Disclaimer

August 27, 2001

G. Cheryl Blundon
Board Secretary
Board of Commissioners of Public Utilities
Suite E210, Prince Charles Building
120 Torbay Road
P.O. Box 21040
St. John's, NF
A1A 5B2

Dear Ms. Blundon:

Re: Newfoundland & Labrador Hydro's 2001 General Rate Application

Please find enclosed the original plus seventeen (17) copies of the following:

1) Newfoundland & Labrador Hydro's responses to Requests for Information IC-211 & IC-227;

2) Hydro's Requests for Information NLH-1 through NLH-89; and

3) Hydro's reply to the Application of Island Industrial Customers affecting Information Requests IC-1, IC-18 (Rev), IC-86 and IC-103.

Yours truly,

Newfoundland and Labrador Hydro

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Maureen P. Greene, Q.C.
Vice-President & General Counsel

MPG/jc

Enclosure

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Q. (a) What consideration, if any, was given by the Department of Finance, Government of Newfoundland for the shares represented by the certificates produced in answer to IC 60?

(b) Provide a copy of any agreement relating to the issuance of these shares.

(c) How was it decided how many shares would be issued and why are there three different share certificates?

(d) Confirm that, aside from the consideration for the shares referred to in (a), no capital contributions have been made by the Government of Newfoundland to Hydro and that the full amount of retained earnings on a regulated basis being considered as equity for the purpose of this application represents an accumulation of amounts earned by Hydro as its net income or margin (previously expressed for regulatory purposes as an interest coverage margin) from sales to ratepayers.

(e) Provide a copy of the audited financial statements for Hydro or its predecessor for each of the years 1973, 1975 and 1975.

A. (a) The Department of Finance, Government of Newfoundland gave Newfoundland and Labrador Hydro 775,998 common shares of Churchill Falls (Labrador) Corporation Limited for the 22,503,492 shares of Newfoundland and Labrador Hydro.

(b) There was no written agreement relating to the issuance of these shares.

(c) Hydro issued the shares in exchange for 775,998 shares in Churchill Falls (Labrador) Corporation Limited (CF(L)Co) transferred to it by the Government of Newfoundland. These CF(L)Co shares were valued at $29 each for a total of $22,503,942. The 22,503,942 common shares issued by Hydro to the Department of Finance, Government of Newfoundland had a par value of $1 each. There was no specific reason why three share certificates were issued.

(d) The Government of Newfoundland provided a capital contribution of $2.2 million to Hydro for the costs incurred on the Muskrat Falls Project and $15.4 million for the purchase of shares in the Lower Churchill Development. Both of these contributions and their related assets are eliminated from the regulated financial statements. The full amount of retained earnings on a regulated basis arose from the accumulation of Hydro's net income less any dividends paid to the Province.

(e) Copies of the audited financial statements for 1973 and 1975 are attached.

Q. In respect of transformer losses:

a) How are such losses currently assigned by Hydro? Provide a schedule showing the total dollar amount associated with these losses and its assignment to customer classes.

b) Provide a schedule in the form of the schedule requested in a) above showing the same information assuming that Hydro's application in this proceeding is granted in its entirety.

c) Identify the financial effects for Newfoundland Power and each of the Industrial Customers of the differences between a) and b) above.

d) Identify the financial effects for Newfoundland Power and the Industrial Customers if transformer losses below 66 kV were specifically assigned and transformer losses from generation voltage down to 66 kV were assigned common.

A. In respect of transformer losses:

a) Transformer losses treatment is dependent upon the nature of the transformer. Losses on common transformers are allocated among the participating rate classes. Distribution transformer losses are therefore allocated among distribution level customers. Common transmission level transformer losses are allocated among rate classes based upon transmission level usage. Losses on transformers specifically assigned to customers are added to the demand and energy of the customer groups for costing purposes. Losses on customer owned transformers are invoiced to the customer, with one exception. Losses on transformers owned by Abitibi Consolidated – Stephenville are treated as specifically assigned to the Industrial class. The dollar amounts associated with those transformer losses cannot be isolated, as the losses affect the rates charged to customers, rather than having a rate per loss unit. Specifically assigning losses to the customer classes results in lower billing units and increased rates. Invoicing these losses increases billing units, and therefore reduces rates. In either case, Hydro is revenue neutral. The attached schedule shows the total billing units and revenue requirement, as it would have been had the current practice been continued (Page 3, Lines, 1-3, Columns 2-4).

b) Please see the attached schedule (Page 3, Lines 1-3, Columns 5-7).

c) Please see the attached schedule (Page 3, Lines 4-8).

d) If transformer losses below 66 kV were specifically assigned and transformer losses from generation voltage down to 66 kV were assigned common, both allocation factors and billing units would change. There would therefore be a shift in cost allocation after deficit, as well as in unit costs. Customer impacts are shown on the attached schedule (Page 4).

Newfoundland and Labrador Hydro
Transformer Losses Impact

		Part a) Specifically Assigned Transformer Losses Not billed			Part b) Proposed			Difference
	1	2	3	4	5	6	7	8
Line No		MWh	Rate	Energy Revenue	MWh	Rate	Energy Revenue	
1	Newfoundland Power	4,452,127	48.03	213,835,676	4,454,800	48.00	213,830,400	(5,276)
2	Industrial Customers - Firm	1,459,627	23.17	33,819,558	1,464,970	23.09	33,826,157	6,600
3	Total Revenue from Energy (Difference due to rate rounding)			247,655,234			247,656,557	1,323

Note: No demand impact is anticipated, as it is assumed the transformer losses will not result in any Industrial Customers exceeding Power on Order.

