Q. RE: p. B-10 install 25kV Distribution Line - Ebbegunbaeg ($1,555,000)

3.1 Provide a copy of the cost benefit study that was completed on this project.

3.2 Have any other projects been identified that may be considered for interconnection at a future date?

3.3 Have there been any objections received concerning the future decommissioning of the presently used diesel generators and their associated infrastructure? What mechanism does the company have for dealing with any that may arise?

A. 3.1 Refer to NP-99, item a.

3.2 Ebbegunbaeg is the site of one of Hydro's hydraulic control structures on the Bay D' Espoir Development watershed. This is the only project of this nature identified by Hydro.

3.3 The existing diesel generation arrangement provides service to only Newfoundland and Labrador Hydro facilities. No objections have been received or are anticipated.

Q. RE: p. B-13 Upgrade Controls on Spherical Valve # 5 – Bay d'Espoir ($153,000)

5.1 When was this equipment determined to be obsolete? By whom was this determination made? What was the rationale for the decision?

5.2 Has the maintenance record of this equipment indicated that it has a high risk of failure? Is there other information that would cause the decision to replace this equipment at this time? Why has it been determined that valves 1, 2 and 3, which are older, can continue to be used?

5.3 How has the company determined that the new Program Logic Controller is the appropriate replacement for the current equipment?

A. 5.1 Operations and Generation Engineering personnel made this determination in the1998 – 1999 period. The rationale for this decision was that it had become impossible to procure or manufacture spare parts for many components.

5.2 The maintenance records indicate that there have been frequent failures in recent years. There is no other information that leads to the decision to replace this equipment. Valves 1 through 4 were built by one manufacturer while valves 5 and 6 were built by another. Valves 1 through 4 are older and the equipment on valve 4 is being replaced in 2001. The equipment being made redundant from valve 4 will be used as spare parts for valves 1, 2 and 3 until that equipment can be

replaced. The schedule for replacement was based on the condition of the equipment on each valve.

5.3 An in-house engineering review identified three spherical valve control options available, namely: 1) hydraulic or mechanical controls 2) PLC (Programmable Logic Control) based controls, and 3) hybrid solution consisting of mechanical and PLC systems. These three options were presented and discussed with the plant operating/maintenance staff. Based on the discussions of the pros and cons of the options available and the plant personnel's experience with PLC systems, it was concluded that Hydro should proceed with option 2.

Q. RE: p. B-14 Install Fault Recorder – Upper Salmon Generating Station ($127,000)

6.1 Does the company have any reliability statistics, either from its own records or from the information of other utilities, that show that the installation of the equipment increases reliability?

6.2 During 1995 – 2000, what have been the reliability statistics with regard to faults, outages and downtime at this generating station?

A. 6.1 The installation of a fault recorder does not directly increase the reliability of the generating unit.

The fault recorder will provide more detailed information on the fault, resulting in a faster restoration and a shorter outage duration.

6.2 This station's reliability is affected by both the generating unit and associated transmission facilities. The number of forced outages for the transmission line TL234 from Upper Salmon to Bay d'Espoir according to year are:

2000	4
1999	2
1998	1
1997	0
1996	0
1995	1

The reliability statistics for the Upper Salmon Generating unit are as follows:

	1995-1999	2000
Incapability Factor (ICbF)	3.44	3.81
Derating Adjusted Forced Outage Rate (DAFOR)	0.75	0.47
Failure Rate (FAILRATE)	5.07	9.82

Incapability Factor (ICbF-%) – This factor indicates the percent of time a generating unit is not able to produce its rated output. The factor is calculated by dividing the total equivalent outage time (includes adjustments for deratings) by the number of unit hours.

Derating Adjusted Forced Outage Rate (DAFOR-%) – This factor gives the percent of operating plus forced outage time a unit was on a forced outage, adjusted for derating of the unit. It is calculated by dividing the total equivalent forced outage time by the total equivalent outage time plus the operating time.

Failure Rate (FAILRATE) – This factor is the rate a unit encounters a forced outage. FAILRATE is determined by dividing the number of forced outage by the operating factor.

Q. RE: p. B-16 Replace Control Cables – Bay d'Espoir ($131,000)

8.1 Does the company intend to replace the other control cables at this site or at other sites with fibre optic cables at a future date?

