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September 4, 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 Newfoundland and Labrador Hydro’s responses to Requests for Information for the following numbers:

CA-171, 172, 173, 174, 175, 176, 177, 178 and 179.

IC-236, 238, 240, 241 and 242.

Yours truly,

Newfoundland and Labrador Hydro

____

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

MPG/jc

Enclosure

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Q. In 1997 Newfoundland Hydro participated in a joint study with Newfoundland Power into the potential for mini-hydro in island rural isolated systems. Please provide a copy of that study.

A. Please refer to the attached study.

Q. Please provide the costs associated with (i.e. producing/printing, etc.) Newfoundland Hydro's Annual Reports for each of the years 1992 to the year 2000.

A. Costs associated with Hydro's Annual Reports are as follows:

Year	Amount
1992	$ 63,304
1993	69,854
1994	61,640
1995	49,078
1996	63,854
1997	52,106
1998	69,204
1999	75,183
2000	62,345

These costs include: photography, layout, printing and related professional costs.

Q. In reference to CA 100, wherein Newfoundland Hydro acknowledges purchases of power from Newfoundland Power, please provide details of specific purchases for the years 1996 to the present, including the reason for the purchase and the cost of the purchase in each instance.

A. Please refer to the following table. Please note that costs are available only on a monthly basis.

YEAR	DATE	DURATION (Hours)	REASON	COST
1996	02-Jan	3.0	Peak load conditions combined with Upper Salmon unavailable due to frazil ice & Holyrood Unit #2 unavailable due to vibration	$6,994.43
1996	31-Dec	0.5	Peak load conditions combined with Holyrood Unit #1 unavailable for maintenance	$1,546.27
1997	08-Dec	1.5	Holyrood Unit #3 unavailable, Units #1 & #2 Tripped, Forced outage on TL 202 while isolating TL 206	$3,907.11
1998	04-Apr	5.0	Holyrood Units #1 & #2 Tripped	$11,826.54
1998	17-Apr	0.5	Holyrood Unit #1 Tripped	
1998	29-Apr	1.5	Holyrood Unit #1, only unit online, had to come down due to blown PT fuse	
1998	27-Oct	3.0	TL 202 tripped while TL 206 out	$2,689.10

Q. Provide a list of the billing payment options that Hydro makes available to its retail customers. For example, does Hydro offer equalized billing to its customers?

A. A list of payment options are as follows:

- By mail
- In person at Happy Valley, Wabush, St. Anthony and St. John's offices
- At any chartered bank including telephone banking, Interac, or internet as offered by the various banking institutions.

Hydro does not presently have preauthorized payment or equalized billing options available.

Q. Provide a comparison of the cost components and their contributions to the basic customer charge for Domestic and General Service customers on the Island Interconnected System, the Labrador Interconnected System and the Isolated Rural Systems.

A. The following table compares the unit customer costs for each rate class as identified in Schedule 1.3 of Exhibit JAB-1 with the proposed basic customer charges for the Labrador Interconnected System and the projected basic customer charges for the Island Interconnected System and Isolated System customers based on applying the projected average increase to Newfoundland Power's customers of 3.68% to existing basic customer charges.

Rate Class	Customer Cost	Basic Customer Charge
Island Interconnected		
Domestic	$20.73	$16.90
General Service 2.1	23.21	19.24
General Service 2.2	38.25	20.97
General Service 2.3	38.82	94.44
General Service 2.4	35.94	188.88
Labrador Interconnected		
Domestic HVGB	$20.06	$7.00
Dom. Lab City / Wab	20.06	3.75
General Service 2.1	22.42	9.10
General Service 2.2	36.72	-
General Service 2.3	37.89	-
General Service 2.4	37.89	-
Island Isolated Systems		
Domestic	$46.69	$16.90
General Service 2.5	53.51	19.24
Labrador Isolated Systems		
Domestic	$22.20	$16.90
General Service 2.5	25.41	19.24

Q. Document the benefits to consumers resulting from the new Customer Information System. What additional information will be available to customers related to their bills? Will the bill itself be revised to add information? Will customers have access to additional billing and consumption information over the internet?

A. Hydro did not have an integrated online Customer Information System before the implementation of J. D. Edwards system therefore the main benefit to consumers is the availability of up-to-date customer information throughout all areas of the Hydro system. Any customer inquiries can be immediately dealt with. Work orders can be issued immediately to field staff and subsequently monitored and reviewed by Customer Services staff.

