**Q. (CA-NP-006 from NP's 2020 Capital Budget Application) NP states "*In the early 1990s, following the cod moratorium, the Company experienced a sharp reduction in electricity sales growth. During that period, Newfoundland Power reduced the amount of capital invested to maintain the electrical system. By 1998, the reliability of service experienced by the Company's customers had deteriorated. A report subsequently commissioned by the Board indicated that it was important for Newfoundland Power to improve its reliability performance.*"**

**(a) Please provide NP SAIDI and SAIFI data for each year and on a 5-year rolling average basis for 1990 through 2020.**

**(b) Please provide the capital expenditures for each year from 1990 through 2000.**

**(c) Please identify the statement and its location in the report commissioned by the Board where it is stated "*it was important for Newfoundland Power to improve its reliability performance*".**

**(d) Please file for the record a copy of the report commissioned by the Board.**

**(e) What strategy and plan did NP implement in order to improve its reliability performance following issuance of the report commissioned by the Board?**

A. (a) Newfoundland Power's SAIDI and SAIFI data for each year and on a 5–year rolling average basis for the period 1990 through 2019 is detailed in Attachment A. The 2020 data is not yet available.[1]

(b) The capital expenditures for each year from 1990 through 2019 are detailed in Attachment A. The 2020 data is not yet available.

(c) The statement "*it was important for Newfoundland Power to improve its reliability performance*" is on page 47 of the report, which is provided in Attachment B. It is the last sentence in the Conclusion.

(d) A copy of the report commissioned by the Board is provided as Attachment B.

(e) Following the issuance of the report commissioned by the Board, Newfoundland Power focused on managing system reliability through capital investment, maintenance practices, and operational deployment.[2] This resulted in targeted capital investments being made through the *Rebuild Distribution Lines* and the *Distribution Reliability Initiative* capital projects, as described on the following page.

[1] Attachment A does not include customer outages related to significant events or loss of supply.
[2] For a description of how Newfoundland Power improved its reliability performance in a strategic and planned way please see the Company's *2008 General Rate Application*, section 2.3.2 Reliability for additional details.

(i) *Rebuild Distribution Lines* – In 1998, the Company formalized its distribution line inspection program.[3] Formal inspection standards and a feeder inspection program were introduced and implemented across the service territory. The inspection program was initially based on a 5 year cycle. The 5 year cycle was later changed to the current 7 year cycle. In addition to condition assessment, the inspection program also identifies specific line components with known reliability issues such as lightning arrestors, CP8080 and 2-piece insulators, current limiting fuses, automatic sleeves, porcelain cutouts and transformers.

(ii) *Distribution Reliability Initiative* – In 1998, the Company formalized its reliability data analysis and introduced the *Distribution Reliability Initiative* project. The project involves the replacement of deteriorated poles, conductor and hardware to reduce both the frequency and duration of power interruptions to the customers served by specific distribution lines referred to as the worst-performing feeders. Customers supplied by the worst-performing feeders experience power interruptions more often or of longer duration than the Company average. Individual feeder projects are identified and prioritized based on their historic interruption statistics. Engineering assessments are completed to determine whether targeted capital investments would improve the reliability experienced by customers served by these feeders.

[3] The *Rebuild Distribution Lines* project was introduced in its current form in 2004. See response to Request for Information CA-NP-043.

**Reliability and Capital Expenditures**
**1990 – 2019**

# Reliability and Capital Expenditure 1990 - 2019

| Year | SAIDI | SAIFI | 5 Year Rolling Average SAIDI | 5 Year Rolling Average SAIFI | Capital Expenditure ($000) |
|---|---|---|---|---|---|
| 1990 | 4.55 | 2.46 | 3.78 | 2.47 | 67,074 |
| 1991 | 3.26 | 2.09 | 3.56 | 2.29 | 43,322 |
| 1992 | 4.75 | 3.46 | 3.74 | 2.44 | 43,080 |
| 1993 | 4.64 | 3.68 | 3.93 | 2.69 | 33,861 |
| 1994 | 4.81 | 2.41 | 4.40 | 2.82 | 34,774 |
| 1995 | 5.34 | 3.70 | 4.56 | 3.07 | 30,782 |
| 1996 | 3.87 | 2.66 | 4.68 | 3.18 | 28,770 |
| 1997 | 3.73 | 2.72 | 4.48 | 3.03 | 30,965 |
| 1998 | 4.91 | 3.21 | 4.53 | 2.94 | 45,245 |
| 1999 | 5.70 | 4.72 | 4.71 | 3.40 | 42,282 |
| 2000 | 5.32 | 4.11 | 4.71 | 3.48 | 42,836 |
| 2001 | 3.42 | 2.99 | 4.62 | 3.55 | 66,305 |
| 2002 | 4.18 | 3.25 | 4.71 | 3.66 | 58,170 |
| 2003 | 4.11 | 3.00 | 4.55 | 3.61 | 64,314 |
| 2004 | 4.56 | 3.10 | 4.32 | 3.29 | 57,761 |
| 2005 | 3.27 | 2.57 | 3.91 | 2.98 | 52,980 |
| 2006 | 2.89 | 2.65 | 3.80 | 2.91 | 58,629 |
| 2007 | 2.65 | 2.11 | 3.50 | 2.69 | 68,485 |
| 2008 | 2.67 | 2.35 | 3.21 | 2.56 | 63,170 |
| 2009 | 2.57 | 1.99 | 2.81 | 2.33 | 70,037 |
| 2010 | 2.59 | 1.52 | 2.67 | 2.12 | 73,580 |
| 2011 | 2.57 | 1.70 | 2.61 | 1.93 | 76,171 |
| 2012 | 2.44 | 1.72 | 2.57 | 1.86 | 80,042 |
| 2013 | 2.23 | 1.71 | 2.48 | 1.73 | 82,361 |
| 2014 | 2.93 | 2.44 | 2.55 | 1.82 | 114,316 |
| 2015 | 2.36 | 2.11 | 2.51 | 1.94 | 100,359 |
| 2016 | 2.24 | 1.36 | 2.44 | 1.87 | 96,073 |
| 2017 | 2.28 | 1.66 | 2.41 | 1.86 | 91,040 |
| 2018 | 2.65 | 1.67 | 2.49 | 1.85 | 92,098 |
| 2019 | 2.34 | 1.62 | 2.37 | 1.68 | 106,566 |

# Quality of Service and Reliability of Supply Report

**D. G. Brown P. Eng**

NP - General Rate Application - 2008
Information - # 18
Filed: Oct. 26, 2007 Board Secretary: CB



October 22, 1998

17 Crestview Drive
Halifax, Nova Scotia
B3P 1G1

Ms. Cheryl Blundon
Clerk of the Board
Board of Commissioners of Public Utilities
P. O. Box 21040
St. John's, Newfoundland
A1A 5B2

Dear Ms. Blundon:

**Re: Report on Newfoundland Light & Power Company Limited - Quality of Service and Reliability of Supply**

I am sending you a copy of the subject report in its final form. Since you have a filing deadline I am sending one copy. Additional copies will come shortly.

I have tried to comply with the Board's request for structural changes, clarification and additional data.

I hope that this final version meets with Board approval. As I mentioned in my letter of July 9, I have enjoyed working with you and your Board over the last number of months.

If you have further questions, requests or requirements on my part, you may let me know at your convenience.

Yours very truly,

D.G. Brown

D. G. Brown, P. Eng.

Encl.

# Report on

# Newfoundland Light & Power Co., Limited

Re

# Quality of Service and Reliability of Supply

Prepared for the

Board of Commissioners of Public Utilities
Newfoundland and Labrador

By

D. G. Brown, P. Eng.

## Summary

On February 1, 1998, D. G. Brown, P. Eng. (the Engineer) was retained by the Board of Commissioners of the Public Utilities of Newfoundland (the Board) to review and report on the quality of service and reliability of supply of Newfoundland Light & Power Company, Limited (the Company).

The process followed in preparing the report was as follows:

- Prepare Terms of Reference for undertaking study.
- Review documents obtained from the Company and the Board.
- Prepare detailed set of questions for meeting with the Company staff.
- Meet with Company staff for discussions on Company activities as per the Terms of Reference.
- Visit Company facilities in the St. John's area.
- Study additional documentation obtained from the Company during the visit to St. John's.

The following is a summary of the findings:

- Voltage and Frequency - The Company follows the Canadian Standards Association specification of ±5% at customers premises but is confident that it meets the ±4% range specified by the Public Utilities Act. Frequency control is beyond the capability of the Company.

- Reliability - The Company's reliability performance is lower than that of the Canadian utility average but in light of the factors facing the utility, particularly problems with insulator failure and weather conditions, the result is reasonable.

- Customer Service/Customer Inquiries - The Company has made a significant commitment to provide high quality customer service and has dedicated the resources necessary to achieve the commitment.

- Generation Planning - The Company has a good load forecasting capability, adequate power system planning criteria and the ability to carry out planning studies as needed.

- Transmission Planning - The Company's transmission planning criteria are reasonable and the Company adequately monitors the need for new transmission and has the capability to determine the optimum subtransmission expansion.

- Distribution Planning - The Company's distribution planning "guidelines" clearly identifies the Company's distribution planning process. The Company has the necessary software and staff to assess its distribution needs.

- System Operations - The Company's communications network, administrative procedures and systems, and software and hardware are sufficient to properly and effectively operate the component parts of its system.

- Safety - The Company has a good health and safety program. When compared with other utilities, the Company's performance is good.

- Environment - The Company's Environmental Management System (EMS) is adequate. The Company appears to be conscious of its commitment to operate in an environmentally responsible manner. It will be using the ISO 14000 system which many Canadian utilities are adopting.

- Operations and Maintenance - General - After a review of many documents and statistics it appears that the Company's productivity and control of costs are adequate and its reorganization and "downsizing" has not adversely affected customer service and/or reliability.

- Thermal Generation Operations and Maintenance - The Company has very little thermal generation capacity, that which it has principally combustion turbines, appears to be well maintained and staff is trained to properly utilize the equipment.

