Q. Reference: *Probabilistic Based Transmission Reliability Summary Report*, Page 1, Line 26 to Page 2, Line 1.

"Hydro's current deterministic based Transmission Planning Criteria are similar to North American Electric Reliability Corporation (NERC) Transmission Planning standards; however, deviations from the NERC standards have been applied due to the isolated nature of the IIS and the potential cost impact of full compliance on the limited customer base."

Please describe any expert opinions Hydro has obtained as to the appropriateness of the deviations from the NERC standards that have been applied.

A. On two occasions, the PUB has commissioned technical reviews of Newfoundland and Labrador Hydro. In 1991 a review was completed by Hiltz and Seamone Company Limited. Please see NP-NLH-112 Attachment 1 Report on the Technical Performance of Newfoundland and Labrador Hydro. The second was in 1999 by Quetta Inc. and Associates. Please see NP-NLH-112 Attachment 2 Technical Performance by Newfoundland & Labrador Hydro – Final Report. Both of these studies confirmed that the criteria and standards used to plan and operate the Island Interconnected System deviated from North American standards but found the criteria applied to the Island Interconnected System to be appropriate and a reasonable balance between cost and reliability.

Hiltz and Seamone COMPANY LIMITED

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536 Main Street
Kentville, Nova Scotia
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October 2, 1991

Mr. R. E. Good
Chairperson
Board of Commissioners of Public Utilities
P. O. Box 9188
St. John's, Newfoundland
A1A 2X9

Dear Mr. Good:

With this letter, I submit for the consideration of the Board my report on the technical performance of Newfoundland & Labrador Hydro.

In brief summary, the report indicates that in terms of the cost efficiency of technical operations, Hydro compares well with other major Canadian utilities deemed to be operating under generally similar circumstances.

I acknowledge with pleasure the complete co-operation provided by Hydro during the course of my investigations, both in providing extensive data and in answering innumerable questions.

Six copies of the report are enclosed. More can easily be provided if required.

Should it be necessary or desirable from the Board's point of view that I testify on the subject matter of my report, I shall of course be available to do so, but would appreciate as much advance notice as possible in order to avoid the possibility of conflict with other commitments.

Yours respectfully,

George Baker

G. C. Baker, P. Eng.

GCB/db

Encl.

REPORT ON THE TECHNICAL PERFORMANCE OF NEWFOUNDLAND & LABRADOR HYDRO

Prepared for the

Board of Commissioners of Public Utilities

Newfoundland and Labrador

By

G. C. Baker, P. Eng.

October 2, 1991

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REPORT ON THE TECHNICAL PERFORMANCE OF NEWFOUNDLAND & LABRADOR HYDRO

1. Foreword

The work covered by this report, comprising a review of technical performance, was undertaken by G. C. Baker (the Consultant) pursuant to instructions of the Board of Commissioners of Public Utilities of Newfoundland and Labrador, hereinafter sometimes referred to as the Board.

The review has been limited to the Newfoundland and Labrador Hydro utility system and excludes any consideration of Hydro's subsidiary companies.

Because the technology employed by utilities is relatively standard, this review has focussed on operating methods and on the economic efficiency of technical operations, rather than on the nature of the technology employed. The basic approach has been to obtain an objective indication of performance by means of inter-utility comparisons.

Utility performance is influenced by many factors unique to each utility. Also, it is difficult or impossible to remove completely the data distortions which occur due to variations between utilities in accounting treatment and nomenclature. Results of the comparisons made in this report must therefore be viewed as general indications rather than precise measures of performance.

Technical operations have been taken to include generation, transmission and distribution, together with such control and support functions as system planning and load dispatching. Administration as such has been excluded from consideration, but administrative costs representing overheads on these functions have been included in some cases where necessary to preserve the validity of comparions.

Newfoundland and Labrador Hydro (NLH) provided a great deal of information for purposes of the review, both in the form of responses to questions and in discussions during a meeting held June 28 at St. John's with NLH executives responsible for technical operations. The Consultant gratefully acknowledges the excellent co-operation received from NLH.

While all the information provided was duly considered by the Consultant, no attempt has been made to include all the details in this report. Significant points have been summarized.

2. The Utility

Newfoundland and Labrador Hydro (sometimes herein referred to as Hydro or NLH) is a Crown Corporation of the Province of Newfoundland. Through subsidiary companies it operates major hydro generation in Labrador and pursues additional development of Labrador's hydro potential.

Hydro's operations as a public utility, the subject of this review, include generation, transmission and distribution on the Island of Newfoundland and transmission and distribution in Labrador.

On the Island, Hydro provides over 80% of the total generating capacity, the remainder being supplied by Newfoundland Light and Power (NLP), Deer Lake Power Company Ltd. and Abitibi Price. Hydro is ultimately responsible for meeting the Island's electricity demand; not by virtue of statutory obligation, although that could be inferred, but because electricity users rely on Hydro to do so.

Hydro acts mainly as a wholesaler, supplying NLP and several industrial customers from its transmission system. However, it also distributes in remote areas of the Island, serving about 22,700 customers either through its transmission system or by local generation in isolated areas.

In Labrador, Hydro obtains electricity supplies from Churchill Falls used to serve the Town of Wabush and an interconnected system in the Goose Bay-Happy Valley area. Hydro also serves seventeen isolated communities scattered from L'Anse-au-Loup in the south to Nain in the north. In addition, Hydro supplies the marginal requirements of Iron Ore Company of Canada. That company now distributes to consumers in Labrador City, but subject to Board approval of an agreement between the parties, Hydro will assume this role effective November 1, 1991.

3. Hydroelectric Generation

The interconnected system includes five hydroelectric generating stations, of which Bay d'Espoir with a net capacity of 580 MW is the largest. The seven units, installed between 1967 and 1977, have individual net capacities totalling 604 MW, but this is reduced 24 MW due to the extra penstock head loss when units 1 to 6 are all running at full output. The plant has extensive storage capacity, equal to about 0.6 years at average production levels.

Other hydroelectric plants are Hinds Lake (75 MW) completed in 1980, Upper Salmon (84 MW) completed in 1983, Cat Arm (127 MW) completed in 1985 and Paradise River (8 MW) completed in 1989. Of these, the first three have associated storage, while Paradise River is essentially a run-of-river plant.

In addition, two very small hydro plants acquired from previous owners at Snooks Arm and Venam's Bight are now connected to the Island Grid.

The only continuously manned plant is Bay d'Espoir. Technical operators to perform running maintenance are located at, or within reasonable distance of, Cat Arm, Hinds Lake, Upper Salmon and Paradise River.

Maintenance functions are centralized at Bay d'Espoir. Limited preventive maintenance tasks are carried out by operating staffs. A computerized preventive maintenance program covers all plants including units, auxiliaries, dykes and dams.

All hydro units have full protection including sensors to provide warning of incipient trouble.

The only major problems which have surfaced in recent years consist of corrosion in surge tanks and settlement in a dam, both at Bay d'Espoir. Both are consequences of construction deficiencies and do not indicate any weakness in operating or maintenance procedures.

The availability and forced outage rates for the major NLH hydroelectric plants are compared to Canadian Electrical Association (CEA) averages in Table 1. The CEA data is for units with operating factors in the same range as the NLH units. The figures are averages for the three-year period 1987-89.

TABLE 1

COMPARISON OF AVAILABILITY & FORCED OUTAGE RATE

PLANT	NLH		CEA	
	AF %	FOR %	AF %	FOR %
BAY D'ESPOIR	89.13	1.56	84.67	8.39
HINDS LAKE	89.37	2.71	77.28	9.84
UPPER SALMON	97.45	0.54	88.59	3.82
CAT ARM	94.36	3.20	92.37	2.42

AF: Availability factor, calculated as unit hours less total equivalent outage time divided by unit hours and expressed as a percentage.

FOR: Forced outage rate, calculated as forced outage time divided by forced outage time plus total operating time and expressed as a percentage.

The table shows clearly that NLH units attain better availability and generally lower forced outage rates than CEA units operating for a similar proportion of total time.

To obtain an indication of economic efficiency, costs of operating the NLH Hydro system are compared with Manitoba Hydro (MH). Of the Canadian utilities with significant dependence on hydro generation, the MH system is considered most directly comparable. Installed capacity per plant is larger, averaging 355 MW vs. 180 MW for NLH, due mainly to Kettle (1,272 MW) and Long Spruce (980 MW). However, all the other plants are smaller than Bay d'Espoir, four are smaller than Upper Salmon and two are smaller than Paradise River. In both systems, plants tend to be located at remote sites.

Costs are taken from the NLH 1990 cost of service study and the MH cost of service study for the year ended March 31, 1991. A comparison of both O & M and total costs for unit output is presented in Table 2.

TABLE 2

COMPARATIVE COSTS OF HYDROELECTRIC GENERATION

ITEM	NLH	MH
O & M cost/rated MW	$ 11,889	$19,446
O & M cost/MWh (average)	$ 2.46	$ 2.85
O & M cost/MWh (firm)	$ 2.91	$ 4.02
Total cost/rated MW	$118,879	$77,259
Total cost/MWh (average)	$ 24.66	$ 11.36
Total cost/MWh (firm)	$ 29.17	$ 16.02

The comparison shows that NLH operating and maintenance costs are appreciably lower in relation to both capacity and energy production. On the other hand, when depreciation and interest charges are included, the total cost of hydro production is higher for the NLH system. This difference in capital charges is to a large extent due to the fact that the MH plants are older, with a weighted average age per MW of about 20 years compared to about 15 in the NLH system. This implies lower capital costs at the time of construction and more time to recover capital costs through depreciation. Secondly, MH uses straight-line depreciation, whereas NLH uses sinking fund depreciation. Due to these differences, MH hydro assets are 35% depreciated while NLH hydro assets are only 14% depreciated.

There is a further major difference between the two systems which affects mainly the unit production costs. With the bulk of its capacity located on the Nelson River and with Lake Winnipeg as a storage reservoir, MH plants operate at an average capacity factor of 78%, while NLH plants operate at 55%.

With these differences taken into account, the comparisons show that NLH operating costs are surprisingly low and the total costs of operation are about on a par with those of Manitoba Hydro.

In the Consultant's opinion, the NLH hydro system is efficiently operated and maintained.

4. Thermal Generation

Hydro's thermal generation consists of the three-unit Holyrood plant with net capacity of 475 MW plus three combustion turbines; two of 54 MW capacity located at Hardwoods and Stephenville respectively, and one of 12 MW at Holyrood.

The operating efficiency of thermal plant is commonly measured in terms of its heat rate; that is, the quantity of heat input required to produce one KWh of electric output. Thermal units such as those at Holyrood typically operate at maximum efficiency when fully loaded or almost so. At lower loads the efficiency is lower and the heat rate higher.

Heat rates achieved by the Holyrood plant are adversely affected by the fact that it is a higher-cost producer than the system hydro plants and is thus a marginal source of system capacity and energy. It thus operates at a relatively low annual capacity factor (47.3% averaged over the years 1987-90 inclusive).

This circumstance of itself does not preclude units operating at full load when on line. However, the overall objective of generation dispatch is to minimize operating costs of the system as a whole, subject to certain constraints relating to reliability and quality of supply. Both the objective and the constraints make it necessary to operate Holyrood units at light loads under certain conditions.

It is appropriate to compare the Holyrood heat rate with that achieved by NS Power's Tufts Cove plant. Tufts Cove like Holyrood is a three-unit, oil-fired thermal generating station. It is a higher-cost producer than NS Power's base load coal-fired plants and is thus a marginal source of power and energy.

Capacity factors and heat rates for Holyrood and Tufts Cove are compared in the following table.

COMPARISON OF THERMAL EFFICIENCIES

YEAR	CAPACITY FACTOR HRD %	CAPACITY FACTOR TC %	NET HEAT RATE HRD Btu/KWh	NET HEAT RATE TC Btu/KWh
1987	58.5	24.4	10,234	10,129
1988	37.8	30.5	10,440	11,152
1989	48.6	42.7	10,577	10,144
1990	44.4	49.5	10,647	10,136
Average	47.3	36.8	10,475	10,390

Note: For Holyrood net heat rates shown above are calculated as gross heat rate/.95.

The figures make it clear that thermal efficiency does not correlate well with capacity factor. Hour-by-hour unit loadings are more important. However, the above comparison indicates that no significant difference in thermal efficiency exists between the two plants.

The average forced outage rate for the three Holyrood units in the years 1987-89 was 4.72%, which is low compared to the average of 6.29% reported for CEA units with similar operating factors.

Holyrood availability was low in 1988 and 1989 when units 1 and 2 were out of service for extended periods by reason of major overhaul and uprating. In 1987, with no unusual conditions at the plant, availability was 75%; somewhat low for oil-fired units.

The low availability of Holyrood units results from two circumstances. Operation at low load results in clogging of air heaters and the back wall of the boiler, and rectifying this condition increases the time required for maintenance. Secondly, the units are only required for limited periods of the year and annual maintenance is scheduled over a relatively long period so that manpower requirements and costs are minimized.

Hydro's cost of service study for 1990 shows Holyrood operating maintenance and fuel costs as $62,302,577. During that year, the plant output was 1839.7 GWh, implying an annual capacity factor of 44.2%.

Deducting Fuel costs of $45,258,628 and Administrative overheads of $7,469,071, the total cost of operating and maintenance was $9,574,878. Most of these costs are fixed so the relatively low capacity factor results in high costs per unit output. Again using the Tufts Cove plant for comparison and assuming the same capacity factor in each case, the relative unit costs would be approximately:

	HRD	TC
Annual O & M cost per KW of capacity:	$213	$299
Annual O & M cost per KWh:	$.0052	$.0059

Because Tufts Cove capacity is somewhat smaller, the figures are indicative of equal economic efficiency.

Hydro's gas turbine are intended to supply reserve capacity for the system and operate much less than 1% of the time. Their fuel costs are therefore negligible compared to other system costs and thermal efficiency is not a material factor. Operating and maintenance costs are typically much lower for gas turbines than for thermal plants generating from steam. For this reason and because the costs appear to be normal, no comparative analysis has been undertaken.

In summary, Hydro's thermal generation is relatively costly by virtue of the fact that it is the marginal source of system capacity and energy. Making due allowance for this circumstance, it is in the Consultant's opinion efficiently operated and maintained.

5. Generation Control and Dispatch

Hydro is now completing the development and commissioning of an energy management system which provides among other facilities the capability for generation control and economic dispatch from Hydro Place in St. John's.

Automatic generation control and economic dispatch for all hydro units is in operation and thermal units are to be tied in by the end of 1991. Control is exercised through a system control and data acquisition (SCADA) system, which provides control of all major generation, generation and transmission substations and most major reservoir control structures.

The energy management system also provides facilities for maintaining optimum power flows in the transmission system, for dispatcher guidance in dealing with contingencies (equipment outages), for logging and data collection, and for inclusion of all Hydro's projected generation additions over the next 15 years.

The system is sophisticated, protected against computer failure and supplied with facilities for program development and operator training.

Hydro should, through these facilities, be able to achieve near-optimum functioning of its system.

6. Transmission

Hydro's Island transmission system interconnects all major sources of generation, supplies its wholesale customers and delivers power to distribution terminals in the areas where it provides retail service. Trunk lines operate at 230 KV, while lines of lower voltage extend into more remote areas. Lines in service total 3,498 km, of which 1,531 km operate at 230 KV, 1,353 km at 138 KV, and 614 km at 69 KV.

Lines receive an aerial inspection four times per year. An aerial inspection is also made after any line fault which causes a circuit breaker trip. There is a ground patrol once per year and all poles or towers are climbed once every five years.

Line troubles are most likely to occur during bad weather when access is difficult, and personnel are strategically located to achieve a reasonable balance between response time and maintenance costs.

Major transmission line damage due to a combination of high winds and severe icing was experienced twice in the last five years. The first occurence in December 1987 affected a 230 KV line from Buchans to Corner Brook. Severe weather conditions hampered repair work and the line was out of service for 67 days while eight damaged towers were replaced. In April 1988, a 230 KV line from Holyrood to Western Avalon was damaged and remained out of service for over 17 days while damaged towers were replaced.

The energetic efficiency of the system is good. Annual losses were 3.966% of sales in 1990 and peak loss was 4.86% of the load served.

Line losses for roughly comparable transmission systems are as follows:

TRANSMISSION LINE LOSS

	NLH %	NS Power %	NB Power %
Annual line loss	3.97	3.30	4.01
Peak loss	4.86	6.00	5.30

In utilities where generation is far removed from load centres, the losses can be considerably higher: 8% for the Manitoba Hydro bulk power system, for example.

To obtain an indication of economic efficiency, transmission and terminal costs are compared in the following table with those of NB Power and NS Power. Figures have been derived from cost of service data relating to 1990. Costs relating to dedicated facilities have been excluded.

TRANSMISSION AND SUBSTATION ANNUAL COSTS

	NLH		NB Power		NS Power	
	$/km	$/KW	$/km	$/KW	$/km	$/KW
Operation & maintenance	2,523	6.71	1.613	3.46	2,485	6.98
Administrative overheads	1,477	3.93	713	1.53	477	1.34
Taxes	--	--	660	1.42	206	.58
Depreciation	636	1.69	1,466	3.14	2,050	5.76
Interest & profit	6,594	17.53	3,809	8.17	6,290	17.67
	11,230	29.86	8,261	17.72	11,508	32.33
KM of transmission	3,498		6,255		4,872	
System peak MW		1,316		2,917		1,734

Costs other than operating and maintenance are peripheral to the subject of this review, but have been included to show the large leverage they exert on total costs.

NB Power's costs per kilowatt of system peak demand are much lower than those of the other utilities, mainly because of NB Power's extensive export and interchange activities. It was not possible with the data at hand to exclude the effect of exports.

NB Power's O & M cost per km of transmission is also lower than those of the other two utilities, in large measure due to advantages of scale and geography.

There is no material difference between Hydro's O & M costs and those of NS Power, which is the more nearly comparable utility both in terms of size and remoteness of major generation from load centres.

7. System Planning

Hydro uses two criteria for generaton planning in its interconnected system.

(a) Sufficient production capacity to meet all needs under firm water conditions (lowest recorded flows), and

(b) A loss of load expectancy of one day in five years.

The first criterion is usual for utilities with significant dependence on hydraulic generation. The second differs from the one-day-in-ten-years LOLE adopted by many utilities.

The main reason for permitting a higher LOLE is economic. Hydro, unlike almost every other major utility, is an isolated system. Other utilities can, and do, rely on capacity support from interconnected utilities in meeting the one-day-in-ten-years criterion. Hydro cannot do this, and would have to maintain a much higher generation reserve. Hydro believes the costs of doing so would not be justified by the difference in reliability. The Consultant agrees.

In isolated systems, Hydro plans for reserve capacity equal to the largest unit in each system. This would enable peak demand to be met when the largest unit is out of service.

Hydro's transmission planning criteria are:

(a) Stable operation at or below rated capacity of equipment under a single fault contingency.

(b) Ability to sustain a successful reclose for a line-to-ground fault, provided all system generation is available.

(c) Voltage stability between 95% to 105% of rated voltage under normal operation or 90% to 110% under single fault contingencies.

(d) For major terminals, transformer capacity sufficient to withstand loss of the largest unit. (For other terminals, an understanding exists between Hydro and Newfoundland Power for use of the latter's mobile equipment.)

Distribution planning is based on maintaining acceptable voltage levels (minimum of 116/120 of rated voltage). Spare substation transformers are supplied at inaccessible locations (e.g. Labrador coast) but not otherwise.

These criteria fall within the range usually adopted by major utilities. The Consultant considers they constitute a reasonable compromise between reliability and economy.

In meeting these criteria, Hydro's planning objective is to find the least-cost solution. This is in most cases a supply solution, but demand/management techniques have been used and DSM programs are in the experimental stage.

Decisions on major plant additions are made on the basis of economic, financial, environmental and cost of service analyses.

Nevertheless, planning and decision-making are always at risk because they must rest at least in part on assumptions and estimates related to future costs, load growth, economic conditions and public policies. Based on planning documents reviewed, the Consultant is of the opinion that planning techniques are accurate, adequate, and much the same as those employed by other large utilities. No opinion is expressed on the quality of planning assumptions and estimates, because such an opinion could only be an exercise in subjective judgment.

8. Reliability

Reliability data averaged over the years 1987-89 for Hydro and for all CEA Region 2 utilities reporting such data is compared in the following table:

INTERRUPTION INDICES

	NLH	CEA Region 2
SAIFI	5.71	4.11
SAIDI	15.00	5.85
CAIDI	2.62	1.42

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

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

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

The data for Hydro is for the whole system; i.e., it includes the isolated areas as well as the interconnected systems. For that reason, the figures almost certainly indicate a greater frequency and longer duration of interruptions than if the data had been prepared for the interconnected system alone.

The system interruption frequency shown is moderately higher than the CEA average and two Hydro policies may contribute to this result. The LOLE is lower than in most utilities, for reasons discussed in section 7 above. Also, Hydro does not carry a spinning reserve but relies on under-frequency relays to maintain system stability when fault conditions occur. The relays shed selected loads and therefore tend to increase interruption frequency. This policy is also adopted for economic reasons; maintaining a spinning reserve would be too costly.

However, the main factor impacting interruption frequency at the transmission level is probably not a matter of Hydro policy but rather the absence of interties with other utilities. Such interties make instantly available the on-line reserves of interconnected utilities, and on a longer time scale provide the ability to purchase capacity to meet emergency situations.

Most faults which result in customer interruptions occur at the distribution level. Because in Hydro's distribution system (and all others of which the Consultant is aware) there is generally no provision to withstand a single fault contingency, outages last until repairs have been effected.

While Hydro's system reliability lower than that of Canadian utilities on average, the Consultant is of the opinion that this is the consequence of isolation from other utilities, the geography and climate of the areas served and not in any way attributable to improper utility policies or substandard technical performance.

9. Distribution

Hydro serves 17,401 customers at distribution voltage from the Island interconnected system and another 5,272 customers in isolated locations on the Island. In Labrador, 3,930 customers are served by the interconnected system supplied from Churchill Falls and 2,915 customers are served at isolated locations. Most of the isolated locations are supplied by diesel, but at Roddickton a thermal plant fired by wood chips serves part of the load. Small amounts of energy are also obtained from a mini-hydro plant at Roddickton and an independent power producer at Marys Harbour.

Hydro's distribution costs are very high compared to those of other major utilities, for reasons which are readily apparent. The 31 isolated locations in Newfoundland and Labrador require operating staffs for diesel generation, incur high costs for fuel, transportation, etc. and suffer from disadvantages of scale. Those customers served from the Island interconnected system also impose high costs due to small scale and remoteness. Generally speaking, Hydro only distributes in areas too remote, or with insufficient loads, to have attracted entrepreneurial interest.

While other Crown electric utilities serve similar areas, none except Hydro do so exclusively. It is therefore inevitable that Hydro's distribution costs should be high.

In such a service territory, the main determinant of operating and maintenance cost is the scale of staffing. For generation Hydro provides full staffing (five operators) at three locations and minimum staffing (two operators) at the remaining 28 locations. Both personnel and stores for maintenance and repair are in the Consultant's opinion located to provide a reasonable balance between cost and quality of service. Distribution transformer capacity was 233,733 KVA in 1990, in reasonable proportion to individual system peaks of 147,901 KW, considering the preponderance of small and dispersed loads.

Distribution losses, tabulated below, are also reasonable under the circumstances. By comparison, NS Power's distribution loss for secondary customers, nearly half urban, is close to 10 percent.

NLH DISTRIBUTION LOSSES (% OF SALES)

Island isolated systems	8.47
Labrador isolated systems	9.67
Island interconnected system	10.00 (a)
Labrador interconnected system	4.36 (b)

(a) - The figure is approximate only.
(b) - Total system: only about 40% of energy is sold at distribution level.

As a measure of economic efficiency, Hydro's distribution costs are compared with those of Manitoba Hydro (MH) incurred in serving its diesel zone. MH serves 2,815 customers in 13 communities, some of which are interconnected to form 11 systems. The number of customers per system is 256 on the average; very close to Hydro's average of 264 per system.

In 1990, the MH cost of service, including diesel O & M but excluding fuel, depreciation, corporate overheads and interest, totalled $2,341,358; or $831.74 per customer. NLH costs would be approximately as follows, assuming the same level of cost efficiency in distribution operations.

(1) Isolated systems

		($000's)
Operating & maintenance:	8,187 customers x $831.74 --	6,809
Fuel (actual)		8,903
		15,712

(2) Island interconnected system

O & M cost for isolated systems:	6,809
Less diesel O & M (estimated):	2,990
	3,819

O & M per customer: 3,819/8,187 = .46647		
Operating & maintenance:	17,401 customers x .46647 --	8,117
Demand, energy & wheeling (actual)		17,833
		25,950

(3) Extra costs (compared to MH), imposed because of remoteness, sea access, etc. (estimated) 1,850

(4) Other NLH actual costs

Administration	3,635	
Depreciation	4,496	
Deficit amortization	2,527	
Interest	11,702	
Guarantee & margin	2,753	
	25,113	25,113

Total cost, this estimate:	68,625
NLH actual cost, per response to NLP 92:	69,536

The estimate indicates that cost of operating and maintaining the NLH distribution system is on a par with MH costs of serving its customers under generally similar conditions.

The costs listed in (4) above are not specifically within the scope of this review. Nevertheless, some comment may be appropriate. In the MH system, isolated customers who pay the same rates as rural interconnected customers are limited to a service capacity of 15 amperes. About 75% of the isolated customers fall in this category. The remaining 25% of isolated customers pay the whole balance of the diesel zone cost of service. Therefore, every isolated customer is under compulsion (either physical or economic) to limit demand and energy use. As one would expect under the circumstances, system size, plant costs, depreciation and interest charges are lower in the MH diesel zone than in the NLH distribution system.