Additionally, the time span between meter reading and billing has been reduced by approximately two weeks. The previous delay in getting bills out to customers resulted in a number of inquiries and complaints since the billing period lagged from the actual consumption period.

The new system has also provided Hydro with additional development capability to implement additional payment options including preauthorized payment and equalized billing. This capability did not exist with the previous system.

The bill itself will be revised as additional system features such as finance charges or equal payment plans are added. No other revisions are currently planned.

Hydro has no short-term plan to provide access to additional billing and consumption information over the internet. Over the next year, Hydro will evaluate the importance of this service feature to our customers with a view to implementation at a later date.

Q. How often does Hydro read meters, and what percentage of customer bills have been estimated over the past two years? Are the past two years reflective of the future, and if not, what is Hydro doing to reduce the number of estimated bills?

A. Meters are read on a monthly basis and over the past two years approximately 1% of readings have been estimated. Where possible, Hydro will obtain a reading rather than estimate. Hydro plans to continue the current practice with regard to reading meters.

Q. Provide typical load profiles for the following: winter weekday, winter weekend, spring week-day, spring weekend, summer weekday, summer weekend, fall weekday, and fall weekend. On each load profile, show the typical resource profile for meeting the load including hydro, Holyrood and combustion turbine/diesel generation.

A. The attached graphs show the load profiles for each of the periods requested. Since combustion turbine and diesel generation are reserved for peak or contingency operation, no production from these types of units are expected on typical days.

Q. Hydro's response to PUB-68 includes a May 11, 2001 letter from Mr. Hayes of Newfoundland Power to Mr. Young of Hydro addressing Newfoundland Power's position regarding an appropriate demand-energy rate structure for Hydro's wholesale tariff. In its response to IC-205, Hydro indicates its agreement with Newfoundland Power's position stated in the letter. With regard to this letter, provide the following:

(i) Explain how a demand-energy rate would create volatility in the earnings of both Hydro and Newfoundland from year to year.

(ii) Provide an estimate of how much consumer rates would increase owing to Hydro's increased business risk resulting from a demand-energy wholesale rate.

(iii) What are the benefits arising from a demand-energy rate? Provide an estimate of the value of benefits arising from a demand-energy rate and compare it to the costs arising from the increased volatility.

(iv) Provide all documentation related to public pressure to provide stable rates and that leads Hydro to believe that public reaction to an increase in the variability of electricity rates would be overwhelmingly negative.

(v) Provide an estimate of Hydro's overall cost to provide stable rates by component, and compare it to the consumer benefits related to reduced rates owing to Hydro's reduced business risk.

A. (i) Newfoundland Power has a very high proportion of weather sensitive load. Therefore their peak for any year would be determined to a great extent by the actual weather conditions for that year. An abnormally cold day could result in significantly higher demand and therefore increased purchased power cost for Newfoundland Power and revenue for Hydro. Conversely the absence of a typical cold day could result in significantly lower peak with the respective impacts on the purchased power expense for Newfoundland Power and revenues for Hydro. Variations in energy related revenue due to abnormal weather are offset somewhat by the load variation component of the RSP.

(ii) The increase in rates due to the increased business risk will be dependent on the increase in ROE allowed by the Board to offset the increase in business risk.

(iii) In theory, pricing each component of a rate close to its embedded cost provides a better matching of revenue to embedded cost. The volatility of revenue from each rate component net of the related change in cost could thereby be reduced if the average embedded cost change is similar to the incremental cost change. It is also desirable to price the run-out energy rate in line with incremental cost to promote efficient use of resources. At times these two objectives are contrary to each other. For example the average energy cost for Newfoundland Power as per JAB-1, Schedule 1.3 is 2.586 ¢/kWh. The incremental cost of energy produced at Holyrood based on $28 /bbl is 4.59 ¢/kWh. The proposed flat energy charge of 4.8 ¢/kWh is more consistent with the pricing objective to promote efficient use of resources. Therefore, the benefits, if any, of a demand-energy rate structure depend on the relative priority one places on the various rate design objectives.

(iv) Please see response to NP-27 regarding Hydro's 2000 Customer Survey whereby "electricity at a reasonable cost" was ranked number 3 by customers. Attached are various 1985 newspaper clippings, as well as extracts from the transcripts of Hydro's 1985 General Rate Application both of which outline customers' concerns at the time, concerning major fluctuations in electricity rates due to the application of a fuel adjustment charge formula. This formula was subsequently eliminated and replaced on January 1, 1986 with the Rate Stabilization Plan.

