2003 GENERAL RATE APPLICATION

An application to the
Board of Commissioners of Public Utilities

Proposed Power Rates
To be charged by
Newfoundland & Labrador
Hydro
To
Newfoundland Power,
Island Industrial Customers
and
Rural Customers

May 2003

Volume II

Newfoundland and Labrador Hydro
2003 General Rate Application

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Vice-President, Transmission and Rural Operations
Newfoundland and Labrador Hydro

At the hearing into Newfoundland and Labrador Hydro's 2003 General Rate Application, the Transmission and Rural Operations Evidence will be adopted by Fred H. Martin, P. Eng., Vice-President, Transmission and Rural Operations for Newfoundland and Labrador Hydro.

A witness profile for Fred Martin is as follows:

- Mr. Martin graduated from the Technical University of Nova Scotia, Dalhousie University in 1971 (B. Eng. – Electrical), and is a member of the Association of Professional Engineers and Geoscientists of Newfoundland and Labrador.

- Mr. Martin joined Hydro in 1971 as Plant Engineer at the Bay D'Espoir Generating Station. He has held several supervisory and managerial positions throughout his career including that of Manager, Telecontrol from 1988 to 1996 and Director, Engineering-Transmission and Rural Operations, from 1996 to 2003.

- On August 1, 2003, Mr. Martin became Vice-President of Transmission and Rural Operations, the position he currently holds.

- Mr. Martin is responsible for Hydro's transmission, distribution and isolated rural systems and the organizational structure in place to manage these assets for the delivery of service to Hydro's customers.

- Mr. Martin is currently a member of the Canadian Electricity Association ("CEA") Transmission Council.

- Mr. Martin testified before the Board of Commissioners of Public Utilities on Hydro's 2004 Capital Budget Application.

Transmission and Rural Operations
Evidence Outline

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TRANSMISSION AND RURAL OPERATIONS

1. RESPONSIBILITIES AND ORGANIZATIONAL STRUCTURE

1.1 Overview

The Transmission and Rural Operations Division ("TRO") is responsible for:

- Operating and maintaining Hydro's transmission, distribution and isolated diesel systems in the Province;
- Providing engineering services to support existing transmission, distribution and isolated diesel systems and the design and construction of new facilities;
- Providing corporate revenue metering and drafting services; and
- Providing corporate environmental and property services.

TRO has five departments as outlined on the organizational chart attached as Schedule I. The roles and responsibilities of these departments are summarized in the following sections.

1.2 Operations

The responsibility for the maintenance of the transmission systems, and the maintenance and operation of the rural systems is assigned to three regions: Central, Northern and Labrador. Each region has a headquarters office, warehousing and centralized maintenance facilities. Due to geographic size, each region has additional depots to facilitate shorter travel time to work sites and ready access to materials.

The regions are responsible for managing the assets through the identification of maintenance and operational requirements, justification of capital requirements and execution of the work.

The operating and maintenance activities are performed by work crews located throughout each region and managed from the regional headquarters. Employees are strategically located throughout the Island and Labrador for routine maintenance and major repairs to transmission, distribution, diesel plant and gas turbine facilities.

The Energy Control Center ("ECC") operates the interconnected transmission systems. The distribution systems throughout the province are operated by the respective regions with the ECC having some distribution feeder control where remote control facilities exist.

Historically, many of the isolated diesel plants required full-time operating staff, however, with changes in technology, these plants now require only "semi-attended" staffing. This requires an operator to be present at the plant for scheduled intervals of time throughout the day to perform plant checks and maintenance activities. During other periods of the day, the operators are available when required.

1.3 Engineering, TRO

The Engineering, TRO Department is responsible for providing various technical services in support of TRO and other departments as required. These services include the investigation and analysis of system disturbances and outages, including recommendations to improve system performance. The department is responsible for the preparation of major capital budget proposals for the division and providing engineering design, construction and project management activities to implement approved projects. The Engineering, TRO Department is also responsible for providing revenue metering and drafting services on a corporate basis.

1.4 Environmental Services and Properties

The Environmental Services and Properties Department provides several services on a corporate basis including the identification of relevant environmental issues and the formulation of appropriate environmental policies and procedures. The department is responsible for conducting environmental audits and assessments, setting standards for environmental emergency response plans and conducting employee environmental training and awareness programs. As well, obtaining environmental approvals and permits and monitoring construction and operations activities are the responsibility of this department. It also provides various property services including surveys and property management.

2. GENERAL DESCRIPTION OF SYSTEM

2.1 Transmission

Hydro owns and operates two interconnected transmission systems, one on the Island and the other in Labrador. These transmission systems connect Hydro's generating stations to its customers throughout the Province.

On the Island Interconnected System, Hydro owns and maintains 3,380 km of high voltage lines, and 53 high voltage terminal stations operating at 230, 138 and 69 kV. When Granite Canal comes into service, there will be an additional 76 km of 230 kV transmission line and one additional high voltage terminal station.

On the Labrador Interconnected System, Hydro owns 269 km of 138 kV transmission line and the associated terminal stations interconnecting Happy Valley/Goose Bay to Churchill Falls. Hydro also owns 44 km of 46 kV sub-transmission lines in Labrador West, 25 km of which are from Wabush to the Newfoundland/Quebec border providing a limited emergency interconnection between Labrador West and Fermont, Quebec. To supply its customers in Labrador West, Hydro has an arrangement with Twin Falls Power Corporation Limited, owner of the 230 kV transmission facilities connecting Churchill Falls to Labrador West, for the wheeling of electrical energy from Churchill Falls.

Schedule II attached shows the major components of Hydro's Interconnected Systems on the Island and in Labrador.

2.2 Interconnected Rural Systems

On the Island Interconnected Rural System, Hydro owns and maintains 2,516 km of low voltage distribution lines, up to 25 kV, and 25 low voltage substations which serve approximately 21,800 Rural Customers. These Rural Customers are provided service from distribution systems located in 181 communities on the south coast, northeast coast and along the Great Northern Peninsula ("GNP").

On the Labrador Interconnected System, Hydro owns and maintains 336 km of low voltage distribution lines and nine substations serving seven communities with approximately 8,900 Rural Customers.

2.3 Isolated Rural Systems

Hydro owns and operates 24 isolated diesel generating and distribution systems serving approximately 4,400 customers in 44 communities throughout coastal Newfoundland and Labrador. Sixteen of these systems are located in Labrador and eight are on the Island of Newfoundland.

Schedule III attached shows the location of these isolated diesel generating plants and Schedule IV attached gives a breakdown of their installed capacity as of December 31, 2002. The total installed capacity of all 24 plants is approximately 30.5 MW.

All of these Isolated Rural Systems are served by Hydro-owned diesel generation with two exceptions. At Mary's Harbour, to supplement diesel generation, Hydro purchases energy from a private company that owns and operates a small hydro plant. On the L'Anse au Loup system, Hydro purchases secondary energy, when available, from the Hydro-Quebec Lac Robertson hydro plant. These two purchases are covered by separate agreements that are based on a share-the-savings principle when compared to more expensive diesel generation.

Schedule IV attached illustrates the changes in capacity in the Isolated Rural Systems since December 2000. Ten communities have had generating capacity changes in this time period, primarily as a result of the replacement of obsolete units or to address a forecast load increase. The plant in one community was decommissioned in 2002 as the residents relocated.

3. OPERATIONS - ISSUES AND DIRECTIONS

3.1 Overview

In carrying out Hydro's mandate to provide reliable energy services to its customers at the lowest possible cost, TRO is faced with multiple challenges.

Reliability of an electric power system is impacted by several factors including major weather events such as ice, sleet and windstorms, as well as lightning activity. All these conditions are prevalent throughout Hydro's operating regions. Salt spray contamination of insulators on transmission and distribution lines near coastal areas also affects reliability performance to a significant degree. The ever increasing age, and the diversity of equipment and systems dispersed over a large geographic area, including 24 isolated communities served by diesel generation, offer unique challenges. This necessitates that adequate numbers of well-trained personnel be strategically located, permitting effective response to address problems in a timely manner. Increased public expectations with respect to reliability of service and environmental practices, as well as increased environmental regulation, are also imposing significant challenges.

3.2 Maintenance Philosophy

Historically, TRO has maintained its equipment using a traditional preventative maintenance program. After reviewing its options, and completing three pilot projects, it was determined that an alternative approach known as Reliability Centered Maintenance ("RCM") should be adopted. This new maintenance philosophy is focused on system functionality and reliability rather than individual system components.

As a result of implementing RCM, certain preventative maintenance tactics will be eliminated while the frequency and scope of others will be changed. The result will be savings to TRO's operating costs which are reflected in the 2003 and 2004 forecasts on Schedule V attached.

It is anticipated that RCM will be in place for distribution systems, diesel plants and terminal stations by mid-2003. Revised maintenance programs employing RCM principles for gas turbine and transmission systems will be established by the end of 2003.

3.3 System Equipment

The assets that fall under the responsibility of TRO are at various stages of their service lives. For example, 35% of Hydro's approximately 80,000 transmission and distribution poles are in excess of 30 years old. The service life of these poles is considered to be 40 years when using traditional inspection and maintenance techniques. Hydro is currently investigating an innovative approach to the management of its wood poles through a program that could potentially extend the life of these assets.

Hydro has experienced significant problems with the insulators of a specific manufacturer (Canadian Ohio Brass) ("COB"). These insulators become defective due to cement growth which culminates in radial cracks developing. The resultant failures, which have been experienced industry-wide, occur with the ingress of moisture into the insulator itself. This problem is being addressed through a major replacement program across the system.

The transmission system includes approximately 100 power transformers ranging in age from five to 40 years. Typically, these units have a service life of 40 years, however, this is influenced by many factors including load duty cycle, overload frequency and maintenance tactics.

The condition of a transformer can be determined by detailed chemical analysis of its insulating oil. Through this means, Hydro identified transformers that required immediate attention. In 2002 a project was initiated to regenerate the oil in three 37-year old units at Bay d'Espoir and clean the interior of their tanks, at a total cost of $180,000. Additional units are planned to be reconditioned in 2003.

In the early 1990's, Hydro conducted condition assessments of most of its diesel plant facilities. Several of these were noted as requiring either total replacement or major refurbishment. Since 1994, new plants have been constructed at Grey River, Port Hope Simpson, Nain and McCallum. Also, a major upgrade was completed at Ramea. The cost of these projects, implemented to rectify the issues arising from the assessments, totaled approximately $12.7 million. Other plants recommended for major rehabilitation such as LaPoile, Mud Lake and Harbour Deep have been addressed either through interconnection or, in the latter case, as a result of the people in the community relocating. Only the diesel plant at St. Lewis is currently in Hydro's future plans for replacement. This project is tentatively scheduled for completion in 2006.

Currently, Hydro operates 83 diesel engines in its Isolated Rural Systems. Approximately 20% of these engines are in excess of 20 years old. Typically, it has been Hydro's practice to replace its diesel engines after 90,000 hours of operation and/or five major overhauls. Generally speaking, this equates to a 25-year service life. Other factors such as reliability, availability of spare parts or increased capacity requirements may influence this replacement criterion. Since 1998, Hydro has replaced approximately 20% of its diesel engines due to age and physical condition at a cost of $4.2 million.

The 54 MW gas turbines at both Stephenville and Hardwoods Terminal Stations have been in service for over 25 years. As these units continue to age, it is expected that increased maintenance and replacement of major equipment and systems will be required.

3.4 Human Resources

Several initiatives have been implemented in TRO to achieve efficiencies and contain costs. Through analysis of a number of processes, improvements have been realized in how the workforce is distributed and how the work is performed. Throughout, Hydro ensured that reliability, environmental stewardship and employee and public safety were not compromised.

As a result of these initiatives implemented since 1999, TRO has been able to reduce its workforce by approximately 15% as can be seen in the following table.

Table 1

TRO Permanent Complement

Year	1999	2000	2001	2002
Complement	412	411	376	349

3.4.1 Lineworker Review

After benchmarking the number of Hydro's lineworkers and driver/ground workers against that of similar utilities it was concluded there were areas where improvements could be made and efficiencies gained. Consequently, a realignment of this workforce was implemented in 2001, resulting in the reduction of 11 lineworker positions and 13 driver/ground worker positions being changed from permanent to part-time temporary. In addition, there were a number of lineworker positions transferred to different locations around the system for operational efficiencies.

3.4.2 Diesel System Representative

In 1998, Hydro initiated the concept of the Diesel System Representative ("DSR") with the objective of establishing a new classification for isolated diesel systems. This provides for more flexible, multi-skilled personnel at each isolated diesel location. Following extensive training, these employees, in addition to their traditional roles, are now able to perform limited line duties, minor electrical/mechanical repairs, utility work, as well as providing customer service representation in the community.

This initiative was implemented in the isolated diesel systems as of December 31, 2001 and has assisted Hydro in optimizing corporate performance as a result of reduced labor and travel costs and improved customer service.

3.5 Isolated System Cost Containment

As highlighted in Section 2.3, Hydro owns and operates 24 isolated diesel generating plants serving approximately 4,400 customers throughout Newfoundland and Labrador. The cost of providing service to these customers exceeds the revenue collected, and the difference is part of what is commonly referred to as the “rural deficit”.

Hydro has identified a number of initiatives to reduce costs which will assist in lowering, to the extent possible, the rural deficit. Some of the initiatives implemented include interconnecting Isolated Systems to the main grid where cost effective, utilizing new technologies, training a multi-skilled workforce in these remote areas (the DSR), and adopting innovative, industry-recognized practices for asset management (RCM).

3.6 Co-ordination with Newfoundland Power

On the Island of Newfoundland there are two regulated electric utilities serving customers. The two utilities, Hydro and Newfoundland Power, have long recognized their obligation to ensure that their respective operations are coordinated in a way that ensures that reliable service is provided to customers at the lowest possible cost.

In 1997, Hydro and Newfoundland Power established a joint task force to explore feasible opportunities to reduce costs through the identification and elimination of duplication and through the sharing of resources. While this initiative determined that the areas of overlap were limited, there were several areas identified where potential exists for the sharing of resources to the benefit of customers.

The issue of duplication of resources was reviewed during Hydro's 2001 GRA and in P.U. 7 the Board required that Hydro submit a report on this issue no later than December 31, 2002. This report entitled "A Report of Joint Co-ordination Between Newfoundland and Labrador Hydro and Newfoundland Power" was submitted to the Board in December 2002 and is attached as Exhibit DWR-1.

4. OPERATING PERFORMANCE

4.1 Reliability

For the transmission system, reliability is determined by measuring the number and duration, in minutes, of interruptions of supply to the 58 bulk delivery points supplying Newfoundland Power, Industrial Customers and Hydro's distribution systems. This is referred to as the Bulk Electrical System ("BES") reliability and is measured by indices which were developed by the electric utility industry through the coordination of the CEA.

For the distribution system, reliability is determined by measuring the overall reliability of supply to the Rural Customers through determining the number and duration, in hours, of interruptions to the customer's service. This is referred to as Service Continuity and is also measured by CEA standard indices.

While CEA does provide consolidated BES reliability statistics for the Canadian utilities, it is difficult to compare these to Hydro statistics. This results from the high portion of delivery points on Hydro's system being supplied by radial lines such as on the GNP. One line outage on the GNP can interrupt nine delivery points and therefore greatly impact performance indices. Similarly, for Service Continuity, the high portion of customers in isolated systems and coastal areas with severe weather exposure makes it difficult to find comparable utilities. Most utilities participating in CEA statistical analysis have a high urban concentration that tends to see better performance than Hydro's.

4.1.1 Bulk Electrical System Reliability and Improvements

The following table shows the BES System Average Interruption Frequency Index ("SAIFI") and the System Average Interruption Duration Index ("SAIDI") for Hydro's 58 delivery points for the period 1998 to 2002.

Table 2

BES Performance		
Year	**SAIFI Interruption/Delivery Point**	**SAIDI Minutes/Delivery Point**
1998	4.57	230.88
1999	2.32	91.16
2000	3.88	111.46
2001	1.43	44.00
2002	1.72	106.72
5 Yr Avg.	2.78	116.84

It is noteworthy that performance is highly variable from year to year due to weather related conditions. It should also be noted that the 2001 performance was the best Hydro has experienced since it began tracking this performance in 1987.

To address BES reliability issues, Hydro has implemented a number of initiatives including transmission line upgrades and replacement of defective insulators. During 2001 and 2002, Hydro completed upgrades of three transmission lines on the Avalon Peninsula at a cost of $23.7 million. This concluded a $45 million program initiated in 1997 to increase the design ice loading capability of 230 kV steel transmission lines from Sunnyside to Oxen Pond. It provides for one upgraded steel line between each 230 kV station on the Avalon Peninsula.

A program for the bulk replacement of defective COB insulators continues. In 2001 and 2002, the following lines were completed at a cost of $2.5 million:

TL 211	-	230 kV line, Massey Drive to Bottom Brook
TL 228	-	230 kV line, Buchans to Massey Drive
TL 231	-	230 kV line, Bay d'Espoir to Stony Brook
L1301	-	138 kV line, Churchill Falls to Happy Valley
TL 226	-	69 kV line, Deer Lake to Berry Hill
TL 229	-	69 kV line, Wiltondale to Glenburnie

Additional lines have been included in Hydro's future plans and it is anticipated that all these insulators will be replaced on the Bulk Electrical System by 2007.

Also in 2001 and 2002, two projects were undertaken to improve the reliability of service to customers on the GNP. A 2-stage upgrade to TL 227, a 69 kV line from Berry Hill to Daniels Harbour, involved the replacement of structures and a new insulator configuration in eleven sections of the line. A second project involved the re-routing and upgrading of TL 262, a 69 kV line from Daniel's Harbour to Peters Barren. Both projects were initiated to address numerous outages as a result of high winds and salt spray contamination and were completed at a total cost of $2.5 million.

4.1.2 Interconnected Rural Systems Reliability and Improvements

The following table shows the Service Continuity SAIFI and SAIDI for the 30,700 Interconnected Rural Customers for 2000, 2001 and 2002. Only the three most recent years are selected for the average as older information on these indices had inconsistencies in the data.

Table 3

Interconnected Rural Systems Service Continuity		
Year	**SAIFI Interruptions/Customer**	**SAIDI Hours/Customer**
2000	7.09	14.34
2001	6.58	10.42
2002	7.35	12.29
3 Yr Avg.	7.01	12.36

SAIFI results are slightly higher in 2002 due to a higher than normal amount of planned outages to allow upgrading of distribution systems.

Hydro has completed several upgrade projects in 2001-2002 on the Interconnected Rural Systems to improve reliability. Distribution line upgrades totaling approximately $3.2 million have been completed on the Bay d'Espoir, Burgeo, Burlington, Bottom Waters, King's Point, South Brook, English Harbour West, St. Anthony and Cook's Harbour systems.

These planned projects were in addition to the annual expenditures incurred for unforeseen distribution upgrades required in the three regions. For 2001 and 2002 these upgrades cost approximately $1.0 million in each year.

4.1.3 Isolated Rural Systems Reliability and Improvements

The following table shows the Service Continuity SAIFI and SAIDI for the 4,400 Isolated Rural Customers for 2000, 2001 and 2002. Similar to the average on the Interconnected Rural Systems, only the three most recent years were used.

Table 4

Isolated Rural Systems Service Continuity		
Year	**SAIFI Interruptions/Customer**	**SAIDI Hours/Customer**
2000	12.66	12.39
2001	13.57	8.44
2002	23.75	22.84
3 Yr Avg.	16.66	14.56

In 2002, major weather-related problems had a negative impact on performance for coastal Labrador customers by causing interruptions on the distribution systems and also preventing maintenance personnel from responding in a timely manner. For these customers there were also a significant number of planned outages to accommodate upgrading of diesel plant and distribution assets.

A number of projects have been completed to address operational issues, including reliability, in Isolated Rural Systems. The construction of a new powerhouse at Nain, complete with three new diesel generator units, was commissioned in the fall of 2002 at a total cost of $4.8 million. The original plant was approximately 25 years old and the size of the installed generation equipment had exceeded the design capacity of the building. Also, the original powerhouse was built on permafrost which caused problems as diesel generator unit size was increased. The new plant will improve the reliability of service to customers in that community.

Similarly, a major upgrade to the diesel plant in McCallum was completed. The previous facility consisted of a wood frame building which caused operational problems related to structural integrity, noise attenuation and fire protection. The new concrete block plant is powered with two new diesel generator units and one unit from the old plant. Commissioning was completed at the end of 2001 at a total cost of $1.1 million.

In addition to these projects, five obsolete diesel generator sets were replaced during 2001-2002 at a cost of approximately $1.6 million. The communities involved were: Black Tickle, Grey River, Postville, Rigolet and St. Brendan's. Also, several distribution upgrades were completed during that period at a total cost of approximately $0.8 million.

4.2 Operating Costs

Schedule V attached shows TRO net operating expenses for 2002 and forecast for 2003 and 2004.

The salaries and fringe benefits expense is the largest component of TRO's operating expenses at approximately 65% for 2004. In 2002, actual expense was slightly less than the 2002 test year final revenue requirement and is expected to decrease in 2003 and 2004 primarily due to the workforce realignment referred to previously, RCM and reductions in temporary staffing.

System equipment maintenance, the second largest component of TRO's operating expenses was greater than the 2002 test year final revenue requirement due to higher than anticipated requirements for corrective maintenance. These expenses are expected to decrease in 2003 and 2004 due to a change in maintenance philosophy with the adoption of RCM and a decrease in the number of operating projects.

In the category of other expenses, costs were greater than the 2002 test year final revenue requirement due to increased travel expense required to respond to major weather-related damage and outages in the isolated Labrador communities and an increase in employee expenses for the provision of newly required personal protective equipment. Other expenses in this category are expected to remain relatively constant for 2003 and 2004, except for professional services which are forecast to be higher. This increase is due to the requirement for specialized external auditors under the ISO 14001 Environmental Management System and for a consultant to assess and report on reliability of transmission lines serving the GNP as required by the Board.

5. ENVIRONMENT

5.1 Environmental Management System

One of the areas of increasing importance to customers and the general public is the area of environmental management. Hydro, by virtue of its business, has a significant environmental footprint that can conflict with fish habitat, land and water use, and air and water quality. Hydro is committed to maintaining a high level of environmental responsibility as it provides cost-effective and reliable energy services to its customers. In 1998, Hydro developed a five-year plan with the goal of implementing a comprehensive Environmental Management System consistent with the ISO 14001 standard to provide the framework through which this high level of performance is to be attained. At the end of 2002, this goal was accomplished. Furthermore, five of the six management areas in the overall Environmental Management System have been certified by the Standards Council of Canada, and the sixth is expected to obtain this designation by the end of 2003.

5.2 Significant Environment Issues

The following are the significant environmental challenges that Hydro must address over the next few years.

5.2.1 Fish Habitat

With respect to hydroelectric facilities, issues primarily relate to the preservation of fish habitat. Efforts are continuing to minimize the release of deleterious substances into fish habitat and to respond quickly to minimize and contain any releases that may occur. As well, for new plant construction such as Granite Canal, measures are taken to ensure that Hydro’s environmental responsibility is met. A fish habitat compensation facility has been constructed to compensate for the habitat disturbed by the construction of the project. It is expected that over time the system will return to its pre-disturbance level of fish productivity.

5.2.2 Environmental Site Assessment

In 2000, Hydro undertook an Environmental Site Assessment Program. This multi-year program guides the implementation of environmental site assessments on all properties owned or occupied by Hydro that have a reasonable risk of being contaminated, and provides a framework for the management of these sites where contamination may be found. To date, 24 properties have been assessed, and remedial action has been taken on two of these sites. The remaining sites will be addressed over the next few years.

5.2.3 Air Emissions

Combustion of fossil fuels at thermal generating facilities produces emissions that can affect local, regional and global air quality. By adhering to the air pollution control regulations, formal compliance agreements, and continuing an ongoing dialogue with the provincial Department of Environment, Hydro attempts to keep these impacts to a minimum, and to improve performance over time. In the past two years, Hydro has committed to installing continuous emission monitoring equipment, and another ground level monitoring station at the Holyrood Generating Station. For the Isolated Rural Systems, Hydro is working with the Department of Environment to review the emissions criteria for diesel plants.

5.2.4 Waste Management

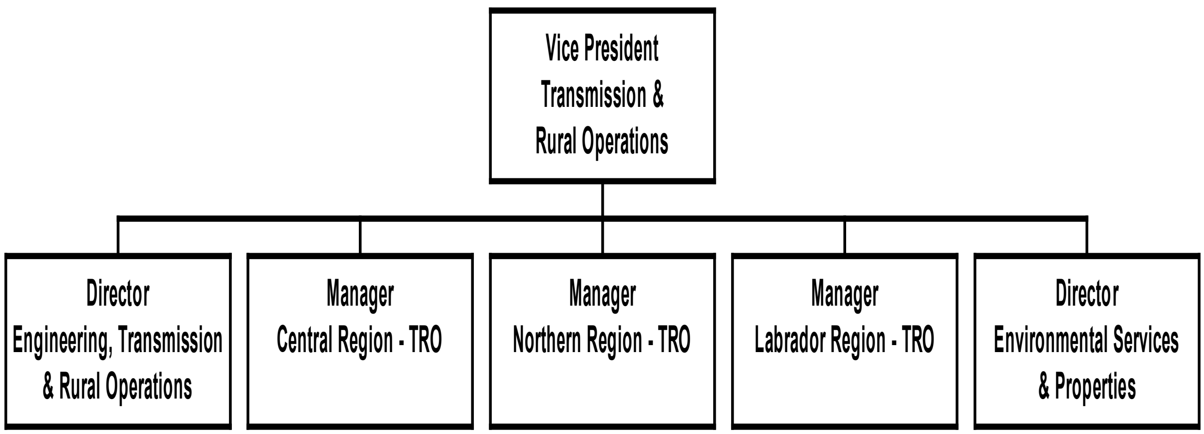
Throughout Hydro, activities have been initiated to reduce the use of equipment and processes that produce potentially hazardous materials, and to reuse and recycle materials that would otherwise be discarded. For example, Hydro:

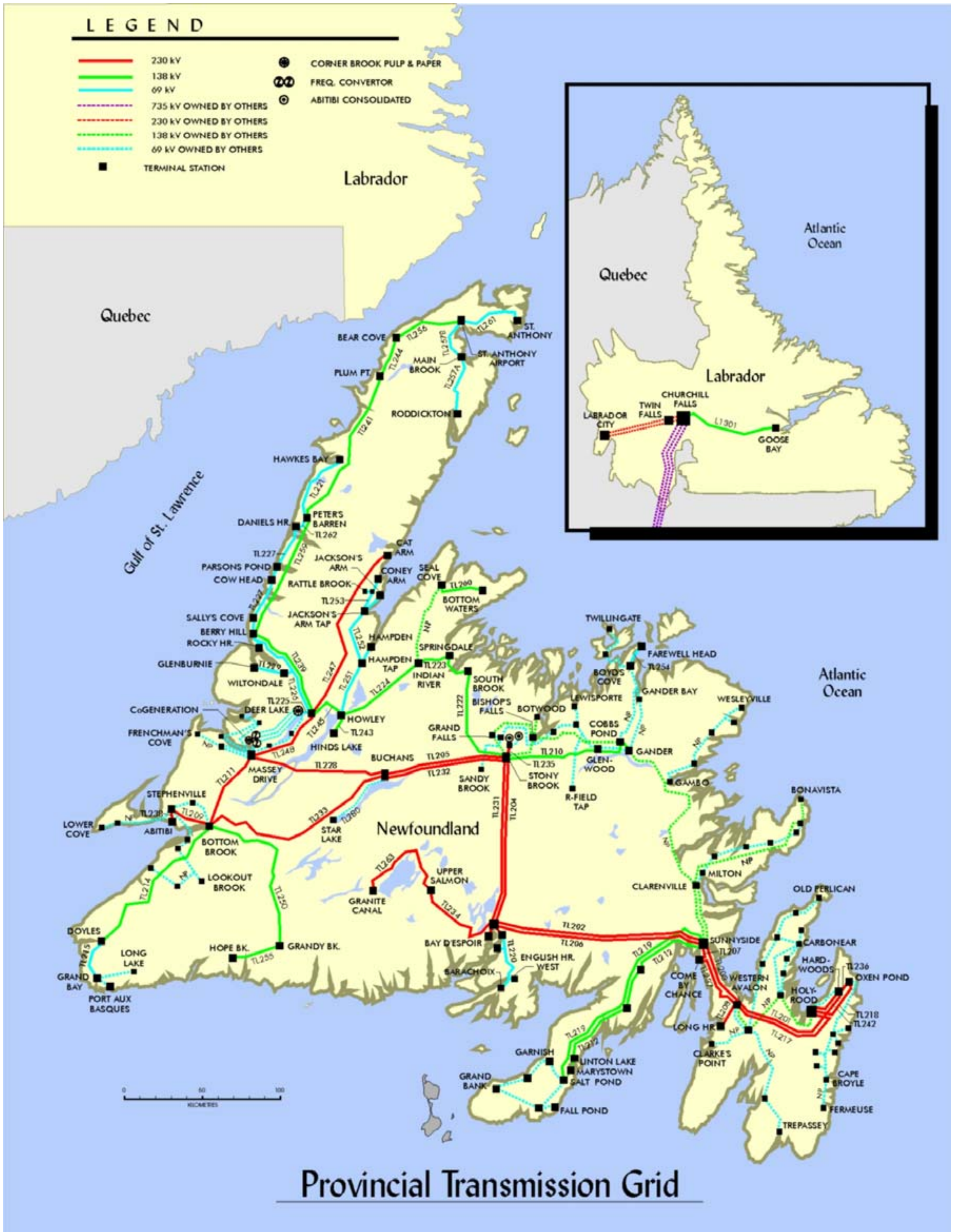
- Periodically contracts certified PCB waste handlers to dispose of PCB-contaminated waste material;
- Reuses and recycles insulating oil from transformers and other equipment;

- Captures waste lubricating oil from Hydro's diesel generating facilities and returns it to suppliers for reuse or recycling;
- Collects waste metal from Hydro's operations whenever practical and auctions it to scrap metal recovery companies for reuse; and
- Reuses and recycles a portion of Hydro's pressure-treated wood waste.

TRANSMISSION AND RURAL OPERATIONS
LIST OF SCHEDULES

Newfoundland and Labrador Hydro
Transmission & Rural Operations Organizational Chart




LEGEND
230 kV
138 kV
69 kV
735 kV OWNED BY OTHERS
230 kV OWNED BY OTHERS
138 kV OWNED BY OTHERS
69 kV OWNED BY OTHERS
TERMINAL STATION
CORNER BROOK PULP & PAPER
FREQ. CONVERTOR
ABITIBI CONSOLIDATED
Labrador
Quebec
Gulf of St. Lawrence
Newfoundland
Atlantic Ocean
CHURCHILL FALLS
TWIN FALLS
LABRADOR CITY
GOOSE BAY
L1301
ST. ANTHONY
ST. ANTHONY AIRPORT
BEAR COVE
MAIN BROOK
PLUM PT.
RODDICKTON
HAWKES BAY
DANIELS HR.
PETER'S BARREN
PARSONS POND
COW HEAD
CAT ARM
JACKSON'S ARM
CONEY ARM
RATTLE BROOK
JACKSON'S ARM TAP
SALLY'S COVE
BERRY HILL
ROCKY HR.
GLENBURNIE
WILTONDALE
SEAL COVE
BOTTOM WATERS
HAMPDEN
HAMPDEN TAP
SPRINGDALE
INDIAN RIVER
TWILLINGATE
FAREWELL HEAD
BOYDS COVE
GANDER BAY
WESLEYVILLE
LEWISPORTE
SOUTH BROOK
BISHOPS FALLS
BOTWOOD
COBBS POND
GANDER
GRAND FALLS
GLEN-WOOD
STONY BROOK
R-FIELD TAP
CoGENERATION
DEER LAKE
HOWLEY
FRENCHMAN'S COVE
HINDS LAKE
MASSEY DRIVE
BUCHANS
SANDY BROOK
GAMBO
BONAVISTA
STEPHENVILLE
LOWER COVE
ABITIBI
BOTTOM BROOK
STAR LAKE
LOOKOUT BROOK
UPPER SALMON
GRANITE CANAL
CLARENVILLE
MILTON
OLD PERLICAN
DOYLES
LONG LAKE
GRAND BAY
PORT AUX BASQUES
HOPE BK.
GRANDY BK.
BAY D'ESPOIR
ENGLISH HR. WEST
BARACHOIX
SUNNYSIDE
CARBONEAR
HARD-WOODS
OXEN POND
COME BY CHANCE
WESTERN AVALON
HOLY-ROOD
LONG HR.
CLARKE'S POINT
GARNISH
LINTON LAKE
MARYSTOWN
SALT POND
GRAND BANK
FALL POND
CAPE BROYLE
FERMEUSE
TREPASSEY
TL256
TL261
TL244
TL241
TL227
TL262
TL253
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TL212
TL201
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TL236
TL218
TL242
NP
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50
100
KILOMETRES
Provincial Transmission Grid


LEGEND
DIESEL
NAIN
DAVIS INLET
HOPEDALE
POSTVILLE
MAKKOVIK
RIGOLET
BLACK TICKLE
CARTWRIGHT
LABRADOR
PARADISE RIVER
NORMAN BAY
CHARLOTTETOWN
WILLIAMS HARBOUR
PORT HOPE SIMPSON
ST. LEWIS
MARY'S HARBOUR
L'ANSE AU LOUP
LITTLE BAY ISLANDS
ST. BRENDAN'S
NEWFOUNDLAND
RENCONTRE EAST
PETITES
RAMEA
GREY RIVER
FRANÇOIS
McCALLUM
Provincial Isolated Systems (Diesel)

NEWFOUNDLAND AND LABRADOR HYDRO
INSTALLED GENERATING CAPACITY
ISOLATED RURAL SYSTEMS
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Plant Location	Installed Capacity		
	2000	**2002**	**Variance**
Labrador			
Black Tickle	850	1,005	155
Cartwright	1,670	2,170	500
Charlottetown	936	2,250	1,314
Davis Inlet	1,222	1,222	0
Hopedale	1,533	1,533	0
L'Anse Au Loup	3,900	3,900	0
Makkovik	1,705	1,705	0
Mary's Harbour	1,550	1,550	0
Nain	2,600	2,595	(5)
Norman Bay	90	90	0
Paradise River	190	190	0
Port Hope Simpson	1,210	1,210	0
Postville	675	677	2
Rigolet	1,167	1,237	70
St. Lewis	1,236	1,236	0
Williams Harbour	362	362	0
SUBTOTAL	20,896	22,932	2,036
Island			
Francois	611	611	0
Grey River	522	522	0
Harbour Deep[1]	613	N/A	(613)
Little Bay Islands	1,250	1,700	450
McCallum	522	482	(40)
Petites	155	155	0
Ramea	2,775	2,775	0
Rencontre East	675	625	(50)
St. Brendan's	735	712	(23)
SUBTOTAL	7,858	7,582	(276)
TOTAL	**28,754**	**30,514**	**1,760**

[1] The residents of Harbour Deep relocated in 2002 and the diesel plant taken out of service.

NEWFOUNDLAND AND LABRADOR HYDRO
NET OPERATING EXPENSES
TRO DIVISION

($ thousands)

Line No.	Description	2002 Test Year Final Revenue Requirement	2002 Actuals	Increase (Decrease)	2003 Estimate	Increase (Decrease)	2004 Forecast	Increase (Decrease)
1	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
2								
3	**Expense Group**							
4	Salaries & Fringe Benefits							
5	Permanent Salaries	19,603	18,743	(860)	20,997	2,254	21,316	319
6	Capitalized Expenses	(2,861)	(4,576)	(1,715)	(3,780)	796	(3,199)	581
7	Hourly Wages	1,952	2,821	869	0	(2,821)	0	0
8	Overtime	1,144	1,987	843	1,382	(605)	1,221	(161)
9	Labrador Travel Benefit	101	99	(2)	94	(5)	94	0
10	Fringe Benefits	2,683	2,827	144	2,941	114	2,985	44
11	Vacancy Adjustment	(655)	0	655	(431)	(431)	(1,068)	(637)
12	**Sub-Total**	21,967	21,901	(66)	21,203	(698)	21,349	146
13								
14	System Equipment Maintenance							
15	Maintenance Materials	6,506	7,043	537	5,530	(1,513)	5,950	420
16	Tools & Operating Supplies	296	282	(14)	304	22	324	20
17	Lubricants & Chemicals	207	86	(121)	176	90	175	(1)
18	**Sub-Total**	7,009	7,411	402	6,010	(1,401)	6,449	439
19								
20	Other Expenses							
21	Office Supplies & Expenses	607	559	(48)	597	38	597	0
22	Professional Services	335	241	(94)	443	202	375	(68)
23	Equipment Rentals	163	191	28	152	(39)	152	0
24	Travel	1,335	1,670	335	1,403	(267)	1,370	(33)
25	Miscellaneous	94	240	146	55	(185)	55	0
26	Property Rentals	429	629	200	593	(36)	561	(32)
27	Transportation	1,595	1,663	68	1,630	(33)	1,730	100
28	**Subtotal**	4,558	5,193	635	4,873	(320)	4,840	(33)
29								
30	**Total Operating Expenses**	33,534	34,505	971	32,086	(2,419)	32,638	552
31								
32	**Allocations**							
33	Recoveries	(136)	(67)	69	(37)	30	(37)	0
34	***Net Operating Expenses***	33,398	34,438	1,040	32,049	(2,389)	32,601	552

NEWFOUNDLAND AND LABRADOR HYDRO

PREPARED TESTIMONY

of

KATHLEEN C. McSHANE

FOSTER ASSOCIATES, INC.
Bethesda, Maryland 20814

April 2003

APPENDIX A
QUALIFICATIONS OF
KATHLEEN C. McSHANE

Kathleen McShane is a Senior Vice President and senior consultant with Foster Associates, Inc., where she has been employed since 1981. She holds an M.B.A. degree in Finance from the University of Florida, and M.A. and B.A. degrees from the University of Rhode Island. She is also a Chartered Financial Analyst.

Ms. McShane worked for the University of Florida and its Public Utility Research Center, functioning as a research and teaching assistant, before joining Foster Associates. She taught both undergraduate and graduate classes in financial management and assisted in the preparation of a financial management textbook.

At Foster Associates, Ms. McShane has worked in the areas of financial analysis, energy economics and cost allocation. Ms. McShane has presented testimony in more than 100 proceedings on rate of return and capital structure before federal, state, provincial and territorial regulatory boards, on behalf of U.S. and Canadian telephone companies, gas pipelines and distributors, and electric utilities. These testimonies include the assessment of the impact of business risk factors (e.g., competition, rate design, contractual arrangements) on capital structure and equity return requirements. Ms. McShane has also provided consulting services for numerous U.S. and Canadian companies on financial and regulatory issues, including financing, dividend policy, corporate structure, cost of capital, automatic adjustments for return on equity, and form of regulation (including performance-based regulation).

Ms. McShane was principal author of a study on the applicability of alternative incentive regulation proposals to Canadian gas pipelines. She was instrumental in the design and preparation of a study of the profitability of 25 major U.S. gas pipelines, in which she developed estimates of rate base, capital structure, profit margins, unit costs of providing services, and various measures of return on investment. In a study prepared for the Canadian

Ministry of Energy, Ms. McShane analyzed Federal regulation of U.S. pipelines, including trends in rate design and rate structures. Ms. McShane has also co-managed market demand studies, focusing on demand for Canadian gas in U.S. markets. Other studies performed by Ms. McShane include a comparison of municipal and privately owned gas utilities, an analysis of the appropriate capitalization and financing for a new gas pipeline, risk/return analyses of proposed water and gas distribution companies and an independent power project, pros and cons of performance-based regulation, and a study on pricing of a competitive product for the U.S. Postal Service. She has also conducted seminars on cost of capital for regulated utilities, with focus on the Canadian regulatory arena.

Publications and Papers

- "The Effects of Unbundling on a Utility's Risk Profile and Rate of Return", (co-authored with Owen Edmondson, Vice President of ATCO Electric), presented at the Unbundling Rates Conference, New Orleans, Louisiana sponsored by Infocast, January 2000.

- Atlanta Gas Light's Unbundling Proposal;: More Unbundling Required?" presented at the 24th Annual Rate Symposium, Kansas City, Missouri, sponsored by several Commissions and Universities, April 1998.

- "Incentive Regulation" An Alternative to Assessing LDC Performance", (co-authored with Dr. William G. Foster), presented at the Natural Gas Conference, Chicago, Illinois sponsored by the Center for Regulatory Studies, May 1993.

- "Alternative Regulatory Incentive Mechanisms", (co-authored with Stephen F. Sherwin), prepared for the National Energy Board, Incentive Regulation Workshop, October 1992.

- "Market-Oriented Sales Rates and Transportation Services of U.S. Natural Gas Distribution Companies", (co-authored with Dr. William G. Foster), published by the IAEE in *Papers and Proceedings of the Eighth Annual North American Conference*, May 1987.

- "Canadian Gas Exports: Impact of Competitive Pricing on Demand", (co-authored with Dr. William G. Foster), presented to A.G.A.'s Gas Price Elasticity Seminar, February 1986.

- "Marketing Canadian Natural Gas in the U.S.", (co-authored with Dr. William G. Foster), published by the IAEE in *Proceedings: Fifth Annual North American Meeting*, 1983.

Expert Testimony/Opinions

on

<u>Rate of Return & Capital Structure</u>

Alberta Natural Gas	1994
Alberta Power/ATCO Electric	1989, 1991, 1993, 1995, 1998, 1999, 2000, 2003
AltaGas Utilities	2000
Ameren (Central Illinois Public Service & Union Electric)	2000 (3 cases), 2002 (3 cases)
ATCO Gas	2000, 2003
ATCO Pipelines	2000, 2003
BC Gas	1992, 1994
Bell Canada	1987, 1993
Benchmark Utility Cost of Equity (British Columbia)	1999
Canadian Western Natural Gas	1989, 1998, 1999
Centra Gas B.C.	1992, 1995, 1996, 2002
Centra Gas Ontario	1990, 1991, 1993, 1994, 1996
Dow Pool A Joint Venture	1992
Edmonton Water/EPCOR Water Services	1994, 2000
Enbridge Gas Distribution	1988, 1989, 1991-1997, 2001, 2002
Enbridge Gas New Brunswick	2000
Gas Company of Hawaii	2000
Gaz Metropolitain	1988
Gazifère	1993, 1994, 1995, 1996, 1997, 1998
Heritage Gas	2002
HydroOne/Ontario Hydro Services Corp.	1999, 2000
Laclede Gas Company	1998, 1999, 2001, 2002
Maritimes NRG (Nova Scotia) and (New Brunswick)	1999
Multi-Pipeline Cost of Capital Hearing (National Energy Board)	1994
Natural Resource Gas	1994, 1997
Newfoundland & Labrador Hydro	2001

Newfoundland Power	1998, 2002
Newfoundland Telephone	1992
Northwestel, Inc.	2000
Northwestern Utilities	1987, 1990
Northwest Territories Power Corp.	1990, 1992, 1993, 1995, 2001
Nova Scotia Power Inc.	2001, 2002
Ozark Gas Transmission	2000
Pacific Northern Gas	1990, 1991, 1994, 1997, 1999, 2001
Platte PipeLine Co.	2002
St. Lawrence Gas	1997, 2002
Southern Union Gas	1990, 1991, 1993
Stentor	1997
Tecumseh Gas Storage	1989, 1990
Telus Québec	2001
TransCanada PipeLines	1988, 1989, 1991 (2 cases), 1992, 1993
TransGas and SaskEnergy LDC	1995
Trans Québec & Maritimes Pipeline	1987
Union Gas	1988, 1989, 1990, 1992, 1994, 1996, 1998, 2001
Westcoast Energy	1989, 1990, 1992 (2 cases), 1993
West Kootenay Power/Utilicorp United Networks (B.C.)	1995, 1999, 2001
Yukon Electric Co. Ltd./Yukon Energy	1991, 1993

Expert Testimony/Opinions

on

Other Issues

Client	**Issue**	**Date**
Gaz Metro/ Province of Québec	Cost Allocation/ Incremental vs. Rolled-In Tolling	1984
Canadian Western Natural Gas	Cash Working Capital/ Compounding Effect	1989
Maritime Electric	Form of Regulation	1995
Enbridge Consumers Gas	Principles of Cost Allocation	1998
Enbridge Consumers Gas	Unbundling/Regulatory Compact	1998
Gazifère Inc.	Cash Working Capital	2000
Maritime Electric	Subsidies	2000
ATCO Electric	Carrying Costs on Deferral Account	2001
Newfoundland & Labrador Hydro	Rate Base, Cash Working Capital	2001

TABLE OF CONTENTS

I. INTRODUCTION AND SUMMARY OF CONCLUSIONS

My name is Kathleen C. McShane and my business address is 4550 Montgomery Avenue, Suite 350N, Bethesda, Maryland 20814. I am a Senior Vice President of Foster Associates, Inc., an economic consulting firm. I hold a Masters in Business Administration with a concentration in Finance from the University of Florida (1980) and am a Chartered Financial Analyst (1989). My professional experience is detailed in Appendix A to this Exhibit.

I have been asked by Newfoundland and Labrador Hydro ("Hydro" or "NLH") to:

- Address the issue of inclusion of interest expense in the lead/lag study for cash working capital;

- Evaluate Hydro's target capital structure of 80% debt;

- Assess the reasonableness of the debt guarantee fee; and

- Estimate a fair rate of return on equity.

My conclusions are as follows:

- I recommend to the Board that the current methodology for calculating the cash working capital allowance be retained, i.e., interest expense should not be included in the lead/lag study.

- Hydro's target capital structure includes a debt ratio that, with the debt guarantee, is at the high end of the range of reasonableness for purposes of being a self-supporting commercial utility. However, there is no evidence that, if Hydro achieves and maintains the target, the Province's credit rating would be negatively impacted.

- The debt guarantee fee of 1% continues to be reasonable and, at recent debt spreads, provides a historically high level of benefits to Hydro's ratepayers.

- A fair return on equity for Hydro at its forecast and target capital structure ratios is no less than that applicable to an average risk (business plus financial) Canadian electric utility. My analysis indicates that a fair return is in the range of 11.25-12.0%.

II. CASH WORKING CAPITAL

In Hydro's last rate case, Mr. Mark Drazen, witness for Labrador City, proposed that the Cash Working Capital calculation should take into account the timing differences between the payment of interest and the receipt of interest. The Board concluded at page 100 of P.U.7 (2002-03):

> At the present time the Board will not act to adjust the CWCA to reflect the timing difference between the payment of semi-annual long term bond interest and the receipt of the funds for their payment. The Board feels this issue warrants further consideration and will require NLH to submit to the Board, prior to the next rate application, an analysis of this issue.

Hydro has filed its analysis with the Board, in which it:

- summarized the regulatory position in the issue from an overall North American standpoint;

- specifically reviewed the approaches utilized by Canadian utilities; and,

- compared the approach used by this Board to those accepted by Canadian regulators.

Hydro concluded that the approach currently utilized by the Board, which focuses on operating expenses, is reasonable from a theoretical standpoint and consistent with what is done in the preponderance of Canadian jurisdictions. Further, Hydro concluded that its approach to estimating interest expense further supports exclusion of interest expense from the lead/lag study. That approach explicitly takes into account the timing of receipt of cash available for reinvestment prior to payment of the interest.

I endorse Hydro's conclusions and support their recommendation to the Board that it continue to approve the methodology used by Hydro to determine its cash working capital allowance.

III. PRINCIPLES FOR ANALYSIS OF A FAIR RETURN

There are legislative and regulatory precedents, which lay the groundwork for the determination of the return on rate base for Hydro.

Hydro is subject to the Electrical Power Control Act 1994 (EPCA), the Hydro Corporation Act and the Public Utilities Act.

The EPCA states that it is the policy of the Province that the rates to be charged for the supply of power within the province,

> should provide sufficient revenue to the producer or retailer of the power to enable it to earn a just and reasonable return as construed under the Public Utilities Act so that it is able to achieve and maintain a sound credit rating in the financial markets of the world.

The Public Utilities Act states,

> A public utility is entitled to earn annually a just and reasonable return as determined by the board on the rate base as fixed and determined by the board for each type or kind of service supplied by the public utility.

P.U. 7 (page 28), the first decision issued for Hydro since it has been subject to full rate base/rate of return regulation, confirmed the standards for a just and reasonable return, as follows:

> The Board sets out the following principles for purposes of its regulatory framework:
>
> 1. Fair Return
> Regulated utilities are given the opportunity to earn a fair rate of return. To be considered fair, the return must be:
>
> - commensurate with return on investments of similar risk;
> - sufficient to assure financial integrity; and
> - sufficient to attract necessary capital.
>
> The fair return principle is consistent with both Section 80(1) of the *Act* and Section 3(a)(iii) of the *EPCA*.

In P.U. 7 (page 43), the Board concluded,

> The Board accepts NLH's proposals for a debt/equity ratio in the 2002 test year of 83/17 and a target short term debt/equity ratio of 80/20. The Board concludes the evidence does not support the principle of NLH moving to a capital structure of 60/40 at the present time. If NLH is committed to move in this direction, it must formulate an appropriate long term financial plan to present to the Board.

Hydro has addressed this issue and concluded that a 60/40 debt/equity capital structure is not practicably achievable. Consequently, Hydro is proposing to maintain 80% debt to capital as its target for the foreseeable future.

In light of the above, the analysis of a fair return for Hydro needs to address the following questions:

1. Is the proposed target capital structure reasonable, in light of the fact that the Province unconditionally guarantees the debt of Hydro and charges Hydro a 1% guarantee fee as compensation? Specifically, the proposed capital structure (in conjunction with the guarantee fee) should be consistent with the capital structure objective laid out in P.U. 7 (page 31), that is,

   > Management must strive to choose an efficient capital structure which will provide access to needed capital at lowest cost.

2. What is a reasonable return on equity to the shareholder given the forecast test year capital structure, the target capital structure, the existence of the debt guarantee and the level of the debt guarantee fee?

3. Is the combination of capital structure, cost of debt, guarantee fee, and return on equity compatible with the basic financial principles which should underpin cost of capital determinations?

Of the basic principles of finance which underpin this analysis, the most basic principle is that the cost of capital to a firm is a function of the business risk it faces. Business risk is a function of the variability of operating income. The more variable are the revenues and the less variable the costs, the higher the business risks. The higher the business risk, the higher the overall cost of capital.

In the absence of income taxes and cost associated with the use of excessive debt (bankruptcy costs or costs of financial distress), financial theory holds that the cost of capital would not change if a company changes its capital structure. However, the use of debt creates a class of investors whose claims on the resources of the firm take precedence over those of the equity owner. In theory, the cash flows available to both the debt and equity holders do not change as the capital structure changes, i.e., the cost of capital remains constant regardless of the capital structure. However, the issuance of debt, which entails fixed costs which must be paid before the equity holder receives any return, increases the potential variability of the equity holders' return. Thus, as the debt ratio rises, the cost of equity rises.

To illustrate, assume the cost of capital is 9.0% and a utility can raise long-term debt at a cost of 7.5%. The cost of equity to a utility which has a 55%/45% debt/equity capital structure would be:

Cost of Capital:	9.0%
Less: Weighted Cost of Debt	<u>4.125</u>
Weighted Cost of Equity:	4.875%

Weighted Cost of Equity ÷ Equity Ratio = Cost of Equity

4.875% ÷ 45% = **10.8%**.

For a utility that has a capital structure of 80% debt and 20% equity, the cost of capital and debt would remain at 9% and 7.5% respectively, but the cost of equity would be 15%.

For an investor-owned utility which raises debt capital without the benefit of a guarantee and which pays income taxes, which are a deductible expense, the cost of capital does change with capital structure. The deductibility of interest expense creates an incentive to use more debt; the increase in the potential for financial distress and decreased access to capital markets with increasing leverage limits the amount of debt it is prudent to assume. In theory, there is an optimal capital structure at which the cost of capital is minimized.

For a Crown Corporation which pays no income tax and whose debt is unconditionally guaranteed by the Province, the achievement of an optimal capital structure is less compelling. Nevertheless, it is important to maintain financial parameters that permit the utility to be self-supporting. For a Crown Corporation, the capital structure should be sufficiently strong so as to:

(1) ensure the ability of the utility to meet all of its financial obligations without negative impact on the guarantor;

(2) provide the equity shareholder an opportunity to earn a fair return on the earnings retained in the business; and,

(3) result in an overall cost of capital to be borne by the ratepayers that is no higher than would be incurred if the utility were operating on a stand-alone basis (i.e., without a provincial debt guarantee).

IV. BUSINESS RISK OF HYDRO

An evaluation of the business risk allows an assessment of the capital structure and return on rate base that would be reasonable if Hydro were operating on a stand-alone basis. The conclusions lay the groundwork against which Hydro's proposed capital structure targets, guarantee fee and a fair return on common equity can be assessed.

The key elements of an electric utility's business risks include:

- demand/market risks
- operating/supply risks
- regulatory risks.

Demand/market risks are a function of the customer profile, the outlook for economic growth in the service area, demographic trends, and the competitive risks, i.e., the ability of customers to access alternative fuels or an alternative supplier.

Hydro's customer base is comprised largely of one wholesale customer, Newfoundland Power (which accounts for approximately 65% of regulated revenues), four large island industrial customers operating in the cyclical pulp and paper and oil refining industries (15% of revenues) and rural small industrial, commercial and residential customers.

Hydro's market/demand risks effectively mirror those of Newfoundland Power, with the added risks associated with its dependence on a small number of large industrial customers and the obligation to serve a declining rural population.

In the near-term, growth in Newfoundland and Labrador is expected to outpace that of Canada as a whole. For 2003, the forecast real GDP growth rate for the Province is expected to be 5.4%,[1] driven by the Voisey's Bay and White Rose developments, employment gains

1 Government of Newfoundland and Labrador, "The Economy 2003", March 2003.

and a slowing of out-migration. The most recent consensus forecast[2] projects growth for Canada as a whole in 2003 at 2.9%.

While the high levels of growth are anticipated in the near term, they are not expected to persist in the longer-term. Between 2003 and 2008, the Conference Board of Canada (*Provincial Outlook,* Long-Term Forecast 2003) expects real growth in Newfoundland and Labrador to decline to 2.0% annually, compared to 2.8% for Canada as a whole. From 2008-2020, the Conference Board is forecasting a further reduction in real growth in Newfoundland and Labrador to 0.8% annually. These growth rates are materially lower than the 2.5% average annual rate it anticipates for Canada as a whole. The expected decline in growth in the Province arises from a combination of a reduction in the contribution of the oil and gas and metal mining sectors to the Provincial economy over time and a declining population.

The population of Newfoundland and Labrador is s expected to continue to decline as a result of population aging, low fertility and out-migration. The Provincial Government's most likely scenario of population growth forecasts an annual decline of 0.3% per year from 2001-2016.[3] The Conference Board's projection from 2001-2020 is for a higher annual decline of 0.6%. The decline in population is expected to lead to slower growth in personal disposal income, consumer spending, housing starts, and service industry growth.

Further, in addition to out-migration, there is an ongoing shift in population within the province from the rural areas which NLH serves to the urban areas. The obligation to serve a declining rural population will tend to increase NLH's unit cost structure and create some competitive pressures versus alternative energy sources (e.g., oil).

2 Consensus Economics, *Consensus Forecasts*, March 10, 2003.
3 Government of Newfoundland and Labrador, "Demographic Change: Newfoundland & Labrador Issues and Implications", April 2002.

With respect to supply and operating characteristics, NLH operates a system that spans a geographically disperse but relatively sparsely populated service area. To illustrate, the Island Interconnected System covers approximately 110,000 square kilometers, but serves only about 250,000 customers.[4] NLH also provides service to isolated communities on the island of Newfoundland and in Labrador, as well as interconnected service in Labrador. The relatively sparsely populated service area limits Hydro's ability to benefit from economies of scale.

Hydro's generating capacity is 56% hydro, 40% thermal, and 4% diesel (for the isolated communities). A key supply risk relates to hydrological conditions, which determine how much of the electricity is generated by the hydro and thermal facilities respectively. Although NLH is protected from underrecovery of unforecast costs of thermal generation through the operation of its Rate Stabilization Plan (RSP), the amounts in the RSP are amortized over a two-year period; consequently cash flows are sensitive to actual water levels and fuel costs. Further, there is a credit, or counterparty, risk associated with recoveries of amounts that are owed by customers. In particular, the concentration of amounts owed by a small number of the industrial customers, imposes a significant counterparty risk. At year-end 2002, the RSP had a balance to be recovered from customers of approximately $125 million.

Other supply risk issues relate to the impact of deviations from forecast thermal efficiencies, the potential cost implications of older plant and complying with more stringent environmental standards associated with thermal generation facilities, and the potential costs of ensuring reliable service in a disperse service area characterized by extreme weather conditions.

With respect to regulatory risks, the move to rate base/rate of return regulation was characterized as a "Strength" by the Dominion Bond Rating Service (DBRS) in its most recent report analyzing NLH (July 30, 2002). Although the transition to a normal rate of return associated with rate base/rate of return regulation is not yet complete, there is no

4 Includes the indirect retail customers of Newfoundland Power.

evidence that the regulatory environment will be other than reasonable and even-handed.

I would note, however, that S&P has recently expressed concern with the high leverage and low returns of Canadian utilities as a group (investor-owned specifically) relative to their global peers. It has placed a number of Canadian utilities on CreditWatch with negative implications, pending a review of the regulatory environments in which they operate (Standard & Poor's, "Canadian Regulation Reassessed as a Ratings Factor", March 5, 2003). The outcome of S&P's analysis of the various Canadian regulatory jurisdictions is uncertain.

With respect to regulatory policy, the Provincial Government identified a number of issues facing the electric utility industry in Newfoundland and Labrador in its *Electricity Policy Review* (March 2002). In my view, at this juncture, any changes to the regulatory model which might result are too speculative to have altered NLH's business risk profile.

However, the fact that the Newfoundland and Labrador market is relatively small and isolated limits the level of competitive pressure from alternative energy suppliers and the urgency to restructure the industry.

In P.U. 7 (page 41) the Board noted the company's comment regarding the impact on the business risk profile of having the Provincial Government as the Corporation's equity shareholder,

> As a Crown Corporation, NLH may receive directions from its shareholder, the Government of Newfoundland and Labrador, which reflects social or public policy considerations, not in conflict with legislation, which NLH will implement.

Those directives may positively or negatively impact Hydro's inherent business risk profile.[5]

5 To illustrate the potential for a negative impact, the Ontario Government's decision to intervene in its restructured electric utility industry and freeze customer rates has recently led Standard & Poor's to downgrade Hydro One and DBRS to revise Hydro One's outlook to a negative trend. S&P noted in its February 21, 2003 downgrade from A to A-, that government intervention, and the risk of continued intrusion in the regulatory process, has materially increased the company's overall business risk exposure.

Although there is no "bright line" between the Province as shareholder and as the author of public and social policy, to the extent feasible, that distinction must be drawn. As shareholder (and representative of the taxpayers of the Province), the Province should have a reasonable expectation of being provided the opportunity to earn a fair return on its equity investment. That return should explicitly recognize that the earnings retained in the business have an opportunity cost that reflects the return which the funds would have earned if invested in an alternative investment of similar risk.

In conclusion, based on its composite demand, supply and regulatory risks, NLH faces no less business risk than the typical investor-owned electric utility in Canada, including Newfoundland Power.

V. CAPITAL STRUCTURE

Based on my assessment of the business risk of Hydro, to achieve, on a stand-alone basis, a similar debt rating to that of the Province (BBB by DBRS, A- by Standard & Poor's), a capital structure comprised of 60% debt/40% equity would be reasonable.[6]

The debt guarantee, however, transfers to the guarantor (in this case the Province) much of the financial risk associated with the debt of NLH, thus permitting it to operate with a higher debt ratio than a stand-alone utility.

However, not all of the financial risk is transferred to the guarantor. While the debt guarantee ensures that Hydro will not default on its financial obligations, it does not ensure that the shareholder will achieve a compensatory return on investment nor a return of its investment. The higher the debt ratio, the more sensitive the return is to variations in revenues and/or expenses. Consequently, the debt ratio target adopted by the Corporation should not only seek to avoid impairment of the guarantor's credit rating, but also should seek to provide an adequate equity cushion to avoid impairment of the shareholders' investment.

Assuming that the Province continues to guarantee Hydro's debt, in my view, a capital structure containing 80% debt provides the minimal equity cushion compatible with being a self-supporting enterprise.

Hydro's target debt ratio is virtually identical to the median debt ratio for a sample of provincially-owned Crown Corporations. The median 2001 year end debt ratio for the

6 Standard & Poor's assigns business profile scores of "1" – "10" to the utilities it rates, with "1" being the least risky and "10" being the most risky. Based on the scores assigned to different utilities in Canada and the U.S., NLH would likely be assigned a score of between "3" and "4". The debt ratio guidelines for a BBB rating for a business risk profile score of "3" are a range of 53-61%. For a score of "4", the range is 49.5-57.0%.

sample was 78%[7] (see Schedule I). The range of the ratios was 60% (Saskatchewan Power) to 105% (NB Power).[8]

The debt rating agencies have commented on the actual debt ratios of these electric utilities. The most recent DBRS reports on utilities make it clear that DBRS considers debt ratios of 80% and above to be excessive:

Table 1

BC Hydro (81%)	Excessive debt levels constrain profitability.
Hydro-Québec (75%)	High debt levels constrain profitability and contribute to weak interest coverage ratios
Manitoba Hydro (83%)	High debt level weakens most financial ratios
New Brunswick Power (105%)	Excessively high debt levels, weak profitability
Newfoundland & Labrador Hydro (68%)	The medium-term outlook for the Utility's financial profile remains reasonable . . . Over the medium-term, the Utility's financial profile is expected to remain weaker relative to comparable investor-owned utilities.
Saskatchewan Power (60%)	Relatively strong balance sheet

Source: *The Canadian Electric Industry in 2002*, DBRS.

7 Includes the capital structure of Hydro, as reported on a consolidated basis. Exclusive of Hydro, the median debt ratio was 81%.
8 As noted below, NB Power is being restructured and its capital structure is expected to more closely resemble those of investor-owned utilities.

Hydro's target capital structure can also be compared to the targets of the other Crown electric utilities.

BC Hydro's target capital structure is 80% debt/20% equity. In its 2001 Annual Report, BC Hydro stated,

> BC Hydro is required to make an annual Payment to the province on or before June 30 of each year, with respect to the financial results of the most recently completed fiscal year. The payment equals 85% of BC Hydro's distribution surplus provided the debt:equity ratio of BC Hydro after deducting the payment is not greater than 80:20.

A target capital structure of 80% debt and 20% equity was most recently confirmed for NB Power in 1991.[9] However, with the restructuring of the industry in New Brunswick as facilitated by the Electric Act introduced on January 31, 2003, the subsidiaries of NB Power (generation, transmission and distribution) will operate as commercial entities and "will be appropriately capitalized, pay dividends and special payments in lieu of income and capital taxes to the Province, and will no longer be dependent on the Province to guarantee their borrowings."[10] Consequently, it should be expected that the capital structure in the future will more closely resemble those of investor-owned utilities.

Manitoba Hydro is targeting a minimum debt/equity ratio of 75:25 by 2005-06, and has noted the improvement of its debt/equity ratio from 80:20 at March 31, 2001 to 77:23 at March 31, 2002.[11]

Hydro Québec has a minimum target equity ratio of 25%. Dividends may not be declared in an amount which would have the effect of reducing the equity ratio below 25%.[12]

Saskatchewan Power's target capital structure includes a maximum debt ratio of 60%.[13]

9 Decision, May 22, 1991.
10 Communications New Brunswick, "Press Release", January 31, 2003.
11 The Manitoba Hydro-Electric Board 51st Annual Report.
12 Hydro-Quebec, 2001 Annual Report.
13 Sask Power, 2001 Annual Report.

Based on these data, an 80% debt ratio is at the upper end of the range of target debt ratios adopted by other Crown Corporations.

In my opinion, a target capital structure for Hydro of 80% debt represents the upper end of reasonableness even with a debt guarantee.

The ability of Hydro to attain its target capital structure is dependent on maintaining a supportive dividend policy in conjunction with a fair and reasonable return on equity. A supportive dividend policy is one which is predictable to both shareholders and management and thus permits reasonable planning on the part of both. It is also compatible with both the level of the utility's capital budget and the objective of maintaining a reasonable and stable capital structure. The predictability of the dividend policy is also in the best interests of ratepayers, who are then provided with the assurance that the cost of capital they incur in rates will be equal to the cost incurred by Hydro.

As indicated in the Finance and Corporate Services Evidence, a reduction in the dividend payout ratio from 75% of operating income, as indicated in the current policy, to 50% is required to achieve a capital structure approaching the target within a five year period. A reduction in the payout ratio is a reasonable approach to manage the achievement of the proposed capital structure ratios.

For 2004, Hydro is forecasting a regulated capital structure containing 86% debt, above its target level of 80%. There is no evidence that this higher debt ratio will negatively impact on the debt rating of the Province in the near-term. First, the debt rating agencies are concerned with Hydro's financial parameters on a consolidated basis. On this basis, the Corporation's consolidated debt ratios have been under 70% since 1996.

Second, to my knowledge, in only one instance has a debt rating agency noted the negative impact of a Crown Corporation's high debt level on the debt rating of the Province. In December 1999, the Canadian Bond Rating Service (CBRS) changed the Province of New Brunswick's outlook from "stable" to "negative" citing, among other factors, a large writedown of asset value taken by NB Power which reduced its common equity ratio to 1%. In that case, the total debt attributable to NB Power accounted for over 30% of the total outstanding liabilities of the Province, compared to approximately 13% in the case of Hydro.

Despite the low probability that, in the short-term, a higher than target debt ratio will impair the Province's debt rating, a failure to progress toward the target will be perceived as an inability to operate as a self-supporting commercial enterprise.

VI. DEBT GUARANTEE FEE

The Province charges Hydro a fee of 1% to unconditionally guarantee Hydro's debt. The 1% guarantee fee does remain reasonable.

Hydro would not be financially viable at either its forecast capital structure or its target capital structure in the absence of a guarantee. The guarantee allows Hydro to raise debt at yields equivalent to those available to the Province.

Under current market conditions, Hydro would be able to raise long-term debt at a spread of approximately 55-60 basis points over the benchmark long-term Government of Canada bond. By comparison, recent long-term indicated spreads for a sample of investor-owned Canadian utilities with no debt guarantee and at least one rating in the BBB category were as follows:

Table 2

	Debt Rating		Spread
	DBRS	S&P	(basis points)
BC Gas Inc.	A(low)	BBB	210
EPCOR Utilities	A(low)	BBB+	215
Nova Scotia Power	A(low)	BBB+	225
TransAlta Corp.	BBB(high)	BBB+	304

Source: RBC Capital Markets, "Credit Weekly", March 24, 2003.

Based on these data, at a BBB rating on a stand-alone basis, Hydro would not, under current market conditions, be able to raise long-term debt at less than 200 basis points above the long Canada yield. Hence, under current market conditions, the guarantee allows Hydro to raise debt at a cost close to 175 basis points lower than stand-alone utilities in the

A(low)/BBB+ category. Consequently, at recent spreads, the benefit of the guarantee to Hydro's customers is at a historically high level.

However, even if yield spreads between corporate and Provincial bonds contract, it is extremely unlikely that, under most (if not all), market conditions Hydro could raise long-term debt at a rate less than 100 basis points above that accessible by the Province with 80% debt and no debt guarantee. Thus the guarantee fee of 1% is clearly reasonable.

VII. RELATIONSHIP BETWEEN CAPITAL STRUCTURE, DEBT GUARANTEE FEE AND RETURN ON EQUITY

To determine the fair return on shareholder's equity for Hydro in the presence of a debt guarantee and the 1% debt guarantee fee, I start with the proposition that the total compensation to the debt guarantor and the shareholder should be no greater than if Hydro were financed on a stand-alone basis.

The typical Canadian investor-owned electric utility has a capital structure containing approximately 40-45% equity and 55-60% debt[14] (see Schedule I). A fair return on equity for an average risk Canadian electric utility is in the range of 11.25-12.0%, or approximately 11.5% (see Section VIII). The cost of long-term debt to Hydro, assuming a benchmark long-term Canada yield of 6.0% and spread of 75 basis points[15], is approximately 6.75%.

Assuming a stand-alone capital structure (i.e., no debt guarantee) of 60% debt and 40% equity, a cost of new debt of 6.75% and a return on equity of 11.5%, the weighted average cost of capital is:

Table 3

Component	Proportion	Cost Rate	Weighted Component
Debt	60	6.75%	4.05%
Equity	40	11.5%	4.60%
Weighted Average Cost of Capital			**8.65%**

14 With preferred shares treated as 50% debt/50% common equity.
15 Based on the average spread over the last five years.

The 8.65% weighted average cost of capital in Table 3 serves as a proxy for Hydro's overall cost of capital at its target capital structure of 80% debt. Including the debt guarantee fee, the 8.65% cost of capital represents compensation for capital provided by three categories of investors: the debtholders, the debt guarantor, and the equityholder.

The debtholders receive 5.4% (6.75% cost of debt x 80% of capital structure) of the 8.65% cost of capital. This leaves 3.25% available for the debt guarantor and the equity holder. The debt guarantor is currently paid 1% of the outstanding debt (or 0.8%, at the target 80% debt ratio), leaving 2.45% available for the equityholder. The indicated return on equity is 12.25%, that is, 2.45% ÷ 20% equity ratio.

That return is 75 basis points higher than the return on equity of 11.5% estimated for a stand-alone utility with average business risk at a 40% equity ratio.

The 12.25% indicated return on equity is not a measure of the "true" cost of equity to Hydro. It is effectively a residual value. It would be an estimate of the "true" cost of equity if it were clear that the debt guarantee fee represented full compensation to the debt guarantor for assuming the default risks associated with Hydro's debt.

It is not necessary, however, to analyze the required compensation to guarantee the debt since:

- The debt guarantor and the equity shareholder are the same; and,

- It has been demonstrated that the level of the guarantee fee is clearly not excessive.

Consequently, it is only necessary to ensure that the total compensation to the debt guarantor/equity shareholder is fair and reasonable.

As noted above, Hydro is forecasting debt at 86% of capital for the test year, above its target of 80%. Based on the analysis above, the indicated return on equity at an 86% debt ratio is in excess of 14.0%. The approximate 200 basis point increase in the equity return from (12.25% to 14.2%) when the debt ratio increases from 80% to 86% demonstrates the sensitivity of the cost of equity to even small changes in capital structure at very high debt ratios.

The indicated cost of equity is also sensitive to small changes in other assumptions, including the size of the debt guarantee fee. A .25 percentage point increase in the debt guarantee fee (to 1.25%) effectively neutralizes the indicated differential in the equity return requirement at the 80% target debt ratio and that indicated at a stand-alone 60% debt ratio. In light of the sensitivity of the return on equity to the capital structure, debt cost and guarantee fee assumptions, I recommend to the Board that the equity return for Hydro be set at a level no less than that applicable to an average risk Canadian utility, i.e., in the range of 11.25-12.0%.[16]

16 The analysis in support of that range developed in Section VIII.

VIII. RETURN ON COMMON EQUITY FOR AN AVERAGE RISK CANADIAN UTILITY

A. STANDARDS OF FAIR RETURN

There are three standards governing the determination of a fair return which have been articulated in landmark court decisions,[17] as well as numerous utility regulatory decisions. These standards set the parameters for the return requirement necessary to induce investment in public utility assets; they call for a utility to be provided the opportunity to:

- Attract capital on reasonable terms;
- Maintain its financial integrity; and,
- Earn a return on the value of its property commensurate with that of comparable risk enterprises.

These standards remain relevant even though Hydro is a Crown Corporation and its shareholder is the Province (and, thus, ultimately the taxpayers of Newfoundland and Labrador).

The equity funds reinvested in Hydro by the Province have an opportunity cost. The determination of a reasonable return on equity should be independent of the happenstance of the identity of the shareholder. The Province (and taxpayers as shareholders) should expect to earn a return on the equity funds reinvested in Hydro equivalent to the return they could have earned on an alternative investment of comparable risk.

Since Hydro does not have publicly traded shares, I have estimated a fair return on equity by reference to proxies which do have publicly traded stock and whose total (business plus financial) risk would approximate that of Hydro.

17 Northwestern Utilities Ltd., v. Edmonton (1929 S.C.R. 186); Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia (262 U.S. 679, 1923); and Federal Power Commission v. Hope Natural Gas Company (320 U.S. 301, 1944).

I have employed the three tests which are typically utilized in the regulatory arena to determine a just and reasonable return:

Equity Risk Premium Test
Discounted Cash Flow Test
Comparable Earnings Test

The concept of a fair and reasonable return does not reduce to a simple mathematical construct. It would be unjust and unreasonable to view it as such. A fair and reasonable return falls within a range, bounded by the cost of attracting capital and the returns achievable by firms of similar risk to utilities (comparable earnings standard).

B. EQUITY RISK PREMIUM TEST

1. CONCEPTUAL UNDERPINNINGS

The equity risk premium test is derived from the basic concept of finance that there is a direct relationship between the level of risk assumed and the return required. Since an investor in common equity takes greater risk than an investor in bonds, the former requires a premium above bond yields in compensation for the greater risk. The equity risk premium test is a measure of the market-related cost of attracting capital, i.e., a return on the market value of the common stock, not the book value.

The estimation of the required equity risk premium, for either the market as a whole or a specific utility, is not an exact science. Hence, it is necessary to evaluate a broad spectrum of data and alternative risk premium estimation approaches to arrive at a reasonable determination of the required equity risk premium.

There are two broad approaches to estimating the equity risk premium for a utility. The first begins with an estimate of the expected equity risk premium for the entire equity market (i.e., the equity market portfolio), subsequently adjusted to reflect the risk of a utility relative to the market as a whole. The second approach develops the risk premium directly for a particular stock or industry (e.g., utilities). In both approaches, the estimated equity risk premiums are obtained by subtracting the estimated risk-free rate from the estimated expected return on the market portfolio or the individual industry/stock. The expected equity risk premium can be developed: (1) from an analysis of historic market risk premiums and (2) from prospective market risk premiums based on discounted cash flow (DCF) estimates of the expected market return. DCF-based estimates of the cost of equity comprise the dividend yield plus investor expectations of longer-term constant growth.

It is critical to recognize that the equity risk premium test is a <u>forward-looking</u> concept that reflects investor expectations. The magnitude of the differential between the expected return on equities and the yield on bonds is a function of investors' views of such key factors as inflation, productivity, profitability and investors' willingness to take risks.

It is precisely because the risk premium is a forward-looking concept that:

- Historic risk premium data need to be evaluated in light of prevailing economic/capital market conditions; and,

- Direct estimates of the forward-looking risk premium need to supplement measurement of the risk premium by reference to historic data.

2. <u>RISK-FREE RATE</u>

The point of departure for applying the equity risk premium test is a forecast of the risk-free rate to which the equity risk premium is applied. Reliance on a long-term government bond yield as the risk-free rate recognizes (1) the administered nature of short-term rates; and (2) the long-term nature of the assets to which the equity return is applicable. The risk-free rate for purposes of this analysis is the forecast 30-year Canada yield.

The forecast 30-year yield in 2004 is based on the consensus forecast of 10-year Canada bonds plus the spread between 10 and 30-year Canadas. *Consensus Forecasts*, Consensus Economics (March 2003) anticipates that the 10-year yield 3-months and 12-months hence will be 5.2% and 5.7% respectively, for an average of 5.45%. The average March 2003 spread between 10 and 30-year Canadas was 49 basis points, which, when added to the 10-year forecast, indicates a long (30-year) Canada yield of 5.94%, rounded to 6.0%. A 6.0% 30-year Canada yield is a reasonable forecast of the risk-free rate for the 2004 test year.