- Hydro Generation Operations and Maintenance - The Company has a valuable asset in its hydro generation capacity. It realizes the value since it produces energy at very low cost. The Company is working to maintain and operate the many hydro electric stations to maximize their economic benefit to the Company and its customers.

- Transmission/Substation Operations and Maintenance - The Company is following good utility practice in the operation and maintenance of its transmission and subtransmission systems. It is regularly subjected to severe ice and wind storms which result in severely damaged transmission. The Company has undertaken a program of rebuilding to improve the strength and ultimately the reliability of the transmission subjected to major storm damage.

- Distribution Operations and Maintenance - The Company has a satisfactory program of distribution maintenance. By using reliability statistics it is able to give priority to capital expenditures for distribution rebuilds. In this regard, it is following good utility practice.

- Contingency Planning - The Company has developed detailed restoration procedures for each region and/or area of its system. These restoration procedures, when fully developed, will provide the utility personnel with plans as to how to cater to different emergencies in different parts of the system.

- Addenda - The report prepared for the Board went somewhat beyond the Terms of Reference as follows:

  1) Year 2000 Problem (Y2K)
  2) Company Objectives
  3) Company-Newfoundland Hydro Interface
  4) Long term Generation and transmission development

## Conclusions

After a thorough review of the material provided by the Board and the Company, detailed discussion with senior people at the Company's offices and visits to some of the Company's facilities in the St. John's region, the Engineer concludes that the Company is doing an effective job in maintaining and operating its facilities in the provision of electric service to its customers. It is noted that the Company's emphasis, now that there is practically no load growth on the system, is directed more toward customer service than construction of new facilities. The reliability of supply to Company customers is considered to be acceptable, although lower than the average for Canadian utilities. It is important that the utility maintain and in fact seek to improve its performance in this regard.

## Recommendations

1. The Company and/or the Board should seek clarification of the Public Utilities Act, Section 37. The Canadian Standards Association Voltage Variations Specification should be reviewed, Specification on Frequency should definitely be reviewed as a variation of 4% is not a practical consideration.

2. The Board should periodically call for a review of the statistics shown in the Utility Interruption Report. Significant variation in the 12-month to date data should require an explanation by the Utility.

3. There should be a more formal reconciliation of load forecast differences between the forecasts prepared by the Company and by Newfoundland Hydro.

4. If the Government's Energy Policy Review does not address the issue of joint planning between Newfoundland Hydro and the Company, the Board should review the issue.

5. The Board should direct Newfoundland Hydro and the Company to regularly review the joint restoration plans and to show that the required training has taken place.

6. The Company should keep the Board informed of its efforts to undertake the ISO 14000 Environmental Management System.

7. The Board should request the Company to report on the effectiveness of the TVD system.

8. The Company should keep the Board informed of the effectiveness of its restoration programs in each Company area. The effective implementation of these plans can contribute significantly to reliability of supply and customer satisfaction.

## TABLE OF CONTENTS

## 1.0 Introduction

By agreement dated 1 February 1998 between the Board of Commissioners of Public Utilities of Newfoundland (the "Board") and Daniel G. Brown, P. Eng. (the "Engineer"), this study is to provide a review of the quality of electric power service in the province of Newfoundland, specifically that area of the province served by Newfoundland Light & Power Company, Limited (the "Company"). The review is to encompass all aspects of the Company's activities which impact on the quality of service and/or the reliability of supply to the customers of the Company.

Prior to the commencement of work under this contract, the Board was provided with Terms of Reference for the conduct of the Study. These Terms of Reference were developed after a review of documents provided by the Company and the Board and meetings with Board members and Company staff. The Terms of Reference are attached as Appendix 1.

To complete the assignment, the Engineer reviewed other documents obtained from the Company and the Board. In addition, meetings with Company staff were held to discuss in detail the Terms of Reference and to solicit data in response to questions raised in the Terms of Reference. As well, some of the Company facilities were visited including a hydro electric generating station, two substations, the Regional Centre in St. John's including a visit to the Meter Shop, the Garage and the Storeroom. While in St. John's, a visual inspection of some of the Company's distribution and transmission circuits was made. As well, an opportunity was taken to visit the Customer Service Centre and the Customer Call Centre and to meet with some of the Customer Service employees.

In reviewing the quality of service the investigation was concerned principally with voltage levels and supply continuity. Other items such as wave form, frequency and harmonics were not included in the review. In today's environment however, customer service has come to include much more than voltage level and continuity of supply. Customers expect their utilities to provide quick and accurate responses to enquiries.

This has resulted in many utilities investing heavily in Customer Service Centres and computer hardware and software to satisfy customer concerns.

With respect to reliability, the principle concern was to review the outage statistics and to discuss with Company staff their approach to maintaining and/or improving continuity of supply.

Quality of service and reliability are functions of a number of things, including the quality, age and condition of the utility's assets, the operation and maintenance of the assets, staffing and staff training, particularly with respect to rapid response to system disturbances which result in customer outage. As mentioned above, in today's environment quality of service also includes customer contact and attempts to satisfy customer concerns with any aspect of the utility's activity.

The report which follows will address each item in the Terms of Reference in sequence.

## 2.0 Quality of Service

### 2.1 Voltage and Frequency

While Section 37 of the Public Utilities Act states that "variation of voltage and frequency at a customer's terminal shall not exceed 4% from the declared constant voltage or frequency", the Canadian Standards Association (CSA) specifies voltage variation in the order of 5%. The Company complies with CSA standards. The Company attempts to keep voltage variations at a customer's premises within the 4% range specified by the Public Utilities Act.

The Company has a sophisticated distribution planning software package, "PSS-U" which is used to analyse feeder loadings and feeder voltage profiles. This model is used when there are changes in load along the feeder so that the voltage profile can be calculated. Distribution feeders are analysed using the PSS-U system when:

1) there are significant loads added to or removed from the feeder;
2) there are significant changes in feeder configuration;
3) there is a significant increase in size of the conductor used on the feeder;
4) when maximum/minimum voltage regulator tap position indicates concerns;
5) when annual voltage surveys indicate possible concerns.

If the voltage is not within acceptable limits, various alternatives to correct the situation are analysed and the least long-term cost solution is adopted.

The Company has undertaken a pilot project to test a device which can be placed in a customer's home to monitor voltage. The DCI (Design Concepts International) Sentry System is part of an overall effort to measure and improve the power quality that customers receive from the Company. This pilot project focuses on real time voltage measurement within the premises of a small sample of customers and company facilities. Its purpose is to better understand the power quality customers are receiving and to improve the Company's response time to customer outages.

At this stage in the project, approximately 60 measurement devices have been installed at customer premises and company facilities. Voltage measurements are being sent to a central facility on a daily cycle. These voltage measurements are also sent whenever they go outside pre-determined levels. This information, while still in relatively crude form, is available on a real time basis to selected staff within the company.

At the present time, one technical person has been designated to review the information on a daily basis and report problems to either the System Control Centre or regional staff. Plans are in place to organize the information so that it can be used more easily by the Company's operating staff. Nova Scotia Power has a similar program.

Maintenance of frequency is beyond the control of the Company as most of the generation in the province is owned and operated by Newfoundland and Labrador Hydro ("Hydro"). Hydro is thus responsible for maintenance of system frequency.

During major system disturbances the Company is called upon to automatically shed load to help maintain system frequency. The first integrated underfrequency (U/F) load shed plan was developed in 1976. Since then, in conjunction with the Company, Deer Lake Power, Abitibi Price and Newfoundland & Labrador Hydro (Hydro) has coordinated updates to the overall plan on a periodic basis. The latest update was in October 1997.

Hydro coordinates the review of the plan and identifies the magnitude of the loads that must be shed at various frequency levels. In order to meet its commitments, the Company has installed U/F load shed equipment at substations which are remotely controlled, have circuit breakers, and have reasonably high loads. In some substations the load has been grouped into several blocks to provide flexibility. Critical loads such as hospitals are excluded from the plan.

The Company has approximately 542 MW of peak load equipped with U/F load shed relays compared to the 406.5 MW that is currently required as part of the October 1997 scheme update. The difference of 135.5 MW provides the Company some flexibility in load shedding. On an annual basis, the SAIFI and SAIDI statistics for customers under the load shed plan are reviewed and blocks of load are moved in or out of the active plan to minimize the inconvenience associated with U/F outages.

2.2 Reliability

The common reliability measures used by the Canadian electricity industry are as follows:

1. SAIFI - System Average Interruption Frequency Index (total customer interruptions divided by total number of customers served)

2. SAIDI - System Average Interruption Duration Index (total customer hours of interruptions divided by total number of customers served)

3. CAIDI - Customer Average Interruption Duration Index (total customer hours of interruptions divided by total number of interruptions)

The method used by the Company to acquire and record interruption data on the transmission and distribution systems was reviewed. The Company collects data on transmission line and distribution lien incidents that cause customer service interruptions. The data collected is consistent with data requirements necessary to complete the annual Canadian Electricity Association (CEA) "Service Continuity report on Distribution System Performance in Canadian Electrical Utilities". The following table contains a list of data which is collected for each incident.

**Interruption Report Data**

| | |
|---|---|
| Location | Area, feeder, transmission line, details |
| Time | Began, ended |
| Customer | Number of customers affected |
| Type of Interruption | Scheduled, unscheduled |
| Type of Trouble | Underground, overhead |
| Cause of Trouble | Wind, lightning, defective equipment, etc. |
| Device which Isolated Fault | Fuse, recloser, breaker, etc. |
| Part that Failed | Conductor, insulator, etc. |
| Voltage | Line to ground voltage |
| Weather Condition | Temperature, wind, precipitation |

On a monthly basis, the data is entered into a software program. The power failure summary, interruption report summary, interruption report feeder detail, and the Public Utilities Board reports are generated from this data base.

The system is consistent with industry recording and reporting systems. As the indices are reported by the utility to the CEA comparisons may be made among utilities and on a time series for a given utility. Table 1 shows the comparison between the Company's performance and the performance of the Canadian utilities taken as a group.

