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September 10, 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
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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-243,244,245,246,252,253,255,257,258(Rev),259,260,261,263,264,265,266, 268,269,270 and 272;

2) IC-18 Rev.2(c) 2000 Actual Cost of Service Study – Interim Methodology;

3) IC-18 Rev.2(d) 2000 Actual Cost of Service Study – Generic Methodology; and

4) IC-87 Rev.2 – This second revision now allocates the distribution substations in Roddickton and St. Anthony to Rural, as referenced in IC-245.

Yours truly,

Newfoundland and Labrador Hydro

____

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

MPG/jc

Enclosure

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Q. Further to IC-205(4), provide:

a. The same revenue/costs information as on page 5 of 5 for the year 1991.

b. Is margin included in the "costs" column shown on page 5 of 5? If it is included, what was the margin in dollars and the interest coverage rate for the Industrial class in each of the years 1991 and 1992?

c. If margin is included in the costs column on p. 5 of 5, calculate the Industrial Class revenue, costs and revenue/cost coverage for 1991 and 1992 using the Board's approved interest coverage rates of 1.03 for 1991 and 1.08 for 1992.

A. a. We are unable to provide the same information for 1991 since at that time, the Cost of Service methodology did not identify Rural Deficit separately from Newfoundland Power's and Industrial customers' own costs.

b. Yes, margin is included in the "costs" column. For 1992, allocated actual margin was $2,731,000, which resulted from a cost of service gross interest coverage of 1.13.

c. An interest coverage of 1.08 for 1992 would result in the following:

	$000
Industrial Class Revenue	47,096
Costs (not including Rural Deficit)	39,144
Revenue / Cost Coverage	1.20

As stated in (a) above, this information is not available for 1991.

Q. In the response to IC-137, the allocators for industrial Customers are 13.07%, 13.09%, 13.27% and 13.63% for 1CP, 2CP, 3CP and 4CP respectively in the test year. The cost of service study (Brickhill's schedule 3.1.A line 15) indicates a 1CP allocator of 14.22% and a 2CP of 14.25% for IC.

a. Confirm the 1CP and 2CP allocators proposed for use in setting industrial rates.

b. Explain, complete with detailed calculations, the difference between the allocators in Brickhill's schedule II and Brickhill's schedule 3.1A for Newfoundland power and the Industrial Customers. In particular, explain why, Industrial allocators increased, whereas NP allocators decreased.

c. Redo the Cost of Service assuming that production demand was allocated using a 3CP allocator.

d. Redo the Cost of Service assuming that production demand was allocated using a 4CP allocator.

A. a. The CP allocators identified in the Cost of Service study (Exhibit JAB-1, Schedule 3.1.A line 15) are as proposed. A proposed correction to the Newfoundland Power generation demand credit will be reflected in a revised Cost of Service study, when filed.

b. Please see attached schedule on page 3 of 3.

c. Please see attached Cost of Service.

d. Please see attached Cost of Service.

Newfoundland and Labrador Hydro
Peak Analysis

1 CP
January

	Load Forecast (kW)	Coincidence Factor	CP (kW)	CP Percentage (Schedule II - J.A. Brickhill)
Newfoundland Power	1,026,791	1.000	1,026,791	79.99%
Island Industrial Firm	187,000	0.897	167,739	13.07%
Rural Bulk	91,100	0.978	89,096	6.94%
Total			1,283,626	

	Load Forecast (kW)	Coincidence Factor	Generation (kW)	Generation Demand Credit (kW)	CP (kW)	CP Percentage (Exhibit JAB-1, page 38)
Newfoundland Power	1,026,791	1.000	46,960	(120,500)	953,251	78.56%
Island Industrial Firm	187,000	0.923 (1)			172,601	14.22%
Rural Bulk	89,590 (1)	0.978			87,619	7.22%
Total					1,213,471	

(1) Adjusted subsequent to Schedule II - J.A. Brickhill preparation

2 CP
December

	Load Forecast (kW)	Coincidence Factor	CP (kW)
Newfoundland Power	1,026,791	1.000	1,026,791
Island Industrial Firm	187,000	0.897	167,739
Rural Bulk	87,049	0.978	85,134
Total			1,279,664

	Load Forecast (kW)	Coincidence Factor	Generation (kW)	Generation Demand Credit (kW)	CP (kW)
Newfoundland Power	1,026,791	1.000	46,960	(120,500)	953,251
Island Industrial Firm	187,000	0.923			172,601
Rural Bulk	84,810	0.978			82,944
Total					1,208,796

January plus December	2 CP (kW)	CP Percentage (Schedule II - J.A. Brickhill)	2 CP (kW)	CP Percentage (Exhibit JAB-1, page 38)
Newfoundland Power	2,053,582	80.12%	1,906,502	78.71%
Island Industrial Firm	335,478	13.09%	345,202	14.25%
Rural Bulk	174,229	6.80%	170,563	7.04%
Total	2,563,290		2,422,267	

Q. In Brickhill's schedule 2.2A, line 22, column 3, $1,204,121 of distribution substations are classified as production demand.

a. List the substation(s) involved.

b. Explain why the substation(s) is classified as production demand rather than distribution.

A. a. The substations involved are:

Roddickton	$369,929
St. Anthony	834,192
Total	$1,204,121

b. Roddickton: These low voltage distribution assets are used to connect the two 850 kW mobile diesel generators to the Roddickton Terminal Station.