3. RISK ADJUSTED MARKET RISK PREMIUM TEST

The risk-adjusted market equity risk premium approach to estimating the required utility equity risk premium entails estimating the equity risk premium for the equity market as a whole, and subsequently adjusting it to recognize the risk of a utility relative to the equity market portfolio.

a. Market Risk Premium

The estimate of the expected market equity risk premium is made by reference to an analysis of historic (experienced) market risk premiums. Analysis of historic risk premiums should not be limited to the Canadian experience, but should consider the U.S. equity market to be a relevant benchmark for estimating the equity risk premium from the perspective of Canadian investors.

The estimation of the expected market risk premium from achieved market risk premiums is premised on the notion that investors' expectations are linked to their past experience. Basing calculations of achieved risk premiums on the longest periods available reflects the notion that it is necessary to reflect as broad a range of event types as possible to avoid overweighting periods that represent "unusual" circumstances. On the other hand, the objective of the analysis is to assess investor expectations in the current economic and capital market environment. Hence, focus should be placed on periods whose economic characteristics, on balance, are more closely aligned with what today's investors are likely to anticipate over the longer-term.

Key structural economic changes have occurred since the end of World War II, including:

- The globalization of the North American economies, which has been facilitated by the reduction in trade barriers of which GATT (1947) was a key driver;

- Demographic changes, specifically suburbanization and the rise of the middle class, which have impacted on the patterns of consumption;

- Transition from a resource-oriented/manufacturing economy to a service-oriented economy; and

- Technological change, particularly in the areas of telecommunications and computerization, which have facilitated both market globalization and rising productivity.

Consequently, I have focused on post-World War II returns.

In principle, when historic risk premiums are used as a basis for estimating the expected risk premium, arithmetic averages should be used. The appropriateness of arithmetic averages, as opposed to geometric averages, for this purpose is succinctly explained by Ibbotson Associates (*Stock, Bonds, Bills and Inflation*, 1998 Yearbook, pp. 157-159): [18]

> The expected equity risk premium should always be calculated using the arithmetic mean. The arithmetic mean is the rate of return which when compounded over multiple periods, gives the mean of the probability distribution of ending wealth values . . .in the investment markets, where returns are described by a probability distribution, the arithmetic mean is the measure that accounts for uncertainty, and is the appropriate one for estimating discount rates and the cost of capital.

18 In Robert F. Bruner, Kenneth M. Eades, Robert S. Harris, and Robert C. Higgins, "Best Practices in Estimating the Cost of Capital: Survey and Synthesis", *Financial Practice and Education*, Spring/Summer 1998, pp. 13-28, the authors found that 71% of the texts and tradebooks in their survey supported use of an arithmetic mean for estimation of the cost of equity. One such textbook, Richard A. Brealey and Stewart C. Myers, *Principles of Corporate Finance,* Boston: Irwin McGraw Hill, 2000, p. 157) states, "Moral: If the cost of capital is estimated from historical returns or risk premiums, use arithmetic averages, not compound annual rates of return."

Expressed simply, the arithmetic average recognizes the uncertainty in the stock market; the geometric average removes the uncertainty by smoothing over annual differences.

In arriving at an estimation of the market risk premium, I looked to both Canadian and U.S. historic returns and risk premiums for the following reasons:

First, Canadian investment opportunities are not limited to domestic investments. The risk premium analysis should recognize the increasing globalization of capital markets and the increasing proportion of Canadians' investments in foreign equity securities (particularly U.S. securities).

As Canadian investors became increasingly aware of the mediocre performance of the Canadian equity market, and, given the relatively small size of that market relative to the total global market (approximately 2%), pressure mounted to increase the cap on foreign investments held in RRSPs and pension funds. The 2000 Federal Budget introduced increases which are codified in the Foreign Property Rule; the cap was raised from 20% to 25% in 2000, and to 30% in 2001. Further, new investment products that permit increased exposure to foreign markets, but are deemed as Canadian content, have proliferated.[19] The Association of Canadian Pension Management and the Pension Investment Association of Canada, associations representing Canadian pension funds, have recently urged the Federal Government to remove the cap, citing a study showing that significant value would be added to retirement savings in the absence of a cap.

More generally, investment outside of Canada has continued to grow rapidly as the barriers to foreign investment (in terms of both transactions and information costs) have continued to decline. The Investment Funds Institute of Canada reports indicate that, on average 37% of total non-money market mutual fund assets were invested in foreign/U.S. funds during 2002,

19 "Many large pension plans in Canada are already at the 30% level or more, through the use of synthetic, derivative-based strategies." (*Globe & Mail*, April 2000). To illustrate, clone funds, first introduced in 1999, can invest up to 30% directly in foreign stocks. The remainder is invested in Canadian Treasury bills used as collateral to buy futures contracts in international stock indexes. Because only 30% is directly invested in foreign stocks, investment in the clone fund is counted as "Canadian content".

compared to 29% in early 1997.[20] Foreign stock purchases by Canadians quadrupled between 1996 and 2001, from $98 billion to $380 billion in 2000, and reached $374 billion in 2001. For 2002, foreign stock purchases soared to over $660 billion. Of that total, 50% were U.S. equities and 41% were U.K. equities.[21] Benefits Canada, in "The Top 100 Pension Funds of 2002" (with assets at the end of 2001 of approximately $490 billion), reported that the asset mix of their equity holdings was 53% Canadian, 27% U.S., and 20% EAFE,[22] emerging markets and global equity.

Second, there are factors specific to the historic Canadian returns that cast doubt on the premise that the data are likely to be a good proxy for future returns. Of key importance with respect to the achieved equity returns is the historical resource-orientation of the Canadian equity market. The average achieved returns on the TSE 300 Index were significantly affected by the relatively poor performance of commodity-linked securities. Over the 1956-2001 period (which represents the entire period for which there were data for the TSE 300 – now the S&P/TSX Index), the compound returns of the commodity-based sectors were exceeded by virtually every other sector of the TSE 300.[23]

Further, the TSE 300 came under severe criticism in the late 1990s regarding the quality, size and liquidity of the stocks contained therein. In late 1998, the S&P/TSE 60 was created as a more liquid index than the TSE 300, with more stringent financial criteria for inclusion. Total return data for the S&P/TSE 60 are only available from 1987; however, over the relatively short period 1987-2001, the S&P/TSE 60 outperformed the TSE 300 by 80 basis

20 Excludes the foreign portion of balanced, bond and income, and dividend and income funds, which is not reported separately.
21 Statistics Canada, *Canada's International Transactions in Securities*, December 2002.
22 Europe, Australia, Far East.
23 The compound returns of commodity-based sectors were as follows:

Metals/Minerals	7.3%
Gold	9.0%
Oil and Gas	8.5%
Paper/Forest	7.4%

By comparison the (simple) average compound return of the remaining sectors was 10.7%.

points.[24]

Third, a major impediment to reliance on the Canadian market as the "market portfolio" has been the undue influence of a small number of companies. In mid-2000, before the debacle in Nortel Networks' stock value and BCE's disposal of its 35% share interest in Nortel, these two stocks accounted for 35% of the total value of the TSE 300. To put this in perspective, the largest two stocks in the S&P/TSX index at the end of December 2002 accounted for 10.5% of its total market value; the largest two stocks in the S&P 500 account for approximately 6.5% of its total market value.

Fourth, the Canadian equity market has undergone significant structural change over the periods typically used to measure historic risk premiums. The historic premiums reflect in considerable measure a resource-based economy. At the end of 1980, no less than 46% of the market value of the TSE 300 was resource-based stocks.[25] At the end of December 2002, the corresponding percentage of the S&P/TSX index was approximately 31%.[26] By comparison, the influence of technology-intensive sectors on the index has risen markedly. Table 4, which compares the 1980 and 2002 year-end market weightings of technology/service sectors, highlights the changes over the past two decades.

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24 An alternative Canadian market index, the Morgan Stanley Capital International (MSCI) Canadian Index, for which total return data are available from 1970-2001, outperformed the TSE 300 by 80 basis points over the last three decades.

25 As measured by the oil and gas, gold and precious minerals, metals/minerals, and pulp and paper products sectors. Excludes conglomerates which also contains stocks with significant commodity exposure.

26 Energy and Materials Industry Sectors.

Table 4

	1980	2002
Biotechnology/Pharmaceuticals/ Health Care	0.0%	2.4%
Information Technology	0.9%	4.7%
Telecommunication Services	4.8%	5.7%
Media & Entertainment	0.6%	3.9%
Financial Services	13.5%	32.2%
TOTAL	**19.8%**	**48.9%**

Source: *TSE Review*, December 1980 and December 2002.

Fifth, despite the shift in the make-up, the Canadian market remains significantly less diversified than the U.S. market. There are various sectors of a diversified economy which are relatively underrepresented in the Canadian equity market, e.g., pharmaceuticals and retailing.

Sixth, from 1947-2001, the achieved risk premiums in Canada were two percentage points lower than in the U.S. Of that amount, approximately 60-70 basis points is accounted for by the higher bond yields in Canada. With the improved economic fundamentals in Canada (including significantly improved fiscal performance), the risk associated with Canadian government bonds has declined. Consequently, the differential between Canadian and U.S. government bonds that existed historically, on average, is not expected to persist in the future. Indeed, the most recent long-term consensus forecasts anticipates 10-year government bond yields in the two countries will be very close, averaging 5.9% for Canada and 5.7% for the U.S.[27]

For all of the above reasons, use of the achieved risk premiums in Canada as an estimate of the required risk premium should be undertaken with caution.

27 For Canada, Consensus Economics, *Consensus Forecasts*, October 7, 2002; for the U.S., Blue Chip *Economic Indicators*, October 10, 2002.

In contrast to the TSE 300, the historic U.S. equity returns reflect a more diversified and liquid market. The diversified nature of the U.S. equity market, as well as the close relationship between the Canadian and U.S. capital markets and economies, make the U.S. equity market a relevant historical benchmark for estimating the equity risk premium.[28]

The average post-World War II Canadian risk premiums were in the approximate range of 4.75-5.5% (compound and arithmetic averages respectively). The corresponding U.S. equity risk premiums were in the approximate range of 6.75-7.5% (Schedule VII).

Some recent studies conclude that market equity risk premiums will be lower in the future than have been achieved historically in the U.S. market. The conclusion that the historic U.S. risk premium overstates the future risk premium stems in part from the fact that the magnitude of the achieved risk premiums is due to an increase in price/earnings ratios. That is, the historic market returns on equity reflect appreciation in the value of the stock in excess of that supported by the underlying growth in earnings or dividends. The increase in P/E ratios, it has been argued, reflects a decline in the rate at which investors are discounting future earnings, i.e., a lower cost of capital.

However, the preponderance of the increase in price/earnings ratios in the U.S. market occurred during the 1990s. The P/E ratio[29] of the S&P 500 averaged 14 times from 1926-1989, with no discernable upward trend. From 1989-1998, the P/E ratio rose from 14.7 to a high of 32.3, and averaged 25 times from 1990-2001. At the height of the equity market (1998 to mid-2000), frequently described as a "speculative bubble", investors believed the only risk they faced was not being in the equity market. In mid-2000, the bubble burst, as the U.S. economy began to lose steam. The events of September 11, 2001, the threat of war,

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28 The CRTC recognized the relevance of the U.S. markets in its March 1998 decision (CRTC 98-2), stating, "that the increased integration of world capital markets has a potential impact on the overall Canadian equity market risk premium since it should, in theory, bring the Canadian market risk premium closer to that experienced in the U.S. equity market. Accordingly, the Commission determines that some weight should be given to the U.S. experience in the estimation of the market premium through the equity risk premium method." In CRTC 2002-43 for Telus Québec, July 2002, the Commission gave 30% weight to U.S. data. The Régie de L'Energie de Québec gave explicit weight (40%) to the U.S. risk premium in Decision 99-150 for Gaz Metro (August 1999).

29 Coincident price and earnings.

the loss of credibility on Wall Street, accounting misrepresentations and outright fraud, led to a loss of confidence in the market, and a sense of pessimism about the equity market. These events led to a heightened appreciation of the inherent risk of investing in the equity market, all of which translated into a "bearish" outlook for the U.S. equity market.[30] Despite this, the P/E ratio for the S&P 500 remains at an elevated level[31] relative to history. In late March (March 28, 2003) the S&P 500 forward P/E ratio was 16.

In light of the impact of rising P/E ratios on the achieved total returns, an analysis of the equity returns achieved prior to 1990 was undertaken. That analysis indicates that the achieved equity returns for the S&P 500 averaged 12.3% (compound average) to 13.5% (arithmetic average) from 1947-1989. The corresponding returns from 1947-2001 were 12.4% (compound average) to 13.7% (arithmetic average). Hence, despite the increase in P/E ratios experienced from during the 1990s, the average returns did not change materially. Consequently, it is not unreasonable to expect a U.S. equity market return of 12.0-13.0% in the future, which equates, at the 2003-2004 forecast of the long-term Treasury bond yield of 5.3%,[32] to an equity risk premium of 6.7-7.7%. Over the longer-term, long-term Treasury bond yields are forecast at 6.0%, based on Blue Chip *Economic Indicators* October 10, 2002 long-term forecast of 5.7% for 10-year (2004-2013) Treasury notes, plus the historic 10-year/long-term yield spread of 30 basis points. The indicated market equity risk premium based on the longer-term forecast of long-term Treasury bond yields is approximately 6-7% (12.0-13.0% minus 6.0%).

A review of Canadian equity returns over the same 1947-1989 period indicates similar results. The returns for the Canadian equity market were 11.9% (compound average) to 13.1% (arithmetic average), very similar to the U.S. returns. Both in relation to the near-

30 Lowered expectations for the equity market at present have led investors to focus elsewhere for superior risk/reward opportunities, e.g., real estate, suggesting that the expectations for the equity market at present may be out-of-line with return requirements.
31 Current price/forecast 2003 earnings.
32 Blue Chip *Financial Forecasts*, March 1, 2003.

term (6.0%) and longer-term forecasts (6.25%)[33] of the 30-year Canada bond yield, the achievement of these returns in the future indicates an equity risk premium of 6-7%.

There are also analysts who believe nominal returns in the U.S. market should be lower in the future because inflation is expected to be lower than that experienced historically. (The average rate of inflation in the U.S. from 1947-1989 was 4.4%, compared to a forecast long-term rate of inflation of 2.5%.) That conclusion is derived from financial theory which says that the expected equity return would be comprised of a real risk-free rate, expected inflation and an equity risk premium. Consequently, theory would suggest that, all other things equal, future nominal equity returns would be lower because future inflation is expected to be lower than that experienced over the past half century. However, as indicated in Table 5 below, in reality, achieved equity market returns have tended to be negatively impacted by high rates of inflation, thus producing lower real returns and lower risk premiums when inflation was high and vice versa.

33 Consensus Economics, *Consensus Forecasts*, October 2002 long-term (2004-2012) forecast of 10-year Canada bond yields of 5.9% plus historic spread between 10- and 30-year Canadas of approximately 35 basis points.

Table 5

U.S. RISK PREMIUMS (1926-2001)

Period	Description	Stock Returns	Bond Total Returns	Bond Income Returns	CPI Growth	GDP Growth	Risk Premiums: Total Returns	Risk Premiums: Income Returns
1926-1939	Pre-War, Market Crash, Deflation	9.8%	5.0%	3.1%	-1.6%	1.3% a/	4.8%	6.7%
1940-1951	Growth and Inflation, Early Post World War II	13.2	2.4	2.3	5.5	6.3	10.8	11.0
1952-1967	Steady Low Inflation, Robust Growth	14.8	1.6	3.6	1.6	3.8	13.2	11.2
1968-1982	Rising Inflation, Interest Rates, Stagflation	8.4	6.0	7.9	7.4	2.7	2.4	0.5
1983-1991	Falling Nominal and Real Interest Rates, Moderately High/Steady Inflation	17.8	13.6	9.4	3.9	3.5	4.2	8.4
1992-2001	Low Inflation and Interest Rates; Strong Growth	14.1	9.4	6.5	2.7	3.3	4.7	7.7

a/ 1930-1939

Source: Ibbotson Associates, *Stocks, Bonds, Bills and Inflation,* 2002 Yearbook; Council of Economic Advisors, *Economic Indicators.*

In conclusion, based on the above analysis, with consideration for both compound and arithmetic average returns, and for both the Canadian and U.S. data, a reasonable estimate of the market risk premium is approximately 6.0-6.5%.

b. <u>Relative Risk Adjustment</u>

The 6.0-6.5% market risk premium needs to be adjusted for the risk of a utility relative to that of the market as a whole. The Capital Asset Pricing Model (CAPM), a rigorous, formal model of the equity risk premium test premised on restrictive assumptions, holds that the investor need only be compensated for systematic, or non-diversifiable, risk.

In its simplest form, the CAPM posits the following relationship between the required return on the risk-free investment and the required return on an individual equity security (or portfolio of equity securities):

$$R_E = R_F + b_e (R_M - R_F)$$

where,

R_E = Required return on individual equity security

R_F = Risk-free rate

R_M = Required return on the market as a whole

b_e = Beta on individual equity security.

The CAPM relies on the premise that an investor requires compensation for non-diversifiable risks only. Non-diversifiable risks are those risks that are related to overall market factors (e.g., interest rate changes, economic growth). Company-specific risks, according to the CAPM, can be diversified away by investing in a portfolio of securities whose expected returns are not perfectly correlated. Therefore the shareholder requires no compensation to bear company-specific risks.

The non-diversifiable risk is captured in the beta, which, in principle, is a forward-looking (expectational) measure of the volatility of a particular stock or group of stocks, relative to the market. Specifically, the beta is equal to:

$$\frac{\text{Covariance } (R_E, R_M)}{\text{Variance } (R_M)}$$

The variance of the market return is intended to capture the uncertainty related to economic events as they impact the market as a whole. The covariance between the return on a particular stock and that of the market reflects how responsive the required return on an individual security is to changes in events which also change the required return on the market.

In the context of the CAPM, investor risk can be captured in a single variable, the stock "beta". The stock "beta" measures risk as the volatility of an individual stock or a portfolio of stocks relative to the volatility of the market.

The equity risk premium applicable to a particular stock or portfolio of stocks is equal to its stock "beta" multiplied by the market equity risk premium. Betas are typically measured by reference to historical relative volatility using simple regression analysis between the change in the market portfolio return and the corresponding change in an individual stock or portfolio of stock returns.

However, historic betas cannot simply be assumed to fully capture the risk for which investors require compensation. The body of evidence on CAPM leads to the conclusion that, while betas do measure relative volatility, the proportionate relationship between risk (beta) and return posited by the CAPM has not been established. For example, a number of empirical studies on CAPM have shown that the return requirement is higher (lower) than the CAPM would predict for a low (high) beta stock. [34] Another study concluded the beta return relationship is flat.[35]

To quote Burton Malkiel in *A Random Walk Down Wall Street*, New York: W. W. Norton & Co., 1999:

> Beta, the risk measure from the capital-asset pricing model, looks nice on the surface. It is a simple, easy-to-understand measure of market sensitivity. Unfortunately, beta also has its warts. The actual relationship between beta and rate of return has not corresponded to the relationship predicted in theory during the last third of the twentieth century. Moreover, betas are not stable from period to period, and they are very sensitive to the particular market proxy against which they are measured.

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34 Evidence is found in the following studies:

Fisher Black, Michael C. Jensen, and Myron S. Scholes "The Capital Asset Pricing Model: Some Empirical Tests," *Studies in the Theory of Capital Markets*, edited by Michael Jensen. (New York: Praeger, 1972), pp. 79-121.

Marshall E. Blume and Irwin Friend, "A New Look at the Capital Asset Pricing Model," *Journal of Finance*, Vol. XXVIII (March 1973), pp. 19-33.

Nancy Jacob, "The Measurement of Systematic Risk for Securities and Portfolios: Some Empirical Results," *Journal of Financial and Quantitative Analysis*, Vol. VI (March 1971), pp. 815-834.

35 Eugene F. Fama and Kenneth R. French, "The Cross Section of Expected Stock Returns" *Journal of Finance,* Volume XLVII, No. 2, June 1992.

> I have argued here that no single measure is likely to capture adequately the variety of systematic risk influences on individual stocks and portfolios. Returns are probably sensitive to general market swings, to changes in interest and inflation rates, to changes in national income, and, undoubtedly, to other economic factors such as exchange rates. And if the best single risk estimate were to be chosen, the traditional beta measure is unlikely to be everyone's first choice. The mystical perfect risk measure is still beyond our grasp. (page 238)

The following table summarizes recent calculated ("raw") betas for individual major publicly-traded Canadian regulated electric and gas companies, the TSE Gas/Electric Index, and the S&P/TSX Utilities Index.[36]

TABLE 6

Canadian Utility Betas
(60 months ending in indicated year)

	1995	1996	1997	1998	1999	2000	2001	2002
Seven [1/] Electric/Gas Utilities (Median)	.51	.52	.43	.54	.33	.23	.14	.12
TSE 300 Gas/Electric Index	.52	.52	.46	.55	.38	.21	.17	NA
S&P/TSX Utilities Index	.67	.65	.53	.55	.30	.14	-.03	-.06

[1/] B.C. Gas, Canadian Utilities, Emera, Enbridge Inc., Fortis, TransAlta Corporation and TransCanada PipeLines.

Source: Schedule VIII

The observed recent decline in the measured utility betas in 1999-2002 can be traced to three factors: (1) the technology sector bubble in general; (2) the dominance in the TSE 300 of two firms during this period, Nortel Networks and BCE;[37] and (3) the negative impact of rising interest rates on utility stocks while the rest of the equity market was soaring (See Chart 1 in Statistical Exhibit). As a result, the disparate movements in utility equities

36 The S&P/TSX Utilities Index was created in 2002, when the TSE 300 was revamped. The new Utilities Index is essentially an amalgamation of the former TSE Gas/Electric and Pipeline sub-indices.
37 The impact on the TSE Gas/Electric Index beta due solely to the dominance of Nortel Networks in the TSE 300 can be estimated by excluding Nortel from the TSE 300 and recalculating the beta. The recalculated beta 1997-2001 was 0.37, versus 0.17 inclusive of Nortel.

relative to the TSE 300 produced lower measured utility betas.

The decoupling between utility shares and the rest of the market during the technology bubble (and subsequent melt-down of Nortel and other high tech stocks) should not be interpreted as a change in the relative riskiness of utility shares, but rather as an indication of the weakness of beta as the sole measure of the relative return requirement.[38]

Utilities are interest-sensitive stocks and thus tend to move with interest rates, which frequently move counter to the equity market. Consequently, utility equity price movements are correlated not only with the stock market, but also with movements in the bond market. The interest-sensitivity of utility shares may not be fully captured in the calculated betas which simply measure the covariability between a stock and the equity market.[39]

Given the infirmities of beta, some recognition should be given to total market risk (including both diversifiable and non-diversifiable risk) as measured by the standard deviation of market returns. To compare the relative total risk of Canadian utilities, the monthly standard deviations[40] of total market returns for the S&P/TSX Index and for each of the 10 major Group Indices of the S&P/TSX Index were calculated, over recent five-year periods. The standard deviations for the Utilities Index show that the <u>absolute</u> volatility of utility stocks has risen significantly since the middle of the 1990s from 3.1% for the five year period 1993-1997 to 4.9% during 1998-2002. The 1998-2002 standard deviation of returns for the Utilities Index was close to 60% higher than the corresponding 1993-1997 value (Schedule X).

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38 Schedule IX shows that utilities were not the only companies whose betas were negatively impacted by the speculative bubble and subsequent market decline. To illustrate, the 60 month beta ending 1997 of the Consumer Staples Sector was 0.62; the corresponding 2002 beta was 0.08. In contrast, over the same periods, the beta of the Information Technology Sector rose from 1.57 to 2.28.

39 In theory, the beta should be measured against the entire "capital market" including short-term debt securities, bonds, real estate, etc. In practice, it is measured using the equity market only.

40 The standard deviation measures the absolute volatility of the market returns, i.e., the extent to which the individual monthly returns vary from the average. To illustrate, if the average annual return is 10% and the standard deviation is 4%, two-thirds of the observed returns fall within a range of 6% to 14%.

The relative market volatility of Canadian utility stocks was measured by comparing the standard deviations of the Utilities Index to the standard deviations of the S&P/TSX Index and the average standard deviations of the 10 Group Indices. Table 7 below shows the ratios of the standard deviations of the Utilities Index to those of the S&P/TSX Index and the 10 S&P/TSX Group Indices. Focusing on the relationship between the standard deviation of the Utilities Index and the simple average of the 10 Major Sector Indices, suggests a relative risk adjustment of 0.60-0.65.

Table 7

	Standard Deviation of S&P/TSX Utilities Index as a Percent of:	
Period	**Standard Deviation of S&P/TSX**	**Standard Deviation of 10 S&P/TSX Group Indices (Simple Average)**
1993-1997	88%	64%
1994-1998	81%	65%
1995-1999	83%	63%
1996-2000	89%	69%
1997-2001	86%	67%
1998-2002	84%	62%

Source: Schedule X

It is of note that the same "decoupling" phenomenon was experienced by U.S. utilities. To illustrate this phenomenon, I relied on a sample of nine relatively "pure-play" U.S. electric utilities who qualify as low risk utilities.[41] The calculated, or "raw", betas for the 60-month period ended December 2002 were in the range of –0.45 to 0.39 (mean and median of 0.05).

41 Identified on Schedule XI; criteria for selection described in Section VIII.C.2.

By comparison, the "raw" mean and median betas for the five-year period ended 1998 were 0.28 and 0.30, lower than the "raw" betas of Canadian utilities (Schedule XI).

However, the most recent published betas available to investors for the sample of U.S. electric utilities are approximately 0.60-0.70 (as published by two major financial advisory services – *Value Line* and Bloomberg), considerably higher than the calculated or "raw" betas (Schedule XI). Both of these investment advisory services, which are widely available to investors, adjust the calculated betas toward the market average beta, which is, by definition, 1.0.

The *Value Line* betas remained in a relatively narrow range of 0.65-0.75 from 1993-1998, before the decoupling of the electric utility industry from the overall stock market depressed the electric utility betas to around 0.50-0.55. The most recent *Value Line* betas of 0.69 and 0.70 (mean and median respectively) indicate a return to pre-"bubble/bust" levels (Schedule XI).

Table 8 below shows the average of the 5-year betas for the Canadian utilities for the periods ending 1993-2002 if adjusted in a manner similar to the *Value Line* and Bloomberg approach.[42]

Table 8

Seven Canadian Utilities		TSE 300 Gas/ Electric Utility	S&P/TSX
Mean	**Median**	**Index [1/]**	**Utilities Index**
(Average 1993-2002)			
.58	.62	.64	.64

[1/] Data not available for 2002.

Source: Schedules VIII and XIII.

42 Adjusted utility beta = 2/3 ("raw" beta) + 1/3 (market beta of 1.0); the 2000-2002 "raw" betas were calculated excluding Nortel from the TSE 300, now the S&P/TSX Index (see Schedule XIII).

Based on the analysis of both betas and standard deviations, a reasonable relative risk adjustment for an average risk Canadian utility is approximately 0.60-0.65.

At a market risk premium of 6.0-6.5% and a relative risk adjustment of 0.60-0.65, the indicated equity risk premium for an average risk Canadian utility is approximately 4.0%.

The following two sections summarize the analysis undertaken to estimate the risk premium for utilities directly.

4. HISTORIC UTILITY RISK PREMIUMS

The historic experienced returns for utilities provide an additional perspective on a reasonable expectation for the forward-looking utility equity risk premium. Over the longer-term, achieved utility equity risk premiums were 4.4-4.9% for Canadian gas and electric utilities (TSE 300 Gas/Electric Sub-Index) over the period 1956-2001, based on both geometric and arithmetic average returns. For U.S. electric utilities, the historic equity risk premiums averaged approximately 4.7-5.4% (based on geometric and arithmetic averages) over the entire post-World War II period (1947-2001) (Schedule XIV). The historic risk premiums for both Canadian and U.S. utilities support an expected equity risk premium estimate for an average risk Canadian utility of approximately 4.5-5.0%.

5. DCF-BASED EQUITY RISK PREMIUM TEST

A forward-looking equity risk premium test was also performed, using the discounted cash flow model (DCF) to estimate expected utility returns over time. Monthly DCF estimates were constructed for a sample of U.S. local gas distribution utilities (LDCs), for the period 1993-2002[43] using the consensus of analysts' forecasts of long-term normalized earnings growth, as compiled by I/B/E/S International (a Thomson Financial Company) plus the corresponding expected dividend yield to measure the expected utility return (Schedule XV). The monthly risk premium was equal to the difference between the median DCF cost of

43 Subsequent to Open Access implemented via FERC Order 636.

equity for the sample and the corresponding 30-year long-term Treasury yield.[44]

In conducting this test, I relied on U.S. LDCs for several reasons. First, although there are company-specific business and financial risk differences which must be recognized, U.S. and Canadian utilities are reasonable proxies for one another, particularly in today's global capital market. Second, there is a dearth of forward-looking estimates of growth for Canadian utilities which would permit the creation of a consistent series of DCF costs of equity and corresponding risk premiums from Canadian data. Estimates of investors' growth expectations are a key component of the discounted cash flow model. Third, LDCs were selected because they have not experienced the same degree of restructuring as other regulated industries, e.g., electric utilities.

Hence, reliance on relatively pure-play gas distribution utilities ensures a time series of observations which reflect a relatively stable regulatory environment, and thus allows the estimation of the relationship between the utility equity risk premium and interest rates. Fourth, the level of business risk faced by U.S. LDCs is quite similar to that of an average risk investor-owned Canadian utility.

The sample of eight LDCs (listed on Schedule XVI) is comprised of all local gas distributors:

- classified by *Value Line* as a gas distributor;

- with no less than 85% of assets devoted to natural gas distribution operations;

- whose Standard & Poor's debt rating is A- or higher; and,

- for which at least three analysts' long-term earnings growth rate forecasts are available from the major data bases that provide long-term consensus forecasts, i.e.,

44 The yield on long-term issues (over 25 years to maturity) is used in place of the 30-year Treasury yield subsequent to February 2001, when the Federal Reserve stopped reporting 30-year Treasury yields.

I/B/E/S International and Zacks, to ensure that the results capture the market view, and not simply the view of a single analyst.[45]

As evidenced by the available betas and debt ratings for Canadian utilities compared to those of U.S. LDCs (Schedules II, XIII and XVI), it is possible to infer that the capital market views the typical Canadian utility and U.S. LDCs to be of approximately similar investment risk. To the extent that the sample of U.S. LDCs faces higher business risk than a typical Canadian electric utility, the higher risk is offset by lower financial risks, as indicated by the differences in capital structure. The median 2001 debt ratio for the sample of U.S. LDCs as reported by Standard & Poor's was 50.4%; the median for the major Canadian investor-owned electric utilities with rated debt in 2001 was 56.3% (as reported by DBRS) (Schedules XVI and I).

For the sample of U.S. LDCs, the DCF-based risk premium test indicates an average risk premium over the 1993-2002 period of 4.5% (Schedule XV); the corresponding average long-term government bond yield was 6.2%, close to the longer-term forecasts for both Canada and the U.S.

To test the relationship between interest rates and risk premiums, a simple regression analysis between the 30-year Treasury yields and the corresponding equity risk premiums was conducted, which shows the following:

Equity Risk Premium = 9.24 - .76 (30-year Treasury Yield)

R^2 = 60.7%

At a 30-year government bond yield of 6.0%, the indicated utility equity risk premium is 4.7%.

In light of the increasing spreads between government bond yields and utility bond yields in

45 Zacks Investment Research compiles, analyzes and distributes on-line investment research for individuals and institutional investors.

both Canada and the U.S., the study was expanded to test the relationship between the utility equity risk premiums, long-term government bond yields, and the spread between A-rated utility bond yields and long-term government bond yields.

The analysis indicated the following:

$$\text{LDC Risk Premium} = 7.53 - .56\ \text{TY} + .34\ \text{Spread}$$

where,

TY	=	30-year Treasury Yield
Spread	=	Spread between Moody's A-rated Utility Bond Yields and 30-year Treasury Yields

Thus, the data indicate that, while the utility risk premium is negatively related to the level of government bond yields, it has been positively related to the spread between utility bond yields and government bond yields.[46]

The spread between 30-year Canadian A-rated utility bonds and 30-year Canadas has averaged close to 140 basis points since 1998.[47] Using a forecast long Canada yield of 6.0% and an A-rated utility bond/long Canada spread of 1.4%, the indicated utility risk premium is 4.6%. In summary, the test results indicate a utility equity risk premium of approximately 4.5-4.7%.

6. <u>"BARE-BONES" COST OF EQUITY</u>

On balance, the various risk premium analyses indicate that the required equity risk premium for an average risk Canadian utility is in the approximate range of 4.0-4.75%. At a forecast long Canada yield of 6.0%, the "bare-bones" cost of equity is 10.0-10.75%.

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46 Statistics for the equation:

R^2	63.3%
t-statistics:	
Long-term bond yield:	-6.8
Utility/government bond yield spread:	3.1

47 An increase in corporate-government bond spreads has been observed since the global financial crisis of August 1998.

7. FINANCING FLEXIBILITY ALLOWANCE

An adjustment to the equity risk premium test result for financing flexibility is required because the measurement of the return requirement based on market data results is a "bare-bones" cost. It is "bare-bones" in the sense that if this return is applied to the book equity of the rate base -- and assuming the expected return corresponds to the approved return -- the market value of the utility would be kept close to book value.

The financing flexibility allowance is an integral part of the cost of capital as well as a required component of the concept of a fair return. That allowance is intended to cover three distinct aspects: (1) flotation costs, comprising financing and market pressure costs arising at the time of the sale of new equity; (2) a margin, or cushion, for unanticipated capital market conditions; and (3) a recognition of the "fairness" principle, in the sense that regulation should not seek to keep the market value of a utility stock close to book value, when industrials of comparable investment risk have been able to consistently maintain the real value of their assets considerably above book value.

The financing flexibility adjustment recognizes that return regulation remains, fundamentally, a surrogate for competition. Competitive industrials of reasonably similar risk to utilities have consistently been able to maintain the real value of their assets significantly in excess of book value, consistent with the proposition that, under competition, market value will tend to equal the replacement cost, not the book value, of assets. Utility return regulation should not seek to target the market/book ratios achieved by such industrials, but it also should not preclude utilities from achieving a level of financial integrity that gives some recognition to the longer run tendency for the market value of industrials to equate to the replacement cost of their productive capacity. This is warranted not only on grounds of fairness, but also on economic grounds, to avoid misallocation of resources. To ignore these principles in determining an appropriate financing flexibility adjustment is to ignore the basic premise of regulation.

As a Crown Corporation, Newfoundland Hydro does not raise capital in the public equity markets; therefore it would not incur out-of-pocket equity financing and market pressure costs. However, both the cushion, or safety margin, for unanticipated capital market conditions and the fairness element are integral components of the economic cost of equity. Both should be recognized in the allowed return on equity for a regulated utility, irrespective of ownership. A recognition of these factors warrants a financing flexibility adjustment to the "bare-bones" equity cost of no less than 50 basis points.

Adding a financing flexibility adjustment of 50 basis points to the 10.0-10.75% "bare-bones" cost of equity range results in a return on equity in the range of 10.5-11.25% for an average risk Canadian utility.

C. DISCOUNTED CASH FLOW TEST

1. <u>CONCEPTUAL UNDERPINNINGS</u>

The discounted cash flow approach proceeds from the proposition that the price of a common stock is the present value of the future expected cash flows to the investor, discounted at a rate which reflects the riskiness of those cash flows. If the price of the security is known (can be observed), and if the expected stream of cash flows can be estimated, it is possible to approximate the investor's required return (or capitalization rate) as the rate which equates the price of the stock to the discounted value of future cash flows.

Although it has flaws, the DCF model has one distinct advantage over risk premium estimates, particularly those made using the CAPM. It allows the analyst to directly estimate the utility cost of equity. In contrast, the CAPM indirectly estimates the cost of equity. The results of the DCF method can then be used, at a minimum, as a means to test the validity of the CAPM results. Further, in light of the recent volatility in the equity markets, and the rapid shifts in investors' risk perceptions, it is important to rely on multiple approaches to estimating the cost of capital.

Theoretically, the cash flows considered in the DCF model extend to infinity. However, as the expected cash flows extend further into the future, their discounted value adds less and less to the price of the stock. Investors in common stocks are unlikely to forecast (or be able to forecast with any accuracy) cash flows beyond five years.

There are multiple versions of the discounted cash flow model available to estimate the investor's required return. An analyst can employ a constant growth model or a multiple period model to estimate the cost of equity. In my analysis, I relied on the constant growth model, which rests on the assumption that investors expect cash flows to grow at a constant rate throughout the life of the stock. The assumption that investors expect a stock to grow at a constant rate over the long-term is most applicable to stocks in mature industries.

Growth rates in these industries will vary from year to year and over the business cycle, but will tend to deviate around a long-term expected value. As a pragmatic matter, the application of a constant growth model is compatible with the likelihood that investors do not forecast beyond five years. Hence, in that context the current market price and dividend yield would not explicitly anticipate any changes in the outlook for growth.

The constant growth model is expressed as follows:

$$\text{Cost of Equity (k)} = \frac{D_1}{P_o} + g,$$

where,

D_1 = next expected dividend[48]
P_o = current price
g = constant growth rate

2. PROXY UTILITIES

The discounted cash flow test was applied to a sample of relative "pure play" U.S. integrated electric utilities that serve as a proxy for Hydro.[49]

48 Alternatively expressed as D_o (1 + g), where D_o is the most recently paid dividend.
49 The rationale for reliance on U.S. utilities was discussed in the context of the DCF-based risk premium test.

The sample of nine companies (listed on Schedule XVII) is comprised of all electric utilities:

- classified by *Value Line* as an electric utility;
- with no less than 90% of assets devoted to electric utility operations;
- whose Standard & Poor's debt rating is BBB- or higher; and,
- for which at least three analysts' long-term earnings growth rate forecasts are available from the major data bases that provide long-term consensus forecasts, to ensure, as with the selection of the LDCs, that the results capture the market view, and not simply the view of a single analyst.

3. <u>INVESTOR GROWTH EXPECTATIONS</u>

The growth component of the DCF model is an estimate of what investors expect over the longer-term. For a regulated utility, whose growth prospects are tied to allowed returns, the estimate of growth expectations is subject to circularity because the analyst is, in some measure, attempting to project what returns the regulator will allow, and the extent to which the utilities will exceed or fall short of those returns. To mitigate that circularity, it is important to rely on proxies, rather than the subject company. Further, to the extent feasible, one should rely on estimates of longer-term growth readily available to investors, rather than superimpose on the analysis one's own view of what growth should be.

The estimates of investor growth expectations rely on consensus forecasts of long-term earnings growth. Specifically, the two widely available sources referenced above in conjunction with the sample selection criteria, I/B/E/S International and Zacks, were utilized, the same sources used in applying the DCF-based risk premium test. Historic growth rates were not utilized, for several reasons:

First, various studies have concluded that analysts' forecasts are a better predictor of growth than naïve forecasts equivalent to historic growth; moreover, analysts' forecasts have been shown to be more closely related to investors' expectations than historic growth rates.[50]

Second, to the extent history is relevant in deriving the outlook for earnings, it should already be reflected in the forecasts. Therefore, reliance on historic growth rates is at best redundant, and, at worst, potentially double counting growth rates which are irrelevant to future expectations.

Third, to the extent that restructuring in the industry has altered investors' growth expectations relative to history, historical growth rates are highly suspect as a measure of investor expectations. This is especially true of the electric utility industry.

Fourth, reliance on historic growth rates to measure investor expectations to some extent renders the replication of that growth a self-fulfilling prophesy.

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50 Empirical studies that conclude that investment analysts' growth forecasts serve as a better surrogate for investors' expectations than historic growth rates include: Lawrence D. Brown and Michael S. Rozeff, "The Superiority of Analyst Forecasts as Measures of Expectations: Evidence from Earnings", *The Journal of Finance*, Vol. XXXIII, No. 1, March 1978; Dov Fried and Dan Givoly, "Financial Analysts Forecasts of Earnings, A Better Surrogate for Market Expectations", *Journal of Accounting and Economics,* Vol. 4 (1982); R. Charles Moyer, Robert E. Chatfield, Gary D. Kelley, "The Accuracy of Long-Term Earnings Forecasts in the Electric Utility Industry", *International Journal of Forecasting* Vol. I (1985); Robert S. Harris, "Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return", *Financial Management*, Spring 1986, and, James H. Vander Weide and William T. Carleton, "Investor Growth Expectations: Analysts vs. History", *The Journal of Portfolio Management*, Spring 1988; David Gordon, Myron Gordon and Lawrence Gould, "Choice Among Methods of Estimating Share Yield," *The Journal of Portfolio Management*, Spring 1989.

The Vander Weide and Carleton study cited

> found overwhelming evidence that the consensus analysts' forecast of future growth is superior to historically oriented growth measures in predicting the firm's stock price [and that these results] also are consistent with the hypothesis that investors use analysts' forecasts, rather than historically oriented growth calculations, in making stock buy-and-sell decisions.

The Gordon, Gordon and Gould study concluded,

> …the superior performance by KFRG [forecasts of [earnings] growth by securities analysts] should come as no surprise. All four estimates [securities analysts' forecasts plus past growth in earnings and dividends and historic retention growth rates] rely upon past data, but in the case of KFRG a larger body of past data is used, filtered through a group of security analysts who adjust for abnormalities that are not considered relevant for future growth.

Reliance on long-term earnings forecasts in the context of a constant growth DCF test recognizes that the two sources of cash flows to the investor, dividends and capital appreciation, must be generated from earnings. The latter results from replowing, or retaining, earnings.

4. APPLICATION OF THE CONSTANT GROWTH DCF MODEL

The DCF model was applied to the sample of U.S. electric utilities using the following inputs:

- the annualized dividend paid during the three months ending January 31, 2003 as D_o;
- the average of the monthly high and low prices for the three months ending January 31, 2003 as P_o; and,
- the average of the most recent I/B/E/S (January 2003) and Zacks (February 2003) consensus earnings growth forecasts[51] to estimate "g" in the growth component and to adjust the current dividend yield to the expected dividend yield.

Based on both the mean and median DCF costs of equity for the sample, the estimated required return on the current (market) value of common equity is in the range of 11.5-11.7% (Schedule XVIII).

The reasonableness of the previous results were tested using *Value Line* longer-term (2005-2007) forecast sustainable growth rates.

Sustainable growth, or earnings retention growth, is premised on the notion that future dividend growth depends on the firm reploughing or retaining a portion of its earnings, in order to produce dividends in the future. The sustainable growth rate is estimated as the

51 Studies have shown that analysts' forecasts are optimistic; however, as long as investors accept the analysts' views, the optimism in the forecasts is also reflected in the stock prices. Thus the resulting DCF estimate is an unbiased estimate of the utility cost of equity.

expected return on equity multiplied by the fraction of earnings expected to be retained, expressed as:

$$g = b(r)$$

where:

g	=	growth
b	=	fraction of earnings retained
r	=	expected return on equity

As shown in detail on Schedule XIX, using the sustainable growth estimates, the sample median DCF cost was 10.4%; the sample mean was 10.7%.

Based on the results using both analysts' earnings forecasts and the sustainable growth estimates, the DCF test indicates a cost of equity of approximately 10.5-11.5% (mid-point of 11.0%) for an average risk integrated U.S. electric utility.

5. DCF COST OF EQUITY AND RETURN ON BOOK EQUITY

The DCF cost for the electric utilities of approximately 11.0% represents the return investors expect to earn on the current market value of their utility common equity investments. It is not, however, the return that investors expect the LDCs to earn on the book value of their common equity. *Value Line*, which publishes projections of utility ROEs quarterly, anticipates that the ROE for the sample of nine electric utilities will be in the range of 12.3% (mean) to 12.5% (median) (2005-2007) (Schedule XIX).

There is, however, a "disconnect" in logic if investors expect the allowed return on equity to be equal to the DCF cost of equity when the market value deviates materially from the original cost book value to which the allowed return is applied. This has clearly been the case during the last business cycle. The average market/book ratio of the U.S. electric utilities from 1993-2002 was 169% (Schedule XX).

To illustrate the problem, assume that a utility whose market/book ratio is 165% were expected to only earn a return on book value equal to the DCF cost of equity of 11.0%. The market price of that utility's stock would tend to decline to book value, so that investors experience a capital loss of 43%. The idea that investors are willing to pay a price equal to 165% of book value in order to see the market value of their investment drop by 43% is illogical.[52]

There is no logical reason to conclude that market value should equal book value when one recognizes that regulation is intended to emulate competition. Under competition, equity market values tend to gravitate toward the replacement cost of the underlying assets. Absent inflation, the market value of firms operating in a competitive environment would tend to equal their book value or cost. This is due to the proposition that, if the discounted present value of expected returns (market value) exceeds the cost of adding capacity, firms will expand until an equilibrium is reached, when the market value equals the replacement cost of the productive capacity of the assets. However, the fact that inflation has occurred changes the above analysis. With inflation, under competition, the market value of a firm trends toward the current cost of its assets. The book value of the assets in contrast, reflects the historic depreciated cost of the assets. Since there have been moderate to relatively high levels of inflation over the past two business cycles (1982-1991 and 1992-2001), one would expect the market value of utilities to deviate systematically from the book value.

On principle, for a market-derived cost of equity (e.g., derived via the DCF or risk premium

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52 To illustrate, assume a utility's book value is $10.00 and its stock sells at $16.50 (so that its market-to-book ratio is 165%); the expected return on book value is 12.5% (earnings per share of $1.25); and its expected payout ratio is 65% (dividend per share of $0.81). An application of the DCF formula would show a current dividend yield of 4.9% ($0.81 / $16.50), and a longer-term "sustainable" growth rate of 4.38% (35% x 12.5%, i.e., sustainable growth = percent of earnings retained x return on equity), for a DCF cost of 9.3%.

If the calculated DCF cost of 9.3% were applied to book value, earnings would decline to $0.93 per share ($10.00 x 9.3%), the payout ratio would rise to 87% ($0.81 / $0.93) and the longer-term growth rate would decline to 1.2%, calculated as (1.0 - .87) x 9.3%. Hence, investors' expectations for growth of 4.38% would not be realized, and the stock price would decline to book value. The expected return on the revalued stock would be 9.3%, comprised of a dividend yield of 8.7% ($0.87 / $10.00) and growth of only 1.2%. However, the realized holding period return for an investor purchasing the stock at $16.50 per share (assuming a one year work-out period) would be a capital loss of 61%. The proposition that investors are willing to invest $16.50 per share to end up with a stock whose value is $10.00 defies common sense.

test) to produce a return compatible with the premise that regulation is a surrogate for competition, the cost of equity should be adjusted to reflect the replacement cost/book value ratio. Economic theory indicates that the replacement cost/book value ratio should correspond to the long-run equilibrium market/book ratio.[53] The replacement cost/book value ratio is, in turn, an estimate of the expected long-run equilibrium market value/book ratio that should be anticipated under competition.

To mitigate the problem created by the divergence between market and book values, at a minimum, the DCF test result should be augmented by the same increment for financial flexibility as applicable to the equity risk premium test results, i.e., a minimum allowance of 50 basis points. An adjustment to the DCF cost of equity of 10.5-11.5% for financing flexibility results in a return on book equity of 11.0-12.0%.

D. COMPARABLE EARNINGS TEST

1. <u>CONCEPTUAL UNDERPINNINGS</u>

The comparable earnings test provides a measure of the fair return based on the concept of opportunity cost. Specifically, the test arises from the notion that capital should not be committed to a venture unless it can earn a return commensurate with that available prospectively in alternative ventures of comparable risk. Since regulation is a surrogate for competition, the opportunity cost principle entails permitting utilities the opportunity to earn a return commensurate with the levels achievable by competitive firms facing similar risk. The comparable earnings test, which measures returns in relation to book value, is consistent with the original cost rate base form of regulation.

53 By repricing the equity of the electric utilities for past inflation, an approximation of the replacement cost can be made. To reprice the equity, each annual increment to common equity must be increased to reflect inflation experienced from the time the equity was added to the present. The total repriced equity is a proxy for replacement cost. The total repriced equity is then compared to the original cost book value of the equity to arrive at an estimate of the replacement cost/book value ratio. The resulting replacement cost/book value for the sample of electric utilities was 1.52 (median) at the end of 2002, well in excess of 1.0 (See Schedule XVII).

The comparable earnings test is an implementation of the comparable earnings standard, as distinguished from the cost of attracting capital standard. The comparable earnings standard recognizes that utility costs are measured in vintaged dollars and that rates are based on accounting costs, not economic costs. In contrast, the cost of attracting capital standard relies on costs expressed in dollars of current purchasing power, i.e., a market-related cost of capital. In the absence of experienced inflation, the two concepts would be quite similar, but the impact of inflation has rendered them dissimilar and distinct.

The concept that regulation is a surrogate for competition may be interpreted to mean that the combination of an original cost rate base and a fair return should result in a value to investors commensurate with that of competitive ventures of similar risk. The fact that an original cost rate base provides a starting point for the application of a fair return does not mean that the original cost of the assets is a measure of their fair value. The comparable earnings standard, as well as the principle of fairness, suggest that, if competitive industrial firms facing similar risk to utilities are able to maintain the value of their assets considerably above book value, the return allowed to utilities should not seek to maintain the value of utility assets at book value. It is critical that the regulator recognize the comparable earnings standard when setting a just and reasonable return.

2. PRINCIPAL APPLICATION ISSUES

The principal issues in the application of the comparable earnings test are:

- The selection of a sample of industrials of reasonably comparable risk to an average risk Canadian utility.

- The selection of an appropriate time period over which returns are to be measured in order to estimate prospective returns.

- The need for an adjustment to the "raw" comparable earnings results to reflect the differential risk of an average risk Canadian utility relative to the selected industrials.

3. SELECTION OF INDUSTRIALS

The selection process starts with the recognition that industrials are generally exposed to higher business risk, but lower financial risk, than an average risk Canadian utility. The selection of industrials focuses on total investment risk, i.e., the combined business and financial risks. The comparable earnings test is based on the premise that industrials' higher business risks can be offset by a more conservative capital structure, thus permitting selection of industrial samples of reasonably comparable investment risk to an average risk Canadian utility.

Utilities are generally characterized by relatively low volatility with respect to both earnings and stock market performance. Consequently, the initial universe (275 companies) was comprised of all companies in the S&P/TSX Index in Global Industry Classification Standard (GICS) sectors 20-30. The sectors represented by the GICS codes in this range are: Industrials, Consumer Discretionary and Consumer Staples.[54] The resulting sample contained 90 firms.

From this group of 90 companies,[55] all firms with missing book equity or negative common equity during the period 1990-2001, and/or missing market data (December 1996 to December 2001) were removed, as were all companies which paid no dividends in any year 1992-2001. To ensure that low risk companies were selected, all companies with betas over 0.70 were removed, as well as any companies whose stock is ranked Higher Risk by the Canadian Business Service (CBS).[56] The final sample of low risk Canadian industrials is comprised of 15 companies (Schedule XXI).

54 Included in these sectors are major industries such as: Food Retail, Food Distributors, Tobacco, Packaged Foods, Soft Drinks, Distillers, Household Appliances, Aerospace and Defense, Electrical Components & Equipment, Industrial Machinery, Publishing & Printing, Department Stores, and General Merchandise

55 SNC-Lavalin was removed due to its recent purchase of regulated electric transmission assets in Alberta.

56 Canadian Business Service (CBS) ranks stocks “Very Conservative”, “Conservative”, “Average”, “Higher Risk”, or “Speculative”.

4. TIME PERIOD FOR MEASURING RETURNS

Since industrials' returns on equity tend to be cyclical, the appropriate period for measuring industrial returns should encompass an entire business cycle, covering years of both expansion and decline. That cycle should be representative of a future normal cycle, e.g., similar in terms of inflation and real economic growth. Over the past trough-to-trough business cycle (1992-2001), the experienced returns on equity of the sample of 15 industrials were as follows.

Table 9

Returns for Canadian Industrials 1992-2001	
Average	14.0%
Median	13.4%
Average of annual medians	12.7%

Source: Schedule XXI

Focusing on the median values, the returns are in the approximate range of 12.75-13.5%.

The average economic growth during this cycle was 3.2%, compared to the consensus forecast growth rate of approximately 3.0% for the next decade (2002-2012).[57] Prospective longer-term Canadian inflation is forecast to average 1.9% (CPI),[58] only slightly higher than the average level achieved during the 1992-2001 business cycle (1.7%) (Schedule XXII). The moderately lower expected real growth, but similar inflation relative to the past business cycle, indicate that the experienced returns on book equity, absent extraordinary events, provide a reasonable, and potentially conservative, proxy for the future.

This conclusion is supported by the increase in the level of returns achieved during the cycle, from 10.5% (based on the average of annual medians) in 1992-1995 to 14.2% in 1996-2001. The 1992-1995 average of 10.5% reflects in part the effect of the prolonged recession and

57 Consensus Economics, *Consensus Forecasts*, October 2002.
58 Consensus Economics, *Consensus Forecasts*, October 2002.

restructuring. The more recent average (1996-2001) return of 14.2% reflects a level of returns similar to those achieved during the prior (1983-1991) business cycle.

5. RISK COMPARISON

With respect to the relative investment risk of the Canadian industrials compared to utilities, the business risk of the industrials exceeds that of utilities; however, this difference is largely offset by the industrials' significantly lower financial risk resulting from higher equity ratios (57% in 2001 compared to approximately 38% on average for Canadian gas and electric utilities) (See Schedules XXIII and III, page 2). Comparison of the industrials' and utilities' bond ratings and stock ratings indicate that they are in a similar risk class. The median Canadian Business Service stock rating for the industrials is "Very Conservative", equal to the median for a sample of seven investor-owned Canadian gas and electric utilities with publicly-traded stock.[59] The median S&P and DBRS debt ratings for the industrials are BBB+ and A(low) respectively, compared to the utilities' median ratings of BBB+/A- and A (See Schedules XXIII and II). The recent median adjusted beta for the industrials was 0.56, compared to the longer-term beta for the utilities of 0.60-0.65 (See Schedules XXIII and VIII).

Based on these comparisons, on balance, the Canadian industrials and utilities are of similar investment risk. Consequently, the industrial returns require no adjustment for differential risk compared with an average risk Canadian utility. As a result, the comparable earnings test applied to Canadian industrials indicates a return in the range of approximately 12.75-13.5%.

6. IMPACT OF CHANGES IN CORPORATE INCOME TAX RATES

The after-tax returns achieved over the past cycle reflect higher corporate tax rates than projected for the future. The average actual tax rate for the sample over the 1992-2001 period was 38%. With the reduction in federal tax rates to 21% by 2004 and in provincial rates (potentially to 8% in Alberta and Ontario), the after-tax returns, all other things equal,

59 BC Gas, Canadian Utilities, Enbridge Inc., Emera, Fortis, TransCanada PipeLines and TransAlta Corporation.

will be higher. To illustrate, a 12% after-tax return on equity at a 38% combined federal/provincial tax rate is equivalent to a pre-tax return of 19.4%. A reduction in the effective corporate tax rate from 38% to 29% increases the after-tax return to 13.8%. Hence, the historic after-tax returns on equity are a conservative measure of future after-tax returns.

7. <u>CONCLUSIONS</u>

The estimate of a normal cycle average level of returns for low risk Canadian industrials is in the range of 12.75-13.5%. Since the level of investment risk faced by the industrials is similar to that of an average risk Canadian utility, no risk adjustment to those returns is required. Consequently, the comparable earnings test indicates a return in the range of approximately 12.75-13.25%.

E. FAIR RETURN ON EQUITY FOR AN AVERAGE RISK CANADIAN UTILITY

The results of the three tests used to estimate a reasonable return on equity for an average risk Canadian utility are summarized below:

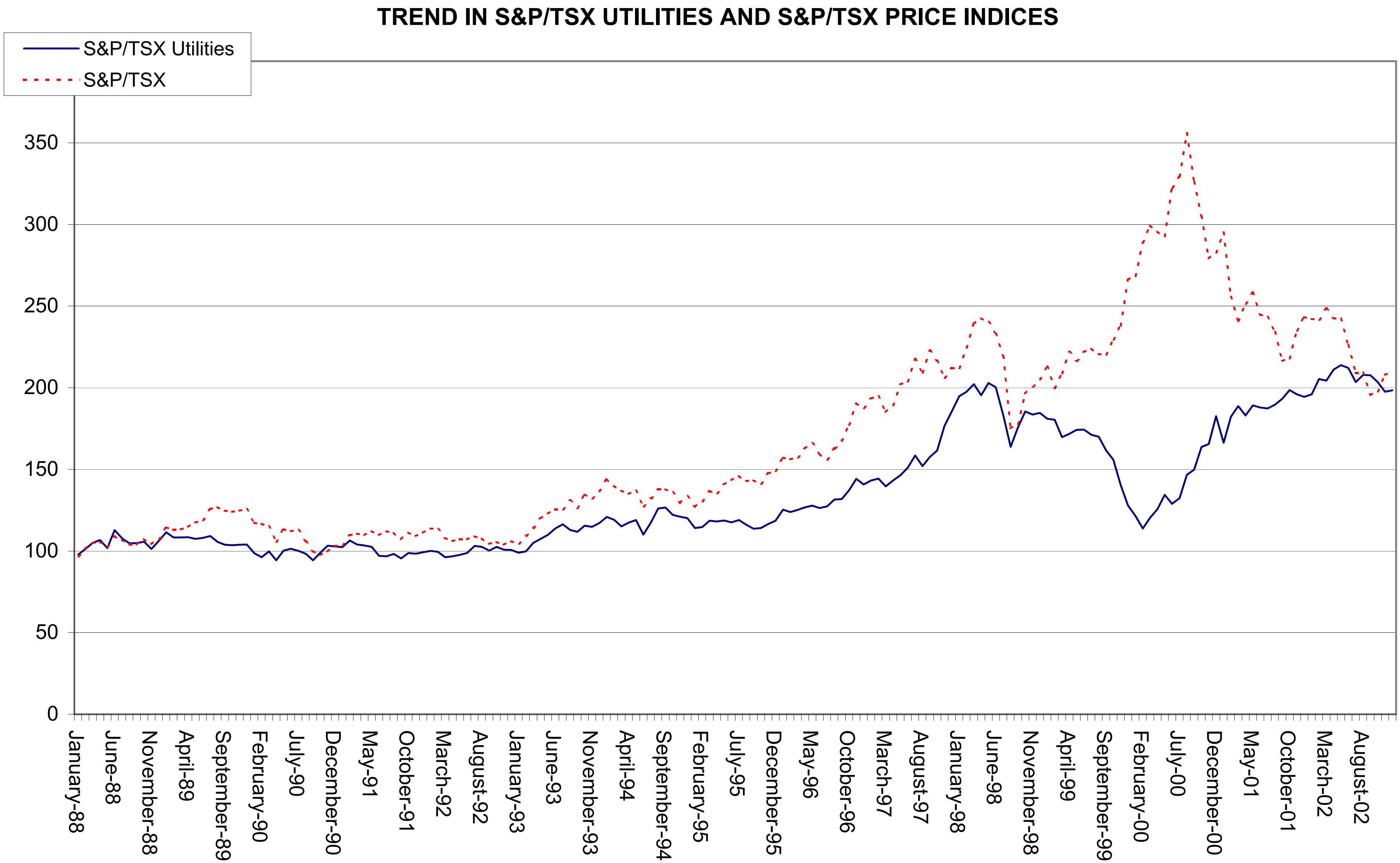
Equity Risk Premium	10.5-11.25%
Discounted Cash Flow	11.0-12.0%
Comparable Earnings	12.75-13.25%

In arriving at a reasonable return on equity for an average risk Canadian utility, I have given primary weight to the cost of attracting capital, as measured by both the equity risk premium and DCF tests. However, the comparable earnings test is entitled to significant weight in setting a fair return that balances both ratepayer and shareholder interests. Based on these results, a fair return for an average risk Canadian utility is in the range of 11.25-12.0%, or approximately 11.5%.

COST OF CAPITAL

LIST OF SCHEDULES

CHART I



TREND IN S&P/TSX UTILITIES AND S&P/TSX PRICE INDICES
S&P/TSX Utilities
S&P/TSX
350
300
250
200
150
100
50
0
January-88
June-88
November-88
April-89
September-89
February-90
July-90
December-90
May-91
October-91
March-92
August-92
January-93
June-93
November-93
April-94
September-94
February-95
July-95
December-95
May-96
October-96
March-97
August-97
January-98
June-98
November-98
April-99
September-99
February-00
July-00
December-00
May-01
October-01
March-02
August-02

FINANCIAL PARAMETERS FOR CANADIAN ELECTRIC UTILITIES

	DBRS Debt Rating	Debt Ratio 1/ (2001)	Pre-tax Interest Coverage 1999	2000	2001
Provincially Owned and Guaranteed 2/					
BC Hydro	AA(low)	81.0	1.91	2.40	1.54
Hydro-Quebec	A	74.7	1.29	1.34	1.36
Manitoba Hydro	A	82.9	1.31	1.53	1.39
NB Power	A	105.3	1.10	1.10	1.20
Newfoundland and Labrador Hydro	BBB	68.2	1.51	1.17	1.39
Saskatchewan Power	A	60.0	1.71	1.85	1.39
Median	**A**	**77.9**	**1.41**	**1.44**	**1.39**
Government Owned - Not Guaranteed					
EPCOR Utilities	A(low)	63.2	1.84	1.98	3.29
Hydro One	A	56.1	2.45	2.50	2.65
Hydro Ottawa	A(low)	56.6	3.10	NMF	NMF
ENMAX Corporation	A(low)	19.1	4.15	2.62	10.53
Enersource Corporation (Hydro Mississauga)	A(low)	61.4	NMF	1.51	1.12
Toronto Hydro	A(low)	63.0	6.04	0.82	1.57
Veridian Corporation	A(low)	54.1	-0.70	0.18	0.42
Median	**A(low)**	**56.6**	**2.78**	**1.75**	**2.11**
Investor Owned					
AltaLink 3/	A(high)	59.9	NA	NA	2.01
Aquila Networks Canada (Alberta)	A	56.3	NA	1.87	1.97
Aquila Networks Canada (BC)	BBB(high)	57.4	2.20	2.19	2.41
CU Inc.	A(high)	54.9	3.12	2.77	2.64
Newfoundland Power	A	56.2	2.49	2.57	2.70
Nova Scotia Power	A(low)	59.1	2.28	2.29	2.32
TransAlta Utilities	A(low)	52.3	2.63	2.00	6.12
Median	**A**	**56.3**	**2.49**	**2.24**	**2.41**

1/ Includes those preferred shares treated by debt rating agencies as debt equivalents (e.g., term preferred shares, retractible preferred shares)
2/ Ratings are a flow - through of the ratings of the Province
3/ Values as of September 2002.

Source: DBRS, The Canadian Electric Industry in 2002.

DEBT AND COMMON STOCK QUALITY RATINGS
OF MAJOR INVESTOR-OWNED CANADIAN GAS AND ELECTRIC UTILITIES

Company	Debt Rated	DBRS Bond Rating	S&P Bond Rating	CBS Stock Ranking
Aquila Networks Canada (British Columbia) Inc.	Secured Debentures	BBB(high)	NR	NR
BC Gas Utility	Senior Secured	A	A-	Very conservative
	Senior Unsecured	A	BBB+	
CU Inc.	Senior Unsecured	A(high)	A+	Very conservative
Enbridge Gas Distribution Inc.	Senior Unsecured	A	A-	Very conservative
Enbridge Inc.	Senior Unsecured	A	A-	Very conservative
Gaz Metropolitain	Senior Secured	A	A	NR
Maritime Electric	Senior Secured	NR	A-	Very conservative
Newfoundland Power	Senior Secured	A	A	Very conservative
Nova Scotia Power	Senior Unsecured	A(low)	BBB+	Very conservative
Pacific Northern Gas	Senior Secured	BB(high)	NR [2/]	Average
TransAlta Utilities	Senior Secured	A	A-	Very conservative
	Senior Unsecured	A(low)	BBB+ [1/]	
TransCanada PipeLines Ltd.	Senior Unsecured	A	A-	Very conservative
Union Gas Limited	Senior Unsecured	A	A-	Very conservative
Westcoast Energy	Senior Unsecured	A(low)	A-	Very conservative

1/ Corporate Rating
2/ Withdrawn by Company; BB- prior to withdrawal

Note: Debt ratings are for utility; Stock rankings are for parent.

Source: DBRS Bond Ratings, Standard & Poor's, The Blue Book of CBS Stock Reports.

CAPITAL STRUCTURE RATIOS OF MAJOR INVESTOR-OWNED CANADIAN ELECTRIC UTILITIES, GAS DISTRIBUTORS AND PIPELINES (2001)

Company	Long-term Debt a/	Short-Term Debt	Preferred Stock Classified as Debt b/	Preferred Stock b/	Common Stock Equity c/
Electric Utilities					
Aquila Networks Canada (B.C.) Inc.	57.4	0.0	0.0	0.0	42.6
CU Inc.	52.4	0.1	0.0	7.7	39.7
Maritime Electric	46.8	11.8	0.0	0.0	41.5
Newfoundland Power	43.3	12.4	0.0	1.6	42.7
Nova Scotia Power	47.3	7.9	0.0	9.4	35.4
TransAlta Utilities	34.3	2.4	0.0	31.1 d/	32.2
Gas Distributors					
BC Gas Utility	58.7	9.7	0.0	0.0	31.6
Enbridge Consumers Gas	40.8	10.8	0.0	11.6 d/	36.8
Gaz Metropolitain	59.9	1.8	0.0	0.0	38.3
Pacific Northern Gas	48.3	5.1	0.0	2.9	43.7
Union Gas	51.9	16.1	0.0	3.3	28.7
Pipelines					
Enbridge Inc.	55.9	17.0	3.0	1.1	23.0
TransCanada PipeLines Ltd.	58.4	2.1	4.1	2.4	33.1
Westcoast Energy Inc.	64.9	7.5	0.0	5.6	21.9
Averages					
Electric Utilities	**46.9**	**5.8**	**0.0**	**8.3**	**39.0**
Gas Distributors	**51.9**	**8.7**	**0.0**	**3.6**	**35.8**
Electric / Gas Utilities	**49.2**	**7.1**	**0.0**	**6.2**	**37.6**
All Companies	**51.5**	**7.5**	**0.5**	**5.5**	**35.1**

a/ Includes current portion of long-term debt.
b/ Includes minority interest in preferred shares of subsidiary companies.
c/ Includes minority interest in common shares of subsidiary companies.
d/ Includes financing of inter-corporate investment in preferred securities. Common Equity ratios exclusive of transaction: Enbridge Gas Distribution, 33.0%; TransAlta Utilities, 45.3%

Source: Annual Reports to Stockholders.

CAPITAL STRUCTURE RATIOS OF MAJOR INVESTOR-OWNED CANADIAN ELECTRIC UTILITIES, GAS DISTRIBUTORS AND PIPELINES (2001)

Company	Long-term Debt a/	Preferred Stock Classified as Debt b/	Preferred Stock b/	Common Stock Equity c/
Electric Utilities				
Aquila Networks Canada (B.C.) Inc.	57.4	0.0	0.0	42.6
CU Inc.	52.5	0.0	7.7	39.8
Maritime Electric	53.0	0.0	0.0	47.0
Newfoundland Power	49.4	0.0	1.8	48.8
Nova Scotia Power	51.3	0.0	10.2	38.4
TransAlta Utilities	35.1	0.0	31.9 d/	33.0
Gas Distributors				
BC Gas Utility	65.0	0.0	0.0	35.0
Enbridge Consumers Gas	45.8	0.0	13.0 d	41.2
Gaz Metropolitain	61.0	0.0	0.0	39.0
Pacific Northern Gas	50.9	0.0	3.1	46.0
Union Gas	61.9	0.0	3.9	34.2
Pipelines				
Enbridge Inc.	67.3	3.7	1.3	27.7
TransCanada PipeLines Ltd.	59.6	4.2	2.4	33.8
Westcoast Energy Inc.	70.2	0.0	6.1	23.7
Averages				
Electric Utilities	**49.8**	**0.0**	**8.6**	**41.6**
Gas Distributors	**56.9**	**0.0**	**4.0**	**39.1**
Electric / Gas Utilities	**53.0**	**0.0**	**6.5**	**40.4**
All Companies	**55.8**	**0.6**	**5.8**	**37.9**

a/ Includes current portion of long-term debt.
b/ Includes minority interest in preferred shares of subsidiary companies.
c/ Includes minority interest in common shares of subsidiary companies.
d/ Includes financing of inter-corporate investment in preferred securities. Common Equity ratios exclusive of transaction: Enbridge Gas Distribution, 38.2%; TransAlta Utilities, 46.9%

Source: Annual Reports to Stockholders.

DEBT RATINGS, BUSINESS PROFILE SCORES, DEBT AND INTEREST COVERAGE RATIOS FOR U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	S & P Rating	Business Profile Scores	Debt Ratio (1999-2001)	Average Pre-Tax Interest Coverage (1999-2001)
Madison Gas & Electric Co.	AA	5	50.1	3.9
Wisconsin Public Service Corp.	AA-	4	46.3	3.6
Median (AA)		**5**	**48.2**	**3.8**
Ameren Corp.	A+	5	47.0	5.0
Central Illinois Public Service Co.	A+	3	51.6	3.6
Consolidated Edison Co. of New York Inc.	A+	3	55.6	3.3
Duke Energy Corp.	A+	5	47.0	4.2
Orange and Rockland Utilities Inc.	A+	3	58.6	2.6
Otter Tail Power Co.	A+	6	46.4	4.1
San Diego Gas & Electric Co.	A+	5	53.5	3.3
Union Electric Co.	A+	4	39.9	5.7
Alabama Power Co.	A	4	49.3	3.6
Boston Edison Co.	A	3	62.3	2.6
Cambridge Electric Light Co.	A	3	39.4	2.0
Central Hudson Gas & Electric Corp.	A	3	44.7	3.3
Commonwealth Electric Co.	A	3	62.9	1.5
Florida Power & Light Co.	A	4	42.8	4.3
FPL Group Inc.	A	6	52.6	3.6
Georgia Power Co.	A	4	45.8	4.6
Gulf Power Co.	A	4	46.3	4.3
Massachusetts Electric Co.	A	3	44.7	3.8
MidAmerican Energy Co.	A	4	46.1	4.3
Mississippi Power Co.	A	4	47.4	4.1
Narragansett Electric Co.	A	3	41.0	3.5
National Grid USA	A	3	47.8	3.6
New England Power Co.	A	3	55.2	4.2
Niagara Mohawk Power Corp.	A	4	69.0	1.0
NSTAR	A	3	82.3	1.5
Savannah Electric & Power Co.	A	4	47.3	3.9
SCANA Corp.	A	4	57.3	2.5
South Carolina Electric & Gas Co.	A	4	45.7	3.9
Southern Co.	A	4	48.8	3.3
Virginia Electric & Power Co.	A	4	55.7	3.0
Wisconsin Electric Power Co.	A	4	50.3	3.8
Wisconsin Power & Light Co.	A	4	54.9	2.6
Alliant Energy Corp.	A-	5	56.7	2.3
Baltimore Gas & Electric Co.	A-	3	60.1	2.4
Commonwealth Edison Co.	A-	4	49.1	3.2
Delmarva Power & Light Co.	A-	3	59.2	3.4
Empire District Electric Co.	A-	5	62.4	1.8
Exelon Corp.	A-	6	51.8	4.1
IDACORP Inc.	A-	5	54.2	3.6
Idaho Power Co.	A-	4	54.0	3.1
OGE Energy Corp.	A-	5	60.7	2.8
Oklahoma Gas & Electric Co.	A-	4	52.9	4.2
PPL Electric Utilities Corp.	A-	4	64.7	3.4
Sempra Energy	A-	4	59.2	3.0
Southern Indiana Gas & Electric Co.	A-	5	50.6	4.1
Tampa Electric Co.	A-	4	46.5	4.0
TECO Energy Inc.	A-	5	61.6	2.6
Wisconsin Energy Corp.	A-	5	62.4	2.4
Median (A)		**4**	**52.2**	**3.5**

DEBT RATINGS, BUSINESS PROFILE SCORES, DEBT AND INTEREST COVERAGE RATIOS FOR U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	S & P Rating	Business Profile Scores	Debt Ratio (1999-2001)	Average Pre-Tax Interest Coverage (1999-2001)
Allegheny Energy Inc.	BBB+	5	60.8	3.4
ALLETE Inc.	BBB+	7	59.0	3.1
American Electric Power Co. Inc.	BBB+	5	66.3	2.0
Appalachian Power Co.	BBB+	3	61.4	2.6
Arizona Public Service Co.	BBB+	3	56.3	3.4
Atlantic City Electric Co.	BBB+	3	63.5	2.2
Central Power & Light Co.	BBB+	2	53.0	3.4
Cincinnati Gas & Electric Co.	BBB+	4	52.5	4.8
Cinergy Corp.	BBB+	5	60.9	3.3
Cleco Corp.	BBB+	6	61.4	3.2
Columbus Southern Power Co.	BBB+	2	56.8	4.2
Conectiv	BBB+	4	70.0	2.4
Connecticut Light & Power Co.	BBB+	4	70.0	0.4
Dayton Power & Light Co.	BBB+	4	37.5	6.6
Detroit Edison Co.	BBB+	6	55.6	2.8
Dominion Resources Inc.	BBB+	5	62.6	2.0
DPL Inc.	BBB+	6	57.7	4.2
DTE Energy Co.	BBB+	6	58.1	2.1
Florida Power Corp.	BBB+	4	53.3	3.3
Florida Progress Corp.	BBB+	5	59.2	1.8
Hawaiian Electric Co.	BBB+	6	47.7	3.1
Indiana Michigan Power Co.	BBB+	4	72.6	1.1
Kentucky Power Co.	BBB+	3	59.8	2.2
Kentucky Utilities Co.	BBB+	4	47.0	4.4
LG&E Energy Corp.	BBB+	6	59.9	2.5
Louisville Gas & Electric Co.	BBB+	4	46.6	5.1
Monongahela Power Co.	BBB+	2	50.3	3.9
Northeast Utilities	BBB+	5	66.2	1.0
Northern States Power Wisconsin	BBB+	4	46.1	3.5
Northwestern Corp.	BBB+	5	59.1	0.3
Northwestern Energy LLC	BBB+	4	43.8	3.9
Ohio Power Co.	BBB+	2	58.8	3.2
Portland General Electric Co.	BBB+	4	49.4	2.9
Potomac Electric Power Co.	BBB+	3	61.6	2.8
Progress Energy Inc.	BBB+	5	55.8	3.2
PSI Energy Inc.	BBB+	4	59.6	3.3
Public Service Co. of New Hampshire	BBB+	5	69.9	3.1
Public Service Co. of Oklahoma	BBB+	3	52.0	3.3
Reliant Energy Inc.	BBB+	3	63.3	2.6
Rochester Gas & Electric Corp.	BBB+	5	51.6	3.1
Southwestern Electric Power Co.	BBB+	3	49.5	3.0
TXU Corp.	BBB+	5	70.2	1.9
Union Light Heat & Power Co.	BBB+	4	47.4	5.8
West Penn Power Co.	BBB+	2	35.7	4.1
West Texas Utilities Co.	BBB+	2	57.7	2.4
Western Massachusetts Electric Co.	BBB+	4	68.9	0.4
Aquila Inc.	BBB	6	58.7	2.6
Bangor Hydro-Electric Co.	BBB	5	58.2	2.0
Cleveland Electric Illuminating Co.	BBB	6	72.3	2.3
DQE Inc.	BBB	5	61.1	1.7
Duquesne Light Co.	BBB	4	62.1	2.8
Entergy Arkansas Inc.	BBB	6	58.4	2.8
Entergy Corp.	BBB	6	53.4	2.6
Entergy Louisiana Inc.	BBB	6	56.3	2.7
Entergy Mississippi Inc.	BBB	7	56.7	2.1
Entergy New Orleans Inc.	BBB	7	61.3	1.7
FirstEnergy Corp.	BBB	6	64.8	2.4
GPU Inc.	BBB	5	63.1	2.6

DEBT RATINGS, BUSINESS PROFILE SCORES, DEBT AND INTEREST COVERAGE RATIOS FOR U.S. INVESTOR-OWNED ELECTRIC UTILITIES

	S & P Rating	Business Profile Scores	Debt Ratio (1999-2001)	Average Pre-Tax Interest Coverage (1999-2001)
Hawaiian Electric Industries Inc.	BBB	6	53.7	2.6
Jersey Central Power & Light Co.	BBB	4	38.1	3.5
Kansas City Power & Light Co.	BBB	6	57.0	2.1
Metropolitan Edison Co.	BBB	5	41.5	3.7
NiSource Inc.	BBB	4	69.0	1.8
Northern Indiana Public Service Co.	BBB	5	54.7	4.9
Northern States Power Co.	BBB	4	56.0	3.1
Ohio Edison Co.	BBB	6	56.3	2.8
Pennsylvania Electric Co.	BBB	5	40.3	4.0
Pinnacle West Capital Corp.	BBB	5	58.0	3.1
PPL Corp.	BBB	7	67.1	3.0
Public Service Co. of Colorado	BBB	4	54.1	2.9
Public Service Electric & Gas Co.	BBB	3	57.4	3.5
Public Service Enterprise Group Inc.	BBB	6	66.0	3.2
Southwestern Public Service Co.	BBB	4	48.2	3.9
Toledo Edison Co.	BBB	6	71.0	2.0
Xcel Energy Inc.	BBB	6	62.9	2.4
Central Illinois Light Co.	BBB-	4	44.9	2.7
Central Vermont Public Service Corp.	BBB-	6	57.1	2.1
El Paso Electric Co.	BBB-	6	64.8	2.1
Entergy Gulf States Inc.	BBB-	6	54.0	2.5
Green Mountain Power Corp.	BBB-	7	61.8	1.6
Indianapolis Power & Light Co.	BBB-	4	46.3	5.7
IPALCO Enterprises Inc.	BBB-	4	66.3	4.4
Mirant Corp.	BBB-	7	60.0	2.1
Public Service Co. of New Mexico	BBB-	6	55.9	3.2
Puget Sound Energy Inc.	BBB-	5	64.0	2.2
System Energy Resources Inc.	BBB-	7	55.7	2.1
Texas-New Mexico Power Co.	BBB-	5	55.4	2.6
Median (BBB)		**5**	**58.0**	**2.8**
Median (all U.S. Electrics)	**BBB+**	**4**	**56.3**	**3.1**

Note: Excludes all utilities with debt ratings below investment grade.