TABLE 1

**Newfoundland Light and Power Reliability Statistics**

| | SAIFI | | | SAIDI | | | CAIDI | | |
|---|---|---|---|---|---|---|---|---|---|
| **Year** | **NP** | **NP1)** | **CAN** | **NP** | **NP1)** | **CAN** | **NP** | **NP1)** | **CAN** |
| 1993 | 4.77 | 3.66 | 3.34 | 5.50 | 4.62 | 3.93 | 1.15 | 1.26 | 1.13 |
| 1996 | 3.82 | 2.66 | 2.39 | 4.22 | 3.86 | 2.86 | 1.10 | 1.45 | 1.20 |

NP - Newfoundland Power
NP1) - Newfoundland Power - adjusted for loss of supply due to Newfoundland Hydro system.
CAN - Canadian Average

As noted from Table 1, the Company's performance is somewhat below the Canadian average. Part of the measure of poor performance is related to loss of supply due to interruptions caused by under frequency relay operation and/or other loss of supply attributed to Hydro. If the statistics are adjusted to remove loss of supply by Hydro the performance is somewhat better but still below the Canadian average.

Two of the major causes of poor performance, as noted in the Company's statistics, can be attributed to defective equipment and adverse weather. Details are shown in Table 2.

TABLE 2

**Effect of Defective Equipment and Adverse Weather on Company Reliability**

| Year | Cause | SAIFI | SAIDI | CAIDI |
|---|---|---|---|---|
| 1993 | Defective Equipment | 1.09 | 1.45 | 1.33 |
| | Adverse Weather | 0.20 | 0.39 | 1.89 |
| 1996 | Defective Equipment | 0.64 | 0.77 | 1.21 |
| | Adverse Weather | 0.13 | 0.18 | 1.44 |

The Company is experiencing many outages due to insulator failure. In March 1997 the Company supplied the Board with a report outlining the problem and its contribution to poor performance on the Company's system. The Company has undertaken a program to replace potentially defective insulators on the transmission and distribution systems. Much of this plan will have been implemented on the transmission and substation systems by the time the next report is filed.

In 1997, the Company began a formal program to replace defective insulators on critical sections of the distribution system. The insulators are porcelain two piece pin type and dead-end type. The failures are due to the expansion of the cement used to hold the insulator together, the phenomenon is known as "cement growth". The program requires testing and subsequent replacement of defective insulators. The 1997 cost was $254,000, the projected cost for 1998 is $978,000 and for 1999 $1,081,000. The program is planned to be completed in 2000 at a preliminary total cost estimate of $3,779,000.

In 1997 a major (five year) rebuild project was started on the DUN-01 feeder in the Placentia Bay area. The project is primarily aimed at replacing deteriorated #2 ACSR conductor, and some insulators and poles will also be replaced. In

1997, 4.6 km of conductor was replaced and in 1998, 8.7 km of conductor will be replaced. The project is scheduled to be completed in 2001.

The Company has undertaken to replace all deteriorated #2 ACSR conductor on trunk feeders in the St. John's Region. This project has been ongoing for several years and is currently scheduled to be completed in 2000.

The Company's 1996 performance relative to Atlantic Canadian utilities is shown in Table 3. It shows the Company has performed well in this comparison.

TABLE 3

**1996 Reliability Statistics**
**Newfoundland Power/Atlantic Canada/Canada**

| | SAIFI | SAIDI | CAIDI |
|---|---|---|---|
| Newfoundland Power | 3.82 | 4.22 | 1.10 |
| Atlantic Canada[1)] | 4.75 | 8.25 | 1.73 |
| Canada[1)] | 2.39 | 2.86 | 1.20 |

[1)] Source - Nova Scotia Utility and Review Board - Report on Nova Scotia Power Incorporated Power Outages November and December 1997, Report NSUARB-P-401.20 dated 9 February 1998.

The Company had been experiencing problems with its underground distribution system particularly in Virginia Park. In response the Board retained Agra Shaw Mont to study the problem and to recommend solutions.

The Virginia Park underground replacement program is completed for 1998. A total of 40 underground services were replaced in 1998 as per the accelerated replacement approach outlined in Section 5.2 of the report: "No Splicing Policy and an Accelerated Replacement Program in the Virginia Park Underground Distribution System" which was submitted to the PUB on September 22, 1997.

The current performance of the Virginia Park Underground system is summarized as follows:

| Year | Number of Underground Service Faults |
|---|---|
| 1996 | 20 |
| 1997 | 3 |
| 1998 (YTD) | 2 |

Note: There were fewer faults experienced in 1997 than in any year since 1997 when records of underground service faults began.

Appendix 2 shows the latest interruption report by area which shows all interruptions including loss of supply. The Company states that its performance has been generally improving over the past five years. This past year has been particularly difficult due to the number of ice storms this winter and spring and a much more severe lightning frequency than normal in summer.

It is noted that there is a wide variation in reliability performance from area to area. This is not unexpected due to the variation in weather severity across the province.

The report is filed monthly with the Board so the Board is able to monitor performance and particularly, changes in performance. It is recommended that the Board review these reports and seek explanations for significant variations among the areas, especially on the "12 Month To Date" data.

Reliability of the Company's generation system is not critical to customer supply. The Company has twenty-two hydro electric stations, three combustion turbines and at present eight small diesel generation units. Since there are a great number of these units and they are all relatively small, the outage of one or more does not materially affect the supply to customers. Most of the power and energy supplied to the customers of the Company is purchased from Hydro. While the Company does not report generation outage statistics to the CEA, it does keep track of its performance to develop an availability index, which it uses internally.

The Island of Newfoundland is subjected to some very severe weather conditions which create problems for both utilities. The Company has initiated a program such that when it must rebuild transmission, due to failure because of ice or wind, it replaces the failed circuits or circuit elements with system elements designed to withstand higher ice and wind loadings, in the exposed areas.

The Company has undertaken a review of its various substations to develop a plan to restore service in the event of a loss of a major piece of equipment. This plan gives a list of transformer voltages, winding configuration, taps and capacity (transformer technical details) at all substations. It then identifies spare units which could be used as replacements. This will also contribute to the reliability of supply.

The Company intends to be able to respond to any outage report within two hours after receiving the report. This is a quantitative measure which can be used in determining the strategic location and number of people and resources needed to restore service in the event of an outage.

To ensure the target is met, the Company logs trouble calls into the Problem Call Logging System (PCLS). The operating regions review the PCLS information on a periodic basis to track the status of the 2 hour target. For 1998, the year-to-date average response time is approximately 80 minutes.

The Company's performance, from a reliability point of view, is acceptable, given the conditions under which it operates. Some aspects of this subject will be covered further in the report under Restoration Program Review.

2.3 Customer Service/Customer Inquiries

Electric utility customers have come to expect more than electrical energy in their dealings with the utility. Many customers today expect service and rapid response to inquiries about any aspect of their electrical service such as connections, disconnections, billing, concerns about safety, voltage, etc. Most utilities have responded to this change in consumer culture by becoming more "customer oriented". A review of the Company's 1997 Annual Report indicates that the Company is also responding to the customer's demands.

The Engineer visited the Customer Services Call Centre and met with senior people in the Customer Service and Telecommunications Group. During this visit typical customer inquiries and the system used for processing them were reviewed.

The Company officials made available customer satisfaction research summaries for review. The results indicate a high degree of customer satisfaction with the Call Centre, Cashier, and Field Service.

One aspect of customer utility interface which may be specific to the Company is the requirement that each Manager complete five customer visits per quarter and Regional Managers complete ten customer visits per quarter. The purpose of these visits is to enable the utility people, especially senior staff, to gain an understanding of the issues that concern customers, particularly medium to large commercial customers.

The customer service system is currently undergoing a series of enhancements to improve payment plans, and the response time to customer inquiries. These are expected to be incorporated by the end of 1998. These system changes plus the replacement of software and hardware should enable the Company to better serve its customers and provide more rapid response to customer inquiries.

It is the Engineer's opinion that the Company is serious in its commitment to provide high quality customer service in a fair and responsive manner and that the Company has dedicated the resources, both human and capital, to achieve its goal.

# 3.0 Planning

## 3.1 Generation Planning

Major generation additions to the interconnected Island system in Newfoundland have been commissioned by Hydro over the last three decades.

Apart from a relatively small hydro electric station at Rose Blanche Brook, the Company has not recently planned, designed, or installed new generation.

Since the Company's load represents the largest component of the total electricity demand on the Island of Newfoundland and since, at least at present, planning for new generation resides with Hydro, it is important that the two utilities work closely together to an agreed generation expansion plan.

The load forecast prepared by the Company is the biggest input into the five year budget of both the Company and Hydro. In the past, the Company has met with Hydro to compare and reconcile the Company's load forecasts. In recent years the Company and Hydro have exchanged forecasts and reconciled any differences during a telephone conversation. During this conversation the various assumptions used in preparing the forecast, as well as, any changes in methodology are discussed. Generally, most forecast variances can be attributed to differences in economic assumptions. Hydro uses projections provided by the Provincial Government while the Company uses the Conference Board of Canada.

It is recommended that the two utilities attempt to reach a consensus on the forecast and its component parts. The long term total forecast for the Island system will drive the expected need for new capacity and/or energy supplies. Here again it is important that the two utilities at least understand each other's forecasts and that the Company understand and comment on the long term forecast by Hydro.

The document, Newfoundland Power System Planning Technical Criteria detailed in Appendix 3, states the objectives and defines the power quality and reliability criteria for the Company in planning to meet its customer load.

The normal operating objective and the abnormal operating objective, Appendix 3, needs some clarification for interpretation. The reliability objective and the transient power quality objectives are more qualitative than quantitative. This requires more detailed justification for expenditures to achieve the objectives.

Recently the utilities studied the feasibility of redeveloping the Company's thermal plant on the south side of St. John's Harbour. The study was well done. The software and hardware available to the two utilities should enable them to work cooperatively when joint studies are required.

One of the problems which is bound to occur in a joint planning process, in establishing the optimum generation expansion plan, is related to the two different capital structures of Hydro and the Company. The discount rate used to calculate present values is bound to be different, since the Company pays income tax and has a capital structure which contains equity as well as debt, its discount rate is higher than that of a "crown" corporation.

