rule (b) is quite different from the rule which was before the Board in 1992 and at the hearing which resulted in the 1996 Report.

A review of Consent 6 indicates that rule (b) as now proposed does not contain the words “or interconnect significant generation facilities of Hydro or of customers to the system” which is found in the 1992 testimony of Mr. Budgell.

From the 1992 principles, it is clear to see that, in relation to transmission and terminal facilities, in the absence of a substantial benefit to more than one customer, Hydro looked for the interconnection of <u>significant</u> generation facilities of Hydro's or one of its customers to the interconnected system.

Rule (c) provides that Hydro's transmission and terminal station plant whose sole function is the interconnection of a generating facility with the system will have its costs classified on the same basis as the generation that it interconnects. This generation may or may not be classified as "common". The Industrial Customers have no difficulty with the rule since it leaves open the question whether that generation provides a substantial benefit to two or more customers.

Hydro's proposed rule (d) is new. Presumably it is intended to replace the last half of the old rule (b) which referred to transmission and terminal facilities 66 kV and above which interconnect significant generation facilities of Hydro or its customers to the system.[42] It is worth noting that the proposed new rule (d) does not refer to "significant" generation facilities of Hydro or its customers. The word "significant" has been eliminated. Mr. Budgell testified that this was because the word "significant" was always problematic to Hydro, being somewhat subjective on what it meant.[43] The second part of the proposed rule (d) attempts a similar objective by trying to deem the meaning of the word substantial in the previous sentence.

[42]Consent 6.

[43]Transcript, November 7, 2001, page 3, lines 58 to 83.

The Industrial Customers submit that the second sentence of Hydro's proposed rule (d) represents an unreasonable interpretation of the requirement of the definition of Common Plant for "substantial benefit".

The Industrial Customers submit that to the extent that Hydro's rules or guidelines are inconsistent with the definition of "Common Plant" that has been adopted by the Board, those guidelines should be rejected.

The Industrial Customers further submit that, notwithstanding the rules or guidelines which the Board may accept at any given point, Hydro's decisions with respect to specific assignments, must still be assessed in the context of a reasonable interpretation of the term "substantial benefit" contained in the definition of Common Plant.

B. Changes in Plant Assignment

Mr. Budgell, in his pre-filed testimony, testified that the fact that remote generation on a number of radial systems can reach the 230 kV grid under normal operating conditions has changed plant assignment.[44]

Bottom Brook to Port-aux Basques

[44]Pre-filed Evidence, page 20, lines 5 to 8.

One of the reassignments involves the 138 kV and 66 kV transmission lines and associated terminal station equipment connecting Newfoundland Power's Port Aux Basques system to the Bottom Brook terminal station. This has been changed from specifically assigned to common.

Under the assignment rules utilized by Hydro in 1992 and, in fact, in 1995, and as discussed above, the transmission and terminal facilities 66 kV and above connecting Newfoundland Power's Port Aux Basques system to the interconnected system, would only be treated as common if it interconnected ***significant*** Newfoundland Power generation facilities. In 1992, the transmission and terminal facilities 66 kV and above linking Newfoundland Power's Port Aux Basques system to the Bottom Brook terminal system was specifically assigned. However, now that Hydro has decided to eliminate the qualification that those generation facilities be significant, Hydro believes that these transmission lines and associated terminal station equipment should be treated as Common Plant.

Mr. Budgell testified that the amount of Newfoundland Power generation in the Port Aux Basques system is 15.8 megawatts. The radial load on the Doyles - Port Aux Basques line at coincident peak is 24.8 megawatts. Thus, at the coincident peak, the amount of generation in the Port Aux Basques system is insufficient to meet the demand.

Mr. Budgell testified that during minimum load conditions, if all the units were operating in Port Aux Basques, 7.12 megawatts might be available.

In addition, the Grand Bay 7.2 megawatt gas turbine is a mobile unit which could be moved by Newfoundland Power and both the Grand Bay gas turbine and the Port Aux Basques diesel unit are standby units.

Mr. Budgell agreed that it is unlikely that you would have minimal load requirements in the Port Aux Basques area at the same time that you needed peaking capacity in the rest of the system. However, if there were minimal load requirements and a generation outage elsewhere in the system that could not be served by Hydro's other generation plant, it might be able to be accessed.

The Industrial Customers submit that while it is possible that Newfoundland Power's generation plant in its Port Aux Basques system could benefit customers other than Newfoundland Power in some limited circumstances, there is no evidence that this generation plant provides a substantial benefit to Hydro's other customers.

Moreover, the Industrial Customers submit that the Doyles - Port Aux Basques transmission line and terminal plant connecting Newfoundland Power's Port Aux Basques system to Bottom Brook was built solely for the purpose of connecting the Port Aux Basques system to the Island interconnected system and cannot, in any sense, be considered to provide a substantial benefit to any of Hydro's customers other than Newfoundland Power.

This re-assignment shifts $94,000.00 in cost to the Industrial Customers.[45]

Great Northern Peninsula

With respect to the Great Northern Peninsula generation and transmission plant, there are three issues: whether the GNP interconnection was prudent, whether the GNP generation meets the definition of Common Plant and whether the GNP transmission meets the definition of Common Plant.

Mr. Osler has, in his supplementary testimony, dealt extensively with an issue of the prudence of the capital expenditure for the GNP interconnection. The Industrial Customers recognize that there is an argument that, as a result of the current legislative regime, the Board may not be able to disallow capital expenditures made prior to December 31, 1996 on the basis that they were imprudent. However, notwithstanding that potential legislative restriction, the Board is still entitled to look at the prudence of the project as one of the factors to be considered in determining whether the generation and transmission plant on the Great Northern Peninsula provides a substantial benefit to anyone other than the Island rural interconnected customers.[46]

[45]IC-181

[46]Pre-filed Supplementary Testimony, September 12, 2001 of C. F. Osler, pages 42 to 46.

The issue of the appropriate assignment of Great Northern Peninsula (GNP) generation and transmission plant cannot be addressed without an understanding of the reasoning of the Board in 1995, the history of Hydro's Island interconnected rural system and isolated system, the treatment of these assets and other similar assets since 1990.

A brief history of rural customers and of what was previously known as Hydro's power distribution district can be found at pages 14 through 22 of the Board's 1990 report.

In short, in 1966 the **Rural Electrification Act** authorizing the formation of Power Distribution Districts was passed. In 1965, the Newfoundland and Labrador Rural Electricity Authority was established and charged with the responsibility of providing for the distribution of power in rural areas within the limits of the funds made available to it by the Provincial Government. In 1967, the then 52 Power Distribution Districts were amalgamated into 4 and the Rural Electrification Authority became the means by which funds from the Consolidated Revenue Fund of the Province were voted to provide grants for capital construction and operating subsidies for the board of trustees of the Power Distribution Districts. In 1971 the 4 districts were combined into the Power Distribution District of Newfoundland and Labrador (PDD). This managed the rural electrification needs in the areas of the Province in which it had responsibility.

It is also important to realize that at various times since 1968 the power distribution district or districts had transferred to Newfoundland Power certain of the distribution systems which had been operated by Power Distribution Districts. Where savings could be achieved by having the investor-owned utility own and operate a section of PDD rural distribution, and where the utility could assure the Public Utilities Board that the assumption of this responsibility was not detrimental to its existing customers, the Government agreed to transfer those sections. These transfers relieved the Government of the responsibility of providing funds for further expenses in these areas.[47] Numerous areas were transferred as wet out in the Board's 1990 Report.

The PDD also became responsible for the isolated diesel systems on the Island and in Labrador. In 1990, the largest isolated system was the Roddickton/St. Anthony system having a total installed generation capacity of 18.3 megawatts.

In its 1990 Report, the Board quoted the following from its 1979 Report:

> "It is clear that PDD was created to continue the work of the Newfoundland Power Commission in providing electricity to rural areas as a social service where it would be uneconomic for investor-owned utilities to extend services and that the rates charged were chosen with some regard for ability to pay.
>
> There was one overriding flaw in the PDD rate policy - its rate structure bears little clear relationship with its cost structure."

The Government fully subsidized the PDD every year until March 31, 1989. In the period 1989 to 1991 the Government phased out the subsidy and transferred the responsibility for the deficit to

[47] 1990 Board Report, page 18.

Hydro's customers. In 1989 the subsidy was $30.94 million. At the time of the Board's 1990 Report it was expected to grow to $46.274 million by 1992.[48]

At the 1992 rate hearing, Hubert Budgell, on behalf of Hydro, proposed that all facilities associated exclusively with the transmission system 66 kV and above and previously specifically assigned as Hydro Rural Interconnected be classified as Common, generation and transmission; that terminal stations 138 kV and below associated exclusively with distribution and previously classified as Hydro Rural Interconnected be classified as Common; that certain transformers previously classified as Hydro Rural Interconnected be treated as Common; and that the diesel generators and transformer T3 at Hawkes Bay previously classified as Hydro Rural Interconnected be classified as Common Plant.[49]

The Board addressed this proposal in its 1992 rate referral decision filed April 4, 1992 at page 64 where it stated:

> "The reclassification of plant formerly specifically assigned to common plant, results in an increase in cost to NP in the 1992 cost of service study of $1,056,000.00.
>
> NP argued that the interrelationship of this 'common' plant has not changed. The only change since 1989 has been the name change from power distribution district (PDD) to Hydro rural. As in the past, NP and the industrials derive no benefit from this plant, just as other Hydro customers derive no benefit from the line serving only NP's customers in the Port Aux Basques area.

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[48]ibid page 23.

[49]Consent 6, pages 14 and 15.

> CONCLUSION
>
> The Board is not convinced that Hydro's proposal is fair and will not accept the proposed classification at this time."[50]

The issue was raised again at the 1993 cost of service methodology hearing. The Board stated:

> "When the Electrical Power Control Act was amended to eliminate the PDD, all its customers, numbering more than 26,000, became customers of Hydro. For purposes of rate design, Hydro divided these customers into numerous classes according to the size and nature of their loads. Under its proposed cost of service methodology, Hydro then treated the transmission lines serving the former PDD as Common Plant and allocated the costs between all customer classes. . . .
>
> However, the Board is not persuaded that the conversion of Rural Customers from one class to several should result in changing the costs allocated to NP and IC. . . . The Board considers that the cost of transmission lines dedicated to the service of Rural classes be included in a sub-transmission function and allocated to such classes. The principle that costs should be allocated to classes only for the facilities used by such classes would justify a second sub-transmission function for common lines used by NP and IC but not by Hydro Rural, provided the costs relating thereto were significant."[51]

The next time the issue arose was in the Board's 1995 Report. By MC93-0432, the Lieutenant-Governor in Council asked the Board to review the cost of service, funding options, structure of rates, views of interested parties, Canadian electrical pricing practices and measures to limit

[50] 1992 Board Decision, Consent 7, page 64.

[51] 1993 Board Report, pages 11 to 15.

electrical usage relating to rural electricity services in the Province. The Board's report in relation to that inquiry was filed October 10, 1995.[52]

At the time of the 1995 hearings, a St. Anthony/Roddickton interconnection had not yet been completed. However, Newfoundland and Labrador Hydro proposed to treat the generation assets as common and transmission plant as specifically assigned through use of a sub-transmission function. Lines of a lesser voltage running from the 138 kV line were also to be specifically assigned.[53]

The Board ultimately concluded:

> "The Board is not convinced sufficient evidence has been provided to conclude whether or not the assignment of generation assets and transmission lines should be common. Newfoundland and Labrador Hydro has warned that if the assignment rules are applied differently, the results may not be consistent with the treatment afforded in similar circumstances elsewhere in the interconnected rural system. However, the Board is struck by the inconsistency in the proposed treatment whereby Newfoundland and Labrador Hydro treats generation assets as common but the related transmission line is treated as specifically assigned.
>
> The Board proposes provisional acceptance of a cost assignment for generation plant whereby it is treated as common, since it will benefit grid customers generally. The Board proposes that for lines located on the Great Northern Peninsula of voltage less than the 138 kV transmission line, transmission costs be assigned through a sub-transmission function to interconnected rural customers. However, the Board believes that assignment of the 138 kV transmission line

[52] CA2 (A).

[53] 1995 Board Report, page 40.

> should be the same as the associated generation assets. On this basis, the Board proposes, on a provisional basis, that this line be treated as common."[54]

The Industrial Customers submit that two clear messages emerge from these conclusions:

1. The Board was not convinced that there was sufficient evidence to conclude whether or not the assignment of generation assets and transmission lines should be common; and

2. The Board was concerned by the inconsistency in the proposed treatment of generation assets as common but related transmission line as specifically assigned.

The Board's 1996 Report did not arise out of a new hearing. It was a revised report to cover rates, cost of service, the views of interested parties and electrical pricing practices as measures to limit electrical usage. However, the Board provided a summary report on a number of issues, including the cost of service issues dealt with it at length in its 1995 Report, without changing the recommendations. This includes the provisional acceptance of the assignment of Great Northern Peninsula generation and 138 kV transmission is common.

The Industrial Customers submit that the explanation for the provisional acceptance contained in the 1995 Report and as summarized above, remained the rationale for the 1996 repeat of the recommendations.

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[54]ibid, pages 43 to 44.

Mr. Osler, for the Industrial Customers, specifically addressed the issue raised by the Board in its 1995 Report with respect to treating generating plant as common while treating the transmission connecting it to customers as specifically assigned. Mr. Osler testified there is no necessary inconsistency with the treatment of GNP transmission being specifically assigned to Rural and the GNP generation being of common benefit. He stated further that it is necessary to look at the specifics in each instance for the transmission as well as for the generation assets. He concluded, based on the available information, that specifically assigning GNP transmission plant to Rural remained reasonable even if GNP generation plant is treated as common.[55]

Great Northern Peninsula Generation Plant

Mr. Budgell testified that all of the generation on the Great Northern Peninsula north of Deer Lake was originally constructed to serve isolated rural systems. Although the Hawkes Bay diesel was added to the system after interconnection, Mr. Budgell testified that it was installed for the purposes of the Great Northern Peninsula interconnected system for voltage support at the end of the long line and for emergency generation in the event that the line was interrupted.[56] He also testified that in the absence of voltage support to boost voltage and to bring voltage down in light

[55]Pre-filed Supplementary Testimony of C. F. Osler, September 12, 2001, page 49, lines 4 to 11.

[56]Transcript, November 7, 2001, page 38.

load conditions, Hydro would not be able to maintain adequate voltage to its Hydro Rural customers.[57]

Furthermore, as emergency generation, the generation in place on the Great Northern Peninsula can be used to provide service to at least some of Hydro's rural customers if there is a problem with the transmission line.[58]

Those units at Hawkes Bay, St. Anthony and Roddickton are now used primarily to provide voltage support and emergency service to Hydro's rural customers. Moreover, voltage support is needed at the end of the line on the Great Northern Peninsula, and the generation when it is on, can provide voltage support. Mr. Budgell further agreed that Hydro would normally install diesel or gas turbine generation for peaking capacity close to the load center.[59]

With respect to GNP demand, Mr. Budgell testified that the radial load at coincident peak on the Great Northern Peninsula is 33.63 megawatts. The radial load in minimal load conditions would be 11.77 megawatts. The result is that even if all of the units on the Great Northern Peninsula were operating, in order to provide any benefit to Hydro's other customers, even in minimal load conditions, the number of megawatts available would be 3.4.

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[57] ibid, lines 70 to 83.

[58] ibid, lines 84 to 94.

[59] ibid, page 39.

Mr. Budgell further confirmed that the primary function of the Hawkes Bay diesel and the St. Anthony/Roddickton diesel units since interconnection has been as standby plant.

In answer to IC-115, with respect to the mobile diesel unit in Roddickton, Hydro has only operated it for testing and has produced a negligible amount of energy since 2000.

In IC-125, the Industrial Customers asked Hydro which customer classes benefitted from the interconnection and how each benefitted. The answer referred only to Hydro rural customers.

In IC-147, Hydro indicates that the Hawkes Bay diesels had been used to maintain acceptable voltages to Hydro rural customers during scheduled or forced outages and that prior to 1990, the Hawkes Bay diesels were used regularly to maintain acceptable voltage to Hydro rural customers. It was used once to supply generation requirements for the entire system on January 2, 1996 when it would have been assisting to meet peak load on the Great Northern Peninsula as well.

Hydro's answer to IC-147 clearly demonstrates that although the plants on the Great Northern Peninsula have been utilized on numerous occasions since 1992, there have been only two occasions since 1990 when any of the generation on the Great Northern Peninsula was used for peaking capacity.[60]

[60]Transcript, ibid, page 40 to 41.

The answer to IC-147 shows that of the 114 occasions since 1996 when the St. Anthony, Roddickton and Hawke's Bay diesel units have been used, on only one of those occasions was it used to help meet peak. That unit was the Hawke's Bay diesel. The evidence is that the Roddickton and St. Anthony units have never been used to meet system peak. This is totally out of proportion to the costs of operating these units which is also shown in IC-147.

In his supplementary testimony, Mr. Osler stated on page 41, footnote 82: "Based on what has been provided by Hydro, the Island interconnected system would appear to have better reliability and lower LOLH in the key winter months if the GNP project was not undertaken. This conclusion is based on the fact that the firm generation on the St. Anthony Roddickton system is lower than the St. Anthony Roddickton peak loads in all but the lowest use months (IC-215)". In other words, during the critical winter months, it appears that the GNP region is unable to provide sufficient firm demand to supply the local load, and that the GNP impact is therefore likely to result in a higher overall Island interconnected LOLH.

The Industrial Customers submit that this evidence in relation to the generation plant north of Deer Lake proves that such generation plant does not provide a substantial benefit to Newfoundland Power or to the Industrial Customers. It should, therefore, be specifically assigned to Hydro's rural interconnected customers.