Part c) The impact on individual Industrial Customers is:

		Specifically Assigned Transformer Losses Not billed			Proposed			
	1	2	3	4	5	6	7	8
Line No		MWh	Rate	Energy Revenue	MWh	Rate	Energy Revenue	Difference
4	Abitibi Consolidated - Stephenville	564,278	23.17	13,074,321	567,512	23.09	13,103,852	29,531
5	Abitibi Consolidated - Grand Falls	145,334	23.17	3,367,389	146,290	23.09	3,377,836	10,447
6	Corner Brook Pulp and Paper Limited	517,568	23.17	11,992,051	517,568	23.09	11,950,645	(41,405)
7	North Atlantic Refining Limited	232,447	23.17	5,385,797	233,600	23.09	5,393,824	8,027
8	Subtotal - Industrial	1,459,627		33,819,558	1,464,970		33,826,157	6,600

Newfoundland and Labrador Hydro
Transformer Losses Impact

Part d)

		Proposed			Losses on > 66kV Transformers Common			
	1	2	3	4	5	6	7	8
Line No	**Energy**	MWh	Rate	Revenue	MWh	Rate	Revenue	Difference
1	Newfoundland Power	4,454,800	48.00	213,830,400	4,451,414	48.06	213,934,971	104,571
2	Abitibi Consolidated - Stephenville	567,512	23.09	13,103,852	564,278	23.13	13,051,750	(52,102)
3	Abitibi Consolidated - Grand Falls	146290	23.09	3,377,836	145,080	23.13	3,355,700	(22,136)
4	Corner Brook Pulp and Paper Limited	517568	23.09	11,950,645	517,568	23.13	11,971,348	20,703
5	North Atlantic Refining Limited	233600	23.09	5,393,824	232,447	23.13	5,376,499	(17,325)
6	Subtotal - Industrial Customers	1,464,970		33,826,157	1,459,373		33,755,297	(70,860)
	Demand	kW			kW			
7	Abitibi Consolidated - Stephenville	840,000	7.01	5,888,400	840,000	6.99	5,871,600	(16,800)
8	Abitibi Consolidated - Grand Falls	264,000	7.01	1,850,640	264,000	6.99	1,845,360	(5,280)
9	Corner Brook Pulp and Paper Limited	780000	7.01	5,467,800	780,000	6.99	5,452,200	(15,600)
10	North Atlantic Refining Limited	360000	7.01	2,523,600	360,000	6.99	2,516,400	(7,200)
11	Subtotal - Industrial Customers	2,244,000		15,730,440	2,244,000		15,685,560	(44,880)
12	Total			263,386,997			263,375,828	(11,169)

[1] Difference due to Labrador Interconnected Deficit Allocation, and Rate rounding

Note: Demand rate is impacted by assigning demand losses on customer owned transformers to common losses.

<u>IN THE MATTER OF</u> *<u>The Public Utilities Act</u>*,
R.S.N., 1990, c. P-47 (the "Act")

<u>AND IN THE MATTER OF</u> an Application by Newfoundland and Labrador 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

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Requests for Information

NLH-1 to NLH-89

(Filed pursuant to ss. 14 and 17 of the *Board of Commissioners of Public Utilities Regulations, 1996)*

Newfoundland & Labrador Hydro, Applicant

August 27, 2001

Newfoundland & Labrador Hydro ("Hydro") 2001 General Rate Review

Requests for Information from Hydro
To <u>Industrial Customers</u>

<u>Pierre G. Côté</u>

NLH-1 (Re: p. 7, lines 8-9)

How would ACI suggest the additional revenue requirement of $4.8 million be collected if a freeze on industrial rates was implemented?

NLH-2 (Re: p.3, lines 10-11; and p.4, line 16)

For any mills shutdown by ACI or those having a machine shutdown, provide the comparative power costs for each mill in the last full year of production with ACI-Stephenville in that year.

<u>Melvin L. Dean</u>

NLH-3 (Re: p. 10, lines 16-20)

Please outline the derivation of the amounts of $6,080,592 and $1,763,371.

NLH-4 For ACI-Stephenville and ACI-Grand Falls, provide a table of actual total manufacturing costs in $/tonne or dollars per year for the period 1992 to 2000 and forecast for 2001 and 2002 broken down by:

- Depreciation and Interest Costs;
- Labour Costs;
- Shipping Costs;
- Maintenance Costs;
- Power Costs;
- Wood or Fibre Costs;
- Other Costs;
- Profit; and
- Total.

NLH-5 (Re: p. 5, lines 12 to 14)

(a) Please show power costs as a percent of manufacturing costs from 1992 – 2000 with and without the Interruptible B arrangement.

(b) Include a description of how the electrical power costs increases compare to all other manufacturing costs over the period from 1992 to 2002.

NLH-6 (Re: p. 5, lines 1-2)

Provide a table of actual electrical power costs in ¢/kWh for the years 1992 to the present for ACI-Stephenville, ACI-Grand Falls and each of the other ACI mills.

NLH-7 Provide an estimate of mill demand at the ACI-Stephenville and ACI-Grand Falls mills that would be altered by the application of a seasonal TOU rate structure assuming that the ratio in rates between the periods November 1 to March 31 and April 1 to October 31 was approximately 1.5 to 1.

NLH-8 (Re: p. 15 – Off Peak Power)

(a) Has ACI-Grand Falls ever used the article with respect to off peak power?

(b) Can industrial customers currently shift their load from Hydro and to what extent? Would this be through generation or through load?

NLH-9 (Re: pp. 11-13 – Transformer Losses)

(a) Who owns the four transformers at the ACI-Stephenville mill? Why should all customers pay for the losses in these transformers?

(b) With respect to specifically assigned transformers at other customer supply points, why should all customers pay for the losses in these transformers?

(c) Please show where losses for specifically assigned or customer owned transformers are absorbed by Hydro (p. 12, lines 7-8).

(d) Please provide the New Brunswick, Nova Scotia, Hydro-Quebéc and Manitoba Hydro rate schedules for different voltage levels and associated transformer loss adjustments (p.13, lines 3-8). Are there differences for customer owned versus utility owned transformers?

NLH-10 (Re: p. 12, lines 4-5)

Please explain the statement "This is a convenient way of avoiding the details around meter location and if customers currently pay for losses or not."

NLH-11 (Re: p. 13, lines 5-6)

Provide details of Hydro-Quebéc's major discount per kilowatt for Industrial Customers taking power at high voltage.

NLH-12 (Re: pp. 13-14)

Explain why Hydro or other customers should bear the fixed cost of facilities normally borne by industrial customers when a strike occurs at the customer's facilities?