A. 8.1 At present Hydro has no plans to replace other control cables at this site or any other site with fibre optic cable. This cable is being replaced because of damage caused by lightning.

Q. RE: p. B-17 Replace Ventilation System at Powerhouse No. 1 - Bay d'Espoir ($164,000)

9.1 When were the current fans installed? At the time was it realized that unit outages would be required in order to maintain these fans? Were other options investigated?

9.2 In the past, have there been forced outages as a result of the high ambient temperature in the powerhouse? Provide details for the period 1995 – 2000.

A. 9.1 The current fans were installed when the powerhouse was constructed in the 1960's. We are not aware if the powerhouse designers realized that unit outages would be required to maintain these fans. Provision of new fans located on the roof is the most viable option. Other alternatives, such as air conditioning, are more expensive.

9.2 There have not been any forced outages as a result of high ambient temperatures, however, any time an outage is required for maintenance of these fans it has an impact on the plant incapability factor. It is recognized that high ambient temperatures increase the rate of degradation of equipment, such as windings and other insulation systems.

Q. Re: p. B-18 Purchase Track Machine – Cat Arm ($177,000)

10.1 By what means are personnel and tools and equipment currently transported to the Cat Arm site? Why is the current means no longer functional or economical?

A. 10.1 The access road to Cat Arm is not plowed during the winter. Currently a Go Track is used as transportation during this period. The Go Track is ineffective in deep snow and has limited carrying capacity, which restricts the quantity, type of equipment and number of people that can be transported to Cat Arm. The track machine will be able to transport heavier materials and more personnel. It will also be able to properly groom the trail, making travel safer for our employees when accessing the plant using snowmobiles.

Q. RE: p. B-22 Replace Turbine Electrohydraulic Control System – Unit No. 1 – Holyrood ($34,000, Future $1,084,000)

14.1 What improvements in reliability have been documented as a result of installation of a similar electrohydraulic control system on Unit No. 2?

A. 14.1 Any reliability improvements due to replacement of electrohydraulic controls have not been documented, however this new system provides the black start capability which is considered as a major reliability improvement. The basic reason to replace this system is the unavailability of spare parts and the technical support by the equipment manufacturer.

Q. RE: p. B-24 Replace Instrument Transformers/Surge Arrestors – Central ($71,000)

16.1 For each year from 1998 to 2000, provide a comparison of the budgeted figure with the actual expenditure for each transformer and for each surge arrestor for each year.

16.2 The budgeted figure for 2000 for the replacement of transformers and surge arrestors is $58,000. (*sic*) What have been the expenditures for this category to June 30, 2001?

A. 16.1 The following table provides a comparison of budget figures with actual expenditures from 1998 to 2000:

Year	Equipment	Expenditure	Budget
1998	Potential Transformer	$6,523	
	Potential Transformer	$6,523	
	Potential Transformer	$6,523	
	Potential Transformer	$6,523	
	Potential Transformer	$6,523	
	Potential Transformer	$6,523	
	Potential Transformer	$6,523	
	Current Transformer	$4,452	
	Labour, Corp. O/H, IDC, etc	$13,591	
	Total	$63,704	$92,000
1999	Potential Transformer	$7,109	
	Potential Transformer	$6,554	
	Potential Transformer	$5,845	
	Current Transformer	$4,452	

	Current Transformer	$15,930	
	Current Transformer	$3,541	
	Current Transformer	$3,541	
	Current Transformer	$3,541	
	Current Transformer	$15,930	
	Surge Arrestors	$4,976	
	Surge Arrestors	$985	
	Surge Arrestors	$985	
	Surge Arrestors	$985	
	Surge Arrestors	$985	
	Surge Arrestors	$985	
	Surge Arrestors	$4,952	
	Surge Arrestors	$4,952	
	Labour, Corp. O/H, IDC, etc	$26,833	
	Total	$113,081	$92,000
2000	Potential Transformer	$6,554	
	Potential Transformer	$6,554	
	Potential Transformer	$6,554	
	Potential Transformer	$6,554	
	Current Transformer	$5,185	
	Current Transformer	$16,276	
	Current Transformer	$16,276	
	Current Transformer	$10,531	
	Current Transformer	$10,531	
	Current Transformer	$10,531	
	Surge Arrestors	$1,408	
	Surge Arrestors	$1,408	
	Surge Arrestors	$1,408	
	Labour, Corp. O/H, IDC, etc	$13,376	
	Total	$113,146	$56,000

16.2 The expenditures in this category to June 30,2001 have been $47,399.06. The budget for 2000 was $56,000 and the budget for 2001 is $69,000.