Mr. Osler does indicate that it may be reasonable to accept on a provisional basis that the GNP generation be maintained and allocated as Common Plant. He qualifies the recommendation by saying that once the Granite Canal Project has been placed in service, and Hydro has completed the required study, consideration should be given to whether the GNP generation continues to be useful overall (and for the non-GNP customers) and whether it should be removed from rate base or should be assigned solely to rural customers.[61] This would increase the Island interconnected revenue requirement in 2002 by $600,000.00 compared to direct specific assignment to Hydro Rural interconnected.[62] He does not suggest that it provides a substantial benefit to the system.

GNP Transmission

With respect to transmission, Mr. Osler recommended that the Board adopt the following test with respect to treatment of radial transmission lines as common or specifically assigned:

> "Following a new interconnection to the Island interconnected system, allocation of new radial transmission lines and terminal stations to Common under the COS methodology should be used only when the addition of the combination of: (1) the radial firm generation capacity, and (2) the radial firm loads (including losses), onto the Island interconnected system results in a benefit to the Island interconnected LOLH in the key winter months. Otherwise, new radial transmission lines and terminal stations should be specifically assigned to rural interconnected.
>
> In addition, the total amounts to be allocated to Common after a new interconnection should not in any event result in costs to previously interconnected customers that are greater than the costs that would have to be incurred to achieve the equivalent LOLH improvement under the least cost scenario (i.e. with low cost peaking until instead of the interconnection being considered)."

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[61]ibid, page 48, lines 19 to 24.

[62]ibid, lines 9 to 10.

The Industrial Customers support that recommendation.

The circumstances, today, with respect to the assignment of Great Northern Peninsula generation plant and transmission plant as common instead of specifically assigned is quite different than that at the time of the 1995 hearing as a result of the elimination of any contribution by the Industrial Customers to the Rural deficit. This is summarized by Mr. Osler in his evidence as follows:

> “In rough terms, when this issue was considered in a preliminary way in 1995, the allocation of the GNP interconnection costs to common versus rural interconnected would have resulted in relatively small differences in the final revenue requirement assigned to each interconnected customer class due to the allocation of the rural deficit to both NP and IC. Today, however, the magnitude of the impact from different COS approaches to very material to the different customer classes (see IC-87 Revision 1 which shows that the impact on IC of assigning the GNP to common versus specifically assigned to rural is over 1.5 million dollars annually, or approximately one-third of the IC firm rate increase being sought by Hydro).”

The Industrial Customers submit that GNP transmission should be specifically assigned to Hydro’s Rural Interconnected Customers.

<u>FREQUENCY CONVERTERS</u>

What Hydro may wish to regard as simply a plant assignment issue-the treatment of frequency converters-in fact illuminates the entire history of the development of electric power and the vital role which Industrial Customers have played in that development.

The historical record is reflected in a number of documents, several of which have been produced in response to IC-56 and IC-219. Looking initially at the Preliminary Report on Integration of the Bay D'Espoir Power Development and Existing Power Systems into a Newfoundland Network prepared by The Shawinigan Engineering Company Limited for the Newfoundland Power Commission at IC-219, one notes that in 1963, 72% of the energy generated on the island of Newfoundland was 50 cycle. (p. 3) The consultants also make the significant assumption at p. 2 that areas of 50 cycles, specifically including Corner Brook and Grand Falls, may exist indefinitely. The report goes on to consider a number of schemes to create the grid, which is essentially the grid we have today as described by Mr. Reeves in his evidence. Consideration was given to having 50 cycle generation installed at Bay D'Espoir with conversion at various later dates. However, it was ultimately concluded that a single system with frequency converters as required had the lowest present worth cost, provided a source of emergency power from existing industrial generation facilities and assisted in voltage control. That scheme was recommended both in the initial report and the supplementary report, which notes further advantages at p. 5 including maximum utilization and economy of equipment, best facilitation of the network, improved frequency regulation, simplified and less expensive facilities at Bay D'Espoir, voltage control, no penalty for delayed conversion and no restriction on growth of the 50 cycle system.

In the Power Commission's presentation to the Royal Commission on Electrical Power and Energy in July, 1965, reproduced as part of IC-56, (which incidentally has an excellent history of the development of the electrical power system in Newfoundland), the vital nature of the 50 cycle issue is highlighted at p. 13 in the final paragraph, and the major efforts of the predecessors of

CBPP and Abitibi to assist in the process are acknowledged on p. 14. The presentation to the Atlantic Development Board of Jan. 1965 (also part of IC-56) confirms at p. 3 that conversion of the paper mills to 60 cycle was impractical and acknowledges the contribution of those customers in absorbing substantial conversion costs. Note also, under Item 6 on p. 14 that the Power Commission (Hydro's predecessor) indicates that two "permanent" frequency converters would be required.

Even in 1982 when Hydro signed a power contract with Bowater Power[63], the parties acknowledged in Article 9.01 that Hydro would continue to provide the converter at Hydro's expense in order to " continue integration of the generating facilities of Hydro and the Customer and thereby derive benefits for both parties".

The converter at Grand Falls is being decommissioned but the one at Corner Brook is still required, primarily to convert 50 cycle generation to 60 cycle for use in the mill, as discussed by Mr. Budgell.[64] Mr. Budgell acknowledges that the converter could serve a purpose in converting 50 to 60 cycle power to provide emergency power to the grid should Hydro require it. He questioned whether CBPP would actually provide same but he did not refer to the contract between CBPP's predecessor and Hydro dated May 15, 1977 (produced in response to IC-43) on which Hydro still relies in respect of secondary purchases from CBPP. That contract provides in

[63] IC-5 - 2nd attachment)

[64] Transcript, November 8, 2001 from p. 1 line 81 to p. 7 line 81

Article 5 that Bowater Power will provide emergency service to Hydro within the limitations of its obligations and requirements. Accordingly, the frequency converter makes a substantial contribution to security on the entire grid, a benefit to all of Hydro's customers. Note also the answer to IC-58 which speaks of the generation of Industrial Customers contributing to the reliability of the interconnected system. Granting that their contribution is not as great as Bay D'Espoir as the answer suggests, that suggestion itself confirms that there is a contribution from the generation, and that contribution must rely, in part, on the frequency converters.

All of this is in addition, of course, to the use contemplated in the evidence of Mr. Osler on Dec. 3, 2001 at p. 21 lines 63-77 in the hypothetical case where the Corner Brook mill was not operating. Accordingly, even on the "simple" principles of plant assignment, therefore, this converter should be regarded as common plant.

The broader issue, of course, is the historic pact between Hydro's predecessor and CBPP's predecessors which gave birth the grid we all enjoy today. The benefits of a single frequency of generation at Bay D'Espoir are still being felt today. It borders on scandalous to think that Hydro, having accepted the benefits of the costs absorbed by the paper mills in the 1960's in return for converters (which it referred to itself as "permanent"), should not be asking to shed itself of its concurrent obligation to maintain the converters. There were many understandings in place among these parties. Hydro wheels power over CBPP's lines to Newfoundland Power's customers at Pasadena and Marble Mountain (See IC-57) and receives no recompense; CBPP will need to re-visit the issue of wheeling charges if other historic agreements are being abandoned. Hydro relies on its history to justify preferential rates for certain customers in Bay D'Espoir itself; its historic obligations to provide these converters are certainly much more concrete. Paper mills, facing competitive pressures such as described in the evidence of Mel Dean and Jay Backus, should not be forced to take on additional costs which have, based on long-standing arrangements, never been assigned to them before.

We would ask the Board to confirm the existing assignment of the two converters, the Grand Falls unit until it is decommissioned and the Corner Brook unit on an on-going basis, as common plant.

STREET LIGHTING IN BAY D'ESPOIR

According to Hydro's evidence, approximately $60,000.00 in street lighting for the Community of Bay D'Espoir, which is part of Hydro's interconnected rural system, is assigned common. This means that Newfoundland Power and the Industrial Customers pay for that street lighting although they do not use it.

The Industrial Customers understand that this treatment of street lighting costs in Bay D'Espoir has a long history. However, it cannot be argued, as in the case of the converters serving Abitibi - Grand Falls or Corner Brook Pulp & Paper, that this street lighting in the community ever provided a benefit to any of Hydro's other customers. Having said that, the Industrial Customers submit that if the converters at Grand Falls or serving Corner Brook Pulp & Paper are specifically assigned to Abitibi in Grand Falls or Corner Brook Pulp & Paper as a result of this hearing, then the street lighting in the Community of Bay D'Espoir should also be specifically assigned back to Hydro's rural interconnected customers.

CLASSIFICATION OF HYDRAULIC PLANT AND ALLOCATION OF GENERATION DEMAND RELATED COSTS

In its 1993 Report, the Board determined that it should consider classification of hydraulic and thermal plant based on operating parameters. The Board concluded:

> "The system load factor is the ratio of average demand to peak demand, and average demand is the amount of capacity required to supply the system energy requirement under ideal conditions; i.e., constant demand throughout the year. It is, therefore, logical to regard the system load factor as the fraction of plant investment necessarily incurred to meet the energy requirement and to classify this portion as energy related."[65]

The result was Recommendation 9 on page 38 of the 1993 Board Report which provides:

> "That a proportion of hydraulic plant costs in the Island interconnected system equal to the annual system coincident load factor be classified as energy-related and the balance be classified as demand related."

The Industrial Customers submit that Hydro, in its cost of service, has made a mistake in calculating annual system coincident load factor.

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[65]1993 Report, page 36.

Mr. Budgell referred the issue of calculation of system load factor to Hydro's expert, Mr. Brickhill.[66]

With respect to Newfoundland Power's load factor, Mr. Brickhill agreed that, during a rate case, every bid of increase in Newfoundland Power's load factor impacts the Industrial Customers be increasing system load factor, and shifting more hydraulic generation costs to energy rather than demand. Mr. Brickhill also agreed that similarly, every increase in Newfoundland Power's load factor impacts the Industrial Customers by increasing the Holyrood forecast generation capacity factor, shifting more Holyrood generation costs to energy from demand. Mr. Brickhill further testified that if Newfoundland Power's load factor increased due to a decline in peak or decline in peak coupled with an increase in energy then every increase in that load factor reduces Newfoundland Power's relative allocation of demand related costs based on coincident peak.[67]

Mr. Brickhill agreed that Hydro uses a coincident peak for generation for Newfoundland Power that is net of the generation demand Newfoundland Power can provide at peak. He agreed that this reduces Newfoundland Power's net system coincident peak contribution but that it does not reduce Newfoundland Power's coincident peak at the meter unless their generation was being used at the time of coincident peak. However, if their generation is not being used at the time of system peak,

[66]Transcript, November 8, 2001, page 16.

[67]Transcript, November 27, 2001, lines 47 to 71.

it does not reduce their coincident peak at the meter. In other words, Newfoundland Power is, in those circumstances, at system peak, consuming the entire demand.

Mr. Brickhill also agreed that generally, Newfoundland Power's contribution to system peak is actually higher than the value used in the cost of service study.[68]

Mr. Brickhill agreed that the whole idea of the coincident peak methodology is that it's designed to capture the relative contribution of customer loads to system peak.[69] He also agreed that when you adjust the Newfoundland Power peak for generation capacity, then the cost of service study may not capture the relative contribution to system peak.[70]

Mr. Osler testified that Hydro has used a coincident peak at generation for Newfoundland Power that is net of the generation that Newfoundland Power can supply to the grid at peak times. This reduces Newfoundland Power's system coincident peak contribution but does not normally reduce Newfoundland Power's coincident peak at the meter.[71]

Allocation of generation demand costs

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[68]Transcript, November 27, 2001, page 20.

[69]ibid.

[70]ibid, page 20/21.

[71]Pre-filed Supplementary Testimony of C. F. Osler, September 12, 2001, page 18, lines 11 to 15 and NP-121, NP-125, NP-126 and IC-202.

Mr. Osler testified that “This treatment serves to reduce the allocation of generation demand costs to Newfoundland Power. . . . The response to NP-121 indicates that Newfoundland Power’s contribution to the system peaks is higher than the value calculated in the COS study..”[72]

Mr. Osler’s estimate of the impact on revenue requirement of Hydro’s customers from this incorrect calculation of system load factor for the purpose of allocating generation demand costs, is that it, before rural deficit allocation, results in lower costs to Newfoundland Power of approximately $810,000.00, increased costs to the Industrial Customers of $540,000.00 and increased costs to the Island rural interconnected customers of $270,000.00.[73]

Classification of generation costs

With respect to classification of generation assets and costs to demand and energy based on system load factor, Hydro again includes the Newfoundland Power generation credit reduction in Newfoundland Power’s coincident peak for the purpose of calculating an adjusted Island interconnected system load factor.

As discussed above, the Board’s 1993 Cost of Service Report directed Hydro to classify generation assets and costs based on it being the ratio of average demand to peak demand where

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[72] ibid, lines 16 to 33.

[73] ibid, lines 32 to 40.

average demand is the amount of capacity required to supply the system energy requirements under ideal conditions; i.e. constant demand throughout the year. Because Hydro's cost of service study in this matter uses an "adjusted" load factor that is markedly different from the load factor that it appears the Board directed it to use, Newfoundland Power's revenue requirement before rural deficit allocation is decreased by approximately $300,000.00, the Industrial Customers' revenue requirement is increased by approximately $300,000.00 and the Island rural interconnected deficit is overstated by $30,000.00.[74]

COINCIDENT PEAK ALLOCATORS - GENERATION DEMAND

In its 1993 report on cost of service methodology, the Board concluded:

1. That generation demand costs be allocated to the Island Inter-connected System using a coincident peak allocator;[75]

2. That a 1 CP allocator be approved for interim use in the island inter-connected system and that Hydro present to the Board at the time of its next rate hearing an analysis of the relationship between load factor and system reserve requirement, together with a

[74] Pre-filed Supplementary Testimony of C. F. Osler, September 12, 2001, pages 19 and 20.

[75] 1993 Report, page 23.

> recommendation regarding the number of peaks on which the CP allocator for generation demand costs should be based.[76]

In reaching that conclusion, the Board found:

> "Nothing in the evidence enables the Board to quantify the relationship between system load factor and reserve requirements and in the absence of such information it is not possible to decide whether cost causation would best be measured by one CP, 5 CP or some other number of peaks. However, it appears that one CP correlates best with the major part of the costs."[77]

During this hearing, John A. Brickhill, President and CEO of Foster Associates Inc., testified as Hydro's expert witness with respect to cost of service methodology issues, including the appropriate coincident peak allocator for generation demand.

In his pre-filed testimony, Mr. Brickhill indicated that subsequent to the 1993 report, Hydro prepared a loss of load hours (LOLH) study which indicated a greater risk of loss of load hours largely in two winter months. Mr. Brickhill further testified that the probabilities for those months increase as load factor increases and that the study supports use of a 2 CP allocator.[78] Hydro proposes use of a 2 CP allocator.

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[76] ibid page 24.

[77] ibid page 24.

[78] Pre-filed evidence of John A. Brickhill, page 8, lines 11 to 22.

However, on cross-examination, Mr. Brickhill testified that he is recommending either a 2 CP allocator or a 1 CP allocator.[79]

Mr. Brickhill testified that Newfoundland Power's expert, Mr. Brockman, was incorrect when he suggested that a 4 CP allocator should be used because the peak could occur on one of four months.[80]

Mr. Brickhill subsequently confirmed that the coincident peak is the point in the month or in the year when the combination of the demands from all of Hydro's customers on the island inter-connected system is at its maximum.[81] He further testified that Hydro's LOLH study would have supported 1 CP as well as 2 CP[82]

Mr. Brickhill testified that the use of 1 CP for generation demand cost is more consistent with other Canadian utilities than 2 CP.[83] Mr. Brickhill testified that it doesn't matter what month the peak occurs.[84]

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[79]Transcript, November 26, 2001, page 32, lines 9 to 15.

[80]Transcript, November 26, 2001, page 44, lines 55 to 62.

[81]Transcript, November 27, 2001, page 16, lines 21 to 25.

[82]ibid, page 16, lines 45 to 56.

[83]Transcript, ibid lines 83 to 86.

[84]Transcript, November 27, 2001, page 17, lines 24 to 70.

Cameron Osler, an expert witness for the Industrial Customers on cost of service methodology in his pre-filed supplementary testimony dated September 12, 2001, testified that "There is no basis to increase the allocation to 4 CP, and there is likely benefit to retaining the current 1 CP for consistency with allocation transmission costs, and consistency with similar utilities."[85] This was further explained in his pre-filed supplementary testimony at page 18 where he added "Further, the data clearly shows that the peak month contributes more to the overall system LOLH than all other months combined (approximately 60% per ca-19)."[86] Mr. Osler testified that the fact that Hydro cannot determine the exact month that its system peak will occur is inconsequential to the cost allocation model required.[87]

Mr. Osler testified that he does not agree with Mr. Brockman's choice of 4 CP for the purposes of demand allocation. He agreed with Mr. Brickhill and Mr. Bowman that the central issue is how many peaks the system has.[88] Mr. Osler testified that he preferred a 1 CP allocator for generation demand.[89]

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[85]Pre-filed supplementary testimony of C. F. Osler dated September 12, 2001, page 13, lines 22 to 25.

[86]ibid, page 18, lines 31 to 32.

[87]ibid, page 19, lines 20 to 29.

[88]Transcript, November 30, 2001, page 1, lines 37 to 62.

[89]ibid.

