Q. With respect to Budgell's evidence page 12, lines 1-13 on the Wind Demonstration Project:

1. What are the actual/estimated cost for each year of the demonstration project?
2. Is this cost being passed on to Hydro's customers?
3. What is the average cost in cents per kwh for Wind generation in other places where it is used?

A.

1. Please refer to Hydro's response to PUB 1.1. These estimates are to be determined by the feasibility study, which won't be completed until June 2002.

2. There are no costs for the project at this time, however should the project proceed, Hydro will seek approval for the costs to be included in rates.

3. Hydro does not have specific information on wind generation costs in other places. However, a Natural Resources Canada publication indicates, "*generators cost about $1500 per kilowatt for wind farms that use multiple-unit arrays of large machines. Smaller individual units cost up to $3000 per kilowatt. In good wind areas, the costs of generating electricity range between five and ten cents per kilowatt hour.*" The cost of a project depends on the consideration of many factors such as average annual wind speed, proximity to the utility grid, climatic conditions and site accessibility.

Q. With regard to Brickhill's evidence page 7, lines 1 - 4, list all the changes in assignment on the Island Interconnected System and the cost impact that each change has on the three customer classes.

A. The changes in plant assignment and cost impacts are attached.

NEWFOUNDLAND AND LABRADOR HYDRO
2002 Forecast Cost of Service
Proposed Changes in Plant Assignment - Cost Impacts ($000)

	Before Deficit & Revenue Credit Allocation			After Deficit & Revenue Credit Allocation		
	NP	Industrial	Rural Island Interconnected	NP	Industrial	Rural Island Interconnected
Doyles / Bottom Brook re-assigned from NP to Common	(146)	94	52	(110)	94	---
GNP Transmission assets re-assigned from Rural to Common	7,661	1,387	(8,751)	18	1,386	---
Frequency Converters re-assigned from Common to Specific	(130)	141	(11)	(140)	141	---
S'ville / Bottom Brook assets re-assigned from Common to NP	6	(4)	(2)	5	(4)	---

Q. With regard to Brickhill's evidence page 8, lines 24 B 29 and schedule II:

1. Provide data to show the variation over time.
2. What was the rationale for using years 1994, 1996, 1997, 1998, 1999 & 2000 in schedule II?
3. Why was 1995 omitted?
4. Provide the 1CP, 2CP, 3CP and 4CP allocators for the three customer classes for each year 1992 to 2000 inclusive.

A. 1. See attached.

2. The years were selected to review the data since the Board's Order (1993).

3. 1995 data was not immediately available in the required format when the analysis was prepared. Since the analysis was intended to provide only an indication of the variation in base data, no further effort was expended. Schedule II has been reproduced, with 1995 included, in the attached page 4.

4. System Peak data prior to 1994 was not reported in a manner designed to capture the data provided in 1994 and subsequent years, after Hydro received approval from the Board for a change in methodology. The effort required to produce the data consistent with that methodology is not considered necessary for the matters currently before the Board.

Multiple CP kW for 1994-2002, at the transmission level, are attached as page 5. Transmission level kW do not include allocated losses between generation and transmission, as do the CP kW used in the Test Year Cost of Service to allocate production demand costs. Please see IC-142 for generation level class CPs for 1999-2000. Historic models are not equipped to provide multiple CP allocators at generation. On a percentage per customer basis, the results should not vary significantly after losses are allocated to derive the CP at generation number.

Q. With regard to Hamilton's evidence page 16, lines 7 - 8:

1. Does the Interconnected Rural Customer class pay for the 138/25 kV transformer losses at Bottom Waters?
2. If so, how do these losses get incorporated into the rural rate?

A.

1. The 138/25 kV transformer losses at Bottom Waters are allocated to the Interconnected Rural Customer class.
2. Hydro doesn't design rates for the Interconnected Rural Customer class. The rates for this group of customers are the same as those charged by Newfoundland Power.

Q. With respect to the Roddickton, Hawkes Bay and St. Anthony diesel units, has the classification of any of them changed since 1992? If so, which ones, when, on what basis and to what classification.

A. In 1992, these three diesel plants were classified 100% demand-related. The same treatment has been accorded diesel generation in the 2002 Forecast Cost of Service.

Q. With respect to the diesel units at St. Anthony, Roddickton, and Hawkes Bay:

1. When did each become part of the Island Interconnected system?

2. Provide a chart showing the number of times each unit has been used in each year since it became interconnected, the reason it was used on each occasion and the class of customers in need of emergency or peaking capacity on each occasion.

3. Provide the number of kWh generated by each unit in each year since it was interconnected, the amount of fuel consumed by that unit in that year, the cost of the fuel consumed in that year, the capital costs incurred in relation to that unit in that year and the operating and maintenance costs associated with that unit in that year.

A. 1. The table below shows when the generating plants in question became a part of the Island Interconnected System.

Generation Source	Available to Island Interconnected System
St. Anthony Diesel Plant	September 7, 1996
Roddickton Diesels	September 7, 1996
Hawke's Bay Diesels	June, 1971

2. Records back to 1971 for Hawke's Bay are not readily available thus data since 1992 are used to answer this question. The table shows

the number of times during 1992 through 2000 when each of the plants were operated. Operation for testing is excluded from the table.

Year	St. Anthony Diesel	Roddickton Diesel	Hawke's Bay Diesel
1992			12
1993			12
1994			9
1995			18
1996	15	5	15
1997	12	5	2
1998	11	9	5
1999	20	2	6
2000	6	0	1

The Hawke's Bay diesels have been used to maintain acceptable voltages to Hydro rural customers during scheduled or forced outages on the Great Northern Peninsula. Prior to the construction of additional lines (1990) on the Great Northern Peninsula, Hawke's Bay diesels were used regularly to maintain acceptable voltage to Hydro rural customers with all available transmission in-service. As well, it was used to supply generation requirements for the entire system on January 2, 1996. It helped meet the peak of 1303 MW on that day. Hawke's Bay diesels were also on for system support prior to 1992. One known case identified from a record peak report is February 3, 1990. On that day it was on to meet a system peak of 1316 MW. On both of these occasions Hawke's Bay diesel served all customer classes.

On all occasions since the interconnection of St. Anthony and Roddickton, the Roddickton and St. Anthony diesel plants were used to supply Hydro rural customers during forced and scheduled transmission outages on the Great Northern Peninsula.

3. The table below provides the number of kWh generated by each unit, the amount of fuel consumed by that unit, the cost of the fuel consumed, operating and maintenance costs and capital costs for each year from 1992 to 2000.

Hawkes Bay Diesel

	Energy Produced (Gross kWh)	Fuel Consumed (gallons)	Fuel Cost	O&M Cost	Capital Cost
1992	192,000	12,915	$12,811	$92,622	$0.00
1993	168,000	11,531	$11,070	$103,796	$0.00
1994	115,200	8,464	$8,061	$91,940	$0.00
1995	600,000	38,386	$47,656	$97,938	$0.00
1996	600,000	39,011	$51,750	$136,628	$0.00
1997	129,600	9,672	$12,546	$28,283	$0.00
1998	115,888	8,092	$8,915	$69,624	$0.00
1999	170,056	11,492	$14,019	$67,358	$0.00
2000	51,100	4,947	$7,088	$76,971	$0.00

St. Anthony Diesel

	Energy Produced (Gross kWh)	Fuel Consumed (gallons)	Fuel Cost	O&M Cost	Capital Cost
1992					
1993					
1994					
1995					
1996	1,051,700	110,272	$132,941	$544,453	$0
1997	257,398	19,136	$23,726	$141,863	$0
1998	395,200	30,300	$28,773	$97,466	$0
1999	216,000	17,136	$17,041	$129,804	$0
2000	139,200	8,596	$11,524	$177,040	$0

Roddickton Diesel

	Energy Produced (Gross kWh)	Fuel Consumed (gallons)	Fuel Cost	O&M Cost	Capital Cost
1992					
1993					
1994					
1995					
1996	180,960	12,939	$15,853	$59,080	$0
1997	66,000	5,266	$6,963	$19,549	$0
1998	122,400	8,050	$10,022	$41,445	$0
1999	19,800	875	$969	$9,338	$0
2000	0	0	$0	$10,086	$0

Q. How have runner replacements on Bay d'Espoir units 1 - 6 improved:

1. reliability?
2. efficiency?
3. environmental performance?