Other problems in the immediate future are the uncertainties surrounding the electrical demand and the timing of the proposed smelter operation for Argentia. As well, the recently announced expansion of the Churchill Falls Generating Station and the development of the Lower Churchill River with a possible interconnection to the Island of Newfoundland, adds another degree of uncertainty. However it is the opinion of the Engineer that the two utilities should jointly arrive at the least cost optimum expansion plan with and without major generation and/or loads such as the Churchill Falls transmission or the smelter at Argentia. This plan can be used to test variations in expansion planning. The utilities together have the staff and the capability to undertake such a planning exercise.

In the absence of joint planning for capacity expansion and perhaps even in the presence of such joint planning, the options available to the Company are limited to demand side management (DSM), curtailable rates, cogeneration and perhaps small scale combustion and/or hydraulic turbines. Some of the Company's DSM initiatives are as follows:

- The Wrap up for Savings Program, the objective of which is to improve energy efficiency, and enhance the comfort of electrical heated homes through rebates and advise on insulation.

- Curtailable Service Option, the objective of which is to reduce electrical demand by curtailing load. This option provides approximately five MW of curtailable load to the Company.

- Residential and Commercial Heat Pumps Program, the objective of which is to evaluate the operational costs and customer acceptance of these systems.

- Load Research is being completed on customers with specific loads such as heat pumps, electric heat with R-2000 insulation, etc.

- Customer Energy Services. Trained employees respond to customer inquiries on energy efficiency, electric heating designs, energy efficient thermostats and financing.

The Curtailable Service Option is meeting the Company's expectation with respect to customer participation and technical success.

In 1994, it was estimated that the take-up for a curtailable load rate option would total about 5 MW. This estimate was based on a customer survey and a pilot project. The Curtailable Service Option was implemented in 1994 and by 1997 the amount of curtailable load available totalled about 6 MW, exceeding initial estimates. At the current price of $29/kVA, the Company now expects its current customer base has the potential to support up to 10 MW of total curtailable load.

The intreruption of the curtailable load has been about 85% to 90% successful. (Success measured in % of customers successfully curtailing load on request.)

The announcement by the provincial Government on the Energy Policy Review could have a significant impact on future generation and DSM projects. It is the Company's intention to maintain the "status quo" until this Policy Review is completed.

3.2 Transmission Planning

The Company has criteria which it uses to determine when additional transmission is required to cater to load growth. The criteria shown in Appendix 4 cover the following subjects:

1. voltage
2. transmission line loading
3. transformer loading
4. reliability

These criteria are reasonable, based on comparisons with other utilities. Studies carried out by the Company over the past ten years are regularly updated, after the system load and energy forecast is tabled, to determine the need for transmission addition and/or strengthening.

In addition to transmission planning, transmission design has been a significant topic on the Island interconnected system because of transmission line failures due to ice and wind loading. The Company has identified sections or areas in its system where ice is potentially a problem. It has identified six zones ranging from normal to extreme and has determined design criteria to be implemented in each area. As noted previously when new transmission replaces existing transmission because of retirement and/or failure due to the wind and ice loading, the new design criteria are used to determine the final design for the replacement circuit.

The principal function of the transmission owned and operated by the Company is to supply area loads rather than serve as bulk transmission between major load and generation centres. Thus most of the Company's transmission is 66 kV with a relatively small amount of 138 kV. However, since the Company supplies the major load centre on the Island, St. John's, its subtransmission system reliability is vital to the service of most of the customers on the Island. The Company adequately monitors the need for new transmission and has the capability to determine the optimum subtransmission expansion.

3.3 Distribution Planning

A document entitled "Distribution Planning Guidelines" was reviewed. The document outlines the method of distribution planning in some detail. It also contains a significant section on technical criteria, which are more of a design than a planning nature, but do assist the planner in developing alternatives which are technically sound. The document also describes the responsibilities of the various departments and/or regions for planning and generating the annual budget and the five year forecast. This is a useful document and clearly identifies the Company's distribution planning process.

Distribution planning is carried out with the aid of sophisticated software, "PSS-U", and the distribution planning guidelines approved for use within the Company. The forecast of customer and energy growth by area is used as the starting point for the planning activity. Feeder reliability based on outage statistics, line inspections and operating data are used to create priorities for capital investment and reliability improvements.

Criteria for selection of projects to get budget approval are as follow.

Deterioration - The project is required to replace aging plant.

Growth - The project is required to service either a new load or an increasing existing load.

Safety - The project is required to ensure the safety and integrity of the power system.

Reliability - The project is required to reduce customer outages.

Regulations - The project is required as a result of some set of regulations. These include federal, provincial and municipal statutes; the joint use agreement, etc.

It is recognized that some projects could span several or all of these reasons. In the Engineer's opinion these criteria are useful. Budget items submitted to the Board should reference these.

The planning guidelines are maintained centrally but the distribution planning itself is carried out by engineering personnel in the regions. In this respect, the Company is de-centralized. This type of organization has the advantage of providing the planning and engineering people a good understanding of some of the problems associated with operating and maintaining the distribution system.

## 4.0 System Operations

As part of the review, the Company's System Control Centre was visited to observe the operation and to review, with staff, the functions of the Centre.

The operation of the principal generation and all of the high voltage transmission (230 kV) is performed by Hydro. The generation is dispatched by Hydro in consultation with the Company. Normally the Company's hydro stations are operated at the point of maximum efficiency except during periods of peak water inflow when they are operated at maximum power.

The storage reservoirs are regulated so that there is enough water to provide firm capacity over the winter peak period from December through March. The combustion turbines and diesel generators normally used for emergency and/or transmission backup, are dispatched by Hydro on an as needed basis. Since the principal function of dispatch is performed by Hydro the Company does not need sophisticated models for the operation of its own hydro and thermal system.

The responsibility for planned outages on the Company system is held by the operating areas. Personnel from these areas, subsets of the regions, notify the Control Centre and critical customers of any planned outages, prepare the switching orders and ensure that safe work practices are followed. Switching is done in accordance with the Company's documented Standard Protection Code. The Company has a computerized switching order program on its main frame computer and standard switching orders are available for routine jobs.

Before any planned outage, protection and line capacities are checked. A load flow analysis is completed to make sure that no overloading of looped circuits occurs. Planned outages for circuits of 138 kV are coordinated between Hydro and the Company. All planned outages on the Island interconnected system are coordinated between the Centres of Hydro and the Company.

There is close interaction between the Company's System Control Centre and Hydro's System Control Centre. There are backup communication links between the Centres to ensure communications circuits are available.

With respect to communications with customers, the Company has installed an automatic answering system (TVD). TVD stands for Telephony Video Data Ltd. of Auckland, New Zealand - the vendor of the product.

The TVD System is comprised of a series of PC based applications which, in conjunction with the capabilities of Newtel's telephone system, allow the Company to concurrently provide large numbers of customers with information regarding power outages in their area.

The system is comprised of the following applications:

- TVD Messaging - Creates and loads prerecorded outage announcements to the telephone system.
- TVD FaxOut - Creates faxes regarding outages and forwards them to a predetermined list of recipients.
- TVD SCADA - Interfaced with the SCADA system. When an outage is seen by the SCADA System TVD automatically creates a message.
- TVD Fault Reporter - An Automated Attendant allows customers to indicate the seriousness of their call before transferring to an operator.

The TVD was implemented in mid 1998. The performance to date has been good. Recent tests of the system indicate that a significant majority of customers get immediate access to the outage information that they desire. This is a big improvement from the past when, due to busy phone lines very few customers could get information during outage situations.

The basic communications network of the Company was completely renovated starting in the late Fall of 1995. The new network replaced an existing ten year old Management Information System (MIS) data network and the combination of radio repeaters and dedicated leased circuits which interconnected the System Control Centre to the various substations and generation stations. The new network gathers MIS data, SCADA data and radio traffic at the area offices and routes it around the Company over the Frame Relay Network of Newfoundland Telephone Company. This new network provides greatly enhanced communication capabilities and is expandable without hardware additions. This network is state-of-the-art and enables the Company to carry out control and communications with a reasonably expected degree of security and reliability over its whole system.

One of the more important aspects of power system protection is an administrative system to monitor control and inform those with a need to know, of relay settings particularly changes in settings. The Company's administrative procedure consists of a relay file which is stored on computer, printed and distributed to the System Control Centre, the Regional Engineering staffs and Hydro every three to six months. Before a setting may be changed the need for the change has to be identified and a request for change issued. After the setting is changed, the change is recorded in a master paper copy and communicated to the System Control Centre and region. The change is also recorded in the computer file for access by any person with a need to know.

If this administrative procedure is followed and adequate inter-company communication between Hydro and the Company is assured, especially at physical interfaces between the two organizations, the system should prevent mis-operation because of improper relay settings. An occasion arose recently, April 4, 1998, where it appeared to the Engineer that there was some problem associated with the administration of this system. A separate short report was prepared for the Board with respect to this item.

An important aspect of System Operations is operator training and restoration procedure documentation. Equally important in the context of Newfoundland, is a good working relationship between Control Centres. The Company has developed restoration plans for loss of supply from Hydro as well Hydro has developed restoration plans for the Holyrood Plant. The two control centres must work closely during system restoration.

When the Company experiences a loss of supply, it assesses the extent of the outage by contacting Hydro. If it appears that Hydro cannot restore power quickly, the Company will have its own hydro plants on the Southern Shore staffed. As soon as the plants are available, it will bring as much generation as possible on line. If Hydro has the bus energized at Hardwoods, the Company will synchronize with the Gas Turbine. If they are unable to start the Gas Turbine the Company will supply the station service to start the unit. Once the Gas Turbine is running, more feeders are energized and a transmission line route is selected to Holyrood. When a transmission route has been determined, appropriate breakers will be opened to accommodate restoration of the Holyrood Thermal Plant.

Restoration plans for the rest of the Island are similar. The operators of both companies discuss all plans before any restoration is started.

The Company has recently been discussing with Hydro the development of a generic operator training program.

