Q. (a) Provide detailed calculations of the interruptible rate credit provided to participating industrials (HGB, page 7, lines 21-25).

(b) What operating criterion is used to interrupt the customers on the interruptible rate?

(c) Provide the statistics on the number of interruptions per year requested and the interruptible credits provided for each year since the creation of the interruptible rate.

A (a) In 1993, Hydro entered into an agreement with the Abitibi Consolidated Inc. mill at Stephenville for the supply to Hydro of 46 MW of interruptible demand. The rate was determined as follows:

<u>For Demand</u>

- Capital Cost Estimate for a gas turbine in 1993 = $50,987,000/50,000 kW = $1,040/kW
- Capital Recovery based on a uniform amount payment using 11% interest and 30 year life = 0.1150 x $1,040/kW = $119.6/kW
- Adjustments to account for terms of service:
  1. Annual availability – December to March. 70% of LOLE index occurs during this period, therefore $119.6/kW x 0.70 = $83.7/kW;
  2. Daily availability – partial day with greater weighting for peak hours, i.e. $83.7/kW x 0.75 = $62.8/kW; and

3. Equivalency – adjustment to account for inability to provide voltage support and emergency backups,

   i.e. $68.2/kW x 0.90 = $56.1/kW

- Converting the annual estimate to a monthly rate, i.e. $56.1/kW ÷ 4 = $14.1/kW

<u>for Energy</u>

The energy rate was based on 90% of the production fuel cost from existing gas turbines for energy interrupted. The energy interrupted was based on the demand interrupted over the number of hours of interruption.

It was recognized that during the course of negotiations there may be other factors that would arise with respect to conditions of availability and further adjustments to the rate may be required for these changes. As well, since the monthly demand charge for firm service was $8.25/kW and the demand credit payment by Hydro was viewed, essentially a discount to the firm service provided. It was decided to offer $7.05/kW as the interruptible rate in negotiations, which was accepted by Abitibi Consolidated Inc.

(b) Hydro has two types of interruptible arrangements. One is power and energy supplied to industrial customers above their Power on Order and is called either Interruptible or Interruptible "A" Power, hereafter called Interruptible “A” Power. The second arrangement enables Hydro to interrupt a portion of the customer’s Power on Order and is called Interruptible "B" Power. The arrangement discussed in item (a) above is Interruptible "B" Power.

ACI (Stephenville) has the only Interruptible "B" arrangement. They interrupt their load when requested by the Energy Control Center. These interruptions are requested when Hydro must start its gas turbine units to meet winter peak power demands. A request to interrupt is made one (1) hour in advance and the interruption can be up to ten (10) hours per day.

Customers taking Interruptible "A" Power have that portion of their load interrupted at anytime Hydro considers it necessary to meet firm load requirements. However, at times, these customers will be given the option to continue to receive the Interruptible "A" Power if they are willing to pay for the energy at the cost of Hydro running its gas turbine units. This option is only available when there is sufficient gas turbine capability available. There are no restrictions on timing or duration of these interruptions.

(c) The table below provides the statistics on the number of interruptions per year requested and the interruptible credits provided for each year since the creation of the interruptible rate.

Newfoundland and Labrador Hydro

Interruptible B Interruptions

Season	Interruptions	Energy Credit	Demand Credit	Capacity Payment	Season Total
1993/1994	5	$41,720	$7,512	$1,297,200	$1,346,432
1994/1995	3	$37,282	$6,793	$1,297,200	$1,341,275
1995/1996				$1,297,200	$1,297,200
1996/1997				$1,297,200	$1,297,200
1997/1998				$1,297,200	$1,297,200
1998/1999				$1,297,200	$1,297,200
1999/2000				$1,297,200	$1,297,200
2000/2001				$1,297,200	$1,297,200

Q. Provide JAB, Schedule 1.2 recalculated using a $28 cost of No. 6 fuel and maintaining the proposed revenues for each customer as presented in Table 2 of PRH.