NLH-13 (Re: p. 5, lines 1-4)

(a) Please give the ranking of the Stephenville mill in terms of overall cost per tonne of newsprint produced from 1992 to 2000 and projected to 2004.

(b) Also, for the same period, provide its ranking in terms of electrical energy costs per tonne with and without the Interruptible B arrangement.

(c) Please state your assumptions with respect to power costs for the other mills in the ACI ranking.

NLH-14 (Re: p. 4, line 18 to 20)

Please show how the $3.2 million per year increase and 18.8% increase are calculated. Separate the increase to show the RSP impact and base rates impact.

NLH-15 (Re: p. 10 – Non-firm Rates)

(a) Please show how the 56% increase on line 10, p. 10, is calculated.

(b) Does the increase reflect the RSP adjustment for 2001 and 2002? If not, recalculate the increase with the RSP adjustments.

(c) What percentage increase in costs per tonne of newsprint is the change in non-firm rates to each of the ACI paper mills in Newfoundland? Please include the RSP impact for 2002 on the existing Interruptible rates if they were to continue.

(d) With the implementation of the power purchase agreement in 2003 for incremental generation on the Exploits River, please estimate how often Generation Outage Demand will be required by ACI and how it will change from the current circumstances in terms of energy, power demands and costs.

(e) What will the cost be to ACI assuming a one day outage is planned to number 4 generator at Grand Falls in 2002 with No. 6 fuel costing $28.00 per barrel, assuming current rate structure and the proposed rate structure? What will the cost to ACI be under each rate structure if the outage was a forced outage? Please show the percent change for each scenario.

(f) In 2000, ACI-Stephenville took Interruptible "A" at an average monthly load factor of approximately 25%. Assuming an industrial customer is taking 1,000 kW of Interruptible "A" at load factors of 10, 25, 40, 65 and 80% and the cost of fuel is $28/bbl, show the cost and the percent difference in cost to the customer at each load factor using the current rate structure for Interruptible “A” including the current RSP adjustment, the current rate structure for Interruptible “A” with the proposed firm rates and forecast 2002 RSP adjustment, and the proposed Interruptible rate structure and rates. Please show your calculations.

(g) Explain why the proposed rate as referred to on line 13 of p. 10 of the evidence of Melvin Dean is prohibitive.

NLH-16 (Re: p. 11 – Converters)

(a) What is ACI-Grand Falls’ plan with respect to 50Hz operation and conversion to 60Hz of the ACI mill in the next 5 years? Why?

(b) What is Corner Brook Pulp and Paper's plan with respect to 50Hz operation and conversion to 60Hz of their mill in Corner Brook? Why?

(c) Which customers require and control the need for the frequency converters at this time?

(d) If the frequency converter at Corner Brook failed and was out of service for one month, what would the impact be to Corner Brook Pulp and Paper? What would the impact be to other Hydro customers?

NLH-17 (Re: p. 15 – Interruptible "B" Power)

What is the cost to Stephenville for providing this service?

Dr. Michael J. Vilbert

NLH-18 (Re: p. 2, lines 5-8)

Dr. Vilbert states, "I testified before the Alberta Energy and Utilities Board ("AEUB") on behalf of TransAlta Utilities in 1999, and I have filed written evidence before the U.S. Federal Energy Regulatory Commission ("FERC"), the Canadian National Energy Board ("NEB") and before the AEUB in 2000."

(a) Please provide Dr. Vilbert's recommended ATWACCs for TransAlta in his evidence before the AEUB in 1999 and 2000 and in the evidence filed with the National Energy Board.

(b) In each of the three cases referred to in part a) above, please indicate what book value common equity ratio and equity return on book value corresponding to Dr. Vilbert's ATWACC recommendations were included in the companies' rate filings.

(c) Please provide a copy of Dr. Vilbert's evidence in the 2000 proceedings before the AEUB.

(d) As an independent expert on cost of capital, does Dr. Vilbert believe Hydro's ATWACC would be significantly different from that which he determined to be reasonable for TransAlta's transmission operations in his 2000 evidence? If so, please explain why and by approximately how much.

NLH-19 (Re: p. 6, lines 8-9)

At this reference Dr. Vilbert states, "Although the ATWACC is constant across a broad middle range of capital structures for investor-owned utilities as well as for Hydro, the before-tax weighted-average cost of capital for Hydro is not."

(a) Please explain if Dr. Vilbert believes the ATWACC for an investor-owned utility would be the same at 85% debt as at 60% debt.

(b) What does Dr. Vilbert believe constitutes a broad middle range of capital structures for a typical Canadian investor-owned utility?

NLH-20 (Re: p. 4, lines 1-4)

Dr. Vilbert states, referring to Ms. McShane's evidence, "Note that she makes no adjustment in the return on equity in going from 15.27 percent to 25 percent equity and only a slight adjustment in going to a capital structure with 40 per equity."

(a) Please specify the return on equity that Dr. Vilbert has concluded that Ms. McShane has estimated at a 40% common equity ratio, and please provide the references relied on in Ms. McShane's testimony for that conclusion.

(b) Please provide the references relied on to conclude that Ms. McShane has made any estimate of the return on equity at a 25% equity ratio.

NLH-21 (Re: p. 6, lines 11-12)

Dr. Vilbert states, "Specifically, the revenue requirement is higher, for higher levels of debt in Hydro's capital structure."

(a) Please confirm that this conclusion is a direct result of Dr. Vilbert's belief that the ATWACC is constant across a broad middle range of capital structures. If it cannot be confirmed, please explain why not.

(b) In light of the conclusion referenced in the preamble, what recommendation would Dr. Vilbert make to the Board with respect to the amount of debt which should be included in Hydro's capital structure?

NLH-22 (Re: p. 6, lines 5-7)

Dr. Vilbert states, “Even though Hydro pays no corporate income taxes, the benchmark sample companies used by cost of capital witnesses do; therefore, an appropriate opportunity cost of capital for evaluation is the ATWACC.”

(a) Please explain in further detail why the ATWACC of utilities who are taxable is the appropriate cost of capital for Hydro, which is not taxable.