(v) As identified in part (ii) above, the impact of a change in business risk cannot be quantified hence the requested comparison cannot be made.

Q. Provide the table shown in the response to IC-7 using the actual amounts of subsidy which would have been assigned by the Cost of Service Study to a class of customers other than the Industrial Customers had the Industrial Customers not been required in those years to contribute to the subsidy.

A. See the table below. Cost of Service studies for 1996 and 1998 are not available. The 1997 Industrial Deficit allocation will be available from the 1997 Cost of Service study, to be filed by the end of September.

Year	Industrial Revenue (excl. RSP)	Cost of Service Industrial Deficit Allocation	Industrial Revenue Net of Subsidy
1992	$46,380,228	$5,128,157	$41,252,071
1993	46,158,300	5,233,203	40,925,097
1994	40,429,978	4,532,058	35,897,920
1995	44,467,369	5,397,548	39,069,821
1996	47,526,674	---	---
1997	47,689,883	---	---
1998	36,269,044	---	---
1999	43,453,323	4,105,999	39,347,324

Q. Provide detailed calculations of the derivation of the average energy rate and average demand charge for Industrial Customers as set out in the response to IC 206(2).

A. The rates used were based on Industrial Rates as outlined in the table below:

	Industrial Rate (IC) as of July 1			
	Column 1	Column 2	Column 3	Column 4
	Energy[1] (¢ per kWh)	Demand[2] ($ per KW)	Average[3] Rate	Industrial Rate[4] Index
1991	2.560	8.25	3.723	1.000
1992	2.560	8.25	3.723	1.000
1993	2.333	8.25	3.496	0.939
1994	2.333	8.25	3.496	0.939
1995	2.265	8.25	3.428	0.921
1996	2.320	8.25	3.483	0.936
1997	2.403	8.25	3.566	0.958
1998	2.482	8.25	3.645	0.979
1999	2.654	8.25	3.817	1.025
2000	2.284	7.36	3.321	0.892
2001F	2.214	7.36	3.251	0.873
2002F	2.867	7.01	3.855	1.036
2003F[5]			4.130	1.109
2004F[5]			4.390	1.179
2005F[5]			4.310	1.158

Notes:

1. Energy is the actual Industrial Rate as of July 1 each year inclusive of all adjustments, including RSP.
2. Demand is the actual Industrial Rate as of July 1 each year.
3. Average Rate =
   Column 1 + (Column 2 ÷ ((365 days X 24 hours X 81% Load factor*) ÷ 1000))
   * Median industrial load factor of 81% for the period used to express energy rate.
4. Industrial Rate Index = Current Year Average Rate ÷ 1991 Average rate
5. 2003F to 2005F average rates were extracted from page 14 of the Newfoundland and Labrador Hydro Financial Plan as filed in response to IC-98.

Q. Outline quantitatively the impact on the Cost of Service Study of the introduction of new generation sources in 2003 as forecast in the five-year plan of Hydro produced in response to IC 98.

A. New sources of generation forecast for 2003 are Granite Canal and NUG power purchases. During 2003 these sources are forecast to have the following financial impact on Hydro:

Interest	$4.7 m
Depreciation	$0.3 m
Operating and Maintenance	$0.3 m
Power Purchases	$3.6 m
Fuel Savings (net of RSP)	($1.5 m)
Total	$7.4 m

Q. The response to IC-87 indicates that if the GNP transmission lines, terminal stations and generators were assigned to the rural class, the wheeling rate would be 0.541 cents / kWh (page 27, line 3). The same reference in J. Brickhill's evidence and page 4 of rate schedule A shows that Hydro's proposed wheeling rate is 0.695 cents / kWh. Explain why the transmission lines and terminal stations on the Great Northern Peninsula increase the wheeling rate by 28.47% when the wheeling is between; (a) Buchans and Grand Falls, (b) Buchans and Stephenville, and (c) Grand Falls and Stephenville.

A. Hydro's wheeling rate is based on costs and energy associated with the Common transmission grid. The allocation of the Great Northern Peninsula in IC-87 changes the definition of the Common transmission grid, and transmission costs and energy change accordingly. Refer also to the response to IC-225.

Q. Further to IC-120 (3),

a) In 2000, what was the total amount re-allocated from Island Interconnected Rural Customers to Industrial Customers?

b) From January 1 to June 30, 2001, what was the total amount re-allocated from the Island Interconnected Rural Customers to Industrial Customers?

c) What is the 2001 forecast for the total amount re-allocated from the Island Interconnected Rural Customers to Industrial Customers?