A. See attached.

Q. Provide JAB, Schedule 1.2 recalculated reducing thermal production by 100 GWh and increasing Hydroelectric production by 100 GWh.

A. See attached.

NEWFOUNDLAND & LABRADOR HYDRO
2002 Frcst Cost of Srvc - Prop Meth. NP-141 thermal -100 GWH, hydro + 100 GWh
Total System
Comparison of Revenue & Allocated Revenue Requirement

	1	2	3	4	5	6	7
Line No.	Rate Class	Revenues	Cost of Service Before Deficit and Revenue Credit Allocation	Revenue Credits	Deficit	Revenue Requirement After Deficit and Revenue Credit Allocation	Revenue to Cost Coverage (Col.2/3)
		($)	($)	($)	($)	($)	
	Total System						
1	Newfoundland Power	213,830,400	188,749,568	(156,446)	22,732,796	211,325,918	1.13
2	Island Industrial	50,356,509	49,400,172	186,738	-	49,586,910	1.02
3	Labrador Industrial	3,084,575	3,084,575	-	-	3,084,575	1.00
4	CFB - Goose Bay Secondary	2,991,483	138,430	2,808,854	44,199	2,991,483	21.61
5	Rural Labrador Interconnected	10,351,585	9,956,042	(2,808,854)	3,178,884	10,326,072	1.04
	Rural Deficit Areas						
6	Island Interconnected	31,639,918	36,546,955	(30,292)	(4,876,745)	31,639,918	0.87
7	Island Isolated	1,277,117	7,868,273	-	(6,591,156)	1,277,117	0.16
8	Labrador Isolated	4,205,660	17,327,951	-	(13,122,291)	4,205,660	0.24
9	L'Anse au Loup	1,136,125	2,501,812	-	(1,365,687)	1,136,125	0.45
10	**Subtotal**	**38,258,820**	**64,244,991**	**(30,292)**	**(25,955,879)**	**38,258,820**	**0.60**
11	**Total**	**318,873,372**	**315,573,777**	**-**	**(0)**	**315,573,777**	**1.01**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Frcst Cost of Srvc - Prop Meth. NP-141 thermal -100 GWH, hydro + 100 GWh
Island Interconnected
Comparison of Revenue & Allocated Revenue Requirement

	1	2	3	4	5	6	7
Line No.	Rate Class	Revenues	Cost of Service Before Deficit and Revenue Credit Allocation	Revenue Credit	Deficit Allocation	Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5)	Revenue to Cost Coverage (Col.2/3)
		($)	($)	($)	($)	($)	
	Island Interconnected						
1	Newfoundland Power	213,830,400	188,749,568	(156,446)			
2	NLP RSP Activity	-					
3	**Subtotal Newfoundland Power**	**213,830,400**	**188,749,568**	**(156,446)**	**22,732,796**	**211,325,918**	**1.13**
4	Industrial - Firm	49,975,388	49,246,607	(40,818)		49,205,789	
5	Industrial - Non-Firm	381,121	153,565	227,556		381,121	
6	Industrial RSP Activity	-				-	
7	**Subtotal Industrial**	**50,356,509**	**49,400,172**	**186,738**	**-**	**49,586,910**	**1.02**
	Rural						
8	1.1 Domestic	9,928,516	12,336,264	(10,225)	(2,397,523)	9,928,516	0.80
9	1.12 Domestic All Electric	9,012,212	12,831,794	(10,636)	(3,808,946)	9,012,212	0.70
10	1.3 Special	10,175	19,957	(17)	(9,766)	10,175	0.51
11	2.1 General Service 0-10 kW	1,876,268	1,806,137	(1,497)	71,628	1,876,268	1.04
12	2.2 General Service 10-100 kW	4,851,683	4,286,694	(3,553)	568,542	4,851,683	1.13
13	2.3 General Service 110-1,000 kVa	3,174,877	2,453,845	(2,034)	723,065	3,174,877	1.29
14	2.4 General Service Over 1,000 kVa	2,007,061	2,201,435	(1,825)	(192,549)	2,007,061	0.91
15	4.1 Street and Area Lighting	779,126	610,829	(506)	168,803	779,126	1.28
16	**Subtotal Rural**	**31,639,918**	**36,546,955**	**(30,292)**	**(4,876,745)**	**31,639,918**	**0.87**
17	**Total Island Interconnected**	**295,826,827**	**274,696,695**	**-**	**17,856,050**	**292,552,746**	**1.08**