Source: Standard & Poor's Credit Stats: Electric Utilities (August 20, 2002); Standard & Poor's Utilities and Perspectives (March 3, 2003).

EQUITY RETURN AWARDS AND CAPITAL STRUCTURES ADOPTED BY REGULATORY BOARDS FOR INVESTOR-OWNED CANADIAN UTILITIES
(Percentages)

	Decision Date	Order/ File Number	Debt	Preferred Stock	Deferred Taxes	Common Stock Equity	Equity Return	Forecast 30-Year Bond Yield
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Electrics								
Aquila Networks Canada (B.C.) Inc	11/02	L-46-02	58.90	0.00	1.10	40.00	9.82	5.92
ATCO Electric a/	10/97	U97065	48.10	16.20		35.70	11.25	7.75
Maritime Electric b/	10/01	EC2001-608	--	--		40.00	11.00	N/A
Newfoundland Power	12/01	PU 28(2001-2002)	53.55	1.93		44.52	9.05	5.50
Nova Scotia Power	10/02	NSUARB-NSPI-P-87	55.70	9.30		35.00	10.15	5.95 d/
TransAlta Utilities (Integrated) c/	11/99	U99099	49.50	9.50		41.00	9.25	5.75
Generation	11/99	U99099	50.50	9.50		40.00	9.25	5.75
Transmission	11/99	U99099	55.50	9.50		35.00	9.25	5.75
Distribution	11/99	U99099	36.00	9.50		54.50	9.25	5.75
Gas Distributors								
Atco Gas and Pipelines e/	12/01	2001-96	54.25	6.52		39.23	9.75	6.00
B.C. Gas	11/02	L-46-02	57.64	9.36		33.00	9.42	5.92
Enbridge Gas Distribution Inc	5/01	RP-2000	61.81	3.19		35.00	9.54	5.77
Gaz Metropolitain	9/02	D-2002-196	54.00	7.50		38.50	9.89	6.07
Northwestern Utilities	1/94	E-94001	38.74	26.74		34.52	11.875	8.00
Pacific Northern Gas	11/02	L-46-02	60.58	3.41		36.00	10.17	5.92
Union Gas	1/99; 7/01	RP-1999-0017	61.09	3.91		35.00	9.95	6.11
Gas Pipelines								
Alberta Natural Gas	12/02	RH-2-94	70.00	0.00		30.00	9.79	5.98
Foothills Pipe Lines (Yukon) Ltd.	12/02	RH-2-94	70.00	0.00		30.00	9.79	5.98
TransCanada PipeLines	12/02	RH-2-94	60.88	9.12		30.00	9.79	5.98
Trans Quebec & Maritimes Pipeline	12/02	RH-2-94	70.00	0.00		30.00	9.79	5.98
Westcoast Energy	12/02	RH-2-94	63.39	1.61		35.00	9.79	5.98

a/ Superseded by settlements for 1999/2000, and 2001/2002; ROEs and capital structures not specified.
b/ Maritime Electric's ROE and common equity ratio are set by legislation.
c/ Superseded by subsequent settlements and sale of distribution assets to Utilicorp Networks Canada (Alberta); ROE and capital structure not specified.
d/ Average of experts' estimates.
e/ The equity ratios for Atco Gas and Atco Pipelines are 37% and 45.5%, respectively.

Source: Board Decisions.

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RATES OF RETURN ON COMMON EQUITY ADOPTED BY REGULATORY BOARDS FOR INVESTOR-OWNED CANADIAN UTILITIES

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Electrics														
Aquila Networks Canada (B.C.) Inc	13.50	NA	11.75	11.50	11.00	12.25	11.25	10.50	10.25	9.50	10.00	9.75	9.53	9.82
ATCO Electric	13.50	13.50	13.25	11.88	NA	NA	11.25	b/	b/	b/	b/	b/	b/	NA
Newfoundland Power	13.95	13.25	NA	NA	NA	NA	11.00	NA	9.25	9.25	9.59	9.59	9.05	NA
Nova Scotia Power	--	--	--	11.75	NA	NA	10.75	NA	NA	NA	NA	NA	10.15	NA
TransAlta Utilities	13.50	13.50	13.25	11.88	NA	12.25	11.25	b/	c/	9.25	9.25	NA	NA	NA
Average of Electrics	**13.61**	**13.42**	**12.75**	**11.75**	**11.00**	**12.25**	**11.10**	**10.50**	**9.75**	**9.33**	**9.61**	**9.67**	**9.58**	**9.82**
LDCs														
BC Gas Utility	NA	NA	12.25	NA	10.65	12.00	11.00	10.25	10.00	9.25	9.50	9.25	9.13	9.42
Canadian Western / Atco Gas	13.25	13.25	12.25	12.25	NA	NA	NA	10.50	9.38	NA	NA	9.75	9.75	NA
Centra Gas Ontario	13.50	13.75	13.50	12.50	11.85	12.13	NA	11.25	10.69	a/	a/	a/	a/	NA
Enbridge Gas Distribution Inc	13.25	13.13	13.13	12.30	11.60	11.65	11.88	11.50	10.30	9.51	9.73	9.54	NA	NA
Gaz Metro	14.25	14.25	14.00	12.50	12.00	12.00	12.00	11.50	10.75	9.64	9.72	9.60	9.67	9.89
Northwestern Utilities	NA	13.75	13.75	11.88	11.88	NA	NA	NA	NA	NA	NA	NA	NA	NA
Pacific Northern Gas	15.00	14.00	13.25	NA	11.50	12.75	11.75	11.00	10.75	10.00	10.25	10.00	9.88	10.17
Union Gas	13.75	13.50	13.50	13.00	12.50	11.75	11.75	11.00	10.44	9.61	9.95	9.95	NA	NA
Average of LDCs	**13.83**	**13.66**	**13.20**	**12.40**	**11.71**	**12.05**	**11.68**	**11.00**	**10.33**	**9.60**	**9.83**	**9.68**	**9.61**	**9.83**
Gas Pipelines														
TransCanada	13.25	13.50	13.25	12.25	11.25	12.25	11.25	10.67	10.21	9.58	9.90	9.61	9.53	9.79
Westcoast Energy	13.25	13.75	12.50	12.25	11.50	12.25	11.25	10.67	10.21	9.58	9.90	9.61	9.53	9.79
Average of Gas Pipelines	**13.25**	**13.63**	**12.88**	**12.25**	**11.38**	**12.25**	**11.25**	**10.67**	**10.21**	**9.58**	**9.90**	**9.61**	**9.53**	**9.79**
Average of All Companies	**13.66**	**13.59**	**13.05**	**12.16**	**11.57**	**12.13**	**11.36**	**10.88**	**10.20**	**9.52**	**9.78**	**9.67**	**9.58**	**9.81**

Note: A rate freeze was in effect for BC Gas in 1990 and 1991, BCUC regulation resumed in late 1991
Nova Scotia Power was privatized in 1992

a/ Merged with Union Gas.
b/ Negotiated settlement, details not available
c/ Negotiated settlement, implicit ROE made public is 10.5%

Source: Regulatory Decisions

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SCHEDULE VI
K. C. McShane

TREND IN INTEREST RATES AND OUTSTANDING BOND YIELDS
(Percent Per Annum)

Year		Government Securities: 3-Month Bills: Canadian	3-Month Bills: U.S. a/	10-Year Bonds: Canadian	10-Year Bonds: U.S.	Long-Term Bonds: Canadian	Long-Term Bonds: U.S. b/	Canada Bonds Over 10 Years c/	Canadian Inflation Indexed Bonds	Scotia Capital Long-Term Corporates	Canadian A-Rated Utility Bonds d/	Exchange Rate (Canadian dolla in U.S. funds)
1976		8.87	5.00		7.61	9.61	7.86	9.18			10.61	1.01
1977		7.33	5.26		7.42	9.15	7.67	8.70			9.95	0.94
1978		8.68	7.22		8.41	9.57	8.49	9.28		10.10	10.16	0.88
1979		11.68	####		9.44	10.50	9.29	10.21		10.91	11.08	0.85
1980		12.80	####		11.46	14.13	11.30	12.48		13.28	13.46	0.86
1981		17.72	####		13.91	15.59	13.44	15.22		16.32	16.26	0.83
1982		13.62	####	13.69	13.00	14.13	12.76	14.26		15.86	15.84	0.81
1983		9.32	8.63	11.43	11.10	12.08	11.18	11.79		12.74	12.85	0.81
1984		11.06	9.58	12.73	12.44	13.00	12.39	12.75		13.50	13.56	0.77
1985		9.43	7.49	10.83	10.62	11.20	10.79	11.04		11.74	11.71	0.73
1986		8.97	5.97	9.12	7.68	9.30	7.80	9.52		10.36	10.42	0.72
1987		8.15	5.82	9.50	8.39	9.75	8.59	9.95		10.71	11.00	0.75
1988		9.48	6.69	9.83	8.85	10.05	8.96	10.24		10.93	11.20	0.81
1989		12.04	8.12	9.80	8.49	9.66	8.45	9.92		10.81	11.05	0.84
1990		12.80	7.51	10.76	8.55	10.69	8.61	10.85		11.91	12.13	0.86
1991		8.73	5.42	9.42	7.86	9.72	8.14	9.76		10.80	11.00	0.87
1992		6.59	3.45	8.05	7.01	8.68	7.67	8.77	4.62	9.90	10.01	0.83
1993		4.84	3.02	7.22	5.87	7.86	6.59	7.85	4.28	8.85	9.08	0.77
1994		5.54	4.34	8.43	7.08	8.69	7.37	8.63	4.41	9.44	9.81	0.73
1995		6.89	5.44	8.08	6.58	8.41	6.88	8.28	4.68	9.02	9.29	0.73
1996		4.21	5.04	7.20	6.44	7.75	6.73	7.50	4.61	8.11	8.38	0.73
1997		3.26	5.11	6.11	6.32	6.66	6.58	6.42	4.14	6.95	7.19	0.72
1998		4.73	4.79	5.30	5.26	5.59	5.54	5.47	4.02	6.22	6.38	0.67
1999		4.69	4.70	5.55	5.69	5.72	5.91	5.69	4.07	6.64	6.92	0.67
2000		5.45	5.85	5.89	5.98	5.71	5.88	5.89	3.69	7.13	7.02	0.67
2001		3.78	3.34	5.49	4.99	5.78	5.51	5.76	3.59	7.09	7.25	0.65
2002		2.55	1.63	5.27	4.56	5.67	5.38	5.65	3.49	6.98	7.22	0.64
2002	Jan	1.96	1.76	5.44	5.07	5.68	5.44	5.74	3.73	6.88	7.12	0.63
	Feb	2.06	1.79	5.33	4.88	5.70	5.42	5.70	3.72	6.87	7.23	0.62
	Mar	2.27	1.79	5.78	5.42	5.97	5.98	6.00	3.68	7.15	7.35	0.63
	Apr	2.40	1.77	5.61	5.11	5.90	5.73	5.87	3.60	7.02	7.20	0.64
	May	2.61	1.74	5.50	5.08	5.79	5.76	5.77	3.53	6.97	7.16	0.65
	June	2.71	1.70	5.43	4.86	5.81	5.67	5.80	3.43	6.99	7.06	0.66
	July	2.81	1.71	5.23	4.51	5.73	5.45	5.70	3.45	7.19	7.32	0.63
	Aug	2.94	1.69	5.08	4.14	5.51	5.08	5.48	3.39	6.99	7.20	0.64
	Sept	2.75	1.57	4.90	3.63	5.44	4.80	5.39	3.24	6.84	7.27	0.63
	Oct	2.71	1.44	5.04	3.93	5.56	5.13	5.53	3.45	7.17	7.44	0.64
	Nov	2.71	1.33	5.12	4.22	5.53	5.20	5.51	3.42	6.96	7.25	0.64
	Dec	2.66	1.22	4.79	3.83	5.36	4.91	5.31	3.29	6.73	7.01	0.63
2003	Jan	2.82	1.18	5.02	4.00	5.47	4.97	5.43	3.21	6.85	7.13	0.66
	Feb	2.92	1.20	4.94	3.71	5.44	4.78	5.38	3.00	6.81	7.17	0.67

a/ Rates on new issues.
b/ 20-year constant maturities for 1974-1978; 30-year maturities 1978-2001, long-term average (25 years and above), February 2001 forward. Series represents yields on the more actively traded issues adjusted to constant maturities by the U.S. Treasury based on daily closing bids.
c/ Terms to maturity of l0 years or more.
d/ Series is comprised of the CBRS Utilities Index through 1995; CBRS 30-year Utilities Index from 1996- August 2000; a series of liquid long-term utility bonds maintained by Foster Associates from September 2000 forward.
Note: Monthly data reflect rate in effect at end of month

Source: Bank of Canada Review; CBRS; Globe and Mail; Annual Statistical Digest (Federal Reserve System); Federal Reserve Bulletin (various issues).

CANADIAN AND U.S. POST-WWII HISTORIC EQUITY RISK PREMIUMS

Canada
(1947-2001)

Average	Stock Return	Bond Return	Risk Premium
Arithmetic	12.3	6.8	5.5
Compound	11.1	6.3	4.7

United States
(1947-2001)

Average	Stock Return	Bond Return	Risk Premium
Arithmetic	13.7	6.1	7.5
Compound	12.4	5.6	6.8

Source: Canadian Institute of Actuaries, Report on Canadian Economic Statistics;
Ibbotson Associates, Stocks, Bonds, Bills and Inflation.

BETAS FOR REGULATED CANADIAN UTILITIES

RAW BETAS
FIVE YEAR PERIOD ENDING

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Electric and Gas Distributors											
BC Gas	0.41	0.41	0.54	0.59	0.54	0.47	0.48	0.36	0.25	0.18	0.12
Canadian Utilities	0.45	0.45	0.54	0.48	0.55	0.63	0.62	0.54	0.38	0.27	0.19
Emera	N/A	N/A	N/A	N/A	0.52 2/	0.40	0.55	0.41	0.27	0.20	0.15
Enbridge	0.23	0.24	0.26	0.32	0.44	0.43	0.48	0.26	0.07	-0.10	-0.18
Fortis	0.41	0.35	0.44	0.51	0.37	0.30	0.49	0.33	0.23	0.14	0.13
TransAlta Corporation	0.36	0.44	0.55	0.59	0.57	0.46	0.54	0.28	0.05	0.08	0.09
TransCanada Pipelines	0.49	0.40	0.57	0.56	0.52	0.36	0.55	0.21	0.15	-0.08	-0.09
Mean	**0.34**	**0.33**	**0.41**	**0.44**	**0.43**	**0.44**	**0.53**	**0.34**	**0.20**	**0.10**	**0.06**
Median	**0.41**	**0.40**	**0.54**	**0.51**	**0.52**	**0.43**	**0.54**	**0.33**	**0.23**	**0.14**	**0.12**
TSE Gas/Electric Index 3/	0.35	0.42	0.48	0.52	0.52	0.46	0.55	0.38	0.21	0.17	NA
S&P/TSX Utilities	0.72	0.55	0.63	0.67	0.65	0.53	0.55	0.30	0.14	-0.03	-0.06

ADJUSTED BETAS 1/
FIVE YEAR PERIOD ENDING

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Electric and Gas Distributors											
BC Gas	0.60	0.60	0.69	0.73	0.69	0.64	0.65	0.57	0.50	0.45	0.41
Canadian Utilities	0.63	0.63	0.69	0.65	0.70	0.75	0.75	0.69	0.58	0.51	0.46
Emera	N/A	N/A	N/A	N/A	0.68	0.60	0.70	0.60	0.51	0.46	0.43
Enbridge	0.48	0.49	0.50	0.54	0.62	0.62	0.65	0.50	0.38	0.26	0.21
Fortis	0.60	0.56	0.62	0.67	0.58	0.53	0.66	0.55	0.48	0.42	0.42
TransAlta Corporation	0.57	0.62	0.70	0.73	0.71	0.64	0.69	0.52	0.36	0.38	0.39
TransCanada Pipelines	0.66	0.60	0.71	0.71	0.68	0.57	0.70	0.47	0.43	0.28	0.27
Mean	**0.51**	**0.50**	**0.56**	**0.57**	**0.67**	**0.62**	**0.69**	**0.56**	**0.46**	**0.40**	**0.37**
Median	**0.60**	**0.60**	**0.69**	**0.67**	**0.68**	**0.62**	**0.69**	**0.55**	**0.48**	**0.42**	**0.41**
TSE Gas/Electric Index 3/	0.56	0.61	0.65	0.68	0.68	0.64	0.70	0.58	0.47	0.44	NA
S&P/TSX Utilities	0.81	0.70	0.75	0.78	0.77	0.69	0.70	0.53	0.42	0.31	0.29

1/ Adjusted beta = "raw" beta * 67% + market beta of 1.0 * 33%.
2/ Beta is based on 51 months
3/ TSE Gas/Electric index discontinued April 2002.

Source: TSE Review.

5-YEAR PRICE BETAS FOR S&P/TSX SECTOR INDICES

	1994	1995	1996	1997	1998	1999	2000	2001	2002
Consumer Discretionary	0.91	0.81	0.82	0.82	0.80	0.73	0.69	0.68	0.73
Consumer Staples	0.75	0.68	0.65	0.62	0.60	0.44	0.23	0.10	0.08
Energy	0.68	0.93	0.92	0.97	0.85	0.90	0.66	0.49	0.43
Financials	1.14	0.93	1.02	0.94	1.12	1.00	0.78	0.66	0.66
Health Care	0.84	0.35	0.39	0.60	1.01	1.00	1.09	0.98	0.99
Industrials	1.15	1.20	1.10	0.97	0.93	0.78	0.72	0.82	0.86
Information Technology	1.12	1.26	1.36	1.57	1.41	1.55	1.78	2.13	2.28
Materials	1.26	1.39	1.27	1.32	1.12	1.04	0.74	0.60	0.57
Telecommunication Services	0.61	0.56	0.64	0.64	0.92	1.11	0.92	0.94	0.93
Utilities	0.63	0.67	0.65	0.53	0.55	0.30	0.14	-0.03	-0.06

Source: Toronto Stock Exchange

STANDARD DEVIATIONS OF MARKET RETURNS FOR 10 SECTOR INDICES OF S&P/TSX

Index	1993-97		1994-98		1995-99		1996-00	1997-01		1998-02	
S&P / TSX	**3.6**	**%**	**4.7**	**%**	**4.8**	**%**	**5.4**	**5.9**	**%**	**5.8**	**%**
10 Sector Indices											
Consumer Discretionary	3.7		4.4		4.6		5.0	5.4		5.7	
Consumer Staples	3.6		4.0		3.7		4.0	4.2		4.8	
Energy	5.6		6.2		7.3		8.0	8.3		8.1	
Financials	4.3		5.9		5.9		6.2	6.2		6.1	
Health Care	6.6		7.7		8.2		9.4	9.0		9.4	
Industrials	4.1		4.9		4.7		5.1	6.5		7.2	
Information Technology	8.0		9.2		10.4		12.3	15.2		17.1	
Materials	5.9		7.0		7.2		7.3	7.4		7.2	
Telecommunication Services	3.7		5.8		7.4		7.9	8.5		8.7	
Utilities	3.1		3.8		4.0		4.8	5.1		4.9	
Mean	**4.9**		**5.9**		**6.3**		**7.0**	**7.6**		**7.9**	
Median	**4.2**		**5.9**		**6.6**		**6.8**	**6.9**		**7.2**	

Source: Toronto Stock Exchange

BETAS FOR SELECTED U.S. ELECTRIC UTILITIES

Companies	"Raw" Betas Five-Year Period Ending 1998	2002	Value Line	Bloomberg
AMEREN CORP	0.36	0.00	0.60	0.57
AMERICAN ELECTRIC POWER	0.19	0.06	0.90	0.72
EXELON CORP	0.22	-0.03	0.70	0.51
FIRSTENERGY CORP	0.38	0.02	0.65	0.53
GREAT PLAINS ENERGY INC	0.30	0.39	0.70	0.67
IDACORP INC	0.32	0.24	0.70	0.69
PINNACLE WEST CAPITAL	0.27	0.15	0.70	0.80
PUGET ENERGY INC	0.32	0.05	0.60	0.61
SOUTHERN CO	0.15	-0.45	NMF	0.36
Mean	**0.28**	**0.05**	**0.69**	**0.61**
Median	**0.30**	**0.05**	**0.70**	**0.61**

Source: S&P Research Insight; Value Line (12/6/02, 1/3/03, 2/14/03); Bloomberg.com (March 2003).

HISTORIC VALUE LINE BETAS FOR SELECTED U.S. ELECTRIC UTILITIES

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
AMEREN CORP.	0.65	0.65	0.65	0.75	0.70	0.65	0.50	0.55	0.55	0.60
AMERICAN ELECTRIC POWER	0.70	0.75	0.75	0.70	0.70	0.55	0.45	0.55	0.55	0.90
EXELON CORP	0.70	0.75	0.70	0.85	0.85	0.65	0.65	NMF	NMF	0.70
FIRSTENERGY CORP	0.80	0.85	0.75	0.75	0.80	0.70	0.50	0.55	0.55	0.65
GREAT PLAINS ENERGY INC.	0.60	0.65	0.65	0.80	0.75	0.80	0.60	0.60	0.55	0.70
IDACORP INC.	0.60	0.65	0.60	0.70	0.70	0.65	0.50	0.50	0.50	0.60
PINNACLE WEST CAPITAL	0.90	0.95	0.90	0.80	0.75	0.70	0.45	0.45	0.45	0.55
PUGET ENERGY INC.	0.65	0.65	0.60	0.70	0.70	0.70	0.55	0.55	0.55	0.60
SOUTHERN CO.	0.65	0.65	0.65	0.70	0.70	0.50	0.45	0.50	NMF	NMF
Mean	**0.69**	**0.73**	**0.69**	**0.75**	**0.74**	**0.66**	**0.52**	**0.53**	**0.53**	**0.66**
Median	**0.65**	**0.65**	**0.65**	**0.75**	**0.70**	**0.65**	**0.50**	**0.55**	**0.55**	**0.63**

Source: Value Line, 4th Quarter issues.

BETAS FOR REGULATED CANADIAN UTILITIES (EXCLUDING NORTEL)

	Raw Betas Five-Year Period Ending			Adjusted Betas Five-Year Period Ending		
	2000	2001	2002	2000	2001	2002
BC Gas	0.41	0.35	0.28	0.60	0.56	0.52
Canadian Utilities	0.57	0.46	0.38	0.71	0.64	0.58
Emera	0.43	0.35	0.30	0.62	0.56	0.53
Enbridge	0.29	0.13	0.05	0.52	0.42	0.36
Fortis	0.36	0.28	0.28	0.57	0.52	0.52
TransAlta Corporation	0.27	0.32	0.35	0.51	0.54	0.56
TransCanada Pipelines	0.40	0.15	0.15	0.60	0.43	0.43
Mean	**0.39**	**0.29**	**0.26**	**0.59**	**0.53**	**0.50**
Median	**0.40**	**0.32**	**0.28**	**0.60**	**0.54**	**0.52**
TSE Gas/Electric Index	0.40	0.37	NA	0.60	0.58	NA
S&P/TSX Utilities	0.35	0.18	0.16	0.56	0.45	0.44

Source: TSE Review

CANADIAN AND U.S. UTILITY
HISTORIC EQUITY RISK PREMIUMS

TSE GAS/ELECTRIC INDEX
(1956-2001)

Holding Period	Stock Return	Bond Return	Risk Premium
Arithmetic	12.6	7.7	4.9
Compound	11.6	7.2	4.4

S&P / MOODY'S ELECTRIC INDEX
(1947-2001)

Average	Stock Return	Bond Return	Risk Premium
Arithmetic	11.5	6.1	5.4
Compound	10.3	5.6	4.7

Sources: TSE Review, Bank of Canada Review, Standard & Poor's Analysts' Handbook, Ibbotson Associates, Stocks, Bonds, Bills and Inflation, Mergent Corporate News Reports.

EQUITY RISK PREMIUM STUDY FOR
SELECTED U.S. LOCAL NATURAL GAS DISTRIBUTION COMPANIES
(Quarterly Averages of Monthly Data)

		Dividend Yields 1/	I/B/E/S EPS Growth Forecast	DCF Cost	30-Year Treasury Yield	Risk Premium
1993	1Q	5.4	6.5	11.9	7.0	4.9
	2Q	5.2	6.4	11.6	6.9	4.7
	3Q	4.9	6.5	11.4	6.3	5.1
	4Q	5.3	6.0	11.2	6.2	5.0
1994	1Q	5.4	5.4	10.8	6.7	4.1
	2Q	5.8	5.6	11.4	7.3	4.0
	3Q	6.0	5.6	11.6	7.6	4.0
	4Q	6.3	5.2	11.5	7.9	3.6
1995	1Q	6.1	4.9	11.0	7.6	3.4
	2Q	5.9	5.1	11.0	6.9	4.1
	3Q	5.8	5.0	10.8	6.7	4.1
	4Q	5.4	5.1	10.5	6.2	4.3
1996	1Q	5.3	5.2	10.5	6.4	4.1
	2Q	5.3	5.2	10.5	7.0	3.6
	3Q	5.2	5.3	10.5	7.0	3.5
	4Q	4.9	5.4	10.3	6.6	3.7
1997	1Q	5.1	5.2	10.3	6.9	3.4
	2Q	5.0	5.2	10.2	6.9	3.3
	3Q	4.8	5.3	10.1	6.5	3.6
	4Q	4.5	5.5	10.0	6.1	4.0
1998	1Q	4.5	5.9	10.3	5.9	4.4
	2Q	4.5	5.9	10.4	5.8	4.6
	3Q	4.8	6.0	10.8	5.3	5.5
	4Q	4.4	5.8	10.2	5.2	5.0
1999	1Q	5.0	5.8	10.8	5.5	5.3
	2Q	4.9	5.6	10.6	5.8	4.8
	3Q	4.9	5.6	10.5	6.1	4.4
	4Q	5.1	5.5	10.6	6.4	4.2
2000	1Q	5.8	5.4	11.3	6.3	5.0
	2Q	5.7	5.3	11.0	6.0	5.0
	3Q	5.3	5.7	11.1	5.8	5.3
	4Q	4.8	5.7	10.5	5.6	4.9
2001	1Q	4.9	5.7	10.6	5.4	5.2
	2Q	4.8	5.6	10.4	5.8	4.6
	3Q	5.0	6.1	11.1	5.5	5.6
	4Q	4.9	5.8	10.7	5.3	5.3
2002	1Q	4.9	5.6	10.5	5.7	4.8
	2Q	4.7	5.6	10.3	5.7	4.6
	3Q	5.3	5.7	11.0	5.1	5.9
	4Q	5.1	5.6	10.7	5.1	5.6
Averages for 30-year Treasury yields:						
up to 5.5				**10.7**	**5.3**	**5.4**
5.6 - 6.0				**10.6**	**5.8**	**4.8**
6.1 - 6.5				**10.7**	**6.3**	**4.4**
over 6.5				**10.9**	**7.0**	**3.9**
All periods				**10.8**	**6.2**	**4.5**

1/ Dividend Yield is adjusted for half of I/B/E/S growth

Source: Standard & Poor's Research Insight, I/B/E/S International, Inc.,
U.S. Federal Reserve Statistical Release

SCHEDULE XVI
K. C. McShane

RISK MEASURES FOR SELECTED U.S.
LOCAL NATURAL GAS DISTRIBUTION COMPANIES

	Value Line					S & P			
Company	Safety Rank	Earnings Predictability	Financial Strength	Beta	Forecast 2002 Equity Ratio	Business Profile	Debt Rating	Debt Ratio (2001)	Average Market/Book Ratio (2002)
AGL RESOURCES INC	2	60	B++	0.75	40.0	3	A-	49.4	189
ATMOS ENERGY CORP	3	50	B+	0.60	46.0	4	A-	61.0	156
NEW JERSEY RESOURCES	2	100	B++	0.65	48.0	2 1/	A 1/	55.5	245
NICOR INC	2	95	A	0.85	64.5	3	AA	49.6	204
NORTHWEST NATURAL GAS C	2	65	B++	0.60	50.5	3	A	51.2	142
PEOPLES ENERGY CORP	1	75	A	0.75	59.5	4	A-	60.8	148
PIEDMONT NATURAL GAS CO	2	85	B++	0.70	58.0	3	A	49.2	201
WGL HOLDINGS INC	1	65	A	0.65	52.0	3	AA-	49.3	151
Mean	**2**	**74**	**B++**	**0.69**	**52.3**	**3**	**A**	**53.3**	**180**
Median	**2**	**70**	**B++**	**0.68**	**51.3**	**3**	**A**	**50.4**	**173**

Source: Value Line (December 20, 2002), Standard & Poor's CreditStats (August/September 2002), Standard & Poor's Utilities and Perspectives (December 16, 2002), Standard & Poor's Research Insight.

1/ For subsidiary, New Jersey Natural Gas

RISK MEASURES FOR SELECTED U.S.
ELECTRIC UTILITY COMPANIES

	Value Line					S & P				
Company	Safety Rank	Earnings Predictability	Financial Strength	Beta	Forecast 2002 Equity Ratio	Business Profile	Debt Rating	Debt Ratio (2001)	Market/Book Ratio (2002)	Repriced Equity / Book Ratio (2002)
AMEREN CORP	1	90	A+	0.60	48.5	7	BBB+	50.5	183.5	147.4
AMERICAN ELECTRIC POWER	3	50	B+	0.90	42.5	5	BBB+	65.8	108.0	139.5
EXELON CORP	2	NMF	A	0.70	37.0	6	BBB+	48.8	220.2	NMF
FIRSTENERGY CORP	3	90	B+	0.65	38.5	6	BBB-	66.2	132.7	129.7
GREAT PLAINS ENERGY INC	2	60	B++	0.70	45.0	6	BBB-	62.3	166.4	171.0
IDACORP INC	3	70	B+	0.70	46.5	5	BBB+	56.5	108.7	157.3
PINNACLE WEST CAPITAL	1	90	A+	0.70	50.0	5	BBB-	60.1	112.1	152.9
PUGET ENERGY INC	3	45	B+	0.60	37.5	5	BBB-	63.3	134.9	151.4
SOUTHERN CO	2	NMF	A	NMF	43.0	4	A-	51.2	236.6	161.9
Mean	**2**	**71**	**B++**	**0.69**	**43.2**	**5**	**BBB**	**58.3**	**155.9**	**151.4**
Median	**2**	**70**	**B++**	**0.70**	**43.0**	**5**	**BBB+**	**60.1**	**134.9**	**152.2**

Source: Value Line (December 6, 2002, January 3, 2003, February 14, 2003); Standard and Poor's, Research Insight;
Standard & Poor's Utilities and Perspectives (February 24, 2003); Standard & Poor's CreditStats (February 12, 2003)

DCF COSTS OF EQUITY FOR SELECTED
ELECTRIC UTILITY COMPANIES
(BASED ON ANALYSTS' EARNINGS GROWTH FORECASTS)

Company	Nov. - Jan. 2003 Dividend Yield	Long-Term EPS Forecasts I/B/E/S (January 2003)	Long-Term EPS Forecasts Zacks (Feb. 14, 2003)	Average of Forecasts	DCF Cost of Equity
AMEREN CORP	6.2	3.0	3.6	3.3	9.7
AMERICAN ELECTRIC POWER	8.8	4.0	5.3	4.7	13.9
EXELON CORP	3.4	6.0	5.3	5.7	9.3
FIRSTENERGY CORP	4.7	7.0	6.0	6.5	11.5
GREAT PLAINS ENERGY INC	7.3	5.0	4.0	4.5	12.1
IDACORP INC	7.7	8.0	8.0	8.0	16.3
PINNACLE WEST CAPITAL	5.4	6.0	5.6	5.8	11.5
PUGET ENERGY INC	4.7	6.0	6.0	6.0	11.0
SOUTHERN CO	4.9	5.0	5.1	5.0	10.2
Mean	**5.9**	**5.6**	**5.4**	**5.5**	**11.7**
Median	**5.4**	**6.0**	**5.3**	**5.7**	**11.5**

1/ Adjusted dividend yield plus growth;
[DY*(1+(Growth))] + Growth

Source: Standard & Poor's Research Insight, January 2003, I/B/E/S and Zacks.com

DCF COSTS OF EQUITY FOR SELECTED ELECTRIC UTILITY COMPANIES (BASED ON SUSTAINABLE GROWTH RATES)

				Value Line	
Company	Nov. - Jan. 2003 Dividend Yield	Sustainable Growth	DCF Cost of Equity	ROE Forecast (2005-2007)	Dividend Payout Forecast (2005-2007)
AMEREN CORP	6.2	2.8	9.1	13.5	0.79
AMERICAN ELECTRIC POWER	8.8	3.1	12.3	12.0	0.74
EXELON CORP	3.4	9.6	13.3	14.0	0.32
FIRSTENERGY CORP	4.7	7.5	12.5	12.5	0.40
GREAT PLAINS ENERGY INC	7.3	3.8	11.3	14.5	0.74
IDACORP INC	7.7	1.5	9.3	9.5	0.85
PINNACLE WEST CAPITAL	5.4	3.7	9.3	9.5	0.61
PUGET ENERGY INC	4.7	4.0	8.9	10.0	0.60
SOUTHERN CO	4.9	5.3	10.4	15.5	0.66
Mean	**5.9**	**4.6**	**10.7**	**12.3**	**0.63**
Median	**5.4**	**3.8**	**10.4**	**12.5**	**0.66**

1/ Adjusted dividend yield plus growth;
[DY*(1+(Growth))] + Growth

Source: Standard & Poor's Research Insight, January 2003 and Value Line, 12/6/02, 1/3/03, 2/14/03.

HISTORIC MARKET TO BOOK RATIO FOR
SELECTED U.S. ELECTRIC UTILITIES

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	1993 - 2002 Average
AMEREN CORP.	181.7	159.2	183.8	167.0	196.6	191.7	145.4	198.8	174.4	183.5	178.2
AMERICAN ELECTRIC POWER	165.0	144.0	174.5	170.3	209.7	186.4	124.6	185.9	170.5	108.0	163.9
EXELON CORP	157.8	126.2	147.7	120.9	197.9	306.8	355.3	310.4	189.7	220.2	213.3
FIRSTENERGY CORP	158.3	121.8	148.9	138.9	161.3	175.1	116.5	155.1	144.8	132.7	145.4
GREAT PLAINS ENERGY INC.	164.4	165.4	181.0	193.8	208.3	205.7	158.0	184.4	200.1	166.4	182.7
IDACORP INC.	170.1	131.2	165.3	168.5	198.8	186.4	133.9	224.6	175.1	108.7	166.2
PINNACLE WEST CAPITAL	118.6	96.6	133.8	141.0	177.3	166.2	117.5	169.5	142.0	112.1	137.5
PUGET ENERGY INC.	133.4	109.2	125.8	129.5	188.0	174.3	119.3	167.5	139.8	134.9	142.2
SOUTHERN CO.	184.6	160.4	187.9	169.4	186.0	207.0	170.0	211.9	221.7	236.6	193.5
Mean	**159.3**	**134.9**	**161.0**	**155.5**	**191.5**	**199.9**	**160.1**	**200.9**	**173.1**	**155.9**	**169.2**
Median	**164.4**	**131.2**	**165.3**	**167.0**	**196.6**	**186.4**	**133.9**	**185.9**	**174.4**	**134.9**	**166.2**

Source: Standard & Poor's Research Insight.

RETURNS ON AVERAGE COMMON STOCK EQUITY FOR 15 LOW RISK CANADIAN INDUSTRIALS

	Returns on Equity												
	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	Average 1992-2001	Average 1992-1995	Average 1996-2001
CANADIAN TIRE CORP	6.4	6.9	0.5	10.2	10.4	11.4	13.0	11.2	10.6	11.5	9.2	6.0	11.4
CARA OPERATIONS LTD	12.6	11.7	9.5	12.2	10.9	13.8	7.4	10.5	34.6	10.3	13.4	11.5	14.6
EMPIRE CO LTD	6.8	12.3	9.4	3.9	11.9	17.9	21.7	13.3	69.1	16.3	18.3	8.1	25.0
FINNING INTERNATIONAL INC	0.7	6.5	14.9	16.3	16.0	16.2	0.5	8.7	10.5	14.1	10.4	9.6	11.0
JEAN COUTU GROUP	18.5	10.1	17.0	15.2	16.2	15.3	15.5	15.7	14.9	15.7	15.4	15.2	15.6
LEONS FURNITURE LTD	11.4	16.4	15.3	14.0	13.4	15.1	16.7	21.1	19.3	17.3	16.0	14.3	17.2
LOBLAW COS LTD	8.7	9.6	12.4	13.3	14.2	15.3	12.8	13.7	15.7	16.8	13.2	11.0	14.8
MAGNA INTERNATIONAL	22.8	19.6	21.7	21.8	15.8	21.6	12.3	12.0	15.9	14.7	17.8	21.5	15.4
MAPLE LEAF FOODS INC	7.9	7.3	7.5	-6.7	14.8	14.7	-6.3	17.9	8.0	10.3	7.5	4.0	9.9
MOLSON INC	15.7	10.1	6.5	-26.8	3.7	11.8	16.3	-4.1	14.7	18.0	6.6	1.4	10.1
ROTHMANS INC	34.4	40.1	45.2	39.7	40.2	37.2	38.4	41.7	38.6	40.1	39.6	39.8	39.4
SHAW COMMUNICATN INC	11.5	11.5	10.2	6.2	11.8	2.9	-0.1	1.9	5.5	-8.4	5.3	9.9	2.3
THOMSON CORP	6.0	10.0	14.6	22.4	14.2	12.9	34.7	8.0	17.9	10.2	15.1	13.2	16.3
TORSTAR CORP	8.4	-1.7	7.9	6.7	11.3	38.4	-0.7	12.8	5.4	-14.6	7.4	5.3	8.8
WESTON (GEORGE) LTD	3.2	4.5	8.7	12.9	15.1	14.5	37.3	14.0	17.4	18.5	14.6	7.3	19.5
Median	**8.7**	**10.1**	**10.2**	**12.9**	**14.2**	**15.1**	**13.0**	**12.8**	**15.7**	**14.7**	**13.4**	**9.9**	**14.8**
Average											**14.0**	**11.9**	**15.4**
Average of Medians											**12.7**	**10.5**	**14.2**

Source: Standard & Poor's Research Insight

CDAIND

SCHEDULE XXII
K. C. McShane

SELECTED INDICATORS OF ECONOMIC ACTIVITY
(1989 = 100)

		Canada					United States				
		Gross Domestic Product			GDP	Consumer	Gross Domestic Product			Implicit	Consumer
		Constant	Current	Industrial	Deflator	Price	Constant	Current	Industrial	Price	Price
Year		Dollars	Dollars	Production	Index	Index	Dollars	Dollars	Production	Index a/	Index
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(I0)
1989		100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
1990		100.2	103.4	97.2	103.1	104.8	102.1	105.7	99.8	103.6	105.4
1991		98.1	104.2	93.5	105.8	110.7	101.6	109.1	97.9	107.3	109.8
1992		99.0	106.5	94.5	107.2	112.3	104.7	115.1	100.9	109.9	113.2
1993		101.3	110.6	98.8	108.8	114.4	107.5	121.0	104.4	112.6	116.5
1994		106.1	117.2	105.1	110.0	114.6	111.9	128.5	110.1	114.9	119.5
1995		109.1	122.7	109.9	112.5	117.1	114.8	134.8	115.4	117.4	122.9
1996		110.9	126.7	111.8	114.3	118.9	118.9	142.3	120.6	119.7	126.5
1997		115.6	133.5	117.9	115.2	120.8	124.2	151.5	128.9	121.7	129.5
1998		120.3	139.2	120.6	114.6	122.0	129.6	160.0	135.2	123.5	131.5
1999		126.8	149.1	126.1	116.7	124.1	134.8	169.0	140.9	125.2	134.4
2000		132.5	161.9	131.4	120.9	127.5	139.9	179.0	148.8	128.1	138.9
2001		134.5	167.4	127.5	121.9	130.8	140.3	183.7	141.7	130.9	142.8
2000	1Q	130.8	157.6	130.1	119.5	125.9	138.5	175.8	143.0	127.1	137.0
	2Q	131.8	161.0	131.3	120.8	127.0	140.1	178.9	145.8	127.8	138.5
	3Q	133.4	164.0	132.2	121.5	128.2	140.3	179.9	146.9	128.4	139.6
	4Q	134.1	165.1	132.2	121.6	129.1	140.7	181.3	149.3	129.0	140.3
2001	1Q	134.3	167.3	129.9	123.1	129.4	140.5	182.7	144.7	130.0	141.7
	2Q	134.4	167.4	129.7	123.1	131.5	140.0	183.1	142.6	130.7	143.2
	3Q	134.2	165.1	126.2	121.5	131.6	139.9	184.0	141.0	131.4	143.4
	4Q	135.2	164.4	124.3	120.1	130.5	140.8	185.0	138.6	131.4	143.0
2002	1Q	137.1	168.2	127.6	121.1	131.3	142.5	187.9	139.4	131.8	143.5
	2Q	138.6	173.0	129.3	123.3	133.3	143.0	189.0	140.8	132.2	145.0
	3Q	139.6	175.1	130.7	123.9	134.7	144.4	191.4	142.1	132.6	145.6

Source: Statistics Canada, National Income and Expenditures Accounts, Canadian Statistical Review; U.S. Department of Commerce, Busine
Statistics Survey of Current Business

Note: Data are based on Chain Weighted Indexe

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RISK MEASURES FOR 15 LOW RISK CANADIAN INDUSTRIALS

	Debt Ratings			Beta		Equity Ratio (Permanent Capital)
Company Name	S&P	DBRS	CBS Stock Rating	Raw	Adjusted	2001
CANADIAN TIRE CORP	BBB+	A (low)	Very Conservative	0.39	0.59	55.0%
CARA OPERATIONS LTD	BBB-	BBB	Average	0.36	0.57	68.8%
EMPIRE CO LTD	BBB-	BBB	Very Conservative	0.48	0.65	57.0%
FINNING INTERNATIONAL INC	BBB+	BBB (high)	Conservative	0.18	0.45	58.9%
JEAN COUTU GROUP			Conservative	0.20	0.46	74.5%
LEONS FURNITURE LTD			Average	0.29	0.52	99.9%
LOBLAW COS LTD	A	A (high)	Very Conservative	0.02	0.34	51.7%
MAGNA INTERNATIONAL	A	A	Conservative	0.34	0.56	86.9%
MAPLE LEAF FOODS INC			Conservative	0.68	0.79	51.2%
MOLSON INC	BBB+	A	Very Conservative	0.07	0.37	41.0%
ROTHMANS INC		A (low)	Average	-0.13	0.24	62.8%
SHAW COMMUNICATN INC	BBB	BBB	Very Conservative	0.67	0.78	41.3%
THOMSON CORP	A-	A (low)	Very Conservative	0.58	0.72	65.5%
TORSTAR CORP		BBB (high)	Very Conservative	0.47	0.65	51.2%
WESTON (GEORGE) LTD	A-	A (low)	Very Conservative	0.15	0.43	39.8%
MEDIAN	**BBB+**	**A (low)**	**Very Conservative**	**0.34**	**0.56**	**57.0%**

Source: Standard & Poor's Research Insight; DBRS Bond Ratings; Canadian Business Service; Standard & Poor's

John C. Roberts, C.A.
Vice-President, Finance and Chief Financial Officer
Newfoundland and Labrador Hydro

At the hearing into Newfoundland and Labrador Hydro's 2003 General Rate Application, the Finance and Corporate Services Evidence will be adopted by John C. Roberts, C.A., Vice-President, Finance and Chief Financial Officer for the Hydro Group of Companies.

A witness profile for John Roberts is as follows:

- Mr. Roberts obtained his C.A. designation in 1973 and is a member of the Institute of Chartered Accountants of Newfoundland.

- Mr. Roberts worked in private industry and with a national accounting firm before joining Newfoundland Hydro in 1983 as Accounting Manager. He was appointed Corporate Controller in 1985.

- In 2003 Mr. Roberts was appointed Vice-President, Finance and Chief Financial Officer.

- Mr. Roberts has testified before the Board of Commissioners of Public Utilities on several occasions, the first in 1985 and most recently in 2001.

Finance and Corporate Services
Evidence Outline

FINANCE AND CORPORATE SERVICES

1. RESPONSIBILITIES AND ORGANIZATIONAL STRUCTURE

1.1 Responsibilities

The various departments included under Finance and Corporate Services are responsible for:

- All accounting functions, including budgeting and financial reporting;
- Cash and debt management;
- Preparation of financial plans, Cost of Service ("COS") studies and rate policies and recommendations;
- Delivery of customer services for Rural Customers and administration of power contracts with major customers;
- Administration of the corporate insurance program;
- Internal audit activity related to the examination, evaluation and reporting on the systems of internal controls;
- Human resource management, including recruitment, training, labour relations and wellness;
- Corporate Safety and Health Program;
- Legal and corporate secretarial services;
- Procurement of goods and services, corporate administrative services and inventory control.

1.2 Organization

Finance and Corporate Services includes the Executive Management and the Internal Audit Department, Human Resources and Finance Divisions. Organizational charts outlining the various departments in each area are attached as Schedule I.

2. FINANCIAL RESULTS

2.1 Overview

Schedule II attached gives a comparison of Hydro's actual and forecast financial results used in the 2001 GRA for 2002 and forecast for 2003 and 2004 based on projections used to prepare this Rate Application.

2.2 Results for 2002

In accordance with P.U. 7, new rates for all of Hydro's customers were implemented on September 1, 2002. Therefore, the actual results for 2002 reflect eight months at rates that were based primarily on the 1992 test year final COS and four months at rates based on the 2002 test year final COS. This combination makes it difficult to make meaningful comparisons of certain categories in the 2002 test year final revenue requirement for a whole year to actual results for 2002.

The 2002 test year final revenue requirement and margin/return on equity have been adjusted to eliminate revenue and margin associated with a non-regulated Labrador Industrial Customer. The costs allocated to this customer from the COS process are shown as a separate line item in the Allocations section of the Revenue Requirement Schedule II attached.

In P.U. 7 the Board reduced the 2002 test year final revenue requirement by a general productivity allowance of $2.0 million. No specific direction was given as to which expenditures were to be reduced. To expedite the completion of the 2002 test year final revenue requirement when it was filed in August 2002, the productivity allowance was shown as a separate item.

Total fuel expense for 2002 is $15.4 million less than the 2002 test year final revenue requirement of $88.6 million. This decrease is primarily due to adjustments arising from the operation of the Rate Stabilization Plan ("RSP") offset by higher No. 6 fuel oil costs resulting from increases in quantity and prices. The RSP adjustments provide for the deferral of variances arising from changes in fuel prices, hydrology and load used in setting rates compared to actual results.

Power purchased costs increased due to more energy being available from the Non-Utility Generators ("NUGS").

Total other costs were $91.1 million in 2002, an increase of $5.4 million over the 2002 test year final revenue requirement due primarily to increased salary and fringe benefit costs, losses on disposal of fixed assets and the productivity allowance offset by higher capitalized expense.

Salaries and fringe benefits were $2.6 million higher than the 2002 test year final revenue requirement. An increase in overtime of $1.0 million, which is directly related to capital projects and reflected in the increase in Hydro capitalized expense, together with approximately $1.0 million in severance costs associated with the elimination in 2002 of 46 full-time positions are the main contributors to this variance.

The write-off of diesel plant assets destroyed in a fire at Rencontre East and disposed assets at Holyrood contributed to the increase in the loss on disposal of fixed assets. The other significant variances are capitalized expenses and the productivity allowance. Capitalized expense allocations increased by $2.4 million in 2002 due to higher than anticipated involvement by Hydro employees in the capital program.

Interest expense was slightly higher than the 2002 test year final revenue requirement. Overall, Hydro earned a margin of $9.7 million in 2002.

2.3 2003 Forecast

New capacity additions are coming into service in 2003 consisting of Granite Canal and the power purchase contracts with the Exploits River Hydro Partnership and Corner Brook Pulp & Paper Limited ("CBPP"). The significant additional costs associated with this new capacity are not reflected in the rates Hydro is presently charging its customers.

Depreciation expense in 2003 is forecast to be $32.8 million, an increase of $1.5 million over 2002 actuals, primarily due to additions to plant in service.

Total fuel expense for 2003 is forecast to be $91.2 million, an increase of $17.9 million from 2002 actuals. This increase is mainly due to higher prices for No. 6 fuel offset in part by a forecast return to average reservoir inflows, new purchases from NUGS and the coming in service of Granite Canal.

Power purchased costs increase because the two new NUGS come into service and begin selling energy during the year. The purchases from CBPP account for the majority of the increase in 2003.

Total other costs are forecast to be $89.4 million in 2003, a decrease of $1.7 million from the 2002 actuals. All categories of expenses under the heading "Other Costs" reflect a decrease in 2003 other than insurance where a restricted market is contributing to significant increasing costs; office supplies where heat, light and telephone costs are expected to increase; and equipment rentals where computer rental costs are expected to increase. The decrease in salaries and fringe benefits reflects the full year effect of the elimination of 46 full-time positions in 2002, offset by negotiated union adjustments and non-union salary adjustments. Capitalized expense decreases in 2003 when compared with 2002 and is directly related to a smaller capital program in 2003 due to the completion of Granite Canal.

The increase in interest expense is due to a higher average debt balance and related debt guarantee fee partially offset by an increased credit for financing charges associated with the projected RSP balances.

In the absence of an increase in Hydro's rates, the cumulative effect of the increases in costs as outlined above, results in a forecast loss of $7.8 million for 2003.

2.4 2004 Forecast

Depreciation expense in 2004 is forecast to be $33.9 million, an increase of $1.1 million over 2003 primarily due to additions to plant in service.

Total fuel expense for 2004 is forecast to be $92.5 million, a $1.4 million increase over 2003. The $84.4 million for No. 6 fuel costs is based on the assumptions set out in this Application in the Production Evidence.

The increase in power purchased costs is primarily the full year's effect of purchasing power from the Exploits River Hydro Partnership.

Total other costs are forecast to be $90.9 million in 2004, an increase of $1.6 million from 2003, due primarily to lower allocations to capitalized expense and non-regulated activities. Costs allocated to the non-regulated customer are determined through the COS study. Salaries and fringe benefits are projected to decline slightly from 2003, while system equipment maintenance costs increase slightly over 2003 and insurance costs continue to increase as a result of market conditions.

Capitalized expense continues to decrease in 2004 when compared to 2003. This is reflective of an overall smaller capital program combined with a change in the mix of capital projects that require the involvement of Hydro personnel.

The increase in interest expense is primarily due to the full year's impact of the 2003 long-term debt issue and forecast increase in short-term interest rates.

The forecast return on equity for 2004 is $19.4 million based on the requested return on equity for 2004 of 9.75%.

The total increase in revenue requirement for 2004 is $54.8 million over the 2002 test year final revenue requirement.

Achieving the forecast 2004 revenue requirement requires an average increase in base electrical rates for Newfoundland Power and Industrial Customers of 13.7% and 13.5% respectively, as outlined in the Rates and Customer Services Evidence.

3. FINANCIAL OBJECTIVES AND TARGETS

3.1 Overview

This section of the evidence reviews the elements of a sound financial position for Hydro, including a consideration of the financial and business risks that are faced by Hydro.

The appropriate financial targets for Hydro are addressed, along with a discussion of Hydro's plans to reach these targets. These targets include achieving and maintaining a percentage of debt to capital of 80%, a return on equity of 9.75% and a return on rate base for 2004 of 8.15%.

The Electrical Power Control Act, 1994 states that rates should be set to allow Hydro to earn a just and reasonable return as construed under the Public Utilities Act so that it is able to achieve and maintain a sound credit rating in the financial markets of the world.

The actual financial results for 2002 and forecast results for 2003, assuming no change in electrical rates, are set out in Table 1 below.

Table 1

Financial Results	2002 Actual	2003 Forecast
Return on Rate Base	7.25%	6.17%
Return on Equity	4.0%	(3.8%)
Debt to Capital	85%	86%

Hydro does not consider these 2003 levels of return to be just and reasonable. These results, if continued, are inadequate to maintain the financial integrity of Hydro. Hydro is requesting an increase in its revenue requirement for 2004, as outlined in section 2.4, to allow it an opportunity to recover all reasonable and prudent costs incurred in providing service to its customers and to earn a just and reasonable return on its rate base.

Hydro's return to suppliers of capital is dictated largely by the degree of financial and business risk inherent in their investment. Hydro's suppliers of capital fall into two groups: debt holders and shareholders; the latter being the people of the Province, as represented by the Government of Newfoundland and Labrador.

The existence of the provincial guarantee permits Hydro to raise debt at a lower cost than a stand-alone utility with a similar debt rating. Holders of Hydro's debt recognize that the presence of the guarantee has the effect of attributing a level of risk to Hydro's debt equal to that associated with the debt of the Province. This is because the presence of the guarantee puts the full weight of the Province's financial resources behind Hydro's debt instruments.

In the case of the shareholder, the presence of the guarantee does not alleviate the business risk faced by the holder of equity. Hydro's financial integrity and credit-worthiness are of concern to the shareholder, and are key determinants in what constitutes a reasonable rate of return on equity.

Hydro has established its financial objectives and targets based on an appropriate level of financial risk, given the business risks it faces and the presence of the guarantee. A consideration of the business and financial risks associated with the Province's investment in Hydro governs the recommendation as to the appropriate level of return on that investment. The financial targets have been established based upon the advice of Ms. McShane, Hydro's financial expert, and consideration of Hydro's future performance estimates.

3.2 Business Risk

Business risk is represented by factors that can unexpectedly impinge on the cash flows of a company. Such risks include credit, interest rate, economic, operating and regulatory risks. These risks are key determinants to providers of capital (e.g. bankers, bondholders and shareholders), of the rate of return required on their capital investment.

The evidence of Ms. McShane contains an analysis of the business risks faced by Hydro and concludes that Hydro's business risk is no less than that faced by the typical Canadian investor-owned electric utility, including Newfoundland Power.

3.3 Financial Risk

Financial risk is represented by the degree of leverage associated with the capital structure. The more debt versus equity, the greater the leverage, and the greater the financial risk. This is because the presence of debt entails the levy of a fixed charge in interest and principal against the cash flows of Hydro. This fixed charge must be covered, regardless of whether Hydro performs well or not. Share capital, on the other hand, does not entail a fixed charge, and hence provides a measure of flexibility in the event of unexpected cash flow requirements. If there is little equity in the capital structure, financial flexibility is reduced.

3.4 Capital Structure

A prudent level of leverage affords a business a level of financial flexibility adequate to withstand a major business risk event, or a series of smaller ones. For a stand-alone utility, it allows access to capital markets at a reasonable cost, that is, permits it to have an investment grade debt rating.

Hydro's goal of 80% debt is too high for a utility by commercial standards. It is only through the presence of the provincial guarantee that Hydro is able to only through the presence of the provincial guarantee that Hydro is able to operate with 80% debt to capital, and maintain its overall cost of capital at a level comparable to that of an independently financed commercial utility. The presence of the guarantee effectively results in Hydro's credit rating being the same as that of the Province. Hydro's goal is to ensure that its financial position is such that it does not impinge on the credit rating of the Province.

Ms. McShane's evidence concludes that an 80% debt to capital target should be viewed as the upper end of a reasonable range associated with being self-supporting. Hydro's ability to withstand an event of business risk must be preserved by maintaining the percentage of debt to capital at a level that provides adequate financial flexibility. As the actual percentage of debt to capital for 2002 of 85% and the 2004 forecast of 86% are both above the high end of the range of reasonableness, it is considered prudent to commence moving toward a capital structure of 80% debt over the next five years. Based on current estimates and assuming the electricity rates proposed in this Application, significant progress toward this goal will entail some modification of the current dividend policy as outlined in Table 2 below:

Table 2

Capital Structure Impacts

	75% Payout	**50% Payout**	**25% Payout**
Net Income for the Period 2004 to 2008 ($millions)	103	108	114
Dividends for the Period 2004 to 2008 ($millions)	77	54	29
Debt to Capital in 2008	85%	83%	81%

Notes:
(1) Debt to capital at December 31, 2002 is 85%.
(2) Net income and resulting dividends are based on the assumption that rates are set annually to recover each year's costs as outlined in the Financial Projection.
(3) Return on Equity is 9.75%.
(4) The above figures for 2008 are based on preliminary analysis

Hydro has initiated discussions with the Province on modifications to the dividend policy, designed to facilitate progress toward our stated goal of 80% debt to capital.

3.5 Return on Equity

The appropriate rate of return on equity for Hydro should be governed by the same principles as would apply to any equity investor. Hydro's shareholder is entitled to a return on its investment commensurate with the attendant risk. Risk is defined by the financial and business risk faced by Hydro. In the case of business risk, Hydro's financial expert has concluded that, on balance, Hydro's business risk is no less than the typical investor-owned electric utility in Canada. With respect to financial risk, Hydro's financial expert concludes that, "a target capital structure for Hydro of 80% debt represents the upper end of reasonableness, even with a debt guarantee". Based on this risk profile, Ms. McShane classifies Hydro as "an average risk Canadian utility", and determines Hydro's appropriate return on equity on that basis, using three alternate tests relied upon by regulators to determine a just and reasonable return. Ms. McShane concludes that a fair return for an average risk Canadian utility is in the range of 11.25-12.0%, or approximately 11.5%, considering all three alternate tests.

The determination of an appropriate return on equity is not an exact science, but is an exercise of judgment. Having considered this and all the relevant factors, including the recommendation of Hydro's financial expert who concludes that Hydro has no less business risks than the typical investor-owned electric utility in Canada including Newfoundland Power, the other regulated utility in this jurisdiction that recently received approval for a 9.75% return on equity, Hydro, to expedite the disposition of this issue, is prepared to accept the same rate of return on equity of 9.75% for this Application.

4. RATE BASE

4.1 Overview

Hydro's rate base is comprised of capital assets in service, fuel inventory, supplies inventory, deferred foreign exchange losses and rate hearing costs, as well as an allowance for cash working capital. Schedule III gives a comparison of Hydro's actual and forecast rate base used in the 2001 GRA for 2002 and forecast results for 2003 and 2004 based on projections used to prepare this Rate Application.

Rate base is increased through capital projects and decreased through the recognition of depreciation expense. To the extent that the capital program exceeds the depreciation amounts, the rate base will grow.

4.2 Rate Base Components

On an actual basis, capital assets brought in service during 2002 were $3.4 million more than the 2002 capital budget of $36.8 million used in the final COS. This is primarily due to the purchase of Aliant support structures approved by the Board in Order No. P.U. 28 (2002-2003). These additions to capital during the year were more than offset by higher than anticipated disposals of assets resulting in the net average assets in service for 2002 being $2.9 million less than forecast.

The primary reason for an increase in capital assets in 2003 and 2004 compared to those contained in the 2002 rate base is the inclusion of the assets of Granite Canal which comes into service during 2003 at a cost of $135 million.

Fuel and supplies inventories are based on projected 13-month average balances. The actual average balances of fuel and supplies inventories on hand during 2002 exceeded the forecast by $2 million. This is the net effect of a $3.8 million increase in fuel inventory balances due to higher than forecast fuel prices, offset by a $1.7 million reduction in average supplies inventory balances. Hydro has been able to reduce its average supplies inventory balances through a review of its business processes, including its inventory management, which has been in progress since early 2002.

Net deferred realized foreign exchange losses totaling $86.3 million, as at December 31, 2001, are being amortized over 40 years commencing in 2002 at a rate of $2.2 million per year, as approved by P.U. 7. The amount in rate base is the average of the opening and closing outstanding balances for each year.

In addition, Hydro has included an estimated $1.2 million in external costs associated with this Rate Application to be recovered over a three-year period. The average of the opening and closing balance of this deferred amount is included in rate base for 2004 since Hydro will have to finance these expenditures until they are recovered from customers.

Finally, the forecast rate base includes an allowance for cash working capital, which has been calculated in accordance with the methodology approved by the Board during the 2001 GRA.

Actual cash working capital requirement during 2002 was $0.6 million higher than forecast primarily due to a $4.3 million increase in operating expenses above those forecast, which increased the base upon which the allowance is calculated and a decrease in the expense lag which increased the working capital percentage.

Although there has been an increase in power purchases for 2003 and 2004, which increases the base upon which the allowance is calculated, there has also been a decrease in capital expenditures, which increases the HST adjustment, resulting in the amount of cash working capital required being approximately equal to that required during the 2002 test year.

4.3 Return on Rate Base

The Board has directed that Hydro not earn any return on equity on Isolated Rural and Island Interconnected Systems assets. Consequently, Hydro's return on rate base is calculated by applying its weighted average cost of debt to those rural assets, and its weighted average cost of capital to the remainder of its rate base. The requested return on rate base for 2004 is $121.1 million and the calculation is shown on Schedule IV attached.

4.4 Weighted Average Cost of Capital

Hydro's rate of return on rate base is based on its weighted average cost of capital as outlined on Schedule V attached.

Hydro's weighted average cost of capital is projected to be 8.32% in 2004, compared to a rate of 7.157% in the 2002 test year final COS. The primary reason for the increase of 1.16 % is that Hydro is requesting a reasonable rate of return on equity during this proceeding.

A number of factors have influenced the capital structure since the last rate hearing. Debt levels have risen due to the growing balance in the RSP and the ongoing financing of Granite Canal. As well, the balance of equity has declined due to the payment of dividends in 2002 and the projected net loss on regulated operations during 2003. The cumulative impact of these factors has resulted in a forecast average debt to capital of 86% for 2004 versus 81% in the 2002 test year final COS. This deterioration in the percentage of debt to capital since the 2001 GRA partially offsets the impact that an increase in return on equity would otherwise have on the weighted average cost of capital.

4.5 Employee Future Benefits

The latest actuarial valuation of Hydro's Employee Future Benefits was completed effective December 31, 2002 and it resulted in an actuarial loss of

$6.6 million. In accordance with generally accepted accounting principles the excess of cumulative net actuarial gains and losses over 10% of the accrued benefit obligation will be amortized over a 12-year period, which is the expected average remaining service life of the employee group.

This loss was primarily caused by higher than previously forecast increases in health care costs as well as retiree usage of health benefits being higher than forecast. These increases in health care costs and usage have also resulted in an increased projection of the current service costs of providing future benefits. Both the increase in the valuation of the accrued benefit obligation and current service costs have caused an increase in the interest expense component as well. Schedule VI attached shows a summary of the impact of the actuarial valuation.

4.6 Cost of Debt

The calculation of the cost of debt is contained on Schedule VII attached and is consistent with the methodology approved by the Board in P.U. 7 during the 2001 GRA. The forecast for 2004 is 8.29% versus 8.17% in the 2002 test year final COS.

4.7 Semi-Annual Long-Term Bond Interest

In P.U. 7 the Board directed Hydro to submit, prior to its next application, an analysis of the issue, raised by Mr. Drazen on behalf of Labrador City, that the calculation of cash working capital should recognize the timing differences between the payment of semi-annual long-term bond interest and the receipt of funds for their payment. This was filed April 8, 2003 and is attached as Exhibit JCR-1. This analysis concludes that while there may be a theoretical validity to an approach which considers all financial terms, including depreciation, that approach adds a degree of complexity which is unwarranted for the purpose of estimating a reasonable cash working capital allowance, particularly given that

4.8 Financial Results

Schedule VIII attached shows Hydro's projected balance sheet for 2004.

Schedule IX attached is a statement of retained earnings and outlines the margin/return on equity and projected dividend payments. It should be noted that the dividend payments shown in 2003 are the final settlement related to 2002 earnings. Average retained earnings and the return on equity percentage have also been included.

Schedule X attached is a statement of cash flows and outlines the sources of funds generated internally from operations and externally through promissory notes and long-term borrowings and how these funds will be expended.

5. BORROWING PROGRAM

5.1 Overview

This section of evidence includes a review of Hydro's 2002 borrowing program in comparison to that which was contemplated in the 2001 GRA. It also outlines Hydro's borrowing plans for the years 2003 and 2004 and the basis for its interest rate estimates for those years.

5.2 Borrowing Strategy

Hydro's borrowing strategy encompasses both a short-term promissory note program and longer-term debentures that are usually issued in the domestic market and denominated in Canadian currency. Pursuant to Section 33 of the Hydro Corporation Act, Hydro's short-term debt as prescribed by Order in Council may not exceed $300 million. Hydro's short-term debt level is impacted by factors such as market conditions and expected cash requirements. When the total short-term debt reaches an amount which indicates that some or all of the balance should be funded long-term, Hydro considers issuing a debenture. Hydro thus utilizes the flexibility afforded by the $300 million limit to ensure the appropriateness of the timing for going to the capital market for long-term debt, rather than being driven by an absolute requirement for funds.

5.3 2002 Borrowing Program Compared to 2002 Test Year Final Revenue Requirement

Hydro's 2002 test year final revenue requirement had contemplated the completion of two long-term debt issues totaling $250 million. The first issue was scheduled for the first half of 2002 and totaled $100 million for a five-year term at an assumed interest rate of 4.9%. The second issue was scheduled for the second half of 2002 and totaled $150 million for a 30-year term at an assumed interest rate of 6.7%. Both debentures were issued at the face value and in the timeframes as planned. The applicable interest rates realized were 5.05% for the five-year debenture and 6.65% for the 30-year debenture.

5.4 2003 Borrowing Plans

In 2003, Hydro is forecasting a long-term borrowing requirement of $125 million which will be funded by one debenture, issued in the Canadian domestic bond market, denominated in Canadian funds. It is expected that the issue will be long term in nature; i.e. beyond a 20-year term, and an applicable interest rate of approximately 6.65% has been assumed with issuance planned for the second half of the year.

The promissory notes balance is expected to average approximately $200 million for the year, with a closing balance at the end of the year of $166 million which represents approximately 11% of Hydro's total debt load.

5.5 2004 Borrowing Plans

At this time, Hydro does not contemplate the issuance of additional long-term debt in 2004. In the absence of any additional long-term borrowing in 2004, current projections are for a promissory note portfolio totaling $153 million at the end of that year, which would represent approximately 11% of Hydro's total debt portfolio at that time. Schedule XI attached provides specific details on Hydro's outstanding long-term debt for 2003 and 2004.

5.6 Interest Rate Projections

In order to arrive at the interest rate projections for 2003 and 2004, Hydro received quarterly interest rate projections from five investment dealers on Treasury Bills and 5 year, 10 year and 30 year Government of Canada Bonds. A simple average of these quarterly projections was computed and the current spreads applicable to our credit as provided by a lead manager was added to this average in order to determine projected interest rates.

6. RATE STABILIZATION PLAN

In accordance with P.U. 7, the balance in the Rate Stabilization Plan ("RSP") as of August 31, 2002 was frozen and is now referred to as the "Old RSP". Effective September 1, 2002 a "New RSP" has been created and operates in accordance with the rules and regulations approved in P.U. 7. Schedule XII attached shows the actual balances in both the old RSP and the new RSP as at December 31, 2002, as well as the projected balances for both plans for 2003 and 2004.

Fuel prices, significantly in excess of those forecast for 2002, have been the primary reason for continued growth in the outstanding balances of the new RSP. The production cost of No. 6 fuel averaged $30.60 per barrel in 2002, compared to the forecast of $25.45. For 2003 and 2004 the forecast production cost of fuel are $34.80 per barrel and $29.42 per barrel, respectively.

7. FINANCIAL REPORTING

Hydro accounts for its non-regulated activities in accordance with written policies and procedures filed with the Board in December 2002 and attached as Exhibit JCR-2.

Hydro charges each of its subsidiary companies for services provided on the basis of timesheet reporting, or other relevant basis of allocation, depending on the type of expense that is being recovered.

Hydro has established business units for each of its non-regulated activities, including: export sales; non-regulated sales to one industrial customer; new business development; and non-regulated costs, such as donations and advertising.

All revenues and expenses related to non-regulated companies or activities have been removed from the revenue requirement for 2004.

8. FINANCE AND CORPORATE SERVICES OPERATING COSTS

8.1 Overview

Schedule XIII attached gives a comparison of the combined net operating expenses for a number of corporate services, including Finance, Executive Management, Internal Audit and Human Resources/Legal ("Corporate Services") for the period 2002 to 2004. Certain corporate costs such as employee future benefits and group insurance are not allocated to other divisions, but are shown in this section.

8.2 Results for 2002

Net operating expenses for 2002 are $0.2 million less than the 2002 forecast of $23.7 million. Overall costs, which include the severance costs associated with the elimination of positions in 2002 and higher professional services and insurance costs, are lower than the 2002 test year final revenue requirement.

8.3 2003 Forecast

Net operating expenses for 2003 are forecast to be $1.4 million more than the 2002 actuals of $23.5 million primarily due to the increase in employee future benefits as determined by the latest actuarial valuation and outlined earlier in Section 4.5.

Salary costs are the single largest expenditure in Corporate Services and include the cost for full-time employees, temporary employees and apprentices. As a result of process changes, technological improvements and organizational changes, Corporate Services has been able to enhance efficiencies and has consequently, reduced its complement of permanent employees by 10% since 1999, as outlined in the following Table.

Table 3

Permanent Complement	1999	2000	2001	2002
Finance	85	84	84	80
Human Resources & Legal	71	66	66	60
Management	9	8	8	8
Internal Audit	4	4	4	4
Totals	169	162	162	152

The decrease in salaries reflects the full year's effect of the elimination of 10 positions which is partially offset by projected salary adjustments. Capitalized expense decreases in 2003 are due to a smaller capital program. The increase in corporate group benefits is primarily due to an increase in the cost of benefits included in the health care coverage. Insurance cost increases are due to a restricted market while professional services decreased due to a forecast reduction in external costs associated with business process improvement initiatives.

8.4 2004 Forecast

Net operating expenses for 2004 are $0.7 million more than the 2003 forecast of $25.0 million and the increase is primarily due to continued projected increases in insurance costs.

9. FINANCE AND CORPORATE SERVICES ISSUES AND DIRECTIONS

9.1 Overview

Optimization of corporate performance has been a focus of Hydro's strategic planning. In keeping with this objective, Finance and Corporate Services have undertaken the review of a number of business processes to identify and eliminate non-value added work and to leverage the functionality of Hydro's integrated software suite.

9.2 Processes Reviewed

Accounts Payable, the corporate purchasing card and travel, consumables and inventory were selected for detailed review and analysis in 2002.

All current processes in Accounts Payable were documented and major areas that contribute to rework have been identified and will be eliminated by the end of 2003.

The corporate purchasing card and travel process review identified improvements in processes which were implemented. General utilization of existing technology permitted automation of the process of recording purchasing card transactions and the payment of per diem travel costs.

Inventory, including practices with respect to consumable items, was also reviewed. Standard definitions were developed for consumables, normal inventory items, critical spares and capital spares. All items included in the supplies inventory were categorized in accordance with these definitions and this will assist in the management of inventory.

New processes with respect to consumables were also introduced. Consumable items (for example, electrical tape, safety gloves) used on a day-to-day basis, are now placed in bulk on the shop floor and readily accessible to workers.

The combined savings arising from the above noted business processes improvements, which has been reflected in the 2004 forecast, is approximately $600,000.

Another process review undertaken in 2002 was a meter reading route optimization study. A number of improvements were identified, including the combination of certain routes and the realignment of resources for meter reading. Implementation of the recommendations commenced in 2003 and will result in cost savings of approximately $128,000 annually once fully implemented.

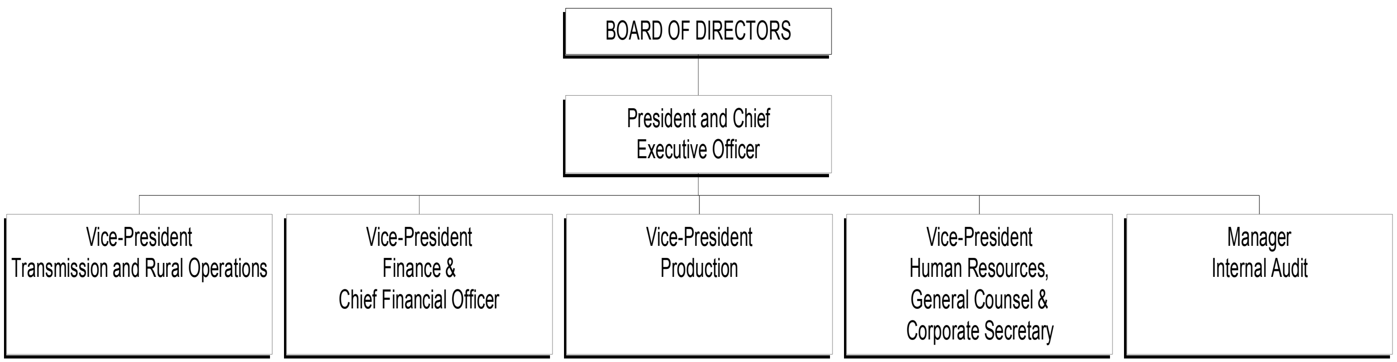
9.3 Initiatives – 2003-2004

There are three other processes that are currently being reviewed. The process used for the acquisition of goods and services is under review, as well as the required organizational structure to support centralization of inventory control. The second process that is being reviewed is work management including work identification and execution and budgeting which is focused on budgeting and reporting work activities. The third process is asset management which is merging the capital asset records with equipment records in order to have a single record that will provide fixed asset cost as well as operations and maintenance cost information.