(b) Dr. Vilbert’s qualifications in Appendix A indicate that he has given expert evidence on cost of capital in both Canada and the U.S. Would Dr. Vilbert use different tax rates for Canadian companies than for U.S. companies to estimate their ATWACCs?

NLH-23 (Re: p. 21, lines 3-5)

Please provide a copy of the article cited at this reference.

NLH-24 (Re: p. 21, lines 7-8, and p. 21, lines 8-9)

Please provide a copy of the articles cited at this reference.

NLH-25 (Re: p. 28, lines 6-8)

Dr. Vilbert states, “The debt guarantee provided by the Province has no effect on the ATWACC for Hydro because Hydro is paying a debt guarantee premium that compensates the Government for the credit risk to taxpayers of providing the guarantee.”

As an independent expert on cost of capital, does Dr. Vilbert believe the guarantee is a component of the debt cost or a component of the return on equity? Please explain the answer.

NLH-26 (Re: p. 31, lines 7-8)

Dr. Vilbert states, “ No, but if it is shown that ratepayers have provided the equity, that equity would be equivalent to the ‘no cost’ capital.”

(a) Please explain in detail what criteria Dr. Vilbert would use to evaluate whether ratepayers have provided the equity.

(b) In Dr. Vilbert's opinion, do retained earnings constitute ratepayer-supported equity?

NLH-27 (Re: p. 34, lines 4-5; and p. 35, line 1)

Dr. Vilbert states, "It may seem counter intuitive to believe that the revenue requirement increases by replacing 'expensive' equity with 'cheap' debt, but debt has no tax advantage for Hydro, whereas equity does."

Could Dr. Vilbert please clarify what he means by the tax advantage for Hydro from equity?

NLH-28 (Re: p. 34, diagram)

Dr. Vilbert shows that the ATWACC of IOUs rises more rapidly than Hydro's at higher levels of debt.

(a) Could Dr. Vilbert please explain why this is the case?

(b) Could Dr. Vilbert please indicate at approximately what levels of debt the deviation between the IOUs' and Hydro's ATWACC would occur?

NLH-29 (Re: p. B-32, lines 16-18)

Dr. Vilbert states, "Specifically, the price of the stock that underlies the DCF method will equal PV(Dividends) + PV(Option to Default), where PV is the prevent value of the quantity in parentheses."

(a) Please explain what is meant by the "option to default."

(b) Please provide documented support for this definition of the price of a stock.

NLH-30 (Re: p. B-37, lines 13-17)

Dr. Vilbert states, "This in turn will result in a negative correlation between measured ATWACC and the debt ratio, not because more debt lowers the ATWACC, but because a lower ATWACC tends to lead to more use of debt. That is, the negative correlation may be real, but the causality the exact opposite of that hypothesized in the AEUB's decision." Please provide the section of the AEUB decision to which Dr. Vilbert is referring.

Newfoundland & Labrador Hydro ("Hydro") 2001 General Rate Review

Requests for Information from Hydro
To Public Utilities Board

Dr. John W. Wilson

NLH-31 (Re: p. 9, Lines 6-9)

Identify any circumstances which would have changed since 1985 regarding customer bill volatility. Outline how circumstances have changed which would warrant the elimination of the Rate Stabilization Plan at this time?

NLH-32 Mr. Brockman states on p. 5 of his evidence that "The major issues of cost allocation were decided by this Board following the 1993 generic cost of service hearing. We should not now have to re-try most of them again anytime soon." What is Dr. Wilson's view of generic proceedings, rather than rate proceedings, as an appropriate forum for settling methodology issues?

NLH-33 (Re: p. 8, Lines 14-17)

Identify the specific items that would be included in the "cost savings to a utility if a customer leaves the system". Is this method of identifying the customer costs of a distribution network typically used in other jurisdictions?

NLH-34 (Re: p. 7, lines 4-8)

To what extent does the timing of the peak and the allocation method for demand costs influence the need for seasonal rates? Is it Dr. Wilson's recommendation that the seasonally differentiated rates be based on marginal or embedded costs?

NLH-35 (Re: p. 8, lines 6-9)

What is the cost driver, for example, peak demand or energy throughput, that is the determinant of investment in a transmission system? If the above answer is energy or a combination of energy and demand, how does a change in energy throughput that does not change peak demand, cause a change in transmission design?

NLH-36 To what extent is the sizing of a transmission line related to the magnitude of the load to be served versus the hours of use of the load to be served?

NLH-37 Related to classifying transmission costs:

(a) Is it true that the Federal Energy Regulatory Commission (FERC) regulates transmission pricing in the U.S.?

(b) Is it true that the so-called FERC pro-forma transmission rate called for in FERC Order 888 is universally used in the U.S., so long as there are no constraints, is calculated by dividing the total annual cost of transmission by the single coincident peak demand for point-to-point transmission service, and by either the single coincident peak, or the average of the twelve monthly coincident peaks for network transmission service?

NLH-38 Please provide the names of any U.S. and Canadian utilities that allocate transmission costs based on energy.

NLH-39 (Re: p. 8, lines 10-17)

(a) Is the size of a distribution substation used to transform voltage from transmission level to distribution primary voltage level determined on the basis of its total peak demand served? If not, how is it sized and what determines when it is fully loaded and requires reinforcement?

(b) What would determine the total peak demand of the aforementioned substation, the coincident peak demand of the various rate classes served by the substation or the sum of the non-coincident demands of the various rate classes? If the answer is the non-coincident peak demand, how does that sum, which is higher than the coincident peak demand, increase the load carrying burden of the transformer.

NLH-40 (Re: p. 8, lines 10-17)

Is it necessary for the distribution system to peak at the same time as the total system in order for the coincident peak method to be used with the local distribution system?

NLH-41 (Re: Dr. Wilson's Report, p. 18)

It is asserted that rate class contributions to those local loads are not generally measured with precision, and therefore some available proxy must be used. It is then recommended that the non-coincident peak method be used for that purpose. If rate class load research can identify the hour of the rate class non-coincident peak demand, should it not, with the same accuracy, be able to identify the rate class contribution to the coincident peak of distribution substations and primary circuits?