Note1:
Calculation of Island Industrial Non-Firm Revenue Credit

Island Industrial Non-Firm Revenues, Ln 5, Col 2	381,121
Island Industrial Non-Firm Allocated Cost of Service, Ln 5, Col 3	(153,565)
Credit to be allocated to Firm Customers	227,556

NEWFOUNDLAND & LABRADOR HYDRO
2002 Frcst Cost of Srvc - Prop Meth. NP-141 thermal -100 GWH, hydro + 100 GWh
Island Isolated
Comparison of Revenue & Allocated Revenue Requirement

	1	2	3	4	5	6	7
Line No.	Rate Class	Revenues	Cost of Service Before Deficit and Revenue Credit Allocation	Revenue Credit	Deficit	Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5)	Revenue to Cost Coverage (Col.2/3)
		($)	($)	($)	($)	($)	
	Island Isolated						
1	1.2 Domestic Diesel	740,271	5,717,975		(4,977,704)	740,271	0.13
2	1.2G Government Domestic Diesel	12,678	77,247		(64,569)	12,678	0.16
3	1.23 Churches & Community Halls	12,886	65,782		(52,896)	12,886	0.20
4	2.2 GS 10-100 kW	0	0		0	0	0.00
5	2.3 GS 110-1,000 kVa	45,006	233,461		(188,455)	45,006	0.19
6	2.5 GS Diesel	245,849	962,966		(717,117)	245,849	0.26
7	2.5G Gov't General Service Diesel	185,489	691,229		(505,740)	185,489	0.27
8	4.1 Street and Area Lighting	33,376	111,433		(78,057)	33,376	0.30
9	4.1G Gov't Street and Area Lighting	1,562	8,180		(6,618)	1,562	0.19
10	**Total**	**1,277,117**	**7,868,273**		**(6,591,156)**	**1,277,117**	**0.16**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Frcst Cost of Srvc - Prop Meth. NP-141 thermal -100 GWH, hydro + 100 GWh
Labrador Isolated
Comparison of Revenue & Allocated Revenue Requirement

	1	2	3	4	5	6	7
Line No.	Rate Class	Revenues ($)	Cost of Service Before Deficit and Revenue Credit Allocation ($)	Revenue Credit ($)	Deficit ($)	Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) ($)	Revenue to Cost Coverage (Col.2/3)
	Labrador Isolated						
1	1.2 Domestic Diesel	1,833,178	9,699,956		(7,866,778)	1,833,178	0.19
2	1.2G Government Domestic Diesel	83,320	346,976		(263,656)	83,320	0.24
3	1.23 Churches & Community Halls	54,749	192,328		(137,579)	54,749	0.28
4	2.2 GS 10-100 kW	45,942	506,058		(460,116)	45,942	0.09
5	2.3 GS 110-1,000 kVa	304,116	1,532,554		(1,228,438)	304,116	0.20
6	2.5 GS Diesel	1,286,816	3,464,113		(2,177,297)	1,286,816	0.37
7	2.5G Gov't General Service Diesel	531,181	1,434,798		(903,617)	531,181	0.37
8	4.1 Street and Area Lighting	63,866	142,499		(78,633)	63,866	0.45
9	4.1G Gov't Street and Area Lighting	2,492	8,668		(6,176)	2,492	0.29
10	**Total**	**4,205,660**	**17,327,951**		**(13,122,291)**	**4,205,660**	**0.24**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Frcst Cost of Srvc - Prop Meth. NP-141 thermal -100 GWH, hydro + 100 GWh
L'Anse au Loup
Comparison of Revenue & Allocated Revenue Requirement