Mr. Douglas Bowman, expert on cost of service methodology issues for the consumer advocate, testified in his pre-filed evidence that he recommends a 1 CP allocator for the allocation of generation demand costs on the island inter-connected system because it is consistent with what Hydro has proposed for its other systems and reflects cost causation.[90] Further, Mr. Bowman testified that 2 CP is not consistent with the 1 CP allocator used on the other Hydro systems and is not a better reflection of cost causation and that loss of load hours are greatest in the peak months.[91]

Mr. Brockman, for Newfoundland Power, was the only expert witness whose testimony with respect to the coincident peak generation demand allocator was dependent upon differences in the months in which peak demand occurred. However, even Mr. Brockman, acknowledged that regardless of whether the peak occurred in March or December or January or February, if the relative contributions of the customers to that peak remained the same, it wouldn't make much difference as to whether you picked the right month.[92]

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[90]Pre-filed testimony of C. Douglas Bowman, page 4, lines 9 to 12.

[91]ibid, page 9, lines 4 to 6. Also Transcript, December 4, 2001, page 42, lines 58 to 71.

[92]Transcript, December 4, 2001, page 39, lines 26 to 35.

Changing the coincident peak allocator for generation demand from 1 CP to 2 CP would transfer $18,000.00 to the Industrial Customers.[93] Changing from 1 CP to 4 CP would transfer $360,000.00 to the Industrial Customers, primarily from Newfoundland Power.[94]

The Industrial Customers submit that there is no evidence before the Board indicating that the 1 CP allocator currently approved by the Board is in any way inappropriate. The Industrial Customers submit that the 1 CP allocator for generation demand costs should be retained.

TRANSFORMER LOSSES

In the existing industrial contracts, Hydro meters the energy delivered on the low voltage side of the transformers, whether the transformers are owned by Hydro or by Hydro's customers. Hubert Budgell described the transformer loss situation as an omission[95]. The existing Abitibi-Stephenville contract states in article 10.02 "the metering equipment is installed on the low voltage side of the Customer's 230 kV transformers, and no account shall be taken of the 230 kV transformer losses when calculating the payments for Power and Energy supplied under this agreement." Hydro's current proposal represents a change, not an omission or oversight.

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[93]Compare IC-95 to JAB-1 - revenue requirement for IC

[94]Compare IC-95 to IC-244 - revenue requirement for IC

[95]Transcript, November 8, 2001, page 12, line 72

Paul R. Hamilton, in his pre-filed testimony dated May 31, 2001 indicated that Hydro is proposing to add wording to the rate descriptions for Newfoundland Power and the Industrial Customers "to ensure consistent treatment of transformer losses based on the location of metering equipment similar to that done for Hydro rural customers." Currently, the rates for Newfoundland Power and the Industrial Customers are based on supply to the low side of transformers of customer owned or specifically assigned transformers.[96]

The Industrial Customers submit that if the existing situation with respect to transformer losses is unfair, then the proposed "cure" for the problem is, in fact, equally unfair. This is illustrated in the pre-filed evidence of Melvin Dean as revised in December, 2001.

The critical principle in reviewing the issue is that the higher the purchase voltage, the greater the losses borne by the customer. The lower the purchase voltage, the more the losses are absorbed by Hydro.[97]

The chart provided by Mr. Dean in his evidence shows that, with the current billing arrangement, different customers do purchase energy at different voltages. Currently, Hydro absorbs the losses from 230 kV to the low voltage side of the transformers.

[96]Pre-filed Testimony of Paul R. Hamilton, page 16, lines 4 to 14.

[97]Pre-filed Evidence of Melvin Dean filed December, 2001, page 10.

With the current arrangement, Corner Brook Pulp & Paper absorbs the transformer losses from 66 kV to its usage voltages of 13.8 and 6.9 kV while Abitibi-Stephenville has no transformer losses to those voltages.

Similarly, under the current system, North Atlantic Refining does not pay for transformer losses from 230 kV to its usage voltage of 13.8 kV while Newfoundland Power pays all of the transformer losses from 66 kV to its usage voltage and some of the transformer losses between 66 kV and 230 kV depending upon where energy is delivered.

Under Hydro's new proposal, as illustrated in the table in Mr. Dean's evidence, Abitibi - Stephenville and Abitibi - Grand Falls will have to absorb (i.e. pay for) all of the losses from 230 kV to their usage voltages while Corner Brook Pulp & Paper will only have to pay for/absorb the losses from 66 kV to its usage voltages and Newfoundland Power will pay some, but not all, of its transformer losses.[98]

Moreover, Hydro' answer to IC-131 1 says "Transmission losses are defined as the difference between net generation and metered sales at the customers' delivery points." As transformers are between the generator and the meters, transformer losses are included in transmission losses. In IC-131 (c), Hydro states that no allowance has been made in the forecast losses to compensate for

[98] ibid

the fact that certain customers will be paying their own losses. Thus Hydro's proposal is not 'distributing losses more fairly'; the extra revenue is flowing to their bottom line

The Industrial Customers submit that if Hydro's treatment of transformer losses is to be addressed, then the new treatment of transformer losses should treat all customers equally.

The lowest transmission level voltage at which Hydro delivers power to its Island Inter-connected Customers (other than its Rural Inter-connected Customers) is 66 kV. The highest voltage at which power is delivered to those customers is 230 kV, the voltage level of the transmission lines from Hydro's major sources of generation on the island.

There are advantages to Hydro associated with the purchase by its customers of their energy requirements at 230 kV. There are costs to Hydro associated with the purchase by customers at lower voltages including, not only the transformer losses from 230 kV to the purchase voltage but also, in cases where the transformers are owned by Hydro and not specifically assigned, the costs associated with the transformers themselves.

Mr. Dean's evidence refers to the means by which other jurisdictions deal with transformer losses. As indicated in Mr. Dean's testimony, both Hydro Quebec and Manitoba Hydro provide discounts to the customers taking power at high voltages such as 230 kV. Nova Scotia Power also provides a discount. New Brunswick Power operates from the opposite direction and increases demand in energy rates by 1.5% where power is supplied at primary voltages between 4 kV and 25 kV.

According to Mr. Dean, Abitibi estimates that Hydro's new proposal would add $75,000.00 to $100,000.00 to Stephenville energy costs. Yet, it would still result in treating different customers differently with respect to transformer losses.

The Industrial Customers submit that Hydro should absorb transformer losses from 230 kV to 66 kV and that the losses from 66 kV to usage voltages should be absorbed by the customers.

The practicality of such a solution would need to be investigated. This could be done through technical evidence on the quantum of transformer losses from one level to another or, in the alternative, the Board could accept a pure mathematical calculation and assume that the losses from 230 kV to 66 kV are proportionate to the losses from 230 kV to 13.8 or 6.9 kV.

The Industrial Customers submit that the Board should reject Hydro's proposal to change its treatment of transformer losses.

RATE STABILIZATION PLAN

Regulators universally recognize that there are certain significant cost factors affecting public utilities that are not, to a greater or lesser degree, controllable by the utility and/or not predictable with a degree of certainty that lends itself to rate making on the basis of a forecast test year. The primary example of a cost of this type is fuel for a utility that has a significant reliance on thermal generation. Another example is water inflows for a utility that has a significant reliance on hydro generation. Newfoundland and Labrador Hydro falls into both categories and has developed a history of reliance on various devices to deal with the unpredictability of costs arising from these items.

History of Rate Stabilization in Newfoundland and Labrador

Prior to 1985, Hydro relied on a water equalization provision and a fuel adjustment charge. The latter was designed to pass on actual fuel costs to customers one month after they were incurred. The tendency of fuel prices to increase in times of high demand (such as the winter heating period) meant that customers faced very high surcharges in winter months and relatively lower bills in the summer months. When fuel prices were at high levels in the early 1980's, this gave rise to public discontent and an alterative approach was sought in the hearing on Hydro's 1985 Referral to the Board.

It must be remembered that, at that time, the Board regulated (and then only by way of report that required implementation by Order in Council) only rates to retailers. Rates to Industrial Customers were not regulated at that time and there was no suggestion at the time of the 1985 hearing that an effort was underway to create a new system which would impact industrial rates.

In its submission to the Board in 1985, Hydro proposed a system that would accrue variations, positive or negative, in the costs arising from the differences between actual and forecast values for oil price and the amount of fuel used, the latter encompassing the difference between forecast hydro production and actual hydro production on the assumption that the difference between electricity actually generated by hydro facilities and that forecast to be generated by hydro facilities translated directly into more or less fuel used at Holyrood. The Hydro proposal was to accrue these differences between rate hearings and then recoup the balance, positive or negative, in the rate to be set at the next hearing. Parenthetically, it may have been this type of plan that the New-Lab Action Committee representative disapproved in her evidence before the Board at that hearing. (See CA 179(iv) p. 22 of 23 final paragraph 5th line)

The consumer representative at that hearing led evidence to show that such a proposal could lead to greater rate de-stabilization and suggested that additional studies be done on two alternative plans, one of which would accrue the differences yearly and provide for an automatic adjustment each year to recover one-third of the existing balance at the chosen time of annual adjustment. While Hydro's final submission still contended for their original plan, other parties supported a plan such as suggested by the consumer representative's expert with certain modifications.

The 1985 Plan and Load Variation

The Board in its Report recommended a plan such as proposed by the consumer representative's expert but went further and said that variations between forecast load and actual load should also be an element of the plan. No party had made any submission about the load variation element of the plan and the implications of that element were never discussed in the hearing. Further, the philosophical or policy issue as to whether the utility should have this type of protection against inaccurate load forecasting was never addressed. The evidence has shown that there is no utility in North America or elsewhere of which any expert is aware which has the benefit of this type of provision. Indeed Hydro's own cost of capital expert, in another proceeding, has given evidence to the effect that the risk of load forecasting typically and properly lies with the utility itself. (See NLH-99 p. 1 of 2 and attachment) This is philosophically consistent with the types of stabilization provisions we are discussing because the utility alone does the forecasts and has control over the accuracy of them. The utility may wish to design its rates to minimize the impact of inaccurate forecasting but good regulation requires that the forecasting risk as regards load be left with the utility, giving it the incentive to improve its methods and practices as regards its load forecasting.

In any event, since 1985 there has been a load element in the Rate Stabilization Plan. The lack of discussion about this at the hearing gave rise to a series of discussions and some exchange of correspondence about how that element should be incorporated into the Plan. (See IC-284(e) and the letter from NP to Hydro included in IC-286(e)) Again, the Industrial Customers were not part of these discussions and not privy to this correspondence, and understandably so as these were not customers whose rates were subject to regulation. The machinations necessary to implement these provisions are discussed in more detail below, in the context of the effects on the rates of Industrial Customers.

Stabilization Schemes as Rates

The various provisions that are used to address uncontrollable or unpredictable costs, whether a simple fuel surcharge or an elaborate scheme such as the existing RSP, all form part of the rate which a utility charges its customers and hence are all subject to the jurisdiction of this Board. These provisions determine what a customer pays for service and are therefore “rates” within the meaning of the *Public Utilities Act*. The fundamental principles of rate making apply to these provisions, particularly those which mandate that rates in total cover costs in total and that stability in rates is an appropriate regulatory objective. As in all rate making exercises, there must be a balance between the interests of the utility and the interests of the customers.

All customers, residential, utility and industrial, have an interest in stable rates, not just in the sense of minimizing rate increases, but also in the sense of foreknowledge or predictability of rate levels. This interest is already reflected in the desire of Industrial Customers to have its RSP adjustment become effective on January 1 in each year to be consistent with their budgetary processes, a desire that Hydro has accommodated and is incorporated in the existing plan. This is also consistent with the overall position of Industrial Customers that they are prepared to pay their fair share of costs on the electrical system and do not seek from Hydro or the Board any special treatment. They do need to know, however, what their costs are likely to be, and it may be that the level of costs they experience will impact the nature and extent of their operations in Newfoundland and Labrador. In all aspects of the rates, base rates, non-firm rates and RSP rates, as well as with the regulatory process itself, the Industrial Customers need to have assurance that they will be paying no more than their fair share of costs and that they will have sufficient advance knowledge of what costs will be in order to make their own economic decisions.

Accepting that hydro production (and hence thermal production) is affected by water inflows that are not necessarily predictable with accuracy year over year, the Industrial Customers realize that they will have to contribute to the cost of additional fuel when inflows are lower than forecast. Accepting that the price of No. 6 fuel is influenced by factors over which Hydro has no control, the Industrial Customers realize that they will have to contribute to whatever increased costs are incurred as a result of increased world fuel prices. It is, however, disruptive to the operations of Industrial Customers to have sharp and unpredictable increases or decreases in electricity costs during any given year. This will result in uneconomic allocation of company resources. Accordingly, Industrial Customers support the continued use a provisions to smooth the rate changes associated with costs arising from forecast errors as they relate to water inflows and oil prices. Consistent with their attachment to the principle of paying their fair share of costs, those costs associated with load forecast errors should be the costs of the utility and not be passed on to customers through any stabilization program.

Another principle of rate making to take into account in designing a stabilization plan is the goal of simple or understandable rates. For planning purposes, the Industrial Customers need to know where they stand under the plan at any time, and the more transparent the plan is the better it serves this goal. While the existing RSP has stabilized rates and ensured Hydro of its ultimate recovery of its costs, it has hidden the underlying factors which have caused the current situation where an inappropriately large balance has accumulated in the Plan. By combining the fuel adjustment element and the water inflow element in a single plan, the increasing magnitude of the crisis arising from oil prices has been hidden. An unrealistically low base price for fuel in the RSP has been allowed to continue because, while huge fuel price related balances were accumulating in the Plan, large water inflow related balances were accumulating in the other direction and setting off the oil price effect. As shown in NLH-99, p. 2 of 2, the fuel price deficit accumulated from 1992 to 2000 was actually $136,189,000. It was only the offsetting effect of very wet years during that period allowing a surplus of $78,667,000 which allows the “balance” in the RSP to be as low as $35,602,000 as of December 31, 2000 after applying recoveries and other adjustments.

It should not be forgotten that, while the RSP is clearly a “rate”, it is serves a different purpose that the base rate. It is intended to fluctuate, to accommodate variations both positive and negative over time arising from particular causes. It is not intended to represent an amount which forms a part of the charge for electricity to customers over the long term. Long run changes in price levels of inputs, such fuel, such be incorporated in base rates; it is the failure to do so in this case, i.e. that continued attachment to the unrealistic $12.50/bbl fuel, that has created something of a crisis.

Proposals for the Future

On an on-going basis, the Board should direct Hydro to establish separate rate elements to track fuel price changes and water inflow changes. An automatic adjustment is appropriate for changes in fuel prices but the evidence tends to show that such adjustments should be made over shorter periods that the three years contemplated by the current RSP. There are various models available for this type of adjustment, but the principles should be directed toward adjusting the rate with respect to fuel price differences so as to reduce the balance to zero in the year following the year in which the differences are experienced.

The water inflow provision is more suited to a longer term adjustment since forecasts are based on long term averages. In the absence of evidence of a long term climate change that is impacting or predicted to impact inflows, over the long term the forecasts of inflows should be correct. That is a fundamentally different situation than applies to oil prices. Accordingly, the water inflow provision should permit Hydro to book the differences in costs arising from the difference between actual and forecast inflows on a continuing basis with a requirement that Hydro apply to the Board for direction as to disposition of the balance when it exceeds a specified amount, positive or negative. The Board could then approve a surcharge or a rate reduction for a period sufficient to return the fund to an acceptable level.

To the extent that the amount in the fund is affected by changes in oil prices from the time that the fund is first established, an adjustment could be made to the fund by transfer of the appropriate amount, positive or negative, to the fuel adjustment account.

Neither of these funds need be segregated as between industrial and retail customers. Each is purely an energy related item and can be distributed on a per kWh basis among all customers.

The Balance in the RSP

With a plan in place for the future, it becomes necessary to deal with the situation as it currently exists under the Rate Stabilization Plan. Clearly there are significant balances due to Hydro which need to be collected. As has been pointed out, under the existing plan of recovering one-third of the balance in the account on a declining balance basis, it would be many years before the existing balance would be entirely liquidated unless the string of wet years continued and oil prices fell below predicted levels. This is inevitably so when, for good reason, Hydro proposes not to base the RSP on actual predicted fuel levels but to continue to use a price lower than actually anticipated - a step that will see the balance in the RSP continue to increase through 200?. Accordingly, it is appropriate to treat the existing balance as a separate extraordinary expense, like the foreign exchange losses, to recovered over an extended period. Given the amount involved and fact that customers have been expecting to have to contribute to this deficit, a five year amortization would probably be appropriate and workable.

The Board must address, however, in the case of the Industrial Customers whether these are amounts properly chargeable in rates to those customers. The Board has never approved, other than on an interim basis, any rates for Industrial Customers. In order to allow recovery of these amounts now, the Board must determine if the balance properly reflects amounts appropriately allocated to Industrial Customers consistent with principles of public utility regulation and the intent of the RSP as outlined in the Board's 1985 Report.

It will be seen from the reply to IC-286, and confirmed by the lack of any RSP related Order-in Council being produced in response to IC-260, that Hydro relies solely on the Board’s Report of 1985 for its implementation of the RSP in the form that it presently exists. There were no other guidelines or rules established relative to the industrial RSP. The correspondence exchanged with the Board as to the method of implementation was done without consultation with or explanation to the Industrial Customers at the time of its implementation and those customers have had, until now, no forum in which to object or make representations as to how the scheme was implemented.

Further, the calculations are so convoluted and, in our submission, contrary to public utility principles that their true implications become clear only after extraordinarily intensive analysis by experts who have access to all of the historical records and statistical information that are used to create the final reports.

The Workings of the RSP-The Monthly Report

To try to understand what the RSP has been doing since 1985, one must begin with a monthly RSP Report. The report used for illustration in the testimony of a number of witnesses was that of December, 2000, the end of the last full year prior to the filing of this application. That report forms part of IC-73.