Q. 28.0 RE: p. B-38 Replace Insulators - English Harbour West ($669,000)

28.1 What is the current status of the insulator replacement program? Is there a plan with regard to replacing insulators over the period from 2001 to 2005? If so, provide a copy.

A. 28.1 Please refer to D.W. Reeves testimony, page 9 line 17 to page 10 line 19 for the current status of the insulator replacement program.

Hydro has no formal plan with regards to replacing insulators over the period from 2001 to 2005. Future requirements will be determined through maintenance inspections.

Q. RE: p. B-40 Replace Conductor/Poles - Burgeo ($300,000)

29.1 Provide the SAIFI and SAIDI figures for the Burgeo area for 1999, 2000, and to June 30, 2001.07.12. (*sic*)

A. 29.1 The SAIFI and SAIDI figures for the Burgeo area are as follows:

Index	1999	2000	YTD (2001/06/30)
SAIFI (1)	0.48	3.24	5.70
SAIDI (2)	0.30	14.04	1.51

(1) SAIFI – $\frac{\text{Total Customer-Interruptions}}{\text{Total Customers Served}}$

(2) SAIDI - $\frac{\text{Total Customer-Hours of Interruptions}}{\text{Total Customers Served}}$

Q. RE: p.B-49 Relocation of Line – Cook's Harbour ($556,000)

33.1 In the years from 1991 to 2000, what upgrading has been done on this section of line at Cook's Harbour? What has been the cost of each project?

33.2 What other options were considered before the decision was made to relocate this 7.5 km section of three-phase line? What characteristics of the area to which the line will be relocated make it a more suitable location?

33.3 How far from the present line route will the new section be moved?

33.4 Could system reliability be improved by re-conductoring and if so, at what cost?

A. 33.1 There has been no upgrading done on the Cooks Harbour line since 1991.

33.2 No other options were considered before the decision was made to relocate this line. The line is in need of a complete rebuild. The steel core of the conductor has corroded, there are numerous long spans and the poles and crossarms are 30 years old and deteriorated.

The existing line is 800 meters from the road. Access and visibility from the road during emergency situations is extremely difficult and

requires crossing bogs and ponds. Relocating the line near the road will significantly reduce maintenance and repair times.

33.3 The new line will be moved approximately 800 meters from its present route.

33.4 Re-conductoring would address one aspect of a general deterioration of all line components and would only marginally improve reliability.

Q. RE: p.B-50 Replace Corroded Transformers – Northern ($276,000)

34.1 Does the company have any information to indicate that the stainless steel tanks (*sic*) more resistant to the corrosion caused by salt contamination?

A. 34.1 One of the specific design applications for stainless steel is for use in areas where high salt contamination is a problem. In these applications, stainless steel has proven to be significantly more resistant to corrosion. It is a common utility industry practice to use stainless steel in these applications.

Hydro also began using stainless steel tanks for voltage regulators in the late 1980's. These have demonstrated significant improvement regarding resistance to corrosion from salt contamination.

Q. RE: p.B-52 Replace 135 kW Diesel Unit No. 266 – William's Harbour ($11,000; Future $288,000)

35.1 To June 30, 2001, what unitsare in use at William's Harbour? What are their ages, sizes, operating hours and scheduled replacement dates?

A. 35.1 The information on the William's Harbour plant is as follows:

William's Harbour Diesel Plant:

Diesel Unit	KW Rating	Total Engine Hours	Unit Age	Scheduled Replacement Date
# 2057 (G1)	100	2,918	2 years	2021
# 266 (G2)	136	80,222	26 years	2003
# 290 (G3)	136	63,741	25 years	2005

Q. **RE: p. B-61 Purchase Additional Corporate Applications ($517,000)**

42.1 Has the Technology, Planning and Integration section finalized the information technology strategic plan that was referred to in the response to PUB 66.0 of the 2001 Capital Budget? If so, provide plan.