A. Further to IC-120 (3),

a) The total amount re-allocated from rural customers to Industrial customers in 2000 is $838,000. This includes Rural Rate Alteration, which is applicable to several systems and an integral part of the re-allocated amount. This amount, along with appropriate interest, will be credited back to the Industrial Plan in the August 2001 RSP report.

b) From January 1 to June 30, 2001, based on the actual RSP, the total amount re-allocated from rural customers to Industrial customers is $742,000. This amount, as well as the July and August amounts, along with appropriate interest, will be credited back to the Industrial Plan in the August 2001 RSP report.

c) The 2001 forecast total amount to be re-allocated from rural customers to Industrial customers is $1,844,000. This is based upon the 2001 forecast entirely, and has not been updated to reflect any 2001 actual activity, including removal of the rural deficit re-allocation noted in parts a) and b). Subsequent to the August 2001 correction, the September to December RSP will be calculated without further allocation of the Rural Deficit to Industrial Customers.

September 4, 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 Newfoundland and Labrador Hydro's responses to Requests for Information IC-239.

Yours truly,

Newfoundland and Labrador Hydro

____

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

MPG/jc

Enclosure

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Q. Confirm that the response to PUB-68 contains the entire rationale of Hydro in determining that a demand/energy rate for Newfoundland Power is inappropriate. If this statement is not accurate, please provide all documents available to Hydro which support this determination, including the latest alternative rate proposals put forward or considered by Hydro or Newfoundland Power when this issue was being dealt with.

A. The letter attached to PUB-68 outlines Newfoundland Power's rationale for determining that a demand/energy rate for Newfoundland Power is inappropriate. Hydro concurs with the conclusion.

The load pattern impact of a choice of rate concept depends upon the response of the end-user to the prices paid for service. Such prices become the cost for the end-user. In this instance, Newfoundland Power is not an end-user, so the load pattern supplied by Hydro is a derived demand. It is derived from the demand of Newfoundland Power's customers as they respond to the rate structure of that firm.

A claimed disadvantage of an energy-only rate is that such a rate will encourage or, at least, not discourage wasteful use of capacity. Similarly, a claimed disadvantage of a demand-only rate is that it will not discourage wasteful use of energy. However, so long as the rate design used by Newfoundland Power to bill its customers reflects the proper recovery of demand, energy, and customer components of the total cost of service of NP, including its purchase from Hydro, there will not be an adverse impact on the load pattern, i.e., a wasteful use of demand caused by Hydro's energy-only rate for service to NP.

An energy only rate also allows for better cooperation between the two utilities regarding the operation of Newfoundland Power's generation as outlined in CA-55. There is also reduced volatility in Hydro's revenue and Newfoundland Power's purchased power expense as outlined in CA-179 with resulting lower business risk for both utilities.

Attached are 2 documents related to analysis of various rate design options discussed by Hydro and Newfoundland Power. Attachment (a) is a compilation of several alternative case impacts that had been prepared as follow up to a meeting held on August 25, 1992. Each case shows the impact on revenue for a two year period compared to the COS. As the various cases were discussed at meetings involving rates personnel from each utility and each meeting was a progression from the previous one and the analyses discussed were typically refinements from ones previously discussed, there was very little documentation involved. Attachment (b) is a letter dated September 11, 1992 from Derek Osmond to John Evans summarizing Hydro position to that point.

N[illegible]oundland Power Three-Part Rate Str[illegible]re

IC-239
Attachment (a)

	(A) Forecast Demand	(B) NLP Hydraulic Generation	(C) NLP Native Load (A)+(B)	(D) NLP Peak Credit	(E) NLP Billing Demand (C)+(D)
Jan	1,044,300	82,840	1,127,140	(143,390)	983,750
Feb	992,100	82,840	1,074,940	(143,390)	931,550
Mar	939,800	82,840	1,022,640	(143,390)	879,250
Apr	783,200	82,840	866,040	(143,390)	722,650
May	731,000	82,840	813,840	(143,390)	670,450
Jun	574,300	82,840	657,140	(143,390)	513,750
Jul	470,000	82,840	552,840	(143,390)	409,450
Aug	470,000	82,840	552,840	(143,390)	409,450
Sep	574,300	82,840	657,140	(143,390)	513,750
Oct	678,800	82,840	761,640	(143,390)	618,250
Nov	939,800	82,840	1,022,640	(143,390)	879,250
Dec	1,044,300	82,840	1,127,140	(143,390)	983,750
Sum of Monthly Billing Demands					8,515,300