There are three elements or variations from forecast which the Plan attempts to deal with- hydraulic production, load variation and fuel cost variations. The Report then also has to deal with revenue adjustments i.e. how the Plan has been adding interest to, and collecting or refunding, the amounts accrued in the Plan. As we will see, the Plan begins with gross results, undifferentiated by customer or customer class. Once the gross results are determined, the process of the so-called customer split is implemented, a process that does not appear in the monthly reports, those reports containing only the result with no explanation as to how the result was derived. It was only very late in the Information Request process, with the answer to IC-271, that any real light was shed on what Hydro was doing to split the RSP results among the customer classes i.e. between the so-called Retail Plan and the Industrial Plan.

The early sections of the RSP Monthly Report are reasonably self-explanatory. Page 2 shows the forecast (COS) production in each month, the actual production, the monthly variation and the cumulative variance to the month in question. Production by hydro plant is provided although not strictly necessary for the purpose of the calculation. The cost of fuel burned or saved in Holyrood as a result of lower or higher production than forecast is then calculated using an efficiency factor. In December, 2000, the hydro plants produced 42.88 GWh of energy more than forecast which would have saved Hydro $885,950.41 if their fuel still cost $12.50 per barrel as is assumed in the 1992 Cost of Service Study. The change to actual fuel price is dealt with later. Note that the use of actual hydro production means that no matter what caused higher or lower production than forecast, whether it was hydraulic variation, breakdowns at hydro plants, or reduced or increased efficiency of hydro plants the cost of the barrels of fuel used or saved is cumulated and included in the RSP.

Page 4 begins the process of dealing with load variations. This shows projected total sales per month in 1992 as per the Cost of Service, actual sales in each month and the monthly and cumulative variances. These are purely energy numbers and do not deal with any variations in demand. Both firm and secondary sales are shown, although Hydro did not forecast any secondary sales in 1992 and the actuals are insignificant. These are all gross figures, undifferentiated by customer or customer class. In December, 2000, load was up above the forecast for December, 1992 by a total of 19.58 GWh. This number appears under the Monthly Variance column opposite the word December. Overall, for the year, however, load was down by 25.05 GWh.

Page 6 continues the exposition of the load variation elements. Here, for the first time and for one purpose, variations by customer and customer class are shown. Utility Firm Energy Sales i.e. sales of Newfoundland Power (or Newfoundland Light and Power as they were known in 1992) are first shown, including the projected 1992 COS amounts, the actual amounts and the variance. Leaving the application of the rate to turn these GWh into dollars for the moment and moving down the page, the projected 1992 COS sales, actual sales and variance are shown for the Large Industrial Customers. These are broken down by customer and by contract power block in the case of Abitibi. The breakdown is based on 1992 circumstances-it shows Deer Lake Power separate from Corner Brook Pulp and Paper and shows two customers, Albright & Wilson Americas and Royal Oak Mines Inc., which have ceased to exist on the system, this fact being noted in a footnote. Accordingly, while NP is assigned (to a certain extent) responsibility for load variations from its 1992 COS forecast load, Abitibi, CBPP and NARL are assigned responsibility for the load variations of their own four operations plus an inevitable variation totaling the entire projected load of Albright and Wilson Americas and Royal Oak Mines Inc.

A further peculiarity in the workings of the RSP to date is illustrated by following the effects of the closure of these two Industrial Customers as illustrated in Exhibit IC-6. As noted, p. 6 of the RSP Report differentiates among customer classes for a certain purposes and one of those purposes is the assignment of revenue losses resulting from sales that are below forecast. All of those losses in this instance are assigned to the Industrial Customers, as appears from Exhibit IC-6. However, there are, of course, fuel savings associated with those reduced sales. Those savings, however, are allocated under the 1992 Cost of Service Methodology and only 21% of them are credited to the industrial RSP. Accordingly, as appears from Exhibit IC-6, NP saves $319,597.62 and Rural Customers save $29,114.26 as a result of the closures (because less fuel is used) from while IC has to pay an additional $322,060.30 as a result of the closures.

When we move to the translation of load variation by GWh into dollars of revenue gained/lost by Hydro, another anomaly appears. Because NP has an energy only rate, its load variation is valued at its full energy rate which has been calculated including costs properly attributable under the COS to demand. Accordingly, using December 2000 as an example, the 19,053,001 kWh of additional energy taken by NP in December above the forecast December 1992 amount, brings in additional revenue to Hydro of 45.31 mills for each kWh, that being NP's energy only rate as of this date. Against that is the assumed amount of 20.66 mills per kWh that Hydro would have to pay for fuel to generate that energy at Holyrood, leaving a net effect on Hydro's revenue of 24.65 mills per kWh or, in December, 2000, a net gain to Hydro of $469,656.47 representing additional income to Hydro beyond what it would have gotten if the December 2000 sales to NP equaled the forecast December, 1992 sales to NP, assuming always that Hydro's fuel costs $12.50 per barrel.

In the case of the Industrial Customers, however, the effect is different. The four industrial operations actually used in December, 2000 more energy than was planned in 1992 to be provided to all six industrial operations (including the two closed facilities) in December, 1992. However the Industrial Customers have a split demand/energy rate and the energy portion of the rate was in December, 2000 19.34 mills per kWh. Accordingly, Hydro being still assumed to have to pay out 20.66 mills per kWh to buy fuel to produce each of the additional 522,262 kilowatt hours of energy used by Industrial Customers beyond the December, 1992 forecast, Hydro appears to suffer a net loss of 1.32 mills per kWh meaning that its income reduces by $689.39 as a result of these "additional" sales. What is not shown here, of course, is what has happened on the demand side. Even if an industrial customer's demand in KW was below its forecast for December 2000, it would nonetheless have to pay based on its Amount of Power on Order under its contract. If it exceeded its Power on Order, it would be paying additional demand charges on one of a number of Interruptible Demand bases, and in 2000 such demand charges were assessed at the same rate as for firm power. Nonetheless, the effect on the RSP of additional load beyond forecast for the industrial group is opposite to the effect on the RSP of additional load beyond forecast for NP-NP's additional load creates a credit for customers in the Plan while IC's additional load creates a balance due from customers in the Plan. Those effects are, however, netted out for the purpose of creating the number which is used in the Plan Summary at page 14 of the Report, which will be dealt with later.

Page 8 of the Report again appears straightforward. This shows the monthly fuel cost as inputted into the 1992 Cost of Service (the weighted average of which should be $12.50 per barrel), the actual fuel cost in each month and the variance. It shows also the actual number of barrels inputted into the Cost of Service monthly and the actual number of barrels used in each month together with monthly and cumulative variances. Note that the use of actual barrels used means that no matter what caused more barrels or fewer barrels to be used, whether it was hydraulic variation, breakdowns at hydro plants, reduced or increased efficiency at Holyrood or the hydro plants, or additional load, the cost of those barrels is cumulated and included in the RSP.

Page 10 shows the actual cost of the barrels of fuel burned in December, 2000. Emergency fuel is omitted since the customer pays the entire cost of that directly. This assigns to the RSP the difference between forecast cost for the number of forecast barrels in December 1992 and the actual cost of the actual barrels used in December 2000.

Page 12 simply calculates the amount refunded or recovered by the existing RSP mill rate adjustment in place in that month based on actual sales in that month. This relates purely to how pre-existing balances in the Plan are refunded or recovered. Page 14 shows a summary for the month on a gross basis, not differentiated by customer or customer class and adds the effect of interest on the various balances. This also shows that an adjustment is made to take into account that Hydro's rural customers pay to or receive from Hydro the same RSP mill rate adjustment as NP's customers pay to or receive from NP; those amounts are reflected in the Plan and cause changes in the total amounts due to or from Hydro.

Earnings Variation v. Cost Re-allocation

One point on which the 1985 Report is clear and consistent is that the RSP generally and the load element in particular were intended to be applied to circumstances which gave rise to an actual change in Hydro's revenues or costs. At page 90 of the Report, the Board states, repeating in part its words on p.88 in item (vi) where it enumerated the changes from Hydro's proposed RSP:

> The Board recommends that any earnings variation because of a difference between the estimated load and the actual load be included in the Rate Stabilization Plan so that Hydro's earnings will not vary. (Emphasis added)

The concern was clearly to ensure that Hydro was made whole in respect of additional costs and refunded amounts which represented income not expected to be received on the basis of its forecasts. There was never a suggestion that the RSP was intended to re-distribute cost responsibility among Hydro's customers. If Hydro's income was not affected, there was no need for the RSP to effect a rate change in response to any experienced result, whether or not that result varied from the forecast.

It became clear in the responses to IC-271, IC-278 and IC-284 that the manner in which Hydro implemented the RSP re-allocated cost responsibility among Hydro's customers. This is reflected on p. 5 of 6 of IC-278 which shows monthly re-calculation of Average and Excess Demand factors which were used under the former Cost of Service methodology to assign costs to customer classes. The calculations shown by Mr. Osler in his evidence make it clear that in 2000 alone, an amount in the order of $1,500,000 in cost was transferred from NP to the Industrial Customers as a result of RSP calculations. This amounts to changing the rates applicable to various customers on the basis of a revised cost of service study that has never received the approval of the Public Utilities Board. In each rate referral, the Board used the cost of service study to determine the appropriate rate to be charged by Hydro to NP. In order to do that, it approved cost allocations as between NP and other customers in order to determine what costs were considered reasonable and prudent under the Act to be recovered from NP. Hydro, through the operation of the RSP, has taken it upon itself to alter those allocations without any reference or application to the Board. It has effectively failed to charge the rates which were approved by the Board and the Lieutenant-Governor in Council by charging in the RSP to Industrial Customers cost elements such as demand related costs in addition to those mandated by the Board and included in base rates. Essentially, the Board decided in 1992 what demand elements NP should pay. That decision determined, by exclusion, what demand elements the Industrial Customers should pay since the Board had to divide up the total demand costs in order to determine a proper rate for NP to pay. Neither NP nor the Industrial Customers have paid, since the first month after implementation of the 1992 Report, the amounts that the Board determined since Hydro has re-allocated those demand elements in the RSP every month since.

Another effect of the management of the RSP which needs examination is the impact on the allocation of rural deficit during the years that that deficit was paid, in part, by Industrial Customers. This is explained at p. 5 of the Pre-Filed 2nd Supplementary Evidence of C. F. Osler. The re-running of the cost of service on a monthly basis from 1992 to 2000 produces different ratios which have assigned an additional $911,000 in rural deficit to Industrial Customers since 1993. The reversal by Hydro of its error in continuing to charge the RSP portion of the rural deficit to Industrial Customers after January 1, 2000 reduces the amount outstanding to $354,000. As these changes in no way impact Hydro's revenue or income, they should not be permitted to affect the Industrial Customers in this way and the Board should reduce the balance in the industrial RSP by the amount so improperly charged.

Perhaps more significant from a regulatory point of view is that this practice effectively undermines the Board's regulatory control and contravenes the Electrical Power Control Act. The Board regulates, as directed by the EPCA, based on a forecast test year or years (EPCA s.3 (a)(ii)). The entire scheme of regulation is based upon Hydro forecasting its costs and revenues and submitting them for the Board's scrutiny. It is then for the Board, and the Board alone, to determine what the rates shall be. The Board may, and does, provide for automatic adjustment mechanisms in respect of items such as fuel costs but the Board does not and cannot abrogate its responsibility to approve the assignment of costs among customers pursuant to the Cost of Service Study. If this were to be the case, the Board would simply be directed to approve a cost of service methodology and let Hydro charge whatever rates that methodology produced in any year. In fact, what Hydro has been doing is even more destructive of the process because it abandons the notion of forecast test years altogether and re-adjusts rates ex post facto based on actual results in any given year or month. While it would be within the power of a legislature to direct that utilities determine actual loads, revenues and costs at the end of each year and then go back and surcharge each customer according to its actual share of total costs (or alternatively, charge next years customers according to their performance in the previous year), this is exactly the opposite of what the Newfoundland and Labrador legislature has done in the EPCA. There is of course good reason for what the legislature has done, both in terms of practical implementation of a system of rates and in terms of inter-generational equity. The point here is, however, that in accordance with proper principles of public utility regulation and the clear dictates of the legislation which binds both Hydro and the Board, rates are to be set on a forecast basis and are not to be re-adjusted on a monthly basis based on actual results. If circumstances develop such that a rate is inappropriate because of changing cost characteristics of a class of customer, then it is incumbent upon Hydro to apply to change the rates. In some situations, a complaint to the Board by a customer may be justified but Hydro is really the only party who would be privy to all the information necessary to determine that cost allocations were, as a result of changing circumstances, no longer fair. It is not, however, for Hydro to manipulate existing rates in a manner inconsistent with forecast test year regulation for any purpose, and any party whose rates have been inappropriately charged as a result must be able to seek satisfaction and recompense through an order of the Board.

RSP Summary and Conclusions

1. The current plan is extraordinarily complex and can produce dangerously misleading results. It inappropriately attempts to move the risk of accurate load forecasting away from the utility and on to the ratepayers by an exercise in ex post facto rate making which is contrary to the intent of the EPCA. Simpler mechanisms need to be adopted to adjust fuel cost variations on a shorter term basis and hydraulic variations on a longer term basis leaving Hydro to manage the risk of load forecasting, as its expert said it should.

2. The balance in each of the existing RSP accounts, industrial and retail, should be amortized over a five year period and paid off by an energy surcharge on rates.

3. Hydro should be directed to determine the proper balance in the industrial RSP by:

(a) eliminating the effect of demand cost re-allocation from 1985 to date, including assignment of additional rural deficit charges, and reducing the balance in the industrial plan accordingly; whether such elimination should result in additional charges to the retail RSP is an issue for the Board-given that NP was apparently aware of how the charges were being calculated and may have relied on that scheme since 1985, it may be inappropriate to add charges to NP. Nonetheless, the charges to the industrial plan are clearly improper and should be corrected, even if the resultant cost falls to Hydro;

(b) while this is clearly a prospective provision to determine future rates, should the Board determine that its jurisdiction does not allow it to make alterations in rates based on events prior to the time that the Industrial Customers' rates became subject to Board approval, such demand cost re-allocation should be removed from the date at which the rates to Industrial Customers became regulated in 1996;

(c) the RSP charges to the industrial plan arising from the continued use of Albright and Wilson and Royal Oak Mines load in determining the load variation for Industrial Customers be reversed from the dates on which those operations ceased in Newfoundland.

In granting this relief, the Board needs to consider certain provisions of the **Hydro Act**. Section 17(1) provides, in part:

"(1) The corporation shall…

(b) adopt and maintain the rate stabilization plan of the corporation on the basis reflected in the audited financial statements of the corporation for the year ended December 31, 1994,

until the Board of Commissioners of Public Utilities otherwise orders under the Public Utilities Act."

Section 17(5) provides:

"(5) The rates, tolls and charges for, and the rules applicable to, each kind of service provided or supplied directly or indirectly to or for the public immediately prior to the

> coming into force of this section or a corporation by the corporation immediately prior to the coming into force of this section shall apply to the same kind of service so provided or supplied by the corporation until altered under the Public Utilities Act and, notwithstanding that Act, no alteration shall have retroactive effect on those rates, tolls or charges or increases, including by providing for refunds or credits to customers."

The 1994 Financial Statements of Hydro (produced in answer to CA-101) show a liability of $5,000,000 associated with the RSP, i.e. at that time Hydro owed consumers $5,000,000 under the Plan. There is also a note concerning the Plan which reads as follows:

> "On January 1, 1986, Hydro, having received the concurrence of the PUB, implemented a rate stabilization plan which primarily provides for the deferral of cost variances resulting from changes in fuel prices, levels of precipitation and load. The balance in the plan is amortized over a three year period. Adjustments required in retail rates to cover the amortization of the balance in the plan do not require a reference to the PUB and are implemented on July 1 of each year. Similar adjustments required in industrial rates are implemented on January 1 of each year. "

This is the basis on which the plan is reflected in the statements of 1994. Note that it specifically refers to "cost variances" and does not extend to cost re-allocations. Whether or not Hydro can rely on Section 17(1) to justify the manner in which it has operated the RSP since 1994, the Board clearly has jurisdiction to modify the terms of the Plan, including the provisions for recovery of amounts owed to Hydro under the Plan. Hydro has, for example, already credited to Industrial Customers amounts improperly charged under the Plan that relate to rural deficit contributions which Industrial Customers were no longer required to make. The Board should in its order confirm that such credit was properly made. Equally, the Board may direct that Hydro not recover certain amounts from Industrial Customers on the basis that the charges to the RSP were not made in accordance with the intent of the Board's report in 1985. This is no reflection on Hydro's having followed the legislative direction in Section 17(1); it merely represents an appropriate exercise of the Board's power to determine what rates Industrial Customers will pay from this point on.

The Board should also note that as of the 1994 financial statements of Hydro, Albright and Wilson and Royal Oak Mines were still customers of Hydro. The legislative direction in Section 17(1) can have no impact on actions taken thereafter by Hydro. It was open to Hydro and, in our submission, more consistent with the intent of the RSP and fairness to customers, to eliminate the load of Albright and Wilson and Royal Oak Mines from RSP calculations at the time they ceased to be customers. The impropriety of not doing so cannot be saved by a legislative provision that did not have that situation in contemplation.

Accordingly the Board can and should direct the alterations to the RSP outlined above in order to calculate the appropriate amount to be included in Hydro's rates to Industrial Customers in the future.

PART 3: REVENUE REQUIREMENT ISSUES

CAPITAL BUDGET

In its current proposal, Hydro is seeking approval of $40,946,000.00 for capital projects in 2002.[99] This is revised from its initial filing which sought $43,112,000.00.[100]

By Order P.U. 30(2001-2002), the Board, with the consent of the parties, approved certain projects, over $50,000.00 each, the total value of which is approximately $27.1 million, without prejudice to the rights of the parties, including the Industrial Customers, to make submissions regarding

(1) the sufficiency of the documentation supplied to support a capital project generally;

(2) the principles and procedures applied in the capital budget process; and

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[99]Revised Capital Budget, November, 2001.