St. Anthony: When this system was interconnected, a high voltage terminal station was established at St. Anthony connecting the 69 kV transmission to the local distribution system. The assets referred to above are low voltage distribution assets used to connect the generation to the high voltage terminal station.

In both cases, if there were no generation at these locations, the distribution assets would not be required. Hydro has therefore functionalized them to generation.

Q. In Brickhill's schedule 2.2A, line 15, columns 3 and 4, there are terminal stations classified to production demand and production and transmission energy. Noting that lines 16, 17 and 18 of this schedule are for terminal stations associated with hydraulic production, Holyrood and gas/turbine production:

a. List the terminal station(s) involved.

b. Explain why the terminal station(s) is classified as production demand and/or production and transmission energy.

A. a. The terminal station is Paradise River.

b. This asset was coded as Production Support, which is classified to demand and energy based on total production demand and energy ratios (48%/52%), derived from line 12. This asset should have been coded more specifically to hydraulic production and classified to demand and energy based on the hydraulic classification ratios (41%/59%). This change will be incorporated in a revised filing.

Q. IC 252. Further to IC-120 (3):

a. In light of: (i) section 3(a)(iv) of the *Electrical Power Control Act,* 1994, (ii) the directive from the Minister of Mines and Energy to Hydro on October 22,1999 (IC-9 attachment), and (iii) the expressed intent of the *ex parte* application of Nov. 19, 1999 (IC-6) and the intent of Order P.U. No. 23 (1999-2000), explain why Hydro has continued to cause the Industrial Customers to subsidize rural customers through the rate stabilization plan rates since Jan.1, 2000.

b. How does Hydro intend to reimburse the Industrial Customers for the amounts paid by Industrial Customers through the RSP in respect of subsidy to rural customers since Jan. 1, 2000?

A. a. The issue of Industrial Customers continuing to subsidize rural customers through the rate stabilization plan was not discussed nor considered in filing for the *ex parte* application of November 19, 1999. Upon review of this issue, Hydro is proposing to make the necessary adjustments as outlined in response to IC-242.

b. Refer to the response to IC-242.

Q. Further to IC-87, provide a cost of service assuming that the generation assets and associated terminal stations on the Great Northern Peninsula are assigned as common, but the transmission lines and associated terminal stations are assigned specifically to the rural customers.

A. Please refer to the Cost of Service Study filed in response to IC-180 (Rev. 1).

Q. Further to IC-105, provide the margin and interest coverage for 1999 before the write-off of the Roddickton wood chip plant.

A. The following is the margin and interest coverage for 1999 before the write-off of the Roddickton Wood Chip Plant.

	Margin	Interest Coverage
1999	$12,934,000	1.13

The above excludes export sales of recall energy to Hydro-Quebec and includes non-regulated sales to IOCC.

Q. With reference to IC-202, page 12 of 12, the first note states that the Industrial coincidence factor is 0.92.

a. What coincidence factors were used in the 1992 and 1995 cost of service study.

b. Provide explanation and calculation as to how this factor was determined.

A. a. Industrial coincidence factors used in the Cost of Service studies are as follows:

1992:	0.937	(Rate Hearing)
1992:	0.883	(Methodology Hearing)
1995:	0.906	

b. Please see attached table for explanation and calculation as to how this factor was determined.

NEWFOUNDLAND & LABRADOR HYDRO
INDUSTRIAL CUSTOMER
COINCIDENT FACTORS

Year	COINCIDENT PEAKS (CP) CBP&P (MW)	ACI GFL (MW)	ACI SVL (MW)	NARL (MW)	NON-COINCIDENT PEAKS (NCP) CBP&P (MW)	ACI GFL (MW)	ACI SVL (MW)	NARL (MW)	Sum of Industrial CP (MW)	Sum of Industrial NCP (MW)	Industrial Coincident Factors
91-92	36.7	22.6	48.8	26.0	40.0	28.0	66.1	26.8	134.1	160.9	0.83
92-93	40.0	22.0	64.2	26.9	40.0	25.0	66.0	29.1	153.1	160.1	0.96
93-94	35.5	11.7	62.0	25.8	40.0	21.1	66.2	26.5	135.0	153.8	0.88
94-95	34.0	17.1	69.2	25.7	40.0	22.0	70.0	27.0	146.0	159.0	0.92
95-96	33.5	17.6	68.6	29.2	40.0	22.0	70.0	30.8	148.9	162.8	0.91
96-97	44.8	18.3	64.6	29.5	48.0	24.0	70.0	31.0	157.2	173.0	0.91
97-98	47.0	21.3	68.5	30.0	48.0	22.0	70.0	31.3	166.8	171.3	0.97
98-99	49.2	17.6	68.0	29.8	56.0	22.0	70.0	30.3	164.6	178.3	0.92
99-00	47.6	17.6	68.5	28.8	51.0	22.0	70.0	30.2	162.5	173.2	0.94
										5 Year Median	0.92

Notes:

1. Coincident and non-coincident peaks exclude all compensation, emergency, exceptional and interruptible demands.
2. 96-97 ACI GFL & SVL CP based on average of 91-92 to 95-96 coincident factors.
3. 97-98 ACI SVL based on median coincident peaks for 94-96 to 97-98 and 98-99 to 99-00.
4. 98-99 and 99-00 ACI GFL based on median coincident peaks for 93-94 to 97-98.