42.2 If no information technology strategic plan has been identified, what areas of business have been targeted as being most likely to benefit from the streamlining, enhancement, and automation of business functions? Have any possible savings been identified as a result of these improvements?

A. 42.1 The technology strategic plan referred to in response to PUB 66.0 of the 2001 Capital Budgets has not been finalized. The architectural portion of the plan is scheduled to be completed by October 2001. The application overview portion of the strategic plan will be completed by December 2001.

42.2 Hydro has targeted two main areas as being most likely to benefit from the streamlining, enhancement and/or automation of business functions:

1. Knowledge, communication and collaboration tools
2. Business Solution Assessment of JDE Implementation.

Both of these target areas are in the planning stages. The assessments will focus on the following as a minimum:

i) Identification and resolution of existing issues;

ii) Cost savings through productivity improvements;

iii) Identification of knowledge gaps which may be resolved through additional training;

iv) New technology awareness and

vi) New software functionality awareness.

No savings have been identified as the assessment is not completed.

Q. **RE: p. B-62 Purchase and Install Uninterruptible Power Supply – Computer Room ($70,000)**

43.1 What problems have been experienced with the present configuration?

A. 43.1 The problems that we have experienced originate with the present configuration where the servers are supported by a number of separate UPS that have been installed over a period of years. Over the past several years, the servers have been replaced with larger units and upgraded and the present UPS Systems are not able to supply adequate power conditioning and battery reserve capabilities. These units are now starting to fail due to battery failures and are in need of replacement and are no longer adequately protecting the servers.

Q. **RE: p. B-63 Replacement of Printers ($130,000)**

44.1 How many printers are due to be replaced? How old are these printers?

A. 44.1 The number of printers to be replaced this year is 66. The age of these printers are from 5 to 7 years old.

Q. **RE: p. B-65 Replace Power Line Carrier Equipment – Transmission System – West Coast (Previous $300,000; $651,000; Future $1,428,000)**
RE: p. B-66 Replace VHF Mobile Radio System ($8,373,000)
RE: p. B-69 Complete Microwave Radio System Interconnection ($269,000; Future $8,673,000)

46.1 Provide a detailed comparison of the original estimates provided in the 1997 Telecommunications Plan with the actual costs to date of the implementation of the various stages of the plan. Provide explanations of the variances.

A. 46.1 The following is as per page 26 of June '97 Report – Telecommunications Plan.

CAPITAL BUDGET PROPOSAL SUMMARY
(as per page 26 of June '97 Report – Telecommunications Plan)

Capital Budget Proposal	1997	1998	1999	2000	2001	2002	2003
Phase I ($4,140,100)							
- Back-up Communications	$197,000						
- West Coast Microwave	$13,000	$2,619,000					
- Replace Omat – GPH		$310,500					
- PLC Upgrade – Central		$342,000	$431,400				
- Data Network Upgrade		$227,100					
Phase II ($8,537,500)							
- East Coast Microwave		$27,500	$8,510,000				
Phase III ($6,358,800)							
- Interconnect East-West Microwave				$6,358,800			
Phase IV ($2,807,000)							
- West Coast PLC Upgrade			$402,000	$342,000	$381,000	$679,000	$1,003,000
Phase V ($1,269,200)							
- VHF System Controller				$1,269,200			
TOTAL BY YEAR	$210,100	$3,526,100	$9,343,400	$7,970,000	$381,000	$679,000	$1,003,000
TOTAL PROPOSAL	$23,112,600						

NOTE: These budgetary estimates were developed in 1995/96.

The following is the current status of the 5 phase Telecommunications Plan as of November 2000. This information was provided to the PUB in a letter "RE: 2001 Capital Budget Hearing" dated November 27, 2000.