The general conclusions with respect to System Operations are that the Company has the available software and hardware to properly and effectively operate the component parts of its system and to cooperate with Hydro during system disturbances.

## 5.0 Safety

Health and safety are two extremely important aspects in the efficient and economic operation of a utility.

The Company's health and safety corporate policy statement and some details of the health and safety management program were reviewed. The trends in the Company's performance with respect to accident frequency and severity and total calendar days lost were also studied. Compared to 1993, 1994 and 1995 the Company's record in 1996 and 1997 showed considerable improvement. Also compared to other utilities in the same CEA group (over 500 employees, under 10,000) the Company's performance was good in the severity rate category, average in the disabling injury/illness frequency rate and adequate in the all injury/illness frequency rate for 1996.

The Company's Safety Program is comprehensive with many on-going programs and activities related to accident prevention. Day-to-day activities such as safety meetings, safety training, workplace inspections, accident investigation, work rules and safe work procedures, and joint committee activities are the backbone on which safety is managed.

The following initiatives have bene given special emphasis in 1998.

1. Corporate Safety Targets
2. Risk Management/job Planning
3. Safety Audits
4. Safety Management System (SMS)
5. Newfoundland Power Safety Week
6. Safety Action Plans
7. Corporate Safety Council
8. Fall Protection
9. Flame Resistant Clothing
10. Contractor Safety
11. Executive Seminar - Health & Safety Management

12. Critical Incident Protocol
13. Safety Leadership Recognition Awards

The facility used by the Company for testing of gloves and hot sticks employed in live line maintenance was visited. It appeared to be well managed.

The Company has a good health and safety program.

## 6.0 Environment

Senior people charged with managing the Company's environmental efforts were interviewed. The mandate and Terms of Reference of the Environment Committee of the Board of Directors of the Company was reviewed. The Environment Committee of the Board is a sub-committee of the full Board of Directors and as such reports to it. It regularly meets with management to ensure the company is operating in an environmentally responsible manner and also conducts site visits to see portions of the Company operations first hand. In the opinion of the Engineer, the Company has adequately addressed its responsibility for the impact of its activities on the environment.

Since the Company operates very little thermal generation, it has little impact on air emission and other emissions associated with thermal plant operation. When it ultimately decommissions its thermal station on the south side of St. John's Harbour there may be some site cleanup required. A plan has been developed to cater to this problem as follows.

In the period between the mothballing and the present time, the following work has been carried out at the plant:

- friable asbestos removed
- bunker C storage tank and associated lines drained and cleaned
- bunker C storage tank subsurface cleanup performed
- fuels and hazardous materials removed
- main station transformers de-energized and drained
- weekly inspections implemented

Legislation requires that the fuel tank be removed within three years of the last use. This is currently underway. As well, the pole line to the water reservoir is being taken down for safety reasons.

The Company is currently notifying affected parties of its intention to apply to the PUB for permission to decommission the plant. Specific plans for the decommissioning have yet to be formulated but the Environmental Assessment Division of the Department of Environment has reviewed the site and advised that there is no need to register the proposed work under the Environmental Assessment Act. All demolition and disposal of materials will be done in accordance with the appropriate legislation and regulations.

One of the problems plaguing utilities over the last few years has been the identification of PCB filled equipment and the disposition of high and low level PCB's. The Company has a policy of decontaminating low level PCB oils and sending a high level PCB outside the province for ultimate destruction. In the interim, moderate level PCB's are stored in a secure storage area at the Company's Duffy Place headquarters. Procedures are in place to adequately handle spills of contaminated insulation oil as is the case with most utilities.

The Company's right-of-way maintenance program involves tree trimming and tree removal and in certain areas, the use of herbicides. Where herbicides are used, a policy document specifies rules to be followed. These rules are followed by Company staff and/or contractors retained by the Company to carry out the work.

The Company is aware of concerns with respect to the disposition of chemically treated wood and has a procedure for handling this material when it is no longer of use to the organization.

In cooperation with the Department of Fisheries and Oceans, the Company has developed a procedure to ensure continuous water release from storage dams when required. In the past, when gates have had to be shut for maintenance and/or water control, some problems have arisen but procedures have been developed to overcome these. The Company is committed to ensuring a continuous water flow where required even if it involves pumping.

The Environmental Managemnet System (EMS) the Company employs is a collection of policies and procedure-based systems which support the utility's environmental commitment.

As a member of CEA the Company is committed to the recently (1997) announced "Environmental Commitment and Responsibility Program". The Program consists of five features, which are:

1. a Declaration of Principles, each having Measures with Indicators;

2. a commitment to implement an ISO 14001 consistent environmental management system (EMS);

3. a Public Advisory Panel (the Panel);

4. a Performance Monitoring and Reporting Process including independent public verification; and

5. a comprehensive communications strategy.

The Declaration of Principles is a commitment to endorse the concept of sustainable development. implementing an ISO 14001 consistent EMS provides each member with the means to achieve the level of environmental and business performance the Program strives for. For all companies generating electricity, it will be necessary to have the Corporate and generating components of the EMS in place by the end of 1999. transmission, distribution and all other aspects of the business will have to be completed by the end of the year 2002. For companies involved only in the transmission and distribution business their corporate component is also due by the end of 2002.

By participating, the Company's EMS will be in the same as all other Canadian electrical utilities.

The list of environmental audits undertaken since 1992 and the proposed list for 1998 was reviewed as well as samples of audits completed.

## 7.0 Operation and Maintenance

### 7.1 General

The Engineer reviewed the capital and operating expenses incurred over the past seven years. This information was provided in detail for easy review. In addition, the CEA data on productivity were reviewed.

Since the Company purchases approximately 90% of the total energy required, a lot of its costs are outside direct control. A review of the 1997 Annual Report indicates that total operating expenses exclusive of purchased power, depreciation, finance charges and net income, represents only 16.7% of the total. The Company has made an effort to control its operating expenses and has reasonably good results with respect to productivity when compared with the CEA composite productivity data.

It must be borne in mind that comparisons between any one utility and the composite of CEA data often requires so much explanation of the variations among utilities that the comparison loses a lot of its meaning in interpretation. One thing that can be done is to look at directional trends of the CEA composite and the utility being analysed. In this respect, the utility is following the general trend set by the utility industry in Canada, relatively constant per unit cost per kilowatt hour delivered and lower cost in dollars per customer as Table 4 below shows.

TABLE 4

**Newfoundland Power and CEA Composite Cost Comparison**

| | Cost per kWh | | Cost per Customer | |
|---|---|---|---|---|
| **Year** | **Nfld. Power** | **CEA Composite** | **Nfld. Power** | **CEA Composite** |
| 1993 | $0.072 | $0.050 | $1,583.24 | $1,700.93 |
| 1994 | $0.073 | $0.052 | $1,548.83 | $1,734.10 |
| 1995 | $0.073 | $0.052 | $1,568.07 | $1,752.02 |
| 1996 | $0.074 | $0.051 | $1,526.43 | $1,750.56 |
| 1997 | $0.073 | $0.055 | $1.533.01 | $1,929.52 |

Notes:

- All cost data are in current year dollars
- Newfoundland Power's cost per kWh includes the cost of purchased power from Hydro and is higher than the CEA Composite Costs because of the customer mix. The Company services primarily residential and small commercial customers which have lower energy use than the main industrial customers served by other utilities.
- In the CEA data base, "customers" is defined as the number of customer accounts.
- Source: CEA COPE Program files:
  Corporate Overall Costs Excluding Taxes
  Residential Customers
  Commercial Customers
  Industrial Customers
  Street and Area Light Customers
  Domestic Energy Delivered (Deliveries within Canada)

After a very thorough review of the data provided, it appears that costs are under control and productivity continues to improve.

The capital expenditures for the period 1993 through 1997 and the budget for 1998 were reviewed. These costs appear to be reasonable with no significant aberrations from year to year except under the category of Energy Supply where the expenditure budgeted for 1998 is significantly higher than previous years. This is due to the construction of a new hydro electric facility at Rose Blanche Brook.

There was considerable reduction in the number of regular employees on the Company's payroll, from 926 in 1988 to 705 in 1997. The 1988 number shown in the Annual Report is 926. The number for 1997 is 705. This measure is often used as an indicator of productivity and progress and it can be considered so provided there is no significant change in the reliability of supply and in the maintenance of Company assets.

From discussions with senior people from the Human Resources Group, it is concluded that many of the staff reductions have taken place because of reorganization and realignment of regions and districts.

The number of personnel employed as linemen has been reduced from a high of 187 in April of 1993 to 159 in April of 1998. The Company is hiring 8 additional linemen/apprentice linemen in 1998 to bring the total number of line staff to 167.

The frequency and duration of customer outages on teh Company's system (outages due to loss fo supply from Newfoundland Hydro are excluded) has been improving sicne 1993. The Table below shows the statistics.

TABLE 5

**Reliability Statistics 1993-1997**

| | 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|
| SAIFI | 3.66 | 4.38 | 3.68 | 2.66 | 2.76 |
| SAIDI | 4.62 | 19.55 | 5.31 | 3.86 | 3.71 |

With the reorganization and reallocation of the regional and district forces the Company should be able to continue to provide the service level it had been providing with this staff. The Company is staffing principally for operations rather than operations and construction and making more use of contractors for construction.

The cost of contractors for 1993 to 1998 is summarized below. During this period contractors were used fr pole installation and removal, vegetation management, underground cable trench excavation and back filling, property restoration (landscaping, paving, sidewalk replacement), meter change outs, flag person work, and in 1998 the Company started using contractors for oil spill clean ups and transmission line inspections. Contractors have also been used from time to time f line work. The costs for 1994 are higher than other years due to an increase in vegetation management work and due to restoration work associated with a major sleet storm on Avalon Peninsula. The costs for 1998 are higher due mainly to an increase in vegetation management cost, increased distribution capital work in the St. John's Region, a major sleet storm on the Bruin Peninsula, and contract labour associated with Information System activities.