NLP Revenues at Existing Rates	194,112,571
Less: Energy Revenue @ 34.00 mills/kwh	(145,659,400)
Less: Specifically Assigned Cost (Jan 92 Final COS)	(2,537,222)
Demand Revenues	45,915,949

		$/KW/MO.	KW	$
Option 1:	Demand Rate, All Year	5.39	8,515,300	45,897,467
Option 2:	Winter Demand Charge +10%			
	Dec - Mar	5.68	3,778,300	21,460,744
	Apr - Nov	5.16	4,737,000	24,442,920
			8,515,300	45,903,664
Option 3:	Winter Demand Charge +20%			
	Dec - Mar	5.94	3,778,300	22,443,102
	Apr - Nov	4.95	4,737,000	23,448,150
			8,515,300	45,891,252

Page 2

92-09-01
09:10

Newfoundland and Labrador Hydro
NLP Demand Revenues Stabilized in RSP
Equivalent Energy Rate Basis - No Demand Variation

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
ALL ENERGY RATE:													
GWH	487.3	460.4	446.4	376.0	321.9	265.7	239.2	238.7	256.8	327.7	386.5	477.5	4,284.1
Mills/kwh	45.31	45.31	45.31	45.31	45.31	45.31	45.31	45.31	45.31	45.31	45.31	45.31	
Revenues ($000)	22,080	20,861	20,226	17,037	14,585	12,039	10,838	10,815	11,636	14,848	17,512	21,636	194,113
THREE-PART RATE:													
Demand:													
KW	983,750	931,550	879,250	722,650	670,450	513,750	409,450	409,450	513,750	618,250	879,250	983,750	8,515,300
$/KW/mo.	5.39	5.39	5.39	5.39	5.39	5.39	5.39	5.39	5.39	5.39	5.39	5.39	
Revenues ($000)	5,302	5,021	4,739	3,895	3,614	2,769	2,207	2,207	2,769	3,332	4,739	5,302	45,897
Energy:													
GWH	487.3	460.4	446.4	376.0	321.9	265.7	239.2	238.7	256.8	327.7	386.5	477.5	4,284.1
Mills/kwh	34.00	34.00	34.00	34.00	34.00	34.00	34.00	34.00	34.00	34.00	34.00	34.00	
Revenues ($000)	16,568	15,654	15,178	12,784	10,945	9,034	8,133	8,116	8,731	11,142	13,141	16,235	145,659
Specific: ($000)	211	211	211	211	211	211	211	211	211	211	211	211	2,537
TOTAL REVENUES:	22,082	20,886	20,128	16,891	14,770	12,014	10,551	10,534	11,712	14,686	18,092	21,749	194,094
Existing Energy Rate	45.31	45.31	45.31	45.31	45.31	45.31	45.31	45.31	45.31	45.31	45.31	45.31	
Equiv. Energy Rate	45.32	45.37	45.09	44.92	45.88	45.22	44.11	44.13	45.61	44.81	46.81	45.55	
	(0.01)	(0.06)	0.22	0.39	(0.57)	0.09	1.20	1.18	(0.30)	0.50	(1.50)	(0.24)	
RSP Entries	(2)	(25)	98	146	(184)	25	287	281	(76)	162	(579)	(113)	18

No Ratchet – Monthly Peaks

Revenue Required from Demand ($000)	37805
Forecast Winter Peak (mw)	N/A
Sum of Monthly Billing Demands (mw)	7013.9
Demand Rate ($/kw/mo)	5.39
Forecasts Used	1989/11/1 0, 1990/10/09 (-80 MW)
Actuals Used	1990, 1991

YEAR 1

Month	Forecast Peak (mw)	Actual Peak (mw)	Billing Demand (mw)	COS Revenue ($ 000)	Actual Revenue ($ 000)	RSP Variance ($ 000)
January	831.8	767.3	767.3	4483	4136	348
February	782.3	930.1	930.1	4217	5013	(797)
March	732.9	791.5	791.5	3950	4266	(316)
April	634.0	580.2	580.2	3417	3127	290
May	535.0	547.3	547.3	2884	2950	(66)
June	436.1	438.2	438.2	2351	2362	(11)
July	337.2	332.0	332.0	1818	1789	28
August	287.7	297.0	297.0	1551	1601	(50)
September	386.7	310.1	310.1	2084	1671	413
October	535.0	513.6	513.6	2884	2768	115
November	683.4	595.7	595.7	3684	3211	473
December	831.8	850.7	850.7	4483	4585	(102)
Total	7013.9	6953.7		37805	37480	324