CAPITAL BUDGET PROPOSAL SUMMARY (as of November 2000)

Capital Budget Proposal	1997	1998	1999	2000	2001	2002	2003	2004
PHASE I ($4,140,100)								
- Back-up Communications	$197,100							
- West Coast Microwave	$13,000	$2,619,000						
- Replace Ormat - GPH		$310,500						
- PLC Upgrade - Central		$342,000	$431,400					
- Data Network Upgrade		$227,100						
PHASE II ($10,723,000)								
- East Coast Microwave				**$300,000**	**$10,423,000**			
PHASE III ($8,942,000)								
- Interconnect East-West Microwave						**$269,000**	**$8,673,000**	
PHASE IV ($4,045,000)								
- West Coast PLC Upgrade			**$855,000**	**$811,000**	**$300,000**	**$651,000**	**$748,000**	**$680,000**
PHASE V ($8,372,001)								
- VHF System Replacement						**$8,372,001**		
TOTAL BY YEAR	$210,100	$3,498,600	$1,286,400	$1,111,000	$10,723,000	$9,292,001	$9,421,000	$680,000
TOTAL PROPOSAL	$36,222,101							

The following is a comparison of the '97 Telecommunications Plan and the revised Plan costs and explanations of the variances. Also provided is an analysis of the capital budgets approved by the PUB versus the actual implementation costs.

Phase I

Original Plan Estimate:	$4,140,100
Revised Plan Estimate:	$4,140,100

Variance:	Nil
Approved Capital Budget Proposal:	$4,140,100
Actual Implementation Costs:	$3,879,000
Variance:	($ 261,100)

Phase II (East Coast Microwave)

Original Plan Estimate:	$ 8,537,500
Revised Plan Estimate:	$10,723,000
Variance:	$ 2,185,500

Explanation of Variances

The original plan estimate was completed in 1995 and the revised plan estimate was completed in 1999. Phase II was rescheduled from 1998/99 to 2000/01 to accommodate the availability of engineering resources. The variance is due primarily to the following:

1. When the original budget estimate was prepared in 1995, a geotechnical survey of the sites had not been completed. Costs increased for civil works including site preparation, roads and buildings.
2. The microwave tower design was changed from a design of 50 mm of radial ice to 70 mm of radial ice. This change is consistent with the updated design criteria for ice loading on Hydro's transmission lines.
3. Increase in microwave radio equipment supply costs. This cost increase became apparent with the contract award for the West Coast Microwave System (i.e. Phase I).

Approved Capital Budget Proposal:	$10,723,000
Actual Implementation Costs:	_____*
Variance:	**

* Project in progress

** The tendered costs reviewed in 2000 for this turnkey project are within budget of the engineering estimates approved by the PUB.

Phase III (Interconnect East-West Microwave)

Original Plan Estimate:	$6,358,800
Revised Plan Estimate:	$8,673,269
Variance:	$2,314,469

Explanation for Variance:

The original estimate was completed in 1995 and the revised estimate was completed in 1999. Phase III was rescheduled from 2000 to 2002/03 because of the rescheduling of Phase II. The explanation of the variance is the same as stated for Phase II.

Phase IV (West Coast PLC Replacement)

Stage 1 – West Coast PLC Replacement (1999/2000)

Original Plan (Stage 1) Estimate:	$ 744,000
Revised Plan (Stage 1) Estimate:	$1,666,000
Variance:	$ 922,000

Stage 2 – West Coast PLC Replacement (2001 – 2004)

Original Plan (Stage 2 Estimate:	$2,063,000
Revised Plan (Stage 2) Estimate:	$2,379,000
Variance:	$ 316,000
Note: Stage 2 (2001-2004)	
Total Variance:	$1,238,000

Explanation of Variance:

As part of Phase I, the PLC's in the central region TL 202, TL206 (Bay D'Espoir to Sunnyside) and TL 204, TL 231 (Bay D'Espoir to Stoney Brook) were to be replaced.

In 1997, Hydro began the design for the (PLC Upgrade Central) replacement of the PLC's on TL202, TL206. ABB, the equipment supplier for the PLC systems, recommended a change from phase to ground (as implemented in the 1960's and 1970's) to phase-to-phase coupling in order to improve performance:

1. Over long transmission lines;
2. During harsh environmental conditions (icing); and
3. Of the teleprotection system during a fault on the transmission line, thereby reducing the risk of misoperation.

The variance of $1.24 Million is due to the additional high voltage coupling equipment required to support phase to phase coupling.

In 1999, Hydro updated the estimates for the replacement of the PLC system on the West Coast.

Approved (Stage 1) Capital Budget Proposal:	$1,666,000
Actual Implementation Costs:	$1,565,000
Variance:	($101,000)

Q. **RE: p. B-68 Replace UHF Radio – Upper Salmon ($556,000)**

47.1 What other options are available with regard to replacing the obsolete UHF radio links? Which of these have been investigated? What cost comparisons resulted from these investigations?