Q. Further to CA-151, complete the following table for the years 1992 – 2000 actual and 2001 Forecast.

Year	Total Actual Deficit	Subsidy received from NP	Subsidy Received from IC	Subsidy entitled from Lab. Customers	Total subsidy received/entitled (col 3+4+5)

A. The table below is based on the final forecast 1992 COS Study as determined by the PUB at Hydro's 1991 General Rate Referral as that was the last time Newfoundland Power's rate was set. At that time the rural deficit allocation reflected 11.46% of the revenue requirement for Newfoundland Power. The same proportion was allocated to the Labrador Interconnected System revenue requirement even though the rates were not revised at that time.

Year	Total Actual Deficit	Subsidy received from NP	Subsidy Received from IC	Subsidy entitled from Lab. Customers	Total subsidy received/entitled (col 3+4+5)
1992	$28,887,826	$22,030,130	$4,981,236	$942,778	$27,954,143
1993	28,024,939	21,880,561	4,957,401	1,151,563	27,989,526
1994	27,735,008	21,811,668	4,342,180	1,150,236	27,304,084
1995	29,316,670	21,878,085	4,758,008	1,152,685	27,788,779
1996	na	21,738,400	5,104,365	1,198,878	28,041,643
1997	na	22,232,088	5,121,893	1,245,188	28,599,169
1998	na	21,414,325	3,895,296	1,243,940	26,553,561
1999	22,099,837	21,035,509	4,666,887	1,284,706	26,987,102
2000	na	21,967,388	-	1,283,645	23,251,033

Q. Reference: Non-regulated Activities

a. Please list all activities of Newfoundland and Labrador Hydro that are considered to be non-regulated.

b. For each non-regulated activity, please provide

i) a detailed description of the non-regulated activity, including the customers served and the source of any energy supplied.

ii) list the value of all assets considered to be solely associated with the non-regulated activity

iii) list all costs associated with the activity in 2002 and 2003

iv) list all revenues associated with the activity in 2002 and 2003

v) provide a description of why the activity is unregulated with reference to the relevant sections of legislation, regulations, Board Orders, etc. Please attach copies of these relevant sections.

A. a. Hydro's non-regulated activities include its investments in subsidiary companies, consisting of Churchill Falls (Labrador) Corporation Limited (CF(L)Co, Gull Island Power Company Limited (GIPCo), and Lower Churchill Development Corporation Limited (LCDC), and sales of power and energy by Hydro to Hydro-Québec and IOCC. It also has some non-regulatory costs for donations as well as costs related to Muskrat Falls in Labrador.

b. i) GIPCo and LCDC were established with the objective of developing hydroelectric potential on the Lower Churchill River in Labrador and these investments have always been excluded from any regulatory review by the PUB. They are currently inactive and thus have no customers or sources of energy. The Public Utilities Act does not apply to CF(L)Co or to the supply of power from the Churchill Falls Generating Plant by Hydro to IOCC and Hydro-Québec (see the Churchill Falls (Labrador) Corporation Limited (Lease) Act, 1961, S.N. No. 51 as amended, section 7, attached).

ii) Assets associated with non-regulated activities are excluded from the current application. Non-regulated matters are not necessary for the understanding of the issues to be considered in this proceeding nor are they relevant.

iii) and iv)

Non-regulated matters are not necessary for the understanding of the issues to be considered in this proceeding nor are they relevant.

v) See i) above.

Q. With reference to Orders-in-Council, please provide a copy of all Orders-in-Council issued regarding Hydro or the PUB since the 1985 rate hearings.

A. The information requested is too broad and unfocused and is not required for an understanding of the issues before the Board.

Q. With reference to RSP Hydraulic Production, please confirm that the figures for hydraulic production in the RSP only include Hydro’s own hydro generating stations and not NUG generation. Please describe any and all ways in which variations in NUG production affects the amounts charged to the RSP.

A. The figures for hydraulic production in the RSP only includes Hydro's own hydro generating stations and does not include NUG generation. Any variation in NUG production from that used in setting rates for 2002 will impact the fuel variation component of the RSP. A decrease in NUG production results in more No. 6 fuel being consumed and the charge to the plan is the additional number of barrels multiplied by the price variance for No. 6 fuel (actual price per barrel less price per barrel included in rates). The opposite would apply for an increase in NUG production.

Q. With reference to NP-129,

a. The table in NP-129 lists a significant reduction in specifically assigned costs to CFB. Please explain this reduction.

b. NP-129 (b) notes that CFB is served under rate class 2.4 General Service Over 1,000 kVa. Is this the only rate class that CFB is served under? Please explain why sales under rate class 2.4 are treated as secondary.

A. a. The significant reduction in specifically assigned charges relates to the 25 kV line which was originally installed to provide secondary energy to the CFB Goose Bay boilers. Since CFB Goose Bay was the sole customer at that time, the line was specifically assigned. Upon review of the plant assignments for the current hearing, it was determined that there are two customers presently served from the 25 kV line and therefore it is no longer specifically assigned thus resulting in a significant assigned cost reduction.

b. As outlined in response to NP-129 (b), which refers to firm power requirements, CFB is served under Rate Class 2.4. In addition, CFB Goose Bay is also currently served secondary energy under separate contractual arrangements. Hydro is applying to serve CFB Goose Bay secondary energy under Rate No. 3.1H which is outlined on Schedule A, page 18, in Hydro's current Application.