Month	Forecast Peak (mw)	Actual Peak (mw)	Billing Demand (mw)	COS Revenue ($ 000)	Actual Revenue ($ 000)	RSP Variance ($ 000)
	YEAR 2					
January	868.2	897.3	897.3	4483	4836	(353)
February	817.0	805.6	805.6	4217	4342	(126)
March	765.8	704.9	704.9	3950	3799	151
April	663.5	643.9	643.9	3417	3471	(53)
May	561.1	559.6	559.6	2884	3016	(133)
June	458.7	557.2	557.2	2351	3003	(653)
July	356.4	359.8	359.8	1818	1939	(122)
August	305.2	366.2	366.2	1551	1974	(423)
September	407.5	378.2	378.2	2084	2038	46
October	561.1	582.1	582.1	2884	3138	(254)
November	714.6	591.9	591.9	3684	3190	493
December	868.2	788.3	788.3	4483	4249	234
Total	7347.3	7235.0		37805	38997	(1,192)

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No Ratchet – Monthly Peaks

Revenue Required from Demand ($000)	42979
Forecast Winter Peak (mw)	N/A
Sum of Monthly Billing Demands (mw)	7973.9
Demand Rate ($/kw/mo)	5.39
Forecasts Used	1989/11/1 0, 1990/10/09
Actuals Used	1990, 1991

	YEAR 1					
Month	Forecast Peak (mw)	Actual Peak (mw)	Billing Demand (mw)	COS Revenue ($ 000)	Actual Revenue ($ 000)	RSP Variance ($ 000)
January	911.8	767.3	767.3	4915	4136	779
February	862.3	930.1	930.1	4648	5013	(365)
March	812.9	791.5	791.5	4382	4266	115
April	714.0	580.2	580.2	3848	3127	721
May	615.0	547.3	547.3	3315	2950	365
June	516.1	438.2	438.2	2782	2362	420
July	417.2	332.0	332.0	2249	1789	459
August	367.7	297.0	297.0	1982	1601	381
September	466.7	310.1	310.1	2516	1671	844
October	615.0	513.6	513.6	3315	2768	547
November	763.4	595.7	595.7	4115	3211	904
December	911.8	850.7	850.7	4915	4585	329
Total	7973.9	6953.7		42979	37480	5,499

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	YEAR 2					
Month	Forecast Peak (mw)	Actual Peak (mw)	Billing Demand (mw)	COS Revenue ($ 000)	Actual Revenue ($ 000)	RSP Variance ($ 000)
January	948.2	897.3	897.3	4915	4836	78
February	897.0	805.6	805.6	4648	4342	306
March	845.8	704.9	704.9	4382	3799	582
April	743.5	643.9	643.9	3848	3471	378
May	641.1	559.6	559.6	3315	3016	299
June	538.7	557.2	557.2	2782	3003	(222)
July	436.4	359.8	359.8	2249	1939	309
August	385.2	366.2	366.2	1982	1974	8
September	487.5	378.2	378.2	2516	2038	477
October	641.1	582.1	582.1	3315	3138	177
November	794.6	591.9	591.9	4115	3190	924
December	948.2	788.3	788.3	4915	4249	666
Total	8307.3	7235.0		42979	38997	3,983

No Ratchet – Monthly Peaks

Revenue Required from Demand ($000)	42965	
Forecast Winter Peak (mw)	N/A	
Sum of Monthly Billing Demands (mw)	7973.9	+10%
Demand Rate ($/kw/mo)	5.16	5.68
Forecasts Used	1989/11/1 0, 1990/10/09	
Actuals Used	1990, 1991	

Month	Forecast Peak (mw)	Actual Peak (mw)	YEAR 1 Billing Demand (mw)	COS Revenue ($ 000)	Actual Revenue ($ 000)	RSP Variance ($ 000)
January	911.8	767.3	767.3	5179	4358	821
February	862.3	930.1	930.1	4898	5283	(385)
March	812.9	791.5	791.5	4617	4496	122
April	714.0	580.2	580.2	3684	2994	690
May	615.0	547.3	547.3	3173	2824	349
June	516.1	438.2	438.2	2663	2261	402
July	417.2	332.0	332.0	2153	1713	440
August	367.7	297.0	297.0	1897	1533	365
September	466.7	310.1	310.1	2408	1600	808
October	615.0	513.6	513.6	3173	2650	523
November	763.4	595.7	595.7	3939	3074	865
December	911.8	850.7	850.7	5179	4832	347
Total	7973.9	6953.7		42965	37618	5,347