[100]Capital Budget filed May 31, 2001.

(3) an adjustment to the 2002 Capital Budget to reflect Hydro's historical budget versus actual expense experience.[101]

In addition, the parties are entitled to argue the merits of those projects to which they have not consented.

Section 41(3) of the **Public Utilities Act** provides that Hydro shall not proceed with the construction, purchase or lease of improvements or additions to its property where the cost of the construction or purchase is in excess of $50,000.00 or the cost of the lease is in excess of $5,000.00 per year of the lease, without the prior approval of the Board.[102]

Implicit in section 41(3) is authorization to Hydro to proceed with projects having costs less than those thresholds, provided that Hydro takes the risk that the board, after the fact, may disallow cost recovery on the basis that those projects were imprudent or unjustified.

CAPITAL BUDGET PRINCIPLES AND PROCEDURES

[101]Order P.U. 30(2001-2002).

[102]**Public Utilities Act**, supra, 41(3).

Hydro's capital budget is contained in Schedule "D" to Hydro's rate application. Starting at page B-6, Hydro provides its commentary with respect to its approach to approval of projects over $50,000.00. Hydro states:

> "It should be recognized that because of the nature of the individual project, not all decisions to proceed are supported by formal cost benefit studies . . . The majority of projects included in Hydro's 2002 capital budget have no formal cost benefit studies supporting the decisions to proceed. These projects are required for one or more of the following reasons: to protect human life, to meet projected customer load demand, to prevent imminent interruption of customer service, to comply with pertinent regulations, standards, etc., to protect Hydro's assets against loss or damage, and to maintain power system reliability and availability."[103]

Hydro points out that, notwithstanding the foregoing, before actual construction or implementation of a project is started, engineering analysis is undertaken to ensure that the most appropriate technical and cost-effective solution has been identified. If there are a number of technically acceptable alternatives to address a particular problem or when implementation of a new alternative may offer cost advantages over an existing condition, cost-effective analysis are performed.[104]

The Industrial Customers submit that Hydro's approach to its capital budget process as outlined on page B-6 of its proposed 2002 Capital budget is unacceptable because:

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[103] Capital Budget, page B-6.

[104] ibid

1. the exemptions from the requirement for a Cost Benefit Study are so broad that virtually no projects require one; and

2. it does not make sense to have the Board approve a capital project before Hydro determines cost-effective solution.

The Capital Budget submitted by Hydro for approval, itself, illustrates the first point. Of the 68 projects over $50,000 in Part B of Hydro's original Capital Budget, all but 1 (97%) state that a formal cost benefit study was **not** required. Only project B-10, "Install 25 kV Distribution Line - Ebbegunbaeg" and project B-57, "Upgrade Diesel Plant - Harbour Deep", alleges that a cost benefit analysis was completed. However, even then, for example, for B-57 - Harbour Deep, the comparison costs are upgrade versus interconnection, not upgrade versus non-upgrade.

The Industrial Customers submit that, before Hydro files its Capital Budget it should have thoroughly investigated and decided upon the most appropriate technical solution. It should be required to provide a detailed analysis of the expected cost of the project, the cost, in dollars and in practical terms, of not proceeding and the gains expected in cost reduction, operational efficiency and reliability, if the project is approved. In addition, Hydro should be required to outline the nature of the options it has considered, the approximate costs of each of those options, the advantages and disadvantages of each option and the reason shy it is preferred/rejected. No projects should be exempt from these minimal requirements.

David Reeves provided an example of the second point. He testified that there are approved capital projects which Hydro cancels intentionally. He indicated that Hydro had, at one time, approved a capital project to install new diesel fuel tanks in Nain. Subsequently, Hydro looked at alternatives and determined that it could purchase directly from local suppliers and canceled the project.[105] If that had happened in a year when Hydro's rates were being set, the costs associated with the storage tanks would have been included in customers' rates even though the project was unnecessary and had not proceeded.

In the current hearing, there is another similar example.

In its May 31, 2002 filing Hydro proposed a 2002 capital expenditure of $2,109,000.00 to replace its AS400 computers.[106] No formal cost benefit study was required. In addition, it is clear from the description under "Nature of Project", that despite the amount of funding requested, Hydro did not expect to make a decision whether to purchase or lease until 2002, <u>after</u> the capital budget was expected to be approved.[107]

[105]Transcript, David Reeves, October 2, 2001, page 28, lines 31-75.

[106]Capital Budget, page B-64.

[107]<u>ibid</u>.

No justification for replacing the computers was provided in the proposal submitted to the board, other than the fact that the 5 year lease was due to expire. The option of keeping the existing computers was not being considered.[108]

In answer to Information Request NP 116)a), Hydro justified this capital expense on the basis that continued use of the AS400s would “prevent Hydro from taking advantage of enhancements of the latest software releases”, particularly, the One World version of the J.D. Edwards financial suite.[109]

On cross-examination, Hubert Budgell testified that, in relation to the replacement of the AS400 computers and the J.D. Edwards financial suite: “What I understand is that I think it’s, if it’s not 2002, it’s 2003, the J.D. Edwards group will not be supporting the current application as we have it, so we have to move, we have to move up to the next suite of operations.[110]

This turned out to be entirely inaccurate.

On cross-examination on behalf of the Industrial Customers, one of whom happens to use the J.D. Edwards financial suite, it was suggested to Mr. Budgell that the current version of the J.D.

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[108] ibid.

[109] Information Request NP - 116(a).

[110] Transcript, Hubert Budgell, November 5, 2001, page 27, lines 7-17.

Edwards financial suite would be supported until at least 2005. Mr. Budgell then indicated that his earlier testimony reflected his best memory of communications with Hydro's Information Services and Technology Group and undertook to check for financial documentation on the issue.[111]

This inquiry resulted in the production of an e-mail from J. D. Edwards dated 2000 indicating that they would support the current software until 2005. However, Mr. Budgell then indicated that Hydro is planning to move to the new software over a two year period beginning in 2003 requiring testing in 2002.[112]

By November 30, 2001, Hydro's Revised Capital Budget contained a revised B-64 reducing the requested capital expense by approximately $2 million to $143,000.00.[113]

Clearly, the proposed capital expenditure was not justified and, the lack of required documentation to support the proposed expenditure resulted in a complete misunderstanding on the part of Hydro and its witness of the need for the project.

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[111]Transcript, Hubert Budgell, November 8, 2001, page 1, lines 19-51.

[112]Transcript, Hubert Budgell, November 9, 2001, page 36, lines 62-91 and U-Hydro-23.

[113]Revised Capital Budget filed November 30, 2001, page B-64.

Similar problems regarding the lack of appropriate substantiation of the need for capital projects are encountered in the other projects to which the Industrial Customers have objected.

For example, even in relation to projects such as B-57 - “Upgrade Diesel Plant - Harbour Deep (Previous $35,000.00; $515,000.00)”, although it is alleged that failure to complete the work “could” result in the interruption of power supply to Hydro’s customers, there is no study or outline of how that could occur, how likely it would be to occur or the nature of the possible interruption in time/reliability/cost consequences. Similarly, while the cost benefit analysis compared the proposal to interconnection as an option, it does not appear to have considered the status quo.

For project B-21, for example, involving $152,000 to purchase and install a closed circuit surveillance system in Holyrood, it is alleged that this will enhance security for the site and will improve public safety. However, there is no explanation relating to serious security issues for the site, no outline of public safety problems, no analysis of the risk to the site of failure to install versus installation and no analysis of the nature of the risk to public safety, the degree of risk or how failure to install various installation would affect that risk.

Even on environmental projects, the rationale is sometimes very thin. For example, Project B-19 “Purchase and Install Continuous Emission Monitoring:” at a cost of $801,000.00.

The proposal acknowledges that air emissions from the Holyrood Generating Station are below the statutory limit. The Industrial Customers have to question why they would be required to contribute to the cost of a monitoring system when the evidence is that Hydro is meeting or exceeding current statutory requirements.

All of the above, and other similar examples in the proposed capital program for 2002 lead to the conclusion that there is inadequate control over Hydro's capital expenditures and inadequate accountability to the Board and the ratepayers for the success or failure of capital projects.

The feasibility study with respect to the wind demonstration is another example. Mr. Budgell testified on November 8, 2001 that the capital cost was reasonable.[114]

However, the revised capital budget withdraws the cost of the wind demonstration project feasibility study from Hydro's capital budget.

This is in sharp contrast to the testimony from Melvin Dean and Jay Backus on Abitibi's capital budget process and from Glenn Mifflin on North Atlantic's process.

[114]Transcript, November 8, 2001, page 8.

On cross-examination, Melvin Dean commented that Hydro's capital budget didn't appear to be tied to anything, such as depreciation or load growth.[115]

Mr. Backus testified that Abitibi's capital budget is limited to 50% of its depreciation cost. Half of that goes into projects that are absolutely essential, such as replacing bad roofs, and the other half is divided between major strategic projects and value added projects. Value added projects are required to have a 2 year payback.[116]

In addition, there are audits to see if the objectives have been met and a mill's budget is reduced the following year to reflect the expected savings or efficiency gains.[117] Mr. Backus had experienced similar restrictions with other paper companies.[118]

Mr. Backus made particular comment respecting projects like B-60 - "Document Management and Imaging System" which says it is the first phase of implementation but doesn't outline the expected scope and cost of the full project, doesn't seem to require a cost benefit analysis and has little

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[115]Transcript, January 10, 2002, page 14, lines 40-53.

[116]ibid page 14, lines 57-78.

[117]ibid, lines 79-87.

[118]ibid, page 15, lines 34-44.

supporting documentation. Mr. Backus felt he would not be able to get such a project approved, based on what was filed.[119]

Mr. Dean testified that proposal B-61 - "Purchase Additional Corporate Applications" for $517,000 seemed more in the nature of an allotment for as yet undetermined needs, rather than a justification of actual, required, software.[120]

Glenn Mifflin also testified on capital budgeting. He indicated that in his company capital dollars are scarce and the budgeting process is rigorous. All proposed projects are prioritized and the highest priority goes to projects meeting the company's strategic goals. The floor, for consideration of a capital project would be a payback of about 3 years or an internal rate of return of 30%, with projects exceeding that criteria getting greater priority.[121]

To get approval, a capital project proposed at North Atlantic must be supported, justified and have the benefits properly outlined. If approved, then the benefits are monitored and, if savings are projected, the amount of the expected savings is reduced from the following year's budget.[122]

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[119]ibid, lines 49-79.

[120]ibid, lines 80-94.

[121]Transcript, January 10, 2002, page 35, lines 71-85

[122]ibid, page 36, lines 2-25.

The Industrial Customers submit that the foregoing illustrates the need for the Board to give direction to Hydro with respect to its capital budget process. The Industrial Customers suggest the following criteria be applied:

1. Except where new generation is demonstrably required or in extraordinary circumstances, Hydro’s capital budget shall not exceed its forecast depreciation cost for that year.

2. All projects not involving serious environmental or safety risks shall require a cost benefit analysis.

3. Projects involving serious environmental or safety risks shall be supported by evidence describing the nature and level of the risk, the consequences of failure to act in that year, the standard Hydro is attempting to achieve and information on legislated or industry standards applicable to the risk.

4. In general the applicable environmental standards shall be those set by the appropriate governments.

5. Projects projected to result in savings or efficiencies will only be approved if the projected savings and/or efficiencies are built into the subsequent year’s budget.

6. All options to the proposed project should be shown to have been investigated and costed against the proposed project prior to submission to the Board.

7. In addition, Hydro should be required to file, as part of its budget submission, copies of the proposal together with such supporting documentation as was submitted to Hydro's Management Committee.

8. Capital projects intended to add value should have a maximum payback of 5 years.

9. The expected costs and benefits of multi-year projects must be known when the project is first submitted to the Board.

PROJECTS TO WHICH THE INDUSTRIAL CUSTOMERS OBJECT

The Industrial Customers submit that items B: 7, 10, 14, 15, 16, 17, 18, 19, 21, 22, 23, 25, 31, 32, 34, 46, 57, 60, 61, 62, 63, 64, 66, 67, 68, 69, 71, 72, and 74 do not meet even the most basic requirements or justification for approval and should be disallowed.

OVERALL CAPITAL BUDGET

In addition to the foregoing problems on a project by project basis, the Board's financial consultants, Grant Thornton, have pointed out that over the last 10 years Hydro has consistently underspent its approved capital budget by 15%.[123]

While various explanations have been offered, the fact remains that significant underspending of approved capital budgets has been a regular occurrence.

Grant Thornton has recommended that Hydro's overall budget for those capital projects which the Board approves be reduced by 15% to account for the likelihood that the capital budget will be underspent.[124]

The Industrial Customers support that recommendation, which, based on the proposed capital budget would reduce the revenue requirement for 2001 by $507,000.00 and for 2002 by $424,000.00[125]

RETURN ON EQUITY/CAPITAL STRUCTURE

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[123] Pre-filed testimony, W. Brushett, page 15

[124] Ibid, page 15

[125] Ibid

Several issues need to be addressed under this heading. These are revenue requirement issues as, to the extent that Hydro is allowed any return on equity, its revenue requirement increases to allow it to recover those amounts. Some points have been raised which the Board need not actually address at this point. The Industrial Customers wish to present their positions on (a) the capital structure (b) the rate of return on equity (c) ratepayers' equity and (d) on-going rate of return regulation, but a brief review of the legislative framework should come first.

Hydro and the Board are subject to the direction in the **EPCA**, section 3(a)(iii) that rates:

> "should provide sufficient revenue to the producer or retailer of the power to enable it to earn a just and reasonable return as construed under the Public Utilities Act so that it is able to achieve and maintain a sound credit rating in the financial markets of the world."

Section 3(b) goes on to say in part:

> "all sources and facilities for the production, transmission and distribution of power in the province should be managed and operated in a manner…
>
> (iii) that would result in power being delivered to consumers in the province at the lowest possible cost consistent with reliable service…"

Further the Board is directed under Section 4 as follows:

> " 4. In carrying out its duties and exercising its powers under this Act or under the Public Utilities Act, the public utilities board shall implement the power policy declared in section 3, and in doing so shall apply tests which are consistent with generally accepted sound public utility practice."

The intent clearly is that Hydro achieve and maintain a sound credit rating and it is that intent or purpose that should guide the Board's thinking on this point. The "just and reasonable return" is merely a tool to reach the goal of a sound credit rating. Management to allow delivery of power at the lowest possible cost consistent with reliable service and the invocation of generally accepted sound public utility practice means that only those costs that are prudent and necessary for the production of power should be allowed to be recovered in rates. These basis principles need to be reflected in the Board's consideration of the issues that follow.

Capital Structure

Hydro, as all witnesses agree, now has a sound credit rating in the markets of the world, and it will continue to maintain that so long as it has the guarantee of the Government of Newfoundland and Labrador on its debt. There is no evidence of any intention on the part of Government to withdraw the guarantee and Hydro (and ultimately the ratepayers) pay a generally appropriate guarantee fee to keep it available. While that fee can "buy" Hydro its sound credit rating, the commercial sensible decision is to continue to pay it rather than attempt to move to a stand-alone situation which could only be viable with a much different debt/equity structure.

There is no economic justification for requiring the injection of many millions of dollars in equity into Hydro to attain a "stand-alone" sound credit rating when the guarantee does the same without the requirement of injecting all those millions.

Further, the evidence is clear that Hydro has no control over its “retained earnings”. Hydro responds, and feels bound to respond, to whatever demands Government makes for dividends. This is clearly illustrated by the test year plan to pay out a dividend of some $70 million which, all witnesses agree, runs directly contrary to Hydro’s expressed goal of building up its equity.

There is no point in the Board attempting to set rates which would allow equity to build up to a “stand-alone” capital structure level when Government can, at any time, frustrate the Board’s intention by taking dividends. The only alternative left to the Board is to deem that the dividends were not taken, the result of which would be more return to Government since retained earnings would have to be deemed to be what they would have been without the dividend having been paid. If equity is to be injected into this company, it should come, as in the private sector, from the shareholder-the Government-and not from the ratepayers. Rates must be set to provide such return as the legislation requires but no additional amount should be allowed in rates for the purpose of building up equity. If that did happen, it would simply increase ratepayers’ equity, as discussed below. In any event, without a mechanism to keep the equity in the company, the goal of assisting Hydro to achieve a sound credit rating on a stand-alone basis cannot be served in any event, even if that were to be accepted as an appropriate goal.

In summary, there is no pressing need to increase the equity in this company. If Government sees fit to do so by injecting capital, so be it, and that would probably be a wise investment decision on the part of Government. That decision is, however, beyond the control of the Board; the Board’s job under the **EPCA, 1994** is to set rates which will maintain the credit rating and ensure that power is provided at the lowest possible cost consistent with a good level of service. The most economical alternative is clear and does not require the Board to address capital structure targets at this point. In any event, as referred to below, when capital structure is approached from the point of view of the after-tax weighted average cost of capital, the debt/equity ratio becomes for the most part a measure that is not relevant to the Board's consideration.