TABLE 6

**Contract Labour Cost**

| Year | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 |
|---|---|---|---|---|---|---|
| Cost ($'000) | 1,178 | 3,174 | 1,353 | 1,936 | 2,058 | 4,007 |

Distribution crews are smaller, partly as a result of better highway access to distribution circuits. Even with the smaller staff the Company expects to be able to meet its objective of being able to respond to any outage report within two hours.

As part of the review of the Company's operations a tabulation of energy and power losses on the transmission and distribution system was reviewed. Table 7 shows the loss for the last five years for both functions.

## TABLE 7

### Transmission/Distribution Energy Losses[1) ] 1992 - 1996

| Year | Transmission | Distribution | Total |
|---|---|---|---|
| 1992 | 1.87 | 3.00 | 4.78 |
| 1993 | 1.11 | 3.27 | 4.30 |
| 1994 | 1.09 | 3.85 | 4.86 |
| 1995 | 1.96 | 2.63 | 4.51 |
| 1996 | 1.30 | 3.17 | 4.40 |

### Transmission/Distribution Peak Losses[1)] 1992 - 1996

| Year | Transmission | Distribution | Total |
|---|---|---|---|
| 1992 | 3.18 | 5.18 | 8.10 |
| 1993 | 1.96 | 5.88 | 7.62 |
| 1994 | 1.85 | 6.61 | 8.33 |
| 1995 | 3.33 | 4.58 | 7.66 |
| 1996 | 2.38 | 5.91 | 8.04 |

[1)] The energy loses are a percentage of total system energy (sales, losses, company use and wheeled). The percentage peak losses are a percentage of actual annual poeak.

It is difficult to make a comparison between the Company system and others since the Company has a mixture of rural and urban distribution, a relatively small subtransmission system and purchases most of its energy from Hydro.

The Engineer asked Company personnel to provide a detailed explanation of the method used to evaluate losses when purchasing equipment or designing transmission and distribution systems. The Company uses the CEA guide for loss evaluation. Data specific to the Company's operation is determined from the Company's recent marginal cost study. The method used by the Company is industry standard but should be periodically reviewed based on any revisions to the Company's estimate of marginal costs.

In summary, the Company's productivity and control of costs and its reorganization and "downsizing" has not adversely affected customer service and/or reliability. The Board should review the Company's performance in this regard, at least annually.

7.2 Thermal Generation Operations and Maintenance

With the closing of the St. John's thermal power station and the possible decommissioning of some diesel stations, the Company's thermal generation assets will be reduced considerably. The thermal generation maintenance planning process was reviewed with senior staff. The maintenance planning and inspection of the thermal facilities, in the opinion of the Engineer, is well done and the basis for long and short term maintenance should assure reliable operation of the equipment.

The Company developed plant restoration procedures for the combustion turbines for use after system outages. The Engineer reviewed the procedure developed for the Greenhill combustion turbine as part of the service restoration plan for the Burin Peninsula. Procedures developed and documented are detailed and should permit area operations staff to synchronize the unit to the system or to operate it in an isolated mode during system disturbances. Staff has been trained in the procedures and must perform one normal and one black start operation per month. This should assure the Company that the unit will be available when needed and that staff will be able to operate it effectively.

### 7.3 Hydro Generation, Operation and Maintenance

The Company has 22 hydro electric generation stations with a total capacity of 87.1 MW. The storages at these stations are operated to supply firm capacity to the system during the winter period, from December through March. While the stations are small and the total output in power and energy, represents less than 10% of the total energy demand of the utility, they are of extreme value. Since most of the stations are relatively old, their original capital costs and residual book values are low. They produce energy at a very low cost relative to today's marginal costs. The total operating costs for 1997 for the whole system represented 0.46 ¢/kilowatt hour. This is probably the lowest cost energy on the Island. Since this is a valuable asset, it is important that the Company maintain it. The maintenance planning process was reviewed. The Company is adequately maintaining its hydro system. When major replacement is required older components are replaced with more efficient designs to increase the energy output.

The Company has established black start and contingency plans. Some of the procedures are presently under review. One of the components of the review is to determine contingency plans, for service restoration, to ensure that critical loads such as hospitals can be served.

A vital part of the operation and maintenance with any hydro system is dam safety. The Engineer discussed the subject with senior staff at the Company and reviewed an Operations Manual bulletin on the subject. The Company has the subject well in hand and has established and documented a comprehensive Corporate Dam Safety Program.

In summary, it is the Engineer's opinion that the Company realizes the value of its hydro electric assets and is working diligently to maintain and operate the stations to maximize their economic benefit to the Company and its customers.

7.4 Transmission/Substation Operations and Maintenance

To comment on this subject, Senior Company personnel were interviewed. The maintenance and operations budget for transmission and substation facilities was reviewed. The Company's maintenance standards document, which contains guidelines for system maintenance was reviewed in detail. The transmission line inspection and maintenance procedures were reviewed.

A document entitled "Standard Protection Code", is a formalized procedure to ensure the status of the power system for those employees involved in operation and maintenance was reviewed. This document is revised periodically and all employees who are affected by this Guide are expected to review it and understand it.

Every two years employees receive a one day training session on the code. Additional sessions are held for new staff as required. Each region has a facilitator who provides training to local staff with refreshers on an annual basis or more often if required these sessions are typically a couple of hours long.

The rules in this document will allow personnel to maintain and operate the system with due regard to personal safety.

The operation and maintenance expenses for substations is relatively constant over the period 1991 through 1997 as well the budgeted amount for 1998 is similar. The expenditures for transmission operation and maintenance vary considerably from year to year with 1994 showing a peak generally attributed to mechanical treatment of transmission line right-of-way. The 1996/97 expenditures show an increased amount for this category, as well as an increased amount for inspection of overhead transmission lines.

The budgeted amount for 1998 for transmission operation and maintenance is significantly higher than the average of the previous seven years. The Company is addressing the problem of replacing defective insulators. This can be an expensive operation especially if hot line equipment is required. The maintenance practices and procedures employed by the Company, and the cost of operation and maintenance, is reasonable. The Company is carrying out its best efforts to ensure its customers of a reliable transmission system. The preventative maintenance practices with respect to inspection and testing of wooden transmission poles and the inspection and testing and cleaning of insulators is adequate.

The switching procedures and practices carried out by the Company are in accordance with the Standard Protection Code mentioned previously. The code is the responsibility of the Superintendent of the System Control Centre. Any changes would have to be approved by this person. The subject of switching procedures, has been referred to in Section 5. The Company is following good utility practice in this regard.

From the point of view of safety and efficient operation, it is important that system diagrams be maintained so that they truly reflect the current state of the system. The system used by the Company requires that detailed single-line diagrams be maintained and kept current for the eight operating areas, transmission lines, substations, generating stations and mobile equipment.

The operating areas are responsible for updates. The proposed changes are forwarded to a coordinator who assures that drawings are updated and sent to the areas for field verification . After field verification the regional/area engineer must stamp the drawings showing approval. The coordinator then forwards copies to all manual holders. Based on a review of sample single-line diagrams, the Company's system is adequate and should enable the Company to maintain an up-to-date set of diagrams describing its system.

The Company has addressed the problem of contingencies for failure of a transmission circuit and/or substation equipment. It has prepared a list of transformers in the various substations and the available backup units. On a system with a significant number of radial transmission circuits providing service to single transformer substations, it is important that a listing of available spare transformers and a plan to cater to transmission failure be available and be understood.

The early April 1998 ice storm which severely damaged transmission systems on the Burin Peninsula provides an example where the Company was able to respond relatively quickly with its own forces plus contractors to re-establish service after major damage to the transmission system.

It is inevitable that the Company will be faced with contingencies where restoration of supply will require line rebuilds and/or transformer replacement. The Company has structured itself to be able to cater to these contingences.

## 7.5 Distribution Operations and Maintenance

As with transmission operation and maintenance, the Engineer reviewed the budget, both capital and operating, for this function. Detailed discussions were held with senior Company personnel, as well as personnel in the St. John's regional operations.

The operations and maintenance expenses for the distribution function have been decreasing over the past three years. The budget for 1998 shows an additional decrease. This may be cause for some concern since the principle activity of the Company is distribution. As noted previously, reorganization and reallocation of resources has resulted in decreased costs with the expectation of no decrease in reliability and customer service.

This trend should be monitored and compared with customer service reliability statistics provided to the Board by the Company. It is noted that the capital expenditures for distribution, while relatively constant over the past three years, have shown an increase in the 1998 budget. The Company is experiencing problems with respect to conductor deterioration and insulator failures. As these problems are addressed, the expenditures may be allocated to capital rather than operations and maintenance.

The Engineer is of the opinion that the Company has a program of distribution maintenance and by using reliability statistics to give priority to capital expenditures for distribution rebuilds, is following good utility practice.

The Company's approach to contingency planning for distribution is similar to the contingency planning for transmission. In fact, the Company is principally a distribution utility with subtransmission supply to the distribution system. Therefore transmission and distribution contingencies are closely inter-related.

The Company has developed or is developing a series of contingency plans for each area which will specifically identify the response expected for various contingencies.

## 8.0 Contingency Planning

Because of the distribution of utility responsibilities between Hydro and the Company, the Company's system almost is actually a number of sub-systems; the interconnection of which is provided by the Hydro backbone transmission. Major contingencies which could impact the total Island system would be expected to occur on Hydro's 230 kV transmission and/or its principle generating centres at Bay d'Espoir and/or Holyrood.

The Company has undertaken the development of restoration procedures for each region and/or area. As previously mentioned the restoration procedure for the Burin area of the eastern region was reviewed in detail. This is a well prepared document, to cater to major or minor system problems.

This is one of a series of plans prepared or under preparation to assist in rapidly responding to power system outages, either minor or major. The plan lists designated functions, general trouble call procedures, preparation checks prior to major storms, operating procedures, system technical information procedures and reference material, spare parts and equipment inventory, a communications summary and a list of employees to be contacted in an emergency. A list of municipal and provincial government officials, emergency telephone numbers, customer information by feeder and feeder diagrams are included.