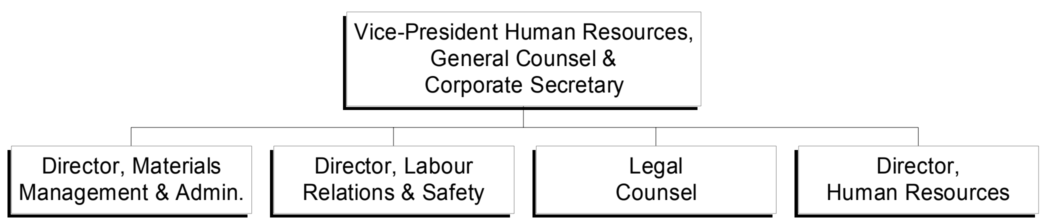
Identification and implementation of changes arising from the reviews of these business processes will extend beyond 2004.

FINANCE AND CORPORATE SERVICES
LIST OF SCHEDULES

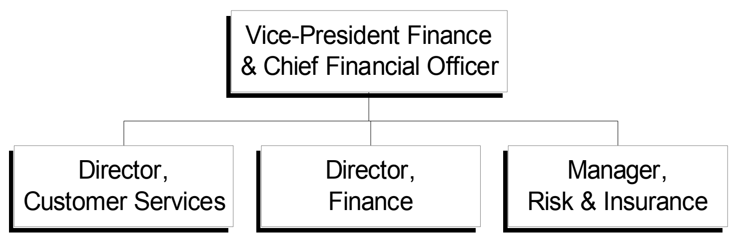
Organizational Chart – Management and Internal Audit



Organizational Chart – Human Resources and Legal



Organizational Chart – Finance



Schedule II
1st Revision - August 12, 2003
J. C. Roberts

NEWFOUNDLAND AND LABRADOR HYDRO

REVENUE REQUIREMENT

($thousands)

Line No.	Description	2002 Final Test Year Revenue Requirement	2002 Actuals	Increase (Decrease)	2003 Estimate	Increase (Decrease)	As Filed 2004 Forecast	As Filed Increase (Decrease)	Revised 2004 Forecast	Revised Increase (Decrease)
1	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
2										
3	**Depreciation**	31,390	31,302	(88)	32,786	1,484	33,932	1,146	33,932	0
4	**Fuel**									
5	No. 6 Fuel	81,237	112,534	31,297	126,029	13,495	84,410	(41,619)	84,410	0
6	Additives and Indirects	178	398	220	211	(187)	240	29	240	0
7	Environmental fee	124	88	(36)	50	(38)	56	6	56	0
8	Ignition Fuel	123	116	(7)	117	1	113	(4)	113	0
9	Gas Turbine Fuel	446	153	(293)	368	215	351	(17)	351	0
10	Diesel Fuel	6,508	6,766	258	7,542	776	7,378	(164)	7,378	0
11	Rate Stabilization Plan	0	(46,807)	(46,807)	(43,158)	3,649	0	43,158	0	0
12	**Total Fuel**	88,616	73,248	(15,368)	91,159	17,911	92,548	1,389	92,548	0
13	**Power Purchased**	15,100	15,881	781	25,288	9,407	33,315	8,027	33,315	0
14	**Other Costs**									
15	Salaries and Fringe Benefits	61,926	64,559	2,633	63,605	(954)	63,237	(368)	63,237	0
16	System Equipment Maintenance	16,763	17,179	416	17,024	(155)	17,419	395	17,419	0
17	Insurance	977	1,198	221	1,614	416	2,019	405	2,019	0
18	Transportation	1,923	1,979	56	1,955	(24)	2,044	89	2,044	0
19	Office Supplies Expenses	1,864	1,856	(8)	1,972	116	1,913	(59)	1,913	0
20	Building Rentals and Maintenance	626	900	274	898	(2)	894	(4)	894	0
21	Professional Services	4,943	5,318	375	4,641	(677)	4,503	(138)	4,503	0
22	Travel Expenses	2,375	2,315	(60)	2,248	(67)	2,139	(109)	2,139	0
23	Equipment Rentals	1,558	1,372	(186)	1,526	154	1,636	110	1,636	0
24	Miscellaneous Expenses	4,398	4,674	276	4,367	(307)	4,485	118	4,485	0
25	Productivity Allowance	(2,000)	0	2,000	0	0	0	0	0	0
26	Loss on Disposal of Fixed Assets	890	2,769	1,879	628	(2,141)	541	(87)	541	0
27	Sub-Total	96,243	104,119	7,876	100,478	(3,641)	100,830	352	100,830	0
28	Allocations									
29	Hydro Capitalized Expense	(5,722)	(8,116)	(2,394)	(6,405)	1,711	(5,464)	941	(5,464)	0
30	CF(L)Co	(1,910)	(2,006)	(96)	(1,807)	199	(1,777)	30	(1,777)	0
31	Non-Regulated Customer	(2,914)	(2,914)	0	(2,914)	0	(2,655)	259	(2,642)	13
31	Sub-Total	(10,546)	(13,036)	(2,490)	(11,126)	1,910	(9,896)	1,230	(9,883)	13
33	**Total Other Costs**	85,697	91,083	5,386	89,352	(1,731)	90,934	1,582	90,947	13
34	**Interest**	88,298	88,547	249	95,767	7,220	101,411	5,644	101,715	304
35	**Margin/Return on Equity**	7,959	9,742	1,783	(7,806)	(17,548)	21,179	28,985	19,384	(1,795)
36	***Revenue Requirement***	317,060	309,803	(7,257)	326,546	16,743	373,319	46,773	371,841	(1,478)

Newfoundland and Labrador Hydro
Rate Base
($thousands)

	2002 Test Year Final	2002 Actual	2003 Forecast	As Filed 2004 Forecast	Revised 2004 Forecast
Capital Assets	1,765,804	1,757,726	1,924,780	1,947,670	1,947,670
Less: Contributions in Aid of Construction	87,272	87,569	86,668	86,397	86,397
Accumulated Depreciation	439,076	433,572	465,334	497,452	497,452
Muskrat Falls Assets	2,010	2,010	2,010	2,010	2,010
Assets not in Service	117	155	79	74	74
Net Capital Assets	1,237,329	1,234,420	1,370,689	1,361,737	1,361,737
Net Capital Assets Previous Year	1,234,447	1,224,068	1,234,420	1,370,689	1,370,689
Average Capital Assets	1,235,888	1,229,244	1,302,555	1,366,213	1,366,213
Cash Working Capital Allowance	2,942	3,579	3,625	3,075	3,057
Fuel Inventory	13,942	17,715	16,292	14,907	14,907
Supplies Inventory	21,095	19,966	19,387	19,387	19,387
Deferred Realized Foreign Exchange Loss plus PUB Costs	85,703	85,703	83,043	81,886	81,886
Average Rate Base	1,359,570	1,356,207	1,424,902	1,485,468	1,485,450
Return – Schedule II	96,257	98,289	87,961	122,590	121,099
Rate of Return on Rate Base	7.08%	7.25%	6.17%	8.25%	8.15%

NEWFOUNDLAND AND LABRADOR HYDRO
RATE BASE

1. Capital Assets

   For 2003 and 2004, the amounts reflect the forecast capital asset balances as at December 31, 2002 and have been adjusted for the impact of the Board approved 2003 capital budget and the projected capital budget for 2004. Construction work in progress is not included in these numbers.

2. Contributions in Aid of Construction

   These funds have been received from customers and governments toward the cost of capital assets. Contributions are treated as a reduction to capital assets and the net capital assets are depreciated.

3. Accumulated Depreciation

   Accumulated depreciation has been calculated on the capital asset balances outlined in Item 1 above.

4. Muskrat Falls Assets

   These assets are fully contributed and are deducted from capital assets.

5. Net Capital Assets

   This is the net capital assets to be included in rate base.

NEWFOUNDLAND AND LABRADOR HYDRO
RATE BASE

6. Cash Working Capital Allowance
   This amount represents an allowance to cover the amount of capital which investors provide in order to bridge the gap between the time expenditures are made to provide service and the time payment is received for the service. For each year, 2002 to 2004, the working capital requirement as a percentage of operating maintenance expenses and power purchases, was 3.34%, 3.10% and 2.42%, respectively.

7. Fuel Inventory
   This amount is based on a thirteen-month average.

8. Supplies Inventory
   This amount is based on a thirteen-month average.

9. Deferred Realized Foreign Exchange Loss and the Board Costs
   This amount is the average of the opening and closing balances of the account for each year-end.

Newfoundland and Labrador Hydro
Return on Rate Base
($thousands)
As filed

Component Base	2004	Weighted Average Cost of Debt	Weighted Average Cost of Capital	Return on Rate Base
Rural Interconnected and Isolated Assets	213,761	7.134%		15,250
Other Rate Base Assets	1,271,707		8.440%	107,332
Average Rate Base	1,485,468			122,582 [1]

Revised

Component Base	2004	Weighted Average Cost of Debt	Weighted Average Cost of Capital	Return on Rate Base
Rural Interconnected and Isolated Assets	213,758	7.138%		15,258
Other Rate Base Assets	1,271,692		8.322%	105,830
Average Rate Base	1,485,450			121,088 [1]

[1] This amount is different than the interest plus margin per Schedule II due to limitations of rate rounding.

Newfoundland and Labrador Hydro
Weighted Average Cost of Capital
($thousands)

As Filed

	2003	2004	Average	Percent	Cost	Weighted Average
Promissory Notes	166,075	153,327				
Long-Term Debt (Schedule VII)	1,420,809	1,417,529				
Less: Sinking Funds	110,981	129,123				
CF(L)Co Share Purchase Debt	28,550	24,104				
Unamortized Debt Discount and Issue Expenses	(5,896)	(6,447)				
Total Debt	1,453,249	1,424,076	1,438,662	86.13	8.283%	7.134%
Employee Future Benefits	27,464	29,941	28,703	1.72	0.000%	0.000%
Retained Earnings	200,419	205,713	203,066	12.15	10.750%	1.306%
	1,681,132	1,659,730	1,670,431	100.00		8.440%

Revised

	2003	2004	Average	Percent	Cost	Weighted Average
Promissory Notes	166,075	153,364				
Long-Term Debt (Schedule XI)	1,420,809	1,417,529				
Less: Sinking Funds	110,981	129,123				
CF(L)Co Share Purchase Debt	28,550	24,074				
Unamortized Debt Discount and Issue Expenses	(5,896)	(6,447)				
Total Debt	1,453,249	1,424,143	1,438,696	86.14	8.287%	7.138%
Employee Future Benefits	27,464	29,941	28,703	1.72	0.000%	0.000%
Retained Earnings	200,419	205,265	202,842	12.14	9.750%	1.184%
	1,681,132	1,659,349	1,670,241	100.00		8.322%

Newfoundland and Labrador Hydro
Employee Future Benefits
($millions)

	2002 COS	2002 Actual	2003 Forecast	2004 Forecast
Current Service	0.7	0.7	1.1	1.0
Interest	1.7	1.7	2.3	2.4
Amortization of Actuarial Loss	0.0	0.0	0.3	0.3
Total Expense	2.4	2.4	3.7	3.7
Accrued EFB Obligation	25.1	31.9	34.1	36.3
Accrued EFB Liability	25.1	24.9	27.4	29.9

Newfoundland and Labrador Hydro
Cost of Debt
($thousands)

	As Filed 2004	Revised 2004
Interest	112,259	112,289
Amortization of Foreign Exchange Loss	2,157	2,157
Amortization of Debt Discount and Issue Expense	550	550
Debt Guarantee Fee	14,453	14,453
	129,419	129,449
Less: Interest on Sinking Fund Assets	8,117	8,117
CF(L)Co Share Purchase Debt	2,136	2,106
Net Interest	119,166	119,226

As Filed	Revised
Cost of Debt = Net Interest / Total Debt = 119,166 / 1,438,662 = 8.283%	Cost of Debt = Net Interest / Total Debt = 119,226 / 1,438,696 = 8.287%

Schedule VIII
1st Revision - August 12, 2003
J. C. Roberts

Newfoundland and Labrador Hydro
Projected Balance Sheet
(Excluding CF(L)Co., LCDC and Contributed Capital - Muskrat Falls)

As at December 31 (thousands of dollars)

	2003	As Filed 2004	Revised 2004
ASSETS			
Capital assets			
Capital assets in service	1,836,023	1,859,189	1,859,189
Less accumulated depreciation	465,334	497,452	497,452
	1,370,689	1,361,737	1,361,737
Construction in progress	55,403	69,299	69,299
	1,426,092	1,431,036	1,431,036
Current assets			
Accounts receivable	42,452	48,137	47,974
Fuels and supplies at average cost	35,817	31,621	31,621
Prepaid expenses	2,056	1,958	1,958
	80,325	81,716	81,553
Rate stabilization plans	161,109	131,502	131,330
Unamortized debt premium and financing expense	(5,896)	(6,446)	(6,446)
Unamortized foreign exchange loss	81,964	79,807	79,807
Unamortized PUB costs	1,200	800	800
	1,744,794	1,718,415	1,718,080
LIABILITIES AND SHAREHOLDER'S EQUITY			
Long-term debt	1,265,437	1,247,909	1,247,939
Current liabilities			
Accounts payable and accrued liabilities	41,603	35,429	35,473
Accrued interest	27,955	29,705	29,705
Long-term debt due within one year	15,841	16,393	16,393
Promissory notes	166,075	153,327	153,364
	251,474	234,852	234,935
Employee future benefits	27,464	29,941	29,941
Shareholder's equity			
Retained earnings	200,419	205,713	205,265
	1,744,794	1,718,415	1,718,080

Newfoundland and Labrador Hydro
Projected Statement of Retained Earnings
(Excluding CF(L)Co., LCDC and Contributed Capital - Muskrat Falls)

Year ended December 31 (thousands of dollars)

	2003	As Filed 2004	Revised 2004
Retained earnings, beginning of year	213,789	200,419	200,419
Margin/return on equity	(7,806)	21,179	19,384
	205,983	221,598	219,803
Dividends	(5,564)	(15,885)	(14,538)
Retained earnings, end of year	200,419	205,713	205,265
Average retained earnings	207,104	203,066	202,842
Return on equity	(3.8)%	10.4%	9.6%

Schedule X
1st Revision - August 12, 2003
J. C. Roberts

Newfoundland and Labrador Hydro
Projected Statement of Cash Flows
(Excluding CF(L)Co., LCDC and Contributed Capital - Muskrat Falls)

Year ended December 31 (thousands of dollars)

	2003	As Filed 2004	Revised 2004
Cash provided by (used in)			
Operating activities			
Net income	(7,806)	21,179	19,384
Adjusted for items not involving a cash flow			
Depreciation	32,786	33,932	33,932
Amortization of deferred charges	3,520	3,107	3,107
Rate stabilization plan	(36,344)	29,607	29,779
Other	703	708	708
	(7,141)	88,533	86,910
Change in working capital balances	(9,156)	(3,340)	(3,131)
	(16,297)	85,193	83,779
Financing activities			
Long-term debt issued	125,000	0	0
Long-term debt retired	(7,360)	1,166	1,196
Dividends	(5,564)	(15,885)	(14,538)
	112,076	(14,719)	(13,342)
Investing activities			
Net additions to capital assets	(71,279)	(39,584)	(39,584)
Increase in sinking funds	(16,292)	(18,142)	(18,142)
Reduction (additions) to deferred charges	7,632	0	0
	(79,939)	(57,726)	(57,726)
Net decrease in promissory notes	15,840	12,748	12,711
Promissory notes, beginning of year	(181,915)	(166,075)	(166,075)
Promissory notes, end of year	(166,075)	(153,327)	(153,364)

Newfoundland and Labrador Hydro
Schedule of Long-Term Debt
($thousands)

Series	Interest Rate %	Year of Issue	Year of Maturity	2003	2004
AA	5.50	1998	2008	200,000	200,000
V	10.50	1989	2014	125,000	125,000
X	10.25	1992	2017	150,000	150,000
Y	8.40	1996	2026	300,000	300,000
AC	5.05	2001/2002	2006	200,000	200,000
AB	6.65	2001/2002	2031	300,000	300,000
	6.65	2003	2031	125,000	125,000
				1,400,000	1,400,000
Government of Canada loans at 5.25% to 7.91%					
maturing in 2006 to 2014				18,805	16,420
Capital Leases				2,004	1,109
Total				1,420,809	1,417,529

Newfoundland and Labrador Hydro
Rate Stabilization Plans
($millions)

	2002 Actual	2003 Forecast	As Filed 2004 Forecast	Revised 2004 Forecast
Old RSP				
Retail	76.3	70.1	59.6	59.5
Industrial	28.0	24.0	19.8	19.8
Total Balance	104.3	94.1	79.4	79.3
New RSP				
Retail	15.8	50.2	42.5	42.5
Industrial	4.7	16.8	9.6	9.5
Total Balance	20.5	67.0	52.1	52.0
Combined RSP Balances				
Retail	92.1	120.3	102.1	102.0
Industrial	32.7	40.8	29.4	29.3
Total Combined RSP	124.8	161.1	131.5	131.3
Average Fuel Price per Barrel	$ 30.60	$ 34.80	$ 29.42	$ 29.42

NEWFOUNDLAND AND LABRADOR HYDRO
NET OPERATING EXPENSES
FINANCE AND CORPORATE SERVICES
($thousands)

Line No.	Description	2002 Test Year Final Revenue Requirement	2002 Actuals	Increase (Decrease)	2003 Estimate	Increase (Decrease)	2004 Forecast	Increase (Decrease)
1	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
2	**Expense Group**							
3	Salaries and Fringe Benefits							
4	Permanent Salaries	9,391	9,311	(80)	9,946	635	10,139	193
5	Hourly Wages	1,662	1,668	6	0	(1,668)	0	0
6	Overtime	129	254	125	185	(69)	168	(17)
7	Capitalized Expenses	(952)	(1,457)	(505)	(952)	505	(818)	134
8	Employee Future Benefits	2,433	2,446	13	3,631	1,185	3,727	96
9	Corporate Group Benefits	1,680	1,123	(557)	2,000	877	1,950	(50)
10	Fringe Benefits	1,498	1,491	(7)	1,579	88	1,606	27
11	Vacancy Adjustment	(314)	0	314	(201)	(201)	(508)	(307)
12	**Sub-Total**	15,527	14,836	(691)	16,188	1,352	16,264	76
13	System Equipment Maintenance							
14	Maintenance Materials	1,029	983	(46)	1,021	38	989	(32)
15	Tools and Operating Supplies	4	(1)	(5)	4	5	4	0
16	Freight	200	293	93	200	(93)	200	0
17	**Sub-Total**	1,233	1,275	42	1,225	(50)	1,193	(32)
18	Other Expenses							
19	Office Supplies and Expenses	812	891	79	916	25	914	(2)
20	Professional Services	1,951	2,302	351	1,686	(616)	1,828	142
21	Insurance	977	1,198	221	1,614	416	2,019	405
22	Equipment Rentals	2	0	(2)	2	2	2	0
23	Travel	401	252	(149)	388	136	331	(57)
24	Miscellaneous	3,842	3,986	144	3,915	(71)	4,091	176
25	Property Rentals	55	44	(11)	58	14	68	10
26	Transportation	84	111	27	108	(3)	107	(1)
27	**Sub-Total**	8,124	8,784	660	8,687	(97)	9,360	673
28	**Total Operating Expenses**	24,884	24,895	11	26,100	1,205	26,817	717
29	**Allocations**							
30	Recoveries	(1,153)	(1,350)	(197)	(1,149)	201	(1,169)	(20)
31	***Net Operating Expenses***	23,731	23,545	(186)	24,951	1,406	25,648	697

Cost of Service Evidence
of
Robert D. Greneman

Newfoundland and Labrador Hydro's
2003 General Rate Application

Robert D. Greneman, P.E.
Associate Director
Stone & Webster Management Consultants, Inc.
1 Penn Plaza
New York, NY 10119

At the hearing into Newfoundland and Labrador Hydro's General Rate Application, the Cost of Service Evidence will be adopted by Robert D. Greneman, P.E., Associate Director with Stone & Webster Management Consultants, Inc.

A witness profile for Robert D. Greneman follows:

- From 1973 through 1978 Mr. Greneman was employed by Alan J. Schultz, Consulting Engineer (later Casazza, Schultz & Associates), a firm that specialized in economic studies and rate work for electric, gas and water utilities. In 1978 he joined Stone & Webster, where, as a consultant he has assisted utility companies in rate and regulatory matters. From 1983 to 1986 he was employed by the Brooklyn Union Gas Company in the Rate and Regulatory Department where he was responsible for conducting the Company's cost of service studies, rate design and the review of gas purchase contracts. In 1986 he rejoined Stone & Webster as an executive consultant in the Rate and Regulatory Services Department.

- Mr. Greneman has prepared cost of service and rate design studies for clients including:

  Canada:
  Centra Gas British Columbia, Centra Gas Manitoba, Inc., Gaz Metropolitan, Inc. (Montreal), ICG Utilities (Toronto) and Winnipeg Hydro

U.S. and Other:

Alpena Power Company (MI), Barbados Light & Power Company, Ltd., Blackstone Valley Electric Company, Brockton Edison Company, Central Illinois Light Company, Chesapeake Utilities Corporation, China Light & Power Company, Ltd. (Hong Kong), Citizens Utilities Company, City of Westfield, MA, Colorado Electric Company, Commonwealth Edison Company, Consolidated Edison Company of New York, Dayton Power & Light Company, Delmarva Power & Light Company, Delta Natural Gas Company, Edison Sault Electric Company, El Paso Electric Company, Energy Services of Pensacola, Equitable Gas Company, Fall River Electric Light Company, Florida Public Utilities Company, Gas del Estado (Buenos Aires), Green Mountain Power Company, Guyana Electricity Corporation, Holyoke Department of Gas & Electric (MA), Jamaica Water Supply Company, Lake Superior District Power Company, Louisville Gas & Electric Company, Northern Indiana Public Service Company, Montana-Dakota Utilities Co., Midland Electric Power Cooperative (IA), Newport Electric Corporation, Roseville Electric (CA), Tampa Electric Company, South Jersey Gas Company, Southwest Louisiana Electric Membership Corporation, Southern Indiana Gas and Electric Company, Suffolk County Water Authority (NY), Valley Gas Company (RI), and Washington Natural Gas Company

- Mr. Greneman has provided expert testimony before the Delaware Public Service Commission, the Commonwealth of Kentucky Public Service Commission, the Louisiana Public Service Commission, the Michigan Public Service Commission, the Indiana Utility Regulatory Commission, the Iowa Utilities Board and the Federal Energy Regulatory Commission.

- He is also a licensed professional engineer in the states of New York and New Jersey.

Cost of Service
Evidence Outline

COST OF SERVICE

1. COS STUDY

A Cost of Service ("COS") study is the industry standard against which rates are judged to be equitably distributed between customer classes and hence, non-discriminatory. Hydro's COS continues to be a key tool in setting rates to its customers. The 2004 test year COS study incorporates methodologies that have been approved by the Board. This section discusses the details of the methodologies that were used.

1.1 Methodology

The COS study is based on Hydro's embedded costs for the 2004 forecast year. As in Hydro's prior studies, a three-step approach of functionalization, classification and allocation is used. These steps are as follows:

- Functionalization assigns all plant and expenses to the basic steps involved in the process of producing, transmitting, distributing and billing for electricity;

- Classification further assigns costs for each function as being demand-, energy- or customer-related; and

- Allocation is the process of apportioning each functionalized and classified cost group to classes of service based on factors related to cost causation.

This widely used three-step process facilitates the determination of a revenue requirement for each class by function and the development of unit costs, which serve as an important guide in the rate design process.

It should be noted though, that since Hydro has five discrete geographic systems, its costs must first be systemized prior to being functionalized.

The procedures used throughout the study are in accordance with the generic methodology set forth in the 1993 Board report, except as prescribed in P.U. 7. Also, based on my review, the methodologies used in the study are consistent with common industry practice.

1.2 Systemization

Hydro performs a COS study for each of the five geographic areas it serves. The five areas are: Island Interconnected, Island Isolated, Labrador Isolated, L'Anse au Loup and Labrador Interconnected. In general, plant that is located within each area along with its associated expenses is assigned to that area. Customer-related costs are systemized using customer ratios. Administrative and general ("A&G") expenses, which are generally not identifiable with a specific service area or function, are systemized and functionalized based on plant or expense ratios, as appropriate to the nature of the expense.

In its prior cost studies, Hydro used physical location as the basis to systemize plant. This did not consider that multiple systems could be served from one location. The most notable example is Hydro Place. Since this facility physically resides in the Island Interconnected System it was assigned to that system. However, in recognition of the fact that it provides administrative support to all systems, it is now being systemized to all five systems on the basis of direct generation, transmission, distribution and customer expenses.

1.3 Functionalization

Functionalization takes the costs in each system and assigns them to the various steps in the process of producing, transmitting, distributing and billing for electricity. These steps, or functional categories, are generally defined in a cost study either to track costs associated with a particular function (e.g., generation or transmission) or to allow a different allocation factor to be applied to sub-functions within a function (e.g., distribution primary vs. distribution secondary). A listing of the explicit functions used in Hydro's COS study is provided in the Classification discussion.

Most plant and operating expenses are readily identifiable such that functionalization of these costs is rather straightforward. However, A&G expenses and general plant are indirect in nature and require different treatment. A&G expenses were functionalized on either plant or expense ratios, based on the nature of the expense. In Hydro's prior cost studies, general plant assets have generally been functionalized on direct plant ratios. In the current study they are predominately functionalized based on generation, transmission, distribution and customer-related expenses. Expenses are largely comprised of labour and the greater reliance on expense as a basis for functionalizing and classifying costs is in keeping with the more widespread use of labour as a means of functionalizing indirect expenses. This is based on: (1) the notion that administrative functions exist to support field labour; and (2) the fact that plant ratios do not assign general plant costs to meter reading and billing and collecting, whereas expense ratios do.

In performing a COS study, a distinction is made between plant from a physical versus operational perspective. An example is transmission lines that function as generator leads to integrate the source of power with the backbone transmission system. In keeping with the Board’s mandates and common industry treatment, these transmission lines have been assigned to the generation function for cost study purposes.

Hydro's COS study distinguishes distribution lines between primary and secondary voltage levels. Distribution lines were assigned between these functions based on an analysis of the type of poles and conductor that are installed for each voltage level. Distribution expenses were generally functionalized based on plant. Services, meters and street lighting were directly assigned to their respective functions.

1.4 Classification

The second step in the costing process is classification. In this step, each functionalized cost group is separated into demand, energy and customer-related components based on the predominant factor for cost causation.

Some costs are related to the quantity of energy produced or sold. These are known as energy-related costs. The cost of fuel and the energy component of purchased power are generally recognized as energy-related costs.

Demand or capacity-related costs are those associated with the maximum rate at which energy is used. Significant portions of generation, transmission and distribution facilities are considered to be demand-related because the investment in these facilities is related to the size of the facility, and facilities are generally sized to provide service under peak demand conditions.

Customer-related costs are those that are associated with serving customers regardless of either the amount of energy used or the maximum demand. For example, every customer has a meter and a service and the costs associated with metering and billing are not related to consumption. These costs are commonly considered to be allocable on factors that are related to the number of customers.

In Hydro's COS study, functionalization and classification were done in the same step. The list below shows each of the explicit functional categories used by

Hydro broken down into its appropriate classification(s), or basis for cost causation.

- Production Demand
- Production and Transmission Energy
- Transmission Demand
- Rural Production and Transmission Demand
- Distribution Substations Demand
- Distribution Primary Lines Demand
- Distribution Primary Lines Customer
- Distribution Line Transformers Demand
- Distribution Line Transformers Customer
- Secondary Lines Demand
- Secondary Lines Customer
- Services Customer
- Meters Customer
- Street Lighting Customer
- Accounting Customer
- Specifically Assigned Customer

The components of plant, net book value, depreciation expense, rate base, operation and maintenance expenses, fuel and purchased power are functionalized and classified to the above categories.

In the current cost study, a change was made with respect to the method of functionalizing and classifying municipal taxes and the Board assessment. In prior cost studies these costs, which are incurred based on level of revenues, were functionalized and classified based on factors that were indirectly related to revenues. In the current study they are held in a revenue-related category and at a later point in the study, are assigned the same functionalization and classification distribution as the sub-total of the COS for each class, excluding revenue-related.

1.4.1 Classification of Generation

The classification of Hydro's generation was done in a manner consistent with the Board's prior orders. The procedures used are summarized below.

On the Island Interconnected System, Holyrood was classified between demand and energy based on the capacity factor for this facility over the last five years. This resulted in an energy and demand split of 42.28% and 57.72%, respectively. With the exception of a mini-hydro site at Roddickton that was assigned to the demand-related Rural Production and Transmission function, hydraulic plant costs on the Island Interconnected System were classified as energy-related based on the 2004 system load factor, or 57.90%. The balance was classified as demand-related. Gas turbine plant and associated fuel expenses were classified as demand-related. Hydraulic and diesel plant on the Great Northern Peninsula ("GNP"), along with diesel fuel were assigned to the Rural Production and Sub-transmission function and treated as demand-related. Further discussion regarding the proposed treatment of these facilities is included in the Allocation section of this evidence, below.

The bulk of the power used to serve the Labrador Interconnected System is purchased from Churchill Falls. These costs were classified 55.04% to energy and 44.96% to demand based on the Labrador system load factor. The diesel and gas turbine on this system, along with associated fuel, serve a backup or emergency function and are also available for peaking. They were therefore classified as demand-related.

The Island and Labrador Isolated Systems are served predominately by diesel units. The costs of the diesels in each system were classified between energy and demand based on the system load factor for each system. The forecast load factor (energy component) for the Island and Labrador Isolated Systems are 54.23% and 61.17%, respectively.

The L'Anse au Loup system is served by on-system diesel and by secondary power from Hydro-Québec ("HQ"). However, for the forecast 2004 test year, HQ is forecast to provide the bulk of the power. The diesel units were classified as demand-related and diesel fuel as energy-related. HQ secondary purchased power was classified as 100% energy-related.

1.4.2 Classification of Transmission

Backbone transmission lines and terminal stations were classified as demand-related. Transmission lines that primarily serve as generator leads were classified in the same manner as the generation source. Rural lines and terminal stations along with diesel terminal stations on the GNP were classified as demand-related within the Rural Production and Transmission function.

1.4.3 Classification of Distribution

Distribution system plant including primary lines, secondary lines and line transformers were classified between customer and demand-related based on a zero-intercept analysis. The rationale in support of the zero-intercept concept is that there is a theoretical system of zero-diameter conductor supported by code-height poles of zero diameter that connects each customer to the backbone transmission system and generation, standing by ready to provide service. This skeleton system can be allocated based on the number of customers in each class while the balance of costs is incurred to meet peak demand. The zero-intercept analysis used in the current study was performed by Foster Associates for Hydro's last rate proceeding. The Board, in Hydro's last rate order, affirmed the use of the zero-intercept methodology.

1.5 Allocation

The third step, allocation of costs, is the process of cost assignment whereby each class of service receives a proportionate cost responsibility for each of the functionalized and classified cost groups. This is accomplished by a combination of direct assignment and by allocation factors that are based on the ratio of the amount of demand, energy sold, or number of customers for each class of service to the system total.

With the exception of General Service ("G.S.") customers in Hydro's isolated systems, the customer classes used in the COS study correspond with the proposed rate schedules in each of Hydro's systems for the 2004 forecast year. Due to the relatively small number of customers in G.S. rates 2.3 and 2.4, these customers have been consolidated into a single class 2.2 for G.S. customers with a demand over 10 kW. The COS study, however, does cost rates 2.2, 2.3 and 2.4 individually, and the results were combined for rate purposes. It is not uncommon to cost components of a single rate individually and then combine the costs to develop a single rate.

1.5.1 Energy Allocation Factors

Energy factors were developed by starting with forecast sales by customer class within each system and adding losses to get to the source, or input to each system.

1.5.2 Demand Allocation Factors

In order to allocate demand-related costs, factors were developed for each voltage level of supply based on a measure of the maximum load imposed at that voltage level, recognizing:

- Customer load served at each voltage level;
- The level of diversity associated with each voltage level; and
- Losses.

The demands used in the study were developed with the support of updated load data from other northern climate electric utilities in North America.

The demand components of generation and transmission costs were allocated to classes using a 1 CP factor in accordance with the Board's order in Hydro's last rate case. Lines and terminal station assets that exclusively serve Newfoundland Power or Industrial Customers were directly assigned.

Distribution substations and the demand component of distribution primary and secondary lines in each system were also allocated using the 1 CP method. This was done in recognition of the fact that Hydro plans its facilities based on the aggregate distribution system load.

1.5.3 Assignment of the GNP, the Doyles-Port aux Basques and the Burin Peninsula Assets

The COS study filed in this proceeding assigns all generation and transmission assets on the GNP, the Doyles-Port aux Basques and the Burin Peninsula as ordered by the Board in Hydro's last rate case. The GNP assets are assigned to rural, the Doyles-Port aux Basques assets are specifically assigned to Newfoundland Power and the Burin Peninsula assets are assigned to common. The Board ordered Hydro to file in its next GRA, a detailed study as to the proper cost assignment of these assets. A study in response to that order was prepared by Hydro's System Planning department, entitled: "Review of COS Assignment for the GNP, Doyles-Port aux Basques, and Burin Peninsula Assets" ("System Planning Report"). That study, which has been filed in this proceeding, concludes that:

- All generation assets on the GNP should be reassigned from rural to common since they act to enhance reliability of the system;

- Transmission assets related to the GNP and Doyles-Port aux Basques remain specifically assigned based on the fact that they are radial lines that serve a single customer with generation of less than sufficient magnitude to justify their assignment to common; and

- Transmission assets on the Burin Peninsula continue to be assigned to common as they serve more than one customer (Newfoundland Power and Hydro Rural).

In reviewing the System Planning Report within the context of my review of Hydro's COS study, I find that the principles relied on are consistent with those commonly used in the industry to evaluate whether an asset should be treated as common or directly assigned.

1.5.4 Customer Allocation Factors

The customer component of primary and secondary distribution lines and customer accounting expenses was allocated based on the number of distribution customers in each system. Services and meters were allocated based on weighted customers.

Revenues from non-firm sales customers were credited to the firm customers' revenue requirement.

Lastly, in accordance with P.U. 7, the COS reflects the partial phase-out of the credit from secondary sales to CFB Goose Bay from the Labrador Interconnected System. This credit will now be applied to the rural deficit.

1.6 Organization of the COS Study

The COS study is attached to this evidence as Exhibit RDG-1, and is organized into the following sections.

- Schedule 1.1 Revenue Requirement and Return on Rate Base
- Schedule 1.2 Revenue to Cost Ratios
- Schedule 1.3 Unit Costs (all systems)
- Schedule 1.4 Calculation of Firming-up charge
- Schedule 1.5 Calculation of Transmission Wheeling Charge
- Schedules 2.1-2.6 Functionalization and Classification by System
- Schedules 3.1-3.3 Allocation by System
- Schedule 4.1 Functionalization and Classification Ratios
- Schedule 4.2 System Load Factor
- Schedule 4.3 Holyrood Capacity Factor
- Schedule 4.4 Power Purchases – Total System

1.7 Study Results

Hydro's revenue requirement is based on return on rate base. The rates of return for each system are shown in Schedule 1.1, Page 2 of 2. The system revenue requirements based on the target rates of return are contained in Schedule 1.1, Page 1 of 2. Schedule 1.2 develops revenue to cost coverage ratios as forecast revenues less allocated costs. The rural deficit in the cost study was allocated to Newfoundland Power and to Labrador Interconnected System customers.

Unit costs for each customer class, before and after the deficit allocation, are shown in Schedule 1.3. These unit costs, which are expressed in terms of $/kW, $/kWh and $/bill although not rates per se, serve a key role in the design of Hydro's proposed rates.

1.8 Rural Rate Design

Rates that are reflective of costs are the most widely recognized measure of rates that are equitable and non-discriminatory. However, in designing appropriate rates there are considerations other than cost that come into play. In "Principles of Public Utility Rates", Dr. James Bonbright identified attributes of a sound rate structure. They include: effectiveness in yielding the total revenue requirement; revenue and rate stability and predictability; ability of the rates to discourage wasteful use and promote justified use; recognition of social costs and benefits; fairness in the apportionment of costs; avoidance of undue discrimination in rate relationships; dynamic efficiency in promoting innovation and responding to changing supply and demand patterns; simplicity; and freedom from controversy.

Some of these goals, however, may be seen to be at odds with one another and tradeoffs are required. One such tradeoff is the need to sell to meet the revenue requirement versus the need to conserve. Thus, there is often the need to strike a balance in order to meet interests of all stakeholders and it is for this reason that rate design has often been characterized as an art as well as a science.

In the case of Hydro, the Board generally prescribes the overall guidelines as to how the relevant objectives are to be incorporated into rate design, while Hydro does the actual implementation. I have reviewed the rural rate design evidence contained in the Rates and Customer Service Evidence in this proceeding, and believe that the manner in which the proposed rural rates have been implemented, fairly and reasonably reflects the Board's mandates as well as the rate design objectives set forth by Dr. Bonbright.

1.9 Summary

The procedures used throughout the COS study are in accordance with P.U. 7, and include three minor refinements to Hydro's prior COS. These refinements, which are discussed within the body of this COS evidence, are summarized below.

- **Hydro Place** is now recognized as providing administrative support to all of Hydro's systems;

- In functionalizing **General Plant**, there is now a greater reliance on expense, rather than plant ratios; and

- **Municipal Taxes and the Board Assessment** are now directly recognized as being revenue-related.

2. REVIEW OF RATE DESIGN FOR NEWFOUNDLAND POWER

Stone & Webster Management Consultants, Inc. ("Stone & Webster") conducted a review as to the appropriateness of the current energy-only rate structure to Newfoundland Power. Based on this review, we found that although the current rate structure is still viable, there are forms of demand/energy rates that offer additional advantages while addressing most, or virtually all of the concerns that have been previously expressed by both utilities. We have therefore recommended that Hydro implement a demand/energy rate structure of the form discussed in the study as Exhibit RDG-2 entitled "Review of Rate Design for Newfoundland Power".

2.1 Background

Discussions surrounding the propriety of the current energy-only rate form for sales of electricity to Newfoundland Power can be traced back to at least 1989. While the record appears to indicate that the Board, Hydro and Newfoundland Power recognize that this is an atypical rate form for sales of electricity to such a large customer, movement towards an alternate rate form has been rather slow and brought to the forefront mostly at the time of a Rate Application or during a Board inquiry.

The most recent proposals and discussions between Hydro and Newfoundland Power to develop a demand rate occurred in 1992. While both parties agreed that in order to implement effective load management it is necessary to send a proper price signal, they were not able to resolve ways to deal with the potential risks.

Hydro has all of its revenue from sales to Newfoundland Power stabilized through its Rate Stabilization Plan ("RSP"), such that any component that is removed from the energy rate and moved to a demand rate becomes at-risk in the sense that if Newfoundland Power reduces its demand Hydro will experience a revenue shortfall.

Newfoundland Power's concerns focused on its ability to effectively pass on a price signal to its customers and to avoid paying a windfall to Hydro due to abnormal weather conditions.

As a result of these concerns an agreement could not be reached.

More recently, in Hydro's 2002 GRA, the record indicates that the current energy-only rate form is still appropriate and a demand-energy rate structure is neither necessary nor desirable in the current environment.

Also, it is believed that both utilities feel that the current rate structure offers operational efficiencies in dispatching their respective generation and that a demand rate would impose a constraint.

2.2 Issues

The following sections discuss some of the relevant issues in moving to a demand-energy rate.

2.2.1 Current Rate Structure

The current rate structure provides a price signal in two ways. Under the current energy-only rate structure, Newfoundland Power's bill is directly related to the quantity of kWh consumed. Stone & Webster, however, does not believe this to be an appropriate price signal. That is, the energy price signals the need to either use or conserve *natural* resources, while the demand price signals the need to conserve *capital* resources. The energy-only rate is therefore seen as giving an incomplete price signal.

The second, is not a price signal per se, but arises by virtue of Newfoundland Power's knowledge that if it increases its peak load this will be recognized in terms of a higher peak load forecast in Hydro's next Rate Application. This is an indirect response to the energy-only rate form, and may persist for years before it is again recognized in the form of higher rates. In this regard, it should be noted that an additional advantage of a demand-energy rate form is that it tracks cost causality and changes in customer load profile much more closely than an energy-only rate structure.

Lastly, with respect to Newfoundland Power's concern that it does not have a means to pass on a demand signal to its Domestic Customers, this situation exists for virtually every other utility with Domestic Customers. Many of these utilities have found ways to deal with this, either in the form of seasonal rates or by the use of load management techniques such as water heating control rates. The demand portion of Hydro's rate will provide Newfoundland Power with a quantitative measure against which to develop a viable load management plan. All things considered, the preferable alternative is to provide Newfoundland Power with a relevant price signal.

2.2.2 Revenue Stability

There are two basic issues: volatility due to weather; and revenue instability to Hydro caused by moving revenue out of its RSP.

Stone & Webster believes that models currently exist or can be developed in efforts between both utilities that will effectively normalize peak demand for the effects of weather.

With respect to revenue stability, in order for Hydro to send a price signal to Newfoundland Power it must accept a degree of risk and the level of that risk should be commensurate with Newfoundland Power's response in terms of expected conservation.

2.2.3 Treatment of Newfoundland Power Generation

Under the current energy-only rate form, Newfoundland Power can dispatch its hydraulic and thermal units in the most efficient manner with virtually no consequence with respect to billing from Hydro. However, the establishment of a demand component in the rate may steer Newfoundland Power to operating its units in a less energy efficient fashion in order to minimize its peak load, which manifests itself in an attendant risk to Hydro in not being able to collect its demand-related revenue requirement. It is for this reason that proper recognition of Newfoundland Power's generation on both the costing and rate side is perhaps one of the more intricate issues in designing a viable demand rate.

Stone & Webster has investigated several alternative costing and pricing combinations with respect to recognizing Newfoundland Power's generation. Based on our analysis, we find that by giving full credit net of reserve for Newfoundland Power's generating capacity on the costing side and basing pricing on Newfoundland Power's native peak load less its full generating capacity net of reserve, a rate can be designed that is generation-independent. Under such a design, Newfoundland Power can achieve at least the same operational efficiencies as it currently enjoys.

2.3 Other Demand Rate Considerations

Many rate forms were considered within the context of Hydro's and Newfoundland Power's circumstances, including those that arose in earlier discussions between both utilities concerning basing billing demand on a single winter peak versus monthly peaks. It is our view that monthly peaks are not relevant in light of the fact that it is only the winter peak that drives demand costs. It is difficult and impractical to normalize monthly metered demands, and monthly peaks have the potential of introducing variations in load in non-winter months due to factors other than weather. Conceptually, the single winter peak normalized for weather and unfettered by other seasonal variables reasonably reflects load growth and load management efforts and that is what is intended to be measured. The use of a single peak is therefore seen as the preferred approach.

2.4 Conclusions

Based on its review, Stone & Webster believes a demand-energy rate can be designed following the principles set out in Sections 4 and 6 of its report that will effectively address many of the issues that have been stumbling blocks in the past; that will provide a proper price signal to Newfoundland Power and its customers; and allow both utilities to achieve the same operational efficiencies as under the current rate structure. It is therefore recommended that Hydro proceed to establish a rate utilizing these principles; that the results of its analyses be shared with Newfoundland Power; and that the proposed rate be based on discussions between both utilities.

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Total System
Revenue Requirement

1		2	3	4	5	6	7	8
Line No.	Description	Total Amount ($)	Island Interconnected ($)	Island Isolated ($)	Labrador Isolated ($)	L'Anse au Loup ($)	Labrador Interconnected ($)	Basis of Proration
	Revenue Requirement							
	Expenses							
1	Operating, Maintenance and Admin.	93,048,681	72,460,822	5,166,240	10,011,783	1,115,316	4,294,520	Detailed Analysis
2	Fuels - No. 6 Fuel	84,819,538	84,819,538	-	-	-	-	Detailed Analysis
3	Fuels - Diesel	7,377,404	54,612	1,390,213	5,848,510	68,661	15,408	Detailed Analysis
4	Fuels - Gas Turbine	350,959	265,277	-	-	-	85,682	
5	Power Purchases -CF(L)Co	2,433,927	-	-	-	-	2,433,927	Detailed Analysis
6	Power Purchases - Other	30,880,947	29,928,330	-	34,275	812,107	106,235	Detailed Analysis
7	Depreciation	33,931,301	27,884,999	891,817	2,163,918	401,179	2,589,389	Detailed Analysis
	Expense Credits:							
8	Sundry	(456,000)	(355,106)	(25,318)	(49,064)	(5,466)	(21,046)	Total O&M Expenses
9	Building Rental Income	(14,028)	(7,200)	-	-	-	(6,828)	Detailed Analysis
10	Tax Refunds	-	-	-	-	-	-	Total O&M Expenses
11	Suppliers' Discounts	(22,800)	(17,755)	(1,266)	(2,453)	(273)	(1,052)	Total O&M Expenses
12	Pole Attachments	(1,256,348)	(883,099)	(26,512)	(87,859)	(55,402)	(203,476)	Detailed Analysis
13	Secondary Energy Revenues	-	-	-	-	-	-	Island Interconnected
14	Wheeling Revenues	(70,493)	(70,493)	-	-	-	-	Island Interconnected
15	Application Fees	(44,112)	(19,452)	(660)	(4,452)	(840)	(18,708)	Detailed Analysis
16	Meter Test Revenues	(90,000)	(53,193)	(2,147)	(6,604)	(2,698)	(25,357)	Weighted Customers
17	**Total Expense Credits**	**(1,953,781)**	**(1,406,298)**	**(55,903)**	**(150,432)**	**(64,679)**	**(276,467)**	
18	**Subtotal Expenses**	**250,888,976**	**214,007,279**	**7,392,367**	**17,908,054**	**2,332,583**	**9,248,693**	
19	Disposal Gain/Loss	541,189	515,443	-	8,248	-	17,498	Detailed Analysis
20	**Subtotal Rev Reqt Excl Return**	**251,430,165**	**214,522,722**	**7,392,367**	**17,916,302**	**2,332,583**	**9,266,191**	
21	Return on Debt	106,037,664	98,967,734	907,304	2,186,368	412,844	3,563,415	Rate Base
22	Return on Equity	15,052,375	14,461,511	-	-	-	590,864	Rate Base
23	**Total Revenue Requirement**	**372,520,204**	**327,951,968**	**8,299,670**	**20,102,669**	**2,745,427**	**13,420,470**	

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Total System
Return on Rate Base

	1	2	3	4	5	6	7	8
Line No		Total $	Island Interconnected $	Island Isolated $	Labrador Isolated $	L'Anse au Loup $	Labrador Interconnected $	Basis of Proration
	Rate Base:							
1	Average Net Book Value	1,366,212,659	1,276,638,287	11,652,916	26,534,805	5,314,268	46,072,383	Schedule 2.3
2	Cash Working Capital	3,057,000	2,856,571	26,074	59,374	11,891	103,090	Prorated on Average Net Book Value - L. 1
3	Fuel Inventory - No. 6 Fuel	11,872,074	11,872,074	-	-	-	-	Specifically Assigned - Holyrood
4	Fuel Inventory - Diesel	2,150,830	48,247	131,042	1,913,083	20,307	38,151	Detailed Fuel Analysis
5	Fuel Inventory - Gas Turbine	884,126	796,938	-	-	-	87,188	Detailed Fuel Analysis
6	Inventory/Supplies	19,387,000	17,679,828	201,676	530,500	118,425	856,571	Prorated on Total Plant in Service, Schedule 2.2
7	Deferred Charges: Foreign Exchange Loss and Regulatory Costs	81,886,000	76,517,226	698,435	1,590,403	318,519	2,761,417	Prorated on Average Net Book Value - L. 1
8	Total Rate Base	**1,485,449,689**	**1,386,409,170**	**12,710,143**	**30,628,165**	**5,783,409**	**49,918,801**	
9	Less: Rural Portion	(213,758,301)	(164,636,583)	(12,710,143)	(30,628,165)	(5,783,409)	-	Schedule 2.6, L. 9
10	Rate Base Available for Equity Return	**1,271,691,388**	**1,221,772,587**	**-**	**-**	**-**	**49,918,801**	
	Corporate Targets:							
11	Capital Structure: Percent of Debt	86.14% (1)						
12	Return	8.287%						
13	Weighted Average Return: Debt	**7.138%**						
14	Capital Structure: Percent of Equity	12.14% (1)						
15	Return	9.750%						
16	Weighted Average Return: Equity	**1.184%**						
17	Weighted Average Cost of Capital	**8.322%**						
	Return on Rate Base by System (%):							
18	Return on Rate Base - Debt Component	-	7.138%	7.138%	7.138%	7.138%	7.138%	
19	Return on Rate Base - Equity Component	-	1.184%	-	-	-	1.184%	
	Return on Rate Base ($):							
20	Return on Debt	106,037,664	98,967,734	907,304	2,186,368	412,844	3,563,415	Schedule 2.6, L.11
21	Return on Equity	15,052,375	14,461,511	-	-	-	590,864	Schedule 2.6, L.12
22	Return on Rate Base ($)	**121,090,040**	**113,429,246**	**907,304**	**2,186,368**	**412,844**	**4,154,278**	Schedule 2.6, L.13
	Return on Total Rate Base (%):							
23	Return on Rate Base - Debt Component	7.138%	7.138%	7.138%	7.138%	7.138%	7.138%	L. 20 divided by L.8
24	Return on Rate Base - Equity Component	1.013%	1.043%	-	-	-	1.184%	L. 21 divided by L.8
25	Return on Rate Base (%)	**8.152%**	**8.182%**	**7.138%**	**7.138%**	**7.138%**	**8.322%**	L. 22 divided by L.8

(1) Debt and equity weightings reflect a 1.72% component for Employee Future Benefits at 0% cost.

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Total System
Comparison of Revenue & Allocated Revenue Requirement

	1	2	3	4	5	6	7
Line No.	Rate Class	Revenues ($)	Cost of Service Before Deficit and Revenue Credit Allocation ($)	Revenue Credits ($)	Deficit ($)	Revenue Requirement After Deficit and Revenue Credit Allocation ($)	Revenue to Cost Coverage (Col.2/3)
	Total System						
1	Newfoundland Power	258,169,230	221,395,182	(18,482)	36,781,375	258,158,074	1.17
2	Island Industrial	52,068,672	52,049,661	23,033	-	52,072,693	1.00
3	Labrador Industrial	2,641,753	2,641,753	-	-	2,641,753	1.00
4	CFB - Goose Bay Secondary	3,014,118	129,969	2,884,149	-	3,014,118	23.19
5	Rural Labrador Interconnected	12,705,760	10,648,748	(2,757,246)	4,813,084	12,704,586	1.19
	Rural Deficit Areas						
6	Island Interconnected	35,031,559	54,507,125	(4,550)	(19,471,016)	35,031,559	0.64
7	Island Isolated	1,496,581	8,299,670	-	(6,803,089)	1,496,581	0.18
8	Labrador Isolated	5,904,667	20,102,669	-	(14,198,002)	5,904,667	0.29
9	L'Anse au Loup	1,496,173	2,745,427	-	(1,249,254)	1,496,173	0.54
10	Revenue Credit Applied to Deficit (4.4%)	-	-	(126,903)	126,903	-	-
11	**Subtotal**	**43,928,980**	**85,654,892**	**(131,453)**	**(41,594,459)**	**43,928,980**	**0.51**
12	**Total**	**372,528,513**	**372,520,204**	**-**	**-**	**372,520,204**	**1.00**

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Island Interconnected
Comparison of Revenue & Allocated Revenue Requirement

	1	2	3	4	5	6	7
Line No.	Rate Class	Revenues ($)	Cost of Service Before Deficit and Revenue Credit Allocation ($)	Revenue Credit ($)	Deficit Allocation ($)	Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) ($)	Revenue to Cost Coverage (Col.2/3)
	Island Interconnected						
1	Newfoundland Power	258,169,230	221,395,182	(18,482)			
2	NLP RSP Activity	-					
3	**Subtotal Newfoundland Power**	**258,169,230**	**221,395,182**	**(18,482)**	**36,781,375**	**258,158,074**	**1.17**
4	Industrial - Firm	52,018,920	52,027,285	(4,343)		52,022,941	
5	Industrial - Non-Firm	49,752	22,376	27,376		49,752	
6	Industrial RSP Activity	-				-	
7	**Subtotal Industrial**	**52,068,672**	**52,049,661**	**23,033**	**-**	**52,072,693**	**1.00**
	Rural						
8	1.1 Domestic	10,585,819	17,762,333	(1,483)	(7,175,032)	10,585,819	0.60
9	1.12 Domestic All Electric	10,043,906	18,543,304	(1,548)	(8,497,850)	10,043,906	0.54
10	1.3 Special	10,915	34,939	(3)	(24,021)	10,915	0.31
11	2.1 General Service 0-10 kW	2,488,947	3,076,177	(257)	(586,973)	2,488,947	0.81
12	2.2 General Service 10-100 kW	6,368,104	8,456,540	(706)	(2,087,730)	6,368,104	0.75
13	2.3 General Service 110-1,000 kVa	3,008,667	3,907,849	(326)	(898,855)	3,008,667	0.77
14	2.4 General Service Over 1,000 kVa	1,669,364	1,839,683	(154)	(170,166)	1,669,364	0.91
15	4.1 Street and Area Lighting	855,837	886,299	(74)	(30,388)	855,837	0.97
16	**Subtotal Rural**	**35,031,559**	**54,507,125**	**(4,550)**	**(19,471,016)**	**35,031,559**	**0.64**
17	**Total Island Interconnected**	**345,269,461**	**327,951,968**	**-**	**17,310,359**	**345,262,326**	**1.05**

Note1:
Calculation of Island Industrial Non-Firm Revenue Credit

Island Industrial Non-Firm Revenues, Ln 5, Col 2	49,752
Island Industrial Non-Firm Allocated Cost of Service, Ln 5, Col 3	(22,376)
Credit to be allocated to Island Interconnected Firm Customers	27,376

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Island Isolated
Comparison of Revenue & Allocated Revenue Requirement

Line No.	1 Rate Class	2 Revenues ($)	3 Cost of Service Before Deficit and Revenue Credit Allocation ($)	4 Revenue Credit ($)	5 Deficit ($)	6 Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) ($)	7 Revenue to Cost Coverage (Col.2/3)
	Island Isolated						
1	1.2 Domestic Diesel	744,272	5,870,791		(5,126,519)	744,272	0.13
2	1.2G Government Domestic Diesel	0	0		0	0	0.00
3	1.23 Churches, Schools & Com Halls	0	0		0	0	0.00
4	2.1 General Service 0-10 kW	173,583	683,356		(509,773)	173,583	0.25
5	2.2 GS 10-100 kW	302,489	768,941		(466,452)	302,489	0.39
6	2.3 GS 110-1,000 kVa	237,195	854,023		(616,828)	237,195	0.28
7	2.4 General Service Over 1,000 kVa	0	0		0	0	0.00
8	2.5 GS Diesel	0	0		0	0	0.00
9	2.5G Gov't General Service Diesel	0	0		0	0	0.00
10	4.1 Street and Area Lighting	39,042	122,559		(83,517)	39,042	0.32
11	4.1G Gov't Street and Area Lighting	0	0		0	0	0.00
12	**Total**	**1,496,581**	**8,299,670**		**(6,803,089)**	**1,496,581**	**0.18**

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Labrador Isolated
Comparison of Revenue & Allocated Revenue Requirement

Line No.	1 Rate Class	2 Revenues ($)	3 Cost of Service Before Deficit and Revenue Credit Allocation ($)	4 Revenue Credit ($)	5 Deficit ($)	6 Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) ($)	7 Revenue to Cost Coverage (Col.2/3)
	Labrador Isolated						
1	1.2 Domestic Diesel	2,631,585	11,890,666		(9,259,081)	2,631,585	0.22
2	1.2G Government Domestic Diesel	0	0		0	0	0.00
3	1.23 Churches, Schools & Com Halls	0	0		0	0	0.00
4	2.1 General Service 0-10 kW	1,020,147	2,162,483		(1,142,336)	1,020,147	0.47
5	2.2 GS 10-100 kW	1,794,802	4,221,092		(2,426,290)	1,794,802	0.43
6	2.3 GS 110-1,000 kVa	178,453	761,034		(582,581)	178,453	0.23
7	2.4 General Service Over 1,000 kVa	180,032	845,137		(665,105)	180,032	0.21
8	2.5 GS Diesel	0	0		0	0	0.00
9	2.5G Gov't General Service Diesel	0	0		0	0	0.00
10	4.1 Street and Area Lighting	99,648	222,256		(122,608)	99,648	0.45
11	4.1G Gov't Street and Area Lighting	0	0		0	0	0.00
12	**Total**	**5,904,667**	**20,102,669**		**(14,198,002)**	**5,904,667**	**0.29**

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
L'Anse au Loup
Comparison of Revenue & Allocated Revenue Requirement

	1	2	3	4	5	6	7
Line No.	Rate Class	Revenues ($)	Cost of Service Before Deficit and Revenue Credit Allocation ($)	Revenue Credit ($)	Deficit ($)	Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) ($)	Revenue to Cost Coverage (Col.2/3)
	L'Anse au Loup						
1	1.1 Domestic	813,220	1,724,763		(911,543)	813,220	0.47
2	1.12 Domestic All Electric	30,014	69,814		(39,800)	30,014	0.43
3	2.1 General Service 0-10 kW	138,240	201,706		(63,466)	138,240	0.69
4	2.2 General Service 10-100 kW	399,690	592,551		(192,861)	399,690	0.67
5	2.3 General Service 110-1,000 kVa	79,322	119,689		(40,367)	79,322	0.66
6	4.1 Street and Area Lighting	35,687	36,904		(1,217)	35,687	0.97
7	**Total L'Anse Au Loup**	**1,496,173**	**2,745,427**		**(1,249,254)**	**1,496,173**	**0.54**

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Labrador Interconnected
Comparison of Revenue & Allocated Revenue Requirement

	1	2	3	4	5	6	7
Line No.	Rate Class	Revenues ($)	Cost of Service Before Deficit and Revenue Credit Allocation ($)	Revenue Credit ($)	Deficit Allocation ($)	Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) ($)	Revenue to Cost Coverage (Col.2/3)
	Labrador Interconnected						
1	Industrial IOCC Firm	2,635,349	2,635,349	-	-	2,635,349	1.00
2	Industrial IOCC Non-Firm	6,404	6,404		-	6,404	1.00
3	**Subtotal Industrial**	**2,641,753**	**2,641,753**		**-**	**2,641,753**	**1.00**
4	**CFB - Goose Bay Secondary**	3,014,118	129,969	2,884,149	-	3,014,118	23.19
	Rural						
5	1.1 Domestic	226,846	341,564	(88,440)	154,382	407,506	0.66
6	1.1A Domestic All Electric	6,181,493	6,564,127	(1,699,629)	2,966,893	7,831,392	0.94
7	2.1 General Service 0-10 kW	180,931	171,313	(44,358)	77,431	204,387	1.06
8	2.2 General Service 10-100 kW	1,812,581	1,110,046	(287,421)	501,725	1,324,350	1.63
9	2.3 General Service 110-1,000 kVa	2,406,094	1,412,693	(365,784)	638,517	1,685,426	1.70
10	2.4 General Service Over 1,000 kVa	1,710,447	877,398	(227,182)	396,572	1,046,788	1.95
11	4.1 Street and Area Lighting	187,368	171,606	(44,433)	77,564	204,737	1.09
12	**Subtotal Rural**	**12,705,760**	**10,648,748**	**(2,757,246)**	**4,813,084**	**12,704,586**	**1.19**
13	**Total Labrador Interconnected**	**18,361,631**	**13,420,470**	**126,903**	**4,813,084**	**18,360,457**	**1.37**

Note1:
Calculation of CFB - Goose Bay Secondary Revenue Credit

CFB - Goose Bay Secondary Revenues, Ln 4, Col 2		3,014,118
CFB - Goose Bay Secondary Allocated Cost of Service, Ln 4, Col 3		(129,969)
CFB - Goose Bay Secondary Allocated Deficit, Ln 4, Col 5		-
Revenue Credit		2,884,149
Revenue Credit Applied to Deficit	**4.4%**	126,903
Revenue Credit Applied to Firm Regulated Labrador Interconnected Customers		2,757,246
		2,884,149

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Total System
Rural Deficit Allocation

	1	2	3	4	5	6
		Before Deficit and Revenue Credit Allocation				
Line No.	Rate Class	Allocated Revenue Reqt ($)	Demand ($)	Energy ($)	Customer ($)	Source
	CLASSIFICATION TO DEMAND, ENERGY, CUSTOMERS:					
1	Newfoundland Power	221,395,182	88,514,377	130,628,947	2,251,858	Schedule 1.3.1, p. 1
2	Rural Labrador Interconnected	10,648,748	7,132,176	833,896	2,682,676	Schedule 1.3.1, p. 3
3	**Total**	**232,043,930**	**95,646,553**	**131,462,843**	**4,934,534**	
4	Deficit Classified	41,594,459	17,144,886	23,565,046	884,528	Prorated on Line 3
	UNIT COSTS OF DEFICIT:		CP kW	MWH	Customers *	
	Island Interconnected:					
5	Newfoundland Power		1,067,783	4,902,167	6,156	
6	**Subtotal Island Interconnected**		**1,067,783**	**4,902,167**	**6,156**	
	Labrador Interconnected:					
7	Rural Labrador Interconnected		125,804	575,167	9,268	
8	**Subtotal Labrador Interconnected**		**125,804**	**575,167**	**9,268**	
9	**Total**		**1,193,586**	**5,477,334**	**15,424**	
10	Deficit Unit Costs		$14.36 $/KW	$4.30 $/MWH	$57.35 $/Customer	Line 4 / Line 9

* Specifically assigned costs are converted to equivalent unweighted customers by dividing the assigned cost by the allocated customer cost per unweighted customer.

Rural Customer Costs per Rural Customer:	
Island Interconnected:	$365.78
Labrador Interconnected:	$289.46

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Total System
Rural Deficit Allocation

Line No.	1	2	3	4	5	6
		Deficit Allocation				
	Rate Class	Allocated Revenue Reqt ($)	Demand ($)	Energy ($)	Customer ($)	Source
	ALLOCATION OF DEFICIT:					
11	Island Interconnected	36,781,375	15,337,818	21,090,516	353,041	Line 6 x Line 10
12	Labrador Interconnected	4,813,084	1,807,068	2,474,530	531,486	Line 8 x Line 10
13	**Allocated Totals**	**41,594,459**	**17,144,886**	**23,565,046**	**884,528**	
	CUSTOMER DEFICIT ALLOCATION:					
	Island Interconnected:					
14	Newfoundland Power	36,781,375				
15	Sub-Total Island Interconnected	36,781,375				
	Labrador Interconnected:					
16	Rural Labrador Interconnected	4,813,084				
17	Subtotal Labrador Interconnected	4,813,084				
18	**Total**	**41,594,459**				

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Unit Demand, Energy & Customer Amounts

	1	2	3	4	5	6	7	8	9	10	11
	Rate Class	Before Deficit and Revenue Credit Allocation					After Deficit and Revenue Credit Allocation				
Line		Demand		Non-Demand			Demand		Non-Demand		
No.		Demand ($/kW)	Non-Demand ($/kWh)	Energy ($/kWh)	Demand & Energy ($/kWh)	Customer ($/Bill)	Demand ($/kW)	Non-Demand ($/kWh)	Energy ($/kWh)	Demand & Energy ($/kWh)	Customer ($/Bill)
	Island Interconnected										
1	Newfoundland Power	-	0.01867	0.02755	0.04622	187,654.80	-	0.02177	0.03213	0.05389	218,815.07
2	Industrial - Firm	6.50	-	0.02755	-	9,863.10	6.49	-	0.02755	-	9,862.27
3	Industrial - Non-Firm	-	-	0.02797	-	-	-	-	0.06219	-	-
	Rural							-	-		
4	1.1 Domestic	-	0.09668	0.03087	0.12755	28.77	-	-	-	-	-
5	1.12 Domestic All Electric	-	0.11231	0.03083	0.14313	28.73	-	-	-	-	-
6	1.3 Special	-	0.12503	0.03066	0.15570	28.57	-	-	-	-	-
7	2.1 General Service 0-10 kW	-	0.08358	0.03102	0.11461	31.93	-	-	-	-	-
8	2.2 General Service 10-100 kW	25.58	-	0.03101	-	50.23	-	-	-	-	-
9	2.3 General Service 110-1,000 kVa	19.80	-	0.03082	-	51.72	-	-	-	-	-
10	2.4 General Service Over 1,000 kVa	15.51	-	0.03076	-	51.88	-	-	-	-	-
11	4.1 Street and Area Lighting	-	0.11408	0.03113	0.14520	43.62	-	-	-	-	-

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Unit Demand, Energy & Customer Amounts

Line No.	1	2	3	4	5	6	7	8	9	10	11
	Rate Class	Before Deficit and Revenue Credit Allocation					After Deficit and Revenue Credit Allocation				
		Demand		Non-Demand			Demand		Non-Demand		
		Demand ($/kW)	Non-Demand ($/kWh)	Energy ($/kWh)	Demand & Energy ($/kWh)	Customer ($/Bill)	Demand ($/kW)	Non-Demand ($/kWh)	Energy ($/kWh)	Demand & Energy ($/kWh)	Customer ($/Bill)
	Isolated Systems:										
1	1.2 Domestic Diesel	-	0.23524	0.36366	0.59891	29.72					
2	2.1 General Service 0-10 kW	-	0.16544	0.35650	0.52194	33.81					
3	2.2 GS 10-100 kW	53.39	-	0.34758	-	56.95					
4	2.3 GS 110-1,000 kVa	12.11	-	0.38536	-	60.93					
5	2.4 General Service Over 1,000 kVa	4.12	-	0.33187	-	55.88					
6	**Subtotal Metered Demand Classes**	28.01	-	0.35315	-	57.27					
7	4.1 Street and Area Lighting	-	0.27778	0.37008	0.64785	56.09					
	Island Isolated										
8	1.2 Domestic Diesel	-	0.36877	0.46490	0.83367	32.02	-	-	-	-	-
9	2.1 General Service 0-10 kW	-	0.26720	0.46638	0.73358	37.66	-	-	-	-	-
10	2.2 GS 10-100 kW	114.87	-	0.46902	-	71.68	-	-	-	-	-
11	2.3 GS 110-1,000 kVa	39.51	-	0.46717	-	74.16	-	-	-	-	-
12	2.4 General Service Over 1,000 kVa	-	-	-	-	-	-	-	-	-	-
13	4.1 Street and Area Lighting	-	0.40851	0.46721	0.87572	49.84	-	-	-	-	-
	Labrador Isolated										
14	1.2 Domestic Diesel	-	0.19335	0.33190	0.52525	28.83	-	-	-	-	-
15	2.1 General Service 0-10 kW	-	0.14467	0.33408	0.47874	32.61	-	-	-	-	-
16	2.2 GS 10-100 kW	47.74	-	0.33345	-	54.35	-	-	-	-	-
17	2.3 GS 110-1,000 kVa	4.40	-	0.33237	-	55.96	-	-	-	-	-
18	2.4 General Service Over 1,000 kVa	4.12	-	0.33187	-	55.88	-	-	-	-	-
19	4.1 Street and Area Lighting	-	0.22807	0.33314	0.56121	59.22	-	-	-	-	-

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Unit Demand, Energy & Customer Amounts

	1	2	3	4	5	6	7	8	9	10	11
		Before Deficit and Revenue Credit Allocation					After Deficit and Revenue Credit Allocation				
		Demand		Non-Demand			Demand		Non-Demand		
Line No.	Rate Class	Demand ($/kW)	Non-Demand ($/kWh)	Energy ($/kWh)	Demand & Energy ($/kWh)	Customer ($/Bill)	Demand ($/kW)	Non-Demand ($/kWh)	Energy ($/kWh)	Demand & Energy ($/kWh)	Customer ($/Bill)
	L'Anse au Loup										
1	1.1 Domestic	-	0.10495	0.05987	0.16482	33.11	-	-	-	-	-
2	1.12 Domestic All Electric	-	0.12226	0.05982	0.18208	33.08	-	-	-	-	-
3	2.1 General Service 0-10 kW	-	0.07382	0.06022	0.13404	35.53	-	-	-	-	-
4	2.2 General Service 10-100 kW	20.75	-	0.06017	-	49.03	-	-	-	-	-
5	2.3 General Service 110-1,000 kVa	8.23	-	0.06031	-	50.26	-	-	-	-	-
6	4.1 Street and Area Lighting	-	0.10869	0.06060	0.16929	47.96	-	-	-	-	-
	Labrador Interconnected										
7	Industrial - IOCC Firm	3.01	-	0.00160	-	0.00	3.01	-	0.00160	-	0.00
8	Industrial - IOCC Non-Firm	-	-	0.00160	0.00160	0.00	-	-	0.00160	0.00160	0.00
9	CFB - Goose Bay Secondary	-	-	0.00167	0.00167	77.47	-	-	0.00167	0.00167	77.47
	Rural							-	-		
10	1.1 Domestic	-	0.01645	0.00173	0.01818	22.02	-	0.01962	0.00206	0.02169	26.27
11	1.1A Domestic All Electric	-	0.01639	0.00174	0.01813	22.16	-	0.01955	0.00208	0.02163	26.44
12	**Subtotal Domestic**	-	0.01639	0.00174	0.01813	22.15	-	0.01955	0.00208	0.02163	26.42
								-	-		
13	2.1 General Service 0-10 kW	-	0.01215	0.00174	0.01389	24.28	-	0.01449	0.00208	0.01657	28.97
14	2.2 General Service 10-100 kW	3.63	-	0.00176	-	37.72	4.33	-	0.00210	-	45.00
15	2.3 General Service 110-1,000 kVa	4.50	-	0.00176	-	38.84	5.37	-	0.00210	-	46.34
16	2.4 General Service Over 1,000 kVa	6.13	-	0.00172	-	37.61	7.31	-	0.00205	-	44.87
17	4.1 Street and Area Lighting	-	0.01707	0.00175	0.01882	43.19	0.00	0.02036	0.00209	0.02245	51.52

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Total Demand, Energy & Customer Amounts

	1	2	3	4	5	6	7	8	9
Line No.	Rate Class	Before Deficit and Revenue Credit Allocation				After Deficit and Revenue Credit Allocation			
		Total ($)	Demand ($)	Energy ($)	Customer ($)	Total ($)	Demand ($)	Energy ($)	Customer ($)
	Island Interconnected								
1	Newfoundland Power	221,395,182	88,514,377	130,628,947	2,251,858	258,158,074	103,212,278	152,320,015	2,625,781
2	Industrial - Firm	52,027,285	13,874,084	37,679,772	473,429	52,022,941	13,872,926	37,676,626	473,389
3	Industrial - Non-Firm	22,376	-	22,376	-	49,752	-	49,752	-
	Rural								
4	1.1 Domestic	17,762,333	10,235,033	3,268,317	4,258,983	-	-	-	-
5	1.12 Domestic All Electric	18,543,304	12,705,681	3,487,680	2,349,944	-	-	-	-
6	1.3 Special	34,939	27,507	6,746	686	-	-	-	-
7	2.1 General Service 0-10 kW	3,076,177	1,706,452	633,376	736,349	-	-	-	-
8	2.2 General Service 10-100 kW	8,456,540	5,889,544	2,039,000	527,996	-	-	-	-
9	2.3 General Service 110-1,000 kVa	3,907,849	2,785,012	1,076,291	46,545	-	-	-	-
10	2.4 General Service Over 1,000 kVa	1,839,683	1,086,201	749,747	3,735	-	-	-	-
11	4.1 Street and Area Lighting	886,299	342,228	93,383	450,688	-	-	-	-
12	**Subtotal Rural**	**54,507,125**	**34,777,660**	**11,354,540**	**8,374,926**				
13	**Total Island Interconnected**	**327,951,968**	**137,166,121**	**179,685,635**	**11,100,212**				

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Total Demand, Energy & Customer Amounts

	1	2	3	4	5	6	7	8	9
Line No.	Rate Class	Before Deficit and Revenue Credit Allocation				After Deficit and Revenue Credit Allocation			
		Total ($)	Demand ($)	Energy ($)	Customer ($)	Total ($)	Demand ($)	Energy ($)	Customer ($)
	Isolated Systems:								
1	1.2 Domestic Diesel	17,761,457	6,560,492	10,141,835	1,059,130				
2	2.1 General Service 0-10 kW	2,845,839	836,440	1,802,485	206,914				
3	2.2 GS 10-100 kW	4,990,033	1,569,843	3,338,183	82,008				
4	2.3 GS 110-1,000 kVa	1,615,058	356,133	1,250,882	8,043				
5	2.4 General Service Over 1,000 kVa	845,137	47,968	796,498	671				
6	**Subtotal Metered Demand Classes**	7,450,228	1,973,944	5,385,563	90,721				
7	4.1 Street and Area Lighting	344,816	114,945	153,138	76,733				
8	**Total Isolated Systems**	**28,402,339**	**9,485,821**	**17,483,020**	**1,433,498**				
	Island Isolated								
9	1.2 Domestic Diesel	5,870,791	2,456,009	3,096,250	318,532	-	-	-	-
10	2.1 General Service 0-10 kW	683,356	228,991	399,686	54,679	-	-	-	-
11	2.2 GS 10-100 kW	768,941	283,967	469,493	15,482	-	-	-	-
12	2.3 GS 110-1,000 kVa	854,023	255,248	596,105	2,670	-	-	-	-
13	2.4 General Service Over 1,000 kVa	-	-	-	-	-	-	-	-
14	4.1 Street and Area Lighting	122,559	46,570	53,262	22,727	-	-	-	-
15	**Total Island Isolated**	**8,299,670**	**3,270,784**	**4,614,796**	**414,090**				
	Labrador Isolated								
16	1.2 Domestic Diesel	11,890,666	4,104,483	7,045,585	740,598	-	-	-	-
17	2.1 General Service 0-10 kW	2,162,483	607,449	1,402,799	152,235	-	-	-	-
18	2.2 GS 10-100 kW	4,221,092	1,285,877	2,868,690	66,526	-	-	-	-
19	2.3 GS 110-1,000 kVa	761,034	100,885	654,777	5,373	-	-	-	-
20	2.4 General Service Over 1,000 kVa	845,137	47,968	796,498	671	-	-	-	-
21	4.1 Street and Area Lighting	222,256	68,375	99,876	54,006	-	-	-	-
22	**Total Labrador Isolated**	**20,102,669**	**6,215,037**	**12,868,224**	**1,019,408**				

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Total Demand, Energy & Customer Amounts

	1	2	3	4	5	6	7	8	9
Line No.	Rate Class	Before Deficit and Revenue Credit Allocation				After Deficit and Revenue Credit Allocation			
		Total ($)	Demand ($)	Energy ($)	Customer ($)	Total ($)	Demand ($)	Energy ($)	Customer ($)
	L'Anse au Loup								
1	1.1 Domestic	1,724,763	910,577	519,393	294,793	-	-	-	-
2	1.12 Domestic All Electric	69,814	41,812	20,459	7,543	-	-	-	-
3	2.1 General Service 0-10 kW	201,706	78,916	64,374	58,415	-	-	-	-
4	2.2 General Service 10-100 kW	592,551	322,257	233,230	37,065	-	-	-	-
5	2.3 General Service 110-1,000 kVa	119,689	69,027	49,456	1,206	-	-	-	-
6	4.1 Street and Area Lighting	36,904	12,608	7,030	17,267	-	-	-	-
7	**Total L'Anse au Loup**	**2,745,427**	**1,435,196**	**893,942**	**416,289**				
	Labrador Interconnected								
8	Industrial - IOCC Firm	2,635,349	2,238,788	396,561	-	2,635,349	2,238,788	396,561	-
9	Industrial - IOCC Non-Firm	6,404	-	6,404	-	6,404	-	6,404	-
10	CFB - Goose Bay Secondary	129,969	-	129,039	930	129,969	-	129,039	930
	Rural								
11	1.1 Domestic	341,564	138,830	14,596	188,137	407,506	165,633	17,414	224,459
12	1.1A Domestic All Electric	6,564,127	4,216,797	447,830	1,899,501	7,831,392	5,030,888	534,287	2,266,217
13	**Subtotal Domestic**	**6,905,691**	**4,355,627**	**462,426**	**2,087,638**	**8,238,898**	**5,196,521**	**551,701**	**2,490,676**
14	2.1 General Service 0-10 kW	171,313	48,140	6,901	116,273	204,387	57,434	8,233	138,720
15	2.2 General Service 10-100 kW	1,110,046	734,086	100,216	275,743	1,324,350	875,809	119,564	328,978
16	2.3 General Service 110-1,000 kVa	1,412,693	1,205,633	150,294	56,765	1,685,426	1,438,392	179,310	67,724
17	2.4 General Service Over 1,000 kVa	877,398	763,239	111,451	2,708	1,046,788	910,590	132,968	3,230
18	4.1 Street and Area Lighting	171,606	25,450	2,608	143,549	204,737	30,363	3,111	171,262
19	**Subtotal Rural**	**10,648,748**	**7,132,176**	**833,896**	**2,682,676**	**12,704,586**	**8,509,108**	**994,887**	**3,200,591**
20	**Total Labrador Incterconnected**	**13,420,470**	**9,370,964**	**1,365,900**	**2,683,606**	**15,476,308**	**10,747,896**	**1,526,891**	**3,200,591**