Rate of Return on Equity

Typically, the real issue for cost of capital witnesses is the level of return to be allowed, i.e. the percentage that is to be applied to the equity to determine the appropriate return. That is not really an issue in this case. If Hydro has equity which should attract a return, the requested return of 3%, based on the collective opinion of expert and non-expert witnesses alike, is so far below the "market" rate that no debate on that point is necessary. Hydro's only justification for calling cost of capital witnesses, and thereby putting others to the expense of replying to them, is that it wished the Board to give an indication of the level of return that it might expect to approve when

Hydro requests a "market" rate. As the evidence developed, it became clear that the "market" rate will have to be assessed at the time that Hydro actually applies for such a rate of return. The Board would really be wasting its time trying to determine a 2002 reasonable rate when Hydro is not requesting it. Hydro's cost of capital witnesses seemed to withdraw somewhat from the request for an "indication" of the market rate as the hearing progressed and simply expressed a concern that no one take the Board as suggesting that 3% was a reasonable rate.[126]

Given that the Board has more than enough other, real, contested issues to decide, it need do nothing more than state at this point that it is satisfied that 3% is not inappropriate in the circumstances but that it has not determined what a reasonable rate should be for 2002 and will not do so until such time as an application requests approval of a market rate.

Ratepayers' Equity

All of the experts agree that it is the investor in any enterprise, regulated or non-regulated, that is entitled to the return on its investment. Note in the pre-filed evidence of K. S. McShane the references to "a fair return on investor-supplied capital"[127]; "capital provided by investors"[128]; "investor-supplied capital"[129] and her numerous references to investor expectations.

As in any proceeding, it is the duty of the Board to identify the investment, i.e. the equity in a regulated utility on which the investor, the shareholder, is entitled to a return. That equity is

[126]Testimony of Douglas Hall, Transcript, Nov. 1, 2001, p. 26 line 82 to p. 27 line 19

[127] page 3, lines 11-12

[128] page 6, line 8

[129] page 10, line 10

composed of the initial investment in the company, normally by the purchase of shares from the treasury of the company itself, together with the retained earnings in the company, i.e. the part of the net income that represents return to the initial investment that has been allowed to be "retained" by the company rather than being paid out by way of dividend to the shareholder. For any number of reasons, requirements of bankers, provision of working capital or funding capital works, the rational shareholder will allow retained earnings to accumulate in a company.

The facts of the present matter are clear. Government, as "shareholder", made no initial investment in Hydro. The only shares that have been issued by Hydro to Government are those issued on the acquisition by Hydro from Government of the shares of CFLCo which had previously been acquired by Government.[130] Those shares are part of the unregulated operations of Hydro and Hydro has been scrupulous in excluding those shares and dividends relating to them from Board scrutiny. Accordingly, the Board cannot look to any existing shares of Hydro as representing any "investment" by Government in respect of which Government could be entitled to a return.

The Board must therefore look to the source of the "retained earnings" of Hydro which are part of its regulated operations. This becomes clear from an examination of the birth of Hydro as reflected in its audited financial statements produced in response to IC-211. Hydro became a corporation in 1975 under the provisions of the Hydro Corporation Act. It is, by law, the successor the Newfoundland and Labrador Power Commission which had an accumulated deficit on its books at

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[130] IC-211

the time of its demise of $2,465,275.00. Accordingly, Hydro began its life with that deficit. It is, of course, only because Hydro is a Crown corporation that such a situation could have occurred. A private company would have required some equity, even if only a dollar, in order to exist as a corporation. In order to operate, a private company would require some source of funds, and, while private companies can operate almost entirely on debt (provided such debt is supported by a credit-worthy guarantor), generally it is in the interests of the owners of any private enterprise of any size to provide some equity, to give the company credibility with financing institutions, provide working capital, facilitate tax planning and avoid the company's being totally dependent on the whims of its bankers. However, Government, through the Legislature, could and did create Hydro with a deficit and without investing any money in it.

The amounts which were to become the regulated retained earnings of Hydro begin showing up in its financial statements in 1976. The source is clear from the financial statements at IC-211. These were monies contributed by the customers of Hydro, i.e. the ratepayers, both utility, industrial and residential, above and beyond the cost of providing the electrical service which they used.

With the advent of the **Electrical Power Control Act** in 1977, a rationale for collection of these funds was enunciated by the legislature and Hydro, and confirmed by this Board. Hydro was to set rates to "recover…a margin of profit sufficient to achieve and maintain a sound financial position". Clearly, this was not a direction to require a "profit" in the ordinary sense of the word which would allow Hydro to operate on a stand-alone basis, and neither Hydro nor this Board has ever taken the position that the **EPCA** as it then existed provided any such mandate. The margin was at the earliest stages of regulation for Hydro defined to be a margin over interest expense sufficient to allow Hydro's debt to be regarded as self-supporting. Initially, the range of interest coverage was set at 1.15-1.25 times and rates were set at the midpoint of 1.20. Over the years, while the guideline was never formally abandoned, rates were often set to provide a lesser level of coverage, most recently in 1992 when rates were designed to produce a coverage of 1.08 and the Board declined to express any opinion on where that coverage should be going in the long term.[131]

The scheme of regulation did not then provide for a return on investment. A margin was required basically to cover risks of forecasting and provide some comfort that interest could be paid when due even if business did not develop in the way it was expected to when the rates were set. Essentially, the margin was used to build up a cushion to be used by Hydro to protect it from unforeseen events. Further, the margin was regarded, by all the participants in the regulatory process, including Hydro, as being a contribution by ratepayers to the capital program of Hydro. The then president of Hydro, Victor L. Young, said that explicitly at both the 1981 and 1983 hearings as appear from Consents 1 and 2 filed in this hearing. It was clearly contemplated that while these margins were being earned and those earnings "retained", these were ratepayers' funds invested in the future of their electrical utility.

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[131] 1992 Report, p.93, 2nd last paragraph

A number of conclusions flow from this characterization. Firstly, these funds, being an investment by the ratepayers, are to be treated as zero cost capital for purposes of regulation. This puts these amounts in the same category as the allowance for future employee benefits properly designated by Ms. McShane as zero cost capital. Dr. Vilbert in his evidence confirms that this is the appropriate designation for amounts contributed by ratepayers beyond the costs that are properly recoverable from them.[132]

Secondly, these amounts, which were not invested by Government, cannot support the payment of dividends to Government. These are ratepayer funds and must be segregated from retained earnings for regulatory purposes and preserved for the benefit of those who contributed them.

This is no different from the imposition by the Board of the Rate Stabilization Plan. In times when there is a surplus in the Rate Stabilization Plan, revenues which would otherwise go the Hydro's bottom line and become retained earnings are diverted by order of the Board to a separate account to allow those monies to be refunded to ratepayers in accordance with the rules of the RSP. Mr. Roberts confirmed this effect in his evidence.[133] Equally, this "ratepayers' equity" must be isolated in a separate account and kept separate from the "shareholders' equity" (i.e. retained earnings), the latter being the only account from which dividends may be paid.

[132] Pre-filed testimony of Michael J. Vilbert, page. 31 lines 7-10)

[133] Transcript November.15, p.23 line 53 to p. 24 line 2

A third, and incidental, effect is to enhance the notion of Hydro as more like an investor-owned utility. Hydro management, under this arrangement, now has a manageable pool of “equity” which it can deal with in the same way as private sector managers do, free from the overriding decisions of Government, based on considerations unrelated to the best interests of the utility, to extract monies from Hydro by way of dividend.

A further implication is that the Board must scrutinize amounts that Hydro has purported to “charge to equity” over the years. Such charges can only be justified against shareholders’ equity and not against this ratepayers’ equity. Donations and items such as the costs of privatization of Hydro referred to in its consolidated financial statement of 1994 at Note 11 (produced as part of CA-101) and discussed with Mr. Wells at p.39 of the transcript of September 25 at lines 8 to 56, should be restored to the ratepayers equity account and charged directly to the shareholder. The effect may be to reduce non-regulated equity, but that, of course, is not unlike what really happens in the case of an IOU.

There was, prior to the 1996 amendments, no legislative support for the notion that Government was to have a return on any “investment” in Hydro. There was no rate base and no one set a rate of return on rate base or a rate of return on equity. The Board fully exercised its jurisdiction over Hydro by setting an interest coverage margin and, Government not having invested in Hydro, there is no “fairness” argument which can support the need for any such return. Ms. McShane could not identify any off-balance sheet contribution by Government which merited such a return. Her only reference was to the debt guarantee, but it is clear that Government is now compensated for providing the guarantee by a fee which no one has suggested is unreasonable.

Further, one must never lose sight of the fact that the debt which Hydro inherited at its inception was in fact the debt of Government, being debt of the then existing government agency, the Newfoundland and Labrador Power Commission. Effectively, Hydro assumed debt of Government from the beginning without any compensation from Government for having done so. The guarantee by Government of that debt did not therefore change Government's financial position at the time, and given that the Hydro debt is self-supporting and Hydro is paying a guarantee fee, there is no adverse impact from Hydro on Government's financial position today. Mr..Hall was quite clear on that point.[134]

In summary, since the mid-1970's, ratepayers of Hydro have been contributing to it amounts above and beyond the cost of the service that they were getting from Hydro. There was no regulatory scheme in place to allow Hydro to earn a return on its rate base and no investment by Government in Hydro to which any such return should accrue. Hydro characterized these monies as ratepayers contributions while they were being made and pledged to apply these monies to Hydro's capital program. As such these monies were to reduce Hydro's borrowing and save interest expense which ratepayers would otherwise pay. These amounts have been allowed to accumulate in the

[134] See, for example Transcript, Oct. 31, 2001, p. 25, line 24-28

retained earnings account, but, in reality, this is zero cost capital and the Board should treat it as such.

On-going Rate of Return Regulation

The Board has been presented in this hearing with an alternative for regulating rate of return which, in our submission, will simplify the Board's task in future hearings and better illustrate the true nature of issues surrounding rate of return for public utilities. The evidence of Michael Vilbert presents a discussion of rate of return determination based upon the after-tax weighted average cost of capital or ATWACC. This discussion outlines a unifying theory behind what has been to some extent a "black box" type of exercise whereby an economist's notion of "risk" is translated into an accountant's notion of "profit" or return.

The more traditional route of establishing a cost of debt and a cost of equity and cumulating these to determine an overall return on rate base fails to address the interaction between the overall business risk of the company and the financial risk associated with a particular capital structure. The overall business risk is a result of economic forces in the marketplace acting on the company; the financial risk is oftentimes the result of decisions made by the management of the company. The ATWACC approach allows the Board to address the assignment of risk between debt and equity while accepting the fact that the overall business risk does not change unless financial distress begins to have an impact.

Dr. Vilbert has illustrated how the application of ATWACC principles needs to be modified to take into account the non-taxable status of Hydro, but the principles remain applicable and valuable to the Board once those modifications have been made. The value is illustrated in the clarity with which the flaws in the approach of Ms. McShane are exposed by application of these principles. Ultimately, Ms. McShane's approach implies that a company with more equity and less debt is a more risky company than one with less equity and more debt, and that point is made clearly in the Supplementary Evidence of Dr. Vilbert. It is not necessary to take the Board's time with detailed submissions on this subject at this point given that "market" rates of return are not at issue here. The Board has, however, had the benefit of a clear and rational introduction to a methodology which will greatly assist it when it needs to deal with these issues.

FUEL PURCHASING

The cost of Bunker "C" fuel is projected to be almost 1/3 of Hydro's total revenue requirement for 2002. However, it appears from the evidence that Hydro devotes minimal effort to controlling its fuel costs.

Hydro retains the PIRA Energy Group of New York for its petroleum product market analysis and price forecasting for crude oil prices.[135]

[135]Transcript, Robert Henderson, October 9, 2001, pg 36 lines 4-10.

Hydro has a fuel purchase contract under which it notifies its supplier one month in advance of its fuel purchase requirement. In other words, Hydro estimates what it needs for the following month and then orders it.[136]

Hydro's storage capacity in Holyrood is only 840,000 barrels[137] which is less than 3 months supply on average.[138] However, since the bulk of Hydro's thermal generation is produced in the November to March period, that storage capacity is less than 2 months supply in those winter months.

Mr. Henderson testified that Hydro doesn't normally look at the price in determining its shipments because it is too speculative.[139] Moreover, Hydro doesn't know, when it places its order, what the price per barrel will be.[140] Its contract provides that the price per barrel is the average price per barrel purchased in the month it is delivered, based on the price on the delivery date.[141]

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[136]Transcript, Robert Henderson, October 10, 2001, pg 24, lines 26-62.

[137]ibid pg. 24 lines 63-65.

[138]$100 million ÷ $28/bb1 = 3,571,428.5 bbls and 3,571,428.5 bbls ÷ 12 months = 297,619.05 bbls/mo.

[139]ibid, lines 75-99.

[140]ibid, pg 25, lines 2-6

[141]ibid, pg 25, lines 8-60.

PIRA provides its fuel price projections in U.S. dollars. According to Mr. Henderson, the treasury department at Hydro looks at exchange rates. However, it seemed from Mr. Henderson's evidence that there is little strategic purchasing or focused attention with respect to obtaining the best price for its Bunker "C" requirements.[142]

Mr. Henderson testified that he is responsible for hydraulic production and for managing fuel oil purchases. However, it seems from his evidence that his real responsibility for fuel is scheduling shipments to meet Hydro's production needs, not managing the cost of fuel.[143] The lack of a coordinated approach to minimizing fuel cost is further evidenced by the fact that Mr. Reeves, responsible for Hydro Rural, is responsible for purchases of diesel fuel for that system.

This approach can be contrasted with that of Abitibi as outlined by Mr. Dean and Mr. Backus. There is a person in each of their Newfoundland mills with responsibility for the cost of Bunker "C" and other fuels consumed. There is also somebody in Abitibi's head office in Montreal with overall responsibility for Bunker "C" and its pricing.[144] Abitibi purchases some Bunker "C" on the spot market, checking vessels at sea, to determine if Bunker "C" can be purchased at a good

[142]ibid, pg 25.

[143]ibid, pg 26, lines 2-30 and pages 42/43.

[144]Transcript Jan. 10, 2002, pg 9, lines 82-88.

price and uses various suppliers depending on its need. Abitibi also burns alternative fuels when they are available and has about nine months storage capacity.[145]

The Industrial Customers are concerned that Hydro may not be paying adequate attention to getting Bunker "C" fuel at the best time and price and that it may be overly limited by its Holyrood storage capacity. On the other hand, in order to determine if additional storage, new or leased, might be cost-effective, a detailed analysis of the cost of the storage versus the potential fuel cost savings and internal return on investment time would need to be undertaken.

The Industrial Customers recommend that the Board direct Hydro to develop an integrated, strategic approach to fuel purchases, based on a thorough analysis, on an on-going basis, of all options to reduce fuel purchase costs.

Given that a 1% reduction in forecast Bunker "C" costs results in savings of $1 million per year, this is worth pursuing.

HYDRAULIC PRODUCTION FORECAST

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[145]ibid, page 10.

Hydro proposes to use what it calls the longest available record to calculate its average hydraulic production. Newfoundland Power witnesses have suggested that a thirty year rolling average of Hydro's actual experience should be utilized.

The use of the thirty year rolling average would increase the forecast average hydraulic production, resulting in a forecast of reduced thermal production and significant reduced costs.

There do appear to be legitimate issues with respect to the reliability of some of the data used by Hydro as part of what it considers the available record. In particular, in the case of some of its largest hydraulic plants, in particular, at Bay d'Espoir, the early data included in the average includes inflows into the reservoir area from the major rivers in the area but not from all sources of water inflow. This raises the legitimate question whether the data from those years is, in fact, reliable.

The Industrial Customers submit that if Hydro is to use the longest available record, it should be the longest reliable available record that it uses to calculate its forecast average hydraulic production.

On the other hand, the Industrial Customers do not have any objection to the use of a thirty year rolling average as proposed by Newfoundland Power.

OTHER FORECASTING ISSUES

C. Thermal efficiency - Holyrood

The key component of Hydro's revenue requirement is the cost of fuel. One of the critical elements of that calculation is the number of kilowatt hours which can be expected from a barrel of bunker C fuel.

In 1992 Hydro used a thermal efficiency factor at Holyrood of 605 kilowatt hours per barrel. Hydro is now proposing a thermal efficiency factor of 610 kilowatt hours per barrel which it alleges is derived from the average thermal efficiency from 1996 to 2000.[146] This was confirmed by Mr. Osmond.[147]

Mr. Henderson testified that Thermal efficiency at Holyrood increases with load.[148]

The testimony shows that the years 1996 though to 2000 were five of Hydro's wettest years. In short, five of the years where it had the greatest hydraulic production and the least thermal production.[149]

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[146]Transcript, October 8, 2001, page 33, lines 63-68.

[147]Transcript, November 20, 2001, page 27, lines 47-48.

[148]Transcript, October 9, 2001, page 34, lines 37-38.

[149]Transcript, October 10, 2001, page 23, lines 18-21.

As noted in the section of this submission on Hydro's cost to be at a hydraulic forecast, Hydro's forecast cost forecast 2002 cost of service is based on the assumption that 2002 will be an average water year. In an average water year, thermal production would be higher than in wet years. Hence, thermal production in 2002 would be expected to be higher than it was in the wet years 1996 to 2000. Based upon the evidence of Mr. Henderson and Mr. Osmond, this should increase the efficiency of Hydro's thermal plant at Holyrood.

The Board's financial consultant, Mr. Brushett, testified that the production level at Holyrood for 2001 is only slightly less than the forecast thermal production for 2002.[150]

Mr. Brushett testified that the efficiency factor of 633 kilowatt hours per barrel experienced in 2001 should therefore be a better proxy for the 2002 forecast than the average thermal efficiency from 1996 to 2000.[151]

This calculation is explained on page 3 of that testimony at lines 17 -15.

In addition, Mr. Wells testified that Hydro has increased the efficiency of the plant through efficiency improvements.[152]

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[150]Transcript, January 8, 2002, page 15, lines 32 - 41. Pre-filed supplementary evidence of Hubert Budgell dated October 31, 2001, Schedule "A"

[151]Transcript, December 13, 2001, page 3, lines 17-18.