The plan is well prepared and well documented and it should be an invaluable aid in rapidly assessing and addressing outages in this area of the eastern region. The Engineer also had a quick review of a similar plan for the St. John's area of the St. John's region. It was similar. It is understood that other restoration programs will be prepared and documented for each of the operating areas within the Company's system. This procedure, as demonstrated by the Burin area document, if kept current and if employees are trained to understand it, should be invaluable in restoration of service and communication with customers and public officials in the event of a system disturbance of major or minor consequence.

All regional/area restoration plans are complete except for Grand Falls. The Grand Falls plan will be completed shortly. Each restoration plan is reviewed and updated every six months.

The Company is following a prudent course to develop and implement such restoration procedures and to instruct its people in their use.

On a related issue, the Company provided its policy with regard to storm insurance, transmission and distribution insurance and utility or risk insurance. The Company has addressed this issue and opted for insurance which is prudent.

# 9.0 Addenda

## 9.1 Year 2000 Problem (Y2K)

In addition to administrative and customer service problems which may arise as a result of the Y2K problem, the electric utility industry may be subjected to particular problems associated with that industry.

According to the North American Electric Reliability Council's (NERC) "Y2K Coordination Plan for the Electricity Production and Delivery Systems of North America", four critical areas are particularly threatened:

1) Power production;
2) Energy management systems;
3) Telecommunications; and
4) Protection systems.

In order to ensure that electric power production and delivery remain operational during critical transition periods, the NERC advocates a coordinated industry action, implementing the following defence strategy:

- Identify and fix known Y2K problems;
- Identify worst-case conditions;
- Prepare for the worst; and
- Operate systems in a precautionary posture during transition periods.

The Y2K problem is being taken seriously by the Canadian electricity industry, which is working collectively, not competitively, to seek solutions. Through such agencies as CEA, NERC and EPRI, North American utilities are working towards fully operational systems during all crisis periods. Due diligence, contingency planning, communications with key publics and the implementation of required solutions are some of the key issues being addressed in preparation for Y2K.

Due to the nature of electricity systems and their interdependencies, some reliability problems are expected. Risks both inside and outside companies, including those due to interconnections and as a result of potential customer problems, are likely to cause some system uncertainties.

An update from the Company outlining the steps it is taking and the progress in meeting this problem was requested. Appendix 5 shows in detail the Company's approach to addressing and solving the problem.

In the Engineer's opinion the Company has taken a prudent course of action in addressing this problem and has dedicated the resources needed to solve the problem where it can and to prepare contingency plans in the event its solutions fail.

9.2 Company Objectives

In visits to Company facilities it was noted that there were quantitative corporate initiatives and targets in place. Appendix 6 shows the corporate targets under various headings. The data for 1996 and 1997 are actual.

9.3 Company - Hydro Interface

While not explicitly listed in the Terms of Reference an issue which perhaps is implicit in many of the Terms of Reference is the relationship between the Company and Hydro. A working committee has been set up to look for areas where cost savings could be enjoyed by one or both utilities, from further cooperation, details are shown in Appendix 7.

These items range all the way from sharing specialized equipment to technical training. Subcommittees will be reporting, through a Steering Committee, to the Board on progress or otherwise in the inter-company analysis of the items under discussion.

Perhaps the most important issue is the possibility of sharing of services between the Company and Hydro at the following locations: Fleur de'Lys, La Scie, Baie Verte, Springdale, South Brook, Fogo, St. Brendan's, Monkstown and Petites.

Resolution of this matter is to be reported to the Board under Item 8, Appendix 7. The progress to date is shown as part of this Appendix.

In the overall system costs of both the Company and Hydro it is unlikely that significant savings could be made by further integration of service provision.

9.4 Long Term Generation and Transmission Development

Perhaps of even greater concern, while not as visible publicly, is the role of the Company vis à vis Hydro with respect to long term generation and transmission development on the Island. Since both utilities now are fully regulated by the Board, the Board should come to understand whether Hydro has the full responsibility for the generation and transmission and the Company is a customer, albeit a large one, or whether both utilities have the joint responsibility to develop the most economic supply system for the Island. This is the most important interface which requires some firm resolution.

It is recognized that if a supply from Labrador to the Island materializes it will likely be the only new capacity addition to the Island system for a decade or more.

Within the next decade there is a possibility that gas will be available, probably on the Avalon Peninsula. This would enable private generation of significant quantities of energy, as is happening elsewhere. It may enable the Company to supply more of its own requirements.

It would be prudent for the Company, Hydro, the Board and perhaps Government, to begin discussions as to how these issues will be addressed.

Premier Tobin's recently announced (August 31, 1998) Energy Policy Review will provide all stakeholders an opportunity to comment on these and other electrical energy issues.

## 10.0 Conclusions

After a thorough review of the material provided by the Board and the Company, detailed discussion with senior people at the Company's offices and visits to some of the Company's facilities in the St. John's region, the Engineer concludes that the Company is doing an effective job in maintaining and operating its facilities in the provision of electric service to its customers. It is noted that the Company's emphasis, now that there is practically no load growth on the system, is directed more toward customer service than construction of new facilities. The reliability of supply to Company customers is considered to be acceptable, although lower than the average for Canadian utilities. It is important that the utility maintain and in fact seek to improve its performance in this regard.

## 11.0 Recommendations

1. The Company and/or the Board should seek clarification of the Public Utilities Act, Section 37. The Canadian Standards Association Voltage Variations Specification should be reviewed, Specification on Frequency should definitely be reviewed as a variation of 4% is not a practical consideration.

2. The Board should periodically call for a review of the statistics shown in the Utility Interruption Report. Significant variation in the 12-month to date data should require an explanation by the Utility.

3. There should be a more formal reconciliation of load forecast differences between the forecasts prepared by the Company and by Newfoundland Hydro.

4. If the Government's Energy Policy Review does not address the issue of joint planning between Newfoundland Hydro and the Company, the Board should review the issue.

5. The Board should direct Newfoundland Hydro and the Company to regularly review the joint restoration plans and to show that the required training has taken place.

6. The Company should keep the Board informed of its efforts to undertake the ISO 14000 Environmental Management System.

7. The Board should request the Company to report on the effectiveness of the TVD system.

8. The Company should keep the Board informed of the effectiveness of its restoration programs in each Company area. The effective implementation of these plans can contribute significantly to reliability of supply and customer satisfaction.

D G Brown

- D. G. Brown, P. Eng. -

1998-10-22

## APPENDIX 1 - Terms of Reference

| Number | Item |
|---|---|
| **1.0** | **Quality of Service** |
| 1.1 | Voltage and Frequency |
| 1.2 | Reliability |
| 1.3 | Customer Service/Customer Inquiries |
| **2.0** | **Planning** |
| 2.1 | Generation Planning |
| 2.2 | Transmission Planning |
| 2.3 | Distribution Planning |
| **3.0** | **System Operations** |
| **4.0** | **Safety** |
| **5.0** | **Environmental** |
| **6.0** | **Operations and Maintenance** |
| 6.1 | General |
| 6.2 | Thermal Generation Operations and Maintenance |
| 6.3 | Hydro Generation Operations and Maintenance |
| 6.4 | Transmission/Substation Operations and Maintenance |
| 6.5 | Distribution Operations and Maintenance |
| **7.0** | **Contingency Planning** |

# APPENDIX 2 - N oundland Power
## Interruption Report - August 31, 1998

| | | AVAILABILITY INDEX | | | | SAIFI | | | | SAIDI | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Area | Total Customers Served Current Month | Current Month % | 12 Month To Date % | 12 Month To Date Last Year % | 5 Year To Date % | Current Month # | 12 Month To Date #/Month | 12 Month To Date Last Year #/Month | 5 Year To Date #/Month | Current Month Hours | 12 Month To Date Hrs/Mth | 12 Month To Date Last Year Hrs/Mth | 5 Year To Date Hrs/Mth |
| St. John's | 77,155 | 99.97 | 99.93 | 99.97 | 99.92 | 0.54 | 0.49 | 0.23 | 0.41 | 0.23 | 0.50 | 0.20 | 0.61 |
| Avalon | 30,482 | 99.82 | 99.89 | 99.93 | 99.76 | 0.47 | 0.53 | 0.26 | 0.46 | 1.33 | 0.80 | 0.51 | 1.73 |
| Burin | 10,661 | 99.99 | 99.79 | 99.89 | 99.89 | 1.21 | 1.15 | 0.50 | 0.57 | 0.86 | 1.55 | 0.77 | 0.83 |
| Bonavista | 14,229 | 99.89 | 99.90 | 99.96 | 99.89 | 0.35 | 0.59 | 0.34 | 0.55 | 0.79 | 0.71 | 0.28 | 0.80 |
| Gander | 17,579 | 99.95 | 99.92 | 99.94 | 99.92 | 0.17 | 0.42 | 0.34 | 0.38 | 0.34 | 0.60 | 0.41 | 0.59 |
| Grand Falls | 17,708 | 99.99 | 99.97 | 99.95 | 99.95 | 0.01 | 0.23 | 0.38 | 0.32 | 0.01 | 0.25 | 0.40 | 0.36 |
| Corner Brook | 19,037 | 99.99 | 99.96 | 99.96 | 99.96 | 0.01 | 0.20 | 0.28 | 0.22 | 0.02 | 0.27 | 0.29 | 0.28 |
| Stephenville | 14,580 | 99.76 | 99.87 | 99.93 | 99.90 | 0.69 | 0.40 | 0.35 | 0.38 | 1.81 | 0.98 | 0.51 | 0.71 |
| Company Totals | 201,431 | 99.93 | 99.92 | 99.95 | 99.90 | 0.43 | 0.48 | 0.29 | 0.41 | 0.55 | 0.62 | 0.35 | 0.76 |

Notes:

1. Availability Index is the percent of time power was available to a typical customer.
2. System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers in an area.
3. System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g., a two hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.
4. All figures include loss of supply from Newfoundland and Labrador Hydro.

## APPENDIX 3 - System Planning's Objectives

The System Planning Group monitors the system performance to identify problems or opportunities with the existing system. The System Planning Group establishes long term tactical plans to overcome these problems and take advantage of new technologies.