Q. With reference to NP-169, please update the table at page 5 of the response for each year since 1994.

A. Please see schedule attached.

Summary of Electric Utility Dividend Comparables

Utility		Dividend	Guarantee Fee	Water Rental	Total Transfers	Dividend/ Net Income	Gurantee Fee/ LT Debt	Transfers/ Book Equity	LT Debt / Capital
		(000's)	(000's)	(000's)	(000's)				
BC Hydro	1994	$245,000	$0	$217,000	$462,000	85%	0.0%	23%	79.1%
	1995	$198,000	$0	$231,000	$429,000	85%	0.0%	21%	79.2%
	1996	$115,000	$0	$239,000	$354,000	77%	0.0%	17%	78.7%
	1997	$279,000	$0	$296,000	$575,000	82%	0.0%	27%	75.6%
	1998	$366,000	$0	$280,000	$646,000	90%	0.0%	30%	76.3%
	1999	$326,000	$0	$267,000	$593,000	83%	0.0%	26%	63.0%
	2000	$343,000	$0	$276,000	$619,000	82%	0.0%	25%	66.4%
	Average	$267,429	$0	$258,000	$525,429	83%	0.0%	24%	74.0%
Saskatchewan Power	1994	$47,000	$0	$8,000	$55,000	55%	0.0%	6%	63.6%
	1995	$54,000	$0	$10,000	$64,000	69%	0.0%	7%	64.3%
	1996	$76,000	$0	$11,000	$87,000	55%	0.0%	9%	60.8%
	1997	$72,000	$0	$10,000	$82,000	55%	0.0%	8%	59.4%
	1998	$77,000	$0	$9,000	$86,000	55%	0.0%	8%	56.8%
	1999	$63,000	$0	$9,000	$72,000	55%	0.0%	6%	54.4%
	2000	$69,000	$0	$8,000	$77,000	55%	0.0%	6%	55.7%
	Average	$65,429	$0	$9,286	$74,714	57%	0.0%	7%	59.3%
Manitoba Hydro	1994	$0	$24,600	$44,100	$68,700	0%	0.5%	20%	85.0%
	1995	$0	$26,900	$45,200	$72,100	0%	0.5%	18%	84.8%
	1996	$0	$25,300	$47,100	$72,400	0%	0.6%	15%	77.0%
	1997	$0	$26,500	$51,300	$77,800	0%	0.7%	12%	82.4%
	1998	$0	$28,800	$54,600	$83,400	0%	0.6%	10%	77.5%
	1999	$0	$31,400	$50,500	$81,900	0%	0.7%	9%	80.3%
	2000	$0	$42,000	$51,000	$93,000	0%	0.8%	9%	81.0%
	Average	$0	$29,357	$49,114	$78,471	0%	0.6%	13%	78.3%
Ontario Hydro	1994	$0	$174,000	$110,000	$284,000	0%	0.6%	7%	78.1%
	1995	$0	$170,000	$113,000	$283,000	0%	0.6%	6%	76.6%
	1996	$0	$162,000	$120,000	$282,000	0%	0.6%	11%	83.2%
	1997	$0	$156,000	$121,000	$277,000	0%	0.6%	**-6%**	93.7%
	1998	$0	$155,000	$119,000	$274,000	0%	0.6%	**-9%**	92.2%
OPG/HydroOne	1999	$206,000	$39,000	$120,000	$365,000	34%	0.6%	4%	39.2%
	2000	$607,000	$0	$117,000	$724,000	62%	0.0%	7%	39.2%
	Average	$406,500	$142,667	$117,143	$355,571	48%	0.5%	7%	* 71.7%

Summary of Electric Utility Dividend Comparables

Utility		Dividend	Guarantee Fee	Water Rental	Total Transfers	Dividend/ Net Income	Gurantee Fee/ LT Debt	Transfers/ Book Equity	LT Debt / Capital
		(000's)	(000's)	(000's)	(000's)				
Hydro Quebec	1994	$0	$174,000	$0	$174,000	0%	0.5%	2%	74.4%
	1995	$0	$192,000	$0	$192,000	0%	0.5%	2%	72.8%
	1996	$0	$192,000	$0	$192,000	0%	0.5%	2%	72.3%
	1997	$357,000	$188,000	$0	$545,000	45%	0.5%	4%	72.6%
	1998	$279,000	$189,000	$0	$468,000	41%	0.5%	4%	70.7%
	1999	$453,000	$197,000	$0	$650,000	50%	0.5%	5%	68.2%
	2000	$539,000	$187,000	$0	$726,000	50%	0.5%	5%	64.5%
	Average	$407,000	$188,429	$0	$421,000	47%	0.5%	3%	70.8%
New Brunswick Power	1994	$0	$19,671	$0	$19,671	0%	0.6%	5%	83.8%
	1995	$0	$21,051	$0	$21,051	0%	0.7%	5%	80.1%
	1996	$0	$21,484	$0	$21,484	0%	0.7%	5%	81.5%
	1997	$0	$22,032	$0	$22,032	0%	0.7%	5%	82.1%
	1998	$0	$22,000	$0	$22,000	0%	0.7%	5%	81.1%
	1999	$0	$21,000	$0	$21,000	0%	0.7%	1050%	91.0%
	2000	$0	$20,000	$0	$20,000	0%	0.8%	100%	85.7%
	Average	$0	$21,034	$0	$21,034	0%	0.7%	5%	83.6%
Newfoundland and Labrador Hydro	1994	$0	$10,700	$0	$10,700	0%	0.8%	2%	64.7%
	1995	$19,500	$10,400	$0	$29,900	59%	0.7%	5%	62.3%
	1996	$12,900	$10,800	$0	$23,700	45%	0.6%	4%	66.2%
	1997	$20,900	$11,100	$0	$32,000	48%	0.8%	5%	57.2%
	1998	$16,800	$11,400	$0	$28,200	24%	0.8%	4%	60.7%
	1999	$17,000	$11,000	$0	$28,000	33%	0.9%	4%	59.9%
	2000	$69,900	$10,600	$0	$80,500	200%	1.0%	12%	51.4%
	Average	$26,167	$10,857	$0	$33,286	68%	0.8%	5%	60.3%