A. 1. Reliability

Prior to the replacement of the runners frequent problems that occurred that affected the reliability of the units included:

a) Galvanic corrosion/cavitation of the runner components.

b) Failure of the bolts securing the stationary primary wearing rings in the headcover and discharge ring.

c) Cracking of the runner blades.

Since the replacement of the runners all these problems have been eliminated and to date there has been no need for any runner repairs.

2. Efficiency

As outlined in the evidence of R. J. Henderson, page 4 lines 10 to 16, there has been a 2.8% increase in unit efficiency.

3. Environmental Performance

The runner replacements were undertaken primarily for reliability and efficiency improvements. However, some environmental benefits have been noted.

a) The change in efficiency and increase in production will result in less production at Holyrood and thereby reduce emissions from that plant.

b) During replacement of the runners the main wicket gate bushings were replaced with self lubricating type bushings eliminating the possibility of grease being released to the environment.

Q. With respect to the runner replacements on Bay d'Espoir units 1 - 6:

1. Have the replacements resulted in increased production? If so, to what extent?

2. Have the replacements resulted in cost savings? If so, in what areas and what savings each year are attributable to that work?

A. 1. Yes, there has been an increase in production as outlined in the evidence of R. J. Henderson, page 4 lines 1 to 16.

2. Yes, there have been savings in the areas of cavitation and corrosion repairs, blade crack repairs and in the dismantling and reassembly of the units to make major repairs. The annual savings for all units is estimated to be $100,000.

Q. How have the exciter replacements on Bay d'Espoir units 1 - 6 improved:

1. reliability?
2. efficiency?
3. environmental performance?

A. 1. Reliability

Items incorporated into the design for the new ABB exciters to improve reliability are redundant bridges, redundant ac/dc power supplies, individual field flashing circuits as opposed to one source for all exciters and monitoring functions in the software itself.

The following statistics are presented to identify the fact that there may have been some problems with the new exciters. However, the majority of the problems with the new exciters have been minor in nature and easier to troubleshoot resulting in reduced outage durations.

The forced outage rate for the new ABB exciters (1997 to present) is 2.22 forced outages/year where as the old GE exciters had a trip rate of 1.74 trips/year (For the period 1967 to 1993). However, the average outage duration for the new ABB exciters is 10.5 hours/year as opposed to 32.95 hours/year for the old GE exciters (for the period 1983 to 1993). In addition, the ABB statistics include all forced outages as opposed to just trips when the units are in service.

2. Efficiency

The ABB exciters installed on Bay d'Espoir Units 1-6 have not had an effect on plant efficiency.

3. Environmental Performance

The GE exciters had PCB capacitors which have now been removed.

Q. With respect to the exciter replacements on Bay d'Espoir units 1 - 6:

1. Have the replacements resulted in increased production? If so, to what extent?

2. Have the replacements resulted in cost savings? If so, in what areas and what savings each year are attributable to that work?

A. 1. There has been no increase in production.

2. The cost savings associated with the new exciters are realized in the reduction in outage time (reduced overtime) and reduced maintenance costs. In 1988/89 $55,000 was spent on the old GE field breakers and in 1990/91 $110,000 was spent on the old GE power supplies.

Q. How have each of (a) the exciter replacements on Holyrood units 1 and 2; (b) the Electro-Hydraulic Control (EHC) replacement on Holyrood unit 2; (c) the installation of on-line performance monitoring at Holyrood; (d) the Boiler Control and Station Service Control replacement on Holyrood unit 3; (e) the new water treatment plant at Holyrood and (f) the upgrade of the wastewater facility and other environmental improvements at Holyrood improved:

1. reliability?
2. efficiency?
3. environmental performance?

A. (a) Holyrood Units 1 and 2 exciter replacements;

1. Reliability

The exciter replacement project was undertaken as a result of equipment obsolescence in that GE no longer supported the electronic cards. Also some of the components on these cards were no longer available. There are no statistics indicating reliability performance before and after installation. However, continued operation with obsolete parts would have led to reliability problems similar to Bay d'Espoir as these exciters were of similar design and vintage.

2. Efficiency

There were no efficiency implications from this project.

3. Environmental Performance

The GE exciter had PCB capacitors which have now been removed.

(b) Holyrood Unit 2 Electro-Hydraulic Control Replacement;

1. Reliability

This project was undertaken as a result of equipment obsolescence in that GE no longer supported the electronic cards.

This project also gave the plant an ability to black start the generator to a dead bus and give frequency control as it is loaded, both of which can provide reliability benefits to customers on the system.

2. Efficiency

There are no efficiency improvements from this project.

3. Environmental Performance

There are no environmental performance improvements from this project.

(c) Holyrood On-Line Performance Monitoring;

1. Reliability

This project did not have a reliability impact.

2. Efficiency

This project was undertaken to improve the efficiency of the Holyrood station. It provides continuous real time data to the operator. This allows the operator to configure the unit at the lowest cost possible and therefore optimum efficiency.

3. Environmental Performance

This project also improves the environmental performance in that any gains in efficiency will mean less fuel consumed and less emissions.

(d) Holyrood Boiler Control and Station Service Control Replacement;

1. Reliability

This project was undertaken as a result of equipment obsolescence in that spare parts were no longer available to maintain the equipment.

2. Efficiency

There are no efficiency improvements from this project.

3. Environmental Performance

There are no environmental performance improvements from this project.

(e) Holyrood New Water Treatment Plant;

1. Reliability

This project was undertaken to replace deteriorated equipment that had reached the end of its useful life.

2. Efficiency

The new plant generates high purity water more efficiently.

3. Environmental Performance

It has improved in environmental performance. Generating high purity water is a chemical process that involves raw materials, caustic soda and sulfuric acid to mention a few. Generating water more efficiently means less raw material present in the output. This results in less waste chemical on an annual basis.

(f) Holyrood – Upgrade of Wastewater Facility;

1. Reliability

   There are no reliability improvements from this project.

2. Efficiency

   There are no efficiency improvements from this project.

3. Environmental Performance

   Industrial wastes generated at the Holyrood plant prior to 1996 were disposed of at Robin Hood Bay Municipal landfill. Development of this site meant all industrial waste would be contained in a secure landfill at the Holyrood site.

Q. With respect to each of the improvements referred to in the previous question:

1. Have the improvements resulted in increased production? If so, to what extent?
2. Have the improvements resulted in cost savings? If so, in what areas and what savings each year are attributable to each improvement?

A. 1. The following improvements resulted in increased production:

Performance Monitoring - auxiliary power consumption has been reduced meaning more energy is available for customers as opposed to being used internally within the plant.

2. The following improvements resulted in cost savings:

Water Treatment Plant – the new water treatment plant has resulted in cost savings resulting from less chemical consumption, lower overtime requirements and less wear and tear on the equipment. There have been no formal computations of the actual cost savings.