Also in the MH diesel zone there is no accumulated deficit to be amortized; guarantee and margin costs are lower because of smaller plant investment and administrative costs are lower.

10. Distribution Cost Reduction

The problem of high cost in isolated systems has been the focus of research by Energy, Mines & Resources Canada, the CEA and others; so far without any notably ecouraging results. Small hydro plants can displace diesel generation under favourable conditions but other alternate energy sources are usually not competitive. Other possible means of cost reduction are interconnection and demand management.

Hydro has used interconnections both to consolidate isolated areas and to displace diesel by central station power wherever economically feasible. Withdrawal of the subsidy heretofore paid by the Government of Newfoundland raises two questions: whether demand management offers any potential for cost reduction, and if so, whether or to what extent it would be consistent with public policy.

It seems clear that any abrupt reduction of demand or energy sales would be counter-productive; merely reducing the sales base upon which sunk costs can be recovered and thus leading to higher rates or higher losses. However, limitation of demand at present levels or increasing demand to achieve fuller utilization of existing plant could prove beneficial. All possibilities should be analyzed.

11. General Observations

Being outside the scope of this review, administrative costs were not analyzed. However, they were necessarily included in, and therefore affect, some of the comparisons presented herein.

Comparisons made in the course of this review suggest that Hydro's interest costs are proportionately higher than those of comparable utilities. In the comparison relating to hydraulic generation the cause has been identified. However, high interest costs do not appear to be confined to hydraulic generation; they are to some degree characteristic of all Hydro's functional costs.

There appear to be two underlying causes: relative youth of the utility and slower capital recovery due to sinking fund depreciation. The major developments which made electricity available in abundance in most parts of the Province are relatively recent and only a small part of the invested capital has yet been recovered. Similar developments occurred in most other provinces at least two decades earlier. To the extent that this generalization is correct, time will erase the present differential in net investment and the cost of service will reduce in real terms.

A second general observation is that Hydro's administrative overheads appear to be somewhat higher than those of other utilities on a per unit (customer, KW, etc.) basis. This may be wholly or partially due to inter-utility differences in cost of service methodology. Other utilities appear to functionalize their administrative costs to a greater extent than Hydro, leaving fewer such costs to be simply prorated as overheads.

If there is in fact any real difference in administrataive costs, it may be attributable to scale effects. Excluding CFLCO, Hydro has substantially lower peak demand and far fewer customers than the utilities used for comparison purposes in this review so that essential technical and administrative infrastructure costs must be supported by a relatively small sales base.

12. Conclusions

As a result of this review and based on analysis of comparative data and consideration of operating methods, problems and policies, the Consultant is of the opinion that:

(1) The utility operations of Newfoundland and Labrador Hydro are conducted in a technically adequate manner and its generation and transmission functions attain an economic efficiency at least on a par with other major Canadian utilities operating under generally similar circumstances.

(2) While distribution operations are costly, such costs are consistent with the remote and/or isolated nature of the locations served and do not reflect any technical or operating deficiencies.

(3) System planning techniques are appropriate.

(4) The approach to optimizing generation dispatch and system load flows, and the facilities devoted thereto, are exemplary.

(5) Demand management may have some potential for reduction of financial losses now incurred in serving distribution customers. The potential should be fully explored.

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Technical Review of Newfoundland and Labrador Hydro Final Report

March 17,1999

Quetta Inc. and Associates
CHARLOTTETOWN, PRINCE EDWARD ISLAND
HALIFAX, NOVA SCOTIA

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Appendices

Summary

Quetta Inc. and Associates (Quetta) were engaged by the Board of Commissioners of the Public Utilities of Newfoundland and Labrador (the Board) to provide the Board with a review of the quality of electric power service in the Province of Newfoundland and Labrador served by Newfoundland and Labrador Hydro ("Hydro"), excluding the operations in Churchill Falls.

The Board asked that the project be conducted in two phases: First to prepare the Terms of Reference for the consideration and approval of the Board, Second to carry out the review and prepare draft and final reports.

Phase One

The Terms of Reference was prepared based on meetings with the Board, materials provided by the Board and meetings with senior management of Hydro.

Phase Two

The process followed in preparing the report was as follows:

- Requested reports and data from Hydro.
- Prepared topics for discussion with Hydro based on the Terms of Reference.
- Reviewed the material provided by Hydro.
- Prepared questions for the interviews with Hydro staff.
- Conducted interviews and meetings with Hydro staff in St. John's March 25 to 31 1998. Over the six days Quetta held some fifty meetings with Hydro staff (40).
- Quetta visited several of Hydro's facilities.
- Follow up interviews were held in Bishops Falls in May 1998.
- The draft report was prepared July 31,98 and Quetta met with the Board on September 14, 1998 to review the draft report.

- Quetta requested additional information from Hydro and obtained additional data to prepare final report.

Findings

The following is a summary of the findings:

1) Voltage and Frequency - The procedures that Hydro has in place to monitor the power system are acceptable and follow prudent utility practice.
2) Hydraulic Unit Generation Reliability - The performance of Hydraulic generation is considerably better than the Canadian average due in part to the manner in which maintenance activities are planned, executed and audited.
3) Thermal and Combustion Turbine Unit Generation Reliability – The performance of Thermal generation is improving from an increased effort on maintenance and capital replacement.
4) Transmission System Reliability – The performance of the Transmission system has been the subject of extensive analysis due to its poor performance under the harsh local conditions. It is expected that as a result of the major rebuilding program now underway the performance will improve.
5) Under-frequency load shedding is an essential program to maintain the integrity of the power system.
6) Distribution System Reliability – The frequency of outages on the distribution system is higher than the Canadian average due to the nature of the system and the harsh operating environment, however there are also regional differences in reliability performance that should be addressed.
7) Hydro is lagging with respect to Customer Service, however there is an increased awareness at Hydro with respect to the importance of Customer Service and a new Customer Service system is being implemented.

8) Hydro has a capable staff and adequate resources to carry out the planning responsibility in all areas and to develop and analyse facility addition plans to meet the utility's requirements.
9) Hydro has good load forecasting methodology and staffing, satisfactory generation planning criteria and a competent staff and planning software to carry out its generation planning responsibility.
10) Hydro's transmission planning criteria are considered acceptable although less stringent than others.
11) The energy control center is "state of the art" and the process to maintain system protection is well established.
12) Overall the safety performance of Hydro compares favorably with Canadian Utilities in the same CEA group (over 500 employees, under 10,000 employees). This area is well looked after at Hydro.
13) Hydro has in place an effective Environmental Management System and conduct proper environmental audits to ensure compliance. Hydro staff has the full support of the Executive and the Board of Directors with respect to environmental stewardship.
14) The restructuring at Hydro has not had a significant impact in areas that affect customer service.
15) Fuel Acquisition – The contract and the resulting prices are reasonable.
16) Maintenance Program – Is a well organized maintenance program. Each significant component in Hydro's system is identified in the maintenance system and inspected and maintained on a regular basis in order to evaluate whether it is suitable or requires replacement.
17) Hydro follows prudent and appropriate practices with respect to storm insurance and insurance in general.
18) The Internal Audit function has evolved satisfactorily at Hydro, is understood by the staff and provides important checks and balances on the many documented plans and procedures at Hydro.

19) If recommendations 1,2,13,15,20,22 and 23 in this report are effectively carried out, the problems that occurred during the storm of 1994 will be lessened in the future.

Conclusions

Quetta, carried out a thorough review of the material provided by the Board and Hydro, had detailed discussions with senior management and staff at Hydro's offices in St. John's and elsewhere on the Island. Based on that review, Quetta concluded that Hydro is following sound utility practice in their approaches to the planning for, and maintenance and operations of, the systems used to provide safe and reliable electric service to its customers. However, having stated that general conclusion, and in the belief that neither the Board nor Hydro accepts the principle that "good enough" is appropriate in this service industry, Quetta respectfully includes the following recommendations for the consideration of the Board and Hydro in their pursuit of the principle of "continuous improvement".

Recommendations

1) It is recommended that the Board request Hydro to include Generation Reliability indicators in its monthly report to the Board. In this way the Board can monitor the performance of the generation system to help ensure that the performance of the thermal and combustion turbine units does no fall back to the low levels of the mid 1990's.
2) It is recommended that the Board request Hydro to include the System Average Restoration Index (SARI) to the monthly report that is provided to the Board by Hydro and that a target for improving this be established.
3) The number of interruptions on the Great Northern Peninsula is too high. Hydro staff indicated that salt contamination has been a problem on the long transmission line to this area and that they were working with different types of insulators to improve the situation. It is recommended that the

Board should ask Hydro to prepare a report on this with an action plan to monitor and improve this.

4) The frequency of outages for the Northern Isolated area is too high. It is recommended that the Board direct Hydro to report on this matter and prepare a plan to improve the reliability in this area over a reasonable period of time. It is also recommended that the Board request Hydro to prepare the System Average Interruption Frequency Index (SAIFI) and Customer Average Interruption Duration Index (CAIDI) for each isolated diesel area and include this in the regular monthly report to the Board.

5) The implementation of the Customer Service System will be the subject of an Internal Audit as part of the 1999 Internal Audit plan. It is recommended that the Board request this audit report from Hydro.

6) It is recommended that the Board require Hydro to continue customer satisfaction survey's on an annual basis and report the results to the Board.

7) The Capital Expenditure historical chart and data table should be updated and expanded as part of the Capital Budget submission to the Board. Data from the five-year capital forecast should also be requested.

8) Hydro should demonstrate, that together with Newfoundland Power, they coordinate their efforts in short term (five year) load forecasts.

9) After the first phase of the 230 kV transmission line reinforcement and rebuilding is complete, Hydro should review the need for further rebuilding.

10) Hydro should justify the need for any rebuilding of the 230 kV transmission circuits from Bay D'Espoir to Sunnyside.

11) The Board should encourage Hydro to revisit the Generation Practices Survey of other Canadian utilities with remote systems, bring it up to date and maintain it that way. This survey should also be expanded to include operating procedures.

12) Objective criteria for the inclusion of a distribution project in the capital program are not clearly defined by Hydro. Objective criteria such as: reliability; customers; loading; losses; condition of line and safety should be

used and documented in order to create priorities for capital investment and reliability improvements. The Budget submitted to the Board should include this evaluation.

13) It is recommended that the instruction #010 covering "System Outages" should be revised to reflect clearly the role and responsibility of Newfoundland Power. The same comment applies to instruction T-022 "Restoration of the Holyrood Plant to an isolated system".

14) It is recommended that the System Protection update procedure be amended so that it is stated explicitly that the responsibilities of the Manager of System Performance and Protection spans both the Production and TRO divisions of Hydro's operations.

15) Hydro should continue to train its staff and test its procedures for "black start" at the Holyrood Plant and load restoration after complete or partial system shutdown. Hydro and Newfoundland Power staff must understand these procedures. The Board should request Hydro to file the new procedure for restoration when the governors at Holyrood are changed and request Hydro to confirm that Newfoundland Power understands its role.

16) It is recommended that the Board request Hydro to provide progress reports on a quarterly basis on the implementation of their ISO 14001 Environmental Management System.

17) It s recommended that the Board ask Hydro to submit reports on each of the Reliability Centered Maintenance (RCM) pilot projects and any justification for plans that expand the RCM process at Hydro.

18) The performance experience at the Nain plant in 96/97 is not consistent with the maintenance procedures described to Quetta by Hydro. Therefore it is recommended that the Board request Hydro to implement a maintenance audit and reporting process at each of the remote diesel sites similar to that done for the hydraulic plants.

19) Operating diagrams are issued to the appropriate staff, however there was no evidence to indicate how an employee would know what size fuse to

install in a distribution line. It is recommended that Hydro address this issue and report to the Board with a plan to correct this.

20) It is recommended that Hydro document and communicate to its staff contingency plans for transmission system problems and that it develops a process to ensure they are updated.

21) It is recommended that Hydro update the distribution system contingency plan for the Central Region, expand it or prepare similar plans for the remaining regions and develop a process to ensure that they are communicated to staff and remain updated.

22) It is recommended that the Board request Hydro to review the Quebec report on the impact of the Ice Storm of 1998 on Hydro Quebec when it becomes available.

23) The Board should direct Hydro to develop formal documented system to manage and maintain its planned response to serious or catastrophic occurrences on the power system and to include in the associated procedures a schedule of training for staff.

24) It is recommended that the Board request Hydro to file its Internal Audit plan annually with the Board to allow the Board to determine which audit reports might be referred for further analysis by the Board.

25) Hydro's year 2000 compliance plan should be formally reviewed by the Board and it's progress monitored.

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

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Appendices

Introduction

By agreement dated February 1,1998 between the Board of Commissioners of Public Utilities of Newfoundland (the "Board") and Quetta Inc. and Associates ("Quetta"), Quetta is to provide the Board with a review of the quality of electric power service in the Province of Newfoundland and Labrador served by Newfoundland and Labrador Hydro ("Hydro"), excluding the operations in Churchill Falls.

The study is to include a review of the planning, operational, maintenance and safety practices of Hydro from the standpoint of efficiency, reliability and safety of the power system. Quality of service and customer satisfaction is also to be reviewed. Quetta prepared the Terms of Reference for this review. These Terms of Reference were developed after a review of documents provided by Hydro and the Board and meetings with Board Members and Hydro staff. The Internal Audit (IA) function is also discussed in this report as it became evident during the study that IA plays an important role in the efficient operation and control of Hydro. A summary of the terms of reference is contained in Appendix 1 of this report.

To complete the assignment, Quetta reviewed further documents obtained from Hydro, met with Hydro staff to discuss in detail issues identified in the Terms of Reference and to solicit data from Hydro staff in response to questions raised in the Terms of Reference. Quetta relied on the information provided by Hydro to prepare this report. Additional information was obtained from the Canadian Electricity Association ("CEA") and from interviews with staff from other Canadian utilities.

The following is a list of Hydro's facilities that Quetta visited or viewed as part of the study:

Head Office, including the Energy Control Centre
Holyrood Thermal Generation Station
Bay D'Espoir Hydro Generation Station

Hardwoods Combustion Turbine Generation Station

Distribution System in the Bay D'Espoir and Harbour Breton areas

Bishop's Falls office and maintenance facilities

Transmission circuits visible in St. John's and Central Newfoundland area

Appendix 2 contains diagrams that show the Provincial generation and transmission grid and the communities served by Hydro's distribution system.

In reviewing quality of service, the investigation was concerned principally with voltage levels, continuity of supply and reliability. Other items such as wave form and harmonics were not included in the review.

The Terms of Reference approved for this report did not include a review of Hydro's plans with respect to the year 2000 compliance issue. This issue was discussed at the 1999 Capital Budget Hearing. It is recommended that Hydro's year 2000 compliance plan should be formally reviewed by the Board.

Quetta's report which follows will address each item in the Terms of Reference in sequence.

1.0 Quality of Service

1.1 Voltage and Frequency

Quetta reviewed the process at Hydro to ensure that it is in compliance with Section 37 of the Act, which states in part that "Variation in voltage and frequency at a customers terminals, unless otherwise ordered by the Board, shall not ... exceed 4 % from the declared constant voltage or frequency". PU Order No.25 (1984) ordered that "the allowed voltage levels for alternating current systems operating at voltages up to 50,000 volts shall be those set forth in the Canadian Standards Association Standard No. Can3-C235-83."

Hydro monitors voltage variations to transmission and delivery points monthly. Any variances outside of the 5% range are highlighted and causes for variances investigated. In all cases the variances outside the band are due to contingency conditions or are due to the customer's request.

At the customer level, Hydro plans and operates its distribution systems in a manner such that voltages, under normal operating conditions, when measured at the service entrances of residential customers should not be less than 110 volts or greater than 125 volts as per Canadian Standards Association Standard No. Can3-C235-83. Adherence to this standard is accomplished by activities of the System Planning Group and Regional office personnel. Using the latest annual load forecasts for the Rural areas, System Planning carries out technical studies to determine if upgrading of the distribution system will be required in the future to ensure compliance with the standard. This analysis is followed up where necessary with the initiation of voltage and load studies to ensure that the planning models of the various distribution systems are correct. Regional operations field personnel regularly measure system voltages when providing service to new customers, performing system maintenance and responding to customer service calls.

There were no recorded complaints from customers on this issue

In Quetta's opinion, the procedures that Hydro has in place to monitor the power system are acceptable and follow prudent utility practice. Reports from the various systems used to monitor voltage and frequency are reviewed at appropriate levels in the organization.

1.2 Reliability

Hydro, as well as most Canadian utilities, uses the Canadian Electricity Association (CEA) indices to report, measure and compare component and system reliability among participating utilities. The indices that have been selected in the following sections are the standard indices used in the Canadian electric utility industry.

While comparisons to the CEA are made in this section, the best use of these indicators is to help and see the direction in which the industry and the specific utility is going.

1.2.1 Generation Reliability

The reliability index used to evaluate and compare the performance of the Hydraulic and Thermal Units at Hydro is the Derating Adjusted Forced Outage Rate (DAFOR). This factor is the rate (%) a unit encounters a forced outage. A forced outage means the occurrence of a component failure or other condition, which requires the generating unit to be removed from service.

The reliability index used to evaluate and compare the performance of the Combustion Turbine Units at Hydro is the Utilization Forced Outage Probability (UFOP %). This factor gives the probability that a generating unit will not be available when required. This is important for combustion turbine units that operate in standby mode and are required for emergency back up and system restoration.

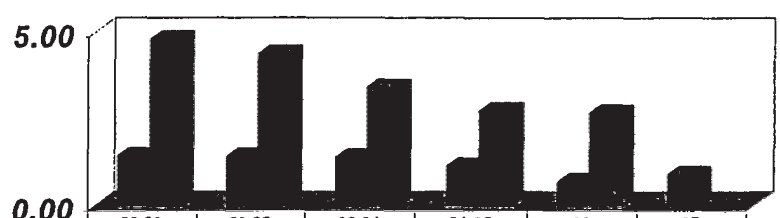
The data for Hydro for 1997 includes outages due to external conditions, as the data to exclude external conditions (outages at the generation level that were not caused by a problem with the generation unit, e.g. transmission line failure during the "Storm of 94") was not available. This material is prepared by the CEA and the CEA report was not available at the time this analysis was prepared. This does not materially influence the analysis, as it is a more conservative number.

In Quetta's opinion, Hydro is improving its performance relative to the past and in keeping with industry averages.

1.2.1.1 Hydraulic Units

Chart 1-1 compares Hydro's performance to the CEA composite for the latest

Hydraulic Unit DAFOR
External Conditions Excluded
Chart 1-1



	88-92	89-93	90-94	91-95	96	97
NLH %	1.40	1.38	1.36	1.10	0.66	0.87
CEA %	4.75	4.33	3.37	2.70	2.64	

four five-year periods and includes annual data for Hydro for 1996 and 1997. The data for 1997 for Hydro includes external conditions. In the last five-year period Hydro's DAFOR improved slightly over the previous periods. In 1996 and 1997 Hydro's DAFOR was less that one percent. In all cases Hydro's performance is better than the CEA.

1.2.1.2 Thermal Units (Holyrood)

Chart 1-2 compares Hydro's performance to the CEA for the latest four five-year

Thermal Unit DAFOR
External Conditions Excluded
Chart 1-2

	88-92	89-93	90-94	91-95	96	97
NLH %	22.76	25.48	26.24	25.63	15.85	9.01
CEA %	11.84	12.11	12.39	16.11	14.75	

periods and includes annual data for Hydro for 1996 and 1997. Up to 1995, Hydro's DAFOR has been almost twice that of the CEA. In 1996 Hydro's DAFOR improved to 16 % and is close to the 1996 CEA average of 15%. In 1997 Hydro's DAFOR again improved and was 9%, which is better than the latest available CEA result. This improvement is due to the improved maintenance effort due to the recognition of the increased requirement for the station due to load growth. As the energy demand increases, without the addition of new capacity, more output will be required from the Holyrood station (See Section 6.2).

It is recommended that the Board request Hydro to include Generation Reliability indicators in its monthly report to the Board. In this way the Board can monitor the performance of the generation system to help ensure that the performance of the thermal units does no fall back to the low levels of the mid 1990's.

1.2.1.3 Combustion Turbine Units

Chart 1-3 compares Hydro's performance to the CEA composite for the latest

Combustion Turbine Unit UFOP
External Conditions Excluded
Chart 1-3

	88-92	89-93	90-94	91-95	96	97
NLH %	8.80	12.67	18.29	23.43	12.79	7.44
CEA %	11.09	10.59	10.49	10.03	6.85	

four five-year periods and includes annual data for Hydro for 1996 and 1997. Up to 1995, Hydro's Utilization Forced Outage Probability (UFOP %) has been increasing and for 91 to 95 was more than twice that of the CEA. In 1997 Hydro's UFOP improved to 7%, which is close to the latest available CEA annual result, 6%.

The combustion turbine unit at Hardwoods plays an important role with respect to the restoration of the system if Holyrood is out as detailed in the System

Hardwoods Combustion Turbine Unit UFOP
External Conditions Excluded
Chart 1-4

	88-92	89-93	90-94	91-95	96	97
NLH %	4.97	7.66	14.81	26.35	10.2	5.63
CEA %	11.09	10.59	10.49	10.03	6.85	

Operations section (3) of this report. Chart 1-4 compares the performance of the Hardwoods turbine to the CEA for the latest four five-year periods and includes annual data for Hardwoods for 1996 and 1997. Up to 1995, Hardwoods Utilization Forced Outage Probability (UFOP %) has been increasing and for 1991 to 1995 was more than 2.5 times that of the CEA. In 1996 Hardwood's UFOP improved to 10 %. In 1997 Hydro's UFOP again improved and was 6 %, which is better than the latest available CEA result.

It is recommended that the Board request Hydro to include Generation Reliability indicators in its monthly report to the Board. In this way the Board can monitor the performance of the generation system to help ensure that the performance of the combustion turbine units does no fall back to the low levels of the mid 1990's

1.2.2 Transmission

The Bulk Electricity System (BES) is composed of the Power Resources, the Transmission System which includes busses, switching equipment and circuits of 110 kV and above, all transformers connected to those busses or circuits and the low voltage busses associated with these transformers as well as the Auxiliary System Equipment. It does not include the Distribution System. Three reliability indices are used to compare the performance of Hydro to the CEA composite as follows:

1) System Average Interruption Frequency Index (SAIFI)
2) System Average Interruption Duration Index (SAIDI)
3) System Average Restoration Index (SARI)

These are common reliability measures that are used by the Canadian electricity industry and provide an overall representation of system reliability.

In order to compare the performance of the transmission system on a regional basis, the number of sustained delivery point interruptions and the average duration per interruption are examined.

The under-frequency load shedding scheme is examined in Section 1.2.2.5.

1.2.2.1 System Average Interruption Frequency Index (SAIFI).

This is the average number of sustained interruptions per delivery point per year. It is one of the more commonly used indices as it provides an overall picture of

Delivery Point Statistics
SAIFI
Chart 1-5

	89-93	90-94	91-95	92-96	93-97	97
NLH	3.25	2.63	2.44	2.84	2.83	2.47
CEA	1.04	1.00	0.99			

system reliability. Chart 1-5 compares Hydro's performance to the CEA composite for the latest five five-year periods and includes annual data for Hydro for 1997. The frequency of delivery point interruptions is about three times more than the CEA average over this time period. This would be due in part to the harsh operating environment in Newfoundland. The number of sustained interruptions had been improving slightly for Hydro until 1996 when there were a high number of interruptions on the Great Northern Peninsula during December 1996. The number of interruptions improved to 2.47 in 1997. As the transmission system is strengthened to stand up to more ice and wind loading, see Section 2.3, these statistics should improve.

1.2.2.2 System Average Interruption Duration Index (SAIDI).

This is the average interruption duration (minutes) per delivery point per year. It

Delivery Point Statistics
SAIDI
Chart 1-6

	89-93	90-94	91-95	92-96	93-97	97
NLH	241.43	212.79	275.12	259.43	242.94	83.09
CEA	63.24	63.14	65.02			

provides an average duration on a system wide basis. Chart 1-6 compares Hydro's performance to the CEA composite for the latest five five-year periods and includes annual data for Hydro for 1997. The storms experienced in 1994 and 1995 affect this indicator. The performance improved to 83 minutes per delivery point in 1997. This is a significant improvement and is closer to the latest CEA five-year average of 65 minutes per delivery point.