Q. With reference to NP-171, please provide a version of the table showing only the regulated equity and return.

A. Please see attached table. Regulated return on equity can only be calculated precisely for years in which a Cost of Service study has been completed.

Q. Interconnection Areas

a. Please provide a definition, including names of all communities, for the following terms as used by Hydro:

i) St. Anthony's and Roddickton area
ii) Area north of Hawke's Bay
iii) Hawke's Bay area
iv) GNP interconnection area.

A. a. i) St. Anthony and Roddickton Area: this is the area from Cook's Harbour on the northern tip of the Great Northern Peninsula to Englee on the eastern side of the Peninsula and includes the following communities:

Boat Harbour	Wild Bight
Cape Norman	Cook's Harbour
Raleigh	Cape Onion
Ship Cove	L'Anse aux Meadows
Cape Bauld	Hay Cove
Straitsview	Noddy Bay (east & west)
Quirpon	Gunner's Cove
White Cape Harbour	St. Lunaire
Lower Griquet	Griquet
Great Brehat	St. Anthony Bight
St. Carol's	St. Anthony
Goose Cove West	Grandois
Main Brook	St. Julien's

Croque	South West Crouse
Conche	Bide Arm
Englee	Fortune Arm
Goose Cove	Roddickton

ii) The Area North of Hawke's Bay: this area includes all communities of the St. Anthony/Roddickton area plus the following communities served by the Plum Point and Bear Cove Terminal Stations.

Blue Cove	Bartlett's Harbour
Castor's River (North & South)	Reef's Harbour
Shoal Cove	Mt. St. Margaret
New Ferrole	Bird Cove
Pond Cove	Forrester's Point
Pigeon Cove	Black Duck Cove
St. Barbe	Anchor Point
Deadman's Cove	Bear Cove
Flower's Cove	Nameless Cove
Savage Cove	Sandy Cove
Shoal Cove East	Pine's Cove
Green Island Cove	Lower Cove
Green Island Brook	Eddies Cove
Brig Bay	Plum Point

iii) Hawke's Bay Area: this is the area served by the Hawke's Bay Terminal Station and includes the following communities.

River of Ponds	Hawke's Bay
Port Saunders	Port aux Choix
Eddies Cove West	

iv) GNP Interconnection Area: this is a term used by Hydro to describe the St. Anthony/Roddickton area.

Q. With reference to PU26 (1999-2000), please provide copies of the Hydro application or this hearing, including pre-filed testimony, a copy of the report of Dr. Wallace Read to the Board, any follow up testimony or evidence filed by Dr. Read, and any other expert testimony filed in that proceeding. Also, please provide a copy of information request PUB-8 from the hearing.

A. Attached are the following documents from the Roddickton hearing:

- Hydro's application, as amended;
- a copy of the report of Dr. Wallace Read;
- excerpts from the transcript of February 2, 2000 constituting additional evidence of Dr. Read; and
- Hydro's response to Information Request PUB-8.

Q. GNP interconnection – Reference PU5 (2000-2001),

a. Please provide all evidence filed in that proceeding to support the claims (noted at page 8, lines 7 to 14 of PU5) that Hydro "believes 9700 kW of generation is adequate to meet the emergency requirements of the St. Anthony's –Roddickton (*sic*) area".

b. Please confirm that the current firm generating capacity in the St. Anthony's-Roddickton area is 9700 kW.

c. Please provide a copy of the response to information request PUB 5 and PUB 7 from that proceeding.

d. Please note all actions taken by Hydro to comply with this Board Order, including relocation of diesel units, and the costs of these actions.

e. Please provide details on the current disposition of the 450 kW diesel unit which was previously at the Roddickton Wood Chip plant, and if still in service, please note the location and assignment as to Island Interconnected customers or to common.

A. a. Please see Hydro's response to Information Request PUB 12 of the Roddickton hearing (attached).

b. The current generating capacity in the St. Anthony-Roddickton area is 10,100 kW. This capacity comprises 8000 kW of diesel capacity in the

St. Anthony diesel generating station, two 850 kW mobile diesel generators located at Roddickton, and a 400 kW of run-of-the-river hydro capacity at the Roddickton mini-hydro generating station.

c. Hydro's responses to PUB 5 and PUB 7 filed in the Roddickton proceeding are attached.

d. The Order required Hydro to put in place between 1500 and 2000 kW of emergency supply in the Roddickton area. In compliance with that Order, Hydro relocated its 850 kW transportable diesel unit from its St. Anthony diesel generating station location to Roddickton, which, when added to the 850 unit that was already located at Roddickton, provided 1700 kW of emergency supply at that location.

The cost of this diesel unit relocation, including the reconfiguration of the St. Anthony generating station to accommodate its removal, was $98,905. Added to this cost there is an annual cost of approximately $34,000 associated with providing an operator in the Roddickton area.