A. 47.1 When considering the transport options for the replacement of the UHF radio systems at the Upper Salmon generating station, only two (2) technologies stand out as practical, fibre optic cable and low capacity radio. Therefore, the options available with regard to the replacement of the UHF radio systems are:

i) fibre optic cable
ii) low capacity spread spectrum digital radio; and
iii) combination of (i) and (ii)

The replacement of the UHF radio systems at Upper Salmon is very similar to the replacement of the UHF radio system completed at Hinds Lake in 1998. At that time the three (3) options noted above were investigated.

The analysis done as part of the Hinds Lake UHF radio replacement indicated that from a capital cost comparison, fibre cable, All Dielectric Self Supporting Fibre (ADSS) was $50,000 more expensive than the low capacity radio alternative. However, it was decided to select the fibre alternative because:

i) the fibre alternative would have a longer life cycle than radio, 20 years compared to 10 years;

ii) the fibre alternative would require less maintenance because of less electronic equipment and its design provides for a self healing fibre ring thereby increasing the reliability of the overall communication system;

iii) the fibre alternative provides for higher bandwidth capabilities between sites.

Q. **RE: p. B-70 Replace Remote Terminal Unit for Hydro – Phase 3 ($311,000)**

48.1 Of the 19 Remote Terminal Units identified in the response to PUB 76.0, 2001 Capital Budget, which have been replaced to June 30, 2001?

A. 48.1 Three of the 19 Remote Terminal Units identified in the response to PUB 76.0, 2001 Capital Budget have been replaced to June 30, 2001.

Q. **RE: p. B-71 Provide Global Positioning System Time Synchronization – Phase 2 ($211,000)**

49.1 How many phases remain of this project? Provide the plan, including estimated costs, for the completion of this work.

A. 49.1 Phase 2 of the Global Positioning System Time Synchronization, proposed for 2002, is the last phase of this project. Phase 2 proposes the installation of 22 GPS clocks at 22 sites.

Q. RE: p.B-74 Replace Vehicles ($1,897,000)

51.1 Provide the budget for each class of vehicle being purchased.

A. 51.1

2002 Vehicle Budget By Class

Vehicle Class	Budget Amount
1000 (Cars/ Mini Vans)	$111,100
2000 (Pick -ups / Cargo Vans)	$506,200
3000 (Lt. Duty Trucks)	$67,200
4000 (Heavy Duty Trucks)	$1,108,200
Contingency	$104,300
Total	$1,897,000

Q. **RE: Rate Stabilization Plan**

59.1 Provide detailed schedules supporting the forecast changes to the various components of the Rate Stabilization Plan for 2001 and 2002.

A. 59.1 Please see attached Rate Stabilization Reports for 2001 and 2002.

Q. RE: Role as Instrument of Public Policy

60.1 How does Hydro reconcile its role as an instrument of public policy with generally accepted public utility practices, particularly with regard to the objectives of:

1) Consumer rationing ("rates are designed to discourage the wasteful use of public utility services while promoting all use that is economically justified in view of the relationships between the private and social costs incurred and benefits received ")[1] and
2) Fair Cost Apportionment ("burden of meeting total revenue requirements must be distributed fairly and without arbitrariness, capriciousness, and inequities among the beneficiaries of the service and so as, if possible, to avoid undue discrimination")?[1] (WEW, p. 6, lines 27-31)

A. 60.1 Rate design is always a balancing of competing objectives. Bonbright et al also discuss several aspects of social principles of ratemaking in an earlier section of their book, pp. 164 – 178. They recognize that involving social aspects into rate design can negatively impact objectives such as consumer rationing and fair cost apportionment.

The long standing policy of uniform rates for customers served from the Island Interconnected System can be considered such a social policy concept as it leads to varying levels of intra-class subsidization.

[1] James C. Bonbright, Albert L. Danielsen, and David R. Kamerschen, Principles of Public Utility Rates (Arlington, Virginia: Public Utilities Reports, Inc., 1988, p. 385.

Rates could be designed to track costs very closely but such rates would likely not be readily understood by consumers or easy to administer and therefore inconsistent with those rate design objectives.

