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.

92-08-26
16:20

N[redacted]oundland Power Three-Part Rate Str[redacted]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

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

Raj

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

Pg 4

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)

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

IC-239
Attachment (a)

	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

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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	YEAR 1 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	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

	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	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	

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	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

File :

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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,

D. W. O.

Derek W. Osmond
Vice-President, Corporate Planning

DWO/mgw

OUTLINE OF ALTERNATE - DEMAND-ENERGY RATE

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.