[152]Transcript, September 25, 2001, page 5, lines 28-32.

Hydro's answer to information request NT-262 shows that a 2% change in thermal efficiency at Holyrood would change Hydro's net income by approximately 1.5 million dollars. Using 633 kilowatt hours per barrel represents a 3.77% change from Hydro's proposed 610 kilowatt hours per barrel. This, using a simple mathematical calculation, should save Hydro's customers approximately 2.8 million dollars on the revenue requirement underpinning their rates. The Industrial Customers estimate that this would result in a $650,000.00 saving for the Industrial Customers over the Hydro's current proposal.

D. 2002 Forecast Load

The quantity of fuel required in a test year depends on the customer load forecasts. Hydro's witnesses testified that they base their load forecasts on information provided from their customers.

However, as noted in the testimony of Hubert Budgell,[153] the Industrial Customers Amount of Power on Order for the purpose of their contracts indicates the demand for which they will have to pay. However, since, at present, Newfoundland Power does not have a specific demand rate, its forecast maximum demand may or may not be accurate, with no financial consequences to Newfoundland Power.

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With respect to energy forecasts, Hydro also relies upon its customers.

In a test year, these Hydro's forecast peak and forecast energy requirement is a critical component of the cost for service study. As discussed elsewhere in this submission, the load factor which results from a utilization of these forecasts, is an integral part of assigning or allocating costs between Hydro's different customers. In a test year, the Board must be particularly vigilant to satisfy itself that forecast demand and energy consumption assumptions are reasonable.

Mr. Budgell in his second supplementary evidence at page 2 indicates that as a result of Newfoundland Power's revised forecast, Newfoundland Power's demand drops and energy is forecast to increase.[154] This will increase Newfoundland Power's forecast load factor and reduce the revenue requirement allocated to it under the cost of service.[155]

Mr. Budgell testified that normally, for the purposes of rate hearings, they accept Newfoundland Power's forecast. However, Hydro has not reviewed the revised forecast from October 2001 for its reasonableness although it did make the observation that it reduces load factor. According to Mr. Budgell, no explanation for the change has been provided by Newfoundland Power. No

[154]Transcript, November 6, 2001, page 19, lines 17-23.

[155]ibid, lines 24 - 41.

Newfoundland Power witness has testified with respect to its forecast change in its demand and energy needs for 2001 and 2002.[156]

With respect to the reasonableness of that forecast, Mr. Budgell acknowledged that Newfoundland Power's revised forecast increases Newfoundland Power's forecast load factor from 49.5% to 51.1%.[157]

Mr. Budgell, in looking at Hydro's reply to NT-121 outlined how load factor would be calculated over the period from 1996. By the Industrial Customers' calculation, as put to Mr. Budgell, Newfoundland Power's load factor over that period only hit 51.3% in the year 2000. Mr. Budgell testified that 2000 system peaked would have been lower because of a warm winter and it would be reasonable to expect that the load factor would have improved in 2000 for utility customers given what actually occurred.[158]

Mr. Budgell testified that, however, in this rate hearing we have forecasting for 2002 and the forecast is not normally based upon the warmest year.[159]

[156]ibid, line 45 -74.

[157]ibid, page 19, lines 25-29.

[158]ibid, page 21.

[159]ibid, lines 65-71.

Mr. Budgell also indicated that you would only expect higher energy requirements associated with a lower peak for Newfoundland Power if there was something material that had happened in the system. He is not aware of anything material that has happened in the system between the pre-filed testimony and the supplemental testimony.[160]

The answer to information request IC 80 indicates that, generally, the load factor forecasts have been higher than the actual .

The Industrial Customers submit that Newfoundland Power's revised demand and energy forecasts are not reasonable and should be rejected.

CALCULATION OF CASH WORKING CAPITAL

Mark Drazen of Drazen Consulting, expert on cost of service issues for Labrador City, in his pre-filed testimony, testified that Hydro has calculated a positive cash working capital requirement of $3,098,000.00 (evidence of J. C. Roberts, Schedule 3). This is comprised of a positive cash working capital requirement of $5,535,000.00 related to operation and maintenance expenses and a negative amount of $2,439,000.00 related to HST. According to Mr. Drazen, the net lag in time from the point when operation and maintenance expenses are incurred to the point when the corresponding revenue is received from customers is 19.37 days. However, Hydro collects HST

[160] ibid, page 22, lines 13-30.

from customers before they are paid to Government, reducing the cash working capital requirement. In addition, Mr. Drazen testified that interest payments provide the utility with cash working capital which reduces the cash working capital requirement.

Mr. Drazen recommended that the Board should include in the calculation of cash working capital, the offset provided by collection of interest expense prior to its being paid by Hydro. Mr. Drazen clarified that the interest expense which he would take into account in calculating the lag is for bonds with semi-annual payments. He would exclude from the interest adjustment the short term debt.[161] By Mr. Drazen's calculation, offsetting this negative lag in interest expense of $13,279,000.00 against Hydro's calculated positive cash working capital requirement of $3,098,000.00, results in a negative net working capital requirement of $10,183,000.00.[162]

According to Mr. Drazen's testimony, this amount should be deducted from the cash working capital and from the rate base, i.e. revenue requirement, recommended by Hydro.[163]

The Board's financial consultant, William Brushett, agreed in principle with Mr. Drazen's conclusions with respect to the handling of the cash working capital allowance calculation.[164]

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[161]ibid, page 16, lines 88 to 99.

[162]Pre-filed Testimony of Mark C. Drazen, Section 2 - Cash Working Capital, pages 4 to 7.

[163]Transcript, December 12, 2001, page 3, lines 93 to 99.

[164]Transcript, January 8, 2002, page 43, lines 15 to 40.

The Industrial Customers submit that Mr. Drazen’s recommendation with respect to reducing required cash working capital to take into account the lag related to interest expense on bonds payable semi-annually, be adopted by the Board. This would reduce the revenue requirement by approximately $10,000,000.00.

RECALL POWER

Hydro receives revenue from sales of recall power to Quebec Hydro which it holds and pays out to Government on a quarterly basis.

The amounts held from time to time from these recall sales are used by Hydro as cash flow, reducing its need for short term debt.

There is no evidence that Hydro is obliged to pay interest on this money to Government. However, Hydro deems that the balance owed attracts an interest expense equal to the short term cost of debt (8.3%) even though the funds, if invested on a short term basis, would not attract that amount of interest. The cost of interest included in Hydro's Cost of Service is $800,000.00[165] but there is no evidence that Hydro has any obligation to pay that out to its shareholder.

Similarly, the debt guarantee fee, which is a statutory, mandatory fee payable to Government, is supposed to be calculated based on Hydro's debt. However, Hydro includes $251,000 in its calculation of the debt guarantee fee as if there were a guarantee on the deemed, but non-existent, short term debt, which might exist in the absence of the recall power revenue.[166]

These notional costs of $1,051,000 associated with non-existent debt are proposed to be included in the rates Hydro charges its customers.

The Industrial Customers submit that, in the absence of an obligation to pay interest on amounts held, no interest should be included in the revenue requirement.

Similarly, since there is no debt associated with these funds, there is no guarantee from Government which would attract a guarantee fee so there is no legal obligation to pay that deemed $251,000 guarantee fee to the Government.

[165]Transcript, January 8, 2002, page 24 and PUB-56.1

[166]Ibid, page 42, lines 15-31 and transcript January 9, 2001, page 6 lines 54-65

It is true that, on this basis, the electrical consumers in the province will benefit from Hydro's use of this money. However, in the absence of an obligation on Hydro to pay out these amounts, they are not part of its cost of service and should be excluded from its revenue requirement.

DUPLICATION

During the course of this hearing it has been clear that there may be many opportunities for Newfoundland Power and Newfoundland and Labrador Hydro to reduce costs by cooperating with each other and avoiding duplication.

Any initiative which reduces Hydro's costs and, hence, its rate base, are in the best interests of all of Hydro's customers.

The Industrial Customers expect that the rate base issue may well be one of the reasons why it has been so difficult for Newfoundland Power and Hydro to agree on a means of reducing duplication.

This issue needs to be addressed by the Board. The Industrial Customers recommend that the Board should conduct a study of the potential areas where duplication exists and the possible solutions to reduce costs and then direct the utilities to act to reduce those costs.

OTHER ISSUES: REVENUE REQUIREMENT

1. The Industrial Customers are prepared to agree to the use of $20.00 per barrel for fuel in order to provide for gradualism in dealing with the proposed rate increase.

2. The Industrial Customers submit that the Public Utilities Board should effectively encourage conservation measures which would contain the growth of peak demand and energy usage on Hydro's system.

3. The Industrial Customers submit that the Board should direct Hydro to give increased focus to cost reduction projects and the Industrial Customers would support the type of Productivity allowance suggested by Mr. Brushett on page 4 of his supplemental testimony.

4. The Industrial Customers submit that the supplies inventory should be reduced by $600,000.00 as pointed out by Newfoundland Power in cross-examination of Mr. Roberts.

PART 4: RATE ISSUES

INDUSTRIAL CONTRACTS - GENERAL

Hydro has submitted to the Board for approval, four (4) proposed industrial contracts. A review of the proposed industrial contracts shows that, in general, the contracts are identical. However, the Corner Brook Pulp & Paper and Abitibi - Grand Falls contracts have provisions dealing with generation outage power, recognizing the different needs of those industrial customers which produce some of their own energy needs. The Abitibi - Grand Falls and Abitibi - Stephenville contracts contain provisions relating to wheeling, the Abitibi - Grand Falls contract refers to accounting for the "compensation energy" which Hydro is required to provide to it and the Abitibi - Stephenville contract contains a clause specifically referring to its interruptible B contract. The North Atlantic contract, as currently proposed, does not contain any similar special provisions.

Section 71 of the **Public Utilities Act** provides:

> "71. A public utility shall submit for the approval of the board the rules and regulations which relate to its service, and amendments to them, and upon approval by the board they are the lawful rules and regulations of the public utility until altered or modified by order of the board."

The Industrial Customers agree that pursuant to Section 71 of the **Public Utilities Act**, the Board has authority to approve the form of contract for the Industrial Customers, with variations between those contracts which relate to the service to be provided by Hydro to individual customers, is the equivalent of setting rules and regulations. Alternatively, the Board can approve a set of rules and regulations which incorporates the provisions of the contracts which are approved by the Board. Support for this proposition is found in Section 3 of the EPCA, 1994 which, in reference to the power policy of the province refers to "rates to be charged, either generally or under specific contracts".[167]

[167] EPCA, 1994, supra, Section 3(a).

As indicated during the course of the hearing, Abitibi - Stephenville, Abitibi - Grand Falls and Corner Brook Pulp & Paper agree with the contractual language proposed in the most recent versions of the proposed contracts filed by Hydro on January 9, 2002. However, while Article 8.02 does provide that "if the metering is installed on the low voltage side of transformers that are specifically assigned plant or owned by the customer, an appropriate adjustment will be made to account for losses in the transformers", all of the Industrial Customers dispute the appropriateness of the transformer loss adjustment proposed by Hydro and outlined elsewhere is this submission.

North Atlantic agrees with the proposed contract language with the exception of Article 9.04 relating to Hydro's proposed limitation of liability for damages arising from Hydro's own negligence, and, in particular, the proposed monetary ceiling or cap on that liability. This issue is dealt with in more detail in the next section.

The agreement of the Industrial Customers with respect to the proposed contractual language was without prejudice to its right to argue specific issues relating to rates to be charged, rate design and cost of service methodology and revenue requirement issues.

LIMITATION OF LIABILITY FOR HYDRO'S OWN NEGLIGENCE

Section 37(1) of the **Public Utilities Act** provides:

> “37(1) A public utility shall provide service and facilities which are reasonably safe and adequate and just and reasonable.”

Section 44 of the **Public Utilities Act** provides:

> “The public utility is responsible for all electric lines, fittings and apparatus belonging to it or under its control upon the customer’s premises being maintained in a proper condition, and in all respects suitable for supplying energy, but it is not responsible for damages arising from the use of the electric current in lines, fittings and apparatus not belonging to it or under its control.”

As noted above in the section on legislative framework, Section 17(7) of the **Hydro Corporation Act**, as amended, provides that until the Board approves the rules and regulations relating to Hydro’s service to the Industrial Customers, for example, “a contract for the supply by the corporation of electricity is considered to provide that the corporation is not liable for damages in respect of any delay, interruption or other partial or complete failure in that supply where those damages are caused by something which is beyond the reasonable control of the corporation.”[168]

A review of Section 44 of the **Public Utilities Act** and of Article 12 of the proposed North Atlantic power contract and equivalent provisions of the other proposed industrial contracts, reveals that the responsibility for damages assumed by Hydro and its customers pursuant to Article 12 is the same as that contemplated by Section 44 of the **Public Utilities Act**.

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[168]EPCA, 1994, Section 17(7) (as amended by the **Hydro Corporation (Amendment) Act**, **Electrical Power Control (Amendment) Act, 1994** and other acts (amendments) S. Nfld. 1995 Chapter 37, Section 7.

However, while Section 37 of the **Public Utilities Act** imposes upon Hydro the obligation to provide service and facilities which are reasonably safe and adequate and just and reasonable, and while Section 17(7) of the EPCA, 1994 provides, on an interim basis, that until the Board has approved the rules and regulations relating to Hydro's service a contract for the supply of electricity is considered to provide that the corporation is responsible for damages in respect of any delay, interruption or other partial or complete failure in that supply where those damages are caused by something which is within the reasonable control of the corporation, Hydro, in its proposed Article 9.04, seeks to obtain the approval of the Board to limit its liability both in respect of the types of damages which a customer can claim as well as capping its liability for those headings of damages for its own negligence which it is prepared to cover.

Abitibi witness, Mel Dean, testified that the provisions of Article 9.04 of the proposed Stephenville and Grand Falls contracts with a restriction on headings of damage and the cap of $1,000,000.00 are adequate for Abitibi for an incident involving Hydro's negligence. North Atlantic witness, Glenn Mifflin, provided evidence that due to the nature of the oil refinery process, the damages which might be suffered by North Atlantic as a result of a power outage caused by Hydro's own negligence, might well exceed the one million dollar cap proposed by Hydro. Mr. Mifflin testified that North Atlantic cannot accept a clause which, in respect of Hydro's own negligence, effectively provides for restitution to the three paper company Industrial Customers as a result of a sudden power outage but which, on its face, is unlikely to fully compensate North Atlantic for its damages in similar circumstances.

The issue with respect to Hydro's proposed liability for service provisions has been under discussion between the Industrial Customers and Hydro since Hydro's application was first filed in May, 2001. During the hearing, Hydro did not call any evidence explaining why it needed such a provision in its contract with North Atlantic or, indeed, any of the Industrial Customers. While we acknowledge that Mr. Mifflin's testimony was late in the hearing process, Hydro did not seek to call any rebuttal evidence.

North Atlantic submits that there is no evidence before the Board justifying a limitation of liability different from that set out in Section 17(7) of the EPCA, 1994. In other words, North Atlantic submits that Hydro should be responsible for damages suffered by its customers, without limit, when the damages are caused by something which is within the reasonable control of Hydro.

WHEELING RATE

Hydro originally proposed a wheeling charge for the Island industrial system set at 6.95 mills per kilowatt hour, derived by dividing the total Island interconnected transmission revenue requirement by the transmission energy output.[169]

In answer to IC-241, it is clear that the calculation of the total Island interconnected system transmission revenue requirement includes transmission assets that are radial and not part of the

[169] JAB-1, Schedule 1.5.

230 kV grid whereas all customers who currently wheel energy appear to be connected to the 230 kV grid.[170]

The allocation of radial transmission costs in the calculation increases the wheeling rate by 28.47% for the GNP interconnection transmission alone.[171]

Mr. Osler testified that there does not appear to be any basis to include non-grid radial transmission in the calculation of a wheeling rate where the wheeling only involves grid transmission.[172] In addition, Table 2 in the evidence of Paul Hamilton shows that the proposed wheeling rate is 7.1% higher than the existing rate.[173]

In addition, according to IC-118 Hydro, in its wheeling rate, assumes 4% transmission losses. However, as indicated in IC-118, the system losses percentage calculated by Hydro is actually 3.6%.[174]

Moreover, IC-256 indicates that system transmission losses in 2000 were only 3.43%.

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[170]IC-241 and IC-35.

[171]IC-241.

[172]Pre-filed Supplementary Testimony of C. F. Osler, September 12, 2001, page 31, lines 1 to 2.

[173]Pre-filed Evidence of Paul R. Hamilton, page 9.

[174]IC-118.

In the last nine years the system losses number, if rounded to the nearest whole number, would have been 3%. The average system losses over the last five years is 3.47%. The nine year average is 3.48%.[175]

The Industrial Customers submit that in the context of the present rate application, there is no reason why system losses should be rounded up to the next whole number.

PHASE-OUT OF INDUSTRIAL CUSTOMER CONTRIBUTION TO ROYAL SUBSIDY - 1996 TO 1999

Section 3 of the **Electrical Power Control Act 1994** declares that it is the policy of the Province that the rates to be charged for the supply of power within a province

> "(iv) should be such that after December 31, 1999 Industrial Customers shall not be required to subsidize the cost of power provided to all customers in the Province and those subsidies being paid by Industrial Customers on the date this Act comes into force shall be gradually reduced during the period prior to December 31, 1999;"[176]

That Section came into force in 1995.

[175] IC-246.

[176] **Electrical Power Control Act**, Section 3(a)(iv).

The use of the word “shall” in the clause is a mandatary direction to Hydro with respect to its rates.