	1	2	3	4	5	6	7
Line No.	Rate Class	Revenues	Cost of Service Before Deficit and Revenue Credit Allocation	Revenue Credit	Deficit	Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5)	Revenue to Cost Coverage (Col.2/3)
		($)	($)	($)	($)	($)	
	L'Anse au Loup						
1	1.1 Domestic	634,530	1,640,124		(1,005,594)	634,530	0.39
2	1.12 Domestic All Electric	28,505	86,866		(58,361)	28,505	0.33
3	2.1 General Service 0-10 kW	148,252	277,002		(128,750)	148,252	0.54
4	2.2 General Service 10-100 kW	220,335	399,911		(179,576)	220,335	0.55
5	2.3 General Service 110-1,000 kVa	68,686	53,312		15,374	68,686	1.29
6	4.1 Street and Area Lighting	35,817	44,598		(8,781)	35,817	0.80
7	**Total L'Anse Au Loup**	**1,136,125**	**2,501,812**		**(1,365,687)**	**1,136,125**	**0.45**

NEWFOUNDLAND & LABRADOR HYDRO
2002 Frcst Cost of Srvc - Prop Meth. NP-141 thermal -100 GWH, hydro + 100 GWh
Labrador Interconnected
Comparison of Revenue & Allocated Revenue Requirement

	1	2	3	4	5	6	7
Line No.	Rate Class	Revenues ($)	Cost of Service Before Deficit and Revenue Credit Allocation ($)	Revenue Credit ($)	Deficit Allocation ($)	Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) ($)	Revenue to Cost Coverage (Col.2/3)
	Labrador Interconnected						
1	Industrial IOCC Firm	3,007,393	3,007,393		-	3,007,393	1.00
2	Industrial IOCC Non-Firm	77,182	77,182		-	77,182	1.00
3	**Subtotal Industrial**	**3,084,575**	**3,084,575**		**-**	**3,084,575**	**1.00**
4	**CFB - Goose Bay Secondary**	2,991,483	138,430	2,808,854	44,199	2,991,483	21.61
	Rural						
5	1.1 Domestic	188,642	300,979	(84,914)	96,100	312,165	0.63
6	1.1A Domestic All Electric	5,521,102	7,160,506	(2,020,162)	2,286,292	7,426,636	0.77
7	2.1 General Service 0-10 kW	217,095	241,493	(68,131)	77,107	250,469	0.90
8	2.2 General Service 10-100 kW	1,448,893	907,148	(255,930)	289,645	940,864	1.60
9	2.3 General Service 110-1,000 kVa	1,997,144	859,223	(242,409)	274,343	891,157	2.32
10	2.4 General Service Over 1,000 kVa	816,016	362,052	(102,144)	115,600	375,508	2.25
11	4.1 Street and Area Lighting	162,693	124,640	(35,164)	39,797	129,273	1.31
12	**Subtotal Rural**	**10,351,585**	**9,956,042**	**(2,808,854)**	**3,178,884**	**10,326,072**	**1.04**
13	**Total Labrador Interconnected**	**16,427,643**	**13,179,046**	**0**	**3,223,083**	**16,402,130**	**1.25**

Note1:
Calculation of CFB - Goose Bay Secondary Revenue Credit

CFB - Goose Bay Secondary Revenues, Ln 4, Col 2	2,991,483
CFB - Goose Bay Secondary Allocated Cost of Service, Ln 4, Col 3	(138,430)
CFB - Goose Bay Secondary Allocated Deficit, Ln 4, Col 5	(44,199)
Credit to be allocated to Firm Regulated Customers	2,808,854

Q. Provide details of the calculation of monthly LOLH for the Island Interconnected system for each month for 2000. Include in the details the following:

a) monthly capacity of hydraulic generation;
b) monthly peak loads on the system;
c) monthly available capacity for thermal;
d) forced outage rate assumptions on thermal; and
e) maintenance assumptions on thermal.