1.2.2.3 System Average Restoration Index (SARI)

This is the average restoration time in minutes per interruption. Given the harsh environment in Newfoundland, there are more interruptions on the electric

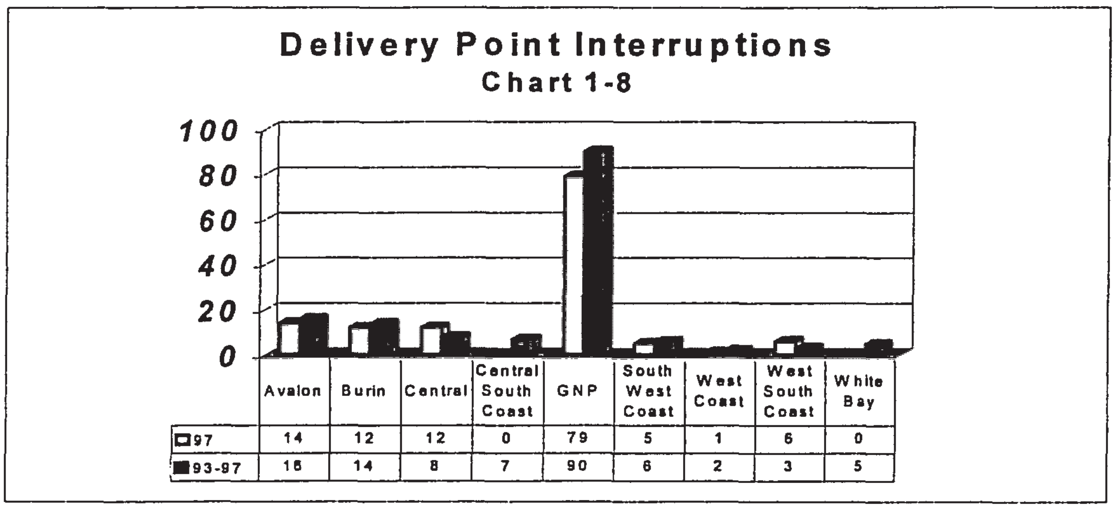
Delivery Point Statistics
SARI
Chart 1-7

	89-93	90-94	91-95	92-96	93-97	97
NLH	74.24	81.06	112.85	91.46	74.68	33.60
CEA	60.88	63.26	65.68			

system so it is important to look at how quickly the system is restored. Chart 1-7 compares Hydro's performance to the CEA composite for the latest five five-year periods and includes annual data for Hydro for 1997. The average restoration time has been improving in the latest two five-year periods, from 113 minutes per interruption in 1991-1995 to 75 minutes per interruption in 1993 to 1997. This is due to the number of short duration interruptions in 1996 and 1997. It is recommended that this measure be added to the monthly report that is provided to the Board by Hydro and that a target for improving this is established.

1.2.2.4 Regional Performance

The number of sustained delivery point interruptions and the average duration per interruption are used to compare the performance of the Bulk Electrical

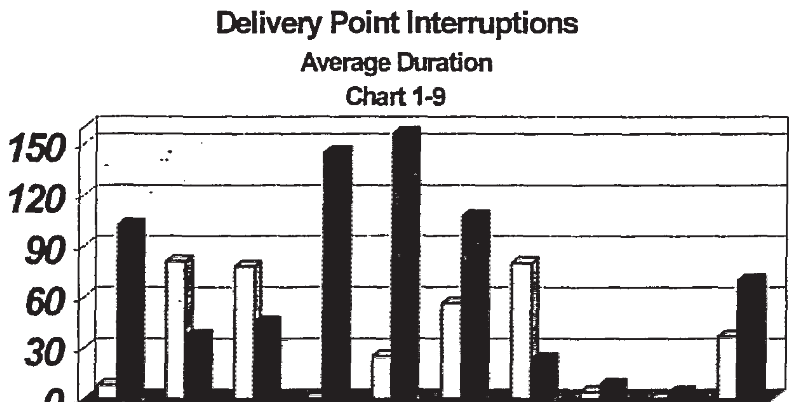


	Avalon	Burin	Central	Central South Coast	GNP	South West Coast	West Coast	West South Coast	White Bay
97	14	12	12	0	79	5	1	6	0
93-97	16	14	8	7	90	6	2	3	5

System (BES) on a regional basis. A sustained interruption is an interruption that is more than one minute. Chart 1-8 compares the average number of delivery point interruptions for the latest five-year period and for 1997. The Great Northern Peninsula has the highest number of delivery point interruptions followed by the Avalon and Burin Peninsulas. The number of interruptions on the Great Northern Peninsula is too high. Hydro staff indicated that salt contamination has been a problem on the long transmission line to this area and that they were working with different types of insulators to improve the situation. It is recommended that the Board should ask Hydro to prepare a report on this with an action plan to monitor and improve this.

The West Coast of the Island has the best performance with respect to the number of interruptions.

Chart 1-9 compares the average duration for interruptions for the nine regions of



	Avalon	Burin	Central	Central South	GNP	South West	West Coast	West South	White Bay	Avg.
97	8	81	78	0	25	56	80	4	0	37
93-97	102	37	45	145	156	107	24	8	4	70

the Island. The five-year average duration per interruption is 70 minutes. The Great Northern Peninsula and the Central South Coast have the longest outages over the five-year period. The two severe wind and freezing rain storms on the Great Northern and Connaigre Peninsulas contributed to this result. As the transmission system is strengthened to stand up to more ice and wind loading, see section 2.3, these statistics should improve.

The West Coast of the Island has the best performance with respect to the duration of the interruptions.

1.2.2.5 Under-Frequency Load Shedding

The obligation of the system which has lost the unit is to restore the interconnecting tie lines to the previously set schedule within a time determined by the agreement among utilities. Such systems use what is called operating reserve, which can be divided among different categories.

On a system such as the interconnected system on the Island of Newfoundland, with relatively large units compared to the Island system peak, loss of a large operating unit can result in a significant change of frequency. Unless automatic corrective action is taken, a complete system collapse will occur. It is virtually impossible for such a system to remain intact under this condition without employing automatic under frequency load shedding to assist in matching the generation and the load.

On large interconnected systems such under frequency load shedding is employed to cater to second or third contingencies such as the loss of a large unit followed by the loss of the interconnections to that system.

Hydro has employed an under frequency load shedding scheme to prevent system collapse since 1977. Over the past five years, under frequency load shed operations have averaged fourteen per year. This affects all customers on the under frequency blocks which are shed.

Since Newfoundland Light and Power Company Limited (Power) supplies most of the residential and commercial load, it must be part of the program. Hydro coordinates the review of the plan and identifies the magnitudes of the loads that must be shed at various frequency levels. In order to meet its commitments, Power has installed 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.

On an annual basis, the SAIFI and SAIDI statistics for Power 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 under frequency outages.

The loss of a large unit such as any of the Holyrood or Bay D'Espoir, units will almost certainly result in loss of load due to under frequency load shedding, it is, therefore, more important for Hydro than for most utilities to minimize forced outages of large generation units. This implies a need for careful and adequate maintenance and skilful operation of these large units. Loss of Load Expectation (LOLE) calculations may show no loss of load due to lack of installed capacity. In the operating mode the loss of a large unit, even though there is sufficient installed capacity available can result in loss of supply to customers.

Quetta has reviewed the system employed by Hydro and the schedule developed during Hydro's 1997 review. In Quetta's opinion, such an under frequency load shedding program is required and in place. The analysis carried out by Hydro engineers is well done and the schedule developed is reasonable.

1.2.3 Distribution

The Distribution System is that portion of an electric power system that links the bulk power source or sources with the customer's facilities. The data collection process for Hydro has been improving over time and is now acceptable. Diesel plant outages were not included up to 1995, some were included in 1996 and all are included in 1997 for data used to compare the performance of the different regions. As a result of this, year to year comparisons are not valid.

The latest (1996) CEA data for region 2 utilities is used as a comparison. Region 2 utilities are utilities that operate in urban and rural areas. A list of Region 2 utilities is provided in Appendix 5. Data from the Yukon Electric Company, Table 1-1 is also used as a reference for reliability in remote diesel areas. A comparison is also made with utilities operating in Eastern Canada in Table 1-2.

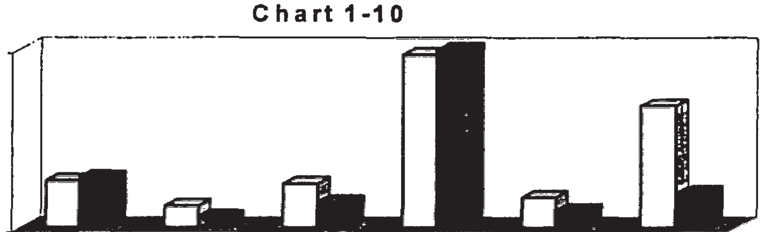
Two reliability indices are used to compare the performance of Hydro as follows:

1) System Average Interruption Frequency Index (SAIFI)
2) Customer Average Interruption Duration Index (CAIDI)

These are common reliability measures that are used by the Canadian electricity industry and provide an overall representation of distribution system reliability.

1.2.3.1 System Average Interruption Frequency Index (SAIFI).

This is the average number of interruptions per customer served per year. Chart



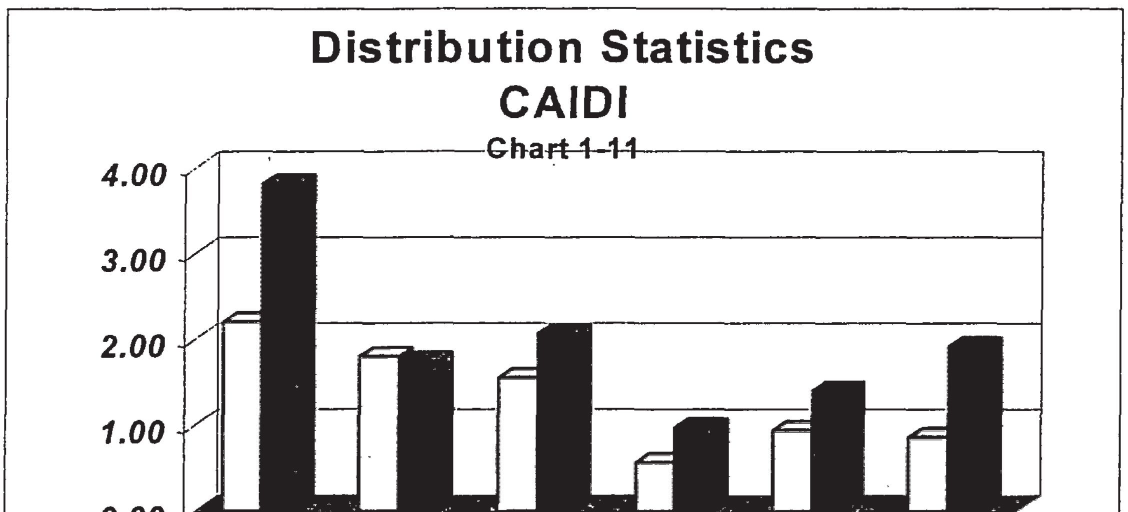
	Central Inter	Central Iso	Northern Inter	Northern Iso	Labrador Inter	Labrador Iso
□97	5.76	2.64	5.40	21.24	3.72	15.00
■94 - 97	6.15	1.35	3.06	21.84	2.07	4.26

1-10 compares regional performance at Hydro. On a regional basis, the highest number of interruptions per customer is in the Northern and Labrador isolated Areas in 1997. Table 1-1 shows SAFI (1997 data) for six isolated diesel communities served by the Yukon Electric Company. Table 1-2 shows SAFI (1996) for six utilities and the Canadian average for region 2 utilities. The average for Hydro is twice the Canadian average and higher than the other utilities. The frequency of outages in the isolated diesel areas for Hydro is much higher than the range of the data for the Yukon.

1.2.3.2 Customer Average Interruption Duration Index (CAIDI)

This is the customer average interruption duration (hours) for customers interrupted during a year. Chart 1-11 compares regional performance at Hydro. On a regional basis, the longest average interruption duration is in the Central Interconnected region. Table 1-1 shows CADI (1997 data) for six isolated diesel communities served by the Yukon Electric Company. Table 1-2 shows CADI (1996) for six utilities and the Canadian average for region 2 utilities.

The average duration of interruptions for customer in 1997 was 1.76 hours which is close to the 1996 CEA region 2 utilities average of 1.2 hours. The average duration of outages in the isolated diesel areas for Hydro is within the range of



	Central Inter	Central Iso	Northern Inter	Northern Iso	Labrador Inter	Labrador Iso
97	2.20	1.80	1.55	0.57	0.94	0.86
94 - 97	3.81	1.74	2.07	0.97	1.40	1.92

the data for the Yukon.

The frequency of outages for the Northern Isolated area is too high. It is recommended that the Board should direct Hydro to report on this matter and prepare a plan to improve the reliability in this area over a reasonable period of time. It is also recommended that the Board require Hydro to prepare the System

Average Interruption Frequency Index (SAIFI) for each isolated diesel area and include this in the regular monthly report to the Board.

Table 1-1
Yukon Electric Company
Isolated Diesel Communities 1997 Distribution Reliability Statistics

	SAIFI	CAIDI
Destruction Bay	2.08	3.67
Beaver Creek	3.31	0.10
Old Crow	1.04	0.04
Stewart Crossing	4.52	1.50
Pelly Crossing	9.83	1.48
Swift River	4.00	0.31

Source: Yukon Electric Company, 1997 Distribution Reliability Indices

Table 1-2
1996 Distribution Reliability Statistics

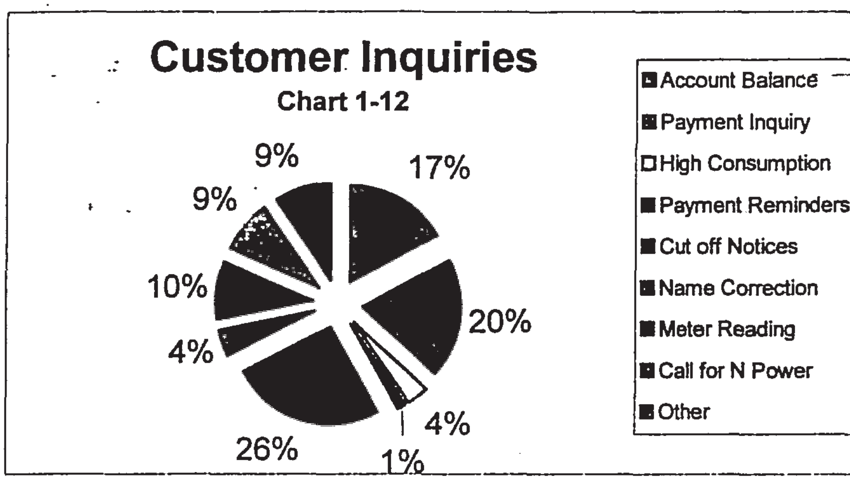
Utility	SAIFI	CAIDI
Newfoundland Hydro	4.74	1.76
Newfoundland Power	3.82	1.10
Nova Scotia Power	3.58	1.69
New Brunswick Power	4.05	1.85
Yukon Electric	3.45	1.35
North West Territories	4.61	
Canada (Region 2)	2.39	1.20

Source: 1996 Annual Service Continuity Report on Distribution System Performance in Canadian Electrical Utilities, Canadian Electricity Association

1.3 Customer Service

1.3.1 Customer Inquires

The existing system at Hydro to record and handle customer inquiries is informal. Local offices handle their own inquiries and files. Inquiries to Head Office are handled through the Customer Service Department. Incoming calls to Customer



Service, Head Office, were logged from March 24,97 to March 27,98. Chart 1-12 shows the breakdown. Almost all of the calls are billing related. It was interesting to note that 9 % of the calls were for Newfoundland Power.

Service related calls are handled in the local offices. Calls related to power outages are recorded on forms that are used as input to the distribution outage reporting system. Records of other service related issues are not kept in a form that allows review. It should also be noted that there are only two written complaints from Hydro's customers in the PUB file, these are related to problems in Mud Lake and Nain in Labrador.

The system to handle Customer Inquiries is in the process of being updated with the introduction of the JD Edwards Utility Customer Information System (UCIS) as part of the Project 2000.The version of this software that Hydro will be using is new. The first utility customer of JD Edwards to go live will be Lower Valley in early 1999. Later in 1999 Guam Power and Vista Irrigation will be going live. Appendix 6 contains additional data on the JD Edwards system. This is scheduled for implementation at Hydro in early 1999. A call center is being set up at the same time. This center will handle calls from across the province. Customer calls will be monitored and tracked using this system. Hydro is presently working to define what information needs to be tracked and is determining how to monitor customer contacts and inquiries. A customer service manual is also being prepared. This will help ensure that customers will be treated on a more uniform basis.

Quetta is not able to comment on the adequacy of this initiative to improve this important area of customer service because the definition of this part of the customer service project was not completed when Quetta visited with Hydro. However, it appears that the new UCIS system should improve the handling and tracking of customer inquiries and provide management the customer information that it needs to help improve customer service levels.

The implementation of the Customer Service System will be the subject of an Internal Audit as part of the 1999 internal audit plan. It is recommended that the Board should request this audit report from Hydro.

1.3.2 Customer Satisfaction

Customer satisfaction information at Hydro is obtained using formal customer survey. The first and only survey to date was conducted in December 1996. The survey was carried out with three objectives in mind:

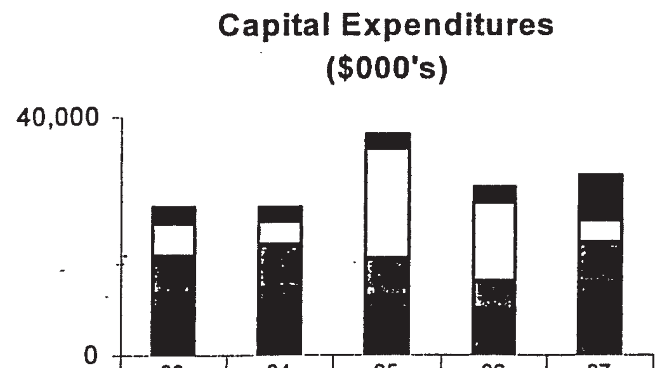
1) the identification, and benchmarking of scores, on issues of importance to the consumer and to rate their level of satisfaction with Hydro's performance in these areas;
2) to provide a basis of analysis , or benchmark, for future assessment of Hydro's customer service performance;

3) to prioritize customer service issues to be addressed through future customer service programs.

The issues that Hydro's customers identified as most important were a reliable supply, quick restoration of power and reasonably priced electricity. This survey also identified customer service issues and measured Hydro's performance with respect to those issues. It will provide a benchmark to judge the impact of the Customer Service initiative that is underway. This process is appropriate and should be continued on a regular basis in the future. It is recommended that the Board require Hydro to continue these surveys on an annual basis and report the results to the Board.

2.0 Planning

The chart below shows the level of capital expenditures for the period 1993 to 1997 by major functional area at Hydro. This chart allows a review of the pattern of capital expenditures to be made. The average capital expenditure for rural systems has been reasonably constant, averaging $10.1 million and was $11.9 million in 1997. This is an indication that the level of capital additions and replacements for the rural system has not been reduced as a result of the downsizing of Hydro. This chart and data table should be updated as part of the Capital Budget submission to the Board, data from the five-year capital forecast should also be requested.



	93	94	95	96	97
General Properties	2822	2483	2587	2698	7493
Transmission	5348	3852	18253	13096	3647
Generation	6545	7470	6653	4834	7076
Rural Systems	10231	11157	9680	7633	11942

2.1 Generation Planning - Interconnection System

2.1.1 General

A typical planning procedure for an integrated electric utility is shown in Appendix 4.

Quetta met with System Planning personnel at Hydro, reviewed a series of documents with respect to Hydro's planning process and a number of planning studies produced by the Hydro group

2.1.2 Load Forecast

Hydro's Official Load Forecast (OLF) is produced by the Economics Group. This forecast is based on econometric modeling with inputs provided principally from the Provincial Department of Finance. The methodology and result of the load forecast exercise were reviewed and the conclusion is that this is well done.

Given the uncertainty with respect to Provincial development, the future of the fishery, etc., the result is considered reasonable. The OLF which covers the period 1998 though 2016 is used by the System Planning group to develop a short term, five year, forecast showing the detailed demand on a monthly basis for power and energy. This latter forecast is used for budgeting and short term planning.

2.1.3 Planning Criteria

The criteria used for resource (generation) planning at Hydro are as follows:

2.1.3.1 Energy

The Island Interconnected System should have sufficient generating capability to supply all of its firm load requirements with firm system capability.

The firm energy capability of the Hydro system is based upon the lowest three consecutive years of inflow to the reservoirs. Diesel and combustion turbine plants are assumed to have zero firm energy capability. The firm energy capability of the Holyrood oil-fired generating station is based upon an annual capacity factor of 73.5%. In the opinion of the Quetta this is a reasonable calculation of firm energy capability. The realization of a 73.5% annual capacity factor for the Holyrood generating station will require Hydro to pay detailed attention to maintenance to ensure this performance.

2.1.3.2 Capacity

The Island Interconnected System should have sufficient generating capacity to satisfy a Loss of Load Expectation (LOLE) target of not more than 2.8 hours per year. This is equivalent to 0.2 days/year or 1 day in 5 years. It results in a capacity reserve requirement of 18%.

The LOLE capacity criterion is somewhat less stringent than that employed by large interconnected systems in the rest of North America (one day in 10 years or 0.1 days/year). Considering the non-interconnected status of the Island's electric utility system, (reserve sharing is not an option) the cost of providing higher reliability level is probably in excess of the benefits to be derived.

Quetta is of the opinion that the capacity and energy criteria are reasonable in the circumstance.

2.1.4 Planning Methodology

The methodologies employed by Hydro's Planning Group for resource planning is state-of-the-art. The models available and there application indicates that Hydro has a competent, well equipped Planning Group.

The options available for on-Island generation are somewhat limited. There is some undeveloped hydro electric potential which Hydro has identified and studied. Two potential developments on the Bay D'Espoir water shed, Granite Canal (42 MW) and Island Pond (36 MW) appear to be the next most economic generation addition on the Island. These developments may imply transmission additions and/or upgrades to deliver the energy from the generating stations to the load centres. This consideration will require further study to assure the utility that the development of these hydroelectric resources is the most economic near term alternative.

The other principal options for on-Island base load generation capacity are the addition of a fourth unit at the Holyrood generating station and/or a greenfield oil-fired generating station. The additional oil-fired generation could be combined cycle or a conventional steam turbine generator system as is presently employed at Holyrood. Consideration of SO_2 emissions and the need to use lower sulphur fuel to meet the emission guidelines will have to be a consideration in the selection of the next oil-fired generating unit on the Island.

One of the major uncertainties facing the Planning Group is the distinct possibility of interconnection of the Island with the Labrador Hydro Electric developments existing and planned. Until this question is resolved, all resource planning will have to be tentative.

The utility has investigated demand side management (DSM). Given the limited potential (little residential or commercial load) and the uncertainty as to future generation system costs DSM does not appear to offer any immediate benefits.

The utility has negotiated a contract with one of its major customers, Abitibi-Price Inc., for curtailing load in the amount of 46 MW during system emergency conditions. This should provide benefits both to the utility and the customer. There is also a 5 MW interruptible agreement with Deer Lake Power/Corner Brook Pulp and Paper.

There may be additional potential for load curtailment however this is principally a capacity consideration. It appears that the utility's energy criterion will be violated at about the same time as the capacity criterion. As load curtailment will not meet the utility's energy requirement, (load curtailment is meant to help meet the capacity criterion) additional DSM cannot defer the need for new capacity. Therefore capacity additions will be required.

As part of the review of resource planning Quetta analysed the studies carried out to determine the benefits or otherwise of independent power producers (IPP's). As a result of a call for proposals the utility will purchase a total of 19 MW over the next three years from two IPP sites. The analysis carried out to determine the value of this purchase to the utility is well and properly done. Further independent power production at this time seems to be uncertain especially, since the Government's August 31, 1998 announced review of energy policy.

The utility shows no additional purchases in its base generation expansion plan.

2.1.5 Joint Planning

Quetta reviewed one joint resource study carried out with Power. This study analysed the benefits or otherwise of repowering the thermal generation facility on the south side of St. John's harbour. It appears as if joint generation planning between the two major utilities is on an ad hoc basis with Hydro assuming the responsibility for capacity additions to the Island interconnected system.

Now that Hydro and Power are both regulated, it may be an appropriate time to determine who has the responsibility for generation capacity additions and if, in the opinion of the Board, joint planning is desirable and/or necessary. The energy policy review should address this issue, at the request of the Board if no other stakeholder raises the issue.

2.2 Generation Planning Diesel Locations

2.2.1 Planning Methodology

Quetta met with Hydro staff having direct responsibilities in the area of planning for isolated diesel generation systems. Hydro's planning process uses a conventional present worth evaluation comparing incremental investment costs and operating costs for different options. The main economic criterion used to compare these options is the minimization of costs based on the discounted value of all system costs. Hydro has no proposed change to this methodology.

Hydro uses a production cost software developed in house. Study inputs include; discount rate, Capital and O & M escalation, fuel price forecasts, Capital Costs, fuel efficiencies, O & M costs, fuel price forecasts. The inputs used are appropriate for such analysis. Planning criteria were reviewed and include reliability, minimum reserves, firm capacity and minimum number of units at a remote station.

The foregoing describes the planning process used by Hydro in this area. Quetta reviewed seven studies done for this part of the system from 1992 to 1997. These studies examined such options as expansions, interconnection, retrofit and automation.

Interconnection on the remaining isolated systems are becoming less and less feasible. The feasibility of interconnection might change in the event certain mining developments go forward.

Other options on the present system might include mini-hydro. Hydro has available a 1979 Shawmont study, updated to 1987 providing an inventory of such mini-hydro sites. Up to one hundred sites have been studied. Economics would probably dictate that the developments would be sized to run of river (R.O.R.) operation.

Fuel costs are very much site related and geography and ice conditions dictate the level of storage required. Nain for example has got a three month "window" for fuel delivery and therefore requires nine (9) months supply based on the average heat rate of the plant. Fuel storage requirements and increases in capacity required are established by prediction of capacity deficits based on forecasts of consumption.

The mini hydro option for systems on-island has been the subject of a further study done jointly by Newfoundland Power and Hydro. The study report dated August 1998 concluded that, of the 40 on-island sites identified, only two passed the initial screening process. These sites were GR.l near Grey River and FR.5 near Francois. Further screening showed that neither GR.1 nor FR.5 could displace enough diesel generation to pay back the capital investment in 30 years or less.