However, as acknowledged by Hydro, it did not gradually reduce the subsidies being paid by Industrial Customers during the period 1996 to 1999. In fact, the first time the subsidy was reduced for the Industrial Customers was effective January 1, 2000 when the current interim rates were set by this Board.

The Industrial Customers submit that a gradual reduction in the subsidies paid by the Industrial Customers would normally have been interpreted to mean that, over the four years, the effect of subsidy reduction would have been that 20% was eliminated in 1996, 40% by 1997, 60% by 1998, 80% by 1999 and all by 2000.

Hydro’s failure to gradually reduce the Industrial Customers’ contribution to the rural deficit, as required by statute, was in breach of the statute.

The Industrial Customers submit that they are entitled to recover from Hydro the amount which they paid as contributions to the rural deficit in the period 1996 to 1999 which should have been deducted from their rates.

The Industrial Customers estimate that this would require a refund of $9,140,317.00.[177]

NEWFOUNDLAND POWER GENERATION CREDIT

Mr. Budgell confirmed Mr. Henderson’s testimony that Hydro has a contract with Abitibi - Stephenville for 46 megawatts of interruptible demand. Similarly, Hydro provides a deposit credit to Newfoundland Power for the ability to call upon its generation to meet peak. Both the interruptible availability of 46 megawatts and the Newfoundland Power capacity, according to Mr. Budgell, meet peak in a similar way.[178]

However, Newfoundland Power and Abitibi - Stephenville are compensated differently for this capacity i.e. for the availability of capacity to meet peak.

Mr. Brockman agreed that the mythology for compensating Newfoundland Power is significantly different than the mythology utilized for compensating Abitibi - Stephenville.[179]

Mr. Brockman also testified that you could not find the amount of the Newfoundland Power Generation Credit in the Cost of Service Study unless you did some calculations. However, he

[177]IC 8, page 202, subtracting column 4 from column 3.

[178]Transcript, November 6, 2001, page 3

[179]Transcript, December 3, 2001, page 46, lines 78-84.

acknowledged, that the Abitibi interruptible B credit is shown directly on page 94 of 94 of JAB-1, the Cost of Service Study.

Exhibit IC-9 was prepared by the Industrial Customers and submitted to Mr. Brockman under cross-examination.[180]

Ultimately, the exhibit demonstrates that the Industrial Customers are paying 1.22 million dollars for the Newfoundland Power generation credit and that the total value of the credit for all of Hydro's customers is 9.1 million dollars. On the other hand, if Newfoundland Power was paid $28.20 per kilowatt per year for its availability capacity to meet peak, being the same as Abitibi - Stephenville receives under its interruptible B contract with Hydro, the cost for the generation capacity would be 2.2 million dollars.[181]

This would have the added advantage of being a transparent charge, easily determined by reviewing the results of the Cost of Service Study.

Mr. Brickhill testified that the amount paid for the interruptible B capacity from Abitibi - Stephenville is much more easily determined than the value of the generation credit for

[180]This evidence starts at lines 63 on page 1 of the December 4, 2001 transcript and goes through to page 6.

[181]Exhibit IC-9, table showing options to pay for Newfoundland Power Generation Credit.

Newfoundland Power.[182] He also agreed that the type of service being provided by Abitibi in Stephenville and Newfoundland Power in making peaking capacity available is similar.[183]

The Industrial Customers submit that the Newfoundland Power generation credit, as presently implemented, is not appropriate.

The Industrial Customers submit that Newfoundland Power should be compensated for that generation capacity on the same basis as other customers of Hydro might be compensated for agreeing to curtail their demand i.e. make interruptible B power available.

The rate to be paid to Newfoundland Power for this benefit should be appropriately costed as indicated in Hydro's answer to NP -133. The appropriate rate would therefore be $14.10/kW.

INTERRUPTIBLE B - CURTAILABLE RATE

The Industrial Customers submit that a curtailable rate such as that given to Abitibi in Stephenville pursuant to its interruptible B contract with Hydro should be available to all of Hydro's customers who have the ability to interrupt their demand and provide peaking capacity to the system. This

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[182]Transcript, November 27, 2001, page 18.

[183]ibid, page 19, lines 31-39.

option has the potential to defer the need for additional generation capacity with a consequent benefit to all of Hydro's customers.

As noted above, the answer to information request NP-133 indicates that Abitibi - Stephenville is receiving only 50% of the reasonable rate for agreeing to curtail its demand.

On January 10, 2002, Mr. Deans testified that Abitibi - Stephenville would be prepared to provide that facility for twelve months of the year. It would also be prepared to consider making it available twenty four hours per day.

The Industrial Customers submit that the appropriate rate which the Board should set for interruptible B demand made available by its customers is $14.10/kw, in accordance with Hydro's response to NP-133.

NEWFOUNDLAND POWER ENERGY ONLY RATE

In this rate application, Hydro proposes an energy only rate for Newfoundland Power.

Mr. Brickhill, Hydro's rate design expert, testified that he recommends an energy only rate for Newfoundland Power. He testified that he does not believe that the energy only rate has any detrimental effects to other customers or to Hydro or to the public at large. He did, however, concede that since Newfoundland Power is not charged for demand, if it understates its demand requirement and overstates its energy requirement, it would be allocated less cost in the cost of service study and pay no penalty if its actual demand exceeds what it forecast. This contrasts with the situation for the Industrial Customers who, each year, provide a maximum demand forecast and have a power on order contract which penalizes them if their demand exceeds that which they forecast.[184]

Mr. Brickhill testified that he was not aware that his colleague from Foster Associates, Dr. Sarikas, had at the time of Hydro's 1990 and 1992 rate hearings, recommended a three part rate for Newfoundland Power. This included a demand rate, an energy rate and specifically assigned charges.[185] Mr. Brickhill admitted that Dr. Sarikas' testimony in 1990 is contrary to his recommendation in this rate hearing.[186]

Mr. Brickhill testified that he was not aware that at both the 1990 and 1992 Hydro rate hearings, Newfoundland Power had also proposed that it had a three part rate.[187]

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[184]Transcript, November 27, 2001, page 23.

[185]Exhibit IC-2, page 14.

[186]Transcript, November 27, 2001, page 25.

[187]ibid, page 26, lines 3 to 12.

Mr. Brickhill, on cross-examination was referred to an extract from a Foster & Associates report dated May, 1991 called “Costing Methodologies and Rate Design Study” which had been entered as Consent 16 in the January, 1992 Hydro rate hearing.[188]

Mr. Brickhill agreed that the Foster & Associates 1991 report to Hydro recommended the use of a three part customer demand energy rate form for Newfoundland Power, modification of industrial rates so that the industrial rate structure parallels the proposed Newfoundland Power rate design and consolidation of the separate Island industrial rates into a single rate class for cost of service allocation. Mr. Brickhill indicated that implementation of these recommendations would result in similar rate forms for both Newfoundland Power and the Island Industrial Customers.[189]

The 1991 study also states that the existing energy only rate for Newfoundland Power is probably wasteful of capacity due to the lack of a demand charge and economically inefficient because the energy charge is thereby substantially in excess of marginal energy cost. The report also says that the lack of a suitable demand charge inhibits a demand side management program and both demand and energy reduction since savings in demand by Newfoundland Power are not reflected in a reduction in demand charges.[190]

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[188] ibid, page 26.

[189] ibid.

[190] Exhibit IC-3, page 52.

Mr. Brickhill testified that he does not believe there is a revenue stability issue for Hydro involved in a demand rate.[191] Mr. Brickhill indicated that the use of a demand rachet would encourage peak saving because the reduction in the annual peak for the customer would also reduce the demand in all the months in which the rachet applies.[192]

Mr. Brickhill also testified that if Newfoundland Power controlled its generation solely for its own benefit then it would not be able to take advantage of a generation credit.[193]

The Board's 1992 Report at page 94 indicates that Hydro was proposing an energy only rate to become effective on May 1, 1992 and, if the Board concludes that a three part rate for sales to Newfoundland Power is superior to the existing energy only rate, a three part rate commencing January 1, 1993.

That 1992 Report also indicates that Paul Hamilton, then testifying on behalf of Newfoundland Power, initiated the proposal for the split demand/energy rate.

Mr. Brockman also recommended a demand/energy rate structure for Newfoundland Power in the 1990 and 1992 rate referrals.

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[191]Transcript, November 27, 2001, page 28, lines 9 to 14.

[192]ibid, lines 17 to 24.

[193]ibid, lines 86 to 96.

In its 1992 report, the Board recommended an energy only rate for Newfoundland Power effective May 1, 1992 and it recommended that Hydro and Newfoundland Power develop an acceptable rate form for review by the Board at the hearing to be held on Hydro's cost of service methodology which was also recommended in the 1992 Report.[194]

The 1993 Board Report indicates that, at that hearing, Hydro and Newfoundland Power informed the Board that their proposal for a three part rate had not yet been finalized and that they were continuing to negotiate on the matter. The Industrial Customers recommended that Hydro and Newfoundland Power be ordered to submit a three part rate for approval within a time limit set by the Board. However, the Board did not recommend a time limit for submission of a proposed three part rate.[195]

It appears from the record at this hearing, that at Newfoundland Power's 1996 general rate hearing, the Board in Order P.U. 7 (1996-97) directed Newfoundland Power to consult with Hydro on the development of an acceptable rate form containing an appropriate division of demand and energy costs. It further appears from a letter dated May 11, 2001 from Newfoundland Power to Hydro, that they simply decided they no longer wished to pursue the issue and, therefore, neither utility has pursued it any further.[196]

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[194]1992 Board Report, page 97.

[195]1993 Report, page 62.

[196]Information Request PUB 68.

In this hearing, Mr. Osler recommends a demand energy rate structure for Newfoundland Power. In addition, Dr. Wilson[197], and Mr. Bowman[198] recommend a demand charge.

Mr. Brockman in his pre-filed testimony in this hearing, doesn't recommend a demand/energy rate for Newfoundland Power but acknowledges that he has done so in the past.[199]

The Industrial Customers submit that a demand energy rate structure for Newfoundland Power sends better price signals, encourages accurate demand forecasts and encourages conservation. The Industrial Customers, therefore, recommend that the Board order that a demand/energy rate be set for Newfoundland Power for 2002.

TIME OF DAY RATES

The Industrial Customers are interested in time-of-day rates, particularly if they would provide a lower rate for off-peak hours.

PART 5:

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[197]Pre-filed Testimony, page 20.

[198]Pre-filed Testimony, pages 10 to 13.

[199]Pre-filed Testimony, page 28.

<u>INDUSTRIAL CUSTOMERS COST OF HEARING</u>

By application heard July 18, 2001, the Industrial Customers sought an order pursuant to Section 90(1) **<u>The Public Utilities Act</u>** that at the conclusion of the hearing they would be entitled to have their costs of the rate application to be taxed. This issue was argued on July 18, 2001. The Board ultimately determined that the application was premature and that it would address the costs issue at the conclusion of the hearing.

Section 90 of **<u>The Public Utilities Act</u>** provides:

> "(1)The costs of or incidental to a proceeding before the Board shall be in the discretion of the Board and may be fixed at a definite amount or may be taxed and the Board may order by whom they are to be taxed, to whom they are to be allowed, and the Board may prescribe a scale under which costs shall be taxed."

This is the very first hearing before this Board in which the rates charged to the Industrial Customers are regulated by the Board. Although Industrial Customers have participated in hearings since 1990, those hearings dealt with issues that were not directly related to their rates, although in some circumstances, as a result of provincial power policy, the results should have been the same as those between Hydro and the Industrial Customers in setting the unregulated industrial rates.

In this hearing, Hydro proposes new industrial contracts and proposes rates for services which it provides to its Industrial Customers. It is proposing an overall increase in the rates to be charged to Industrial Customers amounting to approximately 17%.

Newfoundland Power, as a regulated utility, is entitled to include in its rates the cost of regulatory hearings.

The Consumer Advocate, appointed to represent consumers in the province including Hydro's rural interconnected customers, rural isolated customers and Labrador interconnected customers, is entitled, pursuant to order-in-council, to have his taxed costs in relation to the hearing.

Hydro, too, proposes that it recover its hearing costs in its rates, although it proposes that these costs be deferred.

Each of Hydro, Newfoundland Power and the Consumer Advocate has called expert witnesses in relation to cost for service and rate design issues as well as in relation to capital structure and rate of return.

As the hearing has demonstrated, the issues before the Board include not only issues relating to Hydro's forecast costs, but also issues as to how those costs should be divided between Hydro's customers in its cost for service.

The Industrial Customers submit, as they did not July 18, 2001, that they would have been seriously disadvantaged if they had not participated in this hearing. Further, the Industrial Customers submit that they would have been seriously disadvantaged if they had not called expert witnesses in relation to the issues before the Board affecting them.

This hearing is part of a regulatory process that is mandated by government. If the Industrial Customers are to participate fully and properly in the hearing, like it or not, these costs have to be incurred by them.

There is precedent for the award of costs by this Board to an intervener such as the Industrial Customers. In the 1980's, the Federation of Municipalities was regularly awarded its costs of participating in Hydro's rate referrals.

In Newfoundland and Labrador Hydro v. Newfoundland and Labrador Federation of Municipalities, in 1979, The Supreme Court of Newfoundland, Court of Appeal, dealt with an appeal from a decision of the Board of Commissioners of Public Utilities awarding costs in a fixed sum to the Newfoundland and Labrador Federation of Municipalities. Hydro attacked the award of costs partly on the ground that the amount was excessive and partly on the ground that the costs should have been taxed on a party and party basis. That was rejected by the Court which found that the Public Utilities Board had the jurisdiction to make the costs award which it had made.

The Supreme Court of Canada dealt with the issue of costs in Bell Canada v. Consumer's Association of Canada, a 1986 decision,[200] the court concluded that there should be a broad interpretation of the indemnification or compensation principle and that the strict view of the courts with respect to costs, under Rules of Court, does not apply.

In that case, the principle had been adopted that the costs would only be available to interveners who had participated in a responsible way, and had contributed to a better understanding of the issuer by the Commission.

In this case, the Public Utilities Board has not issued guidelines with respect to the circumstances in which it will award costs. Thus, according to The Supreme Court of Canada, the Board has the discretion to award such costs as it thinks fair to those parties that it considers justly entitled to costs.

The Public Utilities Board has the discretion to award costs and to interpret the provisions with respect to costs in a broad way in order to achieve the objectives which seem to be reasonable in the circumstances.

The Industrial Customers submit that the objective of ensuring that the group of customers, representing all of the Island Industrial Customers of Hydro, that is otherwise unrepresented at the

[200]Copy submitted July 18, 2001.

hearing, is a circumstance in which it would be reasonable and prudent for the Board to award costs.

Obviously, this would be prudent only as long as the Industrial Customers had participated in the process in a valuable way.

The Industrial Customers submit that they have behaved in a responsible way and contributed to the understanding of the issues in this hearing. The Industrial Customers submit that they should be entitled to their taxed costs on a party and party basis. In the circumstances of this hearing, given the funding available to all other major participants, the Industrial Customers submit that a refusal to grant costs on a party and party basis would be unfair.

The Industrial Customers would also support an award of costs in favour of Labrador City.

PROCEDURAL ISSUES

It is apparent from the evidence, whether in relation to Government's rates in the isolated systems, preferential rates or the implementation of the 1993 cost service mythology, among others, that the Board has, in the past, either not set a time limit for Hydro to implement the Board's recommendations or has indicated that the recommendations be implemented at Hydro's next rate hearing.

The result, in the present case, given that it has been ten years since Hydro's last rate hearing was concluded, is that many good and valuable recommendations have yet to be implemented.

Most of those recommendations, such as those respecting preferential and government rates, and implementation of the 1993 cost of service mythology would have resulted in changes in cost assignments and, hence, rates, for Hydro's customers.

In the case of the Industrial Customers, Mr. Wells acknowledged in his testimony that if, in 1999 the generic cost of service mythology had been implemented instead of the interim cost of service mythology, the Industrial Customers would have saved approximately 3.3 million dollars. In 2000, they would have saved 3.7 million dollars.[201]

The Industrial Customers submit that, given the experience of the last ten years, any recommendations for implementation in the future should contain fixed times lines to be met by Hydro.

The Industrial Customers also have procedural recommendations with respect to the end of this hearing. In particular, the Industrial Customers recommend:

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[201]Transcript, September 25, 2001, page 29.

5. that all interveners receive a cost of service study prepared by Hydro based upon the Board's final order in this matter;

6. that all interveners should receive on an ongoing basis, RSP reports modified to show clearly the calculation of allocation and any customer splits, if such splits are so required under the final form of the plan.

7. Actual cost of service results should be provided to Hydro's Industrial Customers and to Newfoundland Power annually.

8. The interveners should be copied annually with Hydro's annual review reports prepared for the Board.

The above will make it easier for Hydro's customers, the interveners in this hearing to have basic information available to them to help them identify issues for future rate hearings, hopefully, streamlining those hearings.

In addition, the Industrial Customers recommend that the Board direct Hydro that, in preparing its next rate application, it provide, with its filing, that information which it would reasonably expect the parties to require in order to make an informed decision on its application.

In addition, the Industrial Customers recommend that the Board order Hydro to conduct a rate referral at least every three years in order to provide for rates which reasonably reflect the cost which Hydro is or should be incurring.

CONCLUSION

The Industrial Customers submit that the evidence in this hearing demonstrates that Hydro does not require the rate increases which it is proposing and that, in implementing the 1993 cost of service mythology, Hydro has effectively assigned costs to the Industrial Customers inappropriately.

The Industrial Customers submit that Hydro's application for a rate increase should be dismissed with costs to the Industrial Customers to be taxed.

DATED at St. John's this 21st day of January, 2002

JANET M. HENLEY ANDREWS, Q.C.

JOSEPH S. HUTCHINGS, Q.C.