Another requirement of the Order was the monitoring of outage statistics for this part of the Great Northern Peninsula and the provision of a report of these statistics to the PUB. This information is being provided to the PUB in Hydro's quarterly reports. These outage statistics comprise information that had been recorded by Hydro for other purposes, therefore, there is no additional costs associated with complying with this part of the Order.

The Order also requires Hydro to conduct a study on the reliability of the transmission lines serving the Roddickton area and the appropriate level of emergency generation for this location. The Order requires that this study be filed by July 1, 2003. No work has been commenced on this study to date.

e. The 450 kW diesel unit from the Roddickton Wood Chip plant is in temporary service at the Little Bay Islands isolated diesel system.

Q. GNP Interconnection – Reference: IC-203:

a. Please provide a diagram comparable to HGB schedule XIII that shows the Island Interconnected system and the St. Anthony's-Roddickton system prior to the GNP interconnection including all transmission line voltages and generating capacity.

b. Please confirm that prior to the GNP interconnection, the area north to Flower's Cove was part of the Island Interconnected System.

c. Please list all communities and provide the loads by month for each community, and the peak loads by month, since 1992 and forecast for 2001 and 2002 separated into three categories:

i) Areas previously part of the Island Interconnected System which are served by upgraded transmission as a result of the GNP interconnection

ii) Areas which are now part of the Island Interconnected System, but which prior to the GNP interconnection were not part of the Island Interconnected System or the St. Anthony's-Roddickton System

iii) Areas which were part of the St. Anthony's-Roddickton system prior to the GNP interconnection.

For each of the areas in 3, please list the local generation capacity that was in place prior to the interconnection, and the location of that generation.

d. Please provide dates for construction of each of the transmission lines TL221, TL241, TL244, TL256, TL261 and TL257. If any of these transmission lines were upgraded or reinforced since they were first constructed in order to carry higher voltages or loads, please provide the date of the upgrade and the change in voltage. If any of them were replacements for earlier lines, please provide the same information for the earlier lines.

A. GNP Interconnection – Reference: IC-203:

a. The attached diagram labeled IC-270(a) shows the Island Interconnected System and the St. Anthony - Roddickton System prior to the GNP Interconnection.

b. The area on the Great Northern Peninsula north to Eddie’s Cove East on the Flower’s Cove system was part of the Island Interconnected System prior to the GNP Interconnection.

c. i) See attached table of monthly peak demands and energy deliveries for Newfoundland and Labrador Hydro’s GNP metered delivery points applicable for this question. A list of system communities is included. Forecasts for GNP metered delivery points for 2001 and 2002 are available for winter peak demand only.

ii) There are no communities in this category.

iii) See attached table of monthly peak demands and energy deliveries for Newfoundland and Labrador Hydro's GNP metered delivery points applicable for this question. A list of system communities is included. Forecasts for GNP metered delivery points for 2001 and 2002 are available for winter peak demand only.

d. The location and capacity of generation in the St. Anthony – Roddickton System prior to the GNP interconnection are as follows:

- St. Anthony Diesel Plant contained 8,850 kW of diesel generation including one 850 kW mobile diesel generator.

- The Roddickton Woodchip Plant had a capacity of 5,000 kW. The site also had a 450 kW diesel generator for black start of the plant and there was one 850 kW mobile diesel generators located on site.

- The Roddickton Diesel Plant in the town of Roddickton had an installed capacity of 2,350 kW.

- The Roddickton Mini-hydro Plant has a capacity of 425 kW.

e. TL221 is a 66 kV transmission line that was built between Daniel's Harbour and Hawke's Bay Terminal Stations in 1970. With the addition of the Peter's Barren Terminal Station in 1990, TL221 was terminated at Peter’s Barren. The line section from Daniel’s Harbour to Peter’s Barren was renumbered as TL262.

TL241 is a 138 kV transmission line that was built between Hawke’s Bay and Plum Point Terminal Stations in 1983. While the line was built to 138 kV standard, it operated at 66 kV. In 1995 TL241 was extended to the Peter’s Barren Terminal Station and commenced operation at 138 kV. Note at that time the TL241 66 kV line termination at Hawke’s Bay Terminal Station was removed from service.

TL244 is a 138 kV transmission line that was built between Plum Point and Bear Cove Terminal Stations in 1983. The original line was built to 66 kV standards. The transmission line was upgraded for operation at 138 kV in 1995.

TL256 is a 138 kV transmission line that was built between Bear Cove and St. Anthony Airport Terminal Stations in 1995.

TL261 is a 69 kV transmission line that was built between St. Anthony Airport and St. Anthony Diesel Plant Terminal Stations in 1996.

TL257 is a 69 kV transmission line that was built between the Roddickton Woodchip and St. Anthony Airport Terminal Stations in 1989.