Performance Monitoring - The performance monitoring has increased efficiency, which has resulted in reduced fuel consumption and lower fuel costs. This along with the reduced auxiliary power consumption has resulted in the increase of the Holyrood conversion factor from an average of 605 kWh/bbl to 610 kWh/bbl.

Q. What are the “other environmental improvements at Holyrood”? What was the cost of each and why was it done?

A. The “other environmental improvements at Holyrood” refers to the following:

(a) Ambient Air Monitoring Program – Hydro in 1995 enhanced its program of monitoring the ambient concentration of Sulphur Dioxide (SO_2) and Particulate Matter. In 1997 Hydro installed a meteorological station near the plant in order to do dispersion modeling of emissions and to assist in identifying future operating problems. This was done as part of regulatory requirements for plant operation. The total purchased and installation cost of the equipment is approximately $354,000. The annual operating cost is approximately $73,000.

(b) Controlled Waste Landfill – In 1999 Hydro initiated the building and operation of a controlled waste landfill. This was done for the reasons outlined on 14 to 18 on page 5 of R. J. Henderson’s evidence. It cost approximately $976,000 to develop this facility. It cost $60,000 in 2000 to operate.

(c) Creation of a Community Liaison Committee – In 1998 this committee was formed with members from the town councils of Conception Bay South and Holyrood, the Provincial Department of Environment and Lands, the Regional Community Health Board, the IBEW union and Holyrood generating Station management. This was initiated to have better communications between Hydro and the stakeholders in its environmental performance. The estimated annual cost is $5,000.

(d) ISO 14001 Environmental Management System – In 1998 an Environmental Management System (EMS) conforming to the ISO 14001 standard was developed. The reasons in addition to those outlined on page 21, lines 12 to 28 of W. E. Wells evidence are as follows:

- better control and management of environmental issues;
- establishment of comprehensive due diligence with respect to environmental aspects;
- cost effective implementation of environmental management programs which is emphasized and promoted;
- budgets for remediation, abatement and prevention of environmental aspects are directed towards the areas of greatest concern first;
- specifically in the case of Holyrood the unit efficiency environmental management program is an environmental initiative that has seen positive improvements in the unit efficiency.

It is estimated to cost approximately $290,000 (excluding internal staff time) per year to maintain Hydro's commitment to this system at Holyrood.

Q. With respect to page 5, lines 23 - 31 of the evidence of R. J. Henderson:

1. How many kWh of energy have each of Corner Brook Pulp and Paper Limited (CBPPL) and Abitibi Consolidated Inc. (ACI) supplied to Hydro in each of the years 1992 - 2000 inclusive?

2. How much did Hydro pay each of CBPPL and ACI for energy supplied in each of the years 1992 - 2000 inclusive for energy surplus to their needs?

3. What is the basis upon which Hydro paid for surplus energy from CBPPL and ACI each of 1992 - 2000?

4. What is the dollar value of the surplus energy supplied by each of CBPPL and ACI in the years 1992 - 2000 for which they were not paid any compensation?

A. 1. Please refer to the following table:

	CBP&P (Deer Lake Power)		ACI (Grand Falls)	
Year	kWh	Cost	kWh	Cost
1992	987,806	$20,305	3,297,411	$32,178
1993	3,198,476	$42,588	3,217,764	$7,573
1994	798,656	$18,168	1,468,994	$13,761
1995	1,112,604	$19,963	567,495	$3,660
1996	737,493	$17,282	9,602,557	$140,498
1997	659,974	$16,386	5,437,879	$80,276
1998	1,708,875	$17,161	168,918,161	$0
1999	453,739	$13,098	0	$0
2000	128,144	$3,305	171,653	$2,760

2. Please refer to the above table.

3. Hydro paid for the surplus energy in accordance with the agreements referenced in IC-43. In relation to the agreement with Corner Brook Pulp and Paper the rate paid is as established by PUB order P.U. 24 (1988).

4. There was surplus energy supplied to Hydro by Corner Brook Pulp and Paper and ACI (Grand Falls) in 1998, which was also surplus to Hydro's requirements. Hydro took receipt of the energy without paying for it as Hydro's reservoirs were near full at the time and at risk of spilling. The energy was taken by Hydro on the condition that if it caused Hydro to spill later it would not be paid for. In September 1998 and from March to June 1999 Hydro spilled water due to high inflows and high reservoirs levels at the end of 1998 caused by low load during the ACI strike at Grand Falls and Stephenville in 1998. Hydro spilled the energy equivalent of water in excess of the 169.9 GWh delivered to Hydro by these customers. Therefore there was no value to this energy.

Q. With respect to “lowest historic inflow sequence experienced”, what was that assumption in the forecast for each of the years 1990 - 2000, the number of years data utilized to support that forecast and the actual experience in that year?

A. In all years the hydroelectric production forecast was the then current annual average energy capability which is based on all historic inflow sequences including the lowest sequence. Hydro’s actual experience in inflows for each year since 1990 are provided in the answer to IC-155. These years experienced significantly higher inflows than the lowest historic inflow sequence.

Q. Identify the dates and nature of any interconnections to the Hydro Rural system in the period 1992 – 2000 and the operating load impacts for Hydro Rural of those connections for 1992 – 2000.

A. There were six systems interconnected to the Hydro rural system in the period 1992 – 2000.

The Petite Forte system was interconnected to the Island Interconnected System in September 1993. This utilized 18 km of 14.4 kV single phase overhead distribution line, originating at Newfoundland Power's Brookside Substation.

The St. Anthony-Roddickton system was interconnected to the Island Interconnected system in September 1996. This required the construction of 103.8 km of 138 kV transmission line, 47.8 km of 69 kV transmission line, conversion of 86.8 km of 66 kV transmission line to 138 kV operation, conversion of the existing 66/12.5 kV terminal stations at Plum Point and Bear Cove to 138/12.5 kV stations, construction of a 138/69 kV station at St. Anthony Airport and construction of a 69/25 kV terminal station at St. Anthony Diesel Plant.

The Westport system was interconnected to the Island Interconnected system in October 1996. This utilized 40.5 km of 14.4 kV single phase overhead distribution line originating at Newfoundland Power's Seal Cove Road Substation.

The South East Bight system was interconnected to the Island Interconnected system in March 1998. This utilized 24 km of 14.4 kV single phase overhead distribution line originating at Monkstown.

The Mud Lake system was interconnected to the Labrador Interconnected system in November 1998. This utilized 9 km of 14.4 kV single phase overhead distribution line and a 1.5 km submarine cable originating at Happy Valley.

The Lapoile system was interconnected to the Island Interconnected system in December 1999. This utilized 11 km of 14.4 kV single phase overhead distribution line and a 3.7 km submarine cable originating at Grand Bruit.

For operating load impacts for Hydro Rural of these connections for 1992 – 2000, please see attached table.

Annual Energy Sales (at Bulk Delivery Point) and Peak Demand

Date of Interconnection		1993		1994		1995		1996		1997		1998		1999		2000	
		MWh	kW	MWh	kW	MWh	kW	MWh	kW	MWh	kW	MWh	kW	MWh	kW	MWh	kW
1993	Petite Forte	149	137	474	150	492	172	485	171	486	182	484	184	485	172	502	173
1996	Roddickton/St. Anthony [1]							15350	9692	45939	10160	47720	10872	50214	11636	53052	11069
1996	Westport							288	424	1527	432	1553	432	1583	396	1626	468
1998	South East Bight [2]											383	145	554	N/A	564	N/A
1999	La Poile [2]													576	N/A	613	N/A
	Total	149	137	474	150	492	172	16123	10287	47952	10774	50140	11633	53412	12204	56357	11710
1998	Mud Lake [3]													N/A	N/A	N/A	N/A

3. Mud Lake is not metered separately from Happy Valley

Q. Provide the same information with respect to the Doyles-Port aux Basques system re-assignments?

A. The cost implications are as follows:

Newfoundland Power	$110,000	decrease
Island Industrial Customers	$94,000	increase

Note that these numbers do not incorporate any changes to revenues, or any related impacts associated with interest and return on rate base, from those filed in Exhibit JAB-1.