Month	Forecast Peak (mw)	Actual Peak (mw)	Billing Demand (mw)	COS Revenue ($ 000)	Actual Revenue ($ 000)	RSP Variance ($ 000)
	YEAR 2					
January	948.2	897.3	897.3	5179	5097	82
February	897.0	805.6	805.6	4898	4576	322
March	845.8	704.9	704.9	4617	4004	613
April	743.5	643.9	643.9	3684	3323	362
May	641.1	559.6	559.6	3173	2888	286
June	538.7	557.2	557.2	2663	2875	(212)
July	436.4	359.8	359.8	2153	1857	296
August	385.2	366.2	366.2	1897	1890	8
September	487.5	378.2	378.2	2408	1952	457
October	641.1	582.1	582.1	3173	3004	170
November	794.6	591.9	591.9	3939	3054	885
December	948.2	788.3	788.3	5179	4478	701
Total	8307.3	7235.0		42965	38995	3,970

No Ratchet – Monthly Peaks

Revenue Required from Demand ($000)	42935	
Forecast Winter Peak (mw)	N/A	
Sum of Monthly Billing Demands (mw)	7973.9	+20%
Demand Rate ($/kw/mo)	4.95	5.94
Forecasts Used	1989/11/1 0, 1990/10/09	
Actuals Used	1990, 1991	

Month	Forecast Peak (mw)	Actual Peak (mw)	YEAR 1 Billing Demand (mw)	COS Revenue ($ 000)	Actual Revenue ($ 000)	RSP Variance ($ 000)
January	911.8	767.3	767.3	5416	4558	858
February	862.3	930.1	930.1	5122	5525	(403)
March	812.9	791.5	791.5	4829	4702	127
April	714.0	580.2	580.2	3534	2872	662
May	615.0	547.3	547.3	3044	2709	335
June	516.1	438.2	438.2	2555	2169	386
July	417.2	332.0	332.0	2065	1643	422
August	367.7	297.0	297.0	1820	1470	350
September	466.7	310.1	310.1	2310	1535	775
October	615.0	513.6	513.6	3044	2542	502
November	763.4	595.7	595.7	3779	2949	830
December	911.8	850.7	850.7	5416	5053	363
Total	7973.9	6953.7		42935	37727	5,208

	YEAR 2					
Month	Forecast Peak (mw)	Actual Peak (mw)	Billing Demand (mw)	COS Revenue ($ 000)	Actual Revenue ($ 000)	RSP Variance ($ 000)
January	948.2	897.3	897.3	5416	5330	86
February	897.0	805.6	805.6	5122	4785	337
March	845.8	704.9	704.9	4829	4187	642
April	743.5	643.9	643.9	3534	3187	347
May	641.1	559.6	559.6	3044	2770	274
June	538.7	557.2	557.2	2555	2758	(203)
July	436.4	359.8	359.8	2065	1781	284
August	385.2	366.2	366.2	1820	1813	7
September	487.5	378.2	378.2	2310	1872	438
October	641.1	582.1	582.1	3044	2881	163
November	794.6	591.9	591.9	3779	2930	849
December	948.2	788.3	788.3	5416	4683	734
Total	8307.3	7235.0		42935	38977	3,957

HYDRO

NEWFOUNDLAND AND LABRADOR HYDRO
Head Office: St. John's, Newfoundland P. O. Box 12400 A1B 4K7 • Telephone (709) 737-1400 • Fax (709) 737-1231

September 11, 1992

Mr. John Evans
Vice-President, Corporate Planning
and Consumer Relations
Newfoundland Power
55 Kenmount Road
P.O. Box 8910
St. John's, Newfoundland
A1B 3P6

Dear John,

This is further to our recent discussions concerning the implementation of a demand/energy rate structure for Newfoundland Power and our telephone discussion of yesterday wherein I agreed to write to you outlining Hydro's position.