NLH-42 (a) Define the following terms:

- Incremental cost
- Short-run marginal cost
- Long-run marginal cost
- Long run incremental cost

(b) How is each calculated for an integrated electric utility?

(c) How should each of these costs be reflected in rate design?

NLH-43 What rate structure would be appropriate for a situation where the average energy cost is 3¢/kWh, the incremental fuel cost is 5¢/kWh, the average demand cost is $10/kW/month and the class load factor is 60%?

NLH-44 Based on your knowledge of TOU rates that have been implemented in other jurisdictions, what level of relative peak to off-peak costs are necessary for customers to change their usage patterns by a significant amount leading to a positive impact on the utility's expansion plan costs?

NLH-45 How does the existence of the RSP affect the implementation of marginal cost based rates?

NLH-46 (Re: Dr. Wilson's Report, p. 27, graph)

Do you agree that the horizontal axis of the figure of your Report represents the unit size of equipment, i.e., for distribution transformers, the kVA rating? Do you agree the vertical axis of the figure on p. 27 of your Report represents the unit cost of the equipment, i.e., for distribution transformers, the installed cost for each size transformer?

NLH-47 (Re: Dr. Wilson's Report, p. 27)

A statement is made that "there would still be no valid basis to attribute all of the difference between actual cost and zero load cost entirely to coincident peak demand and none of these costs to energy." What would be the rationale for treating any of the cost of distribution as energy related?

NLH-48 (Re: Dr. Wilson's Report, pp. 28, 29)

You point out that 5 apartment buildings each with 40 individually metered apartments would have essentially the same distribution system as 4 office buildings with overall identical peak loads. Would 200 single family homes with an average lot width of 30 meters have the same distribution system as 100 single family homes with an average lot width of 30 meters? What if the 200 and 100 homes were rural residences of the type served by Hydro?

NLH-49 (Re: Dr. Wilson's Report, p. 30)

What other clearly identifiable distribution costs besides "accounting and billing, meters, and service line drops" should be classified as customer related costs? Will the inclusion of only costs associated with accounting and billing, meters and service line drops tend to understate the level of customer related costs? Are there distribution costs that are not directly related to demand, energy or customer fluctuations?

NLH-50 Does the use of incremental fuel cost for the energy portion of the industrial non-firm rate reflect short run marginal pricing?

NLH-51 (Re: Dr. Wilson's Report, p. 38)

If "the generators that use this fuel exist for peaking purposes", why is it appropriate to classify this fuel expense to energy rather than demand?

Grant Thornton LLP

NLH-52 Please outline in detail the calculations shown in the table on page 48 of the Grant Thornton, LLP Report regarding the 2001 General Rate Review of Hydro. Also indicate the unit of measure associated with the "Retail adjustment".

Newfoundland & Labrador Hydro ("Hydro") 2001 General Rate Review

Requests for Information from Hydro
To Newfoundland Power

John T. Browne

NLH-53 (Re: p. 20, lines 14-17)

Mr. Browne states, "Therefore, there is a question whether the Government considered the cost of equity to be a cost recoverable through allowed rates at the time it decided to transfer funding for the Deficit from the taxpayer to the ratepayer. There is at least a question whether there was a recoverable cost in excess of the 8% margin."

Would Mr. Browne please explain in greater detail what he means by this paragraph?

NLH-54 (Re: p. 22, line 19)

Mr. Browne is asked the question, "If the Board considers Hydro's dividends to be excessive, what should it do?" to which he responds (lines 20-21), "Where the dividend payments result in higher revenue requirements, one option is to deem a capital structure as if the dividends had not been paid."

(a) As an expert on cost of equity, does Mr. Browne agree that Hydro is requesting a return on equity that is less than the opportunity cost of equity for a Canadian utility as referred to on p. 15, lines 20-22 of his testimony?

(b) As an expert on cost of equity, does Mr. Browne agree that the current opportunity cost of equity to a utility is higher than the total of Hydro's embedded cost of debt plus the guarantee fee? If no, please explain.

(c) Would Mr. Browne agree that the "higher revenue requirements" he refers to results from Hydro's proposal to earn a return on equity which is less than its embedded debt cost? If the answer is no, please explain the answer in detail.

NLH-55 (Re: p. 33, lines 15-24)

Mr. Browne lays out two issues that the Board should consider in deciding whether to approve switching to the accrual method.

(a) Does Mr. Browne consider that intergenerational equity is a third issue that the Board should consider in its decision? Please explain why or why not.

(b) Is there not an inconsistency between accepting the write-off of the transitional obligation (and not seeking to recover it) but at the same time remaining on the cash method for ratemaking purposes? Please explain why or why not.

(c) Is it Mr. Browne's position that, in principle, Hydro should switch to the accrual method, but not for the 2002 test year? Please explain. If the answer is yes, please provide the criteria the Board should rely on to determine when it is an appropriate time to switch methodologies.

Larry B. Brockman

NLH-56 Please provide a table showing Newfoundland Power's 2000 revenue from customer, energy and demand components by rate class and the proportion each component total is of the total revenue from rates.

NLH-57 (a) Define the following terms:

- Incremental cost
- Short-run marginal cost
- Long-run marginal cost
- Long run incremental cost

(b) How is each calculated for an integrated electric utility?

(c) How should each of these costs be reflected in rate design?

NLH-58 What rate structure would be appropriate for a situation where the average energy cost is 3¢/kWh, the incremental fuel cost is 5¢/kWh, the average demand cost is $10/kW/month and the class load factor is 60%?

NLH-59 Based on your knowledge of TOU rates that have been implemented in other jurisdictions, what level of relative peak to off-peak costs are necessary for customers to change their usage patterns by a significant amount leading to a positive impact on the utility's expansion plan costs?

NLH-60 How does the existence of the RSP affect the implementation of marginal cost based rates?

NLH-61 (Re: Conservative Hydraulic Production Forecast)

(a) Why choose 1992 – 2000?

(b) How many years of hydrology were used in assessing the average energy capability of Rose Blanche?