Q. Further to Schedule XIV on the Rate Stabilization Plan (RSP) provided by J. C. Roberts, provide a set of Tables with supporting schedules and notes as required to indicate the following for each year's actual results by month from 1992 to 2000 and for each year's forecast results by month for 2001 and 2002:

1. Opening Balance of RSP, showing the total and the sub-amounts for Newfoundland Power (NP) and Island Industrial Customers (IC);

2. The adjustments made in that month and year for each RSP component (e.g., hydraulic production variations, fuel component of load variations, revenue component of load variations, fuel cost variations, rural rate alterations); fully explain the basis for each adjustment, and provide the specific Test Year Cost of Service Study forecasts used to calculates any variance;

3. The monthly customer allocation (among NP, IC, Rural Island Interconnected, and Labrador Interconnected) for each RSP component; fully explain the basis for each allocation; indicate any allocations to Rural Island Interconnected and Labrador Interconnected that are removed from the RSP and written off against Hydro's net income (loss);

4. The year-end adjustment made to recover or pay out one-third of the RSP amount owing to or from NP; indicate how this is accounted for and when the amounts are actually recovered;

5. The year-end adjustment made to recover or pay out one-third of the RSP amount owing to or from IC; indicate how this is accounted for and when the amounts are actually recovered;

6. Indicate any management fee or administrative charges by Hydro to the RSP; indicate fully the basis for determining any such charges. Indicate how any such fee is accounted for in Hydro's accounts related to its regulated activities;

7. Indicate any financial charges on (or credits to) the RSP; indicate fully the basis for determining any such charges or credits (if a specific Hydro weighted average cost of capital is used, provide this cost for each calculation). Indicate how any such charge or credit is accounted for in Hydro's accounts related to its regulated activities.

A.

1. Please see response to IC-73 for the years 1992 to 2000 and to PUB-59 for 2001 and 2002.

2. Please see response to IC-73 for the years 1992 to 2000 and to PUB-59 for 2001 and 2002.

3. Please see response to IC-73 for the years 1992 to 2000 and to PUB-59 for 2001 and 2002.

4. Please see response to IC-73 for the years 1992 to 2000 and to PUB-59 for 2001 and 2002.

5. Please see response to IC-73 for the years 1992 to 2000 and to PUB-59 for 2001 and 2002.

6. Please see response to IC-13.

7. Please see response to No. 1 above for financing charges included in the RSP and response to NP-47 for the calculation of the interest rate.

Q. Indicate projected costs in U.S. dollars of No. 6 fuel in each of the years 2002 - 2011, inclusive, based (a) on the forecasts adopted in the application (consistent with Henderson, Schedule VII), and (b) based on the best and most current information available to Hydro.

A. (a) The forecast market prices for No. 6 fuel based on the September 2000 PIRA forecast are as follows:

2002	19.88 $US/bbl
2003	18.23 $US/bbl
2004	16.38 $US/bbl
2005	16.58 $US/bbl
2010	19.66 $US/bbl

After contract discounts of $0.11 to $0.14 per BBL

(b) The forecast market prices for No. 6 fuel based on the July (short term) and June (long term) 2001 PIRA forecast are as follows:

2002	18.78 $US/bbl
2003	18.33 $US/bbl
2004	17.28 $US/bbl
2005	17.03 $US/bbl
2010	21.26 $US/bbl

After contract discounts of $0.11 to $0.14 per BBL

Please note PIRA provides a 2010 forecast beyond 2005. Hydro normally does a straight-line interpolation between these dates. For forecasts beyond 2010 Hydro consults with PIRA on long term sustainable crude prices and derives a No. 6 fuel price based on normal spreads between crude and No. 6 fuel.

Q. Indicate projected exchange rates used by Hydro to convert No. 6 fuel costs in Canadian dollars in each of the years 2002 - 2011, inclusive.

A. The projected exchange rates used during the preparation of the Fall 2000 fuel price forecast are as follows:

2001	0.694 $US/$1CAN
2002	0.701
2003	0.701
2004	0.708
2005	0.713
2010	0.727

Q. Indicate how much of the actual fuel costs for No. 6 fuel consumed in each year from 1992 - 2001 inclusive was charged to the RSP, how much of such charges to the RSP were passed through to NP and IC respectively, and what impact such RSP pass through had on average rates charged to NP and IC respectively.

A. Please see responses to IC-73 and PUB-59. Schedules showing the RSP impact on rates is attached.

Q. Indicate the projected No.6 fuel charges to the RSP for each of the years 2002 to 2111 inclusive, as well as any other currently projected charges to the RSP, the amounts of such charges projected to be passed on to NP and IC respectively in each year, and what impact such RSP pass through is projected to have (based on the assumptions and forecasts in Hydro's application) on average firm rates charged in each year to NP and IC respectively.

A. Projections are not available past the year 2005. Please see response to PUB-59 for 2002. The RSP reports for 2003 to 2005 are attached and during this period it is assumed for the purpose of these calculations that there is no change in base rates or the price of No. 6 fuel included in the base rate. Please see IC-191 for schedule showing impact of RSP on rates.

Q. R. Henderson's Testimony

1. With reference to Schedule 1, what is the firm energy capability of each of the plants?
2. Indicate the basis for firm energy determinations for each hydroelectric plant (including each NUG), and the overall probability distribution for the range of hydraulic generation that Hydro could experience based on available information. Indicate the extent to which firm hydraulic generation estimates have changed since 1992.
3. For reliability purposes, what firm energy estimates are used for combustion turbine and diesel generation plants in Schedule 1?
4. Reference page 5, lines 24 and 25, what are the "long standing arrangements to buy energy"?

A.

1. Please refer to Schedule IX of H. G. Budgell's testimony for the firm annual energy capability of each of Hydro's generating plants.

2. Firm energy for hydroelectric plants can be determined in different manners. It is generally the annual production which the facility can maintain under the most onerous hydrological conditions as determined by simulations. For the Bay d'Espoir system which includes the Upper Salmon plant the firm energy is determined by means of simulation of the operation of the plants in the system using a computer model. In the model the load is increased on the system to the point where it is no longer able to meet the load under the lowest inflow conditions. The maximum annual energy that the system can meet as a result of this exercise represents the simulated firm energy. The firm energy from Cat Arm and Hinds Lake were

taken from the results of similar simulations done for the feasibility studies for those projects. The firm energy from the NUG's was that amount provided in their project proposal.

Firm energy estimates are revised from time to time to reflect the impact of operating experience on conversion factors versus those used in the simulation. As well, application of the "definition of firm" may impact on firm energy capabilities.

The table below shows the annual firm energy estimates by plant for the period 1992-2000 inclusive. Of note, Upper Salmon's firm energy capability changed from 420 GWh in 1996 to 474 GWh in 1997. This is primarily due to a change in the firm definition. The new figure was based on the same firm water cycle used for Bay d'Espoir.