A. a) See attached table.

b) See attached table.

c) See attached table.

d) The forced outage rate assumptions on thermal plant are:

Holyrood units 1, 2, and 3:	10.11%
Gas turbines:	9.02%
Diesel units:	1.18%

e) The maintenance assumptions on thermal plant are:

Holyrood units 1, 2, and 3:	8 weeks per year/unit
Gas turbines:	2 weeks per year/unit
Diesel units:	2 weeks per year/unit

Hydro also assumes that thermal unit maintenance will be performed in the period from April through November.

Island Interconnected System
Monthly LOLH Calculation Details for 2000

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Monthly LOLH (hours)	0.07736	0.11671	0.01278	0.00011	0.00004	0.00008	0.00000	0.00000	0.00000	0.00010	0.00843	0.22016
(a) Hydraulic Capacity (MW)	1179	1179	1179	1179	1179	1179	1179	1179	1179	1179	1179	1179
(b) Peak Loads (MW)	1427	1426	1347	1222	1146	1101	909	895	961	1142	1326	1443
(c) Available Thermal Capacity (MW)	652	652	652	652	491	491	390	405	510	510	652	652

Q. Provide the basis for the allocation of employee future benefits between regulated and non-regulated operations (KCM, page 14, lines 5-8).

A. Employee future benefits are included in the Cost of Service as an Overhead, split among systems, functions and classifications based on direct expenses. The allocation between regulated and non-regulated operations is based on the allocation factors applicable to that functionalized and classified amount. Non-regulated operations (IOCC in Labrador Interconnected) is therefore allocated a portion of the expense based on its proportionate Production Demand CP kW, Production and Transmission Energy MWh at Generation, and Transmission Demand CP kW. See Exhibit JAB-1, page 88.

Q. Show the calculation performed to remove CF(L)Co from the corporate capitalization to arrive at utility-only capitalization (KCM, page 12, lines 24-28).

A. Please refer to response to IC-197.

Q. In light of Hydro's 75% dividend payment policy, justify the $70 million dividend proposed in 2002.

A. As indicated in our response to NP-72 (b), a significant portion of the 2002 dividend payment represents a payment of dividends that were not paid in previous years to the shareholder. The 2002 dividend payment results in a debt to capital ratio that exceeds our stated goal of 80:20, but this is viewed as temporary.

While the 2002 dividend payments as estimated are based on requirements as communicated to Hydro by the Department of Finance, they will nevertheless require approval by Hydro's Board of Directors prior to payment. Hydro's current dividend policy requires that dividend payments are to be made only after due consideration has been given by the Board of the impact of such payment on the debt/equity ratio of the Corporation.

Q. Provide a comparison of Hydro's level of subsidization of rural customers to the subsidization between classes of customers in other jurisdictions across Canada.

A. In the spring of 2001, Manitoba Hydro conducted a survey with respect to rates and revenue recovery in remote areas served via diesel generation. A summary of this data is shown below.

Utility	Communities Served	No of Cust	Operating Deficit ($ millions)
BC Hydro	9	9,100	28
Northwest Territories Power Commission	51	15,800	0
ATCO Electric (Alberta)	10	NA	NA
Newfoundland & Labrador Hydro	25	4,500	16
Hydro Quebec	40	13,800	106
Hydro One Remote Communities (Ontario)	20	3,700	18
Manitoba Hydro	4	800	3
Yukon Electrical	10	1,300	NA

There is cross subsidization in all areas except Northwest Territories Power where current rates recover costs. Both ATCO Electric and Yukon Electrical do not track the operating deficit amounts separately however the costs are recovered through cross subsidization as well.