The long standing policy of life-line rates for customers served from isolated systems is certainly consistent with including public policy concepts in rate design. Pricing service well below its cost of service is contrary to the consumer rationing objective and puts significant costs on other customers. It has been argued that such costs are more correctly paid by government if they requested such an approach.

Hydro endorses the cited objectives of accepted public utility practices, subject to Hydro's role as an instrument of public policy. Hydro recognizes that in some instances, the Provincial Government determines all use that is economically justified in view of the relationships between the private and social costs incurred and benefits received.

Q. Demand and Energy Charge for Newfoundland Power Inc.

68.1 Pursuant to the Board's 1992 recommendation please provide the rationale and background information supporting the conclusion that an energy only rate to Newfoundland Power is still appropriate. **(DWO, p. 9, lines 27 - 31)**

A. 68.1 Newfoundland Power sent a letter dated May 11, 2001, attached, outlining their current position on this matter. Hydro has concluded there is now no reason to pursue this matter any further at this time.

Q. Methods of Splitting Certain Distribution Costs Between the Customer and the Demand Component.

69.1 How widely used by generation utilities is the minimum system study? How widely used by distribution utilities? Is a minimum system study generally used in addition to the zero-intercept analysis? What are the challenges to collecting the data necessary to perform a minimum system study? (JAB, p. 5, lines 9 - 10)

A. 69.1 Hydro assumes that a "generation" utility is an integrated utility and that a "distribution" utility is one without generation. Most major electric utilities in North America are integrated utilities. Reliance on the minimum system method is more common than zero intercept method for integrated utilities.

Sometimes both a minimum system and zero intercept study are prepared and/or filed, but normally only one method is used in the filed cost allocation.

The challenges to collect the data necessary to perform a minimum system study relate to the availability of appropriate data and the need to have the data in common dollar denominations. As a practical matter, electric companies don't install minimum systems so the cost data for a minimum system may not be on the accounting records. A second and related consideration is the need to have the costs at a common point in time, for example, costs as of 1999. The available cost data for one element may be from a year, say 1990, requiring an

estimate to get that cost consistent with that for an element purchased in 1999. Hydro's Rural Systems were acquired at various times from various entities. Some of these were for a nominal fee such as $1 and no detailed records were provided regarding the age and quantity of much of the Distribution plant. It was therefore impossible to prepare the data as required for a minimum system analysis as outlined above.

Q. Calculation of Rate Base

70.1 What process has been used to determine that the net book value of Capital Assets includes only assets that are used and useful in the generation, transmission and distribution of electricity?

70.2 Provide a copy of any studies that have been undertaken to determine the appropriateness of including or excluding assets in rate base.

70.3 How are assets not included in rate base recorded and tracked?

A. 70.1 Records of construction work in progress are maintained in the Job Cost system until the in-service date at which time they are transferred to the Plant Ledger system and are added to ratebase. The in-service date is defined as the date a project, or an identifiable part, is available on a permanent basis:

a) to generate power for revenue purposes, or
b) to transmit energy for revenue purposes, or
c) as an operating asset.

For all capital activity in Hydro's capital budget, there is consultation between the Plant Ledger, System Planning and Rates Departments to ensure that the assets are assigned the appropriate class, system, function, and customer location. At this time any assets which are associated with unregulated activity would be identified as such and coded appropriately.

When assets are taken out of service they are assigned an identifier in the Plant Ledger system. The net book value of unregulated and "not in service" assets is excluded from ratebase for the purposes of determining the required regulated return.

70.2 No formal studies have been undertaken to determine the appropriateness of including or excluding assets in ratebase.

70.3 Records of construction work in progress are maintained in the Job Cost system. Records of assets taken out of service are maintained in the Plant Ledger system with a "not in service" designation and records of unregulated assets are maintained in the Fixed Asset system with an identifier as noted in 70.1 above.

Q. Study of Distribution System Cost Classification (Foster & Associates)

71.1 Provide a copy of the "Study of Distribution System Cost Classification" that was prepared by Foster & Associates for Newfoundland and Labrador Hydro in 1996. Provide the updated 1998 and 2000 versions of the report. (JAB, p. 1, line 23)

A. 71.1 Please see response to NP-123