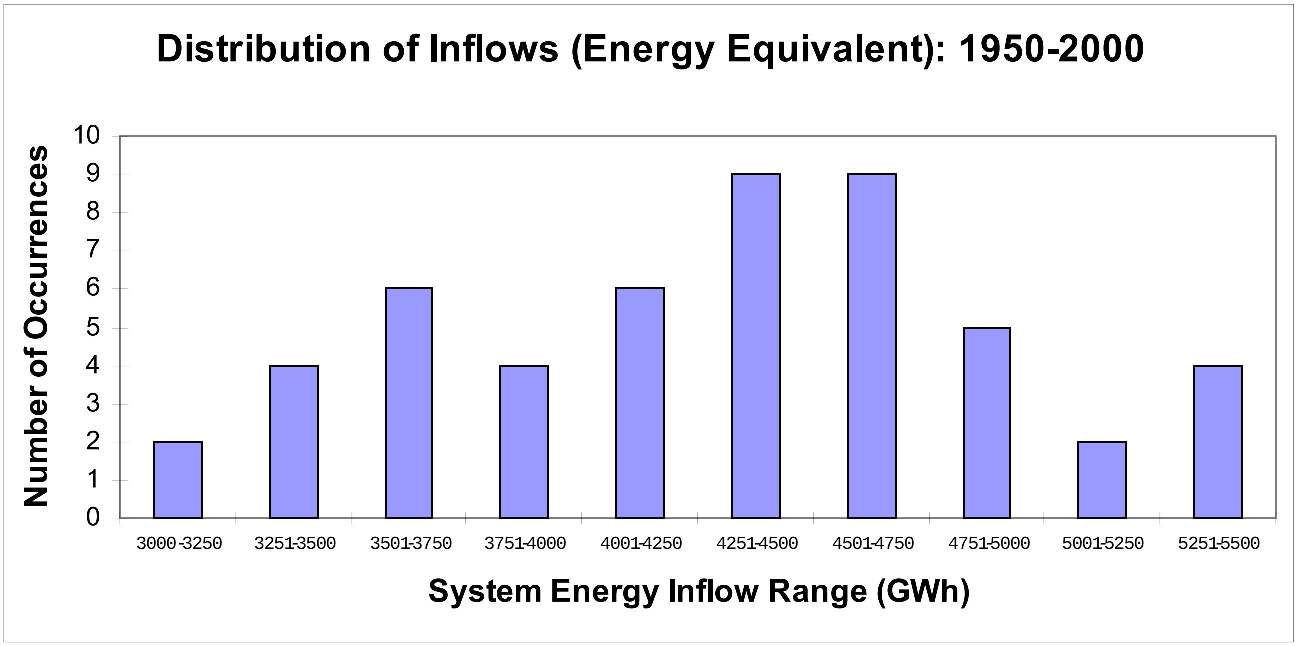
Annual Firm Energy Capability by Plant (GWh)

Year	Bay D'Espoir	Upper Salmon	Hinds Lake	Cat Arm	Paradise River	NLH Mini-Hydro's*	NUGs	Total Firm
1992	2211	418	287	617	26	5	N/A	3564
1993	2211	418	287	617	26	5	N/A	3564
1994	2211	418	287	617	26	5	N/A	3564
1995	2211	418	287	617	26	5	N/A	3564
1996	2216	420	286	613	27	5	N/A	3567
1997	2226	474	286	613	27	5	N/A	3631
1998	2234	476	283	605	27	5	N/A	3630
1999	2234	476	283	605	27	5	107	3737
2000	2234	476	283	605	27	5	107	3737

* Snook's Arm, Venam's Bight, and Roddickton Mini-Hydro.

The graph below shows the distribution of inflows (converted to an energy value) for Hydro's 50 years of hydrological records for all of Hydro's large plants, Bay d'Espoir, Upper Salmon, Hinds Lake and

Cat Arm. This does not give the hydraulic production but is representative of the variation in production.



3. Hydro forecasts no firm energy capability for its combustion turbine and diesel generation plants.
4. Please refer to the response to IC-43.

Q. How is billing demand to be determined for non-firm energy (Schedule C indicates the maximum Interruptible Demand for any month)?

A. There are two categories of non-firm power and energy, Interruptible Power and Energy and Generation Outage Power and Energy.

The Interruptible Demand billing is based on the Maximum Interruptible Demand measured in the month as described in the Interpretation and Interruptible Demand articles to the contracts in Schedule C.

The Generation Outage Demand billing is based on the Maximum Generation Outage Demand measured in the month and pro-rated by the number of days in the month the customer took the Generation Outage Power and Energy. The Generation Outage Demand billing is described in the Generation Outage Power article in the contracts in Schedule C. Please refer to Article 5, Clause 5.01 (d) for Abitibi Consolidated Inc. Grand Falls Division and for Corner Brook Pulp and Paper (Pages 25 and 44 of Schedule C.)

Q. Q. K.C. McShane (paged 23-24) indicates two reasons for differences regarding Hydro's capital structure as reported in 1999 and the forecast capital structure for the test year 2002. Provide adjusted debt/equity and interest coverages estimates for Hydro's regulated "utility only" operations for each of the years 1992 to 2001 inclusive (indicating each of the components required for the calculation) on a basis consistent with the assumptions adopted for the 2002 test year but based on actual dividends (if any) paid in each year.

A. The attached schedule shows the calculation of Hydro's regulated "utility only" debt/equity ratios which includes IOC.

Please refer to the response to NP-2 for the applicable regulated interest coverage ratios.

Q. Schedule VIII of the evidence of H.G. Budgell indicates different loads than Schedule V (see 2001 and 2002). Confirm that these differences reflect the inclusion in Schedule VIII of loads met by customers' generation sources. Revise Schedules X to indicate load forecast excluding load met by customers' generation sources.

A. The loads presented in the direct evidence of H.G. Budgell Schedules V and VIII are different since Schedule VIII loads are for the Total Island Interconnected System, inclusive of load supplied by customers' own generation. Schedule V, by contrast, represents just Hydro's own supply requirements for the Island Interconnected System. The load forecasts contained in Schedules V and VIII are built up from differing methodologies, notably for non-industrial loads, and some underlying differences would be expected.

Please see attached table for revised Schedule X with the load met by customers' generation sources removed from the load forecast and also with those sources removed from system capability.

Newfoundland and Labrador Hydro
Island Interconnected System
Existing Generating Capability
Net of Customer Generation and Customer Serviced Load
Energy Balances and LOLH Indices

	Load Forecast		Existing System			
		Firm	Net	Firm		Energy
	Peak	Energy	Capacity	Capability	LOLH	Balance
Year	MW	GWh	MW	GWh	Hrs/yr	GWh
2001	1,303	6,409	1,559	6,733	2.85	324
2002	1,329	6,557	1,559	6,733	3.96	176
2003	1,338	6,620	1,559	6,733	4.70	113
2004	1,359	6,711	1,559	6,733	5.50	22
2005	1,379	6,792	1,559	6,733	8.48	(59)
2006	1,400	6,871	1,559	6,733	11.14	(138)
2007	1,423	6,966	1,559	6,733	15.04	(233)
2008	1,446	7,063	1,559	6,733	17.52	(330)
2009	1,462	7,126	1,559	6,733	24.37	(393)
2010	1,468	7,161	1,559	6,733	26.44	(428)

Q. **Cost of Service Study (COSS) evidence - Exhibit JAB**

(1) Industrial revenues: Explain the basis for (a) the Industrial - Firm revenue credit of $40,326 in Schedule 1.2, line 4, column 4, and (b) the Industrial - Non Firm Revenues of $381,121 in Schedule 102, line 5, column 2. In each instance, indicate all billing determinants and rates assumed for these estimates.

(2) Industrial -Non Firm costs:

(a) Indicate any cost based rationale for the demand charge of $1.50 per kW proposed for non-firm sales to IC.