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Demands, Sales, & Number of Bills

	1	2	3	4	5
		Units			
Line No.	Rate Class	Billing Demands (kW)	Sales (MWh)	Customers	Bills (Total No)
	Island Interconnected				
1	Newfoundland Power	-	4,741,400	1	12
2	Industrial - Firm	2,136,000	1,367,800	4	48
3	Industrial - Non-Firm	5,600	800	-	-
	Rural				
4	1.1 Domestic	-	105,865	12,337	148,044
5	1.12 Domestic All Electric	-	113,135	6,817	81,804
6	1.3 Special	-	220	2	24
7	2.1 General Service 0-10 kW	-	20,416	1,922	23,064
8	2.2 General Service 10-100 kW	230,279	65,748	876	10,512
9	2.3 General Service 110-1,000 kVa	140,665	34,917	75	900
10	2.4 General Service Over 1,000 kVa	70,054	24,374	6	72
11	4.1 Street and Area Lighting	-	3,000	861	10,332
12	**Subtotal Rural**	**440,997**	**367,675**	**22,896**	**274,752**
13	**Total Island Interconnected**	**2,582,597**	**6,477,675**	**22,901**	**274,812**

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Demands, Sales, & Number of Bills

	1	2	3	4	5
		Units			
Line No.	Rate Class	Billing Demands (kW)	Sales (MWh)	Customers	Bills (Total No)
	Isolated Systems:				
1	1.2 Domestic Diesel	-	27,888	2,970	35,640
2	2.1 General Service 0-10 kW	-	5,056	510	6,120
3	2.2 GS 10-100 kW	29,405	9,604	120	1,440
4	2.3 GS 110-1,000 kVa	29,403	3,246	11	132
5	2.4 General Service Over 1,000 kVa	11,657	2,400	1	12
6	**Subtotal Metered Demand Classes**	70,464	15,250	132	1,584
7	4.1 Street and Area Lighting	-	414	114	1,368
8	**Total Isolated Systems**	**70,464**	**48,608**	**3,726**	**44,712**
	Island Isolated				
9	1.2 Domestic Diesel	-	6,660	829	9,948
10	2.1 General Service 0-10 kW	-	857	121	1,452
11	2.2 GS 10-100 kW	2,472	1,001	18	216
12	2.3 GS 110-1,000 kVa	6,460	1,276	3	36
13	2.4 General Service Over 1,000 kVa	-	-	-	-
14	4.1 Street and Area Lighting	-	114	38	456
15	**Total Island Isolated**	**8,932**	**9,908**	**1,009**	**12,108**
	Labrador Isolated				
16	1.2 Domestic Diesel	-	21,228	2,141	25,692
17	2.1 General Service 0-10 kW	-	4,199	389	4,668
18	2.2 GS 10-100 kW	26,933	8,603	102	1,224
19	2.3 GS 110-1,000 kVa	22,943	1,970	8	96
20	2.4 General Service Over 1,000 kVa	11,657	2,400	1	12
21	4.1 Street and Area Lighting	-	300	76	912
22	**Total Labrador Isolated**	**61,532**	**38,700**	**2,717**	**32,604**

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Demands, Sales, & Number of Bills

	1	2	3	4	5
		Units			
Line No.	Rate Class	Billing Demands (kW)	Sales (MWh)	Customers	Bills (Total No)
	L'Anse au Loup				
1	1.1 Domestic	-	8,676	742	8,904
2	1.12 Domestic All Electric	-	342	19	228
3	2.1 General Service 0-10 kW	-	1,069	137	1,644
4	2.2 General Service 10-100 kW	15,529	3,876	63	756
5	2.3 General Service 110-1,000 kVa	8,392	820	2	24
6	4.1 Street and Area Lighting	-	116	30	360
7	**Total L'Anse au Loup**	**23,921**	**14,899**	**993**	**11,916**
	Labrador Interconnected				
8	Industrial - IOCC Firm	744,000	247,700	1	12
9	Industrial - IOCC Non-Firm	-	4,000		
10	CFB - Goose Bay Secondary	-	77,200	1	12
	Rural				
11	1.1 Domestic	-	8,441	712	8,544
12	1.1A Domestic All Electric	-	257,334	7,143	85,716
13	**Subtotal Domestic**	-	**265,775**	**7,855**	**94,260**
14	2.1 General Service 0-10 kW	-	3,963	399	4,788
15	2.2 General Service 10-100 kW	202,265	56,906	609	7,311
16	2.3 General Service 110-1,000 kVa	267,913	85,210	122	1,461
17	2.4 General Service Over 1,000 kVa	124,484	64,946	6	72
18	4.1 Street and Area Lighting	-	1,491	277	3,324
19	**Subtotal Rural**	**594,662**	**478,291**	**9,268**	**111,216**
20	**Total Labrador Incterconnected**	**1,338,662**	**807,191**	**9,270**	**111,240**

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Island Interconnected
Calculation of Firming Up Charge

	1	2	3	4
Line No.	Description	Total	Gas Turbine	Transmission & Terminals
1	Operating & Maintenance	4,450,957	540,014	3,910,943
2	O&M Overhead	4,315,884	384,308	3,931,575
3	Depreciation	6,219,254	184,896	6,034,358
4	Return (Note 1)	15,576,406	182,265	15,394,141
5	**Total**	**30,562,501**	**1,291,484**	**29,271,017**
6	Capacity (kW)		118,000	1,591,800
7	Cost ($/kW)	$29.33	$10.94	$18.39
8	Rate ($/kWh)	$0.00641		

Note 1 Gas Turbine Return	
Gas Turbine NBV - Sch.2.3A L.10	1,919,319
NBV Including Alloc General, Telecontrol & Feasibility Study	2,030,867
Percent of Total Prod Demand NBV - Schedule 2.3A, L.40, C.3	0.50%

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Island Interconnected
Calculation of Transmission Wheeling Charge

Line No.	1 Description	2
1	Island Interconnected Transmission Revenue Requirement	29,228,905
2	Transmission Energy Output (MWh)	6,516,300
3	Rate ($/kWh)	$0.00449

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Island Interconnected
Functional Classification of Revenue Requirement

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Rural Prod & Transmission Demand ($)	7 Distribution: Substations Demand ($)	8 Distribution: Primary Lines Demand ($)	9 Distribution: Primary Lines Customer ($)	10 Distribution: Line Transformers Demand ($)	11 Distribution: Line Transformers Customer ($)	12 Distribution: Secondary Lines Demand ($)	13 Distribution: Secondary Lines Customer ($)	14 Distribution: Services Customer ($)	15 Distribution: Meters Customer ($)	16 Distribution: Street Lighting Customer ($)	17 Accounting Customer ($)	18 Specifically Assigned Customer ($)
	Expenses																	
1	Operating & Maintenance	72,460,822	24,091,441	21,764,487	7,842,518	4,469,632	1,115,931	4,932,535	1,189,706	243,269	430,607	659,951	729,001	420,440	202,490	83,408	2,179,052	803,617
2	Fuels-No. 6 Fuel	84,819,538	-	84,819,538	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Fuels-Diesel	54,612	-	-	-	54,612	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuels-Gas Turbine	265,277	265,277	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Power Purchases -CF(L)Co	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Power Purchases-Other	29,928,330	12,420,675	17,080,954	-	426,701	-	-	-	-	-	-	-	-	-	-	-	-
7	Depreciation	27,884,999	6,964,159	6,863,254	6,034,358	2,491,138	480,948	2,172,567	509,423	110,063	194,822	279,602	310,035	151,250	90,235	39,565	343,784	849,797
	Expense Credits																	
8	Sundry	(355,106)	(118,064)	(106,660)	(38,434)	(21,904)	(5,469)	(24,173)	(5,830)	(1,192)	(2,110)	(3,234)	(3,573)	(2,060)	(992)	(409)	(10,679)	(3,938)
9	Building Rental Income	(7,200)	(2,524)	(2,266)	(701)	(399)	(107)	(484)	(117)	(24)	(42)	(65)	(72)	(41)	(20)	(8)	(255)	(74)
10	Tax Refunds	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Suppliers' Discounts	(17,755)	(5,903)	(5,333)	(1,922)	(1,095)	(273)	(1,209)	(292)	(60)	(106)	(162)	(179)	(103)	(50)	(20)	(534)	(197)
12	Pole Attachments	(883,099)	-	-	-	-	-	(510,739)	(174,546)	-	-	(90,401)	(107,413)	-	-	-	-	-
13	Secondary Energy	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Wheeling Revenues	(70,493)	-	-	(70,493)	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Application Fees	(19,452)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(19,452)	-
16	Meter Test Revenues	(53,193)	-	-	-	-	-	-	-	-	-	-	-	-	(53,193)	-	-	-
17	**Total Expense Credits**	**(1,406,298)**	**(126,491)**	**(114,259)**	**(111,549)**	**(23,399)**	**(5,849)**	**(536,604)**	**(180,785)**	**(1,276)**	**(2,258)**	**(93,862)**	**(111,236)**	**(2,205)**	**(54,255)**	**(437)**	**(30,920)**	**(4,210)**
18	**Subtotal Expenses**	**214,007,279**	**43,615,060**	**130,413,975**	**13,765,327**	**7,418,684**	**1,591,029**	**6,568,497**	**1,518,344**	**352,057**	**623,170**	**845,692**	**927,800**	**569,485**	**238,470**	**122,536**	**2,491,916**	**1,649,204**
19	Disposal Gain / Loss	515,443	164,740	214,902	69,437	32,751	4,076	13,145	3,175	759	1,344	1,700	1,902	919	558	291	947	4,796
20	**Subtotal Revenue Requirement Ex. Return**	**214,522,722**	**43,779,800**	**130,628,877**	**13,834,764**	**7,451,435**	**1,595,105**	**6,581,642**	**1,521,519**	**352,817**	**624,515**	**847,391**	**929,702**	**570,404**	**239,028**	**122,826**	**2,492,862**	**1,654,000**
21	Return on Debt	98,967,734	31,410,859	41,684,778	13,204,629	6,240,069	779,186	2,514,755	607,410	144,898	256,481	325,351	363,940	176,536	106,695	55,378	181,754	915,014
22	Return on Equity	14,461,511	5,208,359	6,911,918	2,189,512	-	-	-	-	-	-	-	-	-	-	-	-	151,722
23	**Total Revenue Reqmt**	**327,951,968**	**80,399,018**	**179,225,574**	**29,228,905**	**13,691,504**	**2,374,291**	**9,096,398**	**2,128,929**	**497,715**	**880,996**	**1,172,743**	**1,293,642**	**746,941**	**345,723**	**178,204**	**2,674,617**	**2,720,736**

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Island Interconnected
Functional Classification of Revenue Requirement (CONT'D.)

	1	19	20	21
		Revenue Related		
Line No.	Description	Municipal Tax	PUB Assessment	Basis of Functional Classification
	Expenses			
1	Operating & Maintenance	790,576	512,161	Carryforward from Sch.2.4 L.30
2	Fuels-No. 6 Fuel	-	-	Production - Demand, Energy ratios Sch.4.1 L.10
3	Fuels-Diesel	-	-	Production - Demand, Energy ratios Sch.4.1 L.12
4	Fuels-Gas Turbine	-	-	Production - Demand, Energy ratios Sch.4.1 L.11
5	Power Purchases -CF(L)Co	-	-	
6	Power Purchases-Other	-	-	Carryforward from Sch.4.4 L.7
7	Depreciation	-	-	Carryforward from Sch.2.5 L.40
	Expense Credits			
8	Sundry	(3,874)	(2,510)	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.30
9	Building Rental Income	-	-	Prorated on General Plant - Sch.2.2 L.35
10	Tax Refunds	-	-	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.30
11	Suppliers' Discounts	(194)	(125)	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.30
12	Pole Attachments	-	-	Prorated on Distribution Poles - Sch.4.1 L.37
13	Secondary Energy	-	-	Production - Energy
14	Wheeling Revenues	-	-	Transmission - Demand
15	Application Fees	-	-	Accounting - Customer
16	Meter Test Revenues	-	-	Meters - Customer
17	**Total Expense Credits**	**(4,068)**	**(2,635)**	
18	**Subtotal Expenses**	**786,508**	**509,525**	
19	Disposal Gain / Loss	-	-	Prorated on Total Net Book Value - Sch.2.3 L.40
20	**Subtotal Revenue Requirement Ex. Return**	**786,508**	**509,525**	
21	Return on Debt	-	-	Prorated on Rate Base - Sch.2.6 L.8
22	Return on Equity	-	-	Prorated on Rate Base - Sch.2.6 L.10
23	**Total Revenue Reqmt**	**786,508**	**509,525**	

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Island Interconnected
Functional Classification of Plant in Service for the Allocation of O&M Expense

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Rural Prod & Transmission Demand ($)	7 Distribution: Substations Demand ($)	8 Distribution: Primary Lines Demand ($)	9 Distribution: Primary Lines Customer ($)	10 Distribution: Line Transformers Demand ($)	11 Distribution: Line Transformers Customer ($)	12 Distribution: Secondary Lines Demand ($)	13 Distribution: Secondary Lines Customer ($)	14 Distribution: Services Customer ($)	15 Distribution: Meters Customer ($)	16 Distribution: Street Lighting Customer ($)	17 Accounting Customer ($)	18 Specifically Assigned Customer ($)
	Production																	
	Hydraulic																	
1	Bay D'Espoir	187,010,803	78,734,647	108,276,156	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Upper Salmon	169,883,402	71,523,727	98,359,674	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Hinds Lake	79,352,443	33,408,693	45,943,749	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Cat Arm	264,379,817	111,308,284	153,071,533	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Paradise River	21,857,009	9,202,163	12,654,846	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Granite Canal	119,502,667	50,312,603	69,190,064	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Other Hydraulic	2,113,835	355,841	489,353	-	1,268,641	-	-	-	-	-	-	-	-	-	-	-	-
8	**Subtotal Hydraulic**	**844,099,976**	**354,845,958**	**487,985,376**	**-**	**1,268,641**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
9	Holyrood	184,940,225	106,747,498	78,192,727	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Gas Turbines	22,497,317	22,497,317	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Roddickton	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Diesel	7,011,062	-	-	-	7,011,062	-	-	-	-	-	-	-	-	-	-	-	-
13	**Subtotal Production**	**1,058,548,579**	**484,090,773**	**566,178,104**	**-**	**8,279,703**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Transmission																	
14	Lines	239,086,914	-	-	153,486,699	80,469,312	-	168,000	-	-	-	-	-	-	-	-	-	4,962,902
15	Lines - Hydraulic	50,148,749	21,113,455	29,035,295	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Terminal Stations	92,576,769	-	-	59,329,866	19,900,837	-	-	-	-	-	-	-	-	-	-	-	13,346,066
17	Term Stns - Hydraulic	28,035,122	11,803,251	16,231,871	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Term Stns - Holyrood	9,970,272	5,754,841	4,215,431	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Term Stns - Gas Tur/Dsl	1,183,617	382,749	-	-	800,868	-	-	-	-	-	-	-	-	-	-	-	-
20	Term Stns - Distribution	9,695,739	-	-	-	-	9,695,739	-	-	-	-	-	-	-	-	-	-	-
21	**Subtotal Term Stns**	**141,461,519**	**17,940,841**	**20,447,302**	**59,329,866**	**20,701,705**	**9,695,739**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**13,346,066**
22	**Subtotal Transmission**	**430,697,182**	**39,054,295**	**49,482,597**	**212,816,566**	**101,171,017**	**9,695,739**	**168,000**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**18,308,968**
	Distribution																	
23	Substations	8,197,609	-	-	-	1,197,785	6,999,824	-	-	-	-	-	-	-	-	-	-	-
24	Land & Land Improvements	718,717	-	-	-	-	-	541,877	69,033	-	-	62,852	44,956	-	-	-	-	-
25	Poles	57,740,138	-	-	-	-	-	33,393,893	11,412,454	-	-	5,910,742	7,023,048	-	-	-	-	-
26	Primary Conductor & Eqpt	12,925,089	-	-	-	-	-	11,464,554	1,460,535	-	-	-	-	-	-	-	-	-
27	Submarine Conductor	8,198,057	-	-	-	-	-	8,198,057	-	-	-	-	-	-	-	-	-	-
28	Transformers	7,330,650	-	-	-	-	-	-	-	2,646,365	4,684,286	-	-	-	-	-	-	-
29	Secondary Conductor&Eqpt	2,067,885	-	-	-	-	-	-	-	-	-	1,205,577	862,308	-	-	-	-	-
30	Services	4,573,685	-	-	-	-	-	-	-	-	-	-	-	4,573,685	-	-	-	-
31	Meters	2,245,103	-	-	-	-	-	-	-	-	-	-	-	-	2,245,103	-	-	-
32	Street Lighting	907,339	-	-	-	-	-	-	-	-	-	-	-	-	-	907,339	-	-
33	**Subtotal Distribution**	**104,904,271**	**-**	**-**	**-**	**1,197,785**	**6,999,824**	**53,598,381**	**12,942,022**	**2,646,365**	**4,684,286**	**7,179,171**	**7,930,312**	**4,573,685**	**2,245,103**	**907,339**	**-**	**-**
34	**Subttl Prod, Trans, & Dist**	**1,594,150,032**	**523,145,068**	**615,660,701**	**212,816,566**	**110,648,505**	**16,695,563**	**53,766,381**	**12,942,022**	**2,646,365**	**4,684,286**	**7,179,171**	**7,930,312**	**4,573,685**	**2,245,103**	**907,339**	**-**	**18,308,968**
35	General	148,474,674	52,042,275	46,719,053	14,460,831	8,235,921	2,208,443	9,990,085	2,409,877	492,768	872,240	1,336,802	1,476,668	851,646	408,783	168,952	5,266,047	1,534,284
36	Telecontrol - Custmr & Spec	269,144	-	-	-	-	-	-	-	-	-	-	-	-	-	-	170,900	98,244
37	Feasibility Studies	217,135	122,500	-	94,635	-	-	-	-	-	-	-	-	-	-	-	-	-
38	Feasibility Studies - General	290,900	95,463	112,346	38,835	20,191	3,047	9,811	2,362	483	855	1,310	1,447	835	410	166	-	3,341
39	Software - General	1,393,732	457,375	538,259	186,061	96,738	14,597	47,007	11,315	2,314	4,095	6,277	6,933	3,999	1,963	793	-	16,007
40	**Total Plant**	**1,744,795,617**	**575,862,681**	**663,030,358**	**227,596,928**	**119,001,354**	**18,921,650**	**63,813,284**	**15,365,575**	**3,141,929**	**5,561,476**	**8,523,559**	**9,415,361**	**5,430,164**	**2,656,258**	**1,077,249**	**5,436,947**	**19,960,843**

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Island Interconnected
Functional Classification of Plant in Service for the Allocation of O&M Expense (CONT'D.)

	1	19
Line No.	Description	Basis of Functional Classification
	Production	
	Hydraulic	
1	Bay D'Espoir	Production - Demand, Energy ratios Sch.4.1 L.1
2	Upper Salmon	Production - Demand, Energy ratios Sch.4.1 L.1
3	Hinds Lake	Production - Demand, Energy ratios Sch.4.1 L.1
4	Cat Arm	Production - Demand, Energy ratios Sch.4.1 L.1
5	Paradise River	Production - Demand, Energy ratios Sch.4.1 L.1
6	Granite Canal	Production - Demand, Energy ratios Sch.4.1 L.1
7	Other Hydraulic	Production - Demand, Energy ratios Sch.4.1 L.1, 2
8	**Subtotal Hydraulic**	
9	Holyrood	Production - Demand, Energy ratios Sch.4.1 L.3
10	Gas Turbines	Production - Demand, Energy ratios Sch.4.1 L.4
11	Roddickton	Production - Demand, Energy ratios Sch.4.1 L.3
12	Diesel	Production - Demand, Energy ratios Sch.4.1 L.5
13	**Subtotal Production**	
	Transmission	
14	Lines	Transmission - Demand; Distribution - Primary Demand; Spec Assigned - Custmr
15	Lines - Hydraulic	Production - Demand, Energy ratios Sch.4.1 L.17
16	Terminal Stations	Production - Demand, Energy subtotals, L. 13; Transmission - Demand; Spec Assigned - Custmr
17	Term Stns - Hydraulic	Production - Demand, Energy ratios Sch.4.1 L.20
18	Term Stns - Holyrood	Production - Demand, Energy ratios Sch.4.1 L.21
19	Term Stns - Gas Tur/Dsl	Production - Demand, Energy ratios Sch.4.1 L.22, 23
20	Term Stns - Distribution	Distribution - Substations Demand
21	**Subtotal Term Stns**	
22	**Subtotal Transmission**	
	Distribution	
23	Substations	Production - Demand; Dist Substns - Demand
24	Land & Land Improvements	Primary, Secondary - Demand, Customer - zero intercept ratios Sch.4.1 L.32
25	Poles	Primary, Secondary - Demand, Customer - zero intercept ratios Sch.4.1 L.37
26	Primary Conductor & Eqpt	Primary - Demand, Customer - zero intercept ratios Sch.4.1 L.38
27	Submarine Conductor	Primary - Demand, Customer - zero intercept ratios Sch.4.1 L.39
28	Transformers	Transformers - Demand, Customer - zero intercept ratios Sch.4.1 L.40
29	Secondary Conductor&Eqpt	Secondary - Demand, Customer - zero intercept ratios Sch. 4.1 L.41
30	Services	Services Customer
31	Meters	Meters - Customer
32	Street Lighting	Street Lighting - Customer
33	**Subtotal Distribution**	
34	**Subttl Prod, Trans, & Dist**	
35	General	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - Sch.2.4 L.15, 16
36	Telecontrol - Custmr & Spec	Specifically Assigned - Customer
37	Feasibility Studies	Production, Transmission - Demand
38	Feasibility Studies - General	Prorated on subtotal Production, Transmission, & Distribution plant - L.34
39	Software - General	Prorated on subtotal Production, Transmission, & Distribution plant - L.34
40	**Total Plant**	

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Island Interconnected
Functional Classification of Net Book Value

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
							Distribution											
				Production and		Rural Prod &	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Specifically
Line		Total	Production	Transmission	Transmission	Transmission												Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
	Production	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
	Hydraulic																	
1	Bay D'Espoir	148,596,879	62,561,748	86,035,130	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Upper Salmon	163,610,642	68,882,791	94,727,850	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Hinds Lake	73,413,524	30,908,310	42,505,214	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Cat Arm	258,833,029	108,972,994	149,860,035	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Paradise River	21,116,576	8,890,428	12,226,148	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Granite Canal	119,280,253	50,218,963	69,061,290	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Other Small Hydraulic	772,769	262,036	360,352	-	150,381	-	-	-	-	-	-	-	-	-	-	-	-
8	**Subtotal Hydraulic**	**785,623,672**	**330,697,271**	**454,776,020**	-	**150,381**	-	-	-	-	-	-	-	-	-	-	-	-
9	Holyrood	36,604,946	21,128,375	15,476,571	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Gas Turbines	1,919,319	1,919,319	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Roddickton	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Diesel	850,555	-	-	-	850,555	-	-	-	-	-	-	-	-	-	-	-	-
13	**Subtotal Production**	**824,998,492**	**353,744,965**	**470,252,591**	-	**1,000,936**	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																	
14	Lines	188,923,696	-	-	126,526,242	58,766,296	-	62,117	-	-	-	-	-	-	-	-	-	3,569,042
15	Lines - Hydraulic	48,319,129	20,343,154	27,975,975	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Terminal Stations	63,088,890	-	-	39,085,656	16,432,568	-	-	-	-	-	-	-	-	-	-	-	7,570,665
17	Term Stns - Hydraulic	20,554,593	8,653,824	11,900,768	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Term Stns - Holyrood	4,489,558	2,591,373	1,898,185	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Term Stns - Gas Tur/Dsl	964,060	279,981	-	-	684,079	-	-	-	-	-	-	-	-	-	-	-	-
20	Term Stns - Distribution	6,022,272	-	-	-	-	6,022,272	-	-	-	-	-	-	-	-	-	-	-
21	**Subtotal Term Stns**	**95,119,371**	**11,525,178**	**13,798,953**	**39,085,656**	**17,116,647**	**6,022,272**	-	-	-	-	-	-	-	-	-	-	**7,570,665**
22	**Subtotal Transmission**	**332,362,196**	**31,868,332**	**41,774,928**	**165,611,899**	**75,882,942**	**6,022,272**	**62,117**	-	-	-	-	-	-	-	-	-	**11,139,707**
	Distribution																	
23	Substations	3,821,489	-	-	-	683,695	3,137,794	-	-	-	-	-	-	-	-	-	-	-
24	Land & Land Improvements	425,169	-	-	-	-	-	320,556	40,837	-	-	37,181	26,594	-	-	-	-	-
25	Poles	30,559,357	-	-	-	-	-	17,673,943	6,040,118	-	-	3,128,300	3,716,996	-	-	-	-	-
26	Primary Conductor & Eqpt	6,783,411	-	-	-	-	-	6,016,885	766,525	-	-	-	-	-	-	-	-	-
27	Submarine Conductor	4,268,692	-	-	-	-	-	4,268,692	-	-	-	-	-	-	-	-	-	-
28	Transformers	4,633,615	-	-	-	-	-	-	-	1,672,735	2,960,880	-	-	-	-	-	-	-
29	Secondary Conductor&Eqpt	823,828	-	-	-	-	-	-	-	-	-	480,292	343,536	-	-	-	-	-
30	Services	1,917,810	-	-	-	-	-	-	-	-	-	-	-	1,917,810	-	-	-	-
31	Meters	1,209,266	-	-	-	-	-	-	-	-	-	-	-	-	1,209,266	-	-	-
32	Street Lighting	648,558	-	-	-	-	-	-	-	-	-	-	-	-	-	648,558	-	-
33	**Subtotal Distribution**	**55,091,196**	-	-	-	**683,695**	**3,137,794**	**28,280,077**	**6,847,481**	**1,672,735**	**2,960,880**	**3,645,773**	**4,087,126**	**1,917,810**	**1,209,266**	**648,558**	-	-
34	**Subttl Prod, Trans, & Dist**	**1,212,451,884**	**385,613,297**	**512,027,519**	**165,611,899**	**77,567,573**	**9,160,066**	**28,342,193**	**6,847,481**	**1,672,735**	**2,960,880**	**3,645,773**	**4,087,126**	**1,917,810**	**1,209,266**	**648,558**	-	**11,139,707**
35	General	62,067,665	21,755,512	19,530,216	6,045,139	3,442,906	923,207	4,176,209	1,007,414	205,994	364,627	558,830	617,300	356,018	170,886	70,628	2,201,394	641,385
36	Telecontrol - Custmr & Spec	224,773	-	-	-	-	-	-	-	-	-	-	-	-	-	-	143,841	80,933
37	Feasibility Studies	217,135	122,500	-	94,635	-	-	-	-	-	-	-	-	-	-	-	-	-
38	Feasibility Studies - General	247,265	78,641	104,422	33,775	15,819	1,868	5,780	1,396	341	604	744	834	391	247	132	-	2,272
39	Software - General	1,429,565	454,665	603,716	195,268	91,458	10,800	33,417	8,074	1,972	3,491	4,299	4,819	2,261	1,426	765	-	13,134
40	**Total Net Book Value**	**1,276,638,287**	**408,024,614**	**532,265,873**	**171,980,715**	**81,117,756**	**10,095,941**	**32,557,600**	**7,864,365**	**1,881,043**	**3,329,602**	**4,209,646**	**4,710,079**	**2,276,481**	**1,381,824**	**720,083**	**2,345,235**	**11,877,430**

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Island Interconnected
Functional Classification of Operating & Maintenance Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
							Distribution											
							Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Specifically Assigned
Line No.	Description	Total Amount ($)	Production Demand ($)	Production and Transmission Energy ($)	Transmission Demand ($)	Rural Prod & Transmission Demand ($)	Demand ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)
	Production																	
1	Hydraulic	6,435,405	2,705,340	3,720,393	-	9,672	-	-	-	-	-	-	-	-	-	-	-	-
2	Holyrood / Thermal	15,330,091	8,848,529	6,481,563	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Roddickton	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Gas Turbine	487,340	487,340	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Diesel	348,284	-	-	-	348,284	-	-	-	-	-	-	-	-	-	-	-	-
6	Other	2,730,714	1,248,798	1,460,557	-	21,359	-	-	-	-	-	-	-	-	-	-	-	-
7	**Subtotal Production**	**25,331,834**	**13,290,007**	**11,662,512**	**-**	**379,315**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Transmission																	
8	Transmission Lines	3,640,022	265,712	365,408	1,931,625	1,012,704	-	2,114	-	-	-	-	-	-	-	-	-	62,458
9	Terminal Stations	3,127,365	396,628	452,039	1,311,637	457,664	214,349	-	-	-	-	-	-	-	-	-	-	295,049
10	Other	1,351,249	122,527	155,244	667,681	317,409	30,419	527	-	-	-	-	-	-	-	-	-	57,442
11	**Subtotal Transmission**	**8,118,636**	**784,867**	**972,692**	**3,910,943**	**1,787,777**	**244,768**	**2,641**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**414,948**
	Distribution																	
12	Other	5,169,859	-	-	-	60,320	352,507	2,699,185	651,753	133,269	235,898	361,539	399,366	230,328	-	45,693	-	-
13	Meters	110,556	-	-	-	-	-	-	-	-	-	-	-	-	110,556	-	-	-
14	**Subtotal Distribution**	**5,280,415**	**-**	**-**	**-**	**60,320**	**352,507**	**2,699,185**	**651,753**	**133,269**	**235,898**	**361,539**	**399,366**	**230,328**	**110,556**	**45,693**	**-**	**-**
15	**Subttl Prod, Trans, & Dist**	**38,730,885**	**14,074,874**	**12,635,204**	**3,910,943**	**2,227,411**	**597,275**	**2,701,826**	**651,753**	**133,269**	**235,898**	**361,539**	**399,366**	**230,328**	**110,556**	**45,693**	**-**	**414,948**
16	Customer Accounting	1,424,207	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,424,207	-
	Administrative & General:																	
	Plant-Related:																	
17	Production	2,108,655	964,321	1,127,841	-	16,493	-	-	-	-	-	-	-	-	-	-	-	-
18	Prod - Gas Turb & Diesel	470,495	358,707	-	-	111,787	-	-	-	-	-	-	-	-	-	-	-	-
19	Transmission	2,069,447	187,651	237,758	1,022,557	486,114	46,587	807	-	-	-	-	-	-	-	-	-	87,972
20	Distribution	1,095,667	-	-	-	12,510	73,109	559,805	135,172	27,640	48,925	74,982	82,828	47,770	23,449	9,477	-	-
21	Prod, Trans, Distn	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Prod, Trans, Distn and General Plant	373,682	123,332	142,001	48,744	25,486	4,052	13,667	3,291	673	1,191	1,825	2,016	1,163	569	231	1,164	4,275
23	Prod, Trans, Distn, Excl Hydraulic & Holyrood	1,727,795	188,191	151,291	650,676	334,423	51,046	164,388	39,570	8,091	14,322	21,950	24,247	13,984	6,864	2,774	-	55,979
24	Property Insurance	1,139,916	465,453	532,045	61,988	32,271	15,880	8,392	2,024	414	733	1,123	1,240	715	343	142	4,567	12,583
	Revenue-Related:																	
25	Municipal Tax	790,576	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	PUB Assessment	512,161	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	All Expense-Related	21,121,042	7,403,196	6,645,949	2,057,104	1,171,589	314,159	1,421,125	342,813	70,098	124,079	190,165	210,061	121,150	58,151	24,034	749,114	218,257
28	Prod, Trans, and Distn Expense-Related	896,296	325,716	292,399	90,506	51,546	13,822	62,525	15,083	3,084	5,459	8,367	9,242	5,330	2,558	1,057	-	9,603
29	**Subtotal Admin & General**	**32,305,731**	**10,016,567**	**9,129,283**	**3,931,575**	**2,242,220**	**518,655**	**2,230,709**	**537,953**	**110,000**	**194,709**	**298,412**	**329,634**	**190,112**	**91,935**	**37,715**	**754,845**	**388,669**
30	**Total Operating & Maintenance Expenses**	**72,460,822**	**24,091,441**	**21,764,487**	**7,842,518**	**4,469,632**	**1,115,931**	**4,932,535**	**1,189,706**	**243,269**	**430,607**	**659,951**	**729,001**	**420,440**	**202,490**	**83,408**	**2,179,052**	**803,617**

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Island Interconnected
Functional Classification of Operating & Maintenance Expense (CONT'D.)

	1	19	20	21
		Revenue Related		
Line		Municipal	PUB	
No.	Description	Tax	Assessment	Basis of Functional Classification
	Production			
1	Hydraulic	-	-	Prorated on Hydraulic Plant in Service - Sch.2.2 L.8
2	Holyrood / Thermal	-	-	Prorated on Holyrood Plant in Service - Sch.2.2 L.9
3	Roddickton	-	-	Prorated on Roddickton Plant in Service - Sch.2.2 L.11
4	Gas Turbine	-	-	Prorated on Gas Turbines Plant in Service - Sch.2.2 L.10
5	Diesel	-	-	Prorated on Diesel Plant in Service - Sch.2.2 L.12
6	Other	-	-	Prorated on Production Plant in Service - Sch.2.2 L.13
7	**Subtotal Production**	-	-	
	Transmission			
8	Transmission Lines	-	-	Prorated on Transmission Lines Plant in Service - Sch.2.2 L.14, 15
9	Terminal Stations	-	-	Prorated on Transmission Terminal Stations Plant in Service - Sch.2.2 L.21
10	Other	-	-	Prorated on Transmission Plant in Service - Sch.2.2 L.22
11	**Subtotal Transmission**	-	-	
	Distribution			
12	Other	-	-	Prorated on Distribution Plant, excluding Meters - Sch. 2.2 L. 33, less L. 31
13	Meters	-	-	Meters - Customer
14	**Subtotal Distribution**	-	-	
15	**Subttl Prod, Trans, & Dist**	-	-	
16	Customer Accounting	-	-	Accounting - Customer
	Administrative & General:			
	Plant-Related:			
17	Production	-	-	Prorated on Production Plant in Service - Sch.2.2 L.13
18	Prod - Gas Turb & Diesel		-	Prorated on Gas Turbine & Diesel Production Plant in Service - Sch.2.2 L.10, 12
19	Transmission	-	-	Prorated on Transmission Plant in Service - Sch.2.2 L.22
20	Distribution	-	-	Prorated on Distribution Plant in Service - Sch.2.2 L.33
21	Prod, Trans, Distn	-	-	Prorated on Prod, Trans & Distribution Plant in Service - Sch.2.2 L.34
22	Prod, Trans, Distn and General Plant	-	-	Prorated on Total Plant in Service, Sch. 2.2, L. 40
23	Prod, Trans, Distn, Excl Hydraulic & Holyrood	-	-	Prorated on Total Plant in Service, Sch. 2.2, L. 34 Less L. 8 and L. 9
24	Property Insurance	-	-	Prorated on Prod., Trans. Terminal, Dist. Sub & General Plant in Service - Sch.2.2 L.13, 21, 23, 35 - 36
	Revenue-Related:			
25	Municipal Tax	790,576	-	Revenue-related
26	PUB Assessment	-	512,161	Revenue-related
27	All Expense-Related	-	-	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - L 15, 16
28	Prod, Trans, and Distn Expense-Related	-	-	Prorated on Subtotal Production, Transmission, Distribution Expenses - L 15
29	**Subtotal Admin & General**	**790,576**	**512,161**	
30	**Total Operating & Maintenance Expenses**	**790,576**	**512,161**	

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Island Interconnected
Functional Classification of Depreciation Expense

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Rural Prod & Transmission Demand ($)	7 Distribution: Substations Demand ($)	8 Distribution: Primary Lines Demand ($)	9 Distribution: Primary Lines Customer ($)	10 Distribution: Line Transformers Demand ($)	11 Distribution: Line Transformers Customer ($)	12 Distribution: Secondary Lines Demand ($)	13 Distribution: Secondary Lines Customer ($)	14 Distribution: Services Customer ($)	15 Distribution: Meters Customer ($)	16 Distribution: Street Lighting Customer ($)	17 Accounting Customer ($)	18 Specifically Assigned Customer ($)
	Production																	
	Hydraulic																	
1	Bay D'Espoir	1,494,183	629,076	865,107	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Upper Salmon	574,502	241,875	332,627	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Hinds Lake	433,231	182,397	250,834	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Cat Arm	841,223	354,169	487,054	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Paradise River	100,137	42,159	57,977	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Granite Canal	197,964	83,346	114,618	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Other Small Hydraulic	26,458	8,908	12,250	-	5,301	-	-	-	-	-	-	-	-	-	-	-	-
8	**Subtotal Hydraulic**	**3,667,698**	**1,541,930**	**2,120,467**	-	**5,301**	-	-	-	-	-	-	-	-	-	-	-	-
9	Holyrood	2,233,964	1,289,444	944,520	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Gas Turbines	95,580	95,580	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Roddickton	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Diesel	99,154	-	-	-	99,154	-	-	-	-	-	-	-	-	-	-	-	-
13	**Subtotal Production**	**6,096,396**	**2,926,954**	**3,064,987**	-	**104,455**	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																	
14	Lines	4,416,610	-	-	2,601,303	1,578,701	-	9,013	-	-	-	-	-	-	-	-	-	227,592
15	Lines - Hydraulic	272,332	114,656	157,676	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Terminal Stations	3,031,769	-	-	2,335,117	199,776	-	-	-	-	-	-	-	-	-	-	-	496,876
17	Term Stns - Hydraulic	841,805	354,414	487,391	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Term Stns - Holyrood	335,736	193,787	141,949	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Term Stns - Gas Tur/Dsl	13,286	10,241	-	-	3,045	-	-	-	-	-	-	-	-	-	-	-	-
20	Term Stns - Distribution	128,836	-	-	-	-	128,836	-	-	-	-	-	-	-	-	-	-	-
21	**Subtotal Term Stns**	**4,351,432**	**558,442**	**629,340**	**2,335,117**	**202,821**	**128,836**	-	-	-	-	-	-	-	-	-	-	**496,876**
22	**Subtotal Transmission**	**9,040,374**	**673,098**	**787,016**	**4,936,420**	**1,781,522**	**128,836**	**9,013**	-	-	-	-	-	-	-	-	-	**724,468**
	Distribution																	
23	Substations	243,145	-	-	-	37,834	205,310	-	-	-	-	-	-	-	-	-	-	-
24	Land & Land Improvements	20,509	-	-	-	-	-	15,463	1,970	-	-	1,794	1,283	-	-	-	-	-
25	Poles	1,560,376	-	-	-	-	-	902,440	308,411	-	-	159,733	189,792	-	-	-	-	-
26	Primary Conductor & Eqpt	347,690	-	-	-	-	-	308,401	39,289	-	-	-	-	-	-	-	-	-
27	Submarine Conductor	273,269	-	-	-	-	-	273,269	-	-	-	-	-	-	-	-	-	-
28	Transformers	213,932	-	-	-	-	-	-	-	77,230	136,703	-	-	-	-	-	-	-
29	Secondary Conductor&Eqpt	50,675	-	-	-	-	-	-	-	-	-	29,544	21,132	-	-	-	-	-
30	Services	95,614	-	-	-	-	-	-	-	-	-	-	-	95,614	-	-	-	-
31	Meters	63,028	-	-	-	-	-	-	-	-	-	-	-	-	63,028	-	-	-
32	Street Lighting	28,256	-	-	-	-	-	-	-	-	-	-	-	-	-	28,256	-	-
33	**Subtotal Distribution**	**2,896,492**	-	-	-	**37,834**	**205,310**	**1,499,573**	**349,670**	**77,230**	**136,703**	**191,070**	**212,206**	**95,614**	**63,028**	**28,256**	-	-
34	**Subttl Prod, Trans, & Dist**	**18,033,263**	**3,600,052**	**3,852,004**	**4,936,420**	**1,923,811**	**334,147**	**1,508,586**	**349,670**	**77,230**	**136,703**	**191,070**	**212,206**	**95,614**	**63,028**	**28,256**	-	**724,468**
35	General	9,211,030	3,228,584	2,898,344	897,117	510,938	137,007	619,762	149,503	30,570	54,112	82,932	91,609	52,834	25,360	10,481	326,694	95,183
36	Telecontrol - Custmr & Spec	26,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17,090	8,910
37	Feasibility Studies	86,129	30,000	-	56,129	-	-	-	-	-	-	-	-	-	-	-	-	-
38	Feasibility Studies - General	58,180	11,615	12,428	15,926	6,207	1,078	4,867	1,128	249	441	616	685	308	203	91	-	2,337
39	Software - General	470,397	93,907	100,479	128,766	50,182	8,716	39,351	9,121	2,015	3,566	4,984	5,535	2,494	1,644	737	-	18,898
40	**Total Deprecn Expense**	**27,884,999**	**6,964,159**	**6,863,254**	**6,034,358**	**2,491,138**	**480,948**	**2,172,567**	**509,423**	**110,063**	**194,822**	**279,602**	**310,035**	**151,250**	**90,235**	**39,565**	**343,784**	**849,797**

25-Jul-2003

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Island Interconnected
Functional Classification of Rate Base

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
							Distribution											
								Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Specifically Assigned
Line No.	Description	Total Amount ($)	Production Demand ($)	Production and Transmission Energy ($)	Transmission Demand ($)	Rural Prod & Transmission Demand ($)	Substations Demand ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)
1	Average Net Book Value	1,276,638,287	408,024,614	532,265,873	171,980,715	81,117,756	10,095,941	32,557,600	7,864,365	1,881,043	3,329,602	4,209,646	4,710,079	2,276,481	1,381,824	720,083	2,345,235	11,877,430
2	Cash Working Capital	2,856,571	912,985	1,190,984	384,819	181,507	22,590	72,850	17,597	4,209	7,450	9,419	10,539	5,094	3,092	1,611	5,248	26,577
3	Fuel Inventory - No. 6 Fuel	11,872,074	-	11,872,074	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuel Inventory - Diesel	48,247	-	-	-	48,247	-	-	-	-	-	-	-	-	-	-	-	-
5	Fuel Inventory - Gas Turbine	796,938	796,938	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Inventory/Supplies	17,679,828	5,835,155	6,718,416	2,306,215	1,205,828	191,731	646,613	155,698	31,837	56,354	86,368	95,405	55,023	26,916	10,916	55,092	202,261
7	Deferred Charges: Foreign Exchange Loss and Regulatory Costs	76,517,226	24,455,566	31,902,152	10,307,922	4,861,914	605,115	1,951,388	471,362	112,743	199,565	252,311	282,306	136,444	82,822	43,159	140,565	711,892
8	Total Rate Base	**1,386,409,170**	**440,025,258**	**583,949,498**	**184,979,672**	**87,415,252**	**10,915,378**	**35,228,451**	**8,509,022**	**2,029,832**	**3,592,971**	**4,557,745**	**5,098,328**	**2,473,042**	**1,494,653**	**775,769**	**2,546,140**	**12,818,160**
9	Less: Rural Asset Portion	(164,636,583)	-	-	-	(87,415,252)	(10,915,378)	(35,228,451)	(8,509,022)	(2,029,832)	(3,592,971)	(4,557,745)	(5,098,328)	(2,473,042)	(1,494,653)	(775,769)	(2,546,140)	-
10	Rate Base Available for Equity Return	**1,221,772,587**	**440,025,258**	**583,949,498**	**184,979,672**	-	-	-	-	-	-	-	-	-	-	-	-	**12,818,160**
11	Return on Debt	98,967,734	31,410,859	41,684,778	13,204,629	6,240,069	779,186	2,514,755	607,410	144,898	256,481	325,351	363,940	176,536	106,695	55,378	181,754	915,014
12	Return on Equity	14,461,511	5,208,359	6,911,918	2,189,512	-	-	-	-	-	-	-	-	-	-	-	-	151,722
13	Return on Rate Base	**113,429,246**	**36,619,218**	**48,596,696**	**15,394,141**	**6,240,069**	**779,186**	**2,514,755**	**607,410**	**144,898**	**256,481**	**325,351**	**363,940**	**176,536**	**106,695**	**55,378**	**181,754**	**1,066,736**

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Island Interconnected
Functional Classification of Rate Base (CONT'D.)

	1	19
Line No.	Description	Basis of Functional Classification
1	Average Net Book Value	Sch. 2.3 , L. 40
2	Cash Working Capital	Prorated on Average Net Book Value, L. 1
3	Fuel Inventory - No. 6 Fuel	Production - Demand, Energy ratios Sch.4.1 L.10
4	Fuel Inventory - Diesel	Production - Demand, Energy ratios Sch.4.1 L.12
5	Fuel Inventory - Gas Turbine	Production - Demand, Energy ratios Sch.4.1 L.11
6	Inventory/Supplies	Prorated on Total Plant in Service, Sch. 2.2, L. 40
7	Deferred Charges: Foreign Exchange Loss and Regulatory Costs	Prorated on Average Net Book Value, L. 1
8	Total Rate Base	
9	Less: Rural Asset Portion	Rural Transmission and Distribution Rate Base
10	Rate Base Available for Equity Return	
11	Return on Debt	L.8 x Sch.1.1,p2,L.13
12	Return on Equity	L.10 x Sch.1.1,p2,L.16
13	Return on Rate Base	

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Island Interconnected
Basis of Allocation to Classes of Service

Line No.	1 Description	2 Total Amount	3 Production Demand (1 CP kW)	4 Production and Transmission Energy (MWh @ Gen)	5 Transmission Demand (CP kW)	6 Rural Prod & Transmission Demand (CP kW)	7 Distribution: Substations Demand (CP kW)	8 Distribution: Primary Lines Demand (CP kW)	9 Distribution: Primary Lines Customer (Rural Cust)	10 Distribution: Line Transformers Demand (CP kW)	11 Distribution: Line Transformers Customer (Rural Cust)	12 Distribution: Secondary Lines Demand (CP kW)	13 Distribution: Secondary Lines Customer (Rural Cust)	14 Distribution: Services Customer (Wtd Rural Cust)	15 Distribution: Meters Customer (Wtd Rural Cust)	16 Distribution: Street Lighting Customer	17 Accounting Customer (Rural Cust)	18 Specifically Assigned Customer
	Amounts																	
1	Newfoundland Power	-	1,067,783	4,902,167	1,036,700	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Industrial - Firm	-	167,387	1,414,178	162,514	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Industrial - Non-Firm	-	-	827	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																	
4	1.1 Domestic	-	26,368	121,106	25,601	25,601	23,952	23,952	12,337	21,530	12,337	21,530	12,337	12,337	12,337	-	12,337	-
5	1.12 Domestic All Electric	-	32,781	129,422	31,827	31,827	29,777	29,777	6,817	26,766	6,817	26,766	6,817	6,817	6,817	-	6,817	-
6	1.3 Special	-	71	252	69	69	65	65	2	58	2	58	2	2	2	-	2	-
7	2.1 GS 0-10 kW	-	4,375	23,355	4,248	4,248	3,974	3,974	1,922	3,572	1,922	3,572	1,922	3,844	3,844	-	1,922	-
8	2.2 GS 10-100 kW	-	15,105	75,212	14,665	14,665	13,720	13,720	876	12,331	876	12,331	876	7,071	7,071	-	876	-
9	2.3 GS 110-1,000 kVa	-	7,176	39,716	6,967	6,967	6,518	6,518	75	5,354	75	5,354	75	643	643	-	75	-
10	2.4 GS Over 1,000 kVa	-	2,801	27,582	2,719	2,719	2,544	2,544	6	1,911	6	1,911	6	51	51	-	6	-
11	4.1 Street and Area Lighting	-	874	3,432	849	849	794	794	861	714	861	714	861	-	-	1	861	-
12	**Subtotal Rural**	-	**89,551**	**420,076**	**86,944**	**86,944**	**81,345**	**81,345**	**22,896**	**72,236**	**22,896**	**72,236**	**22,896**	**30,765**	**30,765**	**1**	**22,896**	-
13	**Total**	-	**1,324,720**	**6,737,249**	**1,286,158**	**86,944**	**81,345**	**81,345**	**22,896**	**72,236**	**22,896**	**72,236**	**22,896**	**30,765**	**30,765**	**1**	**22,896**	-
	Ratios Excluding Return on Equity																	
14	Newfoundland Power	-	0.8060	0.7276	0.8060	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Industrial - Firm	-	0.1264	0.2099	0.1264	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Industrial - Non-Firm	-	-	0.0001	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																	
17	1.1 Domestic	-	0.0199	0.0180	0.0199	0.2944	0.2944	0.2944	0.5388	0.2980	0.5388	0.2980	0.5388	0.4010	0.4010	-	0.5388	-
18	1.12 Domestic All Electric	-	0.0247	0.0192	0.0247	0.3661	0.3661	0.3661	0.2977	0.3705	0.2977	0.3705	0.2977	0.2216	0.2216	-	0.2977	-
19	1.3 Special	-	0.0001	0.0000	0.0001	0.0008	0.0008	0.0008	0.0001	0.0008	0.0001	0.0008	0.0001	0.0001	0.0001	-	0.0001	-
20	2.1 GS 0-10 kW	-	0.0033	0.0035	0.0033	0.0489	0.0489	0.0489	0.0839	0.0495	0.0839	0.0495	0.0839	0.1249	0.1249	-	0.0839	-
21	2.2 GS 10-100 kW	-	0.0114	0.0112	0.0114	0.1687	0.1687	0.1687	0.0383	0.1707	0.0383	0.1707	0.0383	0.2298	0.2298	-	0.0383	-
22	2.3 GS 110-1,000 kVa	-	0.0054	0.0059	0.0054	0.0801	0.0801	0.0801	0.0033	0.0741	0.0033	0.0741	0.0033	0.0209	0.0209	-	0.0033	-
23	2.4 GS Over 1,000 kVa	-	0.0021	0.0041	0.0021	0.0313	0.0313	0.0313	0.0003	0.0265	0.0003	0.0265	0.0003	0.0017	0.0017	-	0.0003	-
24	4.1 Street and Area Lighting	-	0.0007	0.0005	0.0007	0.0098	0.0098	0.0098	0.0376	0.0099	0.0376	0.0099	0.0376	-	-	1.0000	0.0376	-
25	**Subtotal Rural**	-	**0.0676**	**0.0624**	**0.0676**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	-
26	**Total**	-	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	-

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Island Interconnected
Basis of Allocation to Classes of Service (CONT'D.)

	1	19	20
		Revenue Related	
Line No.	Description	Municipal Tax (Prior Year (Rural Revenues)	PUB Assessment (Prior Year (Revenues + RSP)
	Amounts		
1	Newfoundland Power	-	229,268,380
2	Industrial - Firm	-	50,417,591
3	Industrial - Non-Firm	-	228,581
	Rural		
4	1.1 Domestic	9,835,316	9,835,316
5	1.12 Domestic All Electric	9,234,552	9,234,552
6	1.3 Special	10,229	10,229
7	2.1 GS 0-10 kW	2,276,050	2,276,050
8	2.2 GS 10-100 kW	6,145,471	6,145,471
9	2.3 GS 110-1,000 kVa	2,785,166	2,785,166
10	2.4 GS Over 1,000 kVa	1,524,942	1,524,942
11	4.1 Street and Area Lighting	768,505	768,505
12	**Subtotal Rural**	**32,580,231**	**32,580,231**
13	**Total**	**32,580,231**	**312,494,783**
	Ratios Excluding Return on Equity		
14	Newfoundland Power	-	0.7337
15	Industrial - Firm	-	0.1613
16	Industrial - Non-Firm	-	0.0007
	Rural		
17	1.1 Domestic	0.3019	0.0315
18	1.12 Domestic All Electric	0.2834	0.0296
19	1.3 Special	0.0003	0.0000
20	2.1 GS 0-10 kW	0.0699	0.0073
21	2.2 GS 10-100 kW	0.1886	0.0197
22	2.3 GS 110-1,000 kVa	0.0855	0.0089
23	2.4 GS Over 1,000 kVa	0.0468	0.0049
24	4.1 Street and Area Lighting	0.0236	0.0025
25	**Subtotal Rural**	**1.0000**	**0.1043**
26	**Total**	**1.0000**	**1.0000**

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Island Interconnected
Allocation of Functionalized Amounts to Classes of Service

Line No.	Description (1)	Total Amount (2)	Production Demand (3)	Production and Transmission Energy (4)	Transmission Demand (5)	Rural Prod & Transmission Demand (6)	Distribution: Substations Demand (7)	Distribution: Primary Lines Demand (8)	Distribution: Primary Lines Customer (9)	Distribution: Line Transformers Demand (10)	Distribution: Line Transformers Customer (11)	Distribution: Secondary Lines Demand (12)	Distribution: Secondary Lines Customer (13)	Distribution: Services Customer (14)	Distribution: Meters Customer (15)	Distribution: Street Lighting Customer (16)	Accounting Customer (17)	Specifically Assigned Customer (18)
			($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
	Allocated Rev Reqmt Excl Return																	
1	Newfoundland Power	143,224,003	35,288,442	95,048,380	11,151,428	-	-	-	-	-	-	-	-	-	-	-	-	1,361,930
2	Industrial - Firm	35,073,805	5,531,847	27,419,575	1,748,108	-	-	-	-	-	-	-	-	-	-	-	-	292,069
3	Industrial - Non-Firm	16,410	-	16,037	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																	
4	1.1 Domestic	12,032,928	871,426	2,348,126	275,377	2,194,069	469,677	1,937,959	819,837	105,157	336,506	252,565	500,949	228,738	95,853	-	1,343,223	-
5	1.12 Domestic All Electric	12,175,963	1,083,356	2,509,377	342,349	2,727,665	583,903	2,409,270	453,013	130,731	185,941	313,988	276,807	126,393	52,965	-	742,219	-
6	1.3 Special	22,205	2,358	4,880	745	5,937	1,271	5,244	133	285	55	683	81	37	16	-	218	-
7	2.1 GS 0-10 kW	2,093,198	144,583	452,835	45,689	364,029	77,927	321,536	127,724	17,447	52,425	41,904	78,044	71,271	29,866	-	209,263	-
8	2.2 GS 10-100 kW	5,513,564	499,181	1,458,296	157,745	1,256,835	269,047	1,110,127	58,213	60,225	23,894	144,648	35,570	131,094	54,935	-	95,377	-
9	2.3 GS 110-1,000 kVa	2,530,292	237,142	770,049	74,939	597,075	127,814	527,380	4,984	26,151	2,046	62,810	3,045	11,919	4,995	-	8,166	-
10	2.4 GS Over 1,000 kVa	1,219,274	92,566	534,781	29,252	233,063	49,891	205,858	399	9,333	164	22,417	244	954	400	-	653	-
11	4.1 Street and Area Lighting	621,080	28,899	66,541	9,132	72,762	15,576	64,269	57,216	3,487	23,485	8,376	34,961	-	-	122,826	93,744	-
12	**Subtotal Rural**	**36,208,503**	**2,959,511**	**8,144,885**	**935,229**	**7,451,435**	**1,595,105**	**6,581,642**	**1,521,519**	**352,817**	**624,515**	**847,391**	**929,702**	**570,404**	**239,028**	**122,826**	**2,492,862**	**-**
13	**Total**	**214,522,722**	**43,779,800**	**130,628,877**	**13,834,764**	**7,451,435**	**1,595,105**	**6,581,642**	**1,521,519**	**352,817**	**624,515**	**847,391**	**929,702**	**570,404**	**239,028**	**122,826**	**2,492,862**	**1,654,000**
	Allocated Return on Debt																	
14	Newfoundland Power	67,052,875	25,318,532	30,330,741	10,643,511	-	-	-	-	-	-	-	-	-	-	-	-	760,091
15	Industrial - Firm	14,542,182	3,968,955	8,749,818	1,668,486	-	-	-	-	-	-	-	-	-	-	-	-	154,923
16	Industrial - Non-Firm	5,118	-	5,118	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																	
17	1.1 Domestic	5,457,907	625,225	749,307	262,835	1,837,383	229,431	740,468	327,289	43,187	138,199	96,971	196,101	70,793	42,786	-	97,934	-
18	1.12 Domestic All Electric	6,051,500	777,279	800,764	326,756	2,284,234	285,228	920,549	180,849	53,690	76,364	120,554	108,359	39,118	23,642	-	54,115	-
19	1.3 Special	12,077	1,692	1,557	711	4,972	621	2,004	53	117	22	262	32	11	7	-	16	-
20	2.1 GS 0-10 kW	934,587	103,734	144,503	43,608	304,849	38,066	122,855	50,989	7,165	21,530	16,089	30,551	22,058	13,331	-	15,257	-
21	2.2 GS 10-100 kW	2,781,463	358,149	465,355	150,560	1,052,514	131,425	424,164	23,239	24,734	9,813	55,537	13,924	40,573	24,521	-	6,954	-
22	2.3 GS 110-1,000 kVa	1,296,739	170,143	245,729	71,526	500,010	62,435	201,505	1,990	10,740	840	24,116	1,192	3,689	2,229	-	595	-
23	2.4 GS Over 1,000 kVa	576,471	66,414	170,653	27,919	195,175	24,371	78,656	159	3,833	67	8,607	95	295	178	-	48	-
24	4.1 Street and Area Lighting	256,815	20,734	21,234	8,716	60,933	7,609	24,556	22,842	1,432	9,645	3,216	13,686	-	-	55,378	6,835	-
25	**Subtotal Rural**	**17,367,559**	**2,123,372**	**2,599,102**	**892,632**	**6,240,069**	**779,186**	**2,514,755**	**607,410**	**144,898**	**256,481**	**325,351**	**363,940**	**176,536**	**106,695**	**55,378**	**181,754**	**-**
26	**Total**	**98,967,734**	**31,410,859**	**41,684,778**	**13,204,629**	**6,240,069**	**779,186**	**2,514,755**	**607,410**	**144,898**	**256,481**	**325,351**	**363,940**	**176,536**	**106,695**	**55,378**	**181,754**	**915,014**
	Allocated Return on Equity																	
27	Newfoundland Power	11,118,303	4,198,166	5,029,260	1,764,843	-	-	-	-	-	-	-	-	-	-	-	-	126,034
28	Industrial - Firm	2,411,297	658,108	1,450,842	276,658	-	-	-	-	-	-	-	-	-	-	-	-	25,688
29	Industrial - Non-Firm	849	-	849	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																	
30	1.1 Domestic	271,498	103,671	124,246	43,582	-	-	-	-	-	-	-	-	-	-	-	-	-
31	1.12 Domestic All Electric	315,842	128,884	132,778	54,181	-	-	-	-	-	-	-	-	-	-	-	-	-
32	1.3 Special	657	281	258	118	-	-	-	-	-	-	-	-	-	-	-	-	-
33	2.1 GS 0-10 kW	48,392	17,201	23,961	7,231	-	-	-	-	-	-	-	-	-	-	-	-	-
34	2.2 GS 10-100 kW	161,513	59,386	77,162	24,965	-	-	-	-	-	-	-	-	-	-	-	-	-
35	2.3 GS 110-1,000 kVa	80,817	28,212	40,745	11,860	-	-	-	-	-	-	-	-	-	-	-	-	-
36	2.4 GS Over 1,000 kVa	43,938	11,012	28,297	4,629	-	-	-	-	-	-	-	-	-	-	-	-	-
37	4.1 Street and Area Lighting	8,404	3,438	3,521	1,445	-	-	-	-	-	-	-	-	-	-	-	-	-
38	**Subtotal Rural**	**931,063**	**352,085**	**430,967**	**148,011**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
39	**Total**	**14,461,511**	**5,208,359**	**6,911,918**	**2,189,512**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**151,722**

25-Jul-2003

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Island Interconnected
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

	1	19	20
		Revenue Related	
Line No.	Description	Municipal Tax	PUB Assessment
	Allocated Rev Reqmt Excl Return		($)
1	Newfoundland Power	-	373,824
2	Industrial - Firm	-	82,206
3	Industrial - Non-Firm	-	373
	Rural		
4	1.1 Domestic	237,431	16,037
5	1.12 Domestic All Electric	222,928	15,057
6	1.3 Special	247	17
7	2.1 GS 0-10 kW	54,945	3,711
8	2.2 GS 10-100 kW	148,356	10,020
9	2.3 GS 110-1,000 kVa	67,236	4,541
10	2.4 GS Over 1,000 kVa	36,813	2,486
11	4.1 Street and Area Lighting	18,552	1,253
12	**Subtotal Rural**	**786,508**	**53,122**
13	**Total**	**786,508**	**509,525**
	Allocated Return on Debt		
14	Newfoundland Power	-	-
15	Industrial - Firm	-	-
16	Industrial - Non-Firm	-	-
	Rural		
17	1.1 Domestic	-	-
18	1.12 Domestic All Electric	-	-
19	1.3 Special	-	-
20	2.1 GS 0-10 kW	-	-
21	2.2 GS 10-100 kW	-	-
22	2.3 GS 110-1,000 kVa	-	-
23	2.4 GS Over 1,000 kVa	-	-
24	4.1 Street and Area Lighting	-	-
25	**Subtotal Rural**	-	-
26	**Total**	-	-
	Allocated Return on Equity		
27	Newfoundland Power	-	-
28	Industrial - Firm	-	-
29	Industrial - Non-Firm	-	-
	Rural		
30	1.1 Domestic	-	-
31	1.12 Domestic All Electric	-	-
32	1.3 Special	-	-
33	2.1 GS 0-10 kW	-	-
34	2.2 GS 10-100 kW	-	-
35	2.3 GS 110-1,000 kVa	-	-
36	2.4 GS Over 1,000 kVa	-	-
37	4.1 Street and Area Lighting	-	-
38	**Subtotal Rural**	-	-
39	**Total**	-	-

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Island Interconnected
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Rural Prod & Transmission Demand ($)	7 Distribution: Substations Demand ($)	8 Distribution: Primary Lines Demand ($)	9 Distribution: Primary Lines Customer ($)	10 Distribution: Line Transformers Demand ($)	11 Distribution: Line Transformers Customer ($)	12 Distribution: Secondary Lines Demand ($)	13 Distribution: Secondary Lines Customer ($)	14 Distribution: Services Customer ($)	15 Distribution: Meters Customer ($)	16 Distribution: Street Lighting Customer ($)	17 Accounting Customer ($)	18 Specifically Assigned Customer ($)
	Total Revenue Requiremt																	
40	Newfoundland Power	221,395,182	64,805,140	130,408,381	23,559,781	-	-	-	-	-	-	-	-	-	-	-	-	2,248,055
41	Industrial - Firm	52,027,285	10,158,910	37,620,235	3,693,252	-	-	-	-	-	-	-	-	-	-	-	-	472,681
42	Industrial - Non-Firm	22,376	-	22,003	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																	
43	1.1 Domestic	17,762,333	1,600,322	3,221,679	581,794	4,031,452	699,108	2,678,426	1,147,126	148,344	474,705	349,535	697,050	299,530	138,638	-	1,441,158	-
44	1.12 Domestic All Electric	18,543,304	1,989,519	3,442,919	723,286	5,011,899	869,131	3,329,819	633,862	184,421	262,306	434,542	385,166	165,510	76,607	-	796,334	-
45	1.3 Special	34,939	4,330	6,695	1,574	10,909	1,892	7,248	186	401	77	946	113	49	22	-	234	-
46	2.1 GS 0-10 kW	3,076,177	265,517	621,299	96,528	668,878	115,993	444,391	178,713	24,612	73,955	57,993	108,594	93,329	43,197	-	224,520	-
47	2.2 GS 10-100 kW	8,456,540	916,717	2,000,813	333,271	2,309,349	400,472	1,534,291	81,453	84,959	33,707	200,185	49,495	171,667	79,456	-	102,331	-
48	2.3 GS 110-1,000 kVa	3,907,849	435,498	1,056,523	158,324	1,097,085	190,249	728,884	6,974	36,891	2,886	86,926	4,238	15,608	7,224	-	8,761	-
49	2.4 GS Over 1,000 kVa	1,839,683	169,993	733,731	61,801	428,238	74,262	284,514	558	13,167	231	31,024	339	1,249	578	-	701	-
50	4.1 Street and Area Lighting	886,299	53,071	91,296	19,294	133,695	23,185	88,825	80,058	4,920	33,130	11,592	48,647	-	-	178,204	100,578	-
51	**Subtotal Rural**	**54,507,125**	**5,434,968**	**11,174,954**	**1,975,872**	**13,691,504**	**2,374,291**	**9,096,398**	**2,128,929**	**497,715**	**880,996**	**1,172,743**	**1,293,642**	**746,941**	**345,723**	**178,204**	**2,674,617**	**-**
52	**Total**	**327,951,968**	**80,399,018**	**179,225,574**	**29,228,905**	**13,691,504**	**2,374,291**	**9,096,398**	**2,128,929**	**497,715**	**880,996**	**1,172,743**	**1,293,642**	**746,941**	**345,723**	**178,204**	**2,674,617**	**2,720,736**
	Re-classification of Revenue-Related																	
53	Newfoundland Power	-	109,608	220,566	39,848	-	-	-	-	-	-	-	-	-	-	-	-	3,802
54	Industrial - Firm	-	16,077	59,536	5,845	-	-	-	-	-	-	-	-	-	-	-	-	748
55	Industrial - Non-Firm	-	-	373	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																	
56	1.1 Domestic	0	23,167	46,639	8,422	58,361	10,121	38,774	16,606	2,147	6,872	5,060	10,091	4,336	2,007	-	20,863	-
57	1.12 Domestic All Electric	(0)	25,865	44,761	9,403	65,159	11,299	43,291	8,241	2,398	3,410	5,649	5,007	2,152	996	-	10,353	-
58	1.3 Special	(0)	33	51	12	83	14	55	1	3	1	7	1	0	0	-	2	-
59	2.1 GS 0-10 kW	0	5,161	12,077	1,876	13,002	2,255	8,638	3,474	478	1,438	1,127	2,111	1,814	840	-	4,364	-
60	2.2 GS 10-100 kW	-	17,496	38,187	6,361	44,075	7,643	29,283	1,555	1,621	643	3,821	945	3,276	1,516	-	1,953	-
61	2.3 GS 110-1,000 kVa	(0)	8,149	19,769	2,962	20,528	3,560	13,638	130	690	54	1,626	79	292	135	-	164	-
62	2.4 GS Over 1,000 kVa	(0)	3,711	16,016	1,349	9,348	1,621	6,210	12	287	5	677	7	27	13	-	15	-
63	4.1 Street and Area Lighting	-	1,213	2,087	441	3,056	530	2,030	1,830	112	757	265	1,112	-	-	4,073	2,299	-
64	**Subtotal Rural**	**0**	**84,795**	**179,586**	**30,827**	**213,612**	**37,043**	**141,920**	**31,850**	**7,738**	**13,180**	**18,233**	**19,353**	**11,898**	**5,507**	**4,073**	**40,013**	**-**
65	**Total**	**0**	**210,480**	**460,061**	**76,520**	**213,612**	**37,043**	**141,920**	**31,850**	**7,738**	**13,180**	**18,233**	**19,353**	**11,898**	**5,507**	**4,073**	**40,013**	**4,550**
	Total Allocated Revenue Requirement																	
66	Newfoundland Power	221,395,182	64,914,748	130,628,947	23,599,629	-	-	-	-	-	-	-	-	-	-	-	-	2,251,858
67	Industrial - Firm	52,027,285	10,174,988	37,679,772	3,699,097	-	-	-	-	-	-	-	-	-	-	-	-	473,429
68	Industrial - Non-Firm	22,376	-	22,376	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																	
69	1.1 Domestic	17,762,333	1,623,489	3,268,317	590,216	4,089,813	709,229	2,717,201	1,163,732	150,491	481,577	354,595	707,141	303,866	140,645	-	1,462,021	-
70	1.12 Domestic All Electric	18,543,304	2,015,385	3,487,680	732,689	5,077,058	880,430	3,373,109	642,103	186,818	265,716	440,191	390,173	167,662	77,603	-	806,687	-
71	1.3 Special	34,939	4,363	6,746	1,586	10,992	1,906	7,303	187	404	78	953	114	49	23	-	235	-
72	2.1 GS 0-10 kW	3,076,177	270,679	633,376	98,405	681,880	118,247	453,030	182,186	25,091	75,393	59,120	110,705	95,143	44,037	-	228,885	-
73	2.2 GS 10-100 kW	8,456,540	934,213	2,039,000	339,631	2,353,424	408,115	1,563,574	83,007	86,580	34,350	204,006	50,439	174,943	80,973	-	104,284	-
74	2.3 GS 110-1,000 kVa	3,907,849	443,647	1,076,291	161,287	1,117,613	193,809	742,523	7,104	37,582	2,940	88,552	4,317	15,900	7,359	-	8,925	-
75	2.4 GS Over 1,000 kVa	1,839,683	173,704	749,747	63,150	437,585	75,883	290,724	570	13,454	236	31,701	346	1,276	591	-	716	-
76	4.1 Street and Area Lighting	886,299	54,285	93,383	19,735	136,751	23,714	90,855	81,888	5,032	33,887	11,857	49,759	-	-	182,277	102,877	-
77	**Subtotal Rural**	**54,507,125**	**5,519,763**	**11,354,540**	**2,006,699**	**13,905,117**	**2,411,334**	**9,238,318**	**2,160,779**	**505,453**	**894,176**	**1,190,976**	**1,312,995**	**758,839**	**351,230**	**182,277**	**2,714,630**	**-**
78	**Total**	**327,951,968**	**80,609,498**	**179,685,635**	**29,305,425**	**13,905,117**	**2,411,334**	**9,238,318**	**2,160,779**	**505,453**	**894,176**	**1,190,976**	**1,312,995**	**758,839**	**351,230**	**182,277**	**2,714,630**	**2,725,286**

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Island Interconnected
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

	1	19	20	
		Revenue Related		
Line		Municipal	PUB	
No.	Description	Tax	Assessment	Basis of Proration
	Total Revenue Requiremt	($)	($)	
40	Newfoundland Power	-	373,824	
41	Industrial - Firm	-	82,206	
42	Industrial - Non-Firm	-	373	
	Rural			
43	1.1 Domestic	237,431	16,037	
44	1.12 Domestic All Electric	222,928	15,057	
45	1.3 Special	247	17	
46	2.1 GS 0-10 kW	54,945	3,711	
47	2.2 GS 10-100 kW	148,356	10,020	
48	2.3 GS 110-1,000 kVa	67,236	4,541	
49	2.4 GS Over 1,000 kVa	36,813	2,486	
50	4.1 Street and Area Lighting	18,552	1,253	
51	**Subtotal Rural**	**786,508**	**53,122**	
52	**Total**	**786,508**	**509,525**	
	Re-classification of Revenue-Related			
53	Newfoundland Power	-	(373,824)	Re-classification to demand, energy and customer is based on rate class revenue
54	Industrial - Firm	-	(82,206)	requirements excluding revenue-related items.
55	Industrial - Non-Firm	-	(373)	
	Rural			
56	1.1 Domestic	(237,431)	(16,037)	
57	1.12 Domestic All Electric	(222,928)	(15,057)	
58	1.3 Special	(247)	(17)	
59	2.1 GS 0-10 kW	(54,945)	(3,711)	
60	2.2 GS 10-100 kW	(148,356)	(10,020)	
61	2.3 GS 110-1,000 kVa	(67,236)	(4,541)	
62	2.4 GS Over 1,000 kVa	(36,813)	(2,486)	
63	4.1 Street and Area Lighting	(18,552)	(1,253)	
64	**Subtotal Rural**	**(786,508)**	**(53,122)**	
65	**Total**	**(786,508)**	**(509,525)**	
	Total Allocated Revenue Requirement			
66	Newfoundland Power	-	-	
67	Industrial - Firm	-	-	
68	Industrial - Non-Firm	-	-	
	Rural			
69	1.1 Domestic	-	-	
70	1.12 Domestic All Electric	-	-	
71	1.3 Special	-	-	
72	2.1 GS 0-10 kW	-	-	
73	2.2 GS 10-100 kW	-	-	
74	2.3 GS 110-1,000 kVa	-	-	
75	2.4 GS Over 1,000 kVa	-	-	
76	4.1 Street and Area Lighting	-	-	
77	**Subtotal Rural**	-	-	
78	**Total**	-	-	

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2004 Forecast Cost of Service - Revision 1
Island Interconnected
Allocation of Specifically Assigned Amounts to Classes of Service

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
			OM&A				Depreciation				Expense Credits							
			Transmission				Transmission											
Line No.	Description	Total Amount ($)	Lines ($) (Plant)	Terminals ($) (Plant)	Administrative & General ($) (C3 & C4)	Other ($) (Direct)	Lines ($) (Direct)	Terminals ($) (Direct)	Telecontrol & Feasibility Study ($) (Direct)	General ($) (C7 & C8)	Rental Income ($) (Plant)	Other ($) (C4 + C5)	Gains/Losses ($) (NBV)	Subtotal Excluding Return ($)	Return on Debt ($) (NBV)	Return on Equity ($) (NBV)	Subtotal Excl Rev Related ($)	Revenue Related ($)
	Basis of Allocation - Amounts																	
1	Newfoundland Power		4,839,976	9,447,648	14,287,624	-	-	-	-	639,496	9,447,648	14,287,624	9,320,850	-	9,320,850	9,320,850	-	-
	Industrial																	
2	Abitibi Consolidated - S'ville		122,926	489,197	612,123	-	-	-	-	26,063	489,197	612,123	557,787	-	557,787	557,787	-	-
3	Abitibi Consolidated - GF		-	17,148	17,148	-	-	-	-	160	17,148	17,148	11,236	-	11,236	11,236	-	-
4	Corner Brook P& P - CB		-	2,117,396	2,117,396	-	-	-	-	21,337	2,117,396	2,117,396	547,549	-	547,549	547,549	-	-
5	Corner Brook P& P - DL		-	23,100	23,100	-	-	-	-	208	23,100	23,100	21,686	-	21,686	21,686	-	-
6	North Atlantic Refining Limited		-	1,251,577	1,251,577	-	-	-	-	46,114	1,251,577	1,251,577	761,531	-	761,531	761,531	-	-
7	**Subtotal Industrial**		**122,926**	**3,898,418**	**4,021,344**	-	-	-	-	**93,882**	**3,898,418**	**4,021,344**	**1,899,789**	-	**1,899,789**	**1,899,789**	-	-
8	**Total**		**4,962,902**	**13,346,066**	**18,308,968**	-	-	-	-	**733,378**	**13,346,066**	**18,308,968**	**11,220,639**	-	**11,220,639**	**11,220,639**	-	-
9	**Basis of Allocation - Ratios**																	
10	Newfoundland Power		0.9752	0.7079	0.7804	-	-	-	-	0.8720	0.7079	0.7804	0.8307	-	0.8307	0.8307	-	-
	Industrial																	
11	Abitibi Consolidated - S'ville		0.0248	0.0367	0.0334	-	-	-	-	0.0355	0.0367	0.0334	0.0497	-	0.0497	0.0497	-	-
12	Abitibi Consolidated - GF		-	0.0013	0.0009	-	-	-	-	0.0002	0.0013	0.0009	0.0010	-	0.0010	0.0010	-	-
13	Corner Brook P& P - CB		-	0.1587	0.1156	-	-	-	-	0.0291	0.1587	0.1156	0.0488	-	0.0488	0.0488	-	-
14	Corner Brook P& P - DL		-	0.0017	0.0013	-	-	-	-	0.0003	0.0017	0.0013	0.0019	-	0.0019	0.0019	-	-
15	North Atlantic Refining Ltd.		-	0.0938	0.0684	-	-	-	-	0.0629	0.0938	0.0684	0.0679	-	0.0679	0.0679	-	-
16	**Subtotal Industrial**		**0.0248**	**0.2921**	**0.2196**	-	-	-	-	**0.1280**	**0.2921**	**0.2196**	**0.1693**	-	**0.1693**	**0.1693**	-	-
17	**Total**		**1.0000**	**1.0000**	**1.0000**	-	-	-	-	**1.0000**	**1.0000**	**1.0000**	**1.0000**	-	**1.0000**	**1.0000**	-	-
	Amounts Allocated																	
18	Newfoundland Power	2,251,858	84,529	232,383	303,302	-	226,143	413,353	-	101,515	(53)	(3,227)	3,984	1,361,930	760,091	126,034	2,248,055	3,802
	Industrial																	
19	Abitibi Consolidated - S'ville	110,675	2,147	12,033	12,994	-	1,449	15,704	8,910	4,137	(3)	(138)	238	57,472	45,486	7,542	110,500	175
20	Abitibi Consolidated - GF	2,044	-	422	364	-	-	160	-	25	(0)	(4)	5	972	916	152	2,040	3
21	Corner Brook P& P - CB	173,828	-	52,081	44,949	-	-	21,337	-	3,387	(12)	(478)	234	121,499	44,651	7,404	173,554	275
22	Corner Brook P& P - DL	3,370	-	568	490	-	-	208	-	33	(0)	(5)	9	1,303	1,768	293	3,365	5
23	North Atlantic Refining Ltd.	183,512	-	30,785	26,569	-	-	46,114	-	7,320	(7)	(283)	325	110,824	62,101	10,297	183,222	290
24	**Subtotal Industrial**	**473,429**	**2,147**	**95,889**	**85,366**	-	**1,449**	**83,523**	**8,910**	**14,903**	**(22)**	**(908)**	**812**	**292,069**	**154,923**	**25,688**	**472,681**	**748**
25	**Total**	**2,725,286**	**86,676**	**328,272**	**388,669**	-	**227,592**	**496,876**	**8,910**	**116,419**	**(74)**	**(4,135)**	**4,796**	**1,654,000**	**915,014**	**151,722**	**2,720,736**	**4,550**

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Island Isolated
Functional Classification of Revenue Requirement

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
						Distribution											
				Production and			Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Specifically
Line No.	Description	Total Amount ($)	Production Demand ($)	Transmission Energy ($)	Transmission Demand ($)	Substations Demand ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Assigned Customer ($)
	Expenses																
1	Operating & Maintenance	5,166,240	2,050,248	2,335,048	-	33,134	267,286	85,864	19,913	35,248	66,940	68,113	48,591	15,954	8,319	92,301	-
2	Fuels	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Fuels-Diesel	1,390,213	-	1,390,213	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuels-Gas Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Power Purchases -CF(L)Co	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Power Purchases-Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Depreciation	891,817	378,564	437,199	-	4,961	29,005	9,735	1,984	3,512	7,066	7,413	5,984	2,806	949	2,638	-
	Expense Credits																
8	Sundry	(25,318)	(10,048)	(11,443)	-	(162)	(1,310)	(421)	(98)	(173)	(328)	(334)	(238)	(78)	(41)	(452)	-
9	Building Rental Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Tax Refunds	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Suppliers' Discounts	(1,266)	(502)	(572)	-	(8)	(65)	(21)	(5)	(9)	(16)	(17)	(12)	(4)	(2)	(23)	-
12	Pole Attachments	(26,512)	-	-	-	-	(15,333)	(5,240)	-	-	(2,714)	(3,225)	-	-	-	-	-
13	Secondary Energy Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Wheeling Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Application Fees	(660)	-	-	-	-	-	-	-	-	-	-	-	-	-	(660)	-
16	Meter Test Revenues	(2,147)	-	-	-	-	-	-	-	-	-	-	-	(2,147)	-	-	-
17	**Total Expense Credits**	(55,903)	(10,550)	(12,015)	-	(170)	(16,709)	(5,682)	(102)	(181)	(3,058)	(3,575)	(250)	(2,230)	(43)	(1,135)	-
18	**Subtotal Expenses**	7,392,367	2,418,263	4,150,444	-	37,924	279,583	89,916	21,795	38,580	70,948	71,950	54,324	16,530	9,225	93,804	-
19	Disposal Gain / Loss	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	**Subtotal Revenue Requirement Ex. Return**	7,392,367	2,418,263	4,150,444	-	37,924	279,583	89,916	21,795	38,580	70,948	71,950	54,324	16,530	9,225	93,804	-
21	Return on Debt	907,304	376,042	441,681	-	10,115	30,873	10,341	2,711	4,799	7,825	8,099	7,197	3,949	1,273	2,400	-
22	Return on Equity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	**Total Revenue Requirement**	8,299,670	2,794,305	4,592,125	-	48,039	310,456	100,257	24,506	43,378	78,773	80,049	61,521	20,478	10,499	96,204	-

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Island Isolated
Functional Classification of Revenue Requirement (CONT'D.)