	BEAR COVE SYSTEM		PLUM POINT SYSTEM	
	MWh	kW	MWh	kW
Jan-92	2674	5107	1543	N/A
Feb-92	2525	6931	1498	N/A
Mar-92	2227	4834	1618	N/A
Apr-92	1680	3922	1360	N/A
May-92	1560	4128	1387	N/A
Jun-92	1891	3739	1019	N/A
Jul-92	1368	2976	1178	N/A
Aug-92	667	2784	1031	N/A
Sep-92	1234	2645	1013	N/A
Oct-92	1829	3456	1356	N/A
Nov-92	1910	4150	1231	N/A
Dec-92	2486	4834	809	N/A
Jan-93	2654	5280	1541	N/A
Feb-93	2438	4800	1608	N/A
Mar-93	2203	4800	1390	N/A
Apr-93	1776	4560	1173	N/A
May-93	1930	3466	1280	N/A
Jun-93	1464	3072	1126	N/A
Jul-93	1718	4416	1346	2801
Aug-93	1066	2736	864	2239
Sep-93	1296	2280	1031	2259
Oct-93	1872	3739	1280	2504
Nov-93	2026	6336	1229	N/A
Dec-93	2314	6019	1398	3595
Jan-94	2923	5472	1692	4026
Feb-94	2654	5760	1523	3310
Mar-94	2491	4608	1517	3036
Apr-94	1718	3840	1098	2676
May-94	1661	3840	1085	2556
Jun-94	1949	3744	1000	2419
Jul-94	888	3792	1022	2906
Aug-94	1152	2304	895	1956
Sep-94	1334	3072	1028	2292
Oct-94	1498	3264	1003	2375
Nov-94	1886	4032	1190	2638
Dec-94	2626	4896	1586	3444
Jan-95	2712	4704	1614	3034
Feb-95	2285	4896	1349	3034
Mar-95	1790	5568	1075	4483
Apr-95	1608	3360	1037	2412
May-95	1123	N/A	1123	2416
Jun-95	N/A	N/A	N/A	N/A
Jul-95	N/A	N/A	N/A	N/A
Aug-95	N/A	N/A	N/A	N/A
Sep-95	N/A	N/A	N/A	N/A
Oct-95	N/A	N/A	N/A	N/A
Nov-95	1483	6000	1033	4040
Dec-95	2320	5800	1447	3400

	BEAR COVE SYSTEM		PLUM POINT SYSTEM	
	MWh	kW	MWh	kW
Jan-96	2469	5800	1476	3520
Feb-96	2057	4640	1256	3120
Mar-96	1920	5240	1201	3320
Apr-96	1591	3680	1041	2600
May-96	1597	3480	1065	2240
Jun-96	1360	3000	1016	2280
Jul-96	1264	2880	953	2280
Aug-96	1000	2400	815	1800
Sep-96	980	2840	1132	2840
Oct-96	1496	3160	1106	2400
Nov-96	1706	3480	1121	2400
Dec-96	1360	4288	873	2800
Jan-97	1714	4576	1022	2776
Feb-97	2111	4576	1261	2836
Mar-97	2071	4116	1284	2680
Apr-97	1666	3880	1057	2400
May-97	1574	3468	N/A	2308
Jun-97	1325	3144	N/A	2548
Jul-97	1235	2824	988	2084
Aug-97	1203	3316	973	2088
Sep-97	1241	2760	1060	2388
Oct-97	1556	5652	1078	2544
Nov-97	1722	3556	1137	2472
Dec-97	2110	4620	1349	3368
Jan-98	2277	4856	1369	3068
Feb-98	1859	4292	1174	2968
Mar-98	1893	4504	1192	2608
Apr-98	1631	3452	1012	2260
May-98	1599	3148	947	2048
Jun-98	1257	4792	962	2304
Jul-98	1340	2996	1014	2284
Aug-98	1350	2900	955	2120
Sep-98	1426	3672	1060	2432
Oct-98	1537	3040	1204	2648
Nov-98	1577	3348	1283	2856
Dec-98	2073	4616	1610	3932
Jan-99	2059	4784	1559	3592
Feb-99	1651	3964	1288	2904
Mar-99	1678	3440	1310	2780
Apr-99	1605	3376	1166	2592
May-99	1549	3076	1137	2404
Jun-99	1391	2960	1156	2432
Jul-99	1294	2740	1077	3056
Aug-99	1194	2480	1075	2244
Sep-99	1157	2760	986	2316
Oct-99	1485	4184	1199	3500
Nov-99	1534	4180	1273	3444
Dec-99	1977	4808	1572	4224

	BEAR COVE SYSTEM		PLUM POINT SYSTEM	
	MWh	kW	MWh	kW
Jan-00	1986	4348	1502	3460
Feb-00	1889	3884	1428	3084
Mar-00	1725	3372	1385	2892
Apr-00	1820	3676	1293	2752
May-00	1863	3728	1376	3060
Jun-00	1680	3324	1264	2760
Jul-00	1709	3252	1286	2688
Aug-00	1609	N/A	1211	2368
Sep-00	1460	N/A	1098	2632
Oct-00	1747	N/A	1314	2764
Nov-00	N/A	3496	1352	3056
Dec-00	2430	5137	1677	3960
Jan-01	2439	4606	1544	3184
Feb-01	2170	5801	1389	3056
Mar-01	1940	3022	1368	2868
Apr-01	1998	2826	1253	2764
2001 forecast		5002		4404
2002 forecast		5005		4411

Note: 1. N/A is not available

2. forecast is winter season peak demand

BEAR COVE SYSTEM	PLUM POINT SYSTEM
Anchor Point	Bartlett's Harbour
Bear Cove	Bird Cove
Deadman's Cove	Black Duck Cove
Eddie's Cove East	Blue Cove
Flower's Cove	Brig Bay
Green Island Brook	Castor's River North
Green Island Cove	Castor's River South
Lower Cove	Forrester's Point
Nameless Cove	Mount St. Margaret
Pine's Cove	New Ferrole
Sandy Cove	Pigeon Cove
Savage Cove	Plum Point
Shoal Cove East	Pond Cove
	Reef's Harbour
	Shoal Cove
	St. Barbe