(b) Confirm that the COSS provides no analysis of any demand related costs for non-firm sales, and that the costs assigned to this service in the COSS are solely the firm energy cost of $.02311 per kWh. (Schedule 1.3, page 1)

(c) Provide a table setting out the assumed COSS generation (MWh) by source (hydraulic, No. 6 fuel, diesel fuel, gas turbine fuel, power purchases from NUGs, power purchases from non-NUGs) and month for the test year 2002 for the Island Interconnected System. Indicate the likely percent of load supplied by thermal during off-peak hours (low load evenings and weekend hours) during each month.

(d) Indicate annual functionalized cost of service for each of the above generation sources (in (c) above) and for transmission based on COSS for the Island Interconnected System, showing separately for each generation source and for transmission (where this is separate): fuel expenses, O&M, depreciation, expense credits, disposal gain/loss, return on debt and return on equity. Indicate classified generation and transmission costs (Production Demand, Production and Transmission Energy, Transmission Demand) separately for each fuel source and for transmission.

(e) Compare in detail the COSS firm energy cost of $.02311 per kWh and the non-firm energy charge rate as proposed in Schedule A of the Application (page 3), assuming the average cost of fuel assumed for the COSS; indicate how this charge could likely vary by month and time of day, based on the assumptions adopted for COSS as to expected fuel use. Explain how in practice it will be determined what fuel source is used to supply non-firm energy. What will happen if this energy is supplied in whole or in part from non-thermal sources?

(3) Holyrood average capacity factor: Provide, on the same basis as Schedule 4.3, the calculations to indicate the forecast net capacity factor for Holyrood for the year 2002. Explain the factors affecting variances in this capacity factor for the years 1997 through 2002. Assuming that the COSS for 2002 assumes No. 6 fuel consumption based on average hydraulic generation availability and forecasts loads, why would it not be more appropriate to use the net capacity factor consistent with these assumptions rather than one based on the prior 5-year actual average?

(4) Loads used for COSS: Provide a table or the Island Interconnected System test year 2002 setting out for each rate class the following projections: billing demands at customer meter; coincident peak loads at customer meter and at generator (after provision for losses); 2CP kW at customer meter and at generator (after provision for losses); sales at customer meter and generation energy requirements after losses; number of customers for COSS allocation purposes. Explain all assumptions used to derive these projections.

(5) Load Factor classification - generation costs: Review the rationale behind the Board's 1993 Report recommendation for splitting hydraulic plant costs for the Island Interconnected System between energy and demand based on the system load factor. Indicate the change that this creates from the previous COSS adopted by Hydro for the last rate hearing. Indicate the rationale for also applying the load factor of each Isolated Diesel system group in order to split diesel plant costs between energy and demand.

(6) Generation cost allocation: As reviewed in the evidence of J. A. Brickhill (page 8), generation costs for the Island Interconnected System have been allocated among rate classes based on a 2CP allocator. Provide the loss of load hours (LOLH) study carried out by Hydro which supports use of a 2CP allocator because it indicates a greater risk of loss of load hours largely in two winter months. Provide the annual data supporting Schedule II of J. A Brickhill's evidence for each year indicated in this schedule (1994, 1996, 1997, 1998, 1999, 2000); provide the same information for 1995 (if available), projections for 2001, and the numbers supporting the projections for 2002. Indicate any other tests that could reasonably be considered when testing an allocation method in addition to the variation in results over time, and assess the 2CP method in light of each such test.

(7) Changes to rural deficit allocation: L. A Brickhill indicates at page 14 that the method of allocating the rural deficit between customers has changed to reflect the change in methodology from AED-based to CP-based. Indicate the difference in COSS results due to this one change in methodology, and the impact that this change has on allocation of the rural deficit for the 2002 test year.

(8) Changes in RSP allocation: L. A Brickhill indicates at page 15 that the RSP has historically been split between participating customer groups based on Hydro's COSS. Indicate what changes, if any, the current COS methodology makes with respect to such splits compared to the COSS methodology used previously and provide an assessment of the differences if any that result to the test year 2002 RSP allocation as provided for in schedule 1.2.1 of the COSS.

A. (1)(a) The Industrial - Firm revenue credit of $40,326 in Schedule 1.2, line 4, column 4, (Exhibit JAB-1, page 4) was allocated to customer classes based on revenue requirement. The $40,326 was therefore calculated as follows:

Industrial Firm Revenue Requirement	
Before Deficit and Revenue Credit	$ 50,005,883
Divided by:	
Total Island Interconnected Revenue	
Revenue Requirement (Excluding Non-	
Firm Revenue Requirement)	$277,812,814
Equals	18%
Multiplied By	
Total Island Interconnected Non-Firm	
Revenue Credit	$ 224,033
Equals	$ 40,326

(1)(b) The Industrial - Non Firm Revenues of $381,121 in Schedule 1.2, line 5, column 2 was calculated as shown on the attached Page 10 of 11.

(2) Industrial -Non Firm costs:

a) Please see response to NP-183.

b) The costs assigned to non-firm sales are as detailed in the Island Interconnected schedule showing the allocation of functionalized amounts to classes of service (Exhibit JAB-1, pages 39-40). The $157,088 is comprised of only energy cost allocations. The firm energy cost of $.02311 per kWh was derived from these allocated costs, rather than providing the basis for determining the costs.

c) The table below shows the assumed Cost of Service Generation by source for the test year 2002 for the Island Interconnected System.

Island Interconnected System
Assumed Cost of Service Generation by Source
(MWh)

Month	Hydraulic Plants	Holyrood (No.6 Fuel)	Diesel Plants	Gas Turbine Plants	Power Purchase NUGs	Other Power Purchase
January	410,410	304,890	30	1,070	11,600	0
February	368,120	275,390	30	240	9,320	0
March	426,860	228,670	30	220	9,920	0
April	353,830	196,700	30	220	11,120	0
May	331,890	152,450	30	220	13,810	0
June	329,580	98,350	30	220	13,320	0
July	408,050	0	30	220	13,000	0
August	401,530	0	30	220	12,820	0
September	273,460	147,530	30	220	12,360	0
October	290,850	203,260	30	220	13,240	0
November	314,300	245,880	30	220	12,870	0
December	362,790	304,760	30	900	12,520	0
Total	4,271,670	2,157,880	360	4,190	145,900	0

While thermal generation is required to complement production from Hydro's hydraulic resources in order to meet the overall system load, its output is varied to maintain system security and for water management reasons.

Normally, thermal generation is base loaded at an efficient output level. Hydraulic generation is used to track the system load. Thermal output may be reduced for system security or for system loading reasons (ie. not enough load to share amongst required on-line generation). As well, thermal output may be increased from its base load to meet system peak requirements.

Each week, System Operations sets the thermal base load requirement to manage the water resource while respecting power system security. The likely percent of loading supplied by thermal generation during off peak hours varies as a result of the items previously mentioned, however, the likely percent of system load supplied by thermal generation in the off-peak hours is 2 to 5 percent higher than the percent of system load supplied by thermal generation in the on-peak hours.

d) This analysis is not currently available, but work is in progress.

e) The following table compares the industrial firm energy charge with the industrial non-firm energy charge by month for 2002. It uses the average cost of fuel used in the cost of service for each source.