	1	18	19	20
		Revenue Related		
Line No.	Description	Municipal Tax	PUB Assessment	Basis of Functional Classification
	Expenses			
1	Operating & Maintenance	36,796	2,485	Carryforward from Sch.2.4 L.23
2	Fuels	-	-	Production - Energy
3	Fuels-Diesel	-	-	Production - Energy
4	Fuels-Gas Turbine	-	-	Production - Energy
5	Power Purchases -CF(L)Co	-	-	
6	Power Purchases-Other	-	-	
7	Depreciation	-	-	Carryforward from Sch.2.5 L.23
	Expense Credits			
8	Sundry	(180)	(12)	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.23
9	Building Rental Income	-	-	Prorated on General Plant - Sch.2.2 L.18
10	Tax Refunds	-	-	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.23
11	Suppliers' Discounts	(9)	(1)	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.23
12	Pole Attachments	-	-	Prorated on Distribution Poles - Sch.4.1 L.37
13	Secondary Energy Revenues	-	-	Production - Energy
14	Wheeling Revenues	-	-	Transmission - Demand, Energy ratios Sch.4.1 L.16
15	Application Fees	-	-	Accounting - Customer
16	Meter Test Revenues	-	-	Meters - Customer
17	**Total Expense Credits**	**(189)**	**(13)**	
18	**Subtotal Expenses**	**36,607**	**2,472**	
19	Disposal Gain / Loss	-	-	Prorated on Total Net Book Value - Sch.2.3 L.23
20	**Subtotal Revenue Requirement Ex. Return**	**36,607**	**2,472**	
21	Return on Debt	-	-	Prorated on Rate Base - Sch.2.6 L.8
22	Return on Equity	-	-	Prorated on Rate Base - Sch.2.6 L.10
23	**Total Revenue Requirement**	**36,607**	**2,472**	

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Island Isolated
Functional Classification of Plant in Service for the Allocation of O&M Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
						Distribution											
				Production and		Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Specifically Assigned
Line No.	Description	Total Amount ($)	Production Demand ($)	Transmission Energy ($)	Transmission Demand ($)	Demand ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)
	Production																
1	Diesel	14,456,674	6,618,059	7,838,615	-	-	-	-	-	-	-	-	-	-	-	-	-
2	**Subtotal Production**	**14,456,674**	**6,618,059**	**7,838,615**	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Subtotal Transmission**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Distribution																
6	Substation Structures & Equipment	433,738	305,338	-	-	128,400	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	20,028	-	-	-	-	15,100	1,924	-	-	1,751	1,253	-	-	-	-	-
8	Poles	1,624,275	-	-	-	-	939,396	321,041	-	-	166,274	197,564	-	-	-	-	-
9	Primary Conductor & Equipment	95,037	-	-	-	-	84,298	10,739	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	214,384	-	-	-	-	-	-	77,393	136,991	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	158,033	-	-	-	-	-	-	-	-	92,133	65,900	-	-	-	-	-
13	Services	188,844	-	-	-	-	-	-	-	-	-	-	188,844	-	-	-	-
14	Meters	90,636	-	-	-	-	-	-	-	-	-	-	-	90,636	-	-	-
15	Street Lighting	32,332	-	-	-	-	-	-	-	-	-	-	-	-	32,332	-	-
16	**Subtotal Distribution**	**2,857,307**	**305,338**	-	-	**128,400**	**1,038,794**	**333,704**	**77,393**	**136,991**	**260,158**	**264,716**	**188,844**	**90,636**	**32,332**	-	-
17	**Subttl Prod, Trans, & Dist**	**17,313,980**	**6,923,397**	**7,838,615**	-	**128,400**	**1,038,794**	**333,704**	**77,393**	**136,991**	**260,158**	**264,716**	**188,844**	**90,636**	**32,332**	-	-
18	General	2,573,968	1,059,517	1,220,643	-	12,170	98,463	31,630	7,336	12,985	24,659	25,091	17,900	4,160	3,065	56,349	-
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Software - General	15,137	6,053	6,853	-	112	908	292	68	120	227	231	165	79	28	-	-
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	**Total Plant**	**19,903,086**	**7,988,967**	**9,066,110**	-	**140,683**	**1,138,165**	**365,626**	**84,796**	**150,096**	**285,045**	**290,039**	**206,909**	**94,876**	**35,425**	**56,349**	-

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Island Isolated
Functional Classification of Plant in Service for the Allocation of O&M Expense (CONT'D.)

	1	18
Line No.	Description	Basis of Functional Classification
	Production	
1	Diesel	Production - Demand, Energy ratios Sch.4.1 L.6
2	**Subtotal Production**	
	Transmission	
3	Lines	Production, Transmission - Demand; Distribution - Primary Demand; Spec Assigned - Custmr
4	Terminal Stations	Production, Transmission - Demand; Spec Assigned - Custmr
5	**Subtotal Transmission**	
	Distribution	
6	Substation Structures & Equipment	Production - Demand; Dist Substns - Demand
7	Land & Land Improvements	Primary, Secondary - Demand, Customer - zero intercept ratios Sch.4.1 L.32
8	Poles	Primary, Secondary - Demand, Customer - zero intercept ratios Sch.4.1 L.37
9	Primary Conductor & Equipment	Primary - Demand, Customer - zero intercept ratios Sch.4.1 L.38
10	Submarine Conductor	Primary - Demand, Customer - zero intercept ratios Sch.4.1 L.39
11	Transformers	Transformers - Demand, Customer - zero intercept ratios Sch.4.1 L.40
12	Secondary Conductors & Equipment	Secondary - Demand, Customer - zero intercept ratios Sch. 4.1 L.41
13	Services	Services Customer
14	Meters	Meters - Customer
15	Street Lighting	Street Lighting - Customer
16	**Subtotal Distribution**	
17	**Subttl Prod, Trans, & Dist**	
18	General	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - Sch.2.4 L.10, 11
19	Telecontrol - Specific	Specifically Assigned - Customer
20	Feasibility Studies	Production, Transmission - Demand
21	Software - General	Prorated on subtotal Production, Transmission, & Distribution plant - L.17
22	Software - Cust Acctng	Customer Accounting
23	**Total Plant**	

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Island Isolated
Functional Classification of Net Book Value

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
						Distribution											
Line No.	Description	Total Amount ($)	Production Demand ($)	Production and Transmission Energy ($)	Transmission Demand ($)	Substations Demand ($)	Primary Lines Demand ($)	Primary Lines Customer ($)	Line Transformers Demand ($)	Line Transformers Customer ($)	Secondary Lines Demand ($)	Secondary Lines Customer ($)	Services Customer ($)	Meters Customer ($)	Street Lighting Customer ($)	Accounting Customer ($)	Specifically Assigned Customer ($)
	Production																
1	Diesel	9,102,333	4,166,918	4,935,415	-	-	-	-	-	-	-	-	-	-	-	-	-
2	**Subtotal Production**	**9,102,333**	**4,166,918**	**4,935,415**	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Subtotal Transmission**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Distribution																
6	Substation Structures & Equipment	251,386	126,196	-	-	125,190	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Poles	578,994	-	-	-	-	334,860	114,439	-	-	59,270	70,424	-	-	-	-	-
9	Primary Conductor & Equipment	7,526	-	-	-	-	6,676	850	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	85,477	-	-	-	-	-	-	30,857	54,620	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	47,153	-	-	-	-	-	-	-	-	27,490	19,663	-	-	-	-	-
13	Services	82,960	-	-	-	-	-	-	-	-	-	-	82,960	-	-	-	-
14	Meters	48,819	-	-	-	-	-	-	-	-	-	-	-	48,819	-	-	-
15	Street Lighting	14,742	-	-	-	-	-	-	-	-	-	-	-	-	14,742	-	-
16	**Subtotal Distribution**	**1,117,057**	**126,196**	-	-	**125,190**	**341,536**	**115,290**	**30,857**	**54,620**	**86,761**	**90,087**	**82,960**	**48,819**	**14,742**	-	-
17	**Subttl Prod, Trans, & Dist**	**10,219,391**	**4,293,114**	**4,935,415**	-	**125,190**	**341,536**	**115,290**	**30,857**	**54,620**	**86,761**	**90,087**	**82,960**	**48,819**	**14,742**	-	-
18	General	1,421,476	585,119	674,101	-	6,721	54,376	17,468	4,051	7,171	13,618	13,857	9,885	2,298	1,692	31,119	-
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Software - General	12,049	5,062	5,819	-	148	403	136	36	64	102	106	98	58	17	-	-
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	**Total Net Book Value**	**11,652,916**	**4,883,295**	**5,615,335**	-	**132,059**	**396,315**	**132,894**	**34,945**	**61,855**	**100,481**	**104,050**	**92,943**	**51,174**	**16,451**	**31,119**	-

25-Jul-2003

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Island Isolated
Functional Classification of Operating & Maintenance Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
						Distribution											
							Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Specifically Assigned
Line No.	Description	Total Amount ($)	Production Demand ($)	Production and Transmission Energy ($)	Transmission Demand ($)	Substations Demand ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)
	Production																
1	Diesel	2,154,631	986,359	1,168,272	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Other	260,466	119,237	141,228	-	-	-	-	-	-	-	-	-	-	-	-	-
3	**Subtotal Production**	**2,415,097**	**1,105,597**	**1,309,500**	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
4	Transmission Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	**Subtotal Transmission**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Distribution																
7	Other	281,331	31,048	-	-	13,056	105,631	33,933	7,870	13,930	26,454	26,918	19,203	-	3,288	-	-
8	Meters	4,463	-	-	-	-	-	-	-	-	-	-	-	4,463	-	-	-
9	**Subtotal Distribution**	**285,794**	**31,048**	-	-	**13,056**	**105,631**	**33,933**	**7,870**	**13,930**	**26,454**	**26,918**	**19,203**	**4,463**	**3,288**	-	-
10	**Subttl Prod, Trans, & Dist**	**2,700,891**	**1,136,645**	**1,309,500**	-	**13,056**	**105,631**	**33,933**	**7,870**	**13,930**	**26,454**	**26,918**	**19,203**	**4,463**	**3,288**	-	-
11	Customer Accounting	60,451	-	-	-	-	-	-	-	-	-	-	-	-	-	60,451	-
	Administrative & General:																
	Plant-Related:																
12	Production	276,263	126,469	149,793	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Distribution	230,288	24,609	-	-	10,349	83,723	26,895	6,238	11,041	20,968	21,335	15,220	7,305	2,606	-	-
15	Prod, Trans, Distn Plant	326,867	130,706	147,984	-	2,424	19,611	6,300	1,461	2,586	4,911	4,998	3,565	1,711	610	-	-
16	Prod, Trans, Distn and Gen Plt	4,263	1,711	1,942	-	30	244	78	18	32	61	62	44	20	8	12	-
17	Property Insurance	13,005	5,944	6,746	-	105	73	24	5	10	18	19	13	3	2	42	-
	Revenue Related:																
18	Municipal Tax	36,796	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	PUB Assessment	2,485	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	All Expense-Related	1,452,429	597,860	688,779	-	6,868	55,560	17,848	4,139	7,327	13,915	14,158	10,100	2,348	1,729	31,796	-
21	Prod, Trans, and Distn Expense-Related	62,503	26,304	30,304	-	302	2,444	785	182	322	612	623	444	103	76	-	-
22	**Subtotal Admin & General**	**2,404,898**	**913,603**	**1,025,548**	-	**20,077**	**161,656**	**51,931**	**12,044**	**21,318**	**40,486**	**41,195**	**29,388**	**11,490**	**5,031**	**31,850**	-
23	**Total Operating & Maintenance Expenses**	**5,166,240**	**2,050,248**	**2,335,048**	-	**33,134**	**267,286**	**85,864**	**19,913**	**35,248**	**66,940**	**68,113**	**48,591**	**15,954**	**8,319**	**92,301**	-

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Island Isolated
Functional Classification of Operating & Maintenance Expense (CONT'D.)

	1	18	19	20
		Revenue Related		
Line No.	Description	Municipal Tax	PUB Assessment	Basis of Functional Classification
	Production			
1	Diesel	-	-	Production - Demand, Energy ratios Sch.4.1 L6
2	Other	-		Production - Demand, Energy ratios Sch.4.1 L6
3	**Subtotal Production**	-	-	
	Transmission			
4	Transmission Lines	-	-	Prorated on Transmission Lines Plant in Service - Sch.2.2 L.3
5	Terminal Stations	-	-	Prorated on Transmission Terminal Stations Plant in Service - Sch.2.2 L.4
6	Other	-	-	Prorated on Transmission Plant in Service - Sch.2.2 L.5
6	**Subtotal Transmission**	-	-	
	Distribution			
7	Other	-	-	Prorated on Distribution Plant, excluding Meters - Sch. 2.2 L. 16, less L. 14
8	Meters	-	-	Meters - Customer
9	**Subtotal Distribution**	-	-	
10	**Subttl Prod, Trans, & Dist**	-	-	
11	Customer Accounting	-	-	Accounting - Customer
	Administrative & General:			
	Plant-Related:			
12	Production	-	-	Prorated on Production Plant in Service - Sch.2.2 L.2
13	Transmission	-	-	Prorated on Transmission Plant in Service - Sch.2.2 L.5
14	Distribution	-	-	Prorated on Distribution Plant in Service - Sch.2.2 L.16
15	Prod, Trans, Distn Plant	-	-	Prorated on Production, Transmission & Distribution Plant in Service - Sch.2.2 L.17
16	Prod, Trans, Distn and Gen Plt	-	-	Prorated on Production, Transmission, Distribution & General Plant in Service - Sch.2.2 L.23
17	Property Insurance	-	-	Prorated on Prod., Trans. Terminal, Dist. Sub & General Plant in Service - Sch.2.2 L.2, 4, 6, 18 - 19
	Revenue Related:			
18	Municipal Tax	36,796	-	Revenue-related
19	PUB Assessment	-	2,485	Revenue-related
20	All Expense-Related	-	-	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - L.10, 11
21	Prod, Trans, and Distn Expense-Related	-	-	Prorated on Subtotal Production, Transmission, Distribution Expenses - L.10
22	**Subtotal Admin & General**	36,796	2,485	
23	**Total Operating & Maintenance Expenses**	36,796	2,485	

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Island Isolated
Functional Classification of Depreciation Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
						Distribution											
							Primary Lines		Line Transformers		Secondary Lines						
Line No.	Description	Total Amount ($)	Production Demand ($)	Production and Transmission Energy ($)	Transmission Demand ($)	Substations Demand ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Services Customer ($)	Meters Customer ($)	Street Lighting Customer ($)	Accounting Customer ($)	Specifically Assigned Customer ($)
	Production																
1	Diesel	683,107	312,716	370,390	-	-	-	-	-	-	-	-	-	-	-	-	-
2	**Subtotal Production**	**683,107**	**312,716**	**370,390**	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Subtotal Transmission**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Distribution																
6	Substn Struct & Eqpt	12,162	7,882	-	-	4,280	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Poles	40,455	-	-	-	-	23,397	7,996	-	-	4,141	4,921	-	-	-	-	-
9	Primary Conductor & Equipment	426	-	-	-	-	378	48	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	4,430	-	-	-	-	-	-	1,599	2,831	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	2,779	-	-	-	-	-	-	-	-	1,620	1,159	-	-	-	-	-
13	Services	5,015	-	-	-	-	-	-	-	-	-	-	5,015	-	-	-	-
14	Meters	2,544	-	-	-	-	-	-	-	-	-	-	-	2,544	-	-	-
15	Street Lighting	785	-	-	-	-	-	-	-	-	-	-	-	-	785	-	-
16	**Subtotal Distribution**	**68,597**	**7,882**	-	-	**4,280**	**23,775**	**8,044**	**1,599**	**2,831**	**5,762**	**6,080**	**5,015**	**2,544**	**785**	-	-
17	**Subtotal Prod Tran & Dist**	**751,703**	**320,598**	**370,390**	-	**4,280**	**23,775**	**8,044**	**1,599**	**2,831**	**5,762**	**6,080**	**5,015**	**2,544**	**785**	-	-
18	General	120,506	49,604	57,147	-	570	4,610	1,481	343	608	1,154	1,175	838	195	143	2,638	-
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Software - General	19,608	8,363	9,662	-	112	620	210	42	74	150	159	131	66	20	-	-
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	**Total Depreciation Expense**	**891,817**	**378,564**	**437,199**	-	**4,961**	**29,005**	**9,735**	**1,984**	**3,512**	**7,066**	**7,413**	**5,984**	**2,806**	**949**	**2,638**	-

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Island Isolated
Functional Classification of Rate Base

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
						Distribution											
							Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Specifically Assigned
Line No.	Description	Total Amount ($)	Production Demand ($)	Production and Transmission Energy ($)	Transmission Demand ($)	Substations Demand ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)
1	Average Net Book Value	11,652,916	4,883,295	5,615,335	-	132,059	396,315	132,894	34,945	61,855	100,481	104,050	92,943	51,174	16,451	31,119	-
2	Cash Working Capital	26,074	10,927	12,565	-	295	887	297	78	138	225	233	208	115	37	70	-
3	Fuel Inventory - No. 6 Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuel Inventory - Diesel	131,042	-	131,042	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Fuel Inventory - Gas Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Inventory/Supplies	201,676	80,951	91,866	-	1,426	11,533	3,705	859	1,521	2,888	2,939	2,097	961	359	571	-
7	Deferred Charges: Foreign Exchange Loss and Regulatory Costs	698,435	292,688	336,564	-	7,915	23,754	7,965	2,094	3,707	6,022	6,236	5,571	3,067	986	1,865	-
8	Total Rate Base	**12,710,143**	**5,267,861**	**6,187,371**	-	**141,695**	**432,488**	**144,861**	**37,977**	**67,222**	**109,617**	**113,458**	**100,818**	**55,317**	**17,833**	**33,624**	-
9	Less: Rural Portion	(12,710,143)	(5,267,861)	(6,187,371)	-	(141,695)	(432,488)	(144,861)	(37,977)	(67,222)	(109,617)	(113,458)	(100,818)	(55,317)	(17,833)	(33,624)	-
10	Rate Base Available for Equity Return	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Return on Debt	907,304	376,042	441,681	-	10,115	30,873	10,341	2,711	4,799	7,825	8,099	7,197	3,949	1,273	2,400	-
12	Return on Equity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Return on Rate Base	**907,304**	**376,042**	**441,681**	-	**10,115**	**30,873**	**10,341**	**2,711**	**4,799**	**7,825**	**8,099**	**7,197**	**3,949**	**1,273**	**2,400**	-

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Island Isolated
Functional Classification of Rate Base (CONT'D.)

	1	18
Line No.	Description	Basis of Functional Classification
1	Average Net Book Value	Sch. 2.3 , L. 23
2	Cash Working Capital	Prorated on Average Net Book Value, L. 1
3	Fuel Inventory - No. 6 Fuel	
4	Fuel Inventory - Diesel	Production - Energy
5	Fuel Inventory - Gas Turbine	
6	Inventory/Supplies	Prorated on Total Plant in Service, Sch. 2.2, L. 23
7	Deferred Charges: Foreign Exchange Loss and Regulatory Costs	Prorated on Average Net Book Value, L. 1
8	Total Rate Base	
9	Less: Rural Portion	
10	Rate Base Available for Equity Return	
11	Return on Debt	L.8 x Sch.1.1,p2,L.13
12	Return on Equity	L.10 x Sch.1.1,p2,L.16
13	Return on Rate Base	

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Island Isolated
Basis of Allocation to Classes of Service

Line No.	1 Description	2 Total Amount	3 Production Demand (CP kW)	4 Production and Transmission Energy (MWh @ Gen)	5 Transmission Demand (CP kW)	6 Distribution Substations Demand (CP kW)	7 Primary Lines Demand (CP kW)	8 Primary Lines Customer (Rural Cust)	9 Line Transformers Demand (CP kW)	10 Line Transformers Customer (Rural Cust)	11 Secondary Lines Demand (CP kW)	12 Secondary Lines Customer (Rural Cust)	13 Services Customer (Wtd Rural Cust)	14 Meters Customer	15 Street Lighting Customer (Rural Cust)	16 Accounting Customer (Rural Cust)	17 Specifically Assigned Customer
	Amounts																
1	1.2 Domestic Diesel	-	1,655	7,047	1,655	1,596	1,596	829	1,506	829	1,506	829	829	829	-	829	-
2	1.2G Government Domestic Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	1.23 Churches, Schools & Com Halls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	2.1 GS 0-10 kW	-	154	907	154	148	148	121	140	121	140	121	242	242	-	121	-
5	2.2 GS 10-100 kW	-	190	1,059	190	183	183	18	173	18	173	18	145	145	-	18	-
6	2.3 GS 110-1,000 kVa	-	171	1,350	171	165	165	3	156	3	156	3	26	26	-	3	-
7	2.4 GS Over 1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	2.5 GS Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	2.5G Gov't General Service Diesel		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	4.1 Street and Area Lighting	-	31	121	31	30	30	38	28	38	28	38	-	-	38	38	-
11	4.1G Gov't Street and Area Lighting		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	**Total**	-	**2,201**	**10,484**	**2,201**	**2,122**	**2,122**	**1,009**	**2,003**	**1,009**	**2,003**	**1,009**	**1,242**	**1,242**	**38**	**1,009**	-
	Ratios																
13	1.2 Domestic Diesel	-	0.7520	0.6722	0.7520	0.7520	0.7520	0.8216	0.7520	0.8216	0.7520	0.8216	0.6675	0.6675	-	0.8216	-
14	1.2G Government Domestic Diesel		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	1.23 Churches, Schools & Com Halls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	2.1 GS 0-10 kW	-	0.0699	0.0865	0.0699	0.0699	0.0699	0.1199	0.0699	0.1199	0.0699	0.1199	0.1948	0.1948	-	0.1199	-
17	2.2 GS 10-100 kW	-	0.0862	0.1010	0.0862	0.0862	0.0862	0.0178	0.0862	0.0178	0.0862	0.0178	0.1170	0.1170	-	0.0178	-
18	2.3 GS 110-1,000 kVa	-	0.0778	0.1288	0.0778	0.0778	0.0778	0.0030	0.0778	0.0030	0.0778	0.0030	0.0207	0.0207	-	0.0030	-
19	2.4 GS Over 1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	2.5 GS Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	2.5G Gov't General Service Diesel		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	4.1 Street and Area Lighting	-	0.0142	0.0115	0.0142	0.0142	0.0142	0.0377	0.0142	0.0377	0.0142	0.0377	-	-	1.0000	0.0377	-
23	4.1G Gov't Street and Area Lighting		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	**Total**	-	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	-

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Island Isolated
Basis of Allocation to Classes of Service (CONT'D.)

	1	18	19
		Revenue Related	
Line No.	Description	Municipal Tax (Prior Year (Rural Revenues)	PUB Assessment (Prior Year (Revenues + RSP)
	Amounts		
1	1.2 Domestic Diesel	698,723	698,723
2	1.2G Government Domestic Diesel	-	-
3	1.23 Churches, Schools & Com Halls	-	-
4	2.1 GS 0-10 kW	164,971	164,971
5	2.2 GS 10-100 kW	352,892	352,892
6	2.3 GS 110-1,000 kVa	261,797	261,797
7	2.4 GS Over 1,000 kVa	-	-
8	2.5 GS Diesel	-	-
9	2.5G Gov't General Service Diesel	-	-
10	4.1 Street and Area Lighting	38,001	38,001
11	4.1G Gov't Street and Area Lighting	-	-
12	**Total**	**1,516,384**	**1,516,384**
	Ratios		
13	1.2 Domestic Diesel	0.4608	0.4608
14	1.2G Government Domestic Diesel	-	-
15	1.23 Churches, Schools & Com Halls	-	-
16	2.1 GS 0-10 kW	0.1088	0.1088
17	2.2 GS 10-100 kW	0.2327	0.2327
18	2.3 GS 110-1,000 kVa	0.1726	0.1726
19	2.4 GS Over 1,000 kVa	-	-
20	2.5 GS Diesel	-	-
21	2.5G Gov't General Service Diesel	-	-
22	4.1 Street and Area Lighting	0.0251	0.0251
23	4.1G Gov't Street and Area Lighting	-	-
24	**Total**	**1.0000**	**1.0000**

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Island Isolated
Allocation of Functionalized Amounts to Classes of Service

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
						Distribution											
							Primary Lines		Line Transformers		Secondary Lines						
Line No.	Description	Total Amount ($)	Production Demand ($)	Production and Transmission Energy ($)	Transmission Demand ($)	Substations Demand ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Services Customer ($)	Meters Customer ($)	Street Lighting Customer ($)	Accounting Customer ($)	Specifically Assigned Customer ($)
	Allocated Revenue Requirement Excluding Return																
1	1.2 Domestic Diesel	5,223,879	1,818,463	2,789,863	-	28,518	210,238	73,876	16,389	31,697	53,351	59,115	36,260	11,033	-	77,070	-
2	1.2G Government Domestic Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	1.23 Churches, Schools & Com Halls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	2.1 GS 0-10 kW	610,024	169,012	358,996	-	2,651	19,540	10,783	1,523	4,626	4,959	8,628	10,585	3,221	-	11,249	-
5	2.2 GS 10-100 kW	685,710	208,405	419,317	-	3,268	24,094	1,604	1,878	688	6,114	1,284	6,355	1,934	-	1,673	-
6	2.3 GS 110-1,000 kVa	763,582	188,073	534,514	-	2,949	21,744	267	1,695	115	5,518	214	1,125	342	-	279	-
7	2.4 GS Over 1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	2.5 GS Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	2.5G Gov't General Service Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	4.1 Street and Area Lighting	109,172	34,311	47,754	-	538	3,967	3,386	309	1,453	1,007	2,710	-	-	9,225	3,533	-
11	4.1G Gov't Street and Area Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	**Total**	**7,392,367**	**2,418,263**	**4,150,444**	**-**	**37,924**	**279,583**	**89,916**	**21,795**	**38,580**	**70,948**	**71,950**	**54,324**	**16,530**	**9,225**	**93,804**	**-**
	Allocated Return on Debt																
13	1.2 Domestic Diesel	646,912	282,773	296,891	-	7,606	23,215	8,496	2,039	3,943	5,884	6,654	4,804	2,636	-	1,972	-
14	1.2G Government Domestic Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	1.23 Churches, Schools & Com Halls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	2.1 GS 0-10 kW	73,332	26,281	38,204	-	707	2,158	1,240	189	575	547	971	1,402	769	-	288	-
17	2.2 GS 10-100 kW	83,231	32,407	44,623	-	872	2,661	184	234	86	674	144	842	462	-	43	-
18	2.3 GS 110-1,000 kVa	90,441	29,246	56,882	-	787	2,401	31	211	14	609	24	149	82	-	7	-
19	2.4 GS Over 1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	2.5 GS Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	2.5G Gov't General Service Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	4.1 Street and Area Lighting	13,387	5,335	5,082	-	144	438	389	38	181	111	305	-	-	1,273	90	-
23	4.1G Gov't Street and Area Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	**Total**	**907,304**	**376,042**	**441,681**	**-**	**10,115**	**30,873**	**10,341**	**2,711**	**4,799**	**7,825**	**8,099**	**7,197**	**3,949**	**1,273**	**2,400**	**-**
	Allocated Return on Equity																
25	All Classes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Island Isolated
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

	1	18	19	
		Revenue Related		
Line No.	Description	Municipal Tax ($)	PUB Assessment ($)	Basis of Proration
	Allocated Revenue Requirement Excluding Return			
1	1.2 Domestic Diesel	16,868	1,139	
2	1.2G Government Domestic Diesel	-	-	
3	1.23 Churches, Schools & Com Halls	-	-	
4	2.1 GS 0-10 kW	3,983	269	
5	2.2 GS 10-100 kW	8,519	575	
6	2.3 GS 110-1,000 kVa	6,320	427	
7	2.4 GS Over 1,000 kVa	-	-	
8	2.5 GS Diesel	-	-	
9	2.5G Gov't General Service Diesel	-	-	
10	4.1 Street and Area Lighting	917	62	
11	4.1G Gov't Street and Area Lighting	-	-	
12	**Total**	**36,607**	**2,472**	
	Allocated Return on Debt			
13	1.2 Domestic Diesel	-	-	
14	1.2G Government Domestic Diesel	-	-	
15	1.23 Churches, Schools & Com Halls	-	-	
16	2.1 GS 0-10 kW	-	-	
17	2.2 GS 10-100 kW	-	-	
18	2.3 GS 110-1,000 kVa	-	-	
19	2.4 GS Over 1,000 kVa	-	-	
20	2.5 GS Diesel	-	-	
21	2.5G Gov't General Service Diesel	-	-	
22	4.1 Street and Area Lighting	-	-	
23	4.1G Gov't Street and Area Lighting	-	-	
24	**Total**	-	-	
	Allocated Return on Equity			
25	All Classes	-	-	

NEWFOUNDLAND & LABRADOR HYDRO
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Island Isolated
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Distribution: Substations Demand ($)	7 Distribution: Primary Lines Demand ($)	8 Distribution: Primary Lines Customer ($)	9 Distribution: Line Transformers Demand ($)	10 Distribution: Line Transformers Customer ($)	11 Distribution: Secondary Lines Demand ($)	12 Distribution: Secondary Lines Customer ($)	13 Distribution: Services Customer ($)	14 Distribution: Meters Customer ($)	15 Distribution: Street Lighting Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
	Total Revenue Requirement																
26	1.2 Domestic Diesel	5,870,791	2,101,235	3,086,753	-	36,124	233,454	82,372	18,428	35,640	59,235	65,769	41,064	13,669	-	79,042	-
27	1.2G Government Domestic Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	1.23 Churches, Schools & Com Halls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	2.1 GS 0-10 kW	683,356	195,293	397,199	-	3,357	21,698	12,023	1,713	5,202	5,505	9,600	11,987	3,990	-	11,537	-
30	2.2 GS 10-100 kW	768,941	240,812	463,940	-	4,140	26,755	1,789	2,112	774	6,789	1,428	7,197	2,396	-	1,716	-
31	2.3 GS 110-1,000 kVa	854,023	217,319	591,396	-	3,736	24,145	298	1,906	129	6,126	238	1,274	424	-	286	-
32	2.4 GS Over 1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
33	2.5 GS Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34	2.5G Gov't General Service Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
35	4.1 Street and Area Lighting	122,559	39,646	52,836	-	682	4,405	3,776	348	1,634	1,118	3,015	-	-	10,499	3,623	-
36	4.1G Gov't Street and Area Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37	**Total**	**8,299,670**	**2,794,305**	**4,592,125**	**-**	**48,039**	**310,456**	**100,257**	**24,506**	**43,378**	**78,773**	**80,049**	**61,521**	**20,478**	**10,499**	**96,204**	**-**
	Re-classification of Revenue-Related																
38	1.2 Domestic Diesel	0	6,465	9,497	-	111	718	253	57	110	182	202	126	42	-	243	-
39	1.2G Government Domestic Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40	1.23 Churches, Schools & Com Halls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
41	2.1 GS 0-10 kW	-	1,223	2,487	-	21	136	75	11	33	34	60	75	25	-	72	-
42	2.2 GS 10-100 kW	0	2,882	5,553	-	50	320	21	25	9	81	17	86	29	-	21	-
43	2.3 GS 110-1,000 kVa	-	1,730	4,709	-	30	192	2	15	1	49	2	10	3	-	2	-
44	2.4 GS Over 1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
45	2.5 GS Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
46	2.5G Gov't General Service Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
47	4.1 Street and Area Lighting	0	319	426	-	5	35	30	3	13	9	24	-	-	85	29	-
48	4.1G Gov't Street and Area Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
49	**Total**	**0**	**12,619**	**22,671**	**-**	**217**	**1,402**	**383**	**111**	**166**	**356**	**306**	**298**	**99**	**85**	**367**	**-**
	Total Allocated Revenue Requirement																
50	1.2 Domestic Diesel	5,870,791	2,107,700	3,096,250	-	36,235	234,172	82,625	18,485	35,749	59,417	65,971	41,190	13,711	-	79,285	-
51	1.2G Government Domestic Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
52	1.23 Churches, Schools & Com Halls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
53	2.1 GS 0-10 kW	683,356	196,516	399,686	-	3,378	21,833	12,098	1,723	5,235	5,540	9,660	12,062	4,015	-	11,609	-
54	2.2 GS 10-100 kW	768,941	243,695	469,493	-	4,190	27,075	1,810	2,137	783	6,870	1,445	7,283	2,424	-	1,737	-
55	2.3 GS 110-1,000 kVa	854,023	219,049	596,105	-	3,766	24,337	300	1,921	130	6,175	240	1,284	427	-	288	-
56	2.4 GS Over 1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
57	2.5 GS Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
58	2.5G Gov't General Service Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
59	4.1 Street and Area Lighting	122,559	39,965	53,262	-	687	4,440	3,806	350	1,647	1,127	3,039	-	-	10,583	3,652	-
60	4.1G Gov't Street and Area Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
61	**Total**	**8,299,670**	**2,806,924**	**4,614,796**	**-**	**48,256**	**311,858**	**100,640**	**24,617**	**43,544**	**79,128**	**80,355**	**61,819**	**20,577**	**10,583**	**96,572**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Island Isolated
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

	1	18	19	
		Revenue Related		
Line No.	Description	Municipal Tax ($)	PUB Assessment ($)	Basis of Proration
	Total Revenue Requirement			
26	1.2 Domestic Diesel	16,868	1,139	
27	1.2G Government Domestic Diesel	-	-	
28	1.23 Churches, Schools & Com Halls	-	-	
29	2.1 GS 0-10 kW	3,983	269	
30	2.2 GS 10-100 kW	8,519	575	
31	2.3 GS 110-1,000 kVa	6,320	427	
32	2.4 GS Over 1,000 kVa	-	-	
33	2.5 GS Diesel	-	-	
34	2.5G Gov't General Service Diesel	-	-	
35	4.1 Street and Area Lighting	917	62	
36	4.1G Gov't Street and Area Lighting	-	-	
37	**Total**	**36,607**	**2,472**	
	Re-classification of Revenue-Related			
38	1.2 Domestic Diesel	(16,868)	(1,139)	Re-classification to demand, energy and customer is based on rate class revenue
39	1.2G Government Domestic Diesel	-	-	requirements excluding revenue-related items.
40	1.23 Churches, Schools & Com Halls	-	-	
41	2.1 GS 0-10 kW	(3,983)	(269)	
42	2.2 GS 10-100 kW	(8,519)	(575)	
43	2.3 GS 110-1,000 kVa	(6,320)	(427)	
44	2.4 GS Over 1,000 kVa	-	-	
45	2.5 GS Diesel	-	-	
46	2.5G Gov't General Service Diesel	-	-	
47	4.1 Street and Area Lighting	(917)	(62)	
48	4.1G Gov't Street and Area Lighting	-	-	
49	**Total**	**(36,607)**	**(2,472)**	
	Total Allocated Revenue Requirement			
50	1.2 Domestic Diesel	-	-	
51	1.2G Government Domestic Diesel	-	-	
52	1.23 Churches, Schools & Com Halls	-	-	
53	2.1 GS 0-10 kW	-	-	
54	2.2 GS 10-100 kW	-	-	
55	2.3 GS 110-1,000 kVa	-	-	
56	2.4 GS Over 1,000 kVa	-	-	
57	2.5 GS Diesel	-	-	
58	2.5G Gov't General Service Diesel	-	-	
59	4.1 Street and Area Lighting	-	-	
60	4.1G Gov't Street and Area Lighting	-	-	
61	**Total**	-	-	

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Labrador Isolated
Functional Classification of Revenue Requirement

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
						Distribution											
				Production and		Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Specifically Assigned
Line No.	Description	Total Amount ($)	Production Demand ($)	Transmission Energy ($)	Transmission Demand ($)	Demand ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)
	Expenses																
1	Operating & Maintenance	10,011,783	3,304,268	4,740,881	-	194,537	676,637	204,534	43,134	76,350	120,432	132,350	81,186	28,321	21,030	249,498	-
2	Fuels	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Fuels-Diesel	5,848,510	-	5,848,510	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuels-Gas Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Power Purchases -CF(L)Co	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Power Purchases-Other	34,275	-	34,275	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Depreciation	2,163,918	761,259	1,090,450	-	42,055	126,961	38,650	7,678	13,591	22,139	24,613	15,929	8,680	4,188	7,724	-
	Expense Credits																
8	Sundry	(49,064)	(16,193)	(23,233)	-	(953)	(3,316)	(1,002)	(211)	(374)	(590)	(649)	(398)	(139)	(103)	(1,223)	-
9	Building Rental Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Tax Refunds	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Suppliers' Discounts	(2,453)	(810)	(1,162)	-	(48)	(166)	(50)	(11)	(19)	(30)	(32)	(20)	(7)	(5)	(61)	-
12	Pole Attachments	(87,859)	-	-	-	-	(50,813)	(17,366)	-	-	(8,994)	(10,686)	-	-	-	-	-
13	Secondary Energy Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Wheeling Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Application Fees	(4,452)	-	-	-	-	-	-	-	-	-	-	-	-	-	(4,452)	-
16	Meter Test Revenues	(6,604)	-	-	-	-	-	-	-	-	-	-	-	(6,604)	-	-	-
17	**Total Expense Credits**	(150,432)	(17,003)	(24,395)	-	(1,001)	(54,295)	(18,418)	(222)	(393)	(9,614)	(11,368)	(418)	(6,750)	(108)	(5,736)	-
18	**Subtotal Expenses**	**17,908,054**	**4,048,524**	**11,689,721**	**-**	**235,591**	**749,304**	**224,766**	**50,590**	**89,548**	**132,958**	**145,596**	**96,697**	**30,251**	**25,109**	**251,485**	**-**
19	Disposal Gain / Loss	8,248	2,721	3,817	-	305	651	201	43	76	113	127	96	49	22	27	-
20	**Subtotal Revenue Requirement Ex. Return**	**17,916,302**	**4,051,245**	**11,693,538**	**-**	**235,896**	**749,955**	**224,967**	**50,633**	**89,624**	**133,071**	**145,723**	**96,793**	**30,300**	**25,132**	**251,513**	**-**
21	Return on Debt	2,186,368	676,369	1,085,453	-	75,246	161,811	49,962	10,703	18,946	28,130	31,581	23,700	12,173	5,486	6,809	-
22	Return on Equity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	**Total Revenue Requirement**	**20,102,669**	**4,727,614**	**12,778,991**	**-**	**311,143**	**911,766**	**274,929**	**61,336**	**108,570**	**161,201**	**177,303**	**120,492**	**42,473**	**30,618**	**258,322**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Labrador Isolated
Functional Classification of Revenue Requirement (CONT'D.)

	1	18	19	20
		Revenue Related		
Line No.	Description	Municipal Tax	PUB Assessment	Basis of Functional Classification
	Expenses			
1	Operating & Maintenance	129,855	8,771	Carryforward from Sch.2.4 L.23
2	Fuels	-	-	Production - Energy
3	Fuels-Diesel	-	-	Production - Energy
4	Fuels-Gas Turbine	-	-	Production - Energy
5	Power Purchases -CF(L)Co	-	-	
6	Power Purchases-Other	-	-	Carryforward from Sch.4.4 L.11
7	Depreciation	-	-	Carryforward from Sch.2.5 L.23
	Expense Credits			
8	Sundry	(636)	(43)	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.23
9	Building Rental Income	-	-	Prorated on General Plant - Sch.2.2 L.18
10	Tax Refunds	-	-	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.23
11	Suppliers' Discounts	(32)	(2)	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.23
12	Pole Attachments	-	-	Prorated on Distribution Poles - Sch.4.1 L.37
13	Secondary Energy Revenues	-	-	Production - Energy
14	Wheeling Revenues	-	-	Transmission - Demand, Energy ratios Sch.4.1 L.16
15	Application Fees	-	-	Accounting - Customer
16	Meter Test Revenues	-	-	Meters - Customer
17	**Total Expense Credits**	**(668)**	**(45)**	
18	**Subtotal Expenses**	**129,187**	**8,726**	
19	Disposal Gain / Loss	-	-	Prorated on Total Net Book Value - Sch.2.3 L.23
20	**Subtotal Revenue Requirement Ex. Return**	**129,187**	**8,726**	
21	Return on Debt	-	-	Prorated on Rate Base - Sch.2.6 L.8
22	Return on Equity	-	-	Prorated on Rate Base - Sch.2.6 L.10
23	**Total Revenue Requirement**	**129,187**	**8,726**	

NEWFOUNDLAND & LABRADOR HYDRO
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Labrador Isolated
Functional Classification of Plant in Service for the Allocation of O&M Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
						Distribution											
				Production and			Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Specifically Assigned
Line No.	Description	Total Amount ($)	Production Demand ($)	Transmission Energy ($)	Transmission Demand ($)	Substations Demand ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)
	Production																
1	Diesel	35,663,882	13,849,171	21,814,710	-	-	-	-	-	-	-	-	-	-	-	-	-
2	**Subtotal Production**	**35,663,882**	**13,849,171**	**21,814,710**	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Subtotal Transmission**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Distribution																
6	Substation Structures & Equipment	2,790,260	1,680,300	-	-	1,109,960	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	11,816	-	-	-	-	8,909	1,135	-	-	1,033	739	-	-	-	-	-
8	Poles	5,470,213	-	-	-	-	3,163,687	1,081,199	-	-	559,975	665,353	-	-	-	-	-
9	Primary Conductor & Equipment	794,994	-	-	-	-	705,159	89,834	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	684,751	-	-	-	-	-	-	247,195	437,556	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	221,578	-	-	-	-	-	-	-	-	129,180	92,398	-	-	-	-	-
13	Services	465,268	-	-	-	-	-	-	-	-	-	-	465,268	-	-	-	-
14	Meters	278,727	-	-	-	-	-	-	-	-	-	-	-	278,727	-	-	-
15	Street Lighting	120,520	-	-	-	-	-	-	-	-	-	-	-	-	120,520	-	-
16	**Subtotal Distribution**	**10,838,127**	**1,680,300**	-	-	**1,109,960**	**3,877,755**	**1,172,168**	**247,195**	**437,556**	**690,188**	**758,490**	**465,268**	**278,727**	**120,520**	-	-
17	**Subttl Prod, Trans, & Dist**	**46,502,009**	**15,529,471**	**21,814,710**	-	**1,109,960**	**3,877,755**	**1,172,168**	**247,195**	**437,556**	**690,188**	**758,490**	**465,268**	**278,727**	**120,520**	-	-
18	General	5,811,609	1,952,056	2,817,409	-	107,945	377,116	113,995	24,040	42,553	67,122	73,764	45,248	13,891	11,721	164,750	-
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Software - General	40,656	13,577	19,072	-	970	3,390	1,025	216	383	603	663	407	244	105	-	-
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	**Total Plant**	**52,354,274**	**17,495,105**	**24,651,192**	-	**1,218,875**	**4,258,261**	**1,287,187**	**271,451**	**480,491**	**757,913**	**832,917**	**510,923**	**292,863**	**132,346**	**164,750**	-

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Labrador Isolated
Functional Classification of Plant in Service for the Allocation of O&M Expense (CONT'D.)

	1	18
Line No.	Description	Basis of Functional Classification
	Production	
1	Diesel	Production - Demand, Energy ratios Sch.4.1 L.7
2	**Subtotal Production**	
	Transmission	
3	Lines	Production, Transmission - Demand; Distribution - Primary Demand; Spec Assigned - Custmr
4	Terminal Stations	Production, Transmission - Demand; Spec Assigned - Custmr
5	**Subtotal Transmission**	
	Distribution	
6	Substation Structures & Equipment	Production - Demand; Dist Substns - Demand
7	Land & Land Improvements	Primary, Secondary - Demand, Customer - zero intercept ratios Sch.4.1 L.32
8	Poles	Primary, Secondary - Demand, Customer - zero intercept ratios Sch.4.1 L.37
9	Primary Conductor & Equipment	Primary - Demand, Customer - zero intercept ratios Sch.4.1 L.38
10	Submarine Conductor	Primary - Demand, Customer - zero intercept ratios Sch.4.1 L.39
11	Transformers	Transformers - Demand, Customer - zero intercept ratios Sch.4.1 L.40
12	Secondary Conductors & Equipment	Secondary - Demand, Customer - zero intercept ratios Sch. 4.1 L.41
13	Services	Services Customer
14	Meters	Meters - Customer
15	Street Lighting	Street Lighting - Customer
16	**Subtotal Distribution**	
17	**Subttl Prod, Trans, & Dist**	
18	General	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - Sch 2.4 L.10, 11
19	Telecontrol - Specific	Specifically Assigned - Customer
20	Feasibility Studies	Production, Transmission - Demand
21	Software - General	Prorated on subtotal Production, Transmission, & Distribution plant - L.17
22	Software - Cust Acctng	Customer Accounting
23	**Total Plant**	

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Labrador Isolated
Functional Classification of Net Book Value

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
						Distribution											
							Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Specifically Assigned
Line No.	Description	Total Amount ($)	Production Demand ($)	Production and Transmission Energy ($)	Transmission Demand ($)	Substations Demand ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)
	Production																
1	Diesel	17,587,594	6,829,700	10,757,894	-	-	-	-	-	-	-	-	-	-	-	-	-
2	**Subtotal Production**	**17,587,594**	**6,829,700**	**10,757,894**	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Subtotal Transmission**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Distribution																
6	Substation Structures & Equipment	1,791,205	869,326	-	-	921,879	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	2,572	-	-	-	-	1,939	247	-	-	225	161	-	-	-	-	-
8	Poles	2,776,648	-	-	-	-	1,605,869	548,810	-	-	284,240	337,729	-	-	-	-	-
9	Primary Conductor & Equipment	317,306	-	-	-	-	281,450	35,856	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	347,788	-	-	-	-	-	-	125,552	222,237	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	73,699	-	-	-	-	-	-	-	-	42,966	30,732	-	-	-	-	-
13	Services	283,126	-	-	-	-	-	-	-	-	-	-	283,126	-	-	-	-
14	Meters	150,129	-	-	-	-	-	-	-	-	-	-	-	150,129	-	-	-
15	Street Lighting	64,739	-	-	-	-	-	-	-	-	-	-	-	-	64,739	-	-
16	**Subtotal Distribution**	**5,807,212**	**869,326**	-	-	**921,879**	**1,889,258**	**584,913**	**125,552**	**222,237**	**327,431**	**368,623**	**283,126**	**150,129**	**64,739**	-	-
17	**Subttl Prod, Trans, & Dist**	**23,394,806**	**7,699,026**	**10,757,894**	-	**921,879**	**1,889,258**	**584,913**	**125,552**	**222,237**	**327,431**	**368,623**	**283,126**	**150,129**	**64,739**	-	-
18	General	3,112,415	1,045,426	1,508,867	-	57,810	201,965	61,050	12,875	22,789	35,947	39,504	24,233	7,440	6,277	88,232	-
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Software - General	27,584	9,078	12,684	-	1,087	2,228	690	148	262	386	435	334	177	76	-	-
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	**Total Net Book Value**	**26,534,805**	**8,753,530**	**12,279,446**	-	**980,776**	**2,093,451**	**646,652**	**138,574**	**245,288**	**363,764**	**408,562**	**307,693**	**157,746**	**71,092**	**88,232**	-

Schedule 2.4C
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NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Labrador Isolated
Functional Classification of Operating & Maintenance Expense

Line No.	Description (1)	Total Amount ($) (2)	Production Demand ($) (3)	Production and Transmission Energy ($) (4)	Transmission Demand ($) (5)	Distribution: Substations Demand ($) (6)	Distribution: Primary Lines Demand ($) (7)	Distribution: Primary Lines Customer ($) (8)	Distribution: Line Transformers Demand ($) (9)	Distribution: Line Transformers Customer ($) (10)	Distribution: Secondary Lines Demand ($) (11)	Distribution: Secondary Lines Customer ($) (12)	Distribution: Services Customer ($) (13)	Distribution: Meters Customer ($) (14)	Distribution: Street Lighting Customer ($) (15)	Accounting Customer ($) (16)	Specifically Assigned Customer ($) (17)
	Production																
1	Diesel	4,134,741	1,605,623	2,529,119	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Other	416,233	161,633	254,599	-	-	-	-	-	-	-	-	-	-	-	-	-
3	**Subtotal Production**	**4,550,974**	**1,767,256**	**2,783,718**	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
4	Transmission Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	**Subtotal Transmission**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Distribution																
7	Other	1,014,633	161,457	-	-	106,654	372,606	112,631	23,753	42,044	66,319	72,882	44,707	-	11,581	-	-
8	Meters	13,725	-	-	-	-	-	-	-	-	-	-	-	13,725	-	-	-
9	**Subtotal Distribution**	**1,028,359**	**161,457**	-	-	**106,654**	**372,606**	**112,631**	**23,753**	**42,044**	**66,319**	**72,882**	**44,707**	**13,725**	**11,581**	-	-
10	**Subttl Prod, Trans, & Dist**	**5,579,333**	**1,928,713**	**2,783,718**	-	**106,654**	**372,606**	**112,631**	**23,753**	**42,044**	**66,319**	**72,882**	**44,707**	**13,725**	**11,581**	-	-
11	Customer Accounting	162,780	-	-	-	-	-	-	-	-	-	-	-	-	-	162,780	-
	Administrative & General:																
	Plant-Related:																
12	Production	401,747	156,008	245,738	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Distribution	197,738	30,656	-	-	20,251	70,748	21,386	4,510	7,983	12,592	13,838	8,489	5,085	2,199	-	-
15	Prod, Trans, Distn Plant	39,419	13,164	18,492	-	941	3,287	994	210	371	585	643	394	236	102	-	-
16	Prod, Trans, Distn and General Plt	308,544	103,106	145,279	-	7,183	25,096	7,586	1,600	2,832	4,467	4,909	3,011	1,726	780	971	-
17	Property Insurance	34,209	13,510	19,036	-	941	291	88	19	33	52	57	35	11	9	127	-
	Revenue Related:																
18	Municipal Tax	129,855	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	PUB Assessment	8,771	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	All Expense-Related	3,020,274	1,014,477	1,464,198	-	56,099	195,986	59,243	12,494	22,115	34,883	38,335	23,515	7,219	6,091	85,620	-
21	Prod, Trans, and Distn Expense-Related	129,115	44,634	64,420	-	2,468	8,623	2,606	550	973	1,535	1,687	1,035	318	268	-	-
22	**Subtotal Admin & General**	**4,269,671**	**1,375,555**	**1,957,163**	-	**87,883**	**304,031**	**91,903**	**19,381**	**34,306**	**54,113**	**59,469**	**36,479**	**14,595**	**9,449**	**86,718**	-
23	**Total Operating & Maintenance Expenses**	**10,011,783**	**3,304,268**	**4,740,881**	-	**194,537**	**676,637**	**204,534**	**43,134**	**76,350**	**120,432**	**132,350**	**81,186**	**28,321**	**21,030**	**249,498**	-

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Labrador Isolated
Functional Classification of Operating & Maintenance Expense (CONT'D.)

	1	18	19	20
		Revenue Related		
Line No.	Description	Municipal Tax	PUB Assessment	Basis of Functional Classification
	Production			
1	Diesel	-	-	Production - Demand, Energy ratios Sch.4.1 L7
2	Other	-	-	Production - Demand, Energy ratios Sch.4.1 L7
3	**Subtotal Production**	-	-	
	Transmission			
4	Transmission Lines	-	-	Prorated on Transmission Lines Plant in Service - Sch.2.2 L.3
5	Terminal Stations	-	-	Prorated on Transmission Terminal Stations Plant in Service - Sch.2.2 L.4
6	Other	-	-	Prorated on Transmission Plant in Service - Sch.2.2 L.5
6	**Subtotal Transmission**	-	-	
	Distribution			
7	Other	-	-	Prorated on Distribution Plant, excluding Meters - Sch. 2.2 L. 16, less L. 14
8	Meters	-	-	Meters - Customer
9	**Subtotal Distribution**	-	-	
10	**Subttl Prod, Trans, & Dist**	-	-	
11	Customer Accounting	-	-	Accounting - Customer
	Administrative & General:			
	Plant-Related:			
12	Production	-	-	Prorated on Production Plant in Service - Sch.2.2 L.2
13	Transmission	-	-	Prorated on Transmission Plant in Service - Sch.2.2 L.5
14	Distribution	-	-	Prorated on Distribution Plant in Service - Sch.2.2 L.16
15	Prod, Trans, Distn Plant	-	-	Prorated on Production, Transmission & Distribution Plant in Service - Sch.2.2 L.17
16	Prod, Trans, Distn and General Plt	-	-	Prorated on Production, Transmission, Distribution & General Plant in Service - Sch.2.2 L.23
17	Property Insurance	-	-	Prorated on Prod., Trans. Terminal, Dist. Sub & General Plant in Service - Sch.2.2 L.2, 4, 6, 18 - 19
	Revenue Related:			
18	Municipal Tax	129,855	-	Revenue-related
19	PUB Assessment	-	8,771	Revenue-related
20	All Expense-Related	-	-	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - L.10, 11
21	Prod, Trans, and Distn Expense-Related	-	-	Prorated on Subtotal Production, Transmission, Distribution Expenses - L.10
22	**Subtotal Admin & General**	**129,855**	**8,771**	
23	**Total Operating & Maintenance Expenses**	**129,855**	**8,771**	

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Labrador Isolated
Functional Classification of Depreciation Expense

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Distribution Substations Demand ($)	7 Primary Lines Demand ($)	8 Primary Lines Customer ($)	9 Line Transformers Demand ($)	10 Line Transformers Customer ($)	11 Secondary Lines Demand ($)	12 Secondary Lines Customer ($)	13 Services Customer ($)	14 Meters Customer ($)	15 Street Lighting Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
	Production																
1	Diesel	1,526,961	592,957	934,004	-	-	-	-	-	-	-	-	-	-	-	-	-
2	**Subtotal Production**	**1,526,961**	**592,957**	**934,004**	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Subtotal Transmission**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Distribution																
6	Substn Struct & Eqpt	95,816	59,761	-	-	36,054	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	228	-	-	-	-	172	22	-	-	20	14	-	-	-	-	-
8	Poles	152,383	-	-	-	-	88,130	30,119	-	-	15,599	18,535	-	-	-	-	-
9	Primary Conductor & Equipment	20,520	-	-	-	-	18,201	2,319	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	17,685	-	-	-	-	-	-	6,384	11,301	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	4,959	-	-	-	-	-	-	-	-	2,891	2,068	-	-	-	-	-
13	Services	13,457	-	-	-	-	-	-	-	-	-	-	13,457	-	-	-	-
14	Meters	7,825	-	-	-	-	-	-	-	-	-	-	-	7,825	-	-	-
15	Street Lighting	3,546	-	-	-	-	-	-	-	-	-	-	-	-	3,546	-	-
16	**Subtotal Distribution**	**316,418**	**59,761**	-	-	**36,054**	**106,504**	**32,459**	**6,384**	**11,301**	**18,510**	**20,617**	**13,457**	**7,825**	**3,546**	-	-
17	**Subtotal Prod Tran & Dist**	**1,843,379**	**652,718**	**934,004**	-	**36,054**	**106,504**	**32,459**	**6,384**	**11,301**	**18,510**	**20,617**	**13,457**	**7,825**	**3,546**	-	-
18	General	272,454	91,514	132,083	-	5,061	17,680	5,344	1,127	1,995	3,147	3,458	2,121	651	549	7,724	-
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Software - General	48,084	17,026	24,363	-	940	2,778	847	167	295	483	538	351	204	92	-	-
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	**Total Depreciation Expense**	**2,163,918**	**761,259**	**1,090,450**	-	**42,055**	**126,961**	**38,650**	**7,678**	**13,591**	**22,139**	**24,613**	**15,929**	**8,680**	**4,188**	**7,724**	-

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Labrador Isolated
Functional Classification of Rate Base

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
						Distribution											
							Primary Lines		Line Transformers		Secondary Lines						
Line No.	Description	Total Amount ($)	Production Demand ($)	Production and Transmission Energy ($)	Transmission Demand ($)	Substations Demand ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Services Customer ($)	Meters Customer ($)	Street Lighting Customer ($)	Accounting Customer ($)	Specifically Assigned Customer ($)
1	Average Net Book Value	26,534,805	8,753,530	12,279,446	-	980,776	2,093,451	646,652	138,574	245,288	363,764	408,562	307,693	157,746	71,092	88,232	-
2	Cash Working Capital	59,374	19,587	27,476	-	2,195	4,684	1,447	310	549	814	914	688	353	159	197	-
3	Fuel Inventory - No. 6 Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuel Inventory - Diesel	1,913,083	-	1,913,083	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Fuel Inventory - Gas Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Inventory/Supplies	530,500	177,276	249,788	-	12,351	43,149	13,043	2,751	4,869	7,680	8,440	5,177	2,968	1,341	1,669	-
7	Deferred Charges: Foreign Exchange Loss and Regulatory Costs	1,590,403	524,656	735,987	-	58,784	125,474	38,758	8,306	14,702	21,803	24,488	18,442	9,455	4,261	5,288	-
8	Total Rate Base	**30,628,165**	**9,475,049**	**15,205,780**	**-**	**1,054,105**	**2,266,758**	**699,900**	**149,941**	**265,407**	**394,061**	**442,403**	**332,000**	**170,521**	**76,853**	**95,387**	**-**
9	Less: Rural Portion	(30,628,165)	(9,475,049)	(15,205,780)	-	(1,054,105)	(2,266,758)	(699,900)	(149,941)	(265,407)	(394,061)	(442,403)	(332,000)	(170,521)	(76,853)	(95,387)	-
10	Rate Base Available for Equity Return	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Return on Debt	2,186,368	676,369	1,085,453	-	75,246	161,811	49,962	10,703	18,946	28,130	31,581	23,700	12,173	5,486	6,809	-
12	Return on Equity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Return on Rate Base	**2,186,368**	**676,369**	**1,085,453**	**-**	**75,246**	**161,811**	**49,962**	**10,703**	**18,946**	**28,130**	**31,581**	**23,700**	**12,173**	**5,486**	**6,809**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Labrador Isolated
Functional Classification of Rate Base (CONT'D.)

	1	18
Line No.	Description	Basis of Functional Classification
1	Average Net Book Value	Sch. 2.3 , L. 23
2	Cash Working Capital	Prorated on Average Net Book Value, L. 1
3	Fuel Inventory - No. 6 Fuel	
4	Fuel Inventory - Diesel	Production - Energy
5	Fuel Inventory - Gas Turbine	
6	Inventory/Supplies	Prorated on Total Plant in Service, Sch. 2.2, L. 23
7	Deferred Charges: Foreign Exchange Loss and Regulatory Costs	Prorated on Average Net Book Value, L. 1
8	Total Rate Base	
9	Less: Rural Portion	
10	Rate Base Available for Equity Return	
11	Return on Debt	L.8 x Sch.1.1,p2,L.13
12	Return on Equity	L.10 x Sch.1.1,p2,L.16
13	Return on Rate Base	

NEWFOUNDLAND & LABRADOR HYDRO
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Labrador Isolated
Basis of Allocation to Classes of Service

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
						Distribution											
							Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	
Line No.	Description	Total Amount	Production Demand	Production and Transmission Energy	Transmission Demand	Substations Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Specifically Assigned Customer
			(CP kW)	(MWh @ Gen)	(CP kW)	(CP kW)	(CP kW)	(Rural Cust)	(CP kW)	(Rural Cust)	(CP kW)	(Rural Cust)	(Wtd Rural Cust)		(Rural Cust)	(Rural Cust)	
	Amounts																
1	1.2 Domestic Diesel	-	5,102	22,729	5,102	4,901	4,901	2,141	4,599	2,141	4,599	2,141	2,141	2,141	-	2,141	-
2	1.2G Government Domestic Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	1.23 Churches, Schools & Com Halls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	2.1 GS 0-10 kW	-	750	4,496	750	721	721	389	676	389	676	389	778	778	-	389	-
5	2.2 GS 10-100 kW	-	1,591	9,211	1,591	1,528	1,528	102	1,434	102	1,434	102	823	823	-	102	-
6	2.3 GS 110-1,000 kVa	-	125	2,109	125	120	120	8	113	8	113	8	69	69	-	8	-
7	2.4 GS Over 1,000 kVa	-	60	2,570	60	57	57	1	54	1	54	1	9	9	-	1	-
8	2.5 GS Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	2.5G Gov't General Service Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	4.1 Street and Area Lighting	-	85	321	85	81	81	76	76	76	76	76	-	-	76	76	-
11	4.1G Gov't Street and Area Lighting		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	**Total**	-	**7,712**	**41,436**	**7,712**	**7,409**	**7,409**	**2,717**	**6,952**	**2,717**	**6,952**	**2,717**	**3,819**	**3,819**	**76**	**2,717**	-
	Ratios																
13	1.2 Domestic Diesel	-	0.6615	0.5485	0.6615	0.6615	0.6615	0.7880	0.6615	0.7880	0.6615	0.7880	0.5606	0.5606	-	0.7880	-
14	1.2G Government Domestic Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	1.23 Churches, Schools & Com Halls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	2.1 GS 0-10 kW	-	0.0973	0.1085	0.0973	0.0973	0.0973	0.1432	0.0973	0.1432	0.0973	0.1432	0.2037	0.2037	-	0.1432	-
17	2.2 GS 10-100 kW	-	0.2063	0.2223	0.2063	0.2063	0.2063	0.0375	0.2063	0.0375	0.2063	0.0375	0.2156	0.2156	-	0.0375	-
18	2.3 GS 110-1,000 kVa	-	0.0162	0.0509	0.0162	0.0162	0.0162	0.0029	0.0162	0.0029	0.0162	0.0029	0.0180	0.0180	-	0.0029	-
19	2.4 GS Over 1,000 kVa	-	0.0077	0.0620	0.0077	0.0077	0.0077	0.0004	0.0077	0.0004	0.0077	0.0004	0.0022	0.0022	-	0.0004	-
20	2.5 GS Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	2.5G Gov't General Service Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	4.1 Street and Area Lighting	-	0.0110	0.0077	0.0110	0.0110	0.0110	0.0280	0.0110	0.0280	0.0110	0.0280	-	-	1.0000	0.0280	-
23	4.1G Gov't Street and Area Lighting		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	**Total**	-	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	-

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Labrador Isolated
Basis of Allocation to Classes of Service (CONT'D.)

	1	18	19
		Revenue Related	
Line No.	Description	Municipal Tax (Prior Year (Rural Revenues)	PUB Assessment (Prior Year (Revenues + RSP)
	Amounts		
1	1.2 Domestic Diesel	2,352,629	2,352,629
2	1.2G Government Domestic Diesel	-	-
3	1.23 Churches, Schools & Com Halls	-	-
4	2.1 GS 0-10 kW	972,294	972,294
5	2.2 GS 10-100 kW	1,593,493	1,593,493
6	2.3 GS 110-1,000 kVa	192,430	192,430
7	2.4 GS Over 1,000 kVa	164,634	164,634
8	2.5 GS Diesel	-	-
9	2.5G Gov't General Service Diesel	-	-
10	4.1 Street and Area Lighting	75,934	75,934
11	4.1G Gov't Street and Area Lighting	-	-
12	**Total**	**5,351,414**	**5,351,414**
	Ratios		
13	1.2 Domestic Diesel	0.4396	0.4396
14	1.2G Government Domestic Diesel	-	-
15	1.23 Churches, Schools & Com Halls	-	-
16	2.1 GS 0-10 kW	0.1817	0.1817
17	2.2 GS 10-100 kW	0.2978	0.2978
18	2.3 GS 110-1,000 kVa	0.0360	0.0360
19	2.4 GS Over 1,000 kVa	0.0308	0.0308
20	2.5 GS Diesel	-	-
21	2.5G Gov't General Service Diesel	-	-
22	4.1 Street and Area Lighting	0.0142	0.0142
23	4.1G Gov't Street and Area Lighting	-	-
24	**Total**	**1.0000**	**1.0000**

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Labrador Isolated
Allocation of Functionalized Amounts to Classes of Service

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
						Distribution											
							Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	
Line No.	Description	Total Amount ($)	Production Demand ($)	Production and Transmission Energy ($)	Transmission Demand ($)	Substations Demand ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Specifically Assigned Customer ($)
	Allocated Revenue Requirement Excluding Return																
1	1.2 Domestic Diesel	10,560,673	2,679,948	6,414,256	-	156,048	496,104	177,275	33,494	70,624	88,028	114,830	54,258	16,985	-	198,193	-
2	1.2G Government Domestic Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	1.23 Churches, Schools & Com Halls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	2.1 GS 0-10 kW	1,929,421	394,036	1,268,771	-	22,944	72,943	32,209	4,925	12,832	12,943	20,863	19,716	6,172	-	36,010	-
5	2.2 GS 10-100 kW	3,771,605	835,683	2,599,484	-	48,660	154,699	8,446	10,444	3,365	27,450	5,471	20,864	6,531	-	9,442	-
6	2.3 GS 110-1,000 kVa	689,359	65,777	595,256	-	3,830	12,176	662	822	264	2,161	429	1,738	544	-	741	-
7	2.4 GS Over 1,000 kVa	770,339	31,322	725,184	-	1,824	5,798	83	391	33	1,029	54	217	68	-	93	-
8	2.5 GS Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	2.5G Gov't General Service Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	4.1 Street and Area Lighting	194,905	44,478	90,588	-	2,590	8,234	6,293	556	2,507	1,461	4,076	-	-	25,132	7,035	-
11	4.1G Gov't Street and Area Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	**Total**	**17,916,302**	**4,051,245**	**11,693,538**	**-**	**235,896**	**749,955**	**224,967**	**50,633**	**89,624**	**133,071**	**145,723**	**96,793**	**30,300**	**25,132**	**251,513**	**-**
	Allocated Return on Debt																
13	1.2 Domestic Diesel	1,329,993	447,426	595,403	-	49,776	107,040	39,370	7,080	14,929	18,608	24,886	13,285	6,823	-	5,366	-
14	1.2G Government Domestic Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	1.23 Churches, Schools & Com Halls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	2.1 GS 0-10 kW	233,062	65,786	117,774	-	7,319	15,738	7,153	1,041	2,713	2,736	4,521	4,827	2,479	-	975	-
17	2.2 GS 10-100 kW	449,488	139,520	241,297	-	15,522	33,378	1,876	2,208	711	5,803	1,186	5,108	2,624	-	256	-
18	2.3 GS 110-1,000 kVa	71,676	10,982	55,255	-	1,222	2,627	147	174	56	457	93	425	219	-	20	-
19	2.4 GS Over 1,000 kVa	74,798	5,229	67,315	-	582	1,251	18	83	7	217	12	53	27	-	3	-
20	2.5 GS Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	2.5G Gov't General Service Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	4.1 Street and Area Lighting	27,351	7,426	8,409	-	826	1,776	1,398	118	530	309	883	-	-	5,486	190	-
23	4.1G Gov't Street and Area Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	**Total**	**2,186,368**	**676,369**	**1,085,453**	**-**	**75,246**	**161,811**	**49,962**	**10,703**	**18,946**	**28,130**	**31,581**	**23,700**	**12,173**	**5,486**	**6,809**	**-**
	Allocated Return on Equity																
25	All Classes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Labrador Isolated
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

Line No.	Description	Revenue Related: Municipal Tax ($)	Revenue Related: PUB Assessment ($)	Basis of Proration
	1	18	19	
	Allocated Revenue Requirement Excluding Return			
1	1.2 Domestic Diesel	56,794	3,836	
2	1.2G Government Domestic Diesel	-	-	
3	1.23 Churches, Schools & Com Halls	-	-	
4	2.1 GS 0-10 kW	23,472	1,585	
5	2.2 GS 10-100 kW	38,468	2,598	
6	2.3 GS 110-1,000 kVa	4,645	314	
7	2.4 GS Over 1,000 kVa	3,974	268	
8	2.5 GS Diesel	-	-	
9	2.5G Gov't General Service Diesel	-	-	
10	4.1 Street and Area Lighting	1,833	124	
11	4.1G Gov't Street and Area Lighting	-	-	
12	**Total**	**129,187**	**8,726**	
	Allocated Return on Debt			
13	1.2 Domestic Diesel	-	-	
14	1.2G Government Domestic Diesel	-	-	
15	1.23 Churches, Schools & Com Halls	-	-	
16	2.1 GS 0-10 kW	-	-	
17	2.2 GS 10-100 kW	-	-	
18	2.3 GS 110-1,000 kVa	-	-	
19	2.4 GS Over 1,000 kVa	-	-	
20	2.5 GS Diesel	-	-	
21	2.5G Gov't General Service Diesel	-	-	
22	4.1 Street and Area Lighting	-	-	
23	4.1G Gov't Street and Area Lighting	-	-	
24	**Total**	-	-	
	Allocated Return on Equity			
25	All Classes	-	-	

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Labrador Isolated
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
						Distribution											
							Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	
Line No.	Description	Total Amount ($)	Production Demand ($)	Production and Transmission Energy ($)	Transmission Demand ($)	Substations Demand ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Specifically Assigned Customer ($)
	Total Revenue Requirement																
26	1.2 Domestic Diesel	11,890,666	3,127,375	7,009,659	-	205,825	603,144	216,645	40,575	85,553	106,636	139,715	67,543	23,808	-	203,558	-
27	1.2G Government Domestic Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	1.23 Churches, Schools & Com Halls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	2.1 GS 0-10 kW	2,162,483	459,822	1,386,544	-	30,263	88,681	39,362	5,966	15,544	15,679	25,385	24,544	8,651	-	36,985	-
30	2.2 GS 10-100 kW	4,221,092	975,203	2,840,781	-	64,182	188,077	10,321	12,652	4,076	33,252	6,656	25,972	9,155	-	9,698	-
31	2.3 GS 110-1,000 kVa	761,034	76,759	650,510	-	5,052	14,804	810	996	320	2,617	522	2,163	763	-	761	-
32	2.4 GS Over 1,000 kVa	845,137	36,552	792,500	-	2,406	7,049	101	474	40	1,246	65	270	95	-	95	-
33	2.5 GS Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34	2.5G Gov't General Service Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
35	4.1 Street and Area Lighting	222,256	51,904	98,996	-	3,416	10,010	7,690	673	3,037	1,770	4,960	-	-	30,618	7,226	-
36	4.1G Gov't Street and Area Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37	**Total**	**20,102,669**	**4,727,614**	**12,778,991**	**-**	**311,143**	**911,766**	**274,929**	**61,336**	**108,570**	**161,201**	**177,303**	**120,492**	**42,473**	**30,618**	**258,322**	**-**
	Re-classification of Revenue-Related																
38	1.2 Domestic Diesel	(0)	16,028	35,925	-	1,055	3,091	1,110	208	438	547	716	346	122	-	1,043	-
39	1.2G Government Domestic Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40	1.23 Churches, Schools & Com Halls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
41	2.1 GS 0-10 kW	(0)	5,391	16,255	-	355	1,040	461	70	182	184	298	288	101	-	434	-
42	2.2 GS 10-100 kW	0	9,581	27,909	-	631	1,848	101	124	40	327	65	255	90	-	95	-
43	2.3 GS 110-1,000 kVa	-	503	4,267	-	33	97	5	7	2	17	3	14	5	-	5	-
44	2.4 GS Over 1,000 kVa	0	184	3,999	-	12	36	1	2	0	6	0	1	0	-	0	-
45	2.5 GS Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
46	2.5G Gov't General Service Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
47	4.1 Street and Area Lighting	-	461	879	-	30	89	68	6	27	16	44	-	-	272	64	-
48	4.1G Gov't Street and Area Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
49	**Total**	**(0)**	**32,148**	**89,233**	**-**	**2,116**	**6,200**	**1,747**	**417**	**690**	**1,096**	**1,127**	**905**	**319**	**272**	**1,642**	**-**
	Total Allocated Revenue Requirement																
50	1.2 Domestic Diesel	11,890,666	3,143,403	7,045,585	-	206,880	606,235	217,755	40,782	85,992	107,183	140,431	67,889	23,930	-	204,601	-
51	1.2G Government Domestic Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
52	1.23 Churches, Schools & Com Halls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
53	2.1 GS 0-10 kW	2,162,483	465,213	1,402,799	-	30,617	89,721	39,824	6,036	15,726	15,863	25,683	24,831	8,753	-	37,418	-
54	2.2 GS 10-100 kW	4,221,092	984,784	2,868,690	-	64,812	189,925	10,423	12,777	4,116	33,579	6,722	26,228	9,245	-	9,793	-
55	2.3 GS 110-1,000 kVa	761,034	77,262	654,777	-	5,085	14,901	815	1,002	322	2,634	525	2,177	768	-	766	-
56	2.4 GS Over 1,000 kVa	845,137	36,736	796,498	-	2,418	7,085	102	477	40	1,253	66	272	96	-	96	-
57	2.5 GS Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
58	2.5G Gov't General Service Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
59	4.1 Street and Area Lighting	222,256	52,365	99,876	-	3,446	10,099	7,759	679	3,064	1,786	5,004	-	-	30,890	7,290	-
60	4.1G Gov't Street and Area Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
61	**Total**	**20,102,669**	**4,759,762**	**12,868,224**	**-**	**313,259**	**917,966**	**276,677**	**61,753**	**109,260**	**162,297**	**178,430**	**121,397**	**42,792**	**30,890**	**259,964**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Labrador Isolated
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

	1	18	19	
		Revenue Related		
Line No.	Description	Municipal Tax ($)	PUB Assessment ($)	Basis of Proration
	Total Revenue Requirement			
26	1.2 Domestic Diesel	56,794	3,836	
27	1.2G Government Domestic Diesel	-	-	
28	1.23 Churches, Schools & Com Halls	-	-	
29	2.1 GS 0-10 kW	23,472	1,585	
30	2.2 GS 10-100 kW	38,468	2,598	
31	2.3 GS 110-1,000 kVa	4,645	314	
32	2.4 GS Over 1,000 kVa	3,974	268	
33	2.5 GS Diesel	-	-	
34	2.5G Gov't General Service Diesel	-	-	
35	4.1 Street and Area Lighting	1,833	124	
36	4.1G Gov't Street and Area Lighting	-	-	
37	**Total**	**129,187**	**8,726**	
	Re-classification of Revenue-Related			
38	1.2 Domestic Diesel	(56,794)	(3,836)	Re-classification to demand, energy and customer is based on rate class revenue
39	1.2G Government Domestic Diesel	-	-	requirements excluding revenue-related items.
40	1.23 Churches, Schools & Com Halls	-	-	
41	2.1 GS 0-10 kW	(23,472)	(1,585)	
42	2.2 GS 10-100 kW	(38,468)	(2,598)	
43	2.3 GS 110-1,000 kVa	(4,645)	(314)	
44	2.4 GS Over 1,000 kVa	(3,974)	(268)	
45	2.5 GS Diesel	-	-	
46	2.5G Gov't General Service Diesel	-	-	
47	4.1 Street and Area Lighting	(1,833)	(124)	
48	4.1G Gov't Street and Area Lighting	-	-	
49	**Total**	**(129,187)**	**(8,726)**	
	Total Allocated Revenue Requirement			
50	1.2 Domestic Diesel	-	-	
51	1.2G Government Domestic Diesel	-	-	
52	1.23 Churches, Schools & Com Halls	-	-	
53	2.1 GS 0-10 kW	-	-	
54	2.2 GS 10-100 kW	-	-	
55	2.3 GS 110-1,000 kVa	-	-	
56	2.4 GS Over 1,000 kVa	-	-	
57	2.5 GS Diesel	-	-	
58	2.5G Gov't General Service Diesel	-	-	
59	4.1 Street and Area Lighting	-	-	
60	4.1G Gov't Street and Area Lighting	-	-	
61	**Total**	-	-	

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
L'Anse au Loup
Functional Classification of Revenue Requirement

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
						Distribution											
							Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lightin	Accounting	
Line No.	Description	Total Amount ($)	Production Demand ($)	Production and Transmission Energy ($)	Transmission Demand ($)	Substations Demand ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Specifically Assigned Customer ($)
	Expenses																
1	Operating & Maintenance	1,115,316	584,305	-	-	2,653	214,816	65,005	6,910	12,231	37,753	41,701	11,291	9,507	2,607	91,007	-
2	Fuels	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Fuels-Diesel	68,661	-	68,661	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuels-Gas Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Power Purchases -CF(L)Co	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Power Purchases-Other	812,107	-	812,107	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Depreciation	401,179	158,284	-	-	1,268	125,126	38,535	4,267	7,553	22,217	24,715	6,010	4,006	1,504	7,693	-
	Expense Credits																
8	Sundry	(5,466)	(2,863)	-	-	(13)	(1,053)	(319)	(34)	(60)	(185)	(204)	(55)	(47)	(13)	(446)	-
9	Building Rental Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Tax Refunds	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Suppliers' Discounts	(273)	(143)	-	-	(1)	(53)	(16)	(2)	(3)	(9)	(10)	(3)	(2)	(1)	(22)	-
12	Pole Attachments	(55,402)	-	-	-	-	(32,042)	(10,950)	-	-	(5,671)	(6,739)	-	-	-	-	-
13	Secondary Energy Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Wheeling Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Application Fees	(840)	-	-	-	-	-	-	-	-	-	-	-	-	-	(840)	-
16	Meter Test Revenues	(2,698)	-	-	-	-	-	-	-	-	-	-	-	(2,698)	-	-	-
17	**Total Expense Credits**	(64,679)	(3,007)	-	-	(14)	(33,147)	(11,285)	(36)	(63)	(5,866)	(6,953)	(58)	(2,747)	(13)	(1,308)	-
18	**Subtotal Expenses**	**2,332,583**	**739,582**	**880,768**	-	**3,908**	**306,795**	**92,255**	**11,141**	**19,721**	**54,105**	**59,462**	**17,243**	**10,765**	**4,098**	**97,391**	-
19	Disposal Gain / Loss	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	**Subtotal Revenue Requirement Ex. Return**	**2,332,583**	**739,582**	**880,768**	-	**3,908**	**306,795**	**92,255**	**11,141**	**19,721**	**54,105**	**59,462**	**17,243**	**10,765**	**4,098**	**97,391**	-
21	Return on Debt	412,844	103,261	1,450	-	1,634	163,030	50,882	5,227	9,252	28,163	31,903	7,995	5,044	1,774	3,231	-
22	Return on Equity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	**Total Revenue Requirement**	**2,745,427**	**842,843**	**882,218**	-	**5,542**	**469,825**	**143,137**	**16,368**	**28,973**	**82,267**	**91,365**	**25,237**	**15,809**	**5,871**	**100,623**	-

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
L'Anse au Loup
Functional Classification of Revenue Requirement (CONT'D.)