(c) How many years of hydrological records are involved in the energy capability of all of Newfoundland Power's plants?

(d) What guarantee is there that since it was wet last year, it will be wet this year?

NLH-62 (Re: p. 15, lines 1-13 - Including Granite in Hydraulic Production)

Prior to Granite coming into service, how will the 224 GWh be produced? What will happen to the RSP balances? Is it prudent to cause these changes? Why?

NLH-63 (Re: p. 9 – RSP Cap)

(a) Please elaborate on how a cap of $50 million provides Hydro an incentive to operate efficiently and a $100 million cap does not.

(b) Please explain why a fully regulated utility would decide to absorb the additional RSP cost when it is a true cost incurred to supply customers.

(c) Given the projected year end balances in the RSP for 2001 and 2002 are above $50 million, how are you proposing the amount over $50 million be dealt with if all other aspects of Hydro's cost of service do not change?

(d) If Hydro is able to keep all of its controllable costs under control so that financially it does not require a rate change and its largest uncontrollable cost, world fuel prices, have risen causing higher thermal production costs, should it have a public hearing to review all its costs? Similarly, if Newfoundland Power keeps all of its controlled costs under control so that a rate change is not required, should it have a public hearing to review all its costs at a pass-through hearing resulting from the current Hydro application? Please explain the difference.

(e) If Hydro is more efficient and reduces its costs, should it absorb the additional production costs due to rising world fuel prices? If Newfoundland Power is more efficient and reduces its costs, should it absorb some of the costs passed on to it through the RSP to avoid a rate increase? Please explain the difference.

NLH-64 (Re: p. 23, lines 11-23)

Does Mr. Brockman agree that weather is the single most important variable determining Newfoundland and Labrador Hydro's peak demand? If the answer is no, please identify the single most important variable determining Newfoundland and Labrador Hydro's peak demand.

NLH-65 (Re: p. 28, line 4)

Mr. Brockman indicates that Hydro's rate design goals, as outlined by Mr. Osmond on p. 7 of his evidence, are appropriate. These goals include the continuance of lifeline block rates for Domestic customers in Isolated Rural System areas, yet on p. 27, lines 1 – 2 Mr. Brockman states "I see no economically justifiable reason for having a long term goal of serving any class of customer at 20% - 50% of their cost of service." Please indicate how Mr. Brockman expects to increase the cost recovery for the Domestic rate class above 20% through rate design given the class currently recovers approximately 16% of their cost of service.

Newfoundland & Labrador Hydro ("Hydro") 2001 General Rate Review

Requests for Information from Hydro
To Consumer Advocate

Dr. Basil Kalymon

NLH-66 (Re: p. 14, lines 14-16)

Dr. Kalymon states, "If the actual level of equity in Hydro were to increase to a level of 40%, as proposed in the long-term by the company, the level of the guarantee fee would need to be reduced to a level of 50 basis points."

Please provide documentation for the 50 basis point spread between debt costs for the Province and for corporate bonds of similar debt rating.

NLH-67 (Re: Table on p. 13)

(a) Please explain why employee benefits are included as part of equity at zero cost, rather than as a separate zero cost capital item.

(b) Would Dr. Kalymon agree that, if the capital structure were restated to include employee benefits of 1.55% as a separate item, the 60/40 debt/equity capital structure could be restated so that debt and equity are 60% and 40% respectively of the capital structure not represented by employee benefits as follows:

Debt	59.07%
Equity	39.38%
Employee Benefits	1.55%

If Dr. Kalymon disagrees, please explain why.

(c) For ease of understanding, please assume that there are no employee benefits, and that Hydro's capital structure actually includes 60% debt and 40% equity. Would Dr. Kalymon's analysis indicate that the return on rate base is 8.307%, calculated as follows:

	Structure	Cost	Fee	Total
Debt	60%	7.345		4.407
			.5	.300
Equity	40%	9.0		3.60
				8.307%

If no, please explain why not.

(d) Would Dr. Kalymon agree that the Table on p. 13 indicates that he is recommending a return on the 15.27% of funded equity equal to 10.76%, inclusive of 50 basis points of the 100 basis point guarantee fee? If he does not agree, please explain why not.

NLH-68 (Re: p. 26, lines 4-6)

Dr. Kalymon makes a downward adjustment of 75 basis points to his comparable earnings test for the lower risk of regulated investments versus the industrials.

Please provide quantitative justification for this adjustment.

NLH-69 (Re: p. 25, line 14)

Dr. Kalymon states that the beta of the utilities is 0.37. At p. 28, lines 14-15, Dr. Kalymon makes a downward adjustment of 50 basis points for the lower risk of regulated activities relative to the total risk of the utilities.

Please provide the beta for utilities' regulated activities that is implied by the 50 basis point adjustment.

NLH-70 (Re: p. 32, lines 13-15)

Dr. Kalymon reduces the DCF cost of the utilities by 50 basis points for the lower risk of regulated investments.

(a) What is the approximate proportion of the total operations accounted for by non-regulated operations for the sample of utilities?

(b) Based on the response to (a) above, what is the DCF cost of equity for the non-regulated operations implied by the 50 basis point downward adjustment to the utilities' DCF costs for the lower risk of the regulated activities.

NLH-71 (Re: p. 13)

Please explain the derivation of the 1.655% found in the table on p. 13.

NLH-72 (Re: p. 34, lines 14-15)

Dr. Kalymon indicates that the expected growth rate is in the range of 8.75-10.0%.

In light of the industrials' dividend payout ratio, what is the indicated return on equity necessary to produce a sustainable growth rate of 10%?

NLH-73 (Re: p. 36, lines 11-12)

Dr. Kalymon concludes, "Given the current market conditions and assuming a deemed equity component of 40%, I would recommend a provision of 8.75% to 9.25%."

Would Dr. Kalymon please specify the market conditions which led him to increase the return on equity from 8.50-9.0% to 8.75-9.25%?

NLH-74 (Re: pp. 7-9)

Provide an explanation to support his opinion that Hydro's business risk is lower compared to other regulated utilities and provide copies of all information that he has relied on in forming that opinion.