Q. RSP – Reference PUB-59, PUB-53 and IC-193,

a) Provide detailed explanation for PUB-59 2001 (showing all calculations, assumptions, data, and sources for data derived from earlier COS studies or other sources) to explain each row for “Revised COS” and for “Cost Difference” (at page 12 for 2001).

b) PUB-59 for 2001 shows various interest rates (at page 1 “interest rate 8.40% annually @ 8.11% monthly” and at page 10 “Interest = balance * 8.55% from Jan to Dec 2001”). Please explain the basis for each interest number, and the rationale for suing (*sic*) these different numbers.

c) PUB-59 for 2002, under Fuel Variation at page 4, shows 2002 Forecast Barrels that are less than the forecast barrels consumed for 2002 shown at IC-24 (as well as Grant Thornton (*sic*) report dated August 15, 2001, Exhibit 6-2). Please explain the difference and confirm that it relates only to removal of forecast non-firm No. 6 Fuel requirements.

d) Confirm that PUB-59 2002 Summary Report should be adjusted to reflect 2002 Labrador Interconnection allocations – please provide adjusted Summary Report table, if this is required.

e) PUB-53 and IC-193 provide RSP forecasts for 2002 through 2005 assuming base oil prices reset in 2002 at $25/bbl and $15/bbl respectively. Confirm that these responses assume no adjustment to 2002 Revenue Requirement or rates as set out in the Hydro

Application, and that the Revenue Variance (as part of Load Variance) for 2002 through 2005 assume mill rates as currently applied for. Explain the rational for this assumption. Provide adjusted responses for PUB-53 and IC-193 assuming that the NP and IC mill rates are adjusted to reflect the rebased oil prices at levels different than assumed in the Hydro Application – set out in detail the basis for the adjusted mill rate calculations.

A. a) Response to follow.

b) Hydro's annual embedded cost of debt for 2001 is 8.4% and due to compounding, this translates into a monthly rate of 8.11%. The interest rate shown on page 10 for 2001 should have been 8.4% and not 8.55%.

c) The difference in barrels shown in PUB-59 2002 page 4 of 13 and the forecast barrels shown in IC-24 of 11,142 is due to the removal of forecast non-firm No. 6 fuel requirements.

d) The summary report in PUB-59 2002 should have included the Labrador Interconnection and a revised summary report is attached.

e) Response to follow.

Q. Provide a Table which shows the following for each of the years 1994 - 2000 inclusive assuming the implementation of the Cost of Service Methodology approved in the Public Utility Board 1993 Report (where the vertical axis represents the years and the horizontal access the following data):

1. the demand rate which would have been charged the Industrial Customers for firm power and for each class of non-firm service;
2. the energy rate which would have been charged the Industrial Customers for firm power and for each class of non-firm service and for wheeling;
3. the Specifically Assigned Charges which would have been charged Industrial Customers, and the total for all Industrial Customers;
4. the total number of kWh sold to the Industrial Customers for those years for firm power and for each class of non-firm service and for wheeling;
5. the total dollar amount which would have been billed to the Industrial Customers in those years, exclusive of sales tax, for firm power and for each class of non-firm service and for wheeling (indicate subtotals for each class of service and overall total);
6. the average cost per kilowatt hour which would have resulted;
7. the total dollar amount which was billed to Industrial Customers;
8. the average cost per kilowatt hour which was billed to Industrial Customers;
9. the difference between (5) and (7).

A. In response to an Application to the Board by Industrial Customers, Hydro will file the following Cost of Service Studies as a means of meeting the requirements of this request:

(a) 1999 Actual (Rev) - Generic Methodology (Attached)
(b) 2002 Test Year - Generic Methodology (Attached)

The following will be filed as per the agreement reached with Industrial Customers as outlined at the August 29th, 2001 meeting with the Public Utilities Board:

(c) 2000 Actual – Interim Methodology
(d) 2000 Actual – Generic Methodology
(e) 1997 Actual – Interim Methodology
(f) 1997 Actual – Generic Methodology
(g) 2001 Forecast – Interim Methodology
(h) 2001 Forecast – Generic Methodology

The terminology used by Hydro when referring to Cost of Service methodologies is as follows:

Interim Methodology – Methodology as approved in the PUB report dated April 13, 1992. Recommendation 11 of that report states that "Hydro's proposed cost of service methodology be used until it is examined more fully at another hearing".

Generic Methodology – Methodology as approved in the PUB report dated February, 1993. Recommendation 26 of that report states "That the cost of service methodology recommended herein be adopted by Hydro for the purpose of its next rate referral".

Proposed Methodology – Methodology as contained in the Cost of Service Study in the pre-filed evidence of Mr. John Brickhill, Exhibit JAB-1. The proposed methodology is based on the generic methodology adjusted as outlined in the written testimony of Mr. Brickhill.

Q. Provide the 2002 Forecast Cost of Service with the generation assets, the associated terminal stations and the 138 kV & 66 kV transmission lines on the Great Northern Peninsula assigned as specific to the Rural Interconnected Customers.

A. See attached. This second revision to the Cost of Service Study originally requested in IC-87 now allocates the distribution substations in Roddickton and St. Anthony to Rural, as referenced in IC-245.