Comparison of Industrial Firm Rates and Non-Firm Energy Rates

Month	Firm Energy Rate	Holyrood Non-Firm Energy Rate	Variance from Firm	Gas Turbine Non-Firm Energy Rate	Variance from Firm	Diesel Non-Firm Energy Rate	Variance from Firm
January	$0.02311	$0.04387	$0.02076	$0.10401	$0.08090	$0.10743	$0.08432
February	$0.02311	$0.03914	$0.01603	$0.10278	$0.07967	$0.10743	$0.08432
March	$0.02311	$0.03914	$0.01603	$0.10367	$0.08056	$0.10743	$0.08432
April	$0.02311	$0.03745	$0.01434	$0.10360	$0.08049	$0.10743	$0.08432
May	$0.02311	$0.03745	$0.01434	$0.10354	$0.08043	$0.10743	$0.08432
June	$0.02311	$0.03686	$0.01375	$0.10524	$0.08213	$0.10743	$0.08432
July	$0.02311	$0.03686	$0.01375	$0.10518	$0.08207	$0.10743	$0.08432
August	$0.02311	$0.03686	$0.01375	$0.10514	$0.08203	$0.10743	$0.08432
September	$0.02311	$0.03657	$0.01346	$0.10686	$0.08375	$0.10743	$0.08432
October	$0.02311	$0.03639	$0.01328	$0.10686	$0.08375	$0.10743	$0.08432
November	$0.02311	$0.03620	$0.01309	$0.10683	$0.08372	$0.10743	$0.08432
December	$0.02311	$0.03613	$0.01302	$0.10814	$0.08503	$0.10743	$0.08432

The non-firm energy charge will be at the Holyrood non-firm rate for all periods including the periods when no thermal source is operating, except when either or both of the diesel plants and the gas turbine plants are operated or their output must be increased to meet the non-firm load. Typically the diesel plants or gas turbine plants would be required to meet non-firm energy requirements during peak load periods or when there are transmission restrictions to the area of the grid where the customer is located. Although the higher non-firm rates could apply during any hour of the year due to transmission or generation problems, the probability is higher in the winter period (December to March) and during the peak hours of 0800 to 2000 hours each day.

The decision to use a higher cost source is made by the power system operator when he determines there is insufficient power or energy available from other sources, either hydroelectric or Holyrood to meet the load demanded on the system, or there is insufficient transmission capacity to an area where the non-firm load is being demanded.

(3) The Holyrood net capacity factor for the year 2002 based on the forecast energy production is as follows:

$$\frac{2,157,880,000}{466,000 \times 8,760} = 52.86\%$$

The capacity factors from 1997 to 2000 are based on the thermal production required in those years. Both hydraulic generation and system load affect the Holyrood net production requirement. In all of these years the hydraulic generation was above average resulting in reduced Holyrood requirements. In addition, in 1998 and 1999 net production at Holyrood was reduced further due to the lower load caused by extended labour disputes in the pulp and paper industry. The capacity factors for 2001 and 2002 are based on forecast net production at Holyrood, which is based on the load forecast for those years with average hydraulic production.

(4) The table requested is shown on the attached page 11 of 11.

(5) At the last rate hearing, hydraulic plant costs for the Island Interconnected System were split on a 50% demand/50% energy basis in the 1992 COS Study.

Diesel plants in the Isolated Systems are operated as base load plants similar to the Holyrood Thermal plant. For this application, Hydro has proposed using the system load factor for the Labrador and Island Isolated Systems as a proxy for capacity factor as used for Holyrood for consistency.

(6) See response to NP-135 for copy of 2CP allocator report. See response to IC-137 regarding data supporting Schedule II of J.A. Brickhill. Other tests which could be reasonably considered are Bonbright's fair-cost-apportionment objective and the consumer rationing objective. The 2CP method meets both. It fairly distributes the generation demand requirement among the Island Interconnected System customers as it reflects cost causality. It promotes the use of economically justified service because it allocates costs to those who cause the incurrence of the costs.

(7) The 1992 test year Cost of Service (COS) methodology used Average and Excess Demand (AED) kW to allocate production and transmission demand costs to rate classes. The proposed methodology uses Coincident Peak (CP) to perform these allocations. The Cost of Service, revised to reflect the AED methodology, is attached.

(8) The 1992 test year Cost of Service (COS) methodology used Average and Excess Demand (AED) kW to allocate production and transmission demand costs to rate classes. The proposed methodology uses Coincident Peak (CP) to perform these allocations. This change in methodology impacts the RSP customer splits, as revised actual energy amounts, using AED methodology, also affected demand costs, and revised demands were therefore also required for the RSP split between customer groups. Schedule 1.2.1 (exhibit JAB-1, pages 9-10) is impacted in that CP kW are also used to determine the unit costs of the deficit. It is important to note that cost allocation also would change if AED were used. This analysis does not

consider those impacts. The effects of allocating the rural deficit (Schedule 1.2.1) using AED on the 2002 forecast annual RSP activity are:

	Proposed	Revised	Difference
Newfoundland Power	$19,380,610	$19,375,272	$(5,338)
Island Industrial	5,909,874	5,909,874	-
Labrador interconnected	199,739	205,077	5,338
	$25,490,223	$25,490,223	-

Interruptible 'A' Rates (Industrial):

	January	February	March	April	May	June	July	August	September	October	November	December	Total
A. Bunker 'C' Consumption ($/Bbl.)	28.5734	28.4562	28.4562	28.4144	28.4144	28.3998	28.3998	28.3998	28.3925	28.3879	28.3833	28.3816	
B. Efficiency (kWh/Bbl.)	610	610	610	610	610	610	610	610	610	610	610	610	
C. Mill Rate before Administration- (A / B * 1000)	46.84	46.65	46.65	46.58	46.58	46.56	46.56	46.56	46.55	46.54	46.53	46.53	
D. Administration	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	
E. Mill Rate (C * (1 + D))	51.52	51.32	51.32	51.24	51.24	51.22	51.22	51.22	51.21	51.19	51.18	51.18	
F. Demand ($ per kW)	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	
G. Forecast Energy	88,000	82,000	91,000	88,000	85,000	88,000	91,000	91,000	3,237,000	2,681,000	88,000	88,000	
H. Energy Revenue	4,534	4,208	4,670	4,509	4,355	4,507	4,661	4,661	165,767	137,240	4,504	4,504	348,121
I. Forecast Demand	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	6,000	6,000	1,000	1,000	
J. Demand Revenue	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	9,000	9,000	1,500	1,500	33,000
Total Revenue	6,034	5,708	6,170	6,009	5,855	6,007	6,161	6,161	174,767	146,240	6,004	6,004	381,121

Newfoundland and Labrador Hydro
2002 Test Year Projections
Island Interconnected

		Billing Demands (kW)	CP at Customer Meter (kW)	CP at Generator (kW)	2 CP at Customer Meter (kW)	2 CP at Generation (kW)	Sales at Customer Meter (MWh)	Energy at Generator (MWh)	Number of Customers
1	Newfoundland Power	-	1,026,791	989,280	2,053,582	1,978,568	4,454,800	4,602,195	1
2	Industrial - Firm	2,244,000	172,601	179,125	345,202	358,251	1,464,970	1,513,441	4
3	Industrial - Non-Firm	22,000	-				6,798	7,023	2
	Rural								
4	1.1 Domestic	-	24,142	27,814		54,650	107,264	119,486	12,256
5	1.12 Domestic All Electric	-	30,640	35,301		69,359	109,736	122,240	6,783
6	1.3 Special	-	51	59		115	220	245	2
7	2.1 GS 0-10 kW	-	3,223	3,713		7,044	15,763	17,559	1,931
8	2.2 GS 10-100 kW	188,235	9,250	10,657		21,869	54,336	60,527	830
9	2.3 GS 110-1,000 kVa	165,655	5,507	6,308		10,994	39,444	43,802	70
10	2.4 GS Over 1,000 kVa	91,946	5,510	6,256		11,363	31,237	34,524	8
11	4.1 Street and Area Lighting	-	714	823		1,616	3,000	3,342	974
12	**Subtotal Rural**	445,836	79,037	90,931	-	177,010	361,000	401,725	22,854

Assumptions:

<u>CP at Customer Meter</u>
NP and Industrial CP based on the load forecast January peaks, to which the following Coincidence Factors have been applied:

Newfoundland Power	1.00
Industrial - Firm	0.92

Rural CP based on load research applied to load forecast.