NLH-75 (Re: p. 13)

Why have you not prepared this table on an ATWACC basis as proposed by Dr. Vilbert?

<u>C. Douglas Bowman</u>

NLH-76 (a) Define the following terms:

- Incremental cost
- Short-run marginal cost
- Long-run marginal cost
- Long run incremental cost

(b) How is each calculated for an integrated electric utility?

(c) How should each of these costs be reflected in rate design?

NLH-77 What rate structure would be appropriate for a situation where the average energy cost is 3¢/kWh, the incremental fuel cost is 5¢/kWh, the average demand cost is $10/kW/month and the class load factor is 60%?

NLH-78 (Re: p. 11, lines 17-19)

Please identify Newfoundland and Labrador Hydro's marginal supply costs by generation source. Does Mr. Bowman have an opinion on what the energy rate to Newfoundland Power would be under marginal costs? If the answer is yes, then please provide the rate.

NLH-79 (Re: pp. 10-14)

Regarding comments on Hydro's wholesale rate structure to Newfoundland Power, which would you consider to be more important for providing the correct price signal to promote efficient use of resources; to price the energy at close to incremental fuel cost or have a demand charge?

NLH-80 Based on your knowledge of TOU rates that have been implemented in other jurisdictions, what level of relative peak to off-peak costs are necessary for customers to change their usage patterns by a significant amount leading to a positive impact on the utility's expansion plan costs?

NLH-81 How does the existence of the RSP affect the implementation of marginal cost based rates?

NLH-82 (Re: p. 3, lines 17-18)

Is it possible or likely that "local" peak load occurs at the same time as system peak load when the peak is driven by weather?

NLH-83 (Re: p. 14, line 15)

Please provide a copy of the report entitled *Electric and Gas Rates for the Residential, Commercial and Industrial Sectors.*

NLH-84 (Re: p. 14, lines 5-7)

Would higher volatility in purchased power costs and resulting net income result in higher business risk and therefore require a higher ROE all other things being equal?

NLH-85 (Re: p. 10, lines 19-21)

Mr. Bowman states that "A simple rate design such as this is generally limited to low volume residential customers where it is not cost effective to have more administratively complex and costly metering and billing systems." Given the very large proportion that this customer group is for Newfoundland Power, please explain how the benefits would exceed the costs as described on p. 12 lines 14 – 18.

NLH-86 (Re: p. 12, lines 6-11)

Does Mr. Bowman believe Newfoundland Power would be interested in interruptible service from Hydro? Why or why not?

NLH-87 (Re: p. 11, line 11)

Please provide a copy of the supplementary evidence of Mr. Tom Connors and Mr. Larry Brockman referred to as Exhibit LBB-2 (Newfoundland Power 1996 Rate Application).

NLH-88 (Re: p. 15, line 13)

For which of Hydro's Domestic and General Service customers is Mr. Bowman referring, all systems or only certain ones?

NLH-89 (Re: p. 17)

Regarding comments on the RSP, what specific improvements would Mr. Bowman recommend?

<u>IN THE MATTER OF</u> the *Public Utilities Act,* R.S.N. 1990, c. P-47 (the "Act");

<u>AND IN THE MATTER OF</u> 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 51 of the Act, its 2002 Capital Budget.

REPLY TO APPLICATION OF ISLAND INDUSTRIAL CUSTOMERS AFFECTING INFORMATION REQUESTS IC-1, IC-18(Rev.), IC-86 and IC-103

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<u>IN THE MATTER OF</u> the *Public Utilities Act,* R.S.N. 1990, c. P-47 (the "Act");

<u>AND IN THE MATTER OF</u> 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 51 of the Act, its 2002 Capital Budget.

TO: The Board of Commissioners of Public Utilities (the "Board")

THE REPLY of Newfoundland and Labrador Hydro ("Hydro") to the Application of Abitibi-Consolidated Inc., (Grand Falls), Abitibi-Consolidated Inc., (Stephenville), Corner Brook Pulp & Paper Limited and North Atlantic Refining Limited (the "Industrial Customers") concerning certain Information Requests states:

1. To date Hydro has received Information Requests from all Intervenors that total by number in excess of 765. When individual parts to each of the questions are taken into account, the number of questions which Hydro has been asked exceeds 1,700. This Application of the Industrial Customers concerns four of these hundreds of Information Requests received. To date Hydro has replied to all Information Requests within the timelines established by the Board and the current Application must be put in this context.

IC-1

2. In Information Request IC-1, the Industrial Customers requested Forecast and Actual Cost of Service Studies for each of the years from 1992 through to 2000. Hydro provided Forecast Cost of Service Studies for 1992 (using both the 1992 and 1993 methodology), and 1993, 1994 and 1995. Hydro also provided Actual Cost of Service Studies for 1992, 1993, 1994, 1995 and 1999. Hydro does not routinely, on an annual basis, prepare Forecast or Actual Cost of Service Studies. The Forecast and Actual Cost of Service Studies that were available and that were provided in response to IC-1 have been prepared for other purposes, eg., Hydro's 1992 General Rate Application, the 1993 Cost of Service Methodology Hearing, the Rural Rates Hearing and Hydro's 1999 Application to the Board concerning Industrial Rates.

3. As stated in Hydro's Response to IC-1, it takes approximately eight to ten weeks to complete a full cost of service study. To change certain assumptions, once a study has been done, takes a shorter timeframe. To date, in responding to all Information Requests, Hydro has completed and either filed or filed the results of twenty-four cost of service studies and fourteen historical cost of service studies.

4. In its Response to IC-1, Hydro stated that it would provide Actual Cost of Service Studies for 1997 and 2000 and a Forecast Cost of Service Study for 2001. The 2000 Actual Cost of Service Study will be completed and ready to be filed with the Board and all Intervenors on September 10, 2001. It is planned that the 2001 Forecast and the 1997 Actual Cost of Service Studies will be available by the end of September.