System Planning is responsible for monitoring the power system (up to the distribution substation load buses) to ensure that the system is capable of meeting customer load and voltage requirements without exceeding equipment ratings in a reliable least cost manner.

To define the criteria against which the system performance is compared, general system performance objectives are defined. These general objectives are used to formulate the detailed criteria used by System Planning. The system performance objectives are as follows.

(a) Normal Operating Objective

System Planning will ensure the system is capable of being in a normal operating state when all system components are in service except for the loss of any one generating source.

The Normal Operating State is defined as a system condition where all system components are available for service and all voltages and equipment loadings are within seasonal continuous ratings.

(b) Abnormal Operating Objective

System Planning will ensure the system is capable of being in an abnormal operating state for the loss of any single component with or without load loss, where system security and stability are not jeopardized.

The Abnormal Operating State is defined as a system condition where not all system components are available for service and all voltages and equipment ratings are within emergency limits.

(c) Reliability Objective

System Planning will design the system to perform reliably at minimal cost. The configuration of the system will be based on a backup criteria that allows fr a reasonable level of reliability at minimal cost.

(d) Transient Power Quality Objectives

System Planning will ensure that the system can supply power of reasonably good quality as defined by flicker limits.

## APPENDIX 4 - Transmission Planning Criteria

1) Normal: All voltages and equipment loading are within seasonal continuous rating.

2) Abnormal: Not all system components are available for service and all voltages and equipment ratings are within emergency limits.

### System Criteria

1) The system is capable of being in normal operating state when all system components are operational with the exception that one generation source can be out of service.

2) The system may enter abnormal operating state for loss of single component with or without load loss, where system security and stability are not jeopardized.

3) Normal voltage for transmission is between 1.05 and 0.95 pu.

4) Emergency voltage limits for transmission is between 1.05 and 0.90 pu.

5) The winter load limit for transmission lines is determined using a 75°C conductor temperature, at 0°C ambient and 0.6 m/s wind.

6) The summer load limit for transmission lines is determined using a 75°C conductor temperature, at 25°C ambient and 0.6 m/s wind.

7) Transformer loading at normal conditions is restricted to nameplate rating given a 30°C ambient temp and a 65°C temperature rise.

8) The emergency rating for a power transformer is 120% of nameplate rating during winter and 100% during summer.

## APPENDIX 5 - Newfoundland Power - Approach to Year 2000 Problem

The Company has focused the attention of one of its senior Managers (experienced in IS and System Operations) to manage this process over the next 12 months. it is planned to have brought all of the over 1,000 items into compliance by the first of 1999 leaving that year for further testing and contingency planning.

Technology is deployed in all areas of the Company's operations. Traditional information technology such as the CSS and the infrastructure it runs on all are clearly exposed to Year 2000 risks. However, technology is much more pervasive in the electric utility industry; and the potential exists for the failure of equipment with imbedded electronic components. These embedded technology items can range from remote substation controllers to phone systems and even motor vehicles.

The Company has designed and implemented a thorough process by which all Year 2000 threats are remedied. By staying current with evolving best practices, Newfoundland Power ensured the process incorporated the experience of other businesses where appropriate. The major steps in Newfoundland Power's process include:

| | |
|---|---|
| Inventory - | obtain an accurate listing of every possible item which is electronic or which has electronics involved in its operation |
| Assess - | establish a priority for each item such as "A - mission critical", determine if the item is Year 2000 compliant and develop a plan for repair if required |
| Repair - | for items requiring repair, either replace the item, upgrade or repair it |
| Test - | for higher priority items perform tests to confirm the repair was successful or the initial assessment of compliance was accurate |

Contingency Plan - develop a range of failure scenarios and appropriate action plans to mitigate these situations

The Company's year 2000 initiatives commenced early in 1997 with reviews of the most significant computer programs such as the financial and customer systems. Plans were developed to remedy the year 2000 exposures by early 1999.

Early in 1998 a comprehensive inventory of the more than 280 Company sites identified in excess of 1,000 items that have some form of electronics involved in their use. With a complete list of all potential exposures identified, a process to work through all items was established and a team put in place to lead this process. The process is supported by a cross-functional leadership team with representation from Information Services, Internal Audit, Regional Operations, Materials Management and Corporate Communications.

The following table illustrates the classifications into which the Company has grouped the items identified for review, as well as some representative examples of the types of equipment in each classification.

| Classification | Count | Examples of Items in Classification |
|---|---|---|
| Information Technology | 425 | PC hardware & software, major applications like CSS, printers, modems, network equipment |
| Power Quality | 219 | Power line Thermoscan equipment, load records, power monitoring equipment, revenue meters, protective relays |
| Telecommunications | 146 | Phone systems, SCADA hardware & software, radio equipment, FAX machines, pagers and cellulars, TVD - trouble call information system |
| Building Systems | 145 | Alarms, card access systems, photo copiers, heating cooling & lighting control systems |
| Control Systems | 69 | Water level controllers, sensors |
| Customer Accounting | 44 | Hand held meter reading units, cashiering equipment, energy consumption monitors, banking software |

| | | |
|---|---|---|
| Transportation | 18 | Engine analyser, battery charger, fork lift |
| Purchasing Material | 13 | Weigh scales |
| Total | 1079 | |

Based on the Company's assessment of priority, approximately 45% of the identified items are considered to be critical, or "Priority A", items. The priority placed on each item dictates the steps and the timing requiring to resolve the associated Year 2000 concerns. The following table sets out the schedule by priority classification:

| Priority | Inventory | Assess | Repair | Test | Contingency Plan |
|---|---|---|---|---|---|
| A | Q2/1998 | Q3/1998 | Q4/1998 | Q4/1998 | Q2/1999 |
| B | Q2/1998 | Q3/1998 | Q4/1998 | Q1/1999 | NR |
| C | Q2/1998 | Q3/1998 | Q1/1998 | NR | NR |

Note: NR - this step is not required for this priority item

The following table indicates the completion status of each step in the process in percentage terms as of September 1, 1998:

<u>Steps in Process</u>

| Item | Inventory | Assessment | Repair/ Deem Compliant | Test | Contingency Plan | Resolved |
|---|---|---|---|---|---|---|
| Percent Complete | 100 | 95 | 50 | 3 | 5 | 15 |

A letter has been sent to every Company supplier inviting them to work with the Company to examine and resolve any Year 2000 exposures that may affect their ability to meet the Company's supply requirements. Regular co-ordinative meetings with Newfoundland and

Labrador Hydro are a critical part of the management of supplier risks. To date, key suppliers have been very cooperative.

The Company is committed to focusing its resources on the year 2000 computer problem to ensure all efforts to mitigate year 2000 risks are made in a timely manner.

Because of the pervasiveness of technology in the operations of the Company, it was necessary to make an early start on resolution of the Year 2000 issue. Significant progress has been made. Repairs will be substantially completed by early 1999. At that point, the Company will establish detailed contingency plans to address the unlikely event of a major failure related to the Year 2000 problem.

In the meantime, the Company will be working closely with key suppliers, including Newfoundland and Labrador Hydro, to ensure customers are not affected by any disruption in the supplier's services.

## APPENDIX 6 - Corporate Targets

| CORPORATE TARGETS | | | | | | | |
|---|---|---|---|---|---|---|---|
| | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 |
| **Productivity** | | | | | | | |
| Operating Cost/Customer | $260 | $257 | $250 | $245 | $242 | $241 | $239 |
| Revenue/Employee | $399,000 | $403,000 | $443,000 | $474,000 | $484,000 | $496,000 | $504,000 |
| % Accounts Receivable Overdue | 31.0% | 29.3% | 28.5% | 27.0% | 25.0% | 25.0% | 25.0% |
| **Safety** | | | | | | | |
| Lost Time Accidents | 14 | 13 | 12 | 11 | 10 | 9 | 8 |
| Vehicle Accidents | 37 | 20 | 19 | 18 | 17 | 16 | 15 |
| Medical Aid Accidents | 29 | 33 | 29 | 28 | 27 | 26 | 25 |
| **Reliability** | | | | | | | |
| Outage Hours/Customer | 4.2 | 4.2 | 4.1 | 3.9 | 3.8 | 3.6 | 3.5 |
| Outages/Customer | 3.8 | 3.8 | 3.7 | 3.5 | 3.3 | 3.2 | 3.1 |
| **Customer Service** | | | | | | | |
| Service Cost/Customer | $53 | $52 | $49 | $46 | $45 | $44 | $42 |
| Customer Satisfaction | 70% | 81% | 84% | 85% | 85% | 85% | 85% |
| **Employees** | | | | | | | |
| Absenteeism (Days) | 6.6 | 7.0 | 6.5 | 6.2 | 5.9 | 5.6 | 5.3 |
| **Environment** | | | | | | | |
| Number of Spills | 58 | 80 | 70 | 65 | 60 | 55 | 50 |

## APPENDIX 7 - Joint Utilities Coordination Items for Study

1. Sharing of Specialized Equipment
2. PCB Facilities
3. Customer Enquiries (1-800 number)
4. Printing Services
5. Storage Space
6. Emergency Spill Response
7. Protective Equipment Test Facilities
8. Distribution Maintenance
9. Switching
10. VHF Mobile Radio System
11. Inventories and Common Spares
12. 138 kV Transmission Line Maintenance for Central
13. Equipment and Engineering Standards:
    (1) Common Equipment and Engineering Standards
    (2) 69 kV and 138 kV Transmission
    (3) Substation Design Standards and Practices
    (4) Line Maintenance Construction
14. Meter Shop
15. Technical Training

The joint utilities coordination has reaped a number of benefits even though it is progressing slower than expected. Working groups are still attempting to present their varied ideas on Distribution Maintenance and Transmission Maintenance in particular.

Some of the positive outcomes of the activities so far have been:

- agreement to share printing services,
- agreement on common 1-800 trouble call number,
- agreement on sharing specialized maintenance and test equipment,
- agreement to work together on environmental protection,

- a renewed effort to develop common engineering design standards, and
- agreement to work together on various training issues.

It is anticipated that all issues will be dealt with this fall. Even though some may be unresolved, a better understanding of various options will be available.