The study concluded that prospects for mini hydro development might improve from: increases in fuel costs; decreases in capital costs (from technical advances); or Government funding. The last mentioned funding from Government is not likely because of the recent policy statement by the Government of Newfoundland and Labrador calling for a moratorium on mini hydro development.

2.2.2 Comparison with other utilities

Hydro undertook a survey of other Canadian utilities in 1994 to compare generation planning practices on isolated systems. The results were included in a report dated November 1995. Appendix 7 includes tables 3.1 through 3.5 from the study report showing a comparison of various criteria used by the utilities covered in the study. Quetta has reviewed that report and has reached the conclusion that Hydro has in place planning criteria and processes that are satisfactory.

Quetta recommends that this study initiative by Hydro be commended by the Board and encouraged to the point that Hydro be asked to effect a formal structured association with other Canadian utilities with isolated generation and distribution systems. The association suggested should not be limited to the planning process but should be extended to cover operation and maintenance practices.

Quetta made some informal inquiries from some of the utilities named in the report.

NWT Power Corporation made this response:

> "Planning Criteria, Table 3.1 has changed slightly. We have eliminated the break between plants less than 3MW and those greater than 3MW, and we now use firm capacity equal to 110% of peak load.
> We have added some engine sizing notes for planning; the major one being that units be sized to achieve a minimum 70% load factor where possible."

Should the Board and Hydro accept the earlier recommendation to formalize the relationship between the utilities included in the study then the 1995 report would be kept current and the rationale for changes would be available to Hydro for their consideration as might apply to Hydro's situation.

2.3 Transmission Planning

2.3.1 General

The transmission planning function at Hydro is performed as part of the System Planning Group. As in most utilities this function has a close relationship with Engineering and System Operations. It provides technical specification data for major equipment to the Engineering Department so that the power system will be designed to operate as an integrated entity.

Transmission Planning provides assistance to System Operations in analysis of system disturbances and abnormal operating conditions as well as providing technical assistance to the major Hydro customers. This is a normal activity for such a group.

2.3.2 Planning Methodology

Quetta reviewed the methodology employed by the Transmission Planning Group and the Transmission Planning Criteria. The Transmission Planning Criteria are shown in Appendix 7.

The Planning Criteria are less stringent than those employed on major interconnected systems. As an example, Appendix 8 gives the transmission planning criteria used at one Atlantic Canada interconnected utility. These criteria are much more stringent than are Hydro's. In Quetta's opinion Hydro's criteria should provide reasonably good reliability, in the bulk transmission system.

Quetta reviewed recent studies done by the Transmission Planning Group as follows:

1. The East Coast Voltage Study
2. The Reliability Study of Transmission Lines on the Avalon and Connaigre Peninsulas

3. The Great Northern Peninsula Transmission Line Study

The only significant new transmission constructed by Hydro in recent years has been the 138 kV extension/conversion from Peter's Barren to St. Anthony.

These studies are well done.

Most of the transmission work carried out by Hydro over the past decade has been to rebuild circuits for more stringent ice and wind loading requirements. This has resulted in budget items to rebuild a significant amount of the 230 kV transmission system, particularly the supply to the Avalon Peninsula. When the first phase of this rebuilding is completed in 2000 Hydro should review the situation to determine whether all circuits should be rebuilt to the same standard. The Board has, in fact, ordered Hydro, in PU11 (1997-98) to do so.

As mentioned previously, the transmission line between Bay D'Espoir and the Sunnyside transmission terminal station may have to be strengthened if further generation is added to the Bay D'Espoir system. Quetta has not seen results of such a study although it is noted that Hydro did propose in 1998 a budget item to upgrade these 230 kV circuits.

Quetta has not seen the justification for this item. The Board should request further justification before approving this proposed expenditure.

In addition to reviewing the Island transmission system, Quetta discussed some of the aspects of the supply in Labrador. It is noted that the Happy Valley Goose Bay communities are served by a radial transmission line and that the supply to Labrador City and Wabush does not meet all the criteria for transmission planning. The transmission assets in Labrador West are not owned by Hydro but by the Twin Falls Power Corporation (Twinco). Through an arrangement with Twinco, Hydro utilizes the transmission assets to supply its customers, (IOCC and the towns of Wabush and Labrador City) with power and energy from Churchill Falls. In addition, the transmission system is used to supply Twinco Loads at IOCC and Wabush Mines.

The criterion applied for the Island system is that for the single contingency loss of a transmission element the system must still be capable of supplying full load. The Labrador West transmission system is utilized at near 100% capability and the single contingency loss of one of the two 230 kV transmission lines form Churchill Falls results in an inability to serve full load.

To increase the operating reliability of the Labrador West system to a level consistent with the Island system it would be necessary to:

(i) Construct a third 230 kV transmission line between Churchill Falls and Wabush or

(ii) Install a back-up generation source in the Wabush/Labrador City area.

Either of these alternatives is capital intensive and would significantly impact the electricity rates of customers in Labrador West. As a result no firm commitment has been made to either option. Hydro and the other stakeholders in Twinco (IOCC, Wabush Mines and CF(L)Co) are all aware of the short comings of the Labrador West transmission system and are actively working together to make improvements which are acceptable to all stake holders.

Future development of Lower Churchill generation will impact the transmission supply to the Happy Valley Goose Bay communities. Until the uncertainty with respect to Lower Churchill development is resolved, the utility is exercising prudence in maintaining the existing transmission.

Transmission planning could become the major element in Hydro's future should the proposed interconnection between Labrador and the Island proceed, as the additional energy requirements of the whole Island will be supplied via transmission.

2.4 Distribution Planning

2.4.1 General

The distribution planning function at Hydro is performed as part of the System Planning Group. As in most utilities this function has a close relationship with Engineering and Transmission and Rural Operations (TRO). It uses a computer program to model load flows and system voltage levels for the distribution system. The models are periodically revised and updated to reflect system changes and are calibrated based on the results of load and voltage studies conducted in the field during or close to peak load times.

2.4.2 Planning Methodology

Quetta reviewed the methodology employed by the System Planning Group and the Distribution Planning Criteria. The Distribution Planning Criteria are as follows:

1) Hydro's distribution system is planned to be capable of sustaining nominal voltage based on CSA CAN3-C235-83 (Preferred Voltage Levels) and the CEA "Distribution Planner's Guide". For normal operations, the distribution system is planned on the basis that all voltages be maintained between 95% and 105% of nominal voltage.

2) Substation Loading - equipment no greater than 100% rating, adjusted for appropriate temperature during peak. Short term overloading on transformers is permitted.

3) Voltage Flicker Limit - maximum of 5 % voltage flicker. Voltage flicker is short-term voltage variations allowed on the distribution system due to external influences such as a large electric motor operating from the distribution system.

The Distribution Planning Criteria are acceptable and are comparable to that used by other utilities due to the use of CSA and CEA criteria.

Quetta reviewed the process for the selection of distribution lines in the capital program. The planning department identifies areas in which Hydro's planning criteria are or may be violated, by using appropriate planning software. Transmission and Rural Operations identifies opportunities for service enhancement based on outages, complaints, reliability statistics and information from the inspection reports in the maintenance planning system. Technically feasible alternatives are reviewed by operating and technical staff and then compared using traditional cumulative present worth analysis. Projects are then presented to the Vice President of Transmission and Rural Operations (TRO) for review. The Vice President of TRO then presents proposals to the Management Committee for review. The Management Committee will review its five-year Capital Plan with particular emphasis on the first year. Accepted proposals are presented to the Board of Directors and then to the Public Utility Board (first year only) for approval.

Objective criteria for the inclusion of a distribution project in the capital program are not clearly defined by Hydro. Objective criteria such as reliability, customers, loading, losses, condition of line, safety should be used and documented in order to create priorities for capital investment and reliability improvements. The Budget submitted to the Public Utility Board should include this evaluation.

The only notable distribution planning report prepared by Hydro in recent years was for the Labrador City Distribution System. Quetta reviewed this study and all the significant elements that you would expect to find in such a study were covered.

Diesel areas that are interconnected to the main grid are treated in the same manner as a normal distribution line in that there are no special contingency plans once they are connected. The diesel generators are normally removed as part of the interconnection project unless there are concerns for reliability of service due to the location. Hydro has retained diesel facilities, for emergency standby operation, in the St. Anthony / Roddickton system and at Goose Bay for this reason.

Quetta reviewed the nine distribution projects that were proposed by the System Planning Group for the capital budget years 1994 to 1998. The variances for the projects were discussed with Hydro staff and found to be reasonable. Eight of the projects have been completed. The remaining project, Petites Interconnection, is no longer under active consideration due to the consistent load decreases in recent years.

2.5 Planning Summary

It is Quetta's conclusion that the utility has a capable staff and adequate resources to carry out the planning responsibility in all areas and to develop and analyse facility addition plans to meet the utility's criteria.

3.0 System Operations

3.1 System Dispatch

The policy for power system dispatch reflects the dominance of hydraulic power and energy on the Hydro system. In meeting energy supply, the storage reservoirs are managed to minimize the use of thermal generation while ensuring that forecast firm energy load will be met under any historical hydrological sequence. For capacity supply, generation is scheduled to meet forecast load with the loss of the largest operating unit.

A simulation model of the reservoir systems is used to establish storage targets. Appropriate inputs are used in iteratively repeated simulations until no energy deficit occurs and spills are minimized. Inputs used consider plant availability, planned outages, transmission maintenance and others. Planned system outages are covered by a rigorous standard instruction and co-ordinated through the Superintendent – Energy Control Center (ECC). Outages internal to Hydro call for a minimum notice period of five working days. The instructions are reasonable but they should be improved. It is recommended that the instruction #010 covering "System Outages" should be revised to reflect clearly the role and responsibility of Newfoundland Power. The same comment applies to instruction T-022 "Restoration of the Holyrood Plant to an isolated system". Appendix 9 includes both instructions.

3.2 Communications Planning

Hydro staff reviewed with Quetta a five phase, seven-year strategic communications plan. Phase one is covered in part in the 1998 Capital Budget approved by the Board. The plan comprises: the replacement of obsolete or aging systems in the existing network, the provision of greater carrying capacity at higher speed for the planned expansion of the customer information network and control and protection of the entire system.

The plan was very comprehensive and it was filed by Hydro and thoroughly examined by the Board during the course of the 1999 Capital Budget hearing.

3.3 System Protection

The Manager of System Performance and Protection Group reviewed his responsibilities with Quetta. The history of the development of the protection system was discussed and Quetta is satisfied that Hydro knows and respects its responsibilities in building on this important system.

An area of concern for any power utility is the manner in which changes to the system protection occurs and how the those changes are monitored and recorded. The following describes the updating procedure at Hydro.
System protection settings are prepared, issued and controlled by the System Performance and Protection Group for the transmission system. They are maintained in a database called the Computerized Relay Information System (CRIS) developed some years ago. Approved settings are issued to the field as setting letters. They are implemented by P & C technicians in the area offices. Once the relays are set confirmation is issued back to the System Performance and the database is updated to reflect this. Reviews are done of the settings based on the following:

1) When system changes are made or new equipment additions are made.
2) Changes are implemented based on monitoring actual performance during system disturbances. Each system disturbance is analysed as to actual operation and performance.
3) An annual review of overcurrent settings is done to ensure that peak load values don't encroach or exceed settings.

Quetta considers this procedure to be satisfactory as written; however it is recommended that there be stated in the procedure a clear recognition of a single area of responsibility bridging the Production and TRO divisions of the utility operations

3.4 Interaction of Control Centers

The Control Centre at Hydro is responsible for dispatching the principal generating stations on the Island interconnected system. Power which has enough capacity to supply only 10% of its own requirements normally operates its hydro units for maximum efficiency but assures that there is enough storage to meet full capacity requirements from December through March. The interaction between the two Control Centres, Hydro and Power, is one of information sharing with respect to the generator loading and availability, lines and equipment out of service, etc. Planned outages are coordinated between Centres on an on-going basis. The interaction of the two Centres, is extremely important during restoration efforts involving the "black start" at the Holyrood generating station. The procedure in place requires that Hydro's Hardwoods combustion turbine station and Power's hydro generating stations on the Avalon Peninsula, work in concert to restore service, such that Holyrood units can be started and enabled to accept load. Combined coordinated operation of the Hardwoods combustion turbine and Power's Avalon hydro generation is required. It is important that the two Control Centres be aware of each other's responsibilities and system conditions on each other's system for successful restoration. The need for reliable communication systems and pre-arranged procedures understood by the System Operators is a vital link in the power restoration to the Avalon Peninsula.

As covered in Section 6.2, changes in the governor's of Holyrood Units 1 and 2 should enable Hydro and Power to prepare a simpler restoration program.

Quetta has not seen any new restoration procedures. The Board should request Hydro to file the new procedure for restoration and request Hydro to confirm that Newfoundland Power understands its role.

4.0 Safety

Health and safety are two extremely important aspects in the operation of a utility. This section will consider the manner in which this is managed at Hydro and look at the performance of the program, including switching procedures, safety manual, and inspection and testing of line trucks and other equipment.

4.1 Safety Program

The basis for the safety program at Hydro is the DNV 6th Edition International Safety Rating System (ISRS) Loss Control Program. This is a standard safety program from Det Norske Veritas (DNV) and is used around the world. Utilities that use it in Canada include TransAlta Utilities, Nova Scotia Power and West Kootney Power. The emphasis at Hydro is on Safety and Health Issues. The program has the full participation from the Union and Management at Hydro. It includes a well-defined audit procedure designed to ensure that the program is effectively implemented throughout the Company. Quetta reviewed this program and found that it appears to be an effective approach to managing the health and safety of staff in an Electric Utility.

Quetta reviewed the procedure for accident / incident investigations at Hydro and found it to be complete. It is well-defined and there is a detailed training program provided to employees on this topic. Accidents are reviewed at regularly scheduled group loss control meetings held across the Company.

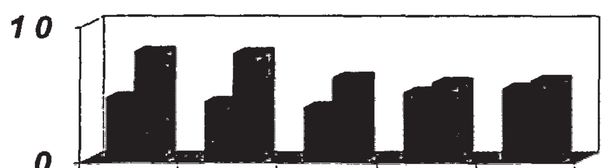
4.2 Safety Performance

Three of the most common safety measures were used in order to evaluate the safety performance of Hydro. In each case Hydro is compared to the Canadian Electricity Association (CEA) results for Group II Utilities. The main use of the three measures selected is to evaluate the trend with respect to safety performance and the relative ranking of the utility with respect to the industry average. Safety improvement is generally accepted to be the goal of a safety program with zero accidents being the target.

Group II Utilities are utilities with between 500 to 10, 000 employees and include the following utilities: Edmonton Power, TransAlta Utilities, NB Power, NS Power, Newfoundland Hydro, Manitoba Hydro, BC Hydro, Newfoundland Power, Alberta Power, Sask Power, City of Calgary Electric System and Winnipeg Hydro. Utilities are grouped by size to evaluated safety performance as the size of a utility influences the nature of the work that employees are required to perform. For example, in smaller utilities employees may carry out work that may be assigned to a specialist crew in a larger utility.

The first measure is the All Injury Frequency Rate as shown in the chart 4.1. This

All Injury Rates
Chart 4.1



	92	93	94	95	96
NLH	4.5	4.2	3.8	4.9	5.2
CEA	7.9	7.8	6.0	5.6	5.8

measure indicates the total number of medical aid injuries, disabling injuries and fatalities compared to the number of employee exposure hours worked in a calendar year. The frequency rate reflects the number of injuries and fatalities per one hundred employees.

Chart 4.1 shows the performance of Hydro compared to the CEA Composite for Group II. In each of the years Hydro was better than the CEA Composite. Using this measure Hydro ranked amongst the top utilities in this group from 1992 to 1996.

The second measure is the Disability Frequency Rate as shown in the chart 4.2. This measure indicates the number of disabling injuries and fatalities compared to the number of employee exposure hours worked in a calendar year. Disability Frequency Rate reflects the number of disabling injuries per one hundred employees.

Disability Frequency Rates

Chart 4.2

	92	93	94	95	96
NLH	1.9	2.7	1.5	1.9	2.2
CEA	4.0	3.8	2.2	1.9	1.8

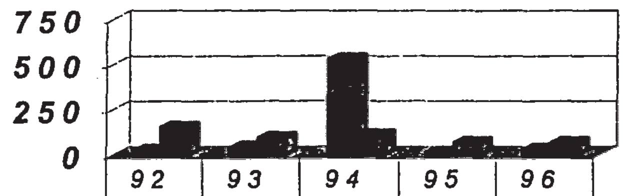
Chart 4.2 shows the performance of Hydro compared to the CEA. In four of the five years Hydro was as good as or better than the CEA Composite .

The third measure is the Severity Rate as shown in the chart 4.3. It reflects the seriousness of injuries. It compares the number of disability days to the number of employee exposure hours in a calendar year. Fatalities are charged at a rate of six thousand disability days.

The chart shows the performance of Hydro compared to the CEA. In four of the five years Hydro was better than the CEA Composite. 1994 was much worse than the CEA Composite was as there was a fatal accident that year at Hydro.

Overall the safety performance of Hydro compares favorably with Canadian

Severity Rate
Chart 4.3



	92	93	94	95	96
NLH	22.3	40.8	527.	11.1	29.4
CEA	151.	92.0	104.	63.0	65.5

Utilities in the same CEA group (over 500 employees, under 10,000 employees).

4.3 Switching Procedures and Safety Manual

Switching procedures are covered under the Corporate Work Protection Code at Hydro. The purpose of the Corporate Work Protection Code at Hydro is to establish a system which will eliminate or control workplace hazards through the use if isolating / de-energizing devices and / or approved work practices. Quetta reviewed the documentation with respect to this area and is of the opinion that this area is well looked after at Hydro.

The Labour Relations and Safety Department at Hydro administers the Corporate Safety Manual. The purpose of the Corporate Safety Manual is to provide employees and contractors with:

1) a basic understanding of general safety concepts,
2) specific guidance and rules associated with equipment use and personal protective equipment,
3) specialized work procedures and rules for line work, helicopter safety, and energized line work;
4) office safety;
5) first aid.

The manual is formally reviewed approximately every three years. All employees and contractors receive a copy of the manual and it is a standard agenda item at regularly scheduled group loss control meetings held across the Company. The process for developing and maintaining the safety manual system at Hydro is well documented and implemented.

4.4 Inspection and Testing of Line Trucks and Other Equipment

Quetta reviewed the procedures and the process used to control the inspection and testing of equipment such as hot sticks and rubber gloves. The procedures for the care and use this equipment is covered in the Corporate Safety Manual. The maintenance of the equipment is controlled through the maintenance management system as described elsewhere in this report. This process is well documented and implemented. Quetta also visited the site where the maintenance for this equipment is carried out and found it to be well organized and maintained.

A new program is being put in place to ensure the safety of the booms on the line trucks. This is in response to an incident in Nova Scotia where a boom failed resulting in a fatality. The new equipment maintenance program has been in place for approximately two years and appears to be evolving in a satisfactory manner. It was noted that dielectric testing of fiberglass extensions is not an issue with Hydro, as the bucket is not used as an insulation point.

5.0 Environmental

5.1 General

The responsibilities for environmental stewardship of a Board of Directors have been the subject of discussion and comment since the mid 1980's. An Environment Committee of the Board of Directors of Newfoundland and Labrador Hydro was formed. The Constitution and Powers of that Committee together with its Terms of Reference were approved by the Board of Directors on September 24, 1993. Hydro has adopted 10 principles to guide their commitment to responsible stewardship of the environment. Documents covering the foregoing were reviewed by Quetta and compared with recommendations by authorities in the field. These authorities included: Blake, Cassels and Graydon, and Ernst and Young. The policies and procedures adopted by Hydro are in conformance with these recommendations. Hydro's documentation is included in Appendix 10

5.2 Environmental Management

Quetta met with the Manager of Environmental Services and reviewed with the Manager how Hydro has complied with and continues to comply with, the wishes of the Board of Directors as outlined in Hydro's Environmental Principles. This review was accomplished by questioning the policies and procedures followed at Hydro with respect to the following environmental concerns identified in other utilities.

5.2.1 PCB's Policy and Procedures

Polychlorinated Biphenols (PCBs) have been used in electrical equipment as an insulating coolant since 1928. PCBs were considered safer than other insulating oil because the presence of PCBs inhibited flash fires. In 1978, because of concerns that PCBs could be linked to birth defects, the manufacture and use of this material in new equipment was prohibited by law. The PCB material already in service was made subject to strict control. Some utilities chose to take PCBs out of service and store them in approved sites. Hydro has adopted this policy.

Oil is deemed to be PCB contaminated and subject to control at concentrations greater than 50 ppm. At concentrations in the range of 50 to 1000 ppm., some utilities store the material and engage contractors to treat the oil in a chemical exchange process to remove the contamination. For very high concentrations [e.g. Askerol, trade name for almost pure PCB] the material is removed from the electric appliance (transformers, capacitors etc.) and stored under tight specifications and subject to inspection on a regular basis by Federal and Provincial agencies.

At Hydro:

1) All high concentration PCB's are in storage.
2) Storage facilities are managed and audited to ensure compliance with Federal and Provincial regulations.
3) 1998 Budget included funds for PCB destruction.
4) Procedures are in place to cover spills of contaminated oil and for the identification of PCB contaminated equipment.

5.2.3 Gaseous Emissions

Agreements have been developed between Hydro and those authorities having jurisdiction respecting thermal generating facilities. Working groups from Hydro and the Department of Environment and Labour maintain surveillance on the monitoring of emissions at Holyrood, Gas Turbine and Diesel sites.

5.2.4 Acid Smut Emissions at Holyrood

This is recognized as the principal area of complaint because of damage to property (e.g. building sidings and automobiles). Hydro continues to monitor the problem and are currently developing a study paper on the issue.

5.2.5 Storage and Disposal of Bottom Ash

Hydro applied for and received planning permission to develop a new secure landfill site at Holyrood for the storage of bottom ash from the Holyrood boilers. This need arose because the previous arrangement for disposal in a municipal landfill was terminated by the municipality.

5.2.6 Right of Way Maintenance

Right of Way (ROW) vegetation management is an environmental issue on two counts due to the methods used for the control of vegetarian (i.e. clear cutting and chemical control using herbicides). Hydro uses both methods in combination to achieve the least overall cost.

Hydro has determined costs to be:

For distribution lines

Cut only	$ 500/hectare
Foliar	$ 556/hectare

For transmission lines

Cut only	$ 256/hectare
Foliar	$ 370/hectare

Hydro's preferred method is to cut undesired species on the R.O.W. and follow within 2 to 3 years with foliar treatments. They estimate that this provides a control cycle up to 3 times longer than cutting alone.

DOE and Labour approvals are required and includes appropriate training and supervision of crews spraying herbicides.

5.2.7 Fuel Deliveries

Environmental concerns with respect to fuel deliveries are covered by appropriate clauses in supply contracts together with Pollution Emergency Plans developed in concert with the various government agencies having jurisdiction.

5.2.8 Penta Treated Poles

The environmental concern here is twofold: leaching of chemicals into run-off water and fumes from the material if it is improperly burned.

Quetta reviewed a comprehensive written procedure covering the safe management of this material. The procedure is satisfactory.

5.2.9 ISO 14001 and the Environmental Commitment Program

The Environmental Commitment Program (ECR Program) was approved by the Board of Directors of the Canadian Electricity Association (CEA) in June 1997. This initiative is aimed at improving environmental performance. Participation in the program is a requirement of membership with CEA effective 1998 for electric utility members. The program requires a commitment to implement an Environmental Management System (EMS) consistent with ISO 14001 requirements.

ISO 14000 is a series of internationally recognized standards for structuring an organization's environmental management system and managing the environmental performance of the system to effect environmental improvement and cost savings. The ISO 14000 series includes standards for EMS

(14001,14004), auditing (14010, 14011, 14012), labeling (14020, 14021, 14024), environmental performance evaluation (14031), and life cycle analysis (14040).

ISO 14001 is the cornerstone document of the ISO 14000 series of standards, and is modeled after the highly successful ISO 9000 quality management system standards. It is the document used for registration, ISO 14001 requires a company to:

1) develop an environmental policy with a commitment to compliance, prevention of pollution, and continual improvement;
2) conduct planning which identifies environmental aspects of an operation and legal requirements, sets objectives and targets consistent with policy and establish an environmental management program;
3) implement and operate the program to include defined structure and responsibility, training, communication, documentation, operational control, and emergency preparedness and response;
4) implement checking, corrective and preventive action and auditing; and
5) conduct management review.

Hydro has elected to be in full compliance with the CEA guidelines including registration under ISO 14001.

5.3 Summary

Quetta examined the performance of Hydro with respect to the foregoing key elements of concern for utilities. Hydro has in place an effective Environmental Management System and conduct proper environmental audits to ensure compliance. Hydro staff has the full support of the Executive and the Board of Directors with respect to environmental stewardship. The conduct of environmental audits was reviewed by Quetta in the course of the examination of the Internal Audit (IA) function covered in Section 8 of this report.

6.0 Operations and Maintenance

The purpose of this section of the report is to examine the operational aspects of Hydro and also to determine if downsizing at Hydro has had an impact on the performance of Hydro in these areas.

The general section will review operational issues from a corporate level and the remaining sections look at specific functional areas.

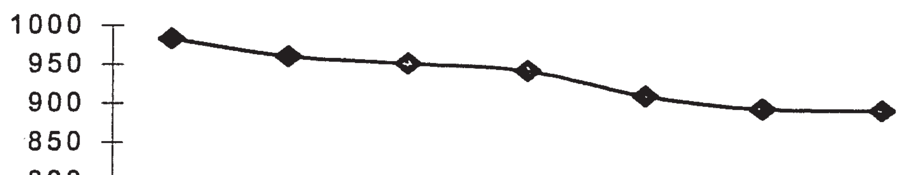
6.1 General Issues

The purpose of this section of the report is to examine operational issues at the corporate level.

6.1.1 Organization

Quetta reviewed the major organizational changes at Hydro for the last five years. Actual staff as at the dates indicated in chart 6-1 was used as an

Permanent Staff
(Actual)
Chart 6-1



	Dec-93	Dec-94	Mar-95	Dec-95	May-96	Dec-96	Dec-97
Total Hydro	982	959	949	940	907	890	887

indication of change in staffing level over the period. The staffing level has been reduced by about 10% over this period. The most significant changes occurred in March 1995 and May 1996.The majority of the reductions were in second level supervision and in the management group. In order to look at the possible impact on customer service the numbers of journeyman line workers and diesel mechanics was examined. Line workers and diesel mechanics are front line staff who are necessary to provide emergency service to customers in their areas.

The number of permanent, term and temporary line workers was 92 in December of 1993 and was 94 as of March 1998. The number of diesel mechanics for the last three years has been reduced slightly from 20 in 1995 to 18 in 1997. A temporary employee is an employee hired for a period of normally less than 12 months. A term employee is an employee hired to fill a position for a special time period that is more than 12 months but less than four years.

In the opinion of Quetta, the restructuring at Hydro has not had a significant impact in areas that affect customer service.

6.1.2 Operating Expenses

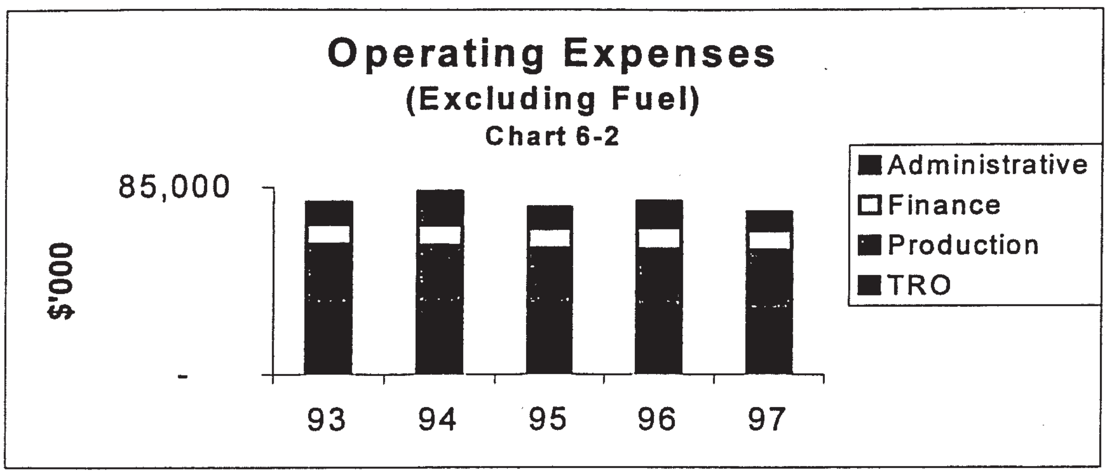
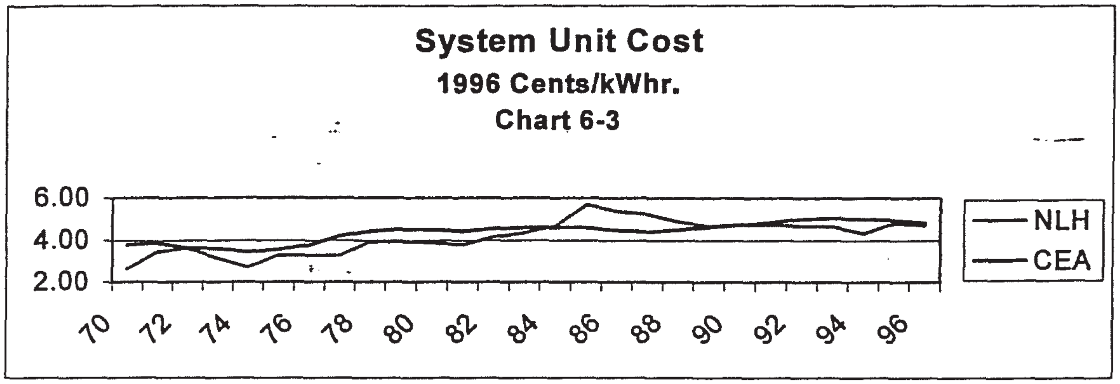


Chart 6-2 shows the level of operating expense, excluding fuel, for the period 1993 to 1997 by function at Hydro. The combined operating expense for Transmission and Rural Operations (TRO) and Production has been reasonably constant, averaging $57.6 million and was $56.4 million in 1997.

6.1.3 Productivity

The CEA Committee on Corporate Performance and Productivity Evaluation (COPE) prepares an annual report on composite utility performance results. All the major generating utilities in Canada participate in the COPE program including: Alberta Power, B.C. Hydro, Calgary Electric System, Edmonton Power, Hydro-Quebec, Manitoba Hydro, Newfoundland and Labrador Hydro, Newfoundland Power, Ontario Hydro, Saskatchewan Power, TransAlta Utilities, West Kootenay Power and Winnipeg Hydro.

System unit cost is used to compare the trend in productivity for Hydro to the



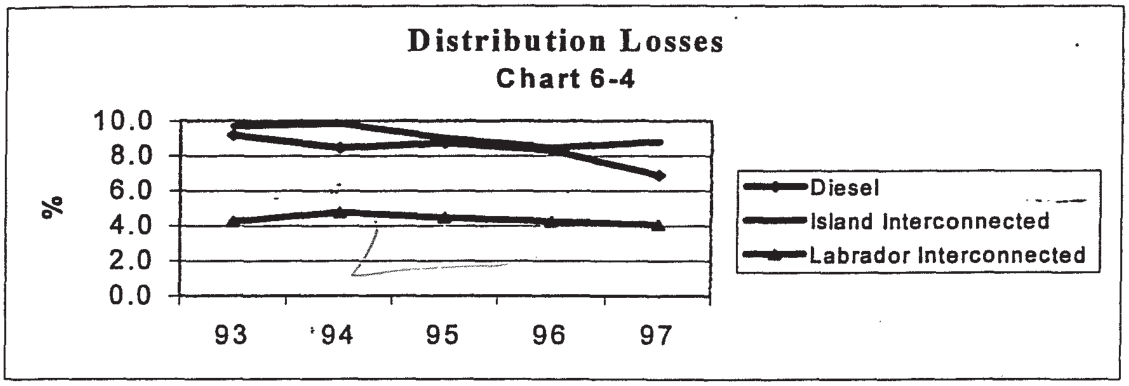
CEA Composite in the chart below. System unit cost is an aggregate measure of cost performance for the total utility system, adjusted to remove the effect of inflation, showing average cost per unit of energy delivered. System cost is the sum of costs for operations, maintenance, fuel, interest, depreciation, and income.

The main purpose of this type of data is to look at the trend for the data. This is due to the fact that there are differences between utilities with respect to size, environmental and economic characteristics. Chart 6-3 shows that Hydro's performance in this area is following the same general trend as the electric utility industry in Canada.

6.1.4 Losses

6.1.4.1 Distribution Losses

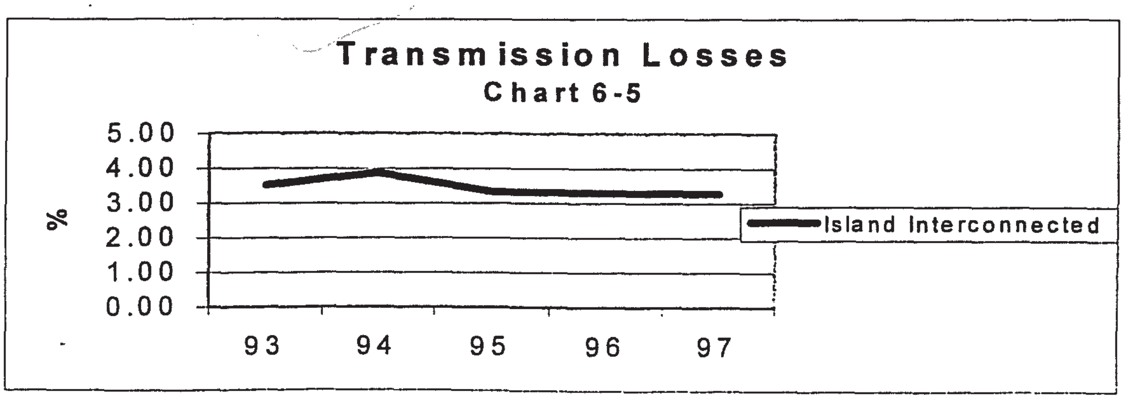
Chart 6-3 shows the energy losses on the distribution system. Losses in the



diesel system improved due to the interconnection of St. Anthony in September 1996.The losses in the Labrador Interconnected system are low due to the concentration of the load in the communities served. The Island Interconnected losses are higher due the method of metering. The metering on the system is at Deer Lake, which means that it includes losses on the transmission system up the Northern Peninsula. In light of the type of system operated by Hydro, Quetta is of the opinion that the losses are not unreasonable.

6.1.4.2 Transmission Losses

Chart 6-5 shows the energy losses for the transmission system. The losses on



the Island interconnected system have been improving slightly. This is due in part to the increased use of the Holyrood Plant as the load grows. In light of the type of system operated by Hydro, Quetta is of the opinion that the losses are not unreasonable.

6.1.4.3 Loss Evaluation Methodology

The calculation used by Hydro to determine the amount that it can afford to pay to prevent losses on its transmission and distribution system is similar to that used by other Canadian utilities. The method involves calculating capacity costs based on the installed cost of a combustion turbine and energy costs based on the marginal cost of energy produced by the Holyrood generating station. This should produce a reasonable estimate for the value of loss avoidance on Hydro's system. The calculation should be reviewed if there is a significant change to the base on Island generation expansion plan. The interconnection with Labrador will require Hydro to review these calculations

6.1.5 Reliability Centered Maintenance (RCM)

6.1.5.1 Reliability Centered Maintenance Pilot Projects

Hydro has in place a comprehensive planning process to identify maintenance projects to be undertaken. A software package (MAXIMO) is used to monitor and control these work orders. Post project audits are done in some areas to examine and explain variances from plans. Recently the Internal Audit function has been expanded to allow IA audit planning to include an independent review. MAXIMO is soon to be replaced with the JD Edwards system.

Reliability Centered Maintenance (RCM) processes are being explored by Hydro in their planning of maintenance. They have commenced pilot projects at three locations. RCM has been defined as " a structured methodology used to develop a cost effective maintenance program to preserve the operating functions of a system while meeting all safety, environmental and regulatory requirements".

RCM has been used in utilities for at least a decade. Utilities using RCM processes include:

Bonneville Power Administration (USA)
Boston Edison (USA)
Statnett (Norway)
Ontario Hydro (Can)
TransAlta (Can)
Sask Power (Can)
Edmonton Power (Can)
Electricite de France (France)
Puget Sound and Power (USA)
Cinergy (USA)
Seattle City Light (USA)

Other Canadian utilities exploring the use of RCM include:

BC Hydro
Scarborough (now part of Toronto Hydro Electric Commission)
Newfoundland Hydro

There were a number of presentations on the subject of RCM at the CEA Technical Conference 27-29 April 98. This is further evidence of the growing interest in RCM.

Quetta undertook a telephone survey of some utilities using or examining RCM.

TransAlta Utilities did a pilot project on part of their T & D systems. They then modified the detailed processes suggested by their consultant because TAU thought them impractical. They used their own experience to accelerate the authorization of RCM. They are proceeding with the identification of 800 to 1000 RCM "systems" in their Distribution; Transformation; Grid components of their system.

Sask Power tried a pilot project and then expanded it into three thermal plants, Boundary Dam (oldest), Popular River and Shand (newest). Comments included: "Popular River was a successful venture, not so at Boundary Dam and at the Shand Plant personnel had to be taken off RCM to attend to the major overhaul of the large unit".

At Sask Power they claim to be using RCM to optimize predicted maintenance on certain equipment. They indicated that the pilot project can be costly and they recommended a hard look at the pay back for the cost of the study. They spoke highly of the training of staff done by competent trainers with their consultant.

Scarborough (Toronto Hydro Electric Commission) did a pilot project on one feeder of their 27.6 kV system. They claim to have used a value based approach seeking to reduce the cost of customer interruption, reducing operating expense and increase the reliability of the feeder. Their plans to expand the RCM approach has gone on hold pending the completion of the integration of six utilities into one.

6.1.5.1 Reliability Centered Maintenance Conclusion

RCM is not an unqualified success story. It calls for a level of dedication that may be difficult to achieve. It calls for additional human resources over extended periods. Utilities entering on RCM must recognize these requirements if they are to enjoy the benefits.

Hydro is engaged in pilot projects to evaluate RCM. The RCM initiative involved three pilot projects for 1998. This phase included a diesel, a distribution, and a transmission and terminals pilot. They have completed the diesel and distribution pilots. The transmission and terminals pilot is in progress and were scheduled be completed by November 1998.

It s recommended that the Board ask Hydro to submit reports on each of the Reliability Centered Maintenance (RCM) pilot projects and any justification for plans that expand the RCM process at Hydro.

6.2 Thermal Generation Operations & Maintenance

6.2.1 Holyrood Thermal Plant

As demand increases on the Hydro system in the absence of the addition of new base load generation, there is a need to be assured that the operation at Holyrood can produce energy at an annual capacity factor of 73.5%. In recognition of this Hydro undertook a complete review of its maintenance practices and results. In late 1994 and early 1995, the Plant management at Holyrood undertook a comprehensive analysis to determine future staffing resource requirements. This analysis took into consideration the following:

- future system generation requirements from Holyrood
- current maintenance practices
- future maintenance practices
- current staff availability
- current and future work load
- staffing resource levels at similar thermal installs (i.e., Tufts Cove and Coleson Cove)

As a result, it was realized that staffing at Holyrood was inadequate to achieve 73.5% capacity factor.

In summary, recognizing that Holyrood would have to increase annual production from an average of 1500 GWhs per year to double that amount, i.e., 3000 GWh within the next 5 to 10 years (meaning shorter maintenance windows, etc.), and also recognizing the increasing back log of maintenance work that had built up specifically in the Mechanical section, plant management recommended organizational restructuring and additions to permanent staff, particularly in the Mechanical maintenance section. Most of these recommendations were approved and implemented in subsequent budgets.

Hydro thus undertook the following:

1. Create 11 new permanent positions to the Holyrood staffing complement.

2. Engage in maintenance agreements with original equipment manufacturers (OEM) to ensure outage schedules can be met while getting all the scheduled work completed.

3. Initiation of a Reliability Centered Maintenance (RCM) program. This was initiated early in 1996.

The maintenance system, implemented through the MAXIMO Maintenance Management System, is described in summary as follows:

a) Review of maintenance backlog.
b) Review of production statistics as compared to CEA average.
c) Review of production statistics as compared to Hydro requirement.
d) Bench marking with other utilities.
e) Reliability Centered Maintenance Program.
f) Feedback from OEM inspections of the equipment

Availability of the units is tracked by unit on a monthly basis.

After discussions with Hydro personnel, a review of documents and a visit to the Holyrood generating station, Quetta is convinced that Hydro is taking seriously its need to increase the reliability and availability of the units at the Holyrood generating station.

The CEA DAFOR (forced outages) results for thermal units is included in the reliability section of this report, chart 1-2. This is a factor which gives the percentage of operating and forced outage time a unit was on a forced outage, adjusted for de-rating of the unit. It is calculated by dividing the total equivalent forced outage time by the total equivalent outage time plus the operating time. This is a significant measure in determining availability.

Quetta reviewed a summary of a typical partnering agreement. Hydro and three OEM's are committed to work together to achieve certain agreed objectives. These objectives are as follows:

To create a pro-active, cost-effective approach in achieving success indicators through value judgements, by understanding and aligning the goals and objectives of the stakeholders and communicating them through both organizations.

To create and maintain an effective process where products and services are provided at a stable and fair market price while achieving the success indicators.

To identify and manage inventory and supply of products based on assessed risk, to ensure success indicators are achieved.

To create and maintain plans for maintenance and operations through detailed schedules and procedures with due consideration for identified success indicators and the time line for the operating and capital budgets.

To identify training needs and ensure that the necessary exchange of knowledge and skills occurs to achieve the success indicators.

To provide effective supervision (technical direction) to Hydro or OEM trades ensuring continuity for routine work, defined work packages and emergency work while achieving the success indicators.

Hydro has entered into these three partnership agreements to provide the maintenance of turbine generators, boilers and pumps. These partners are well-respected suppliers who may well use Holyrood to demonstrate their services. This will accrue to the benefit of Hydro.

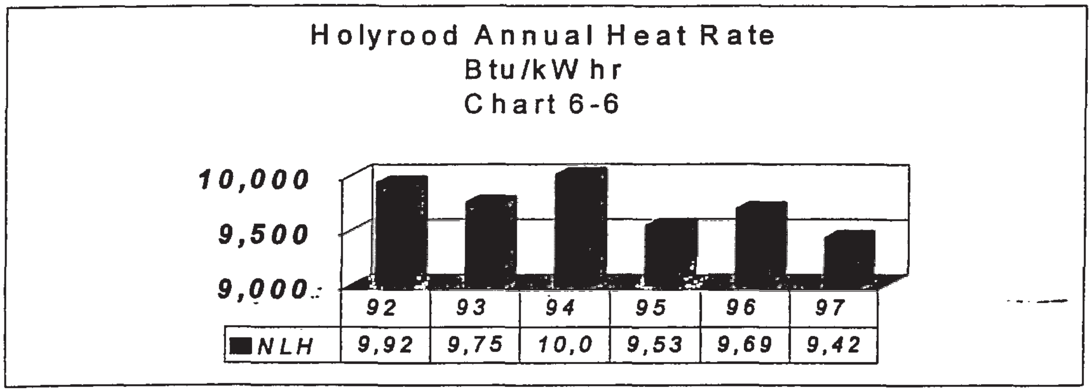
With Hydro's own resources plus the resources provided by the partners, it is expected that maintenance will be more expeditiously done.

In addition to mounting efforts to improve plant availability Hydro has undertaken steps to improve plant efficiency. Hydro has acquired and is using a software package called EtaPro. This system enables the operator, through a computer screen, to monitor each controllable parameter associated with efficient operation of the generating unit. The program presents the operator with actual, as well as target, values for each controllable parameter. It also indicates losses associated with operating off-target. Since installation of this software in 1995, Hydro has demonstrated to Quetta that it has improved its operating efficiency.

The traditional method of measuring plant efficiency, the method quite often used for comparative purposes, is the annual heat rate or the number of heat units required to produce a kilowatt hour of electrical energy. Chart 6-6 shows the gross heat rates for the total station at Holyrood for the period 1992 through 1997. Individual unit rates were not available. This chart demonstrates improvement through time especially since 1995 when EtaPro was introduced.

A previous report on the technical performance of Hydro prepared by Mr. G. C. Baker, P. Eng. in 1991, showed an average net heat rate for the Holyrood station for the years 1987 through 1990 as 10,475 Btu per kilowatt hour. This was compared to the heat rate at Nova Scotia Power's oil-fired station at Tufts Cove, a similar station, which averaged 10,390 Btu per kilowatt hour over the same period.

The average gross heat rate for the Holyrood station, 1995 through 1997, was 9,554 Btu per kilowatt hour. This, converted to a net heat rate as per Mr. Baker's calculation, shows a net heat rate average for those three years of 10,056 Btu



per kilowatt hour. Based on private discussions Quetta had with Nova Scotia Power (NSP) personnel, Quetta can state that Holyrood heat rate compares favourably with NSP's oil-fired station. Hydro's efforts at improving efficiency and availability are showing positive results. It is evident, of course, from what has been said, it is imperative that the Holyrood generating station demonstrate a high degree of availability between now and the time the next base load unit is added to the system. With the increase in consumption of fuel oil, it is important that the efficiency of the operation be optimized as well.

Events over the last decade, especially the ice storm of 1994, have demonstrated that Hydro's transmission system is subject to failures which result in the isolation of the load and generation on the Avalon Peninsula from the rest of the Island system. This has in the past resulted in a complete blackout and the loss of supply to all of the Avalon Peninsula.

It was quickly realized after some unfortunate experiences, that plant restoration procedures had to be implemented to assure that Holyrood generating station could be re-started under "black start" conditions. Efforts were undertaken to develop a restoration program to modify the governing systems at the

Hardwoods combustion turbine station and at Holyrood Units 1 and 2. A brief description of this procedure follows.

The Holyrood plant restoration plan requires an emergency diesel to provide enough power to start the on-site combustion turbine. The combustion turbine provides power enough to supply boiler auxiliary equipment. Procedures for this work are substantial.

During a "black start", it is intended to use the combustion turbine at Hardwoods and Power's Avalon hydro system to pick up small blocks of load while Holyrood follows taking the load from Hardwoods. This procedure is necessary because the Holyrood units do not have governor control until they are at approximately 30 MW load.

Hydro is replacing the electro-hydraulic governor control system on Holyrood Units 1 and 2 so that governor control can be activated at very low loads.

Quetta's understanding is that the changes to the governor on Units 1 and 2 will allow these units to accept load on a dead bus and to start restoration without the need of Hardwoods GT or Power's hydro generation. This should result in a new operation procedure for restoration.

Practical training on plant restoration procedures occurs annually, once on Unit 3 and once on either of Units 1 or 2. Due to the design of the plant, an absolutely "black start" on Unit 3 requires a total plant outage. While a "black start" on Units 1 or 2 can be carried out more easily, both of these units must be off line at the same time to imitate the blackout conditions precisely.

Unless Hydro continues to train its people in plant restoration and regularly tests the system, "black start" of the Holyrood generating station will not be successful.

6.2.2 Combustion Turbines

In addition to the three large conventional oil-fired units at the Holyrood station, Hydro's Island interconnected system has three combustion turbine units, one at Hardwood's Substation of 54 MW, one at Stephenville of 54 MW, and one at the Holyrood Generating Station of 15 MW. There is also a 27 MW unit in Labrador at Happy Valley, Goose Bay. While these units may not be used frequently, the successful start and operation of the units at Hardwoods and Holyrood are essential to the restoration program for the Holyrood thermal generating station. Hydro has undertaken the maintenance and operating practice as follows:

All combustion turbines are under the control of the Energy Control Centre (ECC) for the operation as they are required. If there is a problem in starting or alarms are registered, ECC would call the area office/station affected and the appropriate people would be sent to the site.

Preventative maintenance (PM) is done as per the computerized maintenance program (MAXIMO). Some PM's are time based while others are condition based.

With respect to the operation and testing of start-up procedures from different operating conditions there is no "set" testing. This would be done when changes are made to any equipment or a circuit modification completed. In most cases it would be a judgement call of the supervisor. For example, if the combustion turbine has not been used by ECC for a few weeks, the supervisor may decide to start-up and operate it for a short period of time to test the auxiliaries and circuits.

6.2.3 Fuel Acquisition Practices

Since fuel is a significant cost factor in Hydro's operation Quetta reviewed the contract for supply and delivery of No. 6 fuel oil to the Holyrood generating station. Hydro's approach is to seek public tenders for the supply of multi-year requirement for the Holyrood generating station in the latest instance, 10 million barrels, with 3.175 million barrels to be delivered in 1998, 3.250 in 1999 and 3.575 in the year 2000.

The selling price mechanism is based on United States spot cargo prices ~~in New~~ York for No. 6 fuel oil with 2.2% sulphur content. There are adjustments in price, up and down for certain conditions. Quetta also reviewed average prices paid for 1996 and 1997 and for the first two months of 1998. The contract and the resulting prices look reasonable compared to price data obtained privately by Quetta.

6.3 Hydraulic Generation Operations & Maintenance

6.3.1 General

Quetta met with Hydro staff with direct responsibilities in the operations and maintenance of the hydraulic generation system. Hydro has an extensive planning process to establish what maintenance will be carried out. The list of criteria considered in the development of the maintenance plan includes: preventative maintenance; predictive maintenance; corrective maintenance; projects; frequency of inspection. The planned work is broken out in to work order types reflecting these differing categories of maintenance. These data are input to the MAXIMO database to keep track of the work on the 2,800 + work orders in 1997. Of the planned work orders in 997, over 90% were completed.

An audit of the maintenance program is completed by the maintenance planner covering the work done in the previous year. This audit explores in some detail the three components of the hydraulic maintenance program at Hydro. These components are:

1) Critical parts inspection
2) Preventative maintenance
3) Corrective maintenance WO tracking.

Through such audits Hydro checks maintenance performance and reliability indices such as: forced outages, breakdowns, numbers of corrective maintenance WO's generated by preventative maintenance inspections, number of man-hours spent on breakdowns and emergency WO's, amount of unplanned maintenance work. Hydro uses CEA Performance Indices to determine the appropriate level on maintenance. The CEA DAFOR (forced outages) results for hydraulic units is included in the reliability section, chart 1-1 of this report and can be seen to be reflect quite favorably on Hydro when compared to the composite for the industry. This confirms the effectiveness of the maintenance program.

A RCM pilot project for hydraulic maintenance was in the very preliminary planning stage when Quetta visited the maintenance facility in Bay D'Espoir in May of 1998.

6.3.2 Dam and Dyke Safety

Quetta met with Hydro staff having direct responsibility in the area. It was explained that there was not a structured program until 1982 when Churchill Falls practices were brought to the Island system. There is now in place an extremely structured system to monitor dam and dyke safety. This includes an independent

Dam/Dyke Safety Board, Register of Dams, training programs for inspectors, Hazard Potential Analysis.

Dam and Dyke inspection reports for the years 1996 and 1997 were reviewed. The reports by the Dyke Board Consultants for 1996 and 1997 were reviewed by Quetta. The five-year Dam and Dyke Maintenance were also reviewed. The Dam register is kept up to date with all the relevant information on maintenance and inspections. Emergency Preparedness Plans (EPP's) are developed.

This area of Hydro's responsibility is governed by national standards and monitored by independent consultants to ensure compliance with those standards.

6.4 Diesel Generation Operations and Maintenance

6.4.1 General

Hydro applies the same general categories of maintenance work orders in the diesel plants as done at Holyrood and at the Hydraulic Plants. Maintenance planning for the diesel sites is made more difficult because of the number of sites, their remoteness and their size. There are maintenance committees in the three regions that meet twice a year. They plan for routine visits to the diesel sites and have emergency crews trained to take advantage of those opportunities when they are called in to carry out emergency repairs. As well as completing the breakdown repairs the crews will use their unscheduled visit to reinforce the information gained by the routine visits.

Work orders are raised based on operator feedback and site visits by supervisory staff. Plans are controlled and updated through supervisor's regular visits. Hydro determines the appropriate level of maintenance by monitoring plant availability and technical performance.

Changes proposed include the continuation and evaluation of an RCM pilot project at an isolated diesel generator at Rigolet. Hydro is also investigating a cross training project so that a site could be manned by " a man and a half" (i.e. a permanent employee for two weeks on followed by one week off while a temporary relief employee would cover the plant).

Hydro advised that in 1997 of the twenty planned major projects, nineteen were completed; of the 830 scheduled preventative maintenance projects, 760 were completed; of the 1482 scheduled corrective maintenance projects 1475 were completed.

Hydro has in place maintenance planning procedures for the diesel systems that can be expected to provide the kind of results outlined to Quetta during the course of the March 1998 meetings with Hydro staff. The performance experienced at Nain during 1996 –97 does not reflect the expected results from these procedures.

Quetta recommends that the Board request Hydro to implement a maintenance audit and reporting process at each of the remote diesel sites similar to that done for the hydraulic plants.

6.4.2 Spares and Replacement of Diesel Units

Hydro manages the inventory levels of spare parts as far as possible by "partnerships" with OEM's, and allowing direct orders from the plant to the supplier and limiting their major inventories to long delivery items in stores at Happy Valley, Corner Brook, St. John's and Grand Falls.

The budgeting for the replacement of a diesel unit would be initiated after considering: obsolescence; O & M costs for existing versus costs for new equipment; fuel efficiency. An example cited was a D 353 Cat at Nain – the generator was obsolete, parts unavailable, the engine was twenty years old, the replacement was budgeted in 1996 for replacement in 1997.

There were three emergency replacements of diesel sets in the Northern region in 1997 as follows: two at Williams Harbour and one at Charlottetown.

6.5 Transmission / Substation / Distribution Operations & Maintenance

6.5.1 Maintenance Planning

The MAXIMO system is used to automate and to record the maintenance plans for transmission and distribution lines. Hydro's engineering consultants developed the original maintenance plan for the transmission system several years ago. A lines maintenance committee at Hydro updates the plan on a regular basis. The committee is responsible for the management of: the line maintenance philosophy, standardization of maintenance activities and the monitoring and analysis of reliability indices.

In 1997 90% of the preventative maintenance work orders for transmission and distribution lines were completed. Of the 10% that were carried over to 1997, there were no high priority items

In 1997 75% of the preventative maintenance work orders for stations were completed. Of the 25% that were carried over to 1997, there were no high priority items as noted during a site visit to the maintenance office in Bishops Falls. The result was low due to maintenance issues on equipment that was not in the annual plan for 1997.

This is a well-organized traditional preventative maintenance program.

In 1998 a pilot project was initiated in the transmission area to demonstrate the use of Reliability Centered Maintenance. The pilot project will cover the Come by Chance Substation and Lines (see comments in Section 6.1.5.1).

6.5.2 Transmission and Distribution Right of Way Maintenance

The Vegetation Management Program at Hydro is centralized at Hydro's office in Bishops Falls. The purpose of this program is to ensure that Right of-Way's are effectively cleared to allow crews access to the lines and to limit outages due to tree contact with the lines. Surveys are carried out annually to identify areas needing vegetation control. Information on the condition of lines from the operations staff is sent to the vegetation department using the work order system (also see Section 5.2.6).

In 1997 there was 6.85 hectares of clearing planned. Due to a very low bid in 1997, 92.23 hectares of ROW was cleared. Transmission line ROW's on the Avalon Peninsula and in Central Newfoundland were observed to be in good condition during Quetta's visits to Newfoundland.

In 1997 there was 340 hectares planned and 347 hectares of distribution ROW was treated or cleared. Quetta reviewed the 1996 Service Continuity Report on Distribution System Performance in Canadian Utilities and found that tree contact caused an average 0.24 interruptions per customer for the CEA average of all utilities, the same statistic for Hydro was 0.04 interruptions per year. This confirms the visual observations that Hydro's vegetation program appears to be effective.

6.5.3 Substation Vegetation Management

All sites are treated with herbicides every two years. In 1997 3.71 hectares of land in terminal and substation was treated. Terminal and substations on the Avalon Peninsula and in Central Newfoundland were observed to be in good condition during Quetta's visits to Newfoundland. There is a five- year plan in place that indicates that all substations will be treated every second year.

6.5.4 Inspection and Testing of Wood Pole Lines

There are detailed procedures for inspection of wood pole lines. Transmission poles in each region are inspected every five years. Distribution poles in each region are inspected every six years. This activity is monitored through the MAXIMO system as described earlier. Hydro staff noted that there have not been a lot of failures in this area to date. A plan is being prepared to conduct more extensive pole inspection in the future due to the increasing age of the poles.

6.5.5 Insulator Testing / Cleaning Program

There is an ongoing program in place for insulator testing and replacement of insulators that have caused problems. The following table shows the activity for the last five years in the Eastern and Western Areas:

	Eastern Area	Western Area
Number of insulators replaced in last five years	16,300	3,200
Cost of replacements	$1,300,000	$279,000
Estimated number of insulators to be replaced	2,000	20,332

The following table shows the activity from 1993 to 1997 in the Central Area:

Year	Number of Insulators Replaced	Cost
1993	4,923	$328,328
1994	7,170	$622,487
1995	11,871	$692,661
1996	4,050	$374,840
1997	900	$60,000
Total	**28,914**	**$2,078,316**
Remaining insulators to be replaced	950	

Testing of insulators is based on the history of the type of insulator. In 1995 Hydro conducted a survey of utilities to review the practices and found that it was comparable. Hydro has two high pressure washers that are used when necessary to clean insulators.

6.5.6 Switching Procedures

There is an extensive training program, which outline the rules, regulations and procedures for switching. The system is audited on a regular basis by the Superintendent of the Energy control center to ensure that Hydro staff is using the proper procedures. The program is well documented and implemented.

6.5.7 Maintenance of Switching Diagrams

Each Region has identified a supervisor to be responsible for the maintenance of system diagrams. The process that was described to Quetta appears to be reasonable.

6.5.8 Maintenance of Distribution System Diagrams

Quetta reviewed the written procedure to revise system-operating diagrams and found it to be acceptable. Operating diagrams are issued to the appropriate staff, however there was no evidence to indicate how an employee would know what size fuse to install in a distribution line. It is recommended that Hydro address this issue and report to the Board with a plan to correct this.

6.5.9 Distribution System Protection

The System Planning Group carries out distribution protection and co-ordination studies. The processes described for conducting this work is based on sound engineering principles.

6.5.10 Distribution System Trouble Call Handling / Response Time Policy

Hydro staff told Quetta that they address each trouble call as soon as they receive the call. There is a supervisor on call in each region to co-ordinate the restoration effort. There is plan to centralize the handling of trouble calls. A toll free number is being established and all calls will be handled from a central location.

6.5.11 Rationalization of Services with Newfoundland Power

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 Newfoundland Power 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 11.

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 services between Hydro and Newfoundland Power at the following locations: Fleur de'Lys, La Scie, Baie Verte, Springdale, South Brook, Fogo, St. Brendan's, Monkstown and Petites.

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

7.0 Contingency Planning

7.1 Major Contingencies

" Maximum credible accident" is a term borrowed from the nuclear industry in their analysis and development of emergency planning for that industry.

Hydro did not have in place a formally documented system of serious or catastrophic occurrences on the power system.

In response to a question from Quetta, Hydro staff made a presentation describing their views of the maximum credible contingency in Generation, Transmission, Substation and Distribution and Hydro's planned approach to deal with each of them. Preparation and effort with respect to major contingencies is managed through the Energy Control Center (ECC).

Contingencies identified by Hydro in this presentation included:

1. Loss of Holyrood Plant
2. Single unit unavailable at Holyrood
3. Extremely low reservoir storage
4. Loss of parallel line supplying the East Coast

In each case Hydro identified standard operating procedures and guidelines relied on to cover the contingency under consideration.

7.1.1 Contingencies 1 and 2 Loss of Holyrood Plant or Loss of one unit.

Hydro advised that the maximum load that can be met on the Avalon Peninsula without Holyrood is 325 MW and the maximum on the Avalon is 560 MW when a single unit is unavailable at Hollywood. To put this latter contingency in perspective, Hydro advised that, at current system load levels, loads in excess of

560 MW occur less than seven (7) days during the winter. Hydro plan to add capacitors to the Eastern section in 1999, this will increase the size of load that can be carried.

7.1.2 Contingency 3 Extremely Low Reservoir Storage

Here Hydro uses guidelines that include for the use of Upper Salmon dead storage, gas turbines and curtailment of non-firm energy sales. The guideline was reviewed by Quetta and considered satisfactory. The low reservoir storage contingency can occur following a prolonged period of low precipitation, which last occurred in 1987.

Because reservoir storage is monitored closely and used as an input to the system guide curves used in Generation Scheduling (Ref. Section 3.1 System Operations), there should be a significant lead time warning of such contingency.

7.1.2 Contingency 4 Loss of parallel line to the East Coast

Hydro identified procedures, including that dealing with the "black start" of Holyrood Plant. Quetta reviewed these procedures in the context that they were put forward by Hydro as responses to the contingences covered. The procedures are considered satisfactory with one proviso. They would be strengthened by the inclusion of some schedule or frequency for training of staff responsible for carrying out the procedure. This issue is also referred to in Section 3 of this report - System Operations - Interaction between Control Center's.

7.1.3 Isolated Diesel Sites

Major contingencies at the isolated sites might include the loss of an entire plant (eg fire). Hydro has arrangements with the military to move in equipment from stores or from adjacent plants.

7.2 Other Contingencies Reviewed

7.2.1 Loss of Transformer at Terminal Station

Transformer back up has been established. Stations with a single transformer have been identified and back up supplies have been identified as follows: Mobile transformers or Mobile GT can be used; in 66/69 kV stations spares are available; in 138 kV stations mobile transformers must remain until a replacement is found or ordered.

7.2.2 Storms

The ECC remains the center of operations. On-call lists are maintained for line workers and for senior management during major events. Hydro has direct telephone lines to Newfoundland Power's control center and large industrial customers. Hydro anticipates needs and move crews early based upon past experience. Hydro uses manual recording of trouble calls.

7.2.3 Transmission System Contingency Plans

There is a spares material committee that manages the emergency supplies that would be required in the event of a major storm. While there was no evidence of any formal written contingency plans, Hydro staff that Quetta interviewed was very knowledgeable in this area. This is due to the number of problems experienced by Hydro due to the harsh operating environment in which it operates. It is recommended that Hydro should document and communicate to staff contingency plans for transmission system problems and develop a process to ensure that it remains updated.

7.2.4 Distribution System Contingency Plans

Quetta reviewed a sample contingency plan for the Distribution system in the Central region as outlined in the "Emergency Plan " procedure for the region. The plan is acceptable, however it appears that the contacts listed in the procedure should be updated. The procedure was issued in 1994-02-11 and has not been revised. It is recommended that Hydro update this plan for all regions and develop a process to ensure that it remains updated.

7.2.5 Diesel System Contingency Plans

The operator in the area is trained to do limited line work and he will sectionalize the distribution system and rotate customer outages until the maintenance crew comes in. Operators are trained to use radio communications to ask customers to conserve the limited generation.

Hydro are also prepared for a fire at the plant. Plants are equipped with extinguishers, operators are trained and co-operate with the local fire department. The supervisor for the Region is on call twenty four hours a day

The Board should direct Hydro to develop formal documented system to manage and maintain its planned response to serious or catastrophic occurrences on the power system and to include in the associated procedures a schedule of training for staff.

7.3 ICE STORM '98

"electricity companies from coast to coast must revisit their Emergency Prepardness Plans in light of this new and unexpected threat"

CEA Connections March / April 1998-06-17

Since the January 98 ice storm in Eastern Ontario, Quebec and parts of New Brunswick, utilities are re examining their plans for such major disasters.

Hydro advised Quetta that the Newfoundland and Labrador Emergency Measures Organization (NLEMO) is in the process of revising the Provincial Emergency Plan (PEP). In this regard the formation of an Interdepartmental Emergency Planning Committee was initiated as a result of Cabinet Directive 171-89. The Committee has adopted the Saskatchewan Emergency Plan as a template for the PEP. All government departments have formed internal teams to write the various sections which will make up the PEP. Hydro has a number of emergency plans which will be reviewed by an internal committee with the objective of recommending a common communication protocol for the Corporation.

Roget Nicolet, Eng., the President of the Professional Engineers of Quebec, was asked to prepare a comprehensive report on the impact of the ice storm on the Hydro Quebec system. He provided an over view for the Association of Professional Engineers of Nova Scotia in October 1998. Based on his comments, Quetta recommends that the Board request Hydro to review the report when it comes available in the first quarter of 1999.

7.4 Storm Insurance

Hydro does not have storm insurance on the transmission and distribution lines because the plant is widely spread over the Province and is not a typical risk that one insures.

Hydro does have insurance, including storm damage on buildings, powerhouses, offices and substations. They have Property; and Boiler & Machinery coverage for a large loss with a high deductible, $750,000 to $1,000,000.

Hydro goes to the market each year to test it for storm coverage on lines but find the premiums in the order of 10 to 20 % of the coverage limit, plus a high deductible (ie in the millions of dollars). At present Hydro's insurance costs 2% of the highest value covered.

Quetta considers that Hydro follows prudent and appropriate practices with respect to storm insurance and insurance in general.

8.0 Internal Audit

A review of the Internal Audit (IA) function at Hydro was not included as an item in the Terms of Reference approved by the Board. During discussions with Hydro staff it became evident that the IA function plays an important role in the efficient operation and control of the utility and Quetta sought Hydro's co-operation in achieving an understanding of their IA function.

Quetta met with the Manager of Internal Audit. The IA function at Hydro dates back to the early 1980's. The guidelines followed at Hydro are from the Institute of Internal Audit USA. The first operational audit was carried out at CF(L)Co and the IA function at Hydro continues to include CF(L)Co.

A five-year audit plan is developed, reviewed and revised annually. The plan is developed using a risk assessment analysis. The assessment examines the many functioning sectors of the utility against a series of eleven (11) attributes. These are weighted (on a scale of 1 to 5) and a series of risk factors is determined using a computer data model.

The Internal Auditor has had significant involvement in Hydro's environmental audit since 1994 when the Bishops Falls environmental audit was done. It is planned to have the Senior Auditor certified under ISO 14001 to facilitate Hydro's compliance with their undertaking to implement ISO 14001. See Section 5.2.9 for additional information on ISO 14001.

Internal Audits cover all areas of Production, Transmission and Rural Operations, Finance, Human Resources, Legal and Materials Management. They cover such audits as: capital projects, environment, O & M and policy and procedure compliance. Audit reports are discussed with managers in the area being audited and report do not go forward until these discussions are completed.

The audit reports are distributed as issued to the manager and vice president of the area audited and quarterly to the President and Executive Committee. The Manager IA has a meeting scheduled with the President every two weeks.

The audit reports are reviewed by the Audit Committee of the Board of Directors and the Auditor of the Board of Public Utilities may see the reports by request.

It appears that the Internal Audit function has evolved satisfactorily at Hydro, is understood by the staff and provides important checks and balances on the many formally documented plans and procedures at Hydro.

It is recommended that the Board request Hydro to file its Internal Audit plan annually with the Board to allow the Board to determine which audit reports might be referred for further analysis by the Board.

Appendix 1
Terms of Reference Summary

1.0 Quality of Service

- 1.1 Voltage and Frequency
- 1.2 Reliability
- 1.3 Customer Service

2.0 Planning

- 2.1 Generation Planning - Interconnected System
- 2.2 Generation Planning - Diesel Locations
- 2.3 Transmission Planning
- 2.4 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 Diesel Generation Operations and Maintenance
- 6.5 Transmission / Substation Operations and Maintenance
- 6.6 Distribution Operations and Maintenance

7.0 Contingency Planning

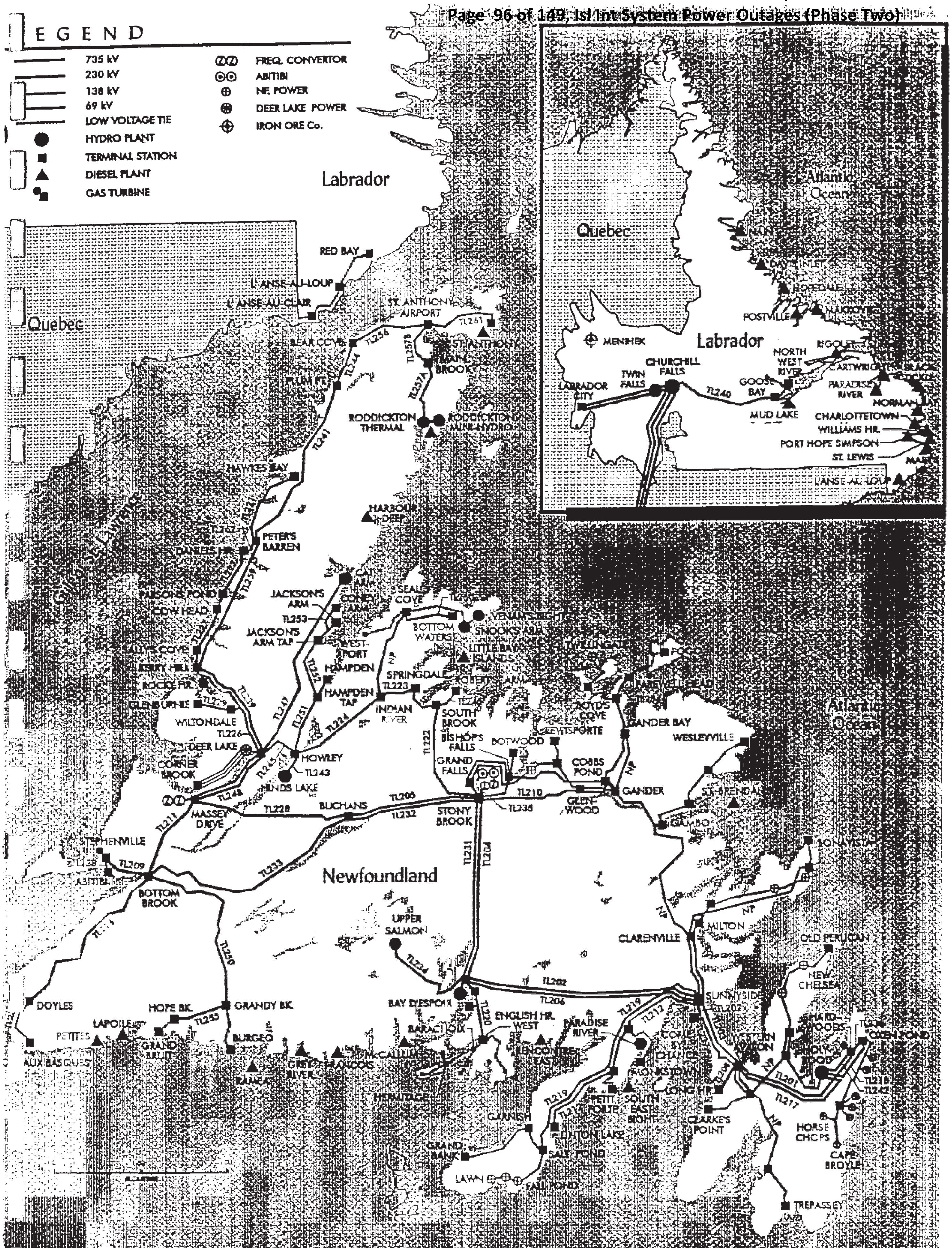
8.0 Internal Audit [1]

(1) Internal audit added by Quetta during the study.

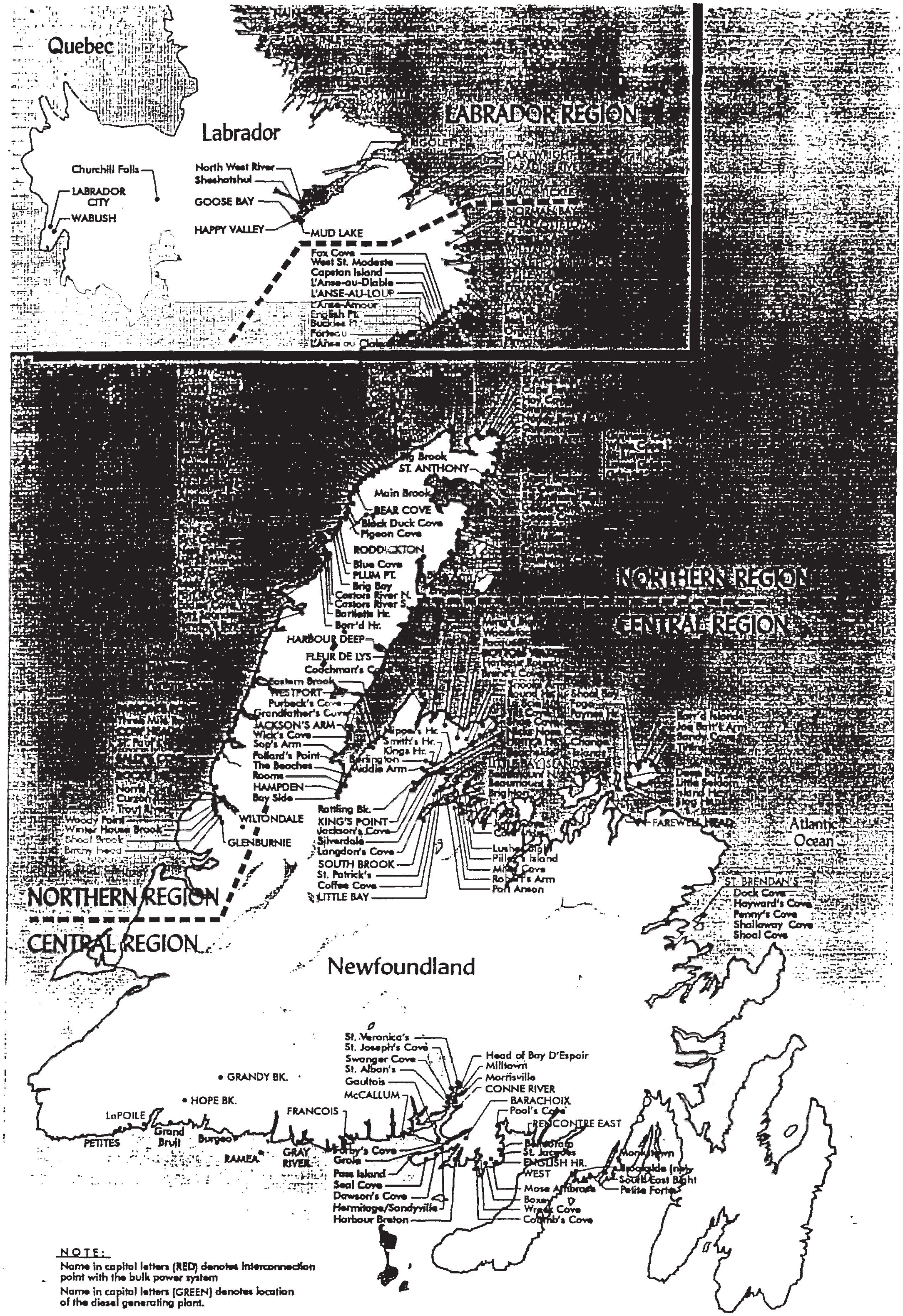
Appendix 2
MAPS

1.0 Provincial Generation and Transmission Grid

2.0 Communities served by Hydro's distribution system



Provincial Generation and Transmission Grid



T.R.O. Communities Served by Interconnected Systems & Diesel Systems

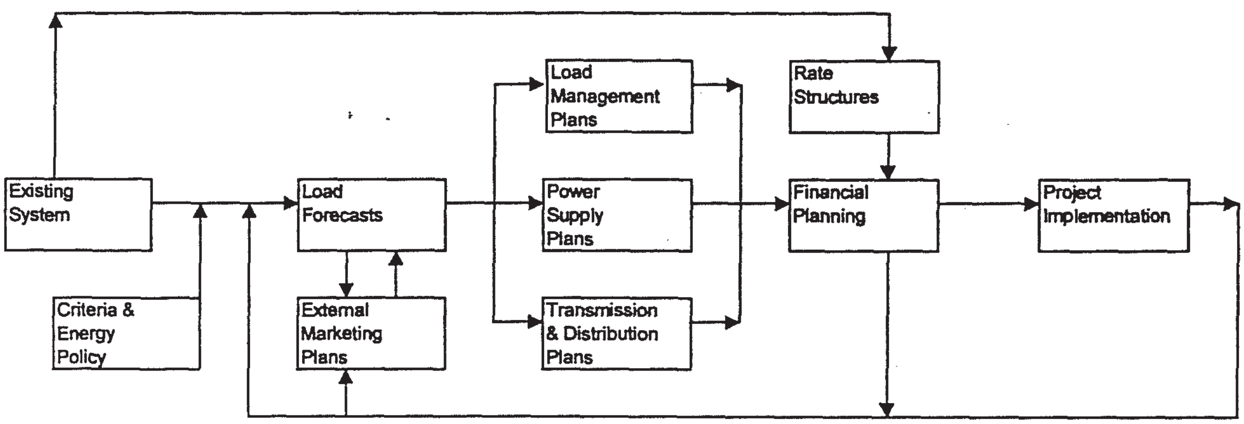
Appendix 3
Definitions

Black Start Capability.	The ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivery power without assistance from the Power System.
Load, Firm	That Power provided to customers that is continuously available on demand and which is subject to interruption only under extreme circumstances.
Load, Interruptible	Those loads that, by contract, can be interrupted in the event of a deficiency on the supplying system.
Load Shedding	Deliberate disconnection of customer load in response to an abnormal condition in order to maintain the integrity of the power system. Disconnection may be automatically or manually initiated.
Syn; Load Rejection	Load Dropping
Outage	A device is in an outage state if it is not connected to the electrical system and fulfilling its design function.
Outage, Forced	An outage that results from conditions affecting a device requiring that it be removed from service.
Outage, Scheduled	An outage that results when a device is deliberately taken out-of-service at a preselected time.
Reserve, Non-Synchronized	That portion of generating capacity which is available for synchronizing to the system and capacity which can be made available by curtailing load to the extent that such curtailment is under the control of the System Operator. Non-synchronized reserve may form part of operating reserve to the extent it can be utilized within the prescribed period.

Reserve, On Automatic Generation Control	That portion of synchronized reserve which is under the command of an automatic controller to respond to load demands without need for manual action.
Reserve, Operating	The sum of ten-minute and thirty-minute reserve.
Reserve, Ten-Minute	The sum of synchronized and non-synchronized reserve which is fully available in ten minutes.
Reserve, Thirty-Minute	The sum of synchronized and non-synchronized reserve that can be utilized in thirty minutes, excluding capacity assigned to ten-minute reserve.
Reserve, Synchronized	The unused portion of generating capacity which is synchronized to the system and ready to pick up load to claimed capacity and capacity which can be made available by curtailing pumping hydro units.

Appendix 4

Planning Procedure



Appendix 5

J.D. Edwards & Company
Integrated Solutions for Utilities

Integrated Solutions for Utilities

prove customer
vice, enhance
mmunications,
d control costs

Utilities face major changes in structure and market dynamics as the twenty-first century approaches. Faced with deregulation, increased competition, and customers' expectations of better service, change is a requisite of survival.

Federal mandates and state regulatory incentives give providers and customers, alike, added choices on how utility services are supplied and received.

As a cost-effecive, customer-based management tool, information technology will play a major role in the industry's transformation. Utilities that fail to utilize information technology to its fullest extent will become victims of the times.

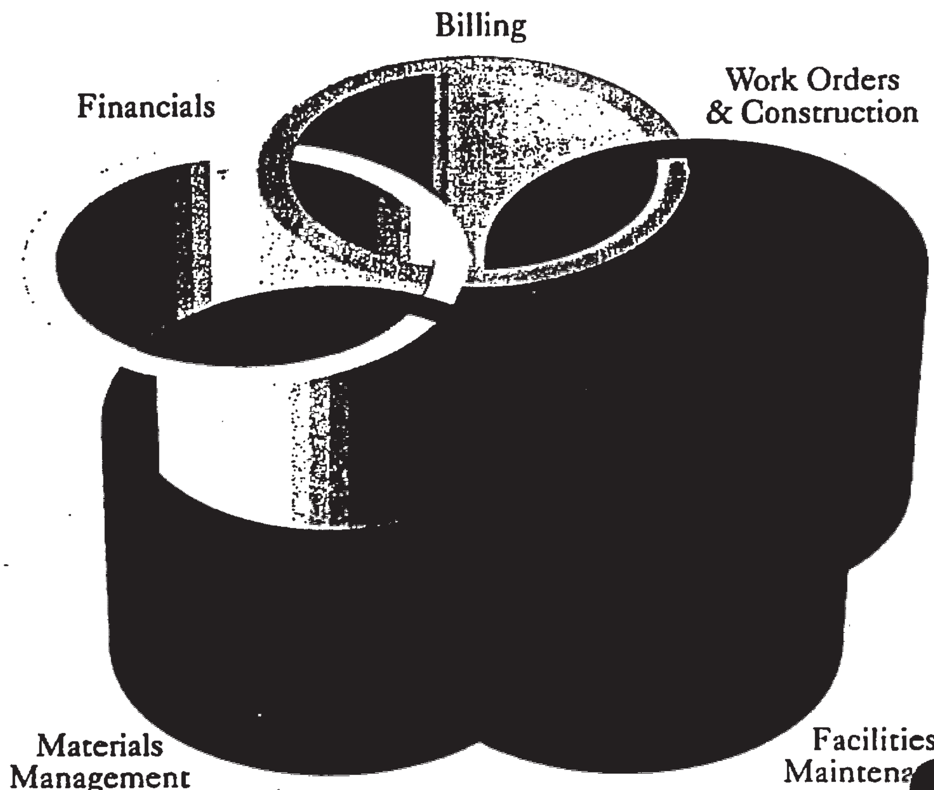
To remain a supplier of choice in an increasingly competitive marketplace, the progressive utility must embrace information management systems that accomplish the following:

- Improve customer access to service
- Provide employees with new and better communication channels to interact with customers
- Fine tune and reengineer customer service business processes
- Manage computing and data processing costs aggressively
- Control capital project costs, assuring maximum allowable return on investment

J.D. Edwards & Company (JDE) offers comprehensive, integrated software solutions for utilities serving domestic and international markets. Our systems adapt easily to the needs of electric, gas, water, or wastewater services, in all organizational forms — investor-owned, municipally operated, cooperatives, or special districts.

For the utilities industry, "the times, they are changing." A poetic yet cogent characterization of a vital segment of the economy. As a leading provider of information technology, JDE becomes an agent of change, helping utilities meet the challenge of operating in today's dynamic business environment.

Integrated Efficiency
The latent power of information, much like that of electricity or water, does little unless it is applied productively. JDE's cost-effective, integrated solutions channel information flow throughout your organization, enhancing customer service, work management, and financial accountability.



Maximize construction and maintenance efficiency with systematic work management.

Your construction activity is continuous, with repairs and upgrades ongoing throughout a facility's useful life. Often, facilities are modified or reconfigured to be more efficient.

As you are aware, there is a direct link between technology, operational efficiency, and rate of return. Technology is a key factor in the equation. It leads to greater efficiency which, in turn, increases your favor with regulators.

Job Cost and Project Management
Increased competition and public scrutiny of rate cases encourage you to adopt better cost management procedures. Early in major construction projects — new or redesign — you must determine if construction is on schedule and within budget. If necessary, you must initiate steps to control costs, manage cash flow, and improve contractor and subcontractor estimates.

With JDE's Job Cost and Project Management systems, you accomplish the following functions:

- Monitor and control subcontractor costs and define cost structures
- Review subcontracts and purchase orders to compare committed, actual, and final costs
- Integrate with JDE's construction related applications and financial management systems

Facilities Management
Efficient planning, meaningful estimating, realistic scheduling, and quality training — these are the essentials of outstanding maintenance management. When you implement these practices to their fullest, maintenance of plants, transmission, and distribution facilities is enhanced.

JDE's integrated systems provide the cost-effective controls you need to implement a quality maintenance program. Our Facilities Management module assists discrete planning and scheduling of your maintenance work force, as well as managing spare parts purchasing and inventory control.
In addition, you have the capability to monitor the following factors:

- Cost of maintenance by type of work
- Equipment uptime
- Causes of downtime
- Maintenance trends and occurrences

rmation collected from work and preventive maintenance ions, you can develop long-range term programs to assure that a...enance department, as a meets its objectives.

still greater advantage through of Facilities Management and DE systems such as Purchasing, ets, and Materials Planning. In Facilities Management is fully ted with JDE's Payroll, Accounts nd General Ledger.

der Management
erm projects such as connects or ts, outages, and meter service rioritized and controlled to effective utilization of personnel uipment.

Work Order Management
helps you manage these

ng quick work order setups single job or group of jobs

hodating multiple levels of bility and task tracking

iding scheduling and expediting orders

eloping management reports ork order activity and costs

ining operations by integrating other JDE systems such as Payroll, ment Management, Inventory , and Accounts Receivable

Rely on systems that provide executive information and incorporate uniform regulatory accounting and reporting.

Your financial performance becomes the foundation on which you build your rate requests. Regulators scrutinize your operating expenses thoroughly. During the process, consumers and special interest groups sometimes question the level and nature of your revenue and expenses. Without current and complete records, the process of building a rate case becomes wearisome and expensive.

However, the JDE solution eases the pain of regulatory accounting by incorporating the FERC Uniform Classification of Accounts. Plus, our financial systems accommodate charts of accounts that may be unique to your way of doing business. In addition, our comprehensive, integrated systems ease your planning, analysis, and administration of:

- Cost-based activity measurement
- Capital project and contract management
- General ledger
- Accounts payable, with automatic posting to the general ledger
- Comprehensive assets management
- Depreciation by class account, vintage, or equal life groups
- Human resources and payroll requirements

Also, you will benefit from the following features:

- Executive information support with "drill down" and graphical presentation capability
- Flexible report preparation
- Imaging, for electronic filing and retrieval of scanned documents and reports

Customer information system improves communication and enhances service.

Public utility executives with the foresight to understand competitive trends and the importance of implementing solid customer information systems will gain the advantage as competition emerges. Also, regulatory incentives become increasingly attractive to utilities because regulators often evaluate the degree of customer satisfaction when hearing rate cases.

To maintain service of the highest quality, you must communicate up-to-the-minute information to your customers, rapidly and accurately. In addition to uninterrupted service at lower costs, customers expect you to provide information about their service agreements and the current status of their accounts.

JDE's Customer Information System (CIS), now in development, will assist you in achieving your customer service goals. Beta test is scheduled to begin in 2Q95 and general product availability is anticipated in 4Q95.

Address your customer service needs — from consumption through collections.

The JDE Customer Information System consists of five integrated modules that give you a comprehensive view of how you serve your customers.

Customer Billing
The billing module generates customer statements at the end of each billing cycle. Also, customer bills can be created manually on demand. Because the system is integrated, entries are updated automatically in Accounts Receivable and General Ledger.

d tional customer billing module
:atures include:

A llowances for budget billing and
e imated meter readings, with recon-
ciliations and adjustments

M ultiple services and miscellaneous
c arges based on fixed or variable
rates, zone differentials, or combinations
of methods

C lculating prorated charges for new
or closed accounts

C lculating penalties or special assess-
ents for excessive consumption

Tracking "at risk", delinquent, and
 d debt accounts

Generating and recording collection
letters, overdue notices, payment plans,
 d collection agency activity

Generating accounts receivable and
general ledger journal entries by receipt
 d revenue type

Posting payments and adjustments
i mediately on customer records and
 the general ledger

Sorting bills by nine-digit ZIP codes
 receive best postal rates

Customers and Accounts

You need to define in a systematic format
 relationship with your customers —
 they are, their locations, and the
nature of their service. Each must be
cross-referenced by name, address, account
n ber, and tax identification number.

The JDE Customers and Accounts
module is linked to the Service
 resses and Meters module to define
he equipment and/or facilities listed on
each service agreement. The module also
 bles you to process exceptions such as
 usion of billings or payment notices
or a specific period. In addition, a link
 DE's Address Book enables you to
c rd a wide spectrum of customer
demographics and statistics.

Service Addresses and Meters

You maintain records on all service drops and service addresses, including the meter type, size, and date installed, as well as date, time, and nature of customer contacts or complaints. Information is recorded for single or multi-meter installations. The module is integrated with the JDE Inventory system where records on mass storage, bills of material, and spare parts lists are maintained. The meter section of the module is linked to the JDE Equipment/Plant Maintenance system, indicating a meter's status — in service, in repair, or on the shelf.

Meter Readings

This module contains detailed information on each customer's meter readings and historical consumption information. It enables you to accomplish the following:

- Upload or download information to and from third-party, hand-held meter reading devices
- Track occurrences of exceptionally high or low readings and billings
- Print exception reports
- Adjust billings

In addition, you can implement the following time and labor saving features:

- Define meter reading routes and sequences
- Capture and upload notes entered into the hand-held reading device
- Generate service orders from the hand-held readers
- Exclude special customers such as seasonal accounts from regularly scheduled reading cycles

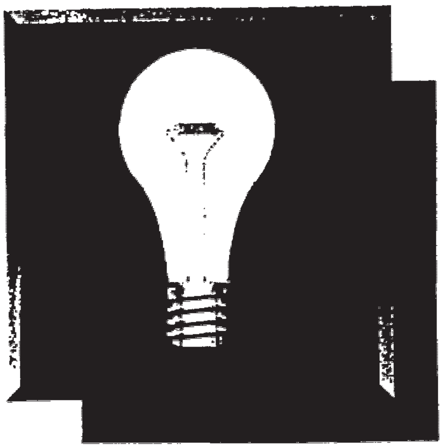
Service Orders

A utilities-specific version of JDE's Work Order Management module enables you to schedule and record work performed by installation and maintenance crews.

You improve labor efficiency and enhance customer service because:

- Service orders are prepared in batch or real-time and directed to the appropriate department.
- Standard customer letters communicating changes or updates are generated automatically.
- Billable service charges are posted against the appropriate accounts automatically.
- Work order histories are maintained by account, date, and service representative.
- Job status, cost account details, account ledger inquiries, and online executive reports and summaries are tracked automatically.

In summary, JDE offers you leading edge information technology to support superior customer service, enhance work flow, and ensure financial accountability. By integrating our solutions into your existing business practices, you will become better prepared to meet the demands, as well as opportunities, of a competitive, rapidly changing operating environment.



Move ahead with superior technology and unparalleled support.

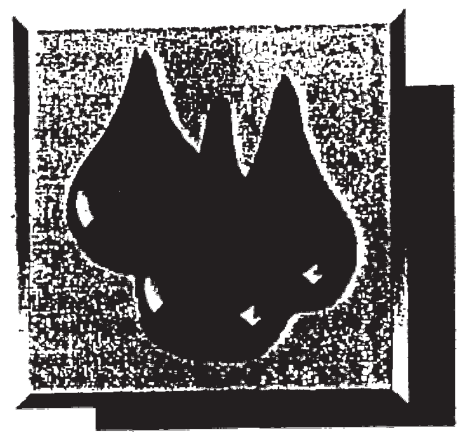
You must choose your software solutions wisely, being certain to calculate long-term return in the same manner as for a capital construction project or acquisition of a fixed asset.

JDE's systems meet your current needs yet are expandable and adaptable as your requirements change. Our applications can be updated or tailored to meet needs that may be unique to your environment. What's more, we're positioned to meet the demanding challenges of client/server and open systems technologies.

When you install JDE software, your investment is backed by outstanding client service. Quality is more than a byword. Your total satisfaction is paramount. In addition to the diversity of experience of our problem-solving consultants, our systems are backed by a Response Line, a Training Department, online help, and user publications that are second to none. Also, user groups are available to you and your peers as a forum to discuss issues of common concern and provide constructive input.

JDE welcomes your ideas on how we can serve the expanding information technology needs of the utilities industry. We listen carefully — and we respond.

Our Premise:
A sizeable differential in cost and level of service exists among providers. Deregulation and increased competition will force utilities to adopt more efficient operations. As a result, progressive utilities will prosper and their customers will see lower rates and better service.



Our Promise:
JDE will support the utility industry with state-of-the-art business solutions to enhance customer service, expedite work management, improve communications, and strengthen financial management.

Appendix 6

Isolated Systems Generation Planning Practices
A survey of Canadian Utilities
Tables 3.1 to 3.5

	Generation Planning Criteria
Newfoundland Hydro	Firm Capacity = Total installed capacity less the largest unit.
Hydro Quebec	Firm capacity = Installed capacity less the capacity of the largest unit, multiplied by 90%, for plants with 5 engines or less. Firm Capacity = Installed capacity less the capacity of the largest and smallest units, multiplied by 90%, for plants with 6 or more engines.
Ontario Hydro	Prime Rating = Sum of two smallest units (3 unit plants).
Manitoba Hydro	Maintain firm capacity to meet the system peak load and pick up cold load after an outage. Firm is total installed less the largest unit. Cold load is 80% * Firm.
Saskatchewan Power	To strive for a safe and continuous supply of electricity.
Alberta Power Ltd.	Firm Capacity = Total installed capacity less the largest unit. For remote sites accessible by road only during the winter months, APL utilizes 90% of firm capacity as the criteria where extra generation is installed.
BC Hydro	Firm Capacity = Installed capacity less the largest unit.
NWT Power Corp.	Firm Capacity = 110% of peak load less the largest unit at plants whose peak loads are less than 3000 kW. Firm Capacity = 105% of peak load less the largest unit at plants whose peak loads are more than 3000 kW.
Yukon Electrical	Reserve capacity > 110% of peak load with the largest unit out.

Table 3.1

Planning Criteria Illustration

The following hypothetical system is used to illustrate how the planning criteria of each of the utilities is applied. The criteria which are stated in a number of different ways by the different utilities are expressed in a common format to provide a means for comparison.

System Name: *Hypothetical*

1994 Peak Load: 580 kW

Load Forecast at an estimated growth rate of 3% per annum:

Year	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Peak	580	597	615	634	653	672	693	713	735	757	779

Installed Generation: 450 kW
300 kW
250 kW
200 kW

Installed Generating Capacity: 1,200 kW

Table 3.2 on the following page presents a summary of how the system would be evaluated from a generation capacity planning point of view by each of the utilities. Based on this evaluation the year in which an increase in generation capacity would be required is identified. Also the reserve capacity in the year that additional generation is required is calculated. The reserve capacity is calculated as follows:

Reserve Capacity = (Installed Capacity - Peak Load) / Peak Load

Planning Criteria Illustration		
	Application of Criteria	Percent Reserve Capacity
Newfoundland Hydro	Firm capacity = 1200kW - 450kW = 750kW Peak load exceeds firm capacity in 2003.	59%
Hydro Quebec	Firm capacity = (1200kW - 450kW) * 90% = 675kW Peak load exceeds firm capacity in 2000.	73%
Ontario Hydro	Prime = 300kW + 250kW + 200kW = 750kW Peak load exceeds firm capacity in 2003.	59%
Manitoba Hydro	Firm capacity = (1200kW - 450kW) * 80% = 600kW Peak load exceeds firm capacity in 1996.	95%
Saskatchewan Power	N/A	N/A
Alberta Power Ltd.	Firm capacity = 1200kW - 450kW = 750kW Peak load exceeds firm capacity in 2003.	59%
BC Hydro	Firm capacity = 1200kW - 450kW = 750kW Peak load exceeds firm capacity in 2003.	59%
NWT Power Corp.	Firm capacity = 1200kW - 450kW = 750kW 110% of peak load exceeds firm capacity in 2000 (693 * 110% = 762 > 750)	73%
Yukon Electrical	In 2000, (1200kW - 450kW)/693kW < 110%	73%

Table 3.2

While the planning criteria and their use are quite clear, there are a number of other inputs into the determination of the level of reliability offered by each utility. These factors, along with the planning criteria, must be considered when making comparisons between utilities. The factors addressed in the questionnaire are presented in Tables 3.3 and 3.4.

Table 3.3 gives an overview of the various means in which the community peaks are measured by each of the utilities. The measured peak load can be significantly different depending on the means by which it is measured. For example, for a given system with a given load profile, the instantaneous peak will, in all probability, be much higher than the peak that is measured by a thermal demand meter which averages demand over a set period. Since the peak load is the parameter by which capacity planning is carried out, a utility which uses an instantaneous reading will typically have overall more generating capacity installed than a utility which uses a thermal demand meter (provided reserve is the same). Similarly, the shorter the duration of the thermal reading, typically, the higher the peak reading and the higher the amount of generation that will be installed.

Also shown in Table 3.3 is a summary of the back-up generation, over and above generation required by the planning criteria, that each utility has available. Quite obviously, the more back-up generation available, the higher the level of reliability supplied.

Questions:

Please indicate how peak load is measured (eg. Instantaneous, Thermal Demand, etc.):

Do you maintain a supply of back-up generation (other than that required under the Planning Criteria)? If YES, please elaborate.

	Method of Peak Measurement	Back-up Generation Available?
Newfoundland Hydro	30 minute thermal demand	Yes. However the quantity and size of the mobiles available for emergency back-up varies from year to year.
Hydro Quebec	Instantaneous	No.
Ontario Hydro	Thermal Demand	No.
Manitoba Hydro	20 minute thermal demand	No. Spare mobiles may or may not be available.
Saskatchewan Power	kVA demand	No, plant operates such that only one unit runs at a time.
Alberta Power Ltd.	15 minute thermal demand	4 x 150 kW mobiles suitable for fly-in, plus 2 x 150 kW, 300 kW & 1000 kW mobiles requiring ground transport.
BC Hydro	15 minute average by PML meter	Yes. Many plants have older units that are kept for back-up.
NWT Power Corp.	Thermal demand at largest system Instantaneous at smallest system	Three gas turbines are permanently located at Yellowknife (5 MW total). No others are available.
Yukon Electrical	Thermal demand	Two mobiles: 250 kW & 300 kW

Table 3.3

Table 3.4 presents a summary showing the number of units in a typical plant and the typical size of the units installed. These two factors work in conjunction with each other. For a given load, a diesel plant with a greater quantity of smaller units will, generally, offer a higher level of reliability than a plant with fewer large units. There is of course, as with all decisions, a trade-off between capital and operating costs and the level of reliability.

Questions:

How many units are installed in a typical plant?

What is the typical unit size (kW rating) installed in your diesel plants?

	Number of Diesel Units in a Typical Plant	Typical Unit Sizes
Newfoundland Hydro	At least 3 units per plant with the typical plant having 4 units.	Most between 136kW and 540kW. Also have units as small as 30kW and as large as 2000kW.
Hydro Quebec	14 of 21 plants have 3 units.	Most between 250kW and 1600kW.
Ontario Hydro	3 units.	Units from 85kW to 1000kW.
Manitoba Hydro	Typical is 3 or 4 units. One site has 7 units.	Most between 300kW and 855kW. Some 175kW units installed.
Saskatchewan Power	2 units.	66kW.
Alberta Power Ltd.	Small communities (<500kW peak) typically have 3 units. Three larger communities have 4 or more units.	Most between 100kW and 500kW. The two largest communities have units between 750kW and 3000kW.
BC Hydro	5 units.	Units from 300kW to 2000kW.
NWT Power Corp.	Majority of the 41 satellite plants have 4 units The 6 central plants have between 4 and 9 units.	Units range from 40kW to 5100kW.
Yukon Electrical	3 units.	150kW to 300kW

Table 3.4

Table 3.5 presents a summary showing the unit rating used by the utilities' for planning purposes. Diesel units typically can be provided with a continuous rating, a prime power rating and a standby rating which indicates the load that the unit is capable of supplying under various operating conditions. The following are based on definitions contained in International Standards Organization publication 3046 - Reciprocating Internal Combustion Engines and are consistent with definitions used by major manufacturers:[1]

Continuous: Output available without varying the load for an unlimited time.

Prime: Output available with varying load between 25% and 100% of the rating for an unlimited time. The unit can be overloaded to 110% of the rating for one hour in twelve.

Standby: Output available with varying load for the duration of an outage of the normal source of electrical supply. In essence, it is the "prime overload" condition with no time limit for an engine which is normally not operated.

Typically the prime rating is approximately 110% of the continuous rating and the standby rating is 110% of the prime rating. Since the rating is the parameter by which capacity planning is carried out, a utility which, for example, uses a continuous rating will have more generating capacity available than a utility which uses a prime rating.

While this question was not addressed in the survey it was identified as an important factor at a recent Prime Power Diesel Inter-Utility Conference and the information was collected by phone following the conference.

Question:

What diesel rating (Continuous, Prime, Standby) does your utility use for capacity planning?

[1] NF Hydro Engineering Department, Operation of Diesel Generating Sets with Arctic Grade Fuel, September 16, 1994.

	Diesel Unit Rating?
Newfoundland Hydro	Prime
Hydro Quebec	Prime
Ontario Hydro	Prime for units up to 600 kW Continuous for units above 600 kW
Manitoba Hydro	Prime
Saskatchewan Power	N/A
Alberta Power Ltd.	Prime
BC Hydro	Continuous
NWT Power Corp.	Continuous
Yukon Electrical	Continuous

Table 3.5

Appendix 7
Newfoundland Hydro
Transmission Planning Criteria

Hydro's bulk transmission system is planned to be capable of sustaining the single contingency loss of any transmission element without loss of system stability.

- In the event a transmission element is out of service, power flow in all other elements of the power system should be at or below normal rating.

- The Hydro system is planned to be able to sustain a successful single pole reclose for a line to ground fault based on the premise that all system generation is available.

- For normal operations, the system is planned on the basis that all voltages be maintained between 95% and 105%.

- For contingency or emergency situations 90% to 110% is considered acceptable.

The majority of Hydro's transmission lines are sagged for 6.7 m ground clearance at a conductor temperature of 50^{0}C.

- While no firm ratings have been applied to these lines the following guidelines are adhered to:
  Summer Time -25^{0}C conductor rise for 25^{0}C ambient temperature.
  Winter Time - 50^{0}C conductor rise for 0^{0}C ambient temperature.

- Transformer additions at all major terminal stations (i.e., two or more transformers per voltage class) are planned on the basis of being able to withstand the loss of the largest unit.

- For single transformer stations there is a back-up plan in place which utilizes Hydro's and/or Newfoundland Power's mobile equipment to restore service.

Appendix 8
Interconnected Utility
Transmission Planning Criteria

Definitions

1. **Primary Transmission** is defined as the high voltage transmission system interconnecting major substations and generation stations and the interconnecting transformation between them.

2. **Secondary Transmission System** is defined to be that part of the system which serves mainly to interconnect miscellaneous generation and Primary Transmission with Subtransmission at major load centres.

   The lesser importance of secondary transmission relative to the Primary Transmission permits a relaxation of the design criteria from that required for the primary transmission system.

3. **Electrically Remote Transmission** is defined by those buses at which ultimate fault levels are projected to not exceed 1500 MV.A three-phase.

4. **Subtransmission System** is defined to be that part of the system which primarily serves as a source for transformation to the distribution level. This type of system is primarily characterized by radial feeds although looped subtransmission exists.

5. **Interconnected Transmission System** is defined as the combined Primary, Secondary and Electrically Remote Transmission systems including connected generation.

6. **Normal system** conditions are defined to include all of the following:

   (a) Any load condition (this includes the full range of annually forecasted loads).

   (b) All transmission facilities in service (no line or transformer maintenance).

(c) Economically scheduled and dispatched generation allowing for planned generator maintenance outages (non-firm generation is not included as economically dispatched generation).

(d) Stable steady-state operation of the Interconnected Transmission System.

(e) All system voltages within 95% to 105% of nominal, unless otherwise noted.

(f) All system elements operating within their continuous thermal ratings, unless otherwise noted.

7. **A system element** is defined to be any one generator, transmission line, transformer or bus section.

8. **Local back-up clearance** is defined to be the time to clear an in-zone fault.

9. **Remote back-up clearance** is defined to be the time to clear an out-of-zone fault.

10. **Breaker back-up** is defined to be protection against local breaker failure to trip for any reason. Breaker back-up will be applied to all Primary Transmission and most of the Secondary Transmission systems.

1. Primary Transmission System

Prime clearance times are defined to be 4.5 cycles first zone and 6 cycles second zone with permissive signal for both three-phase and line-to-ground faults.

Back-up clearance times are defined to be 15 to 18 cycles for both three-phase and line-to-ground faults.

The Design Criteria[1] are:

1. From normal system conditions, the Interconnected Transmission System dynamic response shall be stable and positively-damped following a permanent three-phase fault on any one system element except a generator or bus section, cleared in prime time. No cascade tripping shall occur.

2. From normal system conditions, the Interconnected Transmission System dynamic response shall be stable and positively-damped following a permanent line-to-ground fault on any one system element cleared in prime time. No cascade tripping shall occur.

3. From normal system conditions, the Interconnected Transmission System dynamic response shall be stable and positively-damped following a permanent line-to-ground fault on any one system element except a bus section or generator, cleared in back-up time. No cascade tripping beyond elements cleared by the operative back-up protection shall occur.

4. From normal system conditions following loss of any one system element with or without fault, all system elements shall be within their long-term thermally limited ratings.

[1]Note: The Primary Transmission System Design Criteria may be superseded by the NPCC Basic Criteria for the Design and Operation of Interconnected Power Systems.

5. From normal system conditions, for the loss of any one system element with or without fault, steady post-contingency Interconnected Transmission System bus voltage\s shall not be less than 90% or greater than 110% of nominal following correction by automatic tap-changers. In addition, no bus shall experience a voltage change from pre-fault to post-fault condition greater than 10% before movement of tap changers.

6. As far as possible, provision should be made to ensure that no fault is left permanently on the system.

2. Secondary Transmission System

Prime time clearance is defined to be 6 to 9 cycles for both three-phase and line-to-ground faults. (No additional expenditure may be made to reduce clearing times from 9 to 6 cycles without authorization from System Design.)

Local back-up clearance is defined to be less than 30 cycles (a figure of 20 cycles is desirable but where coordination so dictates, a 30 cycle figure is acceptable).

Remote back-up clearance is defined to be less than 30 cycles which in certain instances implies reduced margins of coordination.

The Design Criteria are:

1. From normal system conditions, the Interconnected Transmission System dynamic response shall be stable and positively-damped following a permanent three-phase fault on any one system element except a generator or bus section cleared in prime time. No cascade tripping shall occur.

2. From normal system conditions, the Interconnected Transmission System dynamic response shall be stable and positively-damped following a permanent line-to-ground fault on any one system element cleared in prime time. No cascade tripping shall occur.

3. From normal system conditions, the Interconnected Transmission System dynamic response shall be stable and positively-damped following a permanent line-to-ground fault on any one system element except a generator or bus section, cleared in back-up time. No cascade tripping beyond elements cleared by the operative back-up protection shall occur.

4. From normal system conditions following loss of any one system element with or without fault, all system elements shall be within their thermally limited ratings in the steady state.

5. From normal system conditions, for the loss of any one system element with or without fault, steady-state post-contingency Interconnected Transmission System bus voltages shall be less than 90% or greater than 110% of nominal following correction by automatic tap-changers. In addition no bus shall experience a voltage change from pre-fault to post-fault condition greater than 10% before movement of tap-changers.

6. As far as possible, provision should be made to ensure that no fault is left permanently on the system.

3. Electrically Remote Transmission

Prime time clearance is defined to be 9 cycles for both -three phase and line-to-ground faults. Note 1; Note 2.

The Design Criteria are:

1. The Interconnected Transmission System dynamic response shall be stable and positively-damped following a fault on any one Electrically Remote system element.

2. From normal system conditions following loss of any one element with or without fault, all remaining elements shall be within their thermally limited ratings.

3. From normal system conditions, for the loss of any one Electrically Remote system element with or without fault, no Interconnected Transmission System bus voltage shall be less than 90% or greater than 110% of nominal following a steady-state settling out of the system nor shall any bus experience a voltage change from pre-fault to post-fault condition greater than 10% before tap-changer correction.

4. As far as possible, provision should be made to ensure that no fault is left permanently on the system.

Notes:

1. No expenditure may be made to reduce clearing times to reference values without authorization from System Design.

2. Permissive tripping between an electrically remote bus and a transmission bus (or between 2 electrically remote buses) is not required, i.e. local back-up clearances are acceptable.

3. Application of the above criteria does not preclude the possibility that for loss of certain remote system elements there will be a designed loss of load. This load would be restored after operator action.

4. Subtransmission System

The Design Criteria are:

1. Subtransmission system loading shall be within the thermally limited ratings.

2. The subtransmission system voltages shall not be less than 97.5% or greater than 105% of nominal.

3. As far as possible, provision should be made to ensure that no fault is left permanently on the system.

4. From normal system conditions, following the loss of any one subtransmission system element with or without a fault, any subtransmission system bus which remains connected to the system, shall maintain sufficient voltage following automatic tap-changer correction to permit operation of any affected distribution bulk supply bus at 105% of nominal following a steady-state settling out of the system. In no case shall any bus experience a voltage change from pre-fault to post-fault condition greater than 10% before tap-changer correction.

(The application of the above criteria does not guarantee a continuity of supply for any single contingency. In the case of a line, since a lengthy outage is considered to have a low probability time to repair is considered adequate for restoration of service; however, in the case of transformation, since an outage is generally a prolonged one, either the use of a mobile transformer for a short-term replacement or the installation of a spare transformer and interconnections with adjacent substations at the distribution level, are considered in decisions concerning the guaranteeing, after outage, of an alternative supply.)

5. Transformation

Design Criteria

Capacity for any individual transformation point shall, under nominal system conditions, be sufficient to meet the daily load requirements after due consideration is given to the following:

(a) Economic dispatch or outage of generation.

(b) Loading of transformer(s) to their (or their associated equipment) thermally-limited ratings as per Note 4.

Reinforcement is required in all cases when, for a single contingency, there will result either, thermal damage to equipment in attempting to continue to supply the load, or, inability to meet the daily load requirements in whole or in part after due consideration is given to the following: -

(a) The capacity of the underlying interconnection(s) with another supply point(s) when applicable.

(b) Out-of-merit running of generation when applicable.

(c) Loading of remaining station(s) transformer(s) to their (or their associated equipment) thermally-limited ratings as per Note 4. (This in conjunction with (a) and (b) above as applicable.)

(d) Largest available suitable mobile transformer loaded to its nameplate rating. (This in conjunction with 9a) and (b) above as applicable.)

Notes:

1. Reinforcement may be the economic choice even if (a), (b) and (c) or (d) result in satisfaction of the load supply criterion because estimated out-of-merit costs may

significantly exceed the costs of capital advancement.

2. The Primary Transmission system may require additional transformation in certain instances when, although the above (a), (b) and (c) may result in satisfaction of this particular criterion, any other of several possible contingencies (transmission lines, generators or transformer(s)) could result in either frequent or prolonged outages to a widespread part of the system.

3. The result of application of these criterion may not be installation of additional transformation.

4. Generally in accordance with methods accepted within North America, and particularly with reference to ANSI-IEEE Std. C57.92-1981 "Guide for Loading Mineral-Oil-Immersed Power Transformers (up to and including 100 MV.A with 55°C or 65°C Winding Rise)", and IEEE Std. C57.115-1991 "IEEE Guide for Loading Mineral-Oil-Immersed Power Transformers Rated in Excess of 100 MV.A (65°C Winding Rise)", it is NSPI practice to permit the loading of transformers to exceed the nominal or nameplate value such that thermal limits calculated in accordance with the above references are not regularly exceeded. Where calculations are not specifically conducted, overload capability assumptions based on normal cyclic daily loading may be made, but shall not exceed 133% of top nameplate rating.

In special circumstances, such as single contingency situations where some means of reducing the overload exists, a thermal rating based on a loss of life of 2 ½% may be applied, in accordance with the above and engineering judgement. The loss of life permitted is measured over the time required to reduce the loading on the transformers. This may be done by switching low voltage circuits or relieving load by use of a mobile transformer.

When no means of reducing the overload exists, a 0% loss of life is used.

Appendix 9
Newfoundland Hydro
Standard Instructions

1.0 Instruction 010, System Outages

2.0 Instruction T-022, Restoration of the Holyrood Plant to an Isolated System.

HYDRO

NEWFOUNDLAND AND LABRADOR HYDRO - OPERATIONS

STANDARD INSTRUCTION

TITLE:	
SYSTEM OUTAGES	Inst. No. 010
	Rev. No. 08
	Page 1 of 6

To adequately plan the operation of the power system, it is necessary to have sufficient time to plan outages and evaluate the effect of these outages on system operation.

1. PLANNED SYSTEM OUTAGES

a) System outages must be requested from the Energy Control Centre (ECC) as far in advance as possible. A minimum of **THREE WORKING DAYS** notice shall be given for outages which are internal to Hydro and for outages involving Hydro customers, a minimum of **FIVE WORKING DAYS** notice is required.

b) When requested outages are dependent on weather conditions (eg. doble testing), alternate outages may be requested at the time of the original outage request.

c) Requests for outages shall originate from:

1. Transmission & Rural Operations - Regional Manager, Area Superintendent, or designate

2. Generation Operations - Superintendent, Plant Operations, or designate

3. Other Departments shall direct their outage requests through the appropriate Department.

d) All requests shall be made to the Superintendent - ECC, or designate with copies to the following:

PREPARED/ REVIEWED BY:	APPROVED BY:	ISSUED DATE: 1980-11-17
D. Fever	[signature]	REV. DATE: 1997-07-31

HYDRO

NEWFOUNDLAND AND LABRADOR HYDRO - OPERATIONS

STANDARD INSTRUCTION

TITLE:	Inst. No. 010
SYSTEM OUTAGES	Rev. No. 08
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1. PLANNED SYSTEM OUTAGES (cont'd.)

   d. (cont'd.)

      1. Outages requested by Transmission & Rural Operations:

         - Superintendent, Telecontrol Maintenance, or designate
         - Plant Managers and other Regional Managers, Area Superintendents, if their area of responsibility is affected.

      2. Outages requested by Generation Operations:

         - Superintendent, Telecontrol Maintenance, or designate
         - Regional Managers or Area Superintendents, if their area of responsibility is affected.
         - Director, Generation Operations

   e. Outages requested by Transmission and Rural Operations shall contain the following information:

      i) specific equipment affected (indicate appropriate section of transmission line)
      ii) starting date and time*
      iii) ending date and time*
      iv) isolation required
      v) type of permit required
      vi) purpose of outage
      vii) switching arrangements

PREPARED/ REVIEWED BY: D. Fever	APPROVED BY:	ISSUED DATE: 1980-11-17
		REV. DATE: 1997-07-31

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NEWFOUNDLAND AND LABRADOR HYDRO - OPERATIONS

STANDARD INSTRUCTION

TITLE: SYSTEM OUTAGES	**Inst. No.** 010 **Rev. No.** 08 **Page** 3 **of** 6

1. PLANNED SYSTEM OUTAGE (cont'd.)

e. (cont'd.)

* The starting and ending times will include switching time and work time. This is especially important when customers interruptions are involved.

f. Outages requested by Generation Operations shall contain the following information:

i) equipment affected
ii) starting date and time*
iii) ending date and time
iv) purpose of outage
v) switching arrangements

* The starting time is the time the equipment is disconnected from the system. The ending time is the time the unit is restored to available status.

g. When a decision has been made, the Superintendent, ECC or designate will notify the originator of the outage request with copies to the same personnel as in the original request and to the Director, Generation Engineering and Telecontrol. The Director, Transmission and Rural Operations shall receive copies of decisions relating to Transmission and Rural Operations only.

PREPARED/ REVIEWED BY: D. Fever	**APPROVED BY:**	**ISSUED DATE:** 1980-11-17 **REV. DATE:** 1997-07-31

HYDRO

NEWFOUNDLAND AND LABRADOR HYDRO - OPERATIONS

STANDARD INSTRUCTION

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1. PLANNED SYSTEM OUTAGES (cont'd.)

   h. Switching arrangements shall be confirmed at the time of the outage confirmation.

   i. Outage confirmation will be given as much in advance as possible with a minimum of one working day's notice.

   j. Outage requests, originated by the customer, will be channelled through the Superintendent - ECC or designate, who will discuss the requirements with the area concerned before the request is granted.

   k. If there is a requirement for an outage to be extended, the Shift Supervisor-ECC shall be advised.

2. WORK ON PROTECTION, CONTROL, METERING AND TELECONTROL EQUIPMENT

   a. Work schedules, which require removal of system equipment from service, shall be submitted to the ECC by WEDNESDAY of the week prior to the work being planned.

PREPARED/ REVIEWED BY: D. Fever	APPROVED BY:	ISSUED DATE: 1980-11-17
		REV. DATE: 1997-07-31

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NEWFOUNDLAND AND LABRADOR HYDRO - OPERATIONS

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2. WORK ON PROTECTION, CONTROL, METERING AND TELECONTROL EQUIPMENT (cont'd.)

   b. The work schedule shall contain the following information:

      i) equipment affected
      ii) starting date and time*
      iii) ending date and time
      iv) work to be performed
      v) work location
      vi) switching requirements

      * The starting and ending date and time will reflect the actual working time and switching time, if necessary.

   c. Work schedules shall be copied to the areas affected.

   d. Work schedules submitted by Wednesday shall be confirmed by Friday of the same week.

3. DEVIATION FROM STANDARD

All parties shall attempt to work within the time limits as outlined in this standard, but with prior consultation and mutual agreement between the requesting area and the Superintendent-ECC or designate, time limits may be relaxed.

PREPARED/ REVIEWED BY: D. Fever	APPROVED BY:	ISSUED DATE: 1980-11-17
		REV. DATE: 1997-07-31

HYDRO

NEWFOUNDLAND AND LABRADOR HYDRO - OPERATIONS

STANDARD INSTRUCTION

TITLE:	
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4. FORCED SYSTEM OUTAGES

Non-scheduled removal of equipment from service shall be determined by the Shift Supervisor-ECC in consultation with available senior personnel.

In case of emergency when time limitations prohibit consultation, the Shift Supervisor, ECC shall exercise proper judgement and report the problem and action taken to senior personnel as soon as possible.

PREPARED/ REVIEWED BY:	APPROVED BY:	ISSUED DATE: 1980-11-17
D. Fever		REV. DATE: 1997-07-31

HYDRO

SYSTEM OPERATING INSTRUCTION

STATION: GENERAL	**Inst. No.** T-022
TITLE: RESTORATION OF THE HOLYROOD PLANT TO AN ISOLATED SYSTEM	**Rev. No.**
	Page 1 **of** 3

1.0 INTRODUCTION

The Holyrood Plant can be restored to a lightly loaded isolated system. However, at an output below 60 MW a unit cannot pick up significant blocks of load. The rate of load increase cannot exceed 2 MW/minute in this output range as the boiler must be in hand control. This means the unit will not respond to load changes on the isolated system.

In order to achieve this loading rate, the Holyrood units must be synchronized with other generation which can respond to system load changes. This generation must be adjusted to control the frequency as the Holyrood units pickup load. This will require very close co-ordination between the Newfoundland Power Control Center, Newfoundland Hydro Control Center and the Holyrood Thermal Plant.

2.0 RESTORATION GUIDELINES

Hardwoods Gas Turbine

The preferred unit to be started to begin restoration of the isolated system is the Hardwoods Gas Turbine (GT). It should be placed on line in isochronous governor mode*. Once it has been started and if the station service has not been restored to the Holyrood Plant a transmission connection to Holyrood shall be made to provide the station service. The Hardwoods unit should then, if possible, be synchronized with Newfoundland Power's Southern Shore generation (appendix 1) to begin load pickup.

The amount of load to be picked up by the Hardwoods G.T. and /or Newfoundland Power generation cannot exceed these units' capability to respond. The Hardwoods G.T. with both power turbines operating can pick up load in no more than 8 MW increments. Therefore, Newfoundland Power must provide the load in these steps when requested.

PREPARED BY: D. Fever	**APPROVED BY:**	**ISSUED DATE:** 1996-11-27
		REV. DATE:

HYDRO

SYSTEM OPERATING INSTRUCTION

STATION: GENERAL	Inst. No. T-022
TITLE: RESTORATION OF THE HOLYROOD PLANT TO AN ISOLATED SYSTEM	Rev. No.
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2.0 **RESTORATION GUIDELINES** (cont'd.)

Load Pickup

Generally, the longer the outage duration for domestic customers the greater ~~the~~ load pickup. It is not unusual to have a cold load pickup that may be 2-4 times the normal distribution feeder peak. It is, therefore, very important that Newfoundland Power accurately indicate the amount of load that will be picked-up when feeders are energized so that underfrequency tripping does not occur. In fact if possible feeders without underfrequency tripping should be used.

Transmission Routes

A number of transmission routes are available to energize the Holyrood Terminal Station and synchronize the Holyrood units. The preferred route is TL 242 energized from the Hardwoods G. T and Newfoundland Power Southern Shore generation . This source will be confirmed through discussion between the two control centers at the time.

If TL 242 is not available, other transmission routes will be discussed between the control centers.

When a transmission route has been determined, appropriate breakers will be opened to accommodate restoration of the Holyrood Thermal Plant.

Synchronizing and Loading Holyrood Unit

Once the Hardwoods G.T. has been loaded to 45 MW the Holyrood unit can be synchronized and start taking load. After the unit has been synchronized, the unit load may be increased at the rate of 2 MW/min. until it reaches 60 MW. For loading above 60 MW, the unit can accept blocks of load as defined in the maximum load pick-up table (attached).

PREPARED BY:	APPROVED BY:	ISSUED DATE: 1996-11-27
D. Fever		REV. DATE:

HYDRO

SYSTEM OPERATING INSTRUCTION

STATION: GENERAL	Inst. No. T-022
TITLE: RESTORATION OF THE HOLYROOD PLANT TO AN ISOLATED SYSTEM	Rev. No. Page 3 of 3

2.0 <u>RESTORATION GUIDELINES</u> (cont'd.)

<u>Synchronizing and Loading Holyrood Unit</u> (cont'd.)

To achieve the 60 MW loading the Hardwoods G.T. will off load as the Holyrood unit picks up the load. In order to maintain a ready supply of load for the Holyrood unit, after each 8 MW increment is taken by Holyrood, an additional 8 MW of load shall be provided to the system. Each additional 8 MW will be taken by the Hardwoods G.T. as it will be in isochronous mode. The ECC shall notify the Newfoundland Power Control Center each time an 8 MW increment of load is to be provided.

Once the Holyrood unit reaches 60 MW and is ready to switch to speed/load control, the Hardwoods G.T. shall be placed in droop mode* so that the Holyrood unit and Hardwoods G.T. can share new load. At this point the Newfoundland Power Control Center will be notified that the Holyrood unit is in speed/load control and that further load increases can be in accordance with the attached table.

When blocks of load are to be picked-up by the Holyrood units, the E.C.C. will inform the Holyrood Control Room Operator of the estimate of the amount of load to be picked-up. He will also request the Holyrood Control Room Operator to observe the frequency and if necessary, increase the load limit to stabilize the frequency.

After a block of load has been picked-up, time will be required to stabilize the unit. This time will be determined by the Holyrood Shift Supervisor and he will inform the E.C.C. when the unit can accept additional load. This will in turn be conveyed to the Newfoundland Power Control Center.

* To change the governor from droop to isochronous mode, select "Dead bus verify on".

To change the governor from isochronous to droop mode, select "Re-synch on."

PREPARED BY: D.Fever	APPROVED BY:	ISSUED DATE: 1996-11-27 REV. DATE:

Appendix 10
Newfoundland Hydro
Environment Documents

1.0 Environment Committee of the Board of Directors, Constitution and Powers.

2.0 Environmental Principals.

3.0 Elements of Hydro's Environmental Management System.

ENVIRONMENT COMMITTEE OF THE BOARD OF DIRECTORS OF NEWFOUNDLAND AND LABRADOR HYDRO

Constitution and Powers

1. The Committee shall consist of three members, a minimum of two members of which will constitute a quorum. All members shall be Directors who are not officers and/or managers of the Corporation.

2. Any member of the Environment Committee may be removed or replaced at any time by the Board of Directors and shall cease to be a member of the Environment Committee upon ceasing to be a Director of the Corporation.

3. The Board of Directors shall fill vacancies on the Environment Committee from among the Directors of the Corporation.

4. The Board of Directors shall appoint a member of the Environment Committee as Chairperson thereof and may, by resolution, modify, dissolve, or reconstitute the Environment Committee and make such regulations with respect to and impose such restrictions upon the exercise of duties and powers hereby delegated.

5. The Corporate Secretary of the Corporation, or designate, shall be the Secretary of the Environment Committee.

6. The Minutes of the meetings and proceedings of the Environment Committee will be signed by the Secretary and approved by the Chairperson of the Environment Committee and such Minutes shall be presented to the Board of Directors at such times as the Chairman of the Environment Committee so directs.

7. The Environment Committee shall invite such Directors, officers, and employees as it may see fit, to attend its meetings and to take part in the discussions and considerations of the affairs of the Corporation.

8. Meetings of the Environment Committee shall be held at least twice a year with additional meetings being held at the request of any member of the Committee.

9. A meeting of the Environment Committee shall be convened, at a time convenient to the Committee, upon a request, made to the Chairperson of the Environment Committee, by either the Chief Executive Officer, the Vice-President responsible for the Environmental Services Department of the Hydro Group for Companies or the Director/Manager responsible for the Environmental Services Department, and these individuals shall

have the right to appear before and be heard by the Environment Committee.

10. The members of the Environment Committee shall be entitled to such remuneration for their services as members of the Environment Committee, as may be fixed by the Board of Directors.

11. Subject to approval by the Board of Directors, the Environment Committee may engage outside technical specialists to assist Committee members in the discharge of their responsibilities.

<u>Terms of Reference</u>

The Environment Committee shall:

1. Review the Corporation's environment policies and procedures to ensure that they are adequate within the terms and practices of its industry to ensure compliance with environmental laws and as well to confirm that the Corporation has appropriate systems and programs in place to ensure implementation of, and compliance with, the aforementioned policies and procedures;

2. Report the results of its activity as well as its findings and recommendations to the Board of Directors at the first meeting of the Board following each Committee meeting, and at any other time which the Chairperson of the Environment Committee deems appropriate;

3. Review the formal reports arising from audits carried out under the Corporation's environmental audit program and to ensure the appropriate measures are taken to appropriately deal with the recommendations contained therein

4. Receive updates from Management on the general management of environmental issues within the Corporation, including the following:

   (a) Government environmental regulations, policies or guidelines;
   (b) situations which do not comply with environmental regulations or corporate policies and procedures;
   (c) environmental incidents and remedial actions; and
   (d) training of employees on environmental issues;

5. Advise the Board of Directors and make recommendations for its consideration regarding environmental issues affecting the

Corporation which are reviewed by the Environmental Committee; and

6. Periodically review with Management all aspects of the Corporation's environmental audit program to ensure that it adequately fulfils the requirements of the Corporation with respect to its efforts to comply with all environmental policies, laws and statutes, such review to include consideration of the scope of the program, the frequency with which audits are carried out, the performance of any external auditors retained and the costs involved in carrying out the program.

APPROVED BY THE NEWFOUNDLAND HYDRO BOARD OF DIRECTORS ON SEPTEMBER 24, 1993.