<u>CP at Generator</u>
Common transmission losses allocated to all rate classes based on transmission level CP.
Distribution losses allocated to rural rate classes only.
Newfoundland Power's CP includes it’s own generation, less generation demand credit.

<u>2 CP at Customer Meter</u>
CP at meter for the two peak months of January and December calculated and summed.
Data not available for rural rate classes.

<u>2 CP at Generator</u>
CP at generator for the two peak months of January and December calculated and summed.

<u>Billing Demands, Sales at Customer Meter</u>
Based on load forecast.

<u>Energy at Generator</u>
Common transmission losses allocated to all rate classes based on transmission level energy.
Distribution losses allocated to rural rate classes only.

Q. **COSS and Rate Design - Other Issues**

(1) **No demand charge for NP**: D. W. Osmond's evidence (page 9) indicates that Hydro and NP have reviewed the issue of implementing a demand and energy charge pricing structure and "both companies concur that an energy only rate to Newfoundland Power is still appropriate." Provide a copy of all studies and/or analysis done by Hydro on this matter since 1992. Assess these rate options in light of each of the rate design principles set out at page 2 of P. R. Hamilton's evidence. Indicate the factors that Hydro believes to support an energy only rate for NP as being in the best interests of efficient and fair rates. Based on the 2002 test year COSS, provide a demand and energy rate option for NP for consideration by the Board.

(2) **Time of Use rates**: Provide any reports or analysis done by Hydro since 1992 to assess time or use rates for Industrial or other customer classes on the Island Interconnected System. Indicate the extent to which Hydro's bulk costs for generation and transmission on this System vary on a time of use basis under normal conditions. Indicate likely peak and off peak periods during each season on this System that might be used for rate purposes, as well as any material variations in seasonal costs that might be considered for such rates. Indicate Hydro's assessment of time-of-use rate implementation within the next five years at least for NP and/or Industrial Customers, and explain fully the basis for this assessment.

(3) **Deferral of rate design adjustments**: The evidence of D.W. Osmond at pages 12-15 mentions several five-year period rate design

adjustments for Isolated Rural System rates which are deferred until the next Rate Application. Explain why these rate design adjustment plans arising from earlier Board reports cannot be placed before the Board today and a plan for implementation set out for review. In particular, explain the rate plan that Hydro is considering to introduce full cost rates for Government agencies and departments (which would require, it is stated, on average increases of 280%) "over a maximum of five years" in light of the current proposal to limit rate increases to these customers at 20% overall.

(4) **Revenue Cost Coverage Ratios**: P.R. Hamilton comments (at pages 3-4) on historic revenue cost coverage (RCC) ratios for different rate classes on the different systems. Indicate the RCC's for the Industrial Class and NP by year from 1992 to 2002 based on all of Hydro's available COS studies (prospective and actual) for these years. Indicate in each instance the portion (if any) of the RCC for each of these rate classes affected by Rural Deficit charges.

(5) **No Rate of Return on Equity charged on Rural Portion**: It is noted that, based on the Board's past directions, no margin or return on equity has been proposed on Hydro's Rural Island Interconnected and Isolated Systems assets (see D.W. Osmond, page 7; J. C. Roberts, page 5). Confirm that Hydro has assessed this position in light of the amended legislation that became effective on January 19th 1996 and now requires Hydro to operate as a fully regulated utility under the jurisdiction of the Public Utilities Board, including the provisions therein for a just and reasonable return on rate base.

(6) **Employee Future Benefits as part of Capital Structure**: Review what conditions and liabilities apply with respect to the mid-year amount for 2002 of $24.9 million under Liability for Employee Future Benefits. Review the rationale for including this amount as a no-cost capital amount in the capital structure used to finance rate base.

A. (1) Please see response to PUB-68 regarding rationale for energy only rate. During the course of discussions with Newfoundland Power, each party developed various rate structures and adjustment mechanisms. The evaluation of these alternatives reflected the relative situation of each party and the relative priority each placed on Bonbright's rate design objectives. As outlined in the letter from Newfoundland Power, circumstances have changed over the years such that moving to a demand/energy rate structure is no longer necessary or desirable. Hydro agrees with this conclusion and has therefore not proposed a demand energy rate option.

(2) Hydro has not performed any analysis of time of use rates since 1992 and is therefore unable to provide the information requested.

Hydro filed the attached letter dated June 28, 1985 as part of Hydro's evidence at its 1985 Rate Referral that outlined its views on marginal cost pricing. Hydro does not have any plans at this time to conduct an assessment of time-of-use rates as uncertainties regarding such things as the Lower Churchill development, Island Infeed and cost effectiveness of mandatory time-of-use rates have not changed significantly since this letter was filed.

(3) Hydro's proposal is to increase rates to these customers by 20% effective January 1, 2002. If these rates were to increase each year by 20% for a further five years and after considering the impact of compounding, rates will have increased by approximately 280% on average over that timeframe.

(4) See attached table of revenue/cost ratios for Industrial Customers and Newfoundland Power for years that COS studies are available. Please see response to IC-1 for explanation of COS study availability.

(5) Hydro has included its Rural Island Interconnected and Isolated Systems in its Rate Base, however Hydro will only recover its weighted average cost of debt on these assets, with no profit or margin being earned.

(6) The 2002 mid-year liability for employee future benefits of $24.3 million has been projected based on an actuarial valuation of this obligation. Please refer to responses to NP-54 and NP-160. Please refer to evidence of K.C. McShane, pages 13-14 for the rationale for including the amount as no-cost capital.

NEWFOUNDLAND AND LABRADOR HYDRO
Revenue / Cost Coverages
($000)

		Newfoundland Power					Industrial Class				
Year	Methodology	Revenues	Costs	Rev / Cost Coverage	Deficit Allocation	Deficit as % of Costs	Revenues	Costs	Rev / Cost Coverage	Deficit Allocation	Deficit as % of Costs
1992 Actual	Interim (92)	195,200	174,395	1.12	22,226	13%	47,096	40,237	1.17	5,128	13%
1993 Actual	Interim (92)	193,133	171,885	1.12	21,118	12%	48,332	42,594	1.13	5,233	12%
1994 Actual	Interim (92)	181,825	159,355	1.14	21,360	13%	37,400	33,812	1.11	4,532	13%
1995 Actual	Interim (92)	203,117	181,240	1.12	22,233	12%	49,240	44,000	1.12	5,398	12%
1999 Actual	Interim (92)	182,517	165,954	1.10	16,546	10%	45,573	41,182	1.11	4,106	10%
1992 Forecast	Interim (92)	194,083	171,839	1.13	22,244	13%	45,547	40,327	1.13	5,220	13%
1992 Forecast	Generic (93)	192,471	169,353	1.14	23,118	14%	43,966	38,685	1.14	5,281	14%
2002 Forecast	Proposed (2001)	213,830	191,058	1.12	22,911	12%	50,357	50,163	1.00	0	0%

Q. Provide a version of Schedule IV to the evidence of H.G. Budgell which incorporates the projected 2001 and 2002 data.

A. Schedule IV provides a comparison of the long term forecast filed with the Board in 1991 against the actual load. In 1991, Hydro did not file forecasts for 2001 and 2002. Projections for 2001 and 2002 are provided in Schedule VIII to the Evidence of H.G. Budgell.