Line No.	1 Description	18 Revenue Related Municipal Tax ($)	19 PUB Assessment ($)	20 Basis of Functional Classification
	Expenses			
1	Operating & Maintenance	33,283	2,248	Carryforward from Sch.2.4 L.24
2	Fuels	-	-	Production - Energy
3	Fuels-Diesel	-	-	Production - Energy
4	Fuels-Gas Turbine	-	-	Production - Energy
5	Power Purchases -CF(L)Co	-	-	
6	Power Purchases-Other	-	-	Carryforward from Sch.4.4 L.12
7	Depreciation	-	-	Carryforward from Sch.2.5 L.23
	Expense Credits			
8	Sundry	(163)	(11)	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.24
9	Building Rental Income	-	-	Prorated on General Plant - Sch.2.2 L.18
10	Tax Refunds	-	-	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.24
11	Suppliers' Discounts	(8)	(1)	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.24
12	Pole Attachments	-	-	Prorated on Distribution Poles - Sch.4.1 L.37
13	Secondary Energy Revenues	-	-	Production - Energy
14	Wheeling Revenues	-	-	Transmission - Demand, Energy ratios Sch.4.1 L.16
15	Application Fees	-	-	Accounting - Customer
16	Meter Test Revenues	-	-	Meters - Customer
17	**Total Expense Credits**	**(171)**	**(12)**	
18	**Subtotal Expenses**	**33,112**	**2,236**	
19	Disposal Gain / Loss	-	-	Prorated on Total Net Book Value - Sch.2.3 L.23
20	**Subtotal Revenue Requirement Ex. Return**	**33,112**	**2,236**	
21	Return on Debt	-	-	Prorated on Rate Base - Sch.2.6 L.8
22	Return on Equity	-	-	Prorated on Rate Base - Sch.2.6 L.10
23	**Total Revenue Requirement**	**33,112**	**2,236**	

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
L'Anse au Loup
Functional Classification of Plant in Service for the Allocation of O&M Expense

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Distribution Substations Demand ($)	7 Distribution Primary Lines Demand ($)	8 Distribution Primary Lines Customer ($)	9 Distribution Line Transformers Demand ($)	10 Distribution Line Transformers Customer ($)	11 Distribution Secondary Lines Demand ($)	12 Distribution Secondary Lines Customer ($)	13 Distribution Services Customer ($)	14 Distribution Meters Customer ($)	15 Distribution Street Lightin Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
	Production																
1	Diesel	3,326,329	3,326,329	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	**Subtotal Production**	**3,326,329**	**3,326,329**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Subtotal Transmission**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Distribution																
6	Substation Structures & Equipment	90,204	44,995	-	-	45,210	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	15,995	-	-	-	-	12,059	1,536	-	-	1,399	1,000	-	-	-	-	-
8	Poles	5,320,337	-	-	-	-	3,077,006	1,051,575	-	-	544,632	647,123	-	-	-	-	-
9	Primary Conductor & Equipment	761,458	-	-	-	-	675,413	86,045	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	335,429	-	-	-	-	-	-	121,090	214,339	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	198,216	-	-	-	-	-	-	-	-	115,560	82,656	-	-	-	-	-
13	Services	197,863	-	-	-	-	-	-	-	-	-	-	197,863	-	-	-	-
14	Meters	113,890	-	-	-	-	-	-	-	-	-	-	-	113,890	-	-	-
15	Street Lighting	45,683	-	-	-	-	-	-	-	-	-	-	-	-	45,683	-	-
16	**Subtotal Distribution**	**7,079,075**	**44,995**	-	-	**45,210**	**3,764,479**	**1,139,156**	**121,090**	**214,339**	**661,591**	**730,780**	**197,863**	**113,890**	**45,683**	-	-
17	**Subttl Prod, Trans, & Dist**	**10,405,404**	**3,371,324**	-	-	**45,210**	**3,764,479**	**1,139,156**	**121,090**	**214,339**	**661,591**	**730,780**	**197,863**	**113,890**	**45,683**	-	-
18	General	1,272,676	687,690	-	-	2,958	246,339	74,544	7,924	14,026	43,293	47,821	12,948	11,384	2,989	120,761	-
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Software - General	9,097	2,947	-	-	40	3,291	996	106	187	578	639	173	100	40	-	-
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	**Total Plant**	**11,687,177**	**4,061,961**	-	-	**48,208**	**4,014,109**	**1,214,696**	**129,120**	**228,552**	**705,463**	**779,239**	**210,983**	**125,373**	**48,712**	**120,761**	-

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
L'Anse au Loup
Functional Classification of Plant in Service for the Allocation of O&M Expense (CONT'D.)

Line No.	1 Description	18 Basis of Functional Classification
	Production	
1	Diesel	Production - Demand, Energy ratios Sch.4.1 L.8
2	**Subtotal Production**	
	Transmission	
3	Lines	Production, Transmission - Demand; Distribution - Primary Demand; Spec Assigned - Custmr
4	Terminal Stations	Production, Transmission - Demand; Spec Assigned - Custmr
5	**Subtotal Transmission**	
	Distribution	
6	Substation Structures & Equipment	Production - Demand; Dist Substns - Demand
7	Land & Land Improvements	Primary, Secondary - Demand, Customer - zero intercept ratios Sch.4.1 L.32
8	Poles	Primary, Secondary - Demand, Customer - zero intercept ratios Sch.4.1 L.37
9	Primary Conductor & Equipment	Primary - Demand, Customer - zero intercept ratios Sch.4.1 L.38
10	Submarine Conductor	Primary - Demand, Customer - zero intercept ratios Sch.4.1 L.39
11	Transformers	Transformers - Demand, Customer - zero intercept ratios Sch.4.1 L.40
12	Secondary Conductors & Equipment	Secondary - Demand, Customer - zero intercept ratios Sch. 4.1 L.41
13	Services	Services Customer
14	Meters	Meters - Customer
15	Street Lighting	Street Lighting - Customer
16	**Subtotal Distribution**	
17	**Subttl Prod, Trans, & Dist**	
18	General	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - Sch.2.4 L.11, 12
19	Telecontrol - Specific	Specifically Assigned - Customer
20	Feasibility Studies	Production, Transmission - Demand
21	Software - General	Prorated on subtotal Production, Transmission, & Distribution plant - L.17
22	Software - Cust Acctng	Customer Accounting
23	**Total Plant**	

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
L'Anse au Loup
Functional Classification of Net Book Value

Line No.	Description	Total Amount ($)	Production Demand ($)	Production and Transmission Energy ($)	Transmission Demand ($)	Distribution: Substations Demand ($)	Distribution: Primary Lines Demand ($)	Distribution: Primary Lines Customer ($)	Distribution: Line Transformers Demand ($)	Distribution: Line Transformers Customer ($)	Distribution: Secondary Lines Demand ($)	Distribution: Secondary Lines Customer ($)	Distribution: Services Customer ($)	Distribution: Meters Customer ($)	Distribution: Street Lightin Customer ($)	Accounting Customer ($)	Specifically Assigned Customer ($)
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
	Production																
1	Diesel	1,084,155	1,084,155	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	**Subtotal Production**	**1,084,155**	**1,084,155**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Subtotal Transmission**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Distribution																
6	Substation Structures & Equipment	21,599	1,552	-	-	20,046	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	8,105	-	-	-	-	6,111	778	-	-	709	507	-	-	-	-	-
8	Poles	3,026,277	-	-	-	-	1,750,241	598,150	-	-	309,794	368,092	-	-	-	-	-
9	Primary Conductor & Equipment	302,743	-	-	-	-	268,533	34,210	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	179,795	-	-	-	-	-	-	64,906	114,889	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	66,755	-	-	-	-	-	-	-	-	38,918	27,837	-	-	-	-	-
13	Services	98,863	-	-	-	-	-	-	-	-	-	-	98,863	-	-	-	-
14	Meters	61,344	-	-	-	-	-	-	-	-	-	-	-	61,344	-	-	-
15	Street Lighting	21,878	-	-	-	-	-	-	-	-	-	-	-	-	21,878	-	-
16	**Subtotal Distribution**	**3,787,359**	**1,552**	-	-	**20,046**	**2,024,885**	**633,138**	**64,906**	**114,889**	**349,421**	**396,436**	**98,863**	**61,344**	**21,878**	-	-
17	**Subttl Prod, Trans, & Dist**	**4,871,514**	**1,085,708**	-	-	**20,046**	**2,024,885**	**633,138**	**64,906**	**114,889**	**349,421**	**396,436**	**98,863**	**61,344**	**21,878**	-	-
18	General	437,010	236,138	-	-	1,016	84,587	25,597	2,721	4,816	14,866	16,421	4,446	3,909	1,026	41,467	-
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Software - General	5,744	1,280	-	-	24	2,387	747	77	135	412	467	117	72	26	-	-
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	**Total Net Book Value**	**5,314,268**	**1,323,126**	-	-	**21,086**	**2,111,860**	**659,481**	**67,703**	**119,840**	**364,699**	**413,324**	**103,426**	**65,325**	**22,931**	**41,467**	-

NEWFOUNDLAND & LABRADOR HYDRO
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L'Anse au Loup
Functional Classification of Operating & Maintenance Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
						Distribution											
							Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	
Line No.	Description	Total Amount ($)	Production Demand ($)	Production and Transmission Energy ($)	Transmission Demand ($)	Substations Demand ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Specifically Assigned Customer ($)
	Production																
1	Diesel	307,160	307,160	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Other	30,176	30,176	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	**Subtotal Production**	**337,335**	**337,335**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
4	Transmission Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	**Subtotal Transmission**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Distribution																
8	Other	224,540	1,451	-	-	1,457	121,357	36,723	3,904	6,910	21,328	23,558	6,379	-	1,473	-	-
9	Meters	5,608	-	-	-	-	-	-	-	-	-	-	-	5,608	-	-	-
10	**Subtotal Distribution**	**230,148**	**1,451**	-	-	**1,457**	**121,357**	**36,723**	**3,904**	**6,910**	**21,328**	**23,558**	**6,379**	**5,608**	**1,473**	-	-
11	**Subttl Prod, Trans, & Dist**	**567,483**	**338,786**	-	-	**1,457**	**121,357**	**36,723**	**3,904**	**6,910**	**21,328**	**23,558**	**6,379**	**5,608**	**1,473**	-	-
12	Customer Accounting	59,492	-	-	-	-	-	-	-	-	-	-	-	-	-	59,492	-
	Administrative & General:																
	Plant-Related:																
13	Production	48,877	48,877	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Distribution	42,060	267	-	-	269	22,366	6,768	719	1,273	3,931	4,342	1,176	677	271	-	-
16	Prod, Trans, Distn Plant	8,820	2,858	-	-	38	3,191	966	103	182	561	619	168	97	39	-	-
17	Prod,Trans, Distn & General Plt	2,503	870	-	-	10	860	260	28	49	151	167	45	27	10	26	-
18	Property Insurance	7,636	6,610	-	-	78	401	121	13	23	71	78	21	19	5	197	-
	Revenue Related:																
19	Municipal Tax	33,283	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	PUB Assessment	2,248	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	All Expense-Related	329,781	178,197	-	-	767	63,832	19,316	2,053	3,634	11,218	12,391	3,355	2,950	775	31,292	-
22	Prod, Trans, and Distn Expense-Related	13,132	7,840	-	-	34	2,808	850	90	160	494	545	148	130	34	-	-
23	**Subtotal Admin & General**	**488,340**	**245,519**	-	-	**1,196**	**93,459**	**28,281**	**3,006**	**5,321**	**16,425**	**18,143**	**4,912**	**3,898**	**1,134**	**31,515**	-
24	**Total Operating & Maintenance Expenses**	**1,115,316**	**584,305**	-	-	**2,653**	**214,816**	**65,005**	**6,910**	**12,231**	**37,753**	**41,701**	**11,291**	**9,507**	**2,607**	**91,007**	-

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
L'Anse au Loup
Functional Classification of Operating & Maintenance Expense (CONT'D.)

	1	18	19	20
		Revenue Related		
Line No.	Description	Municipal Tax	PUB Assessment	Basis of Functional Classification
	Production			
1	Diesel	-	-	Production - Demand, Energy ratios Sch.4.1 L8
2	Other	-	-	Production - Demand, Energy ratios Sch.4.1 L8
3	**Subtotal Production**	-	-	
	Transmission			
4	Transmission Lines	-	-	Prorated on Transmission Lines Plant in Service - Sch.2.2 L.3
5	Terminal Stations	-	-	Prorated on Transmission Terminal Stations Plant in Service - Sch.2.2 L.4
6	Other	-	-	Prorated on Transmission Plant in Service - Sch.2.2 L.5
7	**Subtotal Transmission**	-	-	
	Distribution			
8	Other	-	-	Prorated on Distribution Plant, excluding Meters - Sch. 2.2 L. 16, less L. 14
9	Meters	-	-	Meters - Customer
10	**Subtotal Distribution**	-	-	
11	**Subttl Prod, Trans, & Dist**	-	-	
12	Customer Accounting	-	-	Accounting - Customer
	Administrative & General:			
	Plant-Related:			
13	Production	-	-	Prorated on Production Plant in Service - Sch.2.2 L.2
14	Transmission	-	-	Prorated on Transmission Plant in Service - Sch.2.2 L.5
15	Distribution	-	-	Prorated on Distribution Plant in Service - Sch.2.2 L.16
16	Prod, Trans, Distn Plant	-	-	Prorated on Production, Transmission & Distribution Plant in Service - Sch.2.2 L.17
17	Prod,Trans, Distn & General Plt	-	-	Prorated on Production, Transmission, Distribution & General Plant in Service - Sch.2.2 L.23
18	Property Insurance	-	-	Prorated on Prod., Trans. Terminal, Dist. Sub & General Plant in Service - Sch.2.2 L.2, 4, 6, 18 - 19
	Revenue Related:			
19	Municipal Tax	33,283	-	Revenue-related
20	PUB Assessment	-	2,248	Revenue-related
21	All Expense-Related	-	-	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - L.11, 12
22	Prod, Trans, and Distn Expense-Related	-	-	Prorated on Subtotal Production, Transmission, Distribution Expenses - L.11
23	**Subtotal Admin & General**	**33,283**	**2,248**	
24	**Total Operating & Maintenance Expenses**	**33,283**	**2,248**	

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
L'Anse au Loup
Functional Classification of Depreciation Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
						Distribution											
							Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Specifically Assigned
Line No.	Description	Total Amount ($)	Production Demand ($)	Production and Transmission Energy ($)	Transmission Demand ($)	Substations Demand ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)
	Production																
1	Diesel	111,416	111,416	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	**Subtotal Production**	**111,416**	**111,416**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Subtotal Transmission**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Distribution																
6	Substation Structures & Equipment	1,201	149	-	-	1,052	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	394	-	-	-	-	297	38	-	-	34	25	-	-	-	-	-
8	Poles	156,008	-	-	-	-	90,227	30,835	-	-	15,970	18,976	-	-	-	-	-
9	Primary Conductor & Equipment	18,181	-	-	-	-	16,127	2,055	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	10,157	-	-	-	-	-	-	3,667	6,490	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	5,077	-	-	-	-	-	-	-	-	2,960	2,117	-	-	-	-	-
13	Services	5,053	-	-	-	-	-	-	-	-	-	-	5,053	-	-	-	-
14	Meters	3,197	-	-	-	-	-	-	-	-	-	-	-	3,197	-	-	-
15	Street Lighting	1,280	-	-	-	-	-	-	-	-	-	-	-	-	1,280	-	-
16	**Subtotal Distribution**	**200,550**	**149**	-	-	**1,052**	**106,651**	**32,928**	**3,667**	**6,490**	**18,965**	**21,117**	**5,053**	**3,197**	**1,280**	-	-
17	**Subtotal Prod Tran & Dist**	**311,966**	**111,565**	-	-	**1,052**	**106,651**	**32,928**	**3,667**	**6,490**	**18,965**	**21,117**	**5,053**	**3,197**	**1,280**	-	-
18	General	81,074	43,809	-	-	188	15,693	4,749	505	894	2,758	3,046	825	725	190	7,693	-
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Software - General	8,138	2,910	-	-	27	2,782	859	96	169	495	551	132	83	33	-	-
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	**Total Depreciation Expense**	**401,179**	**158,284**	-	-	**1,268**	**125,126**	**38,535**	**4,267**	**7,553**	**22,217**	**24,715**	**6,010**	**4,006**	**1,504**	**7,693**	-

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
L'Anse au Loup
Functional Classification of Rate Base

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
						Distribution											
							Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lightin	Accounting	
Line No.	Description	Total Amount ($)	Production Demand ($)	Production and Transmission Energy ($)	Transmission Demand ($)	Substations Demand ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Specifically Assigned Customer ($)
1	Average Net Book Value	5,314,268	1,323,126	-	-	21,086	2,111,860	659,481	67,703	119,840	364,699	413,324	103,426	65,325	22,931	41,467	-
2	Cash Working Capital	11,891	2,961	-	-	47	4,725	1,476	151	268	816	925	231	146	51	93	-
3	Fuel Inventory - No. 6 Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuel Inventory - Diesel	20,307	-	20,307	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Fuel Inventory - Gas Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Inventory/Supplies	118,425	41,159	-	-	488	40,675	12,308	1,308	2,316	7,148	7,896	2,138	1,270	494	1,224	-
7	Deferred Charges: Foreign Exchange Loss and Regulatory Costs	318,519	79,304	-	-	1,264	126,577	39,527	4,058	7,183	21,859	24,773	6,199	3,915	1,374	2,485	-
8	Total Rate Base	**5,783,409**	**1,446,549**	**20,307**	**-**	**22,885**	**2,283,838**	**712,792**	**73,221**	**129,607**	**394,522**	**446,918**	**111,994**	**70,657**	**24,850**	**45,269**	**-**
9	Less: Rural Portion	(5,783,409)	(1,446,549)	(20,307)	-	(22,885)	(2,283,838)	(712,792)	(73,221)	(129,607)	(394,522)	(446,918)	(111,994)	(70,657)	(24,850)	(45,269)	-
10	Rate Base Available for Equity Return	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
11	Return on Debt	412,844	103,261	1,450	-	1,634	163,030	50,882	5,227	9,252	28,163	31,903	7,995	5,044	1,774	3,231	-
12	Return on Equity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Return on Rate Base	**412,844**	**103,261**	**1,450**	**-**	**1,634**	**163,030**	**50,882**	**5,227**	**9,252**	**28,163**	**31,903**	**7,995**	**5,044**	**1,774**	**3,231**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
L'Anse au Loup
Functional Classification of Rate Base (CONT'D.)

Line No.	1 Description	18 Basis of Functional Classification
1	Average Net Book Value	Sch. 2.3 , L. 23
2	Cash Working Capital	Prorated on Average Net Book Value, L. 1
3	Fuel Inventory - No. 6 Fuel	
4	Fuel Inventory - Diesel	Production - Energy
5	Fuel Inventory - Gas Turbine	
6	Inventory/Supplies	Prorated on Total Plant in Service, Sch. 2.2, L. 23
7	Deferred Charges: Foreign Exchange Loss and Regulatory Costs	Prorated on Average Net Book Value, L. 1
8	Total Rate Base	
9	Less: Rural Portion	
10	Rate Base Available for Equity Return	
11	Return on Debt	L.8 x Sch.1.1,p2,L.13
12	Return on Equity	L.10 x Sch.1.1,p2,L.16
13	Return on Rate Base	

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
L'Anse au Loup
Basis of Allocation to Classes of Service

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
							Distribution										
				Production and			Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lightin	Accounting	Specifically
Line		Total	Production	Transmission	Transmission	Substations											Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
			(CP kW)	(MWh @ Gen)	(CP kW)	(CP kW)	(CP kW)	(Rural Cust)	(CP kW)	(Rural Cust)	(CP kW)	(Rural Cust)	(Wtd Rural Cust)			(Rural Cust)	
	Amounts																
1	1.1 Domestic Diesel	-	2,420	9,503	2,420	2,269	2,269	742	2,047	742	2,047	742	742	742	-	742	-
2	1.12 Domestic All Electric	-	111	375	111	104	104	19	94	19	94	19	19	19	-	19	-
3	2.1 GS 0-10 kW	-	209	1,171	209	196	196	137	176	137	176	137	274	274	-	137	-
4	2.2 GS 10-100 kW	-	852	4,245	852	799	799	63	721	63	721	63	509	509	-	63	-
5	2.3 GS 110-1,000 kVa	-	182	898	182	171	171	2	154	2	154	2	17	17	-	2	-
6	4.1 Street and Area Lighting	-	33	127	33	31	31	30	28	30	28	30	-	-	1	30	-
7	**Total**	-	**3,807**	**16,319**	**3,807**	**3,570**	**3,570**	**993**	**3,220**	**993**	**3,220**	**993**	**1,561**	**1,561**	**1**	**993**	**0**
	Ratios																
8	1.1 Domestic Diesel	-	0.6357	0.5823	0.6357	0.6357	0.6357	0.7472	0.6357	0.7472	0.6357	0.7472	0.4754	0.4754	-	0.7472	-
9	1.12 Domestic All Electric	-	0.0292	0.0230	0.0292	0.0292	0.0292	0.0191	0.0292	0.0191	0.0292	0.0191	0.0122	0.0122	-	0.0191	-
10	2.1 GS 0-10 kW	-	0.0548	0.0717	0.0548	0.0548	0.0548	0.1380	0.0548	0.1380	0.0548	0.1380	0.1756	0.1756	-	0.1380	-
11	2.2 GS 10-100 kW	-	0.2238	0.2602	0.2238	0.2238	0.2238	0.0634	0.2238	0.0634	0.2238	0.0634	0.3258	0.3258	-	0.0634	-
12	2.3 GS 110-1,000 kVa	-	0.0478	0.0550	0.0478	0.0478	0.0478	0.0020	0.0478	0.0020	0.0478	0.0020	0.0110	0.0110	-	0.0020	-
13	4.1 Street and Area Lighting	-	0.0087	0.0078	0.0087	0.0087	0.0087	0.0302	0.0087	0.0302	0.0087	0.0302	-	-	1.0000	0.0302	-
14	**Total**	-	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**0.0000**

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
L'Anse au Loup
Basis of Allocation to Classes of Service (CONT'D.)

Line No.	Description	Revenue Related: Municipal Tax (Prior Year (Rural Revenues)	Revenue Related: PUB Assessment (Prior Year (Revenues + RSP)
	1	18	19
	Amounts		
1	1.1 Domestic Diesel	729,206	729,206
2	1.12 Domestic All Electric	27,591	27,591
3	2.1 GS 0-10 kW	130,749	130,749
4	2.2 GS 10-100 kW	366,667	366,667
5	2.3 GS 110-1,000 kVa	84,626	84,626
6	4.1 Street and Area Lighting	32,775	32,775
7	**Total**	**1,371,614**	**1,371,614**
	Ratios		
8	1.1 Domestic Diesel	0.5316	0.5316
9	1.12 Domestic All Electric	0.0201	0.0201
10	2.1 GS 0-10 kW	0.0953	0.0953
11	2.2 GS 10-100 kW	0.2673	0.2673
12	2.3 GS 110-1,000 kVa	0.0617	0.0617
13	4.1 Street and Area Lighting	0.0239	0.0239
14	**Total**	**1.0000**	**1.0000**

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
L'Anse au Loup
Allocation of Functionalized Amounts to Classes of Service

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
						Distribution											
				Production and													Specifically
Line		Total	Production	Transmission	Transmsn	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lightin	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
	Allocated Revenue Requirement Excluding Return																
1	1.1 Domestic Diesel	1,454,994	470,135	512,890	-	2,484	195,022	68,936	7,082	14,736	34,393	44,432	8,198	5,118	-	72,774	-
2	1.12 Domestic All Electric	58,998	21,603	20,218	-	114	8,961	1,765	325	377	1,580	1,138	210	131	-	1,863	-
3	2.1 GS 0-10 kW	169,667	40,506	63,195	-	214	16,803	12,728	610	2,721	2,963	8,204	3,027	1,890	-	13,437	-
4	2.2 GS 10-100 kW	514,442	165,533	229,133	-	875	68,667	5,853	2,494	1,251	12,110	3,773	5,618	3,508	-	6,179	-
5	2.3 GS 110-1,000 kVa	104,862	35,375	48,475	-	187	14,674	186	533	40	2,588	120	189	118	-	196	-
6	4.1 Street and Area Lighting	29,621	6,430	6,857	-	34	2,667	2,787	97	596	470	1,796	-	-	4,098	2,942	-
7	**Total**	**2,332,583**	**739,582**	**880,768**	**-**	**3,908**	**306,795**	**92,255**	**11,141**	**19,721**	**54,105**	**59,462**	**17,243**	**10,765**	**4,098**	**97,391**	**-**
	Allocated Return on Debt																
8	1.1 Domestic Diesel	269,769	65,641	844	-	1,038	103,634	38,021	3,323	6,913	17,902	23,839	3,801	2,398	-	2,415	-
9	1.12 Domestic All Electric	10,816	3,016	33	-	48	4,762	974	153	177	823	610	97	61	-	62	-
10	2.1 GS 0-10 kW	32,039	5,655	104	-	89	8,929	7,020	286	1,276	1,542	4,402	1,404	886	-	446	-
11	2.2 GS 10-100 kW	78,110	23,112	377	-	366	36,489	3,228	1,170	587	6,303	2,024	2,605	1,643	-	205	-
12	2.3 GS 110-1,000 kVa	14,827	4,939	80	-	78	7,798	102	250	19	1,347	64	88	55	-	7	-
13	4.1 Street and Area Lighting	7,283	898	11	-	14	1,417	1,537	45	280	245	964	-	-	1,774	98	-
14	**Total**	**412,844**	**103,261**	**1,450**	**-**	**1,634**	**163,030**	**50,882**	**5,227**	**9,252**	**28,163**	**31,903**	**7,995**	**5,044**	**1,774**	**3,231**	**-**
	Allocated Return on Equity																
15	All Classes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
L'Anse au Loup
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

Line No.	Description (1)	Revenue Related: Municipal Tax ($) (18)	Revenue Related: PUB Assessment ($) (19)	Basis of Proration
	Allocated Revenue Requirement Excluding Return			
1	1.1 Domestic Diesel	17,604	1,189	
2	1.12 Domestic All Electric	666	45	
3	2.1 GS 0-10 kW	3,156	213	
4	2.2 GS 10-100 kW	8,852	598	
5	2.3 GS 110-1,000 kVa	2,043	138	
6	4.1 Street and Area Lighting	791	53	
7	**Total**	**33,112**	**2,236**	
	Allocated Return on Debt			
8	1.1 Domestic Diesel	-	-	
9	1.12 Domestic All Electric	-	-	
10	2.1 GS 0-10 kW	-	-	
11	2.2 GS 10-100 kW	-	-	
12	2.3 GS 110-1,000 kVa	-	-	
13	4.1 Street and Area Lighting	-	-	
14	**Total**	-	-	
	Allocated Return on Equity			
15	All Classes	-	-	

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
L'Anse au Loup
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
						Distribution											
							Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lightin		
Line No.	Description	Total Amount ($)	Production Demand ($)	Production and Transmission Energy ($)	Transmsn Demand ($)	Substations Demand ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Accounting Customer ($)	Specifically Assigned Customer ($)
	Total Revenue Requirement																
16	1.1 Domestic Diesel	1,724,763	535,776	513,734	-	3,523	298,657	106,957	10,405	21,650	52,295	68,271	11,999	7,516	-	75,188	-
17	1.12 Domestic All Electric	69,814	24,619	20,251	-	162	13,723	2,739	478	554	2,403	1,748	307	192	-	1,925	-
18	2.1 GS 0-10 kW	201,706	46,161	63,299	-	304	25,731	19,748	896	3,997	4,506	12,605	4,431	2,776	-	13,883	-
19	2.2 GS 10-100 kW	592,551	188,645	229,510	-	1,240	105,156	9,081	3,664	1,838	18,413	5,797	8,223	5,151	-	6,384	-
20	2.3 GS 110-1,000 kVa	119,689	40,314	48,555	-	265	22,472	288	783	58	3,935	184	277	174	-	203	-
21	4.1 Street and Area Lighting	36,904	7,328	6,869	-	48	4,085	4,324	142	875	715	2,760	-	-	5,871	3,040	-
22	**Total**	**2,745,427**	**842,843**	**882,218**	**-**	**5,542**	**469,825**	**143,137**	**16,368**	**28,973**	**82,267**	**91,365**	**25,237**	**15,809**	**5,871**	**100,623**	**-**
	Re-classification of Revenue-Related																
23	1.1 Domestic Diesel	0	5,902	5,659	-	39	3,290	1,178	115	238	576	752	132	83	-	828	-
24	1.12 Domestic All Electric	(0)	253	208	-	2	141	28	5	6	25	18	3	2	-	20	-
25	2.1 GS 0-10 kW	(0)	784	1,075	-	5	437	336	15	68	77	214	75	47	-	236	-
26	2.2 GS 10-100 kW	(0)	3,057	3,719	-	20	1,704	147	59	30	298	94	133	83	-	103	-
27	2.3 GS 110-1,000 kVa	(0)	748	901	-	5	417	5	15	1	73	3	5	3	-	4	-
28	4.1 Street and Area Lighting	(0)	172	161	-	1	96	101	3	21	17	65	-	-	138	71	-
29	**Total**	**(0)**	**10,916**	**11,724**	**-**	**72**	**6,085**	**1,796**	**212**	**363**	**1,066**	**1,146**	**349**	**219**	**138**	**1,262**	**-**
	Total Allocated Revenue Requirement																
30	1.1 Domestic Diesel	1,724,763	541,678	519,393	-	3,562	301,947	108,135	10,520	21,888	52,871	69,023	12,131	7,599	-	76,017	-
31	1.12 Domestic All Electric	69,814	24,873	20,459	-	164	13,865	2,767	483	560	2,428	1,766	310	194	-	1,945	-
32	2.1 GS 0-10 kW	201,706	46,945	64,374	-	309	26,169	20,084	912	4,065	4,582	12,819	4,506	2,823	-	14,118	-
33	2.2 GS 10-100 kW	592,551	191,702	233,230	-	1,260	106,860	9,228	3,723	1,868	18,711	5,891	8,356	5,234	-	6,487	-
34	2.3 GS 110-1,000 kVa	119,689	41,062	49,456	-	270	22,889	294	797	59	4,008	187	282	177	-	206	-
35	4.1 Street and Area Lighting	36,904	7,500	7,030	-	49	4,181	4,426	146	896	732	2,825	-	-	6,009	3,111	-
36	**Total**	**2,745,427**	**853,759**	**893,942**	**-**	**5,614**	**475,910**	**144,933**	**16,580**	**29,337**	**83,333**	**92,512**	**25,586**	**16,028**	**6,009**	**101,885**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
L'Anse au Loup
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

Line No.	1 Description	18 Revenue Related Municipal Tax ($)	19 Revenue Related PUB Assessment ($)	Basis of Proration
	Total Revenue Requirement			
16	1.1 Domestic Diesel	17,604	1,189	
17	1.12 Domestic All Electric	666	45	
18	2.1 GS 0-10 kW	3,156	213	
19	2.2 GS 10-100 kW	8,852	598	
20	2.3 GS 110-1,000 kVa	2,043	138	
21	4.1 Street and Area Lighting	791	53	
22	**Total**	**33,112**	**2,236**	
	Re-classification of Revenue-Related			
23	1.1 Domestic Diesel	(17,604)	(1,189)	Re-classification to demand, energy and customer is based on rate class revenue
24	1.12 Domestic All Electric	(666)	(45)	requirements excluding revenue-related items.
25	2.1 GS 0-10 kW	(3,156)	(213)	
26	2.2 GS 10-100 kW	(8,852)	(598)	
27	2.3 GS 110-1,000 kVa	(2,043)	(138)	
28	4.1 Street and Area Lighting	(791)	(53)	
29	**Total**	**(33,112)**	**(2,236)**	
	Total Allocated Revenue Requirement			
30	1.1 Domestic Diesel	-	-	
31	1.12 Domestic All Electric	-	-	
32	2.1 GS 0-10 kW	-	-	
33	2.2 GS 10-100 kW	-	-	
34	2.3 GS 110-1,000 kVa	-	-	
35	4.1 Street and Area Lighting	-	-	
36	**Total**	-	-	

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Labrador Interconnected
Functional Classification of Revenue Requirement

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Distribution: Substations Demand ($)	7 Distribution: Primary Lines Demand ($)	8 Distribution: Primary Lines Customer ($)	9 Distribution: Line Transformers Demand ($)	10 Distribution: Line Transformers Customer ($)	11 Distribution: Secondary Lines Demand ($)	12 Distribution: Secondary Lines Customer ($)	13 Distribution: Services Customer ($)	14 Distribution: Meters Customer ($)	15 Distribution: Street Lighting Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
	Expenses																
1	Operating & Maintenance	4,294,520	471,049	-	420,358	500,149	657,640	175,418	117,072	207,228	120,879	124,394	103,282	91,168	30,612	1,005,608	145
2	Fuels	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Fuels-Diesel	15,408	15,408	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuels-Gas Turbine	85,682	85,682	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Power Purchases -CF(L)Co	2,433,927	1,094,394	1,339,533	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Power Purchases-Other	106,235	-	-	-	106,235	-	-	-	-	-	-	-	-	-	-	-
7	Depreciation	2,589,389	1,004,888	-	585,356	170,708	303,703	80,314	57,337	101,492	56,331	58,252	48,979	24,731	15,884	81,314	100
	Expense Credits																
8	Sundry	(21,046)	(2,308)	-	(2,060)	(2,451)	(3,223)	(860)	(574)	(1,016)	(592)	(610)	(506)	(447)	(150)	(4,928)	(1)
9	Building Rental Income	(6,828)	(2,273)	-	(1,794)	(682)	(879)	(227)	(151)	(268)	(156)	(161)	(134)	(64)	(40)	-	(0)
10	Tax Refunds	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Suppliers' Discounts	(1,052)	(115)	-	(103)	(123)	(161)	(43)	(29)	(51)	(30)	(30)	(25)	(22)	(8)	(246)	(0)
12	Pole Attachments	(203,476)	-	-	-	-	(117,680)	(40,217)	-	-	(20,829)	(24,749)	-	-	-	-	-
13	Secondary Energy Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Wheeling Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Application Fees	(18,708)	-	-	-	-	-	-	-	-	-	-	-	-	-	(18,708)	-
16	Meter Test Revenues	(25,357)	-	-	-	-	-	-	-	-	-	-	-	(25,357)	-	-	-
17	**Total Expense Credits**	**(276,467)**	**(4,697)**	**-**	**(3,957)**	**(3,255)**	**(121,943)**	**(41,347)**	**(754)**	**(1,334)**	**(21,608)**	**(25,550)**	**(665)**	**(25,890)**	**(197)**	**(23,883)**	**(1)**
18	**Subtotal Expenses**	**9,248,693**	**2,666,724**	**1,339,533**	**1,001,757**	**773,837**	**839,400**	**214,385**	**173,656**	**307,385**	**155,601**	**157,096**	**151,595**	**90,008**	**46,299**	**1,063,039**	**244**
19	Disposal Gain / Loss	17,498	4,749	-	6,076	1,436	1,996	525	393	696	374	383	364	147	119	238	2
20	**Subtotal Revenue Requirement Ex. Return**	**9,266,191**	**2,671,473**	**1,339,533**	**1,007,833**	**775,273**	**841,396**	**214,911**	**174,049**	**308,082**	**155,975**	**157,480**	**151,960**	**90,155**	**46,418**	**1,063,277**	**245**
21	Return on Debt	3,563,415	976,089	-	1,228,215	292,843	406,503	106,950	79,931	141,485	76,020	77,989	73,928	29,977	24,099	49,034	351
22	Return on Equity	590,864	161,849	-	203,655	48,557	67,404	17,734	13,254	23,460	12,605	12,932	12,258	4,971	3,996	8,131	58
23	**Total Revenue Requirement**	**13,420,470**	**3,809,411**	**1,339,533**	**2,439,704**	**1,116,673**	**1,315,303**	**339,594**	**267,234**	**473,026**	**244,600**	**248,400**	**238,146**	**125,103**	**74,513**	**1,120,442**	**655**

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Labrador Interconnected
Functional Classification of Revenue Requirement (CONT'D.)

	1	18	19	20
		Revenue Related		
Line No.	Description	Municipal Tax	PUB Assessment	Basis of Functional Classification
	Expenses			
1	Operating & Maintenance	245,184	24,335	Carryforward from Sch.2.4 L.24
2	Fuels	-	-	
3	Fuels-Diesel	-	-	Production - Demand
4	Fuels-Gas Turbine	-	-	Production - Demand
5	Power Purchases -CF(L)Co	-	-	Carryforward from Sch.4.4 L.8
6	Power Purchases-Other	-	-	Carryforward from Sch.4.4 L.9
7	Depreciation	-	-	Carryforward from Sch.2.5 L.24
	Expense Credits			
8	Sundry	(1,202)	(119)	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.24
9	Building Rental Income	-	-	Prorated on General Plant - Sch.2.2 L.19
10	Tax Refunds	-	-	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.24
11	Suppliers' Discounts	(60)	(6)	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.24
12	Pole Attachments	-	-	Prorated on Distribution Poles - Sch.4.1 L.37
13	Secondary Energy Revenues	-	-	Production - Energy
14	Wheeling Revenues	-	-	Transmission - Demand, Energy ratios Sch.4.1 L.16
15	Application Fees	-	-	Accounting - Customer
16	Meter Test Revenues	-	-	Meters - Customer
17	**Total Expense Credits**	**(1,262)**	**(125)**	
18	**Subtotal Expenses**	**243,922**	**24,210**	
19	Disposal Gain / Loss	-	-	Prorated on Total Net Book Value - Sch.2.3 L.24
20	**Subtotal Revenue Requirement Ex. Return**	**243,922**	**24,210**	
21	Return on Debt	-	-	Prorated on Rate Base - Sch.2.6 L.8
22	Return on Equity	-	-	Prorated on Rate Base - Sch.2.6 L.10
23	**Total Revenue Requirement**	**243,922**	**24,210**	

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Labrador Interconnected
Functional Classification of Plant in Service for the Allocation of O&M Expense

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Distribution: Substations Demand ($)	7 Distribution: Primary Lines Demand ($)	8 Distribution: Primary Lines Customer ($)	9 Distribution: Line Transformers Demand ($)	10 Distribution: Line Transformers Customer ($)	11 Distribution: Secondary Lines Demand ($)	12 Distribution: Secondary Lines Customer ($)	13 Distribution: Services Customer ($)	14 Distribution: Meters Customer ($)	15 Distribution: Street Lighting Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
	Production																
1	Gas Turbines	22,489,284	22,489,284	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Diesel	3,483,441	3,483,441	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	**Subtotal Production**	**25,972,725**	**25,972,725**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
4	Lines	16,538,092	-	-	16,083,896	-	454,196	-	-	-	-	-	-	-	-	-	-
5	Terminal Stations	5,334,238	-	-	4,416,794	912,390	-	-	-	-	-	-	-	-	-	-	5,054
6	**Subtotal Transmission**	**21,872,330**	-	-	**20,500,690**	912,390	454,196	-	-	-	-	-	-	-	-	-	**5,054**
	Distribution																
7	Substations	6,876,688	-	-	-	6,876,688	-	-	-	-	-	-	-	-	-	-	-
8	Land & Land Improvements	412,065	-	-	-	-	310,676	39,579	-	-	36,035	25,775	-	-	-	-	-
9	Poles	11,577,159	-	-	-	-	6,695,627	2,288,249	-	-	1,185,131	1,408,153	-	-	-	-	-
10	Primary Conductor & Eqpt	2,336,007	-	-	-	-	2,072,038	263,969	-	-	-	-	-	-	-	-	-
11	Submarine Conductor	515,827	-	-	-	-	515,827	-	-	-	-	-	-	-	-	-	-
12	Transformers	4,791,523	-	-	-	-	-	-	1,729,740	3,061,783	-	-	-	-	-	-	-
13	Secondary Conductor&Eqpt	968,802	-	-	-	-	-	-	-	-	564,812	403,991	-	-	-	-	-
14	Services	1,525,983	-	-	-	-	-	-	-	-	-	-	1,525,983	-	-	-	-
15	Meters	732,296	-	-	-	-	-	-	-	-	-	-	-	732,296	-	-	-
16	Street Lighting	452,294	-	-	-	-	-	-	-	-	-	-	-	-	452,294	-	-
17	**Subtotal Distribution**	**30,188,644**	-	-	-	6,876,688	**9,594,168**	**2,591,796**	**1,729,740**	**3,061,783**	**1,785,978**	**1,837,918**	**1,525,983**	**732,296**	**452,294**	-	-
18	**Subttl Prod, Trans, & Dist**	**78,033,699**	**25,972,725**	-	**20,500,690**	7,789,077	**10,048,364**	**2,591,796**	**1,729,740**	**3,061,783**	**1,785,978**	**1,837,918**	**1,525,983**	**732,296**	**452,294**	-	**5,054**
19	General	6,431,826	471,138	-	475,038	795,480	1,070,827	286,916	191,485	338,944	197,711	203,461	168,929	163,335	50,070	2,018,302	190
20	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Software - General	68,223	22,707	-	17,923	6,810	8,785	2,266	1,512	2,677	1,561	1,607	1,334	640	395	-	4
23	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	**Total Plant**	**84,533,748**	**26,466,571**	-	**20,993,652**	**8,591,368**	**11,127,975**	**2,880,978**	**1,922,737**	**3,403,404**	**1,985,250**	**2,042,986**	**1,696,246**	**896,272**	**502,759**	**2,018,302**	**5,248**

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Labrador Interconnected
Functional Classification of Plant in Service for the Allocation of O&M Expense (CONT'D.)

Line No.	1 Description	18 Basis of Functional Classification
	Production	
1	Gas Turbines	Production - Demand, Energy ratios Sch.4.1 L.9
2	Diesel	Production - Demand, Energy ratios Sch.4.1 L.9
3	**Subtotal Production**	
	Transmission	
4	Lines	Production, Transmission - Demand; Distribution - Primary Demand; Spec Assigned - Custmr
5	Terminal Stations	Production, Transmission - Demand; Spec Assigned - Custmr
6	**Subtotal Transmission**	
	Distribution	
7	Substations	Production - Demand; Dist Substns - Demand
8	Land & Land Improvements	Primary, Secondary - Demand, Customer - zero intercept ratios Sch.4.1 L.32
9	Poles	Primary, Secondary - Demand, Customer - zero intercept ratios Sch.4.1 L.37
10	Primary Conductor & Eqpt	Primary - Demand, Customer - zero intercept ratios Sch.4.1 L.38
11	Submarine Conductor	Primary - Demand, Customer - zero intercept ratios Sch.4.1 L.39
12	Transformers	Transformers - Demand, Customer - zero intercept ratios Sch.4.1 L.40
13	Secondary Conductor&Eqpt	Secondary - Demand, Customer - zero intercept ratios Sch. 4.1 L.41
14	Services	Services Customer
15	Meters	Meters - Customer
16	Street Lighting	Street Lighting - Customer
17	**Subtotal Distribution**	
18	**Subttl Prod, Trans, & Dist**	
19	General	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - Sch2.4 L.11, 12
20	Telecontrol - Specific	Specifically Assigned - Customer
21	Feasibility Studies	Production, Transmission - Demand
22	Software - General	Prorated on subtotal Production, Transmission, & Distribution plant - L.18
23	Software - Cust Acctng	
24	**Total Plant**	

NEWFOUNDLAND & LABRADOR HYDRO
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Labrador Interconnected
Functional Classification of Net Book Value

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
						Distribution											
				Production and		Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Specifically Assigned
Line No.	Description	Total Amount ($)	Production Demand ($)	Transmission Energy ($)	Transmission Demand ($)	Demand ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)
	Production																
1	Gas Turbines	11,466,748	11,466,748	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Diesel	875,096	875,096	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	**Subtotal Production**	**12,341,844**	**12,341,844**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
4	Lines	12,589,120	-	-	12,459,557	-	129,563	-	-	-	-	-	-	-	-	-	-
5	Terminal Stations	4,272,354	-	-	3,372,393	895,441	-	-	-	-	-	-	-	-	-	-	4,521
6	**Subtotal Transmission**	**16,861,475**	-	-	**15,831,950**	**895,441**	**129,563**	-	-	-	-	-	-	-	-	-	**4,521**
	Distribution																
7	Substations	2,633,357	-	-	-	2,633,357	-	-	-	-	-	-	-	-	-	-	-
8	Land & Land Improvements	145,408	-	-	-	-	109,630	13,966	-	-	12,716	9,095	-	-	-	-	-
9	Poles	5,905,175	-	-	-	-	3,415,246	1,167,170	-	-	604,501	718,258	-	-	-	-	-
10	Primary Conductor & Eqpt	983,949	-	-	-	-	872,763	111,186	-	-	-	-	-	-	-	-	-
11	Submarine Conductor	389,197	-	-	-	-	389,197	-	-	-	-	-	-	-	-	-	-
12	Transformers	2,701,291	-	-	-	-	-	-	975,166	1,726,125	-	-	-	-	-	-	-
13	Secondary Conductor&Eqpt	521,267	-	-	-	-	-	-	-	-	303,898	217,368	-	-	-	-	-
14	Services	905,253	-	-	-	-	-	-	-	-	-	-	905,253	-	-	-	-
15	Meters	335,637	-	-	-	-	-	-	-	-	-	-	-	335,637	-	-	-
16	Street Lighting	297,124	-	-	-	-	-	-	-	-	-	-	-	-	297,124	-	-
17	**Subtotal Distribution**	**14,817,658**	-	-	-	**2,633,357**	**4,786,837**	**1,292,322**	**975,166**	**1,726,125**	**921,115**	**944,722**	**905,253**	**335,637**	**297,124**	-	-
18	**Subttl Prod, Trans, & Dist**	**44,020,977**	**12,341,844**	-	**15,831,950**	**3,528,798**	**4,916,400**	**1,292,322**	**975,166**	**1,726,125**	**921,115**	**944,722**	**905,253**	**335,637**	**297,124**	-	**4,521**
19	General	1,999,503	146,466	-	147,678	247,296	332,895	89,195	59,528	105,370	61,464	63,251	52,516	50,777	15,565	627,442	59
20	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Software - General	51,904	14,552	-	18,667	4,161	5,797	1,524	1,150	2,035	1,086	1,114	1,067	396	350	-	5
23	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	**Total Net Book Value**	**46,072,383**	**12,502,861**	-	**15,998,295**	**3,780,255**	**5,255,092**	**1,383,042**	**1,035,844**	**1,833,530**	**983,665**	**1,009,087**	**958,836**	**386,810**	**313,039**	**627,442**	**4,585**

25-Jul-2003

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Labrador Interconnected
Functional Classification of Operating & Maintenance Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
						Distribution											
						Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Specifically Assigned
Line No.	Description	Total Amount ($)	Production Demand ($)	Production and Transmission Energy ($)	Transmission Demand ($)	Demand ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)
	Production																
1	Gas Turbine / Diesel	123,558	123,558	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Other	28,458	28,458	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	**Subtotal Production**	**152,017**	**152,017**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
4	Transmission Lines	47,654	-	-	46,345	-	1,309	-	-	-	-	-	-	-	-	-	-
5	Terminal Stations	46,816	-	-	38,764	8,008	-	-	-	-	-	-	-	-	-	-	44
6	Other	72,727	-	-	68,166	3,034	1,510	-	-	-	-	-	-	-	-	-	17
7	**Subtotal Transmission**	**167,197**	-	-	**153,275**	**11,041**	**2,819**	-	-	-	-	-	-	-	-	-	**61**
	Distribution																
8	Other	1,052,147	-	-	-	245,627	342,693	92,576	61,784	109,363	63,793	65,648	54,506	-	16,155	-	-
9	Meters	52,702	-	-	-	-	-	-	-	-	-	-	-	52,702	-	-	-
10	**Subtotal Distribution**	**1,104,849**	-	-	-	**245,627**	**342,693**	**92,576**	**61,784**	**109,363**	**63,793**	**65,648**	**54,506**	**52,702**	**16,155**	-	-
11	**Subttl Prod, Trans, & Dist**	**1,424,062**	**152,017**	-	**153,275**	**256,669**	**345,512**	**92,576**	**61,784**	**109,363**	**63,793**	**65,648**	**54,506**	**52,702**	**16,155**	-	**61**
12	Customer Accounting	651,223	-	-	-	-	-	-	-	-	-	-	-	-	-	651,223	-
	Administrative & General:																
	Plant-Related:																
13	Production	58,172	58,172	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Transmission	66,372	-	-	62,209	2,769	1,378	-	-	-	-	-	-	-	-	-	15
15	Distribution	187,587	-	-	-	42,731	59,617	16,105	10,748	19,025	11,098	11,421	9,482	4,550	2,810	-	-
16	Prod, Trans, Distn Plant	66,148	22,017	-	17,378	6,603	8,518	2,197	1,466	2,595	1,514	1,558	1,294	621	383	-	4
17	Prod, Trans, Distn & General Plt	391,675	122,629	-	97,271	39,807	51,560	13,349	8,909	15,769	9,198	9,466	7,859	4,153	2,329	9,352	24
18	Property Insurance	55,235	32,738	-	6,056	10,628	1,326	355	237	420	245	252	209	202	62	2,499	6
	Revenue-Related:																
19	Municipal Tax	245,184	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	PUB Assessment	24,335	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	All Expense-Related	1,091,572	79,959	-	80,621	135,004	181,735	48,694	32,498	57,524	33,554	34,530	28,670	27,720	8,498	342,535	32
22	Prod,Trans & Distn Expense-Related	32,955	3,518	-	3,547	5,940	7,996	2,142	1,430	2,531	1,476	1,519	1,261	1,220	374	-	1
23	**Subtotal Admin & General**	**2,219,235**	**319,032**	-	**267,083**	**243,481**	**312,128**	**82,842**	**55,288**	**97,864**	**57,085**	**58,746**	**48,775**	**38,466**	**14,457**	**354,385**	**84**
24	**Total Operating & Maintenance Expenses**	**4,294,520**	**471,049**	-	**420,358**	**500,149**	**657,640**	**175,418**	**117,072**	**207,228**	**120,879**	**124,394**	**103,282**	**91,168**	**30,612**	**1,005,608**	**145**

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Labrador Interconnected
Functional Classification of Operating & Maintenance Expense (CONT'D.)

	1	18	19	20
		Revenue Related		
Line No.	Description	Municipal Tax	PUB Assessment	Basis of Functional Classification
	Production			
1	Gas Turbine / Diesel	-	-	Production - Demand, Energy ratios Sch.4.1 L.9
2	Other	-	-	Production - Demand, Energy ratios Sch.4.1 L.9
3	**Subtotal Production**	-	-	
	Transmission			
4	Transmission Lines	-	-	Prorated on Transmission Lines Plant in Service - Sch.2.2 L.4
5	Terminal Stations	-	-	Prorated on Transmission Terminal Stations Plant in Service - Sch.2.2 L.5
6	Other	-	-	Prorated on Transmission Plant in Service - Sch.2.2 L.6
7	**Subtotal Transmission**	-	-	
	Distribution			
8	Other	-	-	Prorated on Distribution Plant, excluding Meters - Sch. 2.2 L. 17, less L. 15
9	Meters	-	-	Meters - Customer
10	**Subtotal Distribution**	-	-	
11	**Subttl Prod, Trans, & Dist**	-	-	
12	Customer Accounting	-	-	Accounting - Customer
	Administrative & General:			
	Plant-Related:			
13	Production	-	-	Prorated on Production Plant in Service - Sch.2.2 L.3
14	Transmission	-	-	Prorated on Transmission Plant in Service - Sch.2.2 L. 6
15	Distribution	-	-	Prorated on Distribution Plant in Service - Sch.2.2 L.17
16	Prod, Trans, Distn Plant	-	-	Prorated on Production, Transmission, Distribution Plant in Service - Sch.2.2 L. 18
17	Prod, Trans, Distn & General Plt	-	-	Prorated on Production, Transmission, Distribution & General Plant in Service - Sch.2.2 L.24
18	Property Insurance	-	-	Prorated on Prod., Trans. Terminal, Dist. Sub & General Plant in Service - Sch.2.2 L.3, 5, 7, 19 - 20
	Revenue-Related:			
19	Municipal Tax	245,184	-	Revenue-related
20	PUB Assessment	-	24,335	Revenue-related
21	All Expense-Related	-	-	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - L 11, 12
22	Prod,Trans & Distn Expense-Related	-	-	Prorated on Subtotal Production, Transmission, Distribution Expenses - L.11
23	**Subtotal Admin & General**	**245,184**	**24,335**	
24	**Total Operating & Maintenance Expenses**	**245,184**	**24,335**	

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Labrador Interconnected
Functional Classification of Depreciation Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
				Production and		Distribution											Specifically
Line		Total	Production	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
	Production																
1	Gas Turbines	901,529	901,529	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Diesel	59,314	59,314	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	**Subtotal Production**	**960,843**	**960,843**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
4	Lines	456,030	-	-	441,062	-	14,967	-	-	-	-	-	-	-	-	-	-
5	Terminal Stations	113,876	-	-	110,761	3,025	-	-	-	-	-	-	-	-	-	-	90
6	**Subtotal Transmission**	**569,905**	-	-	**551,823**	**3,025**	**14,967**	-	-	-	-	-	-	-	-	-	**90**
	Distribution																
7	Substations	132,110	-	-	-	132,110	-	-	-	-	-	-	-	-	-	-	-
8	Land & Land Improvements	6,581	-	-	-	-	4,962	632	-	-	576	412	-	-	-	-	-
9	Poles	311,255	-	-	-	-	180,014	61,520	-	-	31,863	37,859	-	-	-	-	-
10	Primary Conductor & Eqpt	42,964	-	-	-	-	38,109	4,855	-	-	-	-	-	-	-	-	-
11	Submarine Conductor	15,886	-	-	-	-	15,886	-	-	-	-	-	-	-	-	-	-
12	Transformers	133,965	-	-	-	-	-	-	48,361	85,604	-	-	-	-	-	-	-
13	Secondary Conductor&Eqpt	25,210	-	-	-	-	-	-	-	-	14,698	10,513	-	-	-	-	-
14	Services	41,101	-	-	-	-	-	-	-	-	-	-	41,101	-	-	-	-
15	Meters	17,689	-	-	-	-	-	-	-	-	-	-	-	17,689	-	-	-
16	Street Lighting	13,514	-	-	-	-	-	-	-	-	-	-	-	-	13,514	-	-
17	**Subtotal Distribution**	**740,274**	-	-	-	**132,110**	**238,970**	**67,007**	**48,361**	**85,604**	**47,136**	**48,783**	**41,101**	**17,689**	**13,514**	-	-
18	**Subttl Prod, Trans, & Dist**	**2,271,023**	**960,843**	-	**551,823**	**135,135**	**253,938**	**67,007**	**48,361**	**85,604**	**47,136**	**48,783**	**41,101**	**17,689**	**13,514**	-	**90**
19	General	259,126	18,981	-	19,138	32,048	43,142	11,559	7,715	13,655	7,965	8,197	6,806	6,580	2,017	81,314	8
20	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Software - General	59,239	25,064	-	14,394	3,525	6,624	1,748	1,262	2,233	1,230	1,272	1,072	461	353	-	2
23	Software - Cust Accctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	**Total Depreciation Expense**	**2,589,389**	**1,004,888**	-	**585,356**	**170,708**	**303,703**	**80,314**	**57,337**	**101,492**	**56,331**	**58,252**	**48,979**	**24,731**	**15,884**	**81,314**	**100**

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Labrador Interconnected
Functional Classification of Rate Base

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
						Distribution											
				Production and		Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Specifically
Line No.	Description	Total Amount ($)	Production Demand ($)	Transmission Energy ($)	Transmission Demand ($)	Demand ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Assigned Customer ($)
1	Average Net Book Value	46,072,383	12,502,861	-	15,998,295	3,780,255	5,255,092	1,383,042	1,035,844	1,833,530	983,665	1,009,087	958,836	386,810	313,039	627,442	4,585
2	Cash Working Capital	103,090	27,976	-	35,797	8,459	11,759	3,095	2,318	4,103	2,201	2,258	2,145	866	700	1,404	10
3	Fuel Inventory - No. 6 Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuel Inventory - Diesel	38,151	38,151	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Fuel Inventory - Gas Turbine	87,188	87,188	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Inventory/Supplies	856,571	268,183	-	212,726	87,055	112,759	29,193	19,483	34,486	20,116	20,701	17,188	9,082	5,094	20,451	53
7	Deferred Charges: Foreign Exchange Loss and Regulatory Costs	2,761,417	749,378	-	958,882	226,575	314,972	82,895	62,085	109,895	58,957	60,481	57,469	23,184	18,762	37,607	275
8	Total Rate Base	**49,918,801**	**13,673,737**	**-**	**17,205,701**	**4,102,344**	**5,694,581**	**1,498,224**	**1,119,730**	**1,982,015**	**1,064,940**	**1,092,527**	**1,035,639**	**419,942**	**337,597**	**686,904**	**4,923**
9	Less: Rural Portion	-															
10	Rate Base Available for Equity Return	**49,918,801**	**13,673,737**	**-**	**17,205,701**	**4,102,344**	**5,694,581**	**1,498,224**	**1,119,730**	**1,982,015**	**1,064,940**	**1,092,527**	**1,035,639**	**419,942**	**337,597**	**686,904**	**4,923**
11	Return on Debt	3,563,415	976,089	-	1,228,215	292,843	406,503	106,950	79,931	141,485	76,020	77,989	73,928	29,977	24,099	49,034	351
12	Return on Equity	590,864	161,849	-	203,655	48,557	67,404	17,734	13,254	23,460	12,605	12,932	12,258	4,971	3,996	8,131	58
13	Return on Rate Base	**4,154,278**	**1,137,938**	**-**	**1,431,871**	**341,400**	**473,907**	**124,683**	**93,185**	**164,945**	**88,625**	**90,921**	**86,187**	**34,948**	**28,095**	**57,165**	**410**

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Labrador Interconnected
Functional Classification of Rate Base (CONT'D.)

	1	18
Line No.	Description	Basis of Functional Classification
1	Average Net Book Value	Sch. 2.3 , L. 24
2	Cash Working Capital	Prorated on Average Net Book Value, L. 1
3	Fuel Inventory - No. 6 Fuel	
4	Fuel Inventory - Diesel	Production - Demand
5	Fuel Inventory - Gas Turbine	Production - Demand
6	Inventory/Supplies	Prorated on Total Plant in Service, Sch. 2.2, L. 24
7	Deferred Charges: Foreign Exchange Loss and Regulatory Costs	Prorated on Average Net Book Value, L. 1
8	Total Rate Base	
9	Less: Rural Portion	
10	Rate Base Available for Equity Return	
11	Return on Debt	L.8 x Sch.1.1,p2,L.13
12	Return on Equity	L.10 x Sch.1.1,p2,L.16
13	Return on Rate Base	

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Labrador Interconnected
Basis of Allocation to Classes of Service

Line No.	1 Description	2 Total Amount	3 Production Demand	4 Production and Transmission Energy	5 Transmission Demand	6 Distribution Substations Demand	7 Primary Lines Demand	8 Primary Lines Customer	9 Line Transformers Demand	10 Line Transformers Customer	11 Secondary Lines Demand	12 Secondary Lines Customer	13 Services Customer	14 Meters Customer	15 Street Lighting Customer	16 Accounting Customer	17 Specifically Assigned Customer
	Amounts		(CP kW)	(MWh @ Gen)	(CP kW)	(CP kW)	(CP kW)	(Rural Cust)	(CP kW)	(Rural Cust)	(CP kW)	(Rural Cust)	(Wtd Rural Cust)			(Rural Cust)	
1	CFB - Goose Bay Secondary	-	-	87,442	-	-	-	1	-	1	-	1	-	-	-	1	1
2	IOCC Firm	-	70,231	280,561	62,000	-	-	-	-	-	-	-	-	-	-	-	-
3	IOCC Non-Firm	-	-	4,531	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																
4	1.1Domestic	-	2,466	10,166	2,177	2,090	2,090	712	1,959	712	1,959	712	712	712	-	712	-
5	1.1A Domestic All Electric	-	74,423	309,916	65,701	63,076	63,076	7,143	59,120	7,143	59,120	7,143	7,143	7,143		7,143	
6	2.1GS 0-10 kW	-	849	4,773	750	720	720	399	675	399	675	399	798	798	-	399	-
7	2.2GS 10-100 kW	-	12,865	68,184	11,358	10,904	10,904	609	8,885	609	8,885	609	4,917	4,917	-	609	-
8	2.3GS 110-1,000 kVa	-	21,093	102,116	18,621	17,877	17,877	122	14,640	122	14,640	122	1,044	1,044	-	122	-
9	2.4GS Over 1,000 kVa	-	13,661	78,217	12,060	11,578	11,578	6	10,852	6	10,852	6	51	51	-	6	-
10	4.1Street and Area Lighting	-	447	1,796	395	379	379	277	355	277	355	277	-	-	1	277	-
11	**Subtotal Rural**		**125,804**	**575,167**	**111,060**	**106,623**	**106,623**	**9,268**	**96,484**	**9,268**	**96,484**	**9,268**	**14,666**	**14,666**	**1**	**9,268**	**-**
12	**Total Labrador Interconnected**		**196,035**	**947,700**	**173,060**	**106,623**	**106,623**	**9,269**	**96,484**	**9,269**	**96,484**	**9,269**	**14,666**	**14,666**	**1**	**9,269**	**1**
	Ratios																
13	CFB - Goose Bay Boiler	-	-	0.0923	-	-	-	0.0001	-	0.0001	-	0.0001	-	-	-	0.0001	1.0000
14	IOCC Firm	-	0.3583	0.2960	0.3583	-	-	-	-	-	-	-	-	-	-	-	-
15	IOCC Non-Firm	-	-	0.0048	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																
16	1.1Domestic	-	0.0126	0.0107	0.0126	0.0196	0.0196	0.0768	0.0203	0.0768	0.0203	0.0768	0.0485	0.0485	-	0.0768	-
17	1.1A Domestic All Electric	-	0.3796	0.3270	0.3796	0.5916	0.5916	0.7706	0.6127	0.7706	0.6127	0.7706	0.4871	0.4871	-	0.7706	-
18	2.1GS 0-10 kW	-	0.0043	0.0050	0.0043	0.0067	0.0067	0.0430	0.0070	0.0430	0.0070	0.0430	0.0544	0.0544	-	0.0430	-
19	2.2GS 10-100 kW	-	0.0656	0.0719	0.0656	0.1023	0.1023	0.0657	0.0921	0.0657	0.0921	0.0657	0.3353	0.3353	-	0.0657	-
20	2.3GS 110-1,000 kVa	-	0.1076	0.1078	0.1076	0.1677	0.1677	0.0131	0.1517	0.0131	0.1517	0.0131	0.0712	0.0712	-	0.0131	-
21	2.4GS Over 1,000 kVa	-	0.0697	0.0825	0.0697	0.1086	0.1086	0.0006	0.1125	0.0006	0.1125	0.0006	0.0035	0.0035	-	0.0006	-
22	4.1Street and Area Lighting	-	0.0023	0.0019	0.0023	0.0036	0.0036	0.0299	0.0037	0.0299	0.0037	0.0299	-	-	1.0000	0.0299	-
23	**Subtotal Rural**		**0.6417**	**0.6069**	**0.6417**	**1.0000**	**1.0000**	**0.9999**	**1.0000**	**0.9999**	**1.0000**	**0.9999**	**1.0000**	**1.0000**	**1.0000**	**0.9999**	**-**
24	**Total Labrador Interconnected**		**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**
	Ratios Excluding IOCC																
25	CFB - Goose Bay Boiler	-	-	0.1320	-	-	-	0.0001	-	0.0001	-	0.0001	-	-	-	0.0001	1.0000
	Rural																
26	1.1Domestic	-	0.0196	0.0153	0.0196	0.0196	0.0196	0.0768	0.0203	0.0768	0.0203	0.0768	0.0485	0.0485	-	0.0768	-
27	1.1A Domestic All Electric	-	0.5916	0.4677	0.5916	0.5916	0.5916	0.7706	0.6127	0.7706	0.6127	0.7706	0.4871	0.4871	-	0.7706	-
28	2.1GS 0-10 kW	-	0.0067	0.0072	0.0067	0.0067	0.0067	0.0430	0.0070	0.0430	0.0070	0.0430	0.0544	0.0544	-	0.0430	-
29	2.2GS 10-100 kW	-	0.1023	0.1029	0.1023	0.1023	0.1023	0.0657	0.0921	0.0657	0.0921	0.0657	0.3353	0.3353	-	0.0657	-
30	2.3GS 110-1,000 kVa	-	0.1677	0.1541	0.1677	0.1677	0.1677	0.0131	0.1517	0.0131	0.1517	0.0131	0.0712	0.0712	-	0.0131	-
31	2.4GS Over 1,000 kVa	-	0.1086	0.1180	0.1086	0.1086	0.1086	0.0006	0.1125	0.0006	0.1125	0.0006	0.0035	0.0035	-	0.0006	-
32	4.1Street and Area Lighting	-	0.0036	0.0027	0.0036	0.0036	0.0036	0.0299	0.0037	0.0299	0.0037	0.0299	-	-	1.0000	0.0299	-
33	**Subtotal Rural**		**1.0000**	**0.8680**	**1.0000**	**1.0000**	**1.0000**	**0.9999**	**1.0000**	**0.9999**	**1.0000**	**0.9999**	**1.0000**	**1.0000**	**1.0000**	**0.9999**	**-**
34	**Total Labrador Interconnected**		**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Labrador Interconnected
Basis of Allocation to Classes of Service (CONT'D.)