5. As stated in Hydro's Response to IC-1, a true Actual Cost of Service Study for 1996 simply cannot be done. During 1996, the St. Anthony/Roddickton system was interconnected to the Island Interconnected System. As a

result, from January to mid-September, this area would be included in the Island Isolated System for costing purposes and in the Island Interconnected System for the remainder of the year. It is not possible to produce an Actual Cost of Service Study for that year in light of this major system being included in both the Isolated and Island Interconnected Systems at different times during the year. Any Cost of Service Study that would be done would have to make certain assumptions or allocations and would not provide an Actual Cost of Service Study and would not provide comparable data to the other Actual Cost of Service Studies being produced in response to IC-1.

6. The Industrial Customers state that the ability to make comparisons between Actual Cost of Services Studies year over year and Forecast Cost of Service Studies is the basis for their request. However, completion of the 1996 Cost of Service study for the reasons noted in the preceding paragraph would not produce meaningful actual results which would be useful for comparison purposes.

7. As stated in Hydro's Response to IC-1, an Actual Cost of Service Study for 1998 is not available and cannot be produced in a meaningful way. During 1998, there was a complete reorganization of the corporation into Business Units. From a Cost of Service Study perspective, it would be impossible to track costs since there was not a one-to-one relationship from the old business centers to the new business units. Some centers were combined and as well, new expense and revenue object codes were introduced. Simultaneously, there was a phased-in implementation of a new integrated accounting system. As with a Cost of Service Study for 1996, any study that could be done for 1998 would have to use assumptions and allocations and would not be an Actual Cost of Service Study producing meaningful results for comparison purposes with other years.

8. It has not been the practice to complete Forecast and Actual Cost of Service Studies for each and every year. Rather, these studies are generally completed in connection with a rate hearing when Forecast Cost of Service Studies are completed and some Actual Cost of Service Studies may be completed. Hydro submits that it is not necessary that each and every year there be a Forecast and Actual Cost of Service Study provided in order for there to be an understanding and discussion of the issues that are material to the current Application. We further state that upon the filing the 1997 and 2000 Actual Cost of Service Studies and 2001 Forecast Cost of Service Study, the only two years for which studies will not be provided will be 1996 and 1998 for which meaningful cost of service studies simply cannot be completed because of the lack of actual reliable input data.

IC-18 (Rev.)

9. The Applicant Intervenors in IC-18 (Rev.) requested information with respect to what the impact of the implementation of the cost of service methodology recommended by the Board in its 1993 Report would have been on a number of factors, including the demand rate charged Industrial Customers, the energy rate, the specifically assigned charge, etc. and said the purpose of the request was to allow comparison to the actual amounts billed. As outlined in its response to IC-18 (Rev.), Hydro submits that it is not now possible to determine what the specific rates would have been had the cost of service methodology approved by the Board in 1993 been implemented.

10. Rates are designed using a forecast year and assumptions are made at that time including the appropriate margin, or profit. Normal or average hydraulic production is used. Completing an Actual Cost of Service Study determines the actual margin and interest coverage, that were achieved with the rates that were in place during the year. To run a cost of service study using the 1993 methodology and based on actual results (eg., load), would not produce the rates that would have been in place if the new methodology had been implemented. Moreover, Hydro has changed its cost of service model to Microsoft Excel from Microsoft DOS-based QuattroPro. The DOS-based computer hardware and software, as well as specialized printing capabilities, are no longer used by Hydro.

11. Hydro further submits that in its 1993 Report, the Board recommended that the cost of service methodology be implemented by Hydro at its next rate hearing, which is the current one before the Board.

12. Hydro submits that it is not necessary to provide the information requested in IC-18 (Rev.) for the Industrial Customers to understand the impact of the change in the cost of service methodology on their rates.

IC-86

13. In IC-86, Item (6), the Industrial Customers requested Hydro to produce a copy of the Major Rate Case Decisions, January 1990 - December 2000, referred to by K.C. McShane in her evidence on page 52-53. The publisher of this information has a copyright for the material. Hydro requested the publishers to allow Hydro to copy the information requested for the purpose of filing with the Board and all Intervenors. Attached is the response of the publisher which stated that it did have copyright for the material and that it would not allow it to be copied, but would allow it to be made available in camera for the Board and other parties. Hydro therefore states that it will provide a copy to the Board which would then be available for viewing by all parties. Alternatively, should the Board order the production of the material, Hydro would have to purchase the copies. The subscription cost for this publication is $500.00 U.S. If Hydro were to purchase forty-one copies, it would cost $20,500.00 U.S., plus tax.

IC-103

14. The information requested by the Industrial Customers can be provided in the manner as further defined and explained in the Application of Industrial Customers. The response will be filed by August 29, 2001.

Dated at St. John's, Newfoundland this 27th day of August 2001.

Maureen P. Greene, Q.C.

TO: Board of Commissioners of Public Utilities
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Attention: Ms. Cheryl Blundon

TO: Consumer Advocate
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Attention: Mr. Dennis Browne, Q.C.

TO: Newfoundland Power Inc.
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Attention: Ms. Gillian Butler, Q.C. / Mr. Peter Alteen

TO: Stewart McKelvey Stirling Scales
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Attention: Ms. Janet Henley-Andrews

TO: Poole, Althouse, Thompson & Thomas
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Attention: Mr. Joseph S. Hutchings

TO: Miller & Hearn
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Attention: Mr. Edward M. Hearn, Q.C.

TO: Town of Happy Valley-Goose Bay
P.O. Box 40, Station B
Happy Valley-Goose Bay, Labrador
A0P 1E0
Attention: Mr. Dennis Peck

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August 15, 2001

Ms. Karen Morgan
Foster Associates, Inc.
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Suite 350N
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Dear Karen:

In response to your request to distribute copies of our January 2001 report entitled *Major Rate Case Decision--January 1990-December 2000* to the intervening parties to a pending rate proceeding in which your firm cited our material, I hereby advise you that such material is copyrighted and proprietary. We are a subscription service and our reports are published exclusively for the distribution to, and use by, our clients. In such situations in the past we have agreed to allow the participants in rate proceedings in which our material was cited to conduct an *in camera* review of the documents in question, but have not and will not agree to the reproduction and distribution of our material outside of a client organization. We regret any inconvenience this may cause you.

Sincerely,

Lillian Federico

Lillian Federico
Senior Vice President