We feel that significant progress has been made in our discussions with you over the last few months in identifying the objectives for a demand/energy rate structure to be charged by Hydro to NP and in reaching agreement on the basic principles for such a structure. There are, as you know, however, still issues which we both need to further consider and review before we believe that a proposal can be submitted to the Public Utilities Board for approval. Attached to this letter is a revision of the "Outline of Alternative Demand Energy Rate" paper which we have previously reviewed. Items 5 to 8 have been added by Hydro. We look forward to our further discussions with you and to reaching agreement on all elements of the demand/energy rate structure.

While we have made significant progress, Hydro still has a substantial concern with respect to the manner in which the rates charged by Newfoundland Power to its customers will be adjusted after the demand/energy rate structure is implemented by Hydro for Newfoundland Power. We believe that it is very important that the proper pricing signals are sent to all the end users of electricity to ensure that the appropriate demand side management programs can be implemented and to ensure that the most efficient use is made of our available resources. We believe, therefore, that the manner in which the rates charged by Newfoundland Power to its customers will be adjusted to reflect the new pricing signal from Hydro must be discussed by the parties and further explored.

It is our understanding, from our discussions with you, that Newfoundland Power does not plan to adjust its rate structures during 1992 and a decision has not been made yet regarding 1993. Moreover, it is our understanding that Newfoundland Power does not intend to adjust the rate structures, to reflect the new demand/energy rate structure from Newfoundland Hydro, to its customers other than the general service class. We believe that it is essential for the most efficient energy utilization in the Province that the proper pricing signal be sent to all of Newfoundland Power's customers, not just the general service rate class. We, therefore, believe that the adjustment in the rates charged by Newfoundland Power to its customers must be more fully explored by Hydro and Newfoundland Power at this stage to ensure that a proper pricing signal is sent.

Given the fact that a number of issues on the appropriate rate structure require further discussion and that Newfoundland Power does not intend to take immediate action to adjust its rate structures for its customers, including the general service class, it is our view that it is in the best interest of both parties and the consumers in Newfoundland that Hydro and Newfoundland Power continue to have discussions on this matter. We believe that agreement on these issues can be reached and the matter submitted to the Board in the near future.

You have also suggested that it might be possible to adjust the rates charged by Hydro to NP to reflect the demand/energy rate structure as of January 1, 1993 and that the parties should seek approval of the Public Utilities Board at the upcoming referral on the Cost of Service Methodology. As outlined above, it is Hydro's position that this is not appropriate. Moreover, Hydro's legal advisors indicate that a change in the rate structure to be charged by Hydro to NP from an energy only rate to a demand/energy rate structure must be approved in advance by the Public Utilities Board. The process for obtaining this approval would be similar to that required under The Electrical Power Control Act for a referral by Hydro to increase rates. It is Hydro's view that the notice and the process followed with respect to the hearing on the Cost of Service Methodology would not meet the requirements of the Electrical Power Control Act with respect to a proposal to alter the rate structure. We believe, however, that it is important that both parties advise the Public Utilities Board at the Cost of Service Methodology hearing of the significant progress that has been made to date by the parties and of the issues that are still being explored.

If you have any questions regarding any of the points raised above please do not hesitate to contact me.

Yours truly,

Derek W. Osmond
Vice-President, Corporate Planning

DWO/mgw

OUTLINE OF ALTERNATE - DEMAND-ENERGY RATE

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1. Hydro to bill NP on basis of Demand-Energy rate using <u>actual current month demand</u> and <u>current energy consumption.</u>

2. On a monthly basis, Hydro would compare the revenue received from actual demand charges from NP based on the actual NP demand in the month, compared with the revenue based on NP's forecast demand. The difference between actual and forecast revenue would then flow into a "Demand Adjustment Account".

3. NP would in turn establish a mirror image account to reflect "Demand Adjustment Transactions" in its record.

4. The balance in the Demand Adjustment Account would be collected from or paid to NP in the following year. There would be no effect from these transactions on Newfoundland Power's customers.

5. Interest would be calculated monthly on the balance in the Demand Adjustment using the same rate of interest as is used in the Rate Stabilization Plan on a monthly basis.

6. A winter and summer demand charge would be proposed to be charged by Hydro with the winter rate from December to March being higher than the same rate from April to December.

7. Hydro would be proposing to the PUB that this pricing arrangement would be implemented on a trial basis and would be reviewed by the PUB with input from Hydro and NP, at Hydro's next rate referral after the pricing structure was implemented.

8. The new pricing structure as outlined above should be implemented after it has been reviewed and approved by the Public Utilities Board.