Line No.		18	19
		Revenue Related	
		Municipal Tax (Prior Year (Rural Revenues)	PUB Assessment (Prior Year (Revenues + RSP)
	Amounts		
1	CFB - Goose Bay Secondary	-	3,363,030
2	IOCC Firm	-	-
3	IOCC Non-Firm	-	-
	Rural		
4	1.1Domestic	206,586	206,586
5	1.1A Domestic All Electric	5,560,637	5,560,637
6	2.1GS 0-10 kW	148,782	148,782
7	2.2GS 10-100 kW	1,650,655	1,650,655
8	2.3GS 110-1,000 kVa	2,173,122	2,173,122
9	2.4GS Over 1,000 kVa	186,109	1,567,094
10	4.1Street and Area Lighting	178,320	178,320
11	**Subtotal Rural**	**10,104,211**	**11,485,196**
12	**Total Labrador Interconnected**	**10,104,211**	**14,848,226**
	Ratios		
13	CFB - Goose Bay Boiler	-	0.2265
14	IOCC Firm	-	-
15	IOCC Non-Firm	-	-
	Rural		
16	1.1Domestic	0.0204	0.0139
17	1.1A Domestic All Electric	0.5503	0.3745
18	2.1GS 0-10 kW	0.0147	0.0100
19	2.2GS 10-100 kW	0.1634	0.1112
20	2.3GS 110-1,000 kVa	0.2151	0.1464
21	2.4GS Over 1,000 kVa	0.0184	0.1055
22	4.1Street and Area Lighting	0.0176	0.0120
23	**Subtotal Rural**	**1.0000**	**0.7735**
24	**Total Labrador Interconnected**	**1.0000**	**1.0000**
	Ratios Excluding IOCC		
25	CFB - Goose Bay Boiler	-	0.2265
	Rural		
26	1.1Domestic	0.0204	0.0139
27	1.1A Domestic All Electric	0.5503	0.3745
28	2.1GS 0-10 kW	0.0147	0.0100
29	2.2GS 10-100 kW	0.1634	0.1112
30	2.3GS 110-1,000 kVa	0.2151	0.1464
31	2.4GS Over 1,000 kVa	0.0184	0.1055
32	4.1Street and Area Lighting	0.0176	0.0120
33	**Subtotal Rural**	**1.0000**	**0.7735**
34	**Total Labrador Interconnected**	**1.0000**	**1.0000**

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Labrador Interconnected
Allocation of Functionalized Amounts to Classes of Service

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Distribution: Substations Demand ($)	7 Distribution: Primary Lines Demand ($)	8 Distribution: Primary Lines Customer ($)	9 Distribution: Line Transformers Demand ($)	10 Distribution: Line Transformers Customer ($)	11 Distribution: Secondary Lines Demand ($)	12 Distribution: Secondary Lines Customer ($)	13 Distribution: Services Customer ($)	14 Distribution: Meters Customer ($)	15 Distribution: Street Lighting Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
	Allocated Rev Reqmt Excl Return																
1	CFB - Goose Bay Boiler	129,512	-	123,595	-	-	-	23	-	33	-	17	-	-	-	115	245
2	IOCC Firm	1,714,697	957,073	396,561	361,063	-	-	-	-	-	-	-	-	-	-	-	-
3	IOCC Non-Firm	6,404	-	6,404	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural:																
4	1.1Domestic	250,063	33,604	14,369	12,677	15,196	16,492	16,508	3,534	23,665	3,167	12,097	7,378	4,377	-	81,676	-
5	1.1A Domestic All Electric	4,598,489	1,014,199	438,053	382,614	458,634	497,751	165,617	106,647	237,418	95,572	121,359	74,014	43,911	-	819,397	-
6	2.1GS 0-10 kW	127,974	11,572	6,746	4,366	5,233	5,679	9,251	1,217	13,262	1,090	6,779	8,269	4,906	-	45,771	-
7	2.2GS 10-100 kW	771,890	175,323	96,376	66,142	79,283	86,045	14,125	16,028	20,249	14,363	10,351	50,951	30,229	-	69,886	-
8	2.3GS 110-1,000 kVa	957,519	287,452	144,336	108,443	129,990	141,076	2,824	26,409	4,048	23,666	2,069	10,816	6,417	-	13,970	-
9	2.4GS Over 1,000 kVa	588,636	186,159	110,556	70,230	84,184	91,364	139	19,575	199	17,542	102	533	316	-	688	-
10	4.1Street and Area Lighting	121,007	6,090	2,538	2,298	2,754	2,989	6,423	640	9,207	574	4,706	-	-	46,418	31,776	-
11	**Subtotal Rural**	**7,415,578**	**1,714,399**	**812,973**	**646,770**	**775,273**	**841,396**	**214,888**	**174,049**	**308,048**	**155,975**	**157,463**	**151,960**	**90,155**	**46,418**	**1,063,162**	**-**
12	**Total**	**9,266,191**	**2,671,473**	**1,339,533**	**1,007,833**	**775,273**	**841,396**	**214,911**	**174,049**	**308,082**	**155,975**	**157,480**	**151,960**	**90,155**	**46,418**	**1,063,277**	**245**
	Allocated Return on Debt																
13	CFB - Goose Bay Boiler	392	-	-	-	-	-	12	-	15	-	8	-	-	-	5	351
14	IOCC Firm	789,707	349,691	-	440,017	-	-	-	-	-	-	-	-	-	-	-	-
15	IOCC Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural:																
16	1.1Domestic	78,487	12,278	-	15,449	5,740	7,968	8,215	1,623	10,868	1,543	5,991	3,589	1,455	-	3,767	-
17	1.1A Domestic All Electric	1,686,065	370,563	-	466,280	173,239	240,478	82,419	48,977	109,033	46,580	60,101	36,008	14,601	-	37,787	-
18	2.1GS 0-10 kW	37,175	4,228	-	5,320	1,977	2,744	4,604	559	6,090	531	3,357	4,023	1,631	-	2,111	-
19	2.2GS 10-100 kW	290,060	64,059	-	80,605	29,947	41,571	7,029	7,361	9,299	7,001	5,126	24,788	10,051	-	3,223	-
20	2.3GS 110-1,000 kVa	390,434	105,028	-	132,157	49,101	68,158	1,405	12,128	1,859	11,535	1,025	5,262	2,134	-	644	-
21	2.4GS Over 1,000 kVa	247,691	68,018	-	85,587	31,799	44,140	69	8,990	92	8,550	50	259	105	-	32	-
22	4.1Street and Area Lighting	43,403	2,225	-	2,800	1,040	1,444	3,196	294	4,228	280	2,331	-	-	24,099	1,465	-
23	**Subtotal Rural**	**2,773,315**	**626,398**	**-**	**788,199**	**292,843**	**406,503**	**106,938**	**79,931**	**141,469**	**76,020**	**77,981**	**73,928**	**29,977**	**24,099**	**49,029**	**-**
24	**Total**	**3,563,415**	**976,089**	**-**	**1,228,215**	**292,843**	**406,503**	**106,950**	**79,931**	**141,485**	**76,020**	**77,989**	**73,928**	**29,977**	**24,099**	**49,034**	**351**
	Allocated Return on Equity																
25	CFB - Goose Bay Boiler	65	-	-	-	-	-	2	-	3	-	1	-	-	-	1	58
26	IOCC Firm	130,944	57,984	-	72,961	-	-	-	-	-	-	-	-	-	-	-	-
27	IOCC Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural:																
28	1.1Domestic	13,014	2,036	-	2,562	952	1,321	1,362	269	1,802	256	993	595	241	-	625	-
29	1.1A Domestic All Electric	279,573	61,445	-	77,316	28,725	39,875	13,666	8,121	18,079	7,724	9,966	5,971	2,421	-	6,266	-
30	2.1GS 0-10 kW	6,164	701	-	882	328	455	763	93	1,010	88	557	667	270	-	350	-
31	2.2GS 10-100 kW	48,096	10,622	-	13,365	4,966	6,893	1,166	1,221	1,542	1,161	850	4,110	1,667	-	534	-
32	2.3GS 110-1,000 kVa	64,739	17,415	-	21,913	8,142	11,302	233	2,011	308	1,913	170	872	354	-	107	-
33	2.4GS Over 1,000 kVa	41,071	11,278	-	14,192	5,273	7,319	11	1,491	15	1,418	8	43	17	-	5	-
34	4.1Street and Area Lighting	7,197	369	-	464	172	239	530	49	701	46	386	-	-	3,996	243	-
35	**Subtotal Rural**	**459,854**	**103,866**	**-**	**130,694**	**48,557**	**67,404**	**17,732**	**13,254**	**23,458**	**12,605**	**12,930**	**12,258**	**4,971**	**3,996**	**8,130**	**-**
36	**Total**	**590,864**	**161,849**	**-**	**203,655**	**48,557**	**67,404**	**17,734**	**13,254**	**23,460**	**12,605**	**12,932**	**12,258**	**4,971**	**3,996**	**8,131**	**58**

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NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Labrador Interconnected
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

	1	18	19	
		Revenue Related		
Line		Municipal	PUB	
No.	Description	Tax	Assessment	Basis of Proration
	Allocated Rev Reqmt Excl Return	($)	($)	
1	CFB - Goose Bay Boiler	-	5,483	
2	IOCC Firm	-	-	
3	IOCC Non-Firm	-	-	
	Rural:			
4	1.1Domestic	4,987	337	
5	1.1A Domestic All Electric	134,237	9,067	
6	2.1GS 0-10 kW	3,592	243	
7	2.2GS 10-100 kW	39,848	2,691	
8	2.3GS 110-1,000 kVa	52,461	3,543	
9	2.4GS Over 1,000 kVa	4,493	2,555	
10	4.1Street and Area Lighting	4,305	291	
11	**Subtotal Rural**	**243,922**	**18,727**	
12	**Total**	**243,922**	**24,210**	
	Allocated Return on Debt			
13	CFB - Goose Bay Boiler	-	-	
14	IOCC Firm	-	-	
15	IOCC Non-Firm	-	-	
	Rural:			
16	1.1Domestic	-	-	
17	1.1A Domestic All Electric	-	-	
18	2.1GS 0-10 kW	-	-	
19	2.2GS 10-100 kW	-	-	
20	2.3GS 110-1,000 kVa	-	-	
21	2.4GS Over 1,000 kVa	-	-	
22	4.1Street and Area Lighting	-	-	
23	**Subtotal Rural**	-	-	
24	**Total**	-	-	
	Allocated Return on Equity			
25	CFB - Goose Bay Boiler	-	-	
26	IOCC Firm	-	-	
27	IOCC Non-Firm	-	-	
	Rural:			
28	1.1Domestic	-	-	
29	1.1A Domestic All Electric	-	-	
30	2.1GS 0-10 kW	-	-	
31	2.2GS 10-100 kW	-	-	
32	2.3GS 110-1,000 kVa	-	-	
33	2.4GS Over 1,000 kVa	-	-	
34	4.1Street and Area Lighting	-	-	
35	**Subtotal Rural**	-	-	
36	**Total**	-	-	

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Labrador Interconnected
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Distribution: Substations Demand ($)	7 Distribution: Primary Lines Demand ($)	8 Distribution: Primary Lines Customer ($)	9 Distribution: Line Transformers Demand ($)	10 Distribution: Line Transformers Customer ($)	11 Distribution: Secondary Lines Demand ($)	12 Distribution: Secondary Lines Customer ($)	13 Distribution: Services Customer ($)	14 Distribution: Meters Customer ($)	15 Distribution: Street Lighting Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
	Total Revenue Requirement																
37	CFB - Goose Bay Boiler	129,969	-	123,595	-	-	-	37	-	51	-	27	-	-	-	121	655
38	IOCC Firm	2,635,349	1,364,748	396,561	874,041	-	-	-	-	-	-	-	-	-	-	-	-
39	IOCC Non-Firm	6,404	-	6,404	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural:																
40	1.1Domestic	341,564	47,918	14,369	30,688	21,888	25,781	26,086	5,425	36,336	4,966	19,081	11,562	6,074	-	86,067	-
41	1.1A Domestic All Electric	6,564,127	1,446,207	438,053	926,210	660,598	778,103	261,702	163,744	364,530	149,876	191,426	115,992	60,933	-	863,450	-
42	2.1GS 0-10 kW	171,313	16,501	6,746	10,568	7,537	8,878	14,618	1,868	20,362	1,710	10,693	12,958	6,807	-	48,231	-
43	2.2GS 10-100 kW	1,110,046	250,003	96,376	160,112	114,196	134,509	22,320	24,609	31,090	22,525	16,327	79,849	41,946	-	73,643	-
44	2.3GS 110-1,000 kVa	1,412,693	409,895	144,336	262,514	187,232	220,536	4,462	40,548	6,215	37,113	3,264	16,950	8,904	-	14,721	-
45	2.4GS Over 1,000 kVa	877,398	265,456	110,556	170,009	121,255	142,823	220	30,056	306	27,510	161	835	439	-	725	-
46	4.1Street and Area Lighting	171,606	8,684	2,538	5,562	3,967	4,672	10,149	983	14,136	900	7,423	-	-	74,513	33,484	-
47	**Subtotal Rural**	**10,648,748**	**2,444,663**	**812,973**	**1,565,663**	**1,116,673**	**1,315,303**	**339,557**	**267,234**	**472,975**	**244,600**	**248,374**	**238,146**	**125,103**	**74,513**	**1,120,321**	**-**
48	**Total**	**13,420,470**	**3,809,411**	**1,339,533**	**2,439,704**	**1,116,673**	**1,315,303**	**339,594**	**267,234**	**473,026**	**244,600**	**248,400**	**238,146**	**125,103**	**74,513**	**1,120,442**	**655**
	Re-classification of Revenue-Related																
49	CFB - Goose Bay Boiler	-	-	5,444	-	-	-	2	-	2	-	1	-	-	-	5	29
50	IOCC Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
51	IOCC Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural:																
52	1.1Domestic	-	759	228	486	347	408	413	86	575	79	302	183	96	-	1,363	-
53	1.1A Domestic All Electric	0	32,277	9,777	20,672	14,744	17,366	5,841	3,655	8,136	3,345	4,272	2,589	1,360	-	19,271	-
54	2.1GS 0-10 kW	-	378	154	242	173	203	335	43	466	39	245	297	156	-	1,104	-
55	2.2GS 10-100 kW	0	9,962	3,840	6,380	4,551	5,360	889	981	1,239	898	651	3,182	1,672	-	2,935	-
56	2.3GS 110-1,000 kVa	(0)	16,920	5,958	10,837	7,729	9,104	184	1,674	257	1,532	135	700	368	-	608	-
57	2.4GS Over 1,000 kVa	-	2,150	895	1,377	982	1,157	2	243	2	223	1	7	4	-	6	-
58	4.1Street and Area Lighting	0	239	70	153	109	129	279	27	389	25	204	-	-	2,050	921	-
59	**Subtotal Rural**	**-**	**62,685**	**20,922**	**40,146**	**28,633**	**33,727**	**7,943**	**6,708**	**11,064**	**6,140**	**5,810**	**6,957**	**3,655**	**2,050**	**26,208**	**-**
60	**Total**	**0**	**62,685**	**26,367**	**40,146**	**28,633**	**33,727**	**7,945**	**6,708**	**11,066**	**6,140**	**5,811**	**6,957**	**3,655**	**2,050**	**26,213**	**29**
	Total Allocated Revenue Requirement																
61	CFB - Goose Bay Boiler	129,969	-	129,039	-	-	-	38	-	53	-	28	-	-	-	126	684
62	IOCC Firm	2,635,349	1,364,748	396,561	874,041	-	-	-	-	-	-	-	-	-	-	-	-
63	IOCC Non-Firm	6,404	-	6,404	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural:		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
64	1.1Domestic	341,564	48,676	14,596	31,174	22,234	26,189	26,499	5,511	36,911	5,045	19,383	11,745	6,170	-	87,430	-
65	1.1A Domestic All Electric	6,564,127	1,478,484	447,830	946,882	675,342	795,469	267,543	167,399	372,666	153,221	195,698	118,580	62,293	-	882,721	-
66	2.1GS 0-10 kW	171,313	16,879	6,901	10,810	7,710	9,081	14,953	1,911	20,828	1,749	10,938	13,255	6,963	-	49,336	-
67	2.2GS 10-100 kW	1,110,046	259,965	100,216	166,493	118,747	139,869	23,210	25,590	32,329	23,422	16,977	83,031	43,618	-	76,578	-
68	2.3GS 110-1,000 kVa	1,412,693	426,816	150,294	273,350	194,961	229,640	4,646	42,221	6,471	38,645	3,398	17,650	9,272	-	15,328	-
69	2.4GS Over 1,000 kVa	877,398	267,605	111,451	171,385	122,237	143,980	222	30,299	309	27,733	162	842	442	-	731	-
70	4.1Street and Area Lighting	171,606	8,923	2,608	5,715	4,076	4,801	10,428	1,010	14,525	925	7,628	-	-	76,563	34,405	-
71	**Subtotal Rural**	**10,648,748**	**2,507,349**	**833,896**	**1,605,809**	**1,145,307**	**1,349,030**	**347,501**	**273,942**	**484,040**	**250,740**	**254,184**	**245,103**	**128,758**	**76,563**	**1,146,528**	**-**
72	**Total**	**13,420,470**	**3,872,096**	**1,365,900**	**2,479,850**	**1,145,307**	**1,349,030**	**347,539**	**273,942**	**484,093**	**250,740**	**254,212**	**245,103**	**128,758**	**76,563**	**1,146,655**	**684**

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Labrador Interconnected
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

	1	18	19	
		Revenue Related		
Line No.	Description	Municipal Tax ($)	PUB Assessment ($)	Basis of Proration
	Total Revenue Requirement			
37	CFB - Goose Bay Boiler	-	5,483	
38	IOCC Firm	-	-	
39	IOCC Non-Firm	-	-	
	Rural:			
40	1.1Domestic	4,987	337	
41	1.1A Domestic All Electric	134,237	9,067	
42	2.1GS 0-10 kW	3,592	243	
43	2.2GS 10-100 kW	39,848	2,691	
44	2.3GS 110-1,000 kVa	52,461	3,543	
45	2.4GS Over 1,000 kVa	4,493	2,555	
46	4.1Street and Area Lighting	4,305	291	
47	**Subtotal Rural**	**243,922**	**18,727**	
48	**Total**	**243,922**	**24,210**	
	Re-classification of Revenue-Related			
49	CFB - Goose Bay Boiler	-	(5,483)	Re-classification to demand, energy and customer is based on rate class revenue requirements excluding revenue-related items.
50	IOCC Firm	-	-	
51	IOCC Non-Firm	-	-	
	Rural:			
52	1.1Domestic	(4,987)	(337)	
53	1.1A Domestic All Electric	(134,237)	(9,067)	
54	2.1GS 0-10 kW	(3,592)	(243)	
55	2.2GS 10-100 kW	(39,848)	(2,691)	
56	2.3GS 110-1,000 kVa	(52,461)	(3,543)	
57	2.4GS Over 1,000 kVa	(4,493)	(2,555)	
58	4.1Street and Area Lighting	(4,305)	(291)	
59	**Subtotal Rural**	**(243,922)**	**(18,727)**	
60	**Total**	**(243,922)**	**(24,210)**	
	Total Allocated Revenue Requirement			
61	CFB - Goose Bay Boiler	-	-	
62	IOCC Firm	-	-	
63	IOCC Non-Firm	-	-	
	Rural:	-	-	
64	1.1Domestic	-	-	
65	1.1A Domestic All Electric	-	-	
66	2.1GS 0-10 kW	-	-	
67	2.2GS 10-100 kW	-	-	
68	2.3GS 110-1,000 kVa	-	-	
69	2.4GS Over 1,000 kVa	-	-	
70	4.1Street and Area Lighting	-	-	
71	**Subtotal Rural**	**-**	**-**	
72	**Total**	**-**	**-**	

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Functionalization & Classification Ratios

Line No.	1 Description	2 Total Amount (%)	3 Production Demand (%)	4 Production & Transmission Energy (%)	5 Transmission Demand (%)	6 Rural Prod & Transmission Demand (%)	7 Distribution Substations Demand (%)	8 Distribution Primary Lines Demand (%)	9 Distribution Primary Lines Customer (%)	10 Distribution Line Transformers Demand (%)	11 Distribution Line Transformers Customer (%)	12 Distribution Secondary Lines Demand (%)	13 Distribution Secondary Lines Customer (%)	14 Distribution Services Customer (%)	15 Distribution Meters Customer (%)	16 Distribution Street Lighting Customer (%)	17 Accounting Customer (%)	18 Specifically Assigned Customer (%)
	Generation																	
1	Hydraulic	100%	42.10%	57.90%														
2	Hydraulic - GNP	100%	0.00%	0.00%		100.0%												
3	Holyrood	100%	57.72%	42.28%														
4	Gas Tur Island Intercnctd	100%	100.00%	0.00%														
5	Diesel Island Intercnctd - GNP	100%	0.00%	0.00%		100.0%												
6	Dsl / Gas Tur Island Isolated	100%	45.78%	54.22%														
7	Dsl / Gas Tur Labrador Isolated	100%	38.83%	61.17%														
8	Dsl / Gas Tur L'Anse au Loup	100%	100.00%	0.00%														
9	Dsl / Gas Tur Labrador Intercnctd	100%	100.00%	0.00%														
	Fuel																	
10	No. 6 Fuel	100%	0.00%	100.00%														
11	Gas Tur Island Intercnctd	100%	100.00%	0.00%														
12	Diesel Island Intercnctd - GNP	100%	0.00%	0.00%		100.0%												
13	Dsl / Gas Tur Island / Lab Isolated	100%	0.00%	100.00%														
14	Dsl / Gas Tur L'Anse au Loup	100%	0.00%	100.00%														
15	Dsl / Gas Tur Labrador Intercnctd	100%	100.00%	0.00%														
	Transmission Lines & Terminals																	
16	Lines	100%		0.00%	100%													
17	Lines - Hydraulic	100%	42.10%	57.90%														
18	Lines - Customer Specific	100%																100%
19	Terminal Stations	100%		0.00%	100%													
20	Term Stns - Hydraulic	100%	42.10%	57.90%														
21	Term Stns - Holyrood	100%	57.72%	42.28%														
22	Term Stns - Gas Tur	100%	100%															
23	Term Stns - Diesel GNP	100%	0.00%	0.00%		100.0%												
24	Terminal Stations - Distribution	100%					100%											
25	Term Stns - Custmr Specific	100%																100%
26	Rural Lines	100%				100.0%												
27	Rural Terminal Stations	100%				100.0%												

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Functionalization & Classification Ratios

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
							Distribution											
								Primary Lines		Line Transformers		Secondary Lines						
Line No.	Description	Total Amount (%)	Production Demand (%)	Production & Transmission Energy (%)	Transmission Demand (%)	Rural Prod & Transmission Demand (%)	Substations Demand (%)	Demand (%)	Customer (%)	Demand (%)	Customer (%)	Demand (%)	Customer (%)	Services Customer (%)	Meters Customer (%)	Street Lighting Customer (%)	Accounting Customer (%)	Specifically Assigned Customer (%)
	Distribution																	
28	Substation Structures & Equipment						100%											
29	Land & Land Improvements - by Sub-function:																	
30	Primary	85%						88.7%	11.3%									
31	Secondary	15%										58.3%	41.7%					
32	Land & Land Improvements	100%						75.4%	9.6%			8.7%	6.3%					
33	Poles - by Subfunction:																	
34	3 phase - Primary	41.2%						100.0%										
35	Other Primary	36.4%						45.7%	54.3%									
36	Secondary	22.4%										45.7%	54.3%					
37	Poles	100%						57.8%	19.8%			10.2%	12.2%					
38	Primary Condctr & Equip	100%						88.7%	11.3%									
39	Submarine Conductor	100%						100.0%										
40	Transformers	100%								36.1%	63.9%							
41	Secondary Condctr & Equip	100%										58.3%	41.7%					
42	Services	100%												100.0%				
43	Meters	100%													100.0%			
44	Street Lighting	100%														100.0%		
45	Customer Accounting	100%															100.0%	

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1

System Load Factor

Line No.	1	2	3	4	5	6
		Island Interconnected	**Island Isolated**	**Labrador Isolated**	**L'Anse au Loup**	**Labrador Interconnected**
1	Sales+Losses for System Load Factor (MWh)	6,737,249	10,484	41,436	16,319	947,700
2	Hours in Year	8,784	8,784	8,784	8,784	8,784
3	Average Demand (kW)	766,991	1,193	4,717	1,858	107,889
4	Coincident Peak at Generation (kW)	1,324,720	2,201	7,712	3,807	196,035
5	System Load Factor	57.90%	54.22%	61.17%	48.80%	55.04%

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Holyrood Capacity Factor

	1	2	3	4	5
Line No.	Year	Net Production (kWh)	Net Capacity (MW)	Net Production Hours	Net Capacity Factor
1	1999 Actual	919,801,520	466	8,760	22.53%
2	2000 Actual	970,283,280	466	8,784	23.70%
3	2001 Actual	2,098,489,700	466	8,760	51.41%
4	2002 Actual	2,385,262,000	466	8,760	58.43%
5	2003 Forecast	2,259,860,000	466	8,760	55.36%
6	5-Year Average	1,726,739,300	466	8,765	42.28%

NEWFOUNDLAND & LABRADOR HYDRO
2004 Forecast Cost of Service - Revision 1
Total System
Power Purchases

	1	2	3	4	5	6	7	
Line No.		Total ($)	Production Demand ($)	Production & Transmission Energy ($)	Transmission Demand ($)	Rural Transmission Demand ($)	Distribution Demand ($)	Basis of Functional Classification
	Island Interconnected:							
1	DLP Secondary	-		-				Production - Energy (Same as RSP Sec Load Var)
2	AP Secondary	-		-				Production - Energy (Secondary)
3	Wheeling	426,701				426,701		Rural Transmission
4	Interruptible Demand	-	-	-				Production - Demand
5	Interruptible Energy	-		-				Production - Energy
6	Non-utility Generation	29,501,629	12,420,675	17,080,954				Energy: System Load Factor
7	**Subtotal**	**29,928,330**	**12,420,675**	**17,080,954**	**-**	**426,701**	**-**	
	Labrador Interconnected:							
8	CF(L)Co	2,433,927	1,094,394	1,339,533				Energy: System Load Factor
9	Other	106,235					106,235	
10	**Subtotal**	**2,540,162**	**1,094,394**	**1,339,533**	**-**	**-**	**106,235**	
	Isolated Systems:							
11	Mary's Harbour	34,275		34,275				Production - Energy
12	L'Anse au Loup	812,107		812,107				Production - Energy
13	**Subtotal**	**846,382**	**-**	**846,382**	**-**	**-**	**-**	
14	**Total**	**33,314,874**	**13,515,068**	**19,266,870**	**-**	**426,701**	**106,235**	

Sam D. Banfield, P. Eng.
Director of Customer Services
Newfoundland and Labrador Hydro

At the hearing into Newfoundland and Labrador Hydro's 2003 General Rate Application, the Rates and Customer Services Evidence will be adopted by Sam D. Banfield, P. Eng., Director of Customer Services of Newfoundland and Labrador Hydro.

A witness profile for Sam D. Banfield follows.

- Mr. Banfield graduated from the Technical University of Nova Scotia, Dalhousie University in 1971 (B. Eng. (Electrical), with honors) and is a member and a past president of the Association of Professional Engineers and Geoscientists of Newfoundland and Labrador. Mr. Banfield received his P. Eng. designation from the Professional Engineers of Ontario in 1973.

- Mr. Banfield joined Newfoundland and Labrador Hydro in 1975 as an Electrical Engineer. Since that time, Mr. Banfield has held various positions within the Hydro Group in System Planning, Engineering & Construction and Churchill Falls.

- Since 1996, Mr. Banfield has held the position of Director of Customer Services, which includes the Rates & Financial Planning Department and includes rural customer service activities.

- Mr. Banfield has appeared before the Board of Commissioners of Public Utilities in 1989.

Rates and Customer Services
Evidence Outline

RATES AND CUSTOMER SERVICES

1. OVERVIEW

On the Island Interconnected System, Hydro provides electricity service to Newfoundland Power, and four Industrial Customers, namely, Abitibi-Consolidated Company of Canada (“ACCC”) - Grand Falls, ACCC - Stephenville, Corner Brook Pulp and Paper Limited (“CBPP”) and North Atlantic Refining Limited (“NARL”). Hydro also serves 21,800 Rural Customers at the retail level.

On the Labrador Interconnected System, Hydro serves 8,900 Rural Customers and one non-regulated Industrial Customer. On the 24 isolated systems, including the L’Anse au Loup system, Hydro has 4,400 Rural Customers.

The Rates and Customer Services evidence will cover the following areas:

- The rates proposed for Newfoundland Power and the Island Industrial Customers;
- The rates proposed for all Rural Customers and the impacts they will have on various customer classes, including:
    - < >
    - Elimination of the lifeline block for Isolated General Service (“G.S.”) customers;
    - Implementation of a demand and energy rate structure for large Isolated G. S. customers; and
    - < >
    - Implementation of a five-year plan for the Labrador Interconnected Customers incorporating approved cost recovery targets and the phase-in of applying the CFB Goose Bay secondary energy revenue credit to the overall rural deficit.
    - < >

- The 2004 revenues based on existing and proposed rates;
- The projected Rate Stabilization Plan ("RSP") balances and their effect on customers' rates;
- The proposed changes to Hydro's rules and regulations; and
- Customer service initiatives.

2. RATES FOR NEWFOUNDLAND POWER

As approved by the Board most recently in P.U. 7, the energy only rate for Newfoundland Power is designed to recover the direct assigned demand, energy and customer costs from the Cost of Service ("COS") plus Newfoundland Power's portion of the rural deficit. In this Application, Hydro is proposing an energy only rate of 54.45 mills per kWh for Newfoundland Power to be effective no later than January 1, 2004. This is a 13.7% increase in the base rate currently paid by Newfoundland Power. Including revenue for the rural deficit, the 2004 revenue to cost ratio for Newfoundland Power is forecast to be 1.17.

Hydro is also proposing a rate for firming up secondary energy purchased from CBPP and resold to Newfoundland Power as firm energy of 6.41mills per kWh as shown on Schedule 1.4 of the 2004 COS Study attached as Exhibit RDG-1 Rev. 1 to the Cost of Service Evidence. This is an 19.1% decrease from the current rate.

As directed in P.U. 7, Hydro has, in this Application, filed further evidence regarding a demand and energy rate structure for Newfoundland Power. Hydro's COS and rates consultant, Stone & Webster Management Consultants Inc., prepared a report on this issue entitled, Review of Rate Design for Newfoundland Power, a copy of which is included with this Application as Exhibit RDG-2. This report recommends that an energy and demand structure be implemented once a number of important issues are resolved including: the degree of risk to be assumed by Hydro; an appropriate weather normalization methodology; the treatment of Newfoundland Power generation; and appropriate costing and billing determinants. Subject to resolution of these issues, Hydro recommends that such a rate be implemented instead of the energy only rate outlined above.

3. RATES FOR ISLAND INDUSTRIAL CUSTOMERS

As approved by the Board in P.U. 7, rates charged to Island Industrial Customers for firm power and energy are designed to recover the direct assigned costs from the COS.

Hydro proposes a firm service rate effective no later than January 1, 2004 comprised of a demand charge of $6.49 per kW of billing demand per month and an energy charge of 27.55 mills per kWh plus the appropriate specifically assigned charges as outlined in Table 1.

Table 1

Industrial Customer Specifically Assigned Charges	Annual Amount
ACCC-Grand Falls Division	$2,043
ACCC-Stephenville Division	$110,666
CBPP	$177,184
NARL	$183,497

This will result in an average base rate increase of 13.5% for Island Industrial Customers and a 2004 revenue to cost ratio of 1.0.

Hydro is proposing a rate for non-firm service, unchanged from the current rate of $1.50 per kW per month and a variable energy charge based on the calculation outlined on Page 3 of the proposed rates schedules which are included with the Application under the “Rates Schedules 2004” Tab.

Hydro recommends that the rate for wheeling energy for ACCC be 4.49 mills per kWh based on the calculation outlined on Schedule 1.5 of the revised 2004 test year COS attached as Exhibit RDG-1 Rev. 1. This is a 4.7% decrease from the current rate.

4. RATES FOR RURAL CUSTOMERS

This section has been completely revised.

Rates proposed in this Application for Rural Customers reflect the direction given to the Board on July 9, 2003 by the Government and are otherwise in accordance with the policies for rural rates outlined in P.U. 7. Hydro is proposing a five-year plan to establish uniform rates on the Labrador Interconnected System and a three-year plan to implement a demand energy rate structure and eliminate the lifeline block rate for Isolated Rural G.S. Customers. In the same manner as current policy, rates for customers on the Island Interconnected, L'Anse au Loup and Isolated Systems, (excluding Government Departments) including preferential rate customers, wwill continue to be based on Newfoundland Power rates.

For rate-setting purposes, there are four distinct areas for Rural Customers as follows:

- Island Interconnected System;
- L'Anse au Loup system;
- Island and Labrador Isolated systems; and
- Labrador Interconnected System.

4.1 Island Interconnected System

4.1.1 Rural Customers - General

Rural Customers on the Island Interconnected System, with the exception of the Burgeo school and library, pay the same rates as Newfoundland Power customers. The Burgeo school and library receive a preferential rate which is increased or decreased by the average rate of change granted Newfoundland Power at its general rate applications. It is estimated that Hydro's proposed rates for Newfoundland Power will see a flow-through increase for all Rural Customers on the Island Interconnected System of approximately 7.4% no later than January 1, 2004, compared to the rates in effect on December 31, 2003 (which include the July 2003 RSP adjustment). The 2004 revenue to cost ratio for the Island Interconnected Rural Customers is projected to be 0.64.

4.2 L'Anse au Loup System

4.2.1 Rural Customers - General

Customers on the L'Anse au Loup system pay the same rates as Newfoundland Power customers. It is estimated that Hydro's current proposal for Newfoundland Power will see a flow-through increase for these customers of approximately 7.4% no later than January 1, 2004, compared to the rates in effect on December 31, 2003 (which include the July 2003 RSP adjustment). The 2004 revenue to cost ratio for these customers is projected to be 0.54.

4.3 Isolated Systems

4.3.1 Rural Customers - General

For rate-setting purposes on the isolated systems, Hydro is proposing four rate classes: a Domestic rate class, a small G.S. rate class (0 – 10 kW), a large G.S. rate class (10 kW and over) and street and area lighting rate class. The rates for these classes are based on the combined Island and Labrador Isolated Systems 2004 test year COS. The large G.S. class reflects the combined costs associated with the G.S. classes 2.2, 2.3 and 2.4 from the 2004 test year COS. Based on current rate setting policy for Isolated systems, the following cost recovery levels are projected for 2004:

Government departments	
All classes	100%
Non-Government	
Domestic	17%
G.S.	32%
Street and Area Lighting	39%

Further as outlined below, Hydro is proposing a three-year rate plan of automatic annual adjustments which will see the elimination the lifeline block for Isolated G.S. customers and the implementation of a demand and energy rate structure for large Isolated G.S. customers.

The 2004 revenue to cost ratio for customers on the Island and Labrador Isolated systems, excluding L'Anse au Loup, is projected to be 0.18 and 0.29 respectively, or a combined 0.26.

4.3.2 Isolated Rural Domestic Customers

Isolated Rural Domestic Customers, excluding Government departments, pay the same rates as Newfoundland Power customers for the first 700 kWh per month of consumption and rates charged for consumption above this amount are automatically adjusted by the average rate of change granted to Newfoundland Power. Based on this policy, it is estimated that Hydro's current proposal for Newfoundland Power will see a flow-through increase for these customers of approximately 7.4%, compared to the rates in effect on December 31, 2003 (which include the July 2003 RSP adjustment), effective no later than January 1, 2004.

4.3.3 Isolated Rural Domestic Customers – Government Departments [1]

As approved by the Board in P.U. 7, Government departments are charged rates based on full cost recovery. Based on the proposed combined costing for both Government and Non-Government Domestic Customers, the rate for Government Departments - Domestic (1.2G) will increase on average by 8.7%, resulting in an average monthly increase of $66 in 2004, effective no later than January 1, 2004. Further details on the rate impacts for these customers are outlined in Schedule I, Page 1 attached.

[1] Excludes hospitals and schools as outlined in P.U. 7, p. 130

4.3.4 Isolated Rural G.S. Customers

Isolated Rural G.S. customers, excluding Government departments which are paying 100% cost recovery, and churches, schools and community halls which pay Domestic rates, pay the same rates as Newfoundland Power customers for the first 700 kWh per month of consumption and rates charged for consumption above this amount are automatically adjusted by the average rate of change granted to Newfoundland Power. The Board in P.U. 7 directed Hydro in this GRA, to file a plan addressing the elimination of the lifeline block and the implementation a demand and energy rate structure for G.S. customers. The Government, in July, 2003, further directed that the new rates should target the current cost recovery level for these customers. To reflect current policy it is also proposed that rates for these customers would be automatically adjusted by the average rate of change granted to Newfoundland Power in any general rate application. Hydro is proposing 2004 rates which are based on these criteria however in order to mitigate customer impacts, Hydro is proposing that the phase-in of targeted rate components (e.g. the level of demand and energy charges) be implemented over three years. Hydro is requesting that the Board approve that the rates schedules for these customers would automatically come into effect January 1 of each year, as outlined, with the provision that adjustments could be made should a general rate application be filed in the intervening period. Based on this proposal, rates for small G.S. customers will increase on average by 7.4%, resulting in an average monthly increase of $10 in 2004, effective no later than January 1, 2004. Rates for large G.S. customers will increase on average by 7.4%, resulting in an average monthly increase of $97 in 2004, effective no later than January 1, 2004. Further details on the rate impacts for these customers are outlined in Schedule I, Pages 2 and 4 attached

4.3.5 Isolated Rural G.S. Customers - Government Departments

Government departments are charged rates based on full cost recovery. Based on the proposed combined costing for both Government and Non-Government G.S. customers, the rate for small G.S. – Government departments (2.1G) will decrease by 8.1% resulting in an average monthly decrease of $57 in 2004, effective no later than January 1, 2004. The rate for large G.S. Government departments (2.2G) will decrease on average by 20.3% resulting in an average monthly decrease of $843 in 2004, effective no later than January 1, 2004. Further details on the rate impacts for these customers are outlined in Schedule I, Pages 3 and 5 attached.

4.3.6 Isolated Rural Street and Area Lighting

Isolated Rural street and area lighting, excluding Government departments, is based on the same rates as Newfoundland Power customers. Based on this policy, it is estimated that Hydro's current proposal for Newfoundland Power will see a flow-through increase of approximately 7.4%, compared to the rates in effect on December 31, 2003 (which include the July 2003 RSP adjustment), effective no later than January 1, 2004.

4.3.7 Isolated Rural Street and Area Lighting – Government Departments

Government departments are charged rates based on full cost recovery. Based on the proposed combined costing for both Government and Non-Government street and area lighting service, rates will decrease on average by 35.6% resulting in an average monthly decrease of $44 in 2004, effective no later than January 1, 2004.

4.3.8 Isolated Rural Rate Recommendation

Isolated Rural Domestic Customers, excluding Government departments, pay the same rates as Newfoundland Power customers for the first 700 kWh per month of consumption and rates charged for consumption above this amount are automatically adjusted by the average rate of change granted to Newfoundland Power. Hydro is not proposing any amendment to this policy. Similarly, based on direction from Government, Hydro is not proposing any amendments to the rate setting policy for customers receiving preferential rates. Specifically, churches, schools and community halls would pay domestic rates; fish plants would continue to benefit from Island Interconnected rates and street; and lighting rates would also be the same as Island Interconnected rates.

Based on these rate policies, the proposed rates for 2004 are outlined in the schedule of rates under the “Rates Schedules” Tabs attached to the Application and proposed rates for the period 2004 – 2006 are summarized in Schedule II attached. Customer rate impacts for the period 2005 – 2006 are outlined in Schedule III attached. Hydro is requesting that the Board approve that the rates schedules for these customers would automatically come in to effect January 1 of each year with the provision that adjustments could be made should a general rate application be filed in the intervening period.

4.4 Labrador Interconnected System

Hydro is proposing a five-year plan to implement uniform rates for Labrador Interconnected Customers using the following cost recovery targets:

Domestic	95%
G.S.	105% -115%
Street Lighting	100%

Hydro was directed to phase in the application of the revenue credit for secondary energy sales to CFB Goose Bay to the rural deficit and keep the level of rate increases on the Labrador system as low as possible in moving to a uniform rate structure.

In keeping with this direction, Table 2 outlines Hydro’s proposal for the phase-in of rates on the Labrador Interconnected System.

1 **Table 2**

Target Rate Recoveries
Labrador Interconnected System

Customer	Current Rate Recovery	Target Rate Recovery	Target Rate Level(1) 2004	2005	2006	2007	2008
Happy Valley/Goose Bay							
Domestic	100%	100%					
General Service 2.1	63%	100%	76%	91%	100%		
General Service 2.2	120%	100%	120%	110%	100%		
General Service 2.3	136%	100%	136%	117%	100%		
General Service 2.4	133%	100%	133%	116%	100%		
Street and Area Lighting	85%	100%	100%	100%			
Labrador West							
Domestic	41%	100%	49%	59%	71%	85%	100%
General Service 2.1	47%	100%	56%	67%	80%	96%	100%
General Service 2.2	74%	100%	89%	100%			
General Service 2.3	77%	100%	92%	100%			
General Service 2.4	82%	100%	98%	100%			
Street and Area Lighting	53%	100%	60%	69%	79%	90%	100%

(1) The target rate level is based on each rate class' appropriate rate being 100%. The appropriate rate is calculated based on the cost recovery targets plus the rate class' portion of the rural deficit.

The proposed phase-in of uniform rates outlined above limits average rate increases for each class to a maximum of 20%. Restricting rate increases in this manner however, reduces the amount of CFB Goose Bay secondary revenue credit which can be applied to the rural deficit in the initial years. Table 3 details the cumulative amount of secondary revenue credit available each year to be applied to the rural deficit.

Table 3

CFB Goose Bay Secondary Revenue Credit
Available to Reduce the Rural Deficit

Description	2004	2005	2006	2007	2008
Secondary Credit Available	$126,903	$562,409	$960,422	$1,903,538	$2,884,149
Cumulative Percentage	4.4%	19.5%	33.3%	66.0%	100%

Based on the target rate levels outlined in Table 2, the proposed rates schedules for 2004 are included in the schedule of rates under the “Rates Schedules” Tabs to the Application and the 2004 customer impacts are shown in Schedule IV attached. A summary table of the proposed rates for the period 2004 – 2008 is detailed in Schedule V attached and customer impacts for 2005 – 2008 are outlined in Schedule VI attached. Hydro is requesting that the Board approve that the rates schedules for these customers would automatically come into effect January 1 of each year, as outlined, with the provision that adjustments could be made should a general rate application be filed in the intervening period.

Including revenue for the rural deficit, and excluding revenue for the secondary revenue credit, the 2004 revenue to cost ratio for Labrador Interconnected System customers is 1.19.

5. REVENUES BASED ON EXISTING AND PROPOSED RATES

Table 4 summarizes the projected 2004 revenue based on the proposed and existing rates.

Table 4

Comparison of Revenue at Existing and Proposed Rates Based on Full Year 2004

	Existing Rates	Proposed Rates	Change $	Change %
Newfoundland Power	$227,065,646	$258,169,230	$31,103,584	13.7%
Industrial				
- firm	45,823,492	52,018,920	6,195,428	13.5%
- non-firm	50,360	49,752	(608)	-1.2%
- wheeling	73,947	70,493	(3,454)	-4.7%
Rural Island Interconnected	32,606,102	35,031,560	2,425,458	7.4% *
Rural Isolated Systems				
Excluding Government Departments	5,696,761	6,120,199	423,438	7.4% *
Government Departments	1,466,261	1,281,050	(185,211)	-12.6%
< >				
Rural Isolated Systems Total	$7,163,022	$7,401,249	$238,227	3.3%
L'Anse au Loup	1,392,565	1,496,172	103,607	7.4% *
Rural Labrador Interconnected				
Domestic	5,963,763	6,408,339	444,576	7.5%
GS 2.1 0 - 10 kW	150,500	180,931	30,431	20.2%
GS 2.2 10 - 100 kW	1,683,293	1,812,581	129,288	7.7%
GS 2.3 110 - 1000 kVA	2,207,631	2,406,094	198,463	9.0%
GS 2.4 Over 1000 kVA	1,668,689	1,710,447	41,758	2.5%
Street & Area Lighting	179,160	187,368	8,208	4.6%
Labrador Interconnected Total	$11,853,036	$12,705,760	$852,724	7.2%
CFB Goose Bay - Secondary	3,980,020	3,980,020	0	0.0%
Total	$330,008,190	$370,923,156	$40,914,966	12.4%

* Estimated increase resulting from Newfoundland Power's subsequent pass-through hearing.

6. RATE STABILIZATION PLAN

As ordered in P.U. 7, the balance in the RSP as of Aug. 31, 2002 was frozen and is now referred to as the "Old RSP". The Old RSP is being recovered over a five-year period commencing in 2003. On September 1, 2002 a "New RSP" was established. The balance accumulating in this plan is to be recovered or refunded over a two-year period, commencing in 2004.

The forecast balances for both RSPs and their impact on customers in 2004 are as follows:

Table 5

Forecast RSP

Forecast RSP Balances – December 31, 2003	**Old RSP $ million**	**New RSP $ million**	**Total $ million**
Newfoundland Power	70.1	50.2	120.3
Industrial Customers	24.0	16.8	40.8
Total	94.1	67.0	161.1
Forecast RSP Recovery Rates Based on above Plans	**5 year Recovery (mills/kWh)**	**2 year Recovery (mills/kWh)**	**Total (mills/kWh)**
Newfoundland Power	3.4	5.6	9.0
Island Industrials	4.3	6.1	10.4

In 2004, it is projected that Newfoundland Power's rates to end consumers, which include the effect of Hydro's 2003 RSP adjustments, will increase 7.4% on January 1 with a further 5.8% RSP adjustment on July 1, 2004. This is based on the rates shown in Table 6.

Table 6

2004 Projected End Consumer Impacts

	December 31, 2003 mills/kWh	January 1, 2004 mills/kWh	Wholesale Increase %	End Consumer Increase %	July 1, 2004 mills/kWh	Wholesale Increase %	End Consumer Increase %
Energy	47.89	54.45	13.7	-	54.45	-	-
Old RSP (effective July 1, 2003)	3.24	3.24	-	-	3.44	-	-
New RSP	_				5.58	-	-
Total Rate	51.13	57.69	12.8	7.4	63.47	10.0	5.8

Newfoundland Power rates, including the July 1, 2004 adjustment, will be 24.1% higher than rates that were in effect at the end of 2003.

Island Industrial Customers, in combination with the 13.5% base rate increase outlined earlier, will see a total increase of 28.5% no later than January 1, 2004 including the RSP adjustment.

7. RULES AND REGULATIONS

Hydro proposes the following changes to its rules and regulations consistent with the practice to have its rules and regulations for Rural Customers as similar as possible to those of Newfoundland Power.

7.1 Reduction in the Application Fee for Name Changes

Hydro is proposing to reduce its application fee for a customer requiring a name change at an existing premise, currently $14.00, to match the fee for a new service, currently $8.00. To make this change, Hydro is proposing that the wording for Regulation 9(o) be changed as follows:

> **"An application fee of $8.00 will be charged for all requests for Customer name changes and connection of new Serviced Premises.** Landlords will be exempted from the application fee for name changes at Serviced Premises for which a landlord agreement pursuant to Regulation 11(f) is in effect."

7.2 Elimination of the Statement Preparation Fee

Hydro is proposing to remove clause 9(n) which charges a customer for the preparation of account statements for billing information prior to the most recent twelve months.

7.3 Extension of the Reconnection Fee

Hydro is proposing to change its regulations to permit charging the reconnection fee to new customers where a reconnection of service is required subsequent to a request by a landlord to disconnect an apartment. New customers in apartments that are required to pay the reconnection fee will not be required to pay the application fee. Regulation 9(f) currently allows Hydro to charge for reconnections in most situations except where a landlord requests disconnection for a change in tenancy. Hydro is proposing that the wording of Regulation 9(f) be changed as follows:

> **"Where a Service is Disconnected pursuant to Regulation 12(a), b(ii), (c), or (d) and the Customer subsequently requests that the service be reconnected, the Customer shall pay a reconnection fee. Where a Service is Disconnected pursuant to Regulation 12(g) and an Applicant subsequently requests that the service be reconnected, the Applicant shall pay a reconnection fee. Applicants that pay the reconnection fee will not be required to pay the application fee.** The reconnection fee shall be $20.00 where the reconnection is done during normal office hours or $40.00 if it is done at other times."

A new clause 12(g) that defines disconnecting a service as a result of a landlord agreement will be added, as follows:

> **"Hydro may Disconnect the Service to a rental premises where the landlord has an agreement with Hydro authorizing Hydro to Disconnect the Service for periods when Hydro does not have a contract for Service with a tenant of that premises."**

7.4 Other Amendments

Hydro proposes that other amendments will be made, as necessary, to the Rules and Regulations to give effect to the Board Order arising from this GRA.

8. CUSTOMER SERVICE INITIATIVES

The Customer Services department, in addition to its rates and regulatory functions, is responsible for coordinating customer service activities for Hydro. In addition to Newfoundland Power and Industrial Customers, service is also provided to approximately 35,000 Rural Customers.

To determine Hydro's customers' views on various aspects of their electricity supply, customer surveys are carried out annually. These surveys evaluate the customers' views based on 16 attributes and compare their importance to customers against how customers rank Hydro's performance. An overall customer satisfaction index is then developed from this comparison. The overall customer satisfaction index for residential customers has continued to increase since the inception of the surveys in 1999 and was rated at 8.1 in 2002. Hydro continues to evaluate the responses of customers in terms of the importance associated with various attributes in an effort to focus on those initiatives that are more meaningful from the customers' perspective. Some of the initiatives implemented to enhance customer service follow.

In 1996, Hydro consolidated the customer service processes of the corporation in one department. In 1999, a customer billing system was implemented, which has shortened the time between meter reading and billing for Rural Customers. It has also facilitated the establishment of a call centre allowing customers access through toll-free numbers. The call centre handles approximately 2,500 calls per month related to, for example, account inquiries and new services, in addition to power outages calls.

In July of 2002, Hydro introduced an Equal Payment Plan option, as well as a Pre-Authorized Plan for Rural Domestic Customers to allow them to spread their electricity payments in equal installments over a 12-month period and, if desired, allow automatic withdrawal from the customer's bank account. To date, 1,400 customers have taken advantage of the Equal Payment Plan with approximately 350 adopting the Pre-Authorization Payment method.

In April 2003, Hydro introduced an Integrated Voice Response ("IVR")/ Internet Customer Information System. This system allows customers telephone and Internet access to their account information as well as power outage information at any time.

In 2002, Hydro began a multi-year conservation initiative under the brand name "Hydro Wise", the main purpose of which was to promote energy efficiency by making information available to educate customers in the wise use of electricity. Hydro continues to partner with the Conservation Corps and in 2002 extended funding to assist customers with the cost of an energy audit.

RATES AND CUSTOMER SERVICES

LIST OF SCHEDULES

This section has been completely revised.

I < >

I Impact of Proposed Rates on Annual Electricity Costs for 2004
- Isolated Systems

II Comparison of Rates Schedules 2004-2006- Isolated Systems

III Impact of Proposed Rates on Annual Electricity Costs for 2005-2006
- Isolated Systems

IV Impact of Proposed Rates on Annual Electricity Costs for 2004
- Labrador Interconnected

V Comparison of Rates Schedules 2004-2008 - Labrador Interconnected

VI Impact of Proposed Rates on Annual Electricity Costs for 2005-2008
- Labrador Interconnected

Newfoundland & Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs for 2004
Government Departments
Domestic Diesel 1.2G

Percentage Change in Annual Costs

Dollars Change in Annual Costs	8% to 9.1%
$317 to $865	65.22%
$865 to $1413	13.04%
$1413 to $1961	8.70%
$1961 to $2509	8.70%
$2509 to $3057	4.35%
Total:	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Notes: (1) The average number of customers for 2001 was 23.

(2) This analysis is based on 2001 usage patterns.

Newfoundland & Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs for 2004
General Service Diesel 2.1D

Percentage Change in Annual Costs

Dollars Change in Annual Costs	**1% to 5%**	**5% to 9%**	**9% to 13%**	**13% to 17%**	**17% to 21%**	**Total**
\$16 to \$58		8.54%	10.19%	4.68%		23.42%
\$58 to \$100		0.55%	0.28%	7.99%	5.23%	14.05%
\$100 to \$142	0.55%	1.10%	1.10%	2.20%	7.16%	12.12%
\$142 to \$184		3.03%	3.31%	1.65%	4.68%	12.67%
\$184 to \$226	10.74%	12.12%	5.23%	5.79%	3.86%	37.74%
Total:	**11.29%**	**25.34%**	**20.11%**	**22.31%**	**20.94%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Notes: (1) The average number of customers for 2001 was 385.

(2) This analysis is based on 2001 usage patterns.

Newfoundland & Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs for 2004
Government Departments
General Service Diesel 2.1G

Percentage Change in Annual Costs

Dollars Change in Annual Costs	-9% to -5%	-5% to -2%	-2% to 0%	0% to 3%	3% to 5%	Total
$-2091 to $-1669	3.77%					3.77%
$-1669 to $-1247	13.21%					13.21%
$-1247 to $-825	15.09%					15.09%
$-825 to $-403	30.19%					30.19%
$-403 to $19	28.30%	1.89%	3.77%		3.77%	37.74%
Total:	**90.57%**	**1.89%**	**3.77%**	**0.00%**	**3.77%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Notes: (1) The average number of customers for 2001 was 53.

(2) This analysis is based on 2001 usage patterns.

Newfoundland & Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs for 2004
General Service Diesel 2.2D

Percentage Change in Annual Costs

Dollars Change in Annual Costs	0% to 20%	20% to 40%	40% to 60%	60% to 80%	80% to 99%	Total
$24 to $752	26.79%	3.57%		1.79%		32.14%
$752 to $1480	26.79%	7.14%			1.79%	35.71%
$1480 to $2208	16.07%					16.07%
$2208 to $2936	8.96%					8.93%
$2936 to $3663	7.14%					7.14%
Total:	**85.71%**	**10.71%**	**0.0%**	**1.79%**	**1.79%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Notes: (1) The average number of customers for 2001 was 60.

(2) This analysis is based on 2001 usage patterns.

Newfoundland & Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs for 2004
Government Departments
General Service Diesel 2.2G

Percentage Change in Annual Costs

Dollars Change in Annual Costs	-28% to -21%	-21% to -15%	-15% to -8%	-8% to -2%	-2% to 5%	Total
$-27418 to $-21846	6.25%	6.25%				12.50%
$-21846 to $-16274						0.00%
$-16274 to $-10702	18.75%					18.75%
$-10702 to $-5130	6.25%					6.25%
$-5130 to $440		12.50%	18.75%	25.00%	6.25%	62.50%
Total:	**31.25%**	**18.75%**	**18.75%**	**25.00%**	**6.25%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Notes: (1) The average number of customers for 2001 was 16.

(2) This analysis is based on 2001 usage patterns.

Comparison of Rates Schedules 2004-2006
Isolated Systems

	Rate Class	2004	2005	2006
Basic Charge $/mo.	1.2G	29.83		
kWh Charge ¢/kWh		60.112		
Basic Charge $/mo.		19.45	19.45	19.45
kWh Charge ¢/kWh	2.1D	11.74	13.92	16.05
Second Block Charge ¢/kWh		20.00	18.00	
Basic Charge $/mo.	2.1G	34.11		
kWh Charge ¢/kWh		52.68		
Basic Charge $/mo.	2.2D	25.96	25.96	25.96
Demand Charge $/kW/mo.		8.10	10.38	12.70
kWh Charge ¢/kWh		11.84	13.61	16.11
Second Block Charge ¢/kWh		23.36	20.10	
Basic Charge $/mo.	2.2G	57.84		
Demand Charge $/kW/mo.		28.01		
kWh Charge ¢/kWh		35.830		

Note: Blank cells indicate that there are no further change in rates.

Newfoundland & Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs for 2005
General Service Diesel 2.1D

Percentage Change in Annual Costs

Dollars Change in Annual Costs	-8% to -4%	-4% to 0%	0% to 5%	5 to 10%	10% to 15%	Total
$-969 to $-741	0.27%					0.27%
$-741 to $-513	0.80%					0.80%
$-513 to $-285	4.02%					4.02%
$-285 to $-57	2.68%	6.17%				8.85%
$-57 to $167		10.19%	25.74%	25.20%	24.93%	86.06%
Total:	**7.77%**	**16.35%**	**25.74%**	**25.20%**	**24.93%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Notes: (1) The average number of customers for 2001 was 385.

(2) This analysis is based on 2001 usage patterns.

Newfoundland & Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs for 2005
General Service Diesel 2.2D

Percentage Change in Annual Costs

Dollars Change in Annual Costs	-11% to -5%	-5% to 1%	1% to 7%	7% to 14%	14% to 20%	Total
$-2237 to $-1501	7.27%	3.64%				10.91%
$-1501 to $-765	1.82%	3.64%				5.45%
$-765 to $-29		25.45%				25.45%
$-29 to $707		7.27%	16.36%	7.27%	7.27%	38.48%
$707 to $1440			5.45%	5.45%	9.09%	20.00%
Total:	**9.09%**	**40.00%**	**21.82%**	**12.73%**	**16.36%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Notes: (1) The average number of customers for 2001 was 60.

(2) This analysis is based on 2001 usage patterns.

Newfoundland & Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs for 2006
General Service Diesel 2.1D

Percentage Change in Annual Costs

Dollars Change in Annual Costs	-9% to -4%	-4% to 1%	1% to 4%	4% to 8%	8% to 13%	Total
$-946 to $-724	0.55%					0.55%
$-724 to $-502	0.83%					0.83%
$-502 to $-280	4.13%					4.13%
$-280 to $-58	2.75%	6.34%				9.09%
$-58 to $163		19.01%	12.12%	21.49%	32.78%	85.40%
Total:	**8.26%**	**25.34%**	**12.12%**	**21.49%**	**32.78%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Notes: (1) The average number of customers for 2001 was 385.

(2) This analysis is based on 2001 usage patterns.

Newfoundland & Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs for 2006
General Service Diesel 2.2D

Percentage Change in Annual Costs

Dollars Change in Annual Costs	-14% to -7%	-7% to -1%	-1% to 6%	6% to 13%	13% to 20%	Total
$-2654 to $-1785	5.45%	5.45%				10.91%
$-1785 to $-916	1.82%	3.64%				5.45%
$-916 to $-47		21.82%	3.64%			25.45%
$-47 to $822			18.18%	10.91%	9.09%	38.18%
$822 to $1691			3.64%	7.27%	9.09%	20.00%
Total:	**7.27%**	**30.91%**	**25.45%**	**18.18%**	**18.18%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Notes: (1) The average number of customers for 2001 was 60.

(2) This analysis is based on 2001 usage patterns.

Newfoundland & Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs for 2004
Happy Valley/Goose Bay
General Service 2.1HV

Percentage Change in Annual Costs

Dollars Change in Annual Costs	0% to 5%	5% to 10%	10% to 15%	15% to 20%	20% to 26%	Total
\$0 to \$78	23.65%	8.37%	7.39%	20.69%		60.10%
\$78 to \$156					23.65%	23.65%
\$156 to \$234					12.32%	12.32%
\$234 to \$312					2.96%	2.96%
\$312 to \$388					0.99%	0.99%
Total:	**23.65%**	**8.37%**	**7.39%**	**20.69%**	**39.90%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Notes: (1) The average number of customers for 2001 was 226.

(2) This analysis is based on 2001 usage patterns.

Newfoundland & Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs for 2004
Labrador West
Domestic 1.1W

<u>Percentage Change in Annual Costs</u>

Dollars Change in Annual Costs	13% to 15%	15% to 18%	18% to 21%	21% to 24%	24% to 26%	Total
$7 to $56	0.03%		19.27%	2.24%	0.32%	21.85%
$56 to $105			21.01%			21.01%
$105 to $154			45.52%			45.52%
$154 to $203			11.12%			11.12%
$203 to $254			0.50%			0.50%
Total:	**0.03%**	**0.00%**	**97.42%**	**2.24%**	**0.32%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Notes: (1) The average number of customers for 2001 was 4245.

(2) This analysis is based on 2001 usage patterns.

Newfoundland & Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs for 2004
Labrador West
General Service 2.1W

Percentage Change in Annual Costs

Dollars Change in Annual Costs	0% to 6%	6% to 11%	11% to 16%	16% to 21%	21% to 27%	Total
$0 to $64	27.19%	5.26%	12.28%	15.79%		60.53%
$64 to $128				8.77%	18.42%	27.19%
$128 to $192					6.14%	6.14%
$192 to $256					4.39%	4.39%
$256 to $318					1.75%	1.75%
Total:	**27.19%**	**5.26%**	**12.28%**	**24.56%**	**30.70%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Notes: (1) The average number of customers for 2001 was132.

(2) This analysis is based on 2001 usage patterns.

Newfoundland & Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs for 2004
Labrador West
General Service 2.2W

Percentage Change in Annual Costs

Dollars Change in Annual Costs	3% to 8%	8% to 12%	12% to 16%	16% to 20%	20% to 24%	Total
\$21 to \$373	0.49%	2.43%	10.19%	26.21%	13.59%	52.91%
\$373 to \$725		0.49%	0.97%	7.28%	20.39%	29.13%
\$725 to \$1077				3.88%	7.28%	11.17%
\$1077 to \$1429				0.97%	4.85%	5.83%
\$1429 to \$1781					0.97%	0.97%
Total:	**0.49%**	**2.91%**	**11.17%**	**38.35%**	**47.09%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Notes: (1) The average number of customers for 2001 was 235.

(2) This analysis is based on 2001 usage patterns.

Newfoundland & Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs for 2004
Labrador West
General Service 2.3W

Percentage Change in Annual Costs

Dollars Change in Annual Costs	13% to 14%	14% to 16%	16% to 18%	18% to 20%	20% to 22%	Total
$602 to $4718	1.64%	4.92%	13.11%	44.26%	16.39%	80.33%
$4718 to $8834			1.64%	6.56%	4.92%	13.11%
$8834 to $12950				1.64%	1.64%	3.28%
$12950 to $17066					1.64%	1.64%
$17066 to $21184					1.64%	1.64%
Total:	**1.64%**	**4.92%**	**14.75%**	**52.46%**	**26.23%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Notes: (1) The average number of customers for 2001 was 68.

(2) This analysis is based on 2001 usage patterns.

Newfoundland & Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs for 2004
Labrador West
General Service 2.4W

	Change in Annual Costs	
Number of Customers	**Dollar Change**	**Percentage Change**
2	\$12,762 to \$18,355	19.09% to 19.86%

Note: This analysis is based on 2001 usage patterns.

Comparison of Rates Schedules 2004-2008
Labrador Interconnected

Happy Valley/Goose Bay

	Rate Class	2004	2005	2006	2007	2008
Basic Charge $/mo.	1.1	7.00	7.00	7.00	7.00	8.00
kWh Charge ¢/kWh		0.03250	0.03250	0.03250	0.03250	0.03255
Basic Charge $/mo.	2.1	9.10	9.10	10.10		
kWh Charge ¢/kWh		0.04032	0.05050	0.05610		
Basic Charge $/mo.	2.2	2.00	2.00	2.00		
kWh Charge ¢/kWh		0.03000	0.02684	0.02386		
Basic Charge $/mo.	2.3	1.85	1.85	1.85		
kWh Charge ¢/kWh		0.02950	0.02402	0.02039		
Basic Charge $/mo.	2.4	1.70	1.70	1.70		
kWh Charge ¢/kWh		0.02500	0.02144	0.01802		
Basic Charge $/mo.	3.1*	2.00				
kWh Charge ¢/kWh		0.02500				

* Effective January 2005, Rate 3.1 will be eliminated and customers will become part of Rate 2.2 and 2.3.

Labrador West

	Rate Class	2004	2005	2006	2007	2008
Basic Charge $/mo.	1.1	4.45	5.50	6.25	7.15	8.00
kWh Charge ¢/kWh		0.01601	0.01921	0.02322	0.02788	0.03255
Basic Charge $/mo.	2.1	9.10	9.10	9.10	9.55	10.10
kWh Charge ¢/kWh		0.02832	0.03582	0.04466	0.05504	0.05610
Basic Charge $/mo.	2.2	2.00	2.00			
kWh Charge ¢/kWh		0.02056	0.02386			
Basic Charge $/mo.	2.3	1.85	1.85			
kWh Charge ¢/kWh		0.01882	0.02039			
Basic Charge $/mo.	2.4	1.70	1.70			
kWh Charge ¢/kWh		0.01731	0.01802			

Note: Blank cells indicate that there are no further change in rates.

Comparison of Street Light Rates Schedules 2004-2008
Labrador Interconnected

Happy Valley/Goose Bay ***Monthly Rate***	
Type	**2004**
MVP 250	$12.10
HPS 100	$10.07
HPS 150	$12.10
HPS 250	$15.95
HPS 400	$20.10

Labrador West	***Monthly Rate***				
Type	**2004**	**2005**	**2006**	**2007**	**2008**
Rate 4.1W					
MVP 250	$ 5.80	$ 7.30	$ 9.00	$11.36	$12.10
HPS 100	$ 7.11	$ 7.54	$ 8.27	$ 9.00	$10.07
HPS 150	$12.10				
HPS 250	$15.95				
HPS 400	$20.10				
Rate 4.11W	(Labrador City Street lights owned by Hydro existing as of Sept 1, 2002)				
HPS 100	$ 4.15	$ 5.65	$ 7.15	$ 9.00	$10.07
Rate 4.12W	(Electricity Only)				
HPS 100	$ 3.12	$ 3.59	$ 4.06	$ 4.53	$ 5.02

Note: Blank cells indicate that there are no further change in rates.

Newfoundland & Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs for 2005
Happy Valley/Goose Bay
General Service 2.1HV

Percentage Change in Annual Costs

Dollars Change in Annual Costs	0% to 4%	4% to 9%	9% to 14%	14% to 19%	19% to 24%	Total
\$0 to \$91	21.08%	8.33%	7.35%	18.14%	4.90%	59.80%
\$91 to \$182					23.53%	23.53%
\$182 to \$273					12.25%	12.25%
\$273 to \$364					2.94%	2.94%
\$364 to \$454					1.47%	1.47%
Total:	**21.08%**	**8.33%**	**7.35%**	**18.14%**	**45.10%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Notes: (1) The average number of customers for 2001 was 226.

(2) This analysis is based on 2001 usage patterns.

Newfoundland & Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs for 2005
Happy Valley/Goose Bay
General Service 2.2HV

Percentage Change in Annual Costs

Dollars Change in Annual Costs	-10% to -9%	-9% to -7%	-7% to -5%	-5% to -3%	-3% to -1%	Total
$-966 to $-772	0.46%	0.46%				0.92%
$-772 to $-578	0.46%	5.50%				5.96%
$-578 to $-384	1.38%	12.84%				14.22%
$-384 to $-190	1.83%	24.31%	0.46%			26.61%
$-190 to $-4	2.29%	42.20%	6.42%		1.38%	52.29%
Total:	**6.42%**	**85.32%**	**6.88%**	**0.00%**	**1.38%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Notes: (1) The average number of customers for 2001 was 241.

(2) This analysis is based on 2001 usage patterns.

Newfoundland & Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs for 2005
Happy Valley/Goose Bay
General Service 2.3HV

Percentage Change in Annual Costs

Dollars Change in Annual Costs	-17% to -14%	-14% to -10%	-10% to -7%	-7% to -4%	-4% to 0%	Total
$-16396 to $-13117	4.44%					4.44%
$-13117 to $-9838	2.22%					2.22%
$-9838 to $-6559	2.22%					2.22%
$-6559 to $-3280	20.00%					20.00%
$-3280 to $0	46.67%	15.56%	2.22%	4.44%	2.22%	71.11%
Total:	**75.56%**	**15.56%**	**2.22%**	**4.44%**	**2.22%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Notes: (1) The average number of customers for 2001 was 48.

(2) This analysis is based on 2001 usage patterns.

Newfoundland & Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs for 2005
Happy Valley/Goose Bay
General Service 2.4 HV

	Change in Annual Costs	
Customers	**Dollar Change**	**Percentage Change**
2	-$143,683 to -$19,529	-12.88% to -12.01%

Note: This analysis is based on 2001 usage patterns.

Newfoundland & Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs for 2005
Labrador West
Domestic 1.1W

Percentage Change in Annual Costs

Dollars Change in Annual Costs	13% to 15%	15% to 18%	18% to 20%	20% to 23%	23% to 26%	Total
$7 to $56	0.03%		16.12%	4.96%	0.69%	21.79%
$56 to $105			21.39%			21.39%
$105 to $154			45.45%			45.45%
$154 to $203			10.89%			10.89%
$203 to $253			0.47%			0.47%
Total:	**0.03%**	**0.00%**	**94.33%**	**4.96%**	**0.69%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Notes: (1) The average number of customers for 2001 was 4245.

(2) This analysis is based on 2001 usage patterns.

Newfoundland & Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs for 2005
Labrador West
General Service 2.1W

Percentage Change in Annual Costs

Dollars Change in Annual Costs	0% to 5%	5% to 10%	10% to 15%	15% to 20%	20% to 25%	Total
\$0 to \$75	22.81%	7.89%	9.65%	20.18%		60.53%
\$75 to \$150				4.39%	21.93%	26.32%
\$150 to \$225					7.02%	7.02%
\$225 to \$300					4.39%	4.39%
\$300 to \$377					1.75%	1.75%
Total:	**22.81%**	**7.89%**	**9.65%**	**24.56%**	**35.09%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Notes: (1) The average number of customers for 2001 was 132.

(2) This analysis is based on 2001 usage patterns.

Newfoundland & Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs for 2005
Labrador West
General Service 2.2W

Percentage Change in Annual Costs

Dollars Change in Annual Costs	2% to 4%	4% to 7%	7% to 10%	10% to 13%	13% to 15%	Total
\$15 to \$270	0.49%	1.46%	11.17%	36.89%	2.91%	52.91%
\$270 to \$525			1.46%	21.84%	5.83%	29.13%
\$525 to \$780				9.22%	1.94%	11.17%
\$780 to \$1035				3.40%	2.43%	5.83%
\$1035 to \$1289				0.49%	0.49%	0.97%
Total:	**0.49%**	**1.46%**	**12.62%**	**71.84%**	**13.59%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Notes: (1) The average number of customers for 2001 was 235.

(2) This analysis is based on 2001 usage patterns.

Newfoundland & Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs for 2005
Labrador West
General Service 2.3W

Percentage Change in Annual Costs

Dollars Change in Annual Costs	4% to 5%	5% to 6%	6% to 7%	7% to 8%	Total
$247 to $1939	1.64%	13.11%	60.66%	4.92%	80.33%
$1939 to $3631			8.20%	4.92%	13.11%
$3631 to $5323			3.28%		3.28%
$5323 to $7015				1.64%	1.64%
$7015 to $8707			1.64%		1.64%
Total:	**1.64%**	**13.11%**	**73.77%**	**11.48%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Notes: (1) The average number of customers for 2001 was 68.

(2) This analysis is based on 2001 usage patterns.

Newfoundland & Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs for 2005
Labrador West
General Service 2.4W

	Change in Annual Costs	
Customers	**Dollar Change**	**Percentage Change**
2	$3,937 to $2,738	3.44% to 3.55%

Note: This analysis is based on 2001 usage patterns.

Newfoundland & Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs for 2006
Happy Valley/Goose Bay
General Service 2.1HV

Percentage Change in Annual Costs

Dollars Change in Annual Costs	10% to 13%
$12 to $62	59.80%
$62 to $112	23.53%
$112 to $162	12.25%
$162 to $212	2.94%
$212 to $262	1.47%
Total:	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Notes: (1) The average number of customers for 2001 was 226.

(2) This analysis is based on 2001 usage patterns.

Newfoundland & Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs for 2006
Happy Valley/Goose Bay
General Service 2.2HV

Percentage Change in Annual Costs

Dollars Change in Annual Costs	-10% to -8%	-8% to -6%	-6% to -4%	-4% to -2%	-2% to 0%	Total
$-911 to $-729	0.92%					0.92%
$-729 to $-548	5.96%					5.96%
$-548 to $-367	14.22%					14.22%
$-367 to $-186	24.31%	1.38%				25.69%
$-186 to $-3	33.49%	16.06%	2.29%		1.38%	53.21%
Total:	**78.90%**	**17.43%**	**2.29%**	**0.00%**	**1.38%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Notes: (1) The average number of customers for 2001 was 241.

(2) This analysis is based on 2001 usage patterns.

Newfoundland & Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs for 2006
Happy Valley/Goose Bay
General Service 2.3HV

Percentage Change in Annual Costs

Dollars Change in Annual Costs	-14% to -11%	-11% to -8%	-8% to -5%	-5% to -3%	-3% to 0%	Total
$-10861 to $-8689	4.44%					4.44%
$-8689 to $-6517	2.22%					2.22%
$-6517 to $-4345	2.22%					2.22%
$-4345 to $-2173	20.00%	2.22%				22.22%
$-2173 to $0	44.44%	15.56%	2.22%	4.44%	2.22%	68.89%
Total:	**73.33%**	**17.78%**	**2.22%**	**4.44%**	**2.22%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Notes: (1) The average number of customers for 2001 was 48.

(2) This analysis is based on 2001 usage patterns.

Newfoundland & Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs for 2006
Happy Valley/Goose Bay
General Service 2.4HV

	Change in Annual Costs	
Customers	**Dollar Change**	**Percentage Change**
2	-$138,033 to -$18,761	-14.21% to -13.11%

Note: This analysis is based on 2001 usage patterns

Newfoundland & Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs for 2006
Labrador West
Domestic 1.1W

Percentage Change in Annual Costs

Dollars Change in Annual Costs	11% to 13%	13% to 15%	15% to 17%	17% to 19%	19% to 21%	Total
\$8 to \$86	0.03%	0.58%	2.58%	5.67%	13.15%	22.01%
\$86 to \$164					21.88%	21.88%
\$164 to \$242					45.02%	45.02%
\$242 to \$320					10.65%	10.65%
\$320 to \$399					0.45%	0.45%
Total:	**0.03%**	**0.58%**	**2.58%**	**5.67%**	**91.14%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Notes: (1) The average number of customers for 2001 was 4245.

(2) This analysis is based on 2001 usage patterns.

Newfoundland & Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs for 2006
Labrador West
General Service 2.1W

Percentage Change in Annual Costs

Dollars Change in Annual Costs	0% to 4%	4% to 9%	9% to 14%	14% to 19%	19% to 24%	Total
$0 to $89	21.24%	8.85%	7.08%	22.12%	1.77%	61.06%
$89 to $178					27.43%	27.43%
$178 to $256					6.19%	6.19%
$256 to $334					4.42%	4.42%
$334 to $412					0.88%	0.88%
Total:	**21.24%**	**8.85%**	**7.08%**	**22.12%**	**40.71%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Notes: (1) The average number of customers for 2001 was 132.

(2) This analysis is based on 2001 usage patterns.

Newfoundland & Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs for 2007
Labrador West
Domestic 1.1W

Percentage Change in Annual Costs

Dollars Change in Annual Costs	**12% to 14%**	**14% to 16%**	**16% to 17%**	**17% to 18%**	**18% to 20%**	**Total**
$9 to $100	0.03%	1.06%	1.35%	3.51%	16.01%	21.95%
$100 to $191					22.08%	22.08%
$191 to $282					44.95%	44.95%
$282 to $373					10.58%	10.58%
$373 to $464					0.45%	0.45%
Total:	**0.03%**	**1.06%**	**1.35%**	**3.51%**	**94.06%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Notes: (1) The average number of customers for 2001 was 4245.

(2) This analysis is based on 2001 usage patterns.

Newfoundland & Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs for 2007
Labrador West
General Service 2.1W

Percentage Change in Annual Costs

Dollars Change in Annual Costs	5% to 8%	8% to 12%	12% to 16%	16% to 20%	20% to 23%	Total
\$5 to \$109	20.18%	7.89%	6.14%	26.32%		60.53%
\$109 to \$213				1.75%	25.44%	27.19%
\$213 to \$317					6.14%	6.14%
\$317 to \$421					4.39%	4.39%
\$421 to \$526					1.75%	1.75%
Total:	**20.18%**	**7.89%**	**6.14%**	**28.07%**	**37.72%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Notes: (1) The average number of customers for 2001 was 132.

(2) This analysis is based on 2001 usage patterns.

Newfoundland & Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs for 2008
Happy Valley/Goose Bay
Domestic 1.1HV

Percentage Change in Annual Costs

Dollars Change in Annual Costs	0% to 3%	3% to 7%	7% to 10%	10% to 14%	14% to 17%	Total
$10 to $11	0.21%	0.03%		0.03%	0.03%	0.31%
$11 to $13	18.88%	5.52%	1.66%	1.73%	1.52%	29.30%
$13 to $14	56.73%	0.03%			0.03%	56.80%
$14 to $16	13.56%					13.56%
$16 to $17	0.03%					0.03%
Total:	**89.41%**	**5.59%**	**1.66%**	**1.76%**	**1.59%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Notes: (1) The average number of customers for 2001 was 3410.

(2) This analysis is based on 2001 usage patterns.

Newfoundland & Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs for 2008
Labrador West
Domestic 1.1W

Percentage Change in Annual Costs

Dollars Change in Annual Costs	10% to 11%	11% to 13%	13% to 14%	14% to 15%	15% to 17%	Total
$9 to $100	0.03%	0.90%	1.74%	3.64%	15.72%	22.03%
$100 to $191					22.21%	22.21%
$191 to $282					44.74%	44.74%
$282 to $373					10.58%	10.58%
$373 to $465					0.45%	0.45%
Total:	**0.03%**	**0.90%**	**1.74%**	**3.64%**	**93.70%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Notes: (1) The average number of customers for 2001 was 4245.

(2) This analysis is based on 2001 usage patterns.

Newfoundland & Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs for 2008
Labrador West
General Service 2.1W

Percentage Change in Annual Costs

Dollars Change in Annual Costs	2% to 3%	3% to 4%	4% to 5%	5% to 6%	6% to 7%	Total
$6 to $17	18.26%	12.17%	8.70%	7.83%	13.91%	60.87%
$17 to $28	26.96%					26.96%
$28 to $39	6.09%					6.09%
$39 to $50	4.35%					4.35%
$50 to $60	1.74%					1.74%
Total:	**57.39%**	**12.17%**	**8.70%**	**7.83%**	**13.91%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Notes: (1) The average number of customers for 2001 was 132.

(2) This analysis is based on 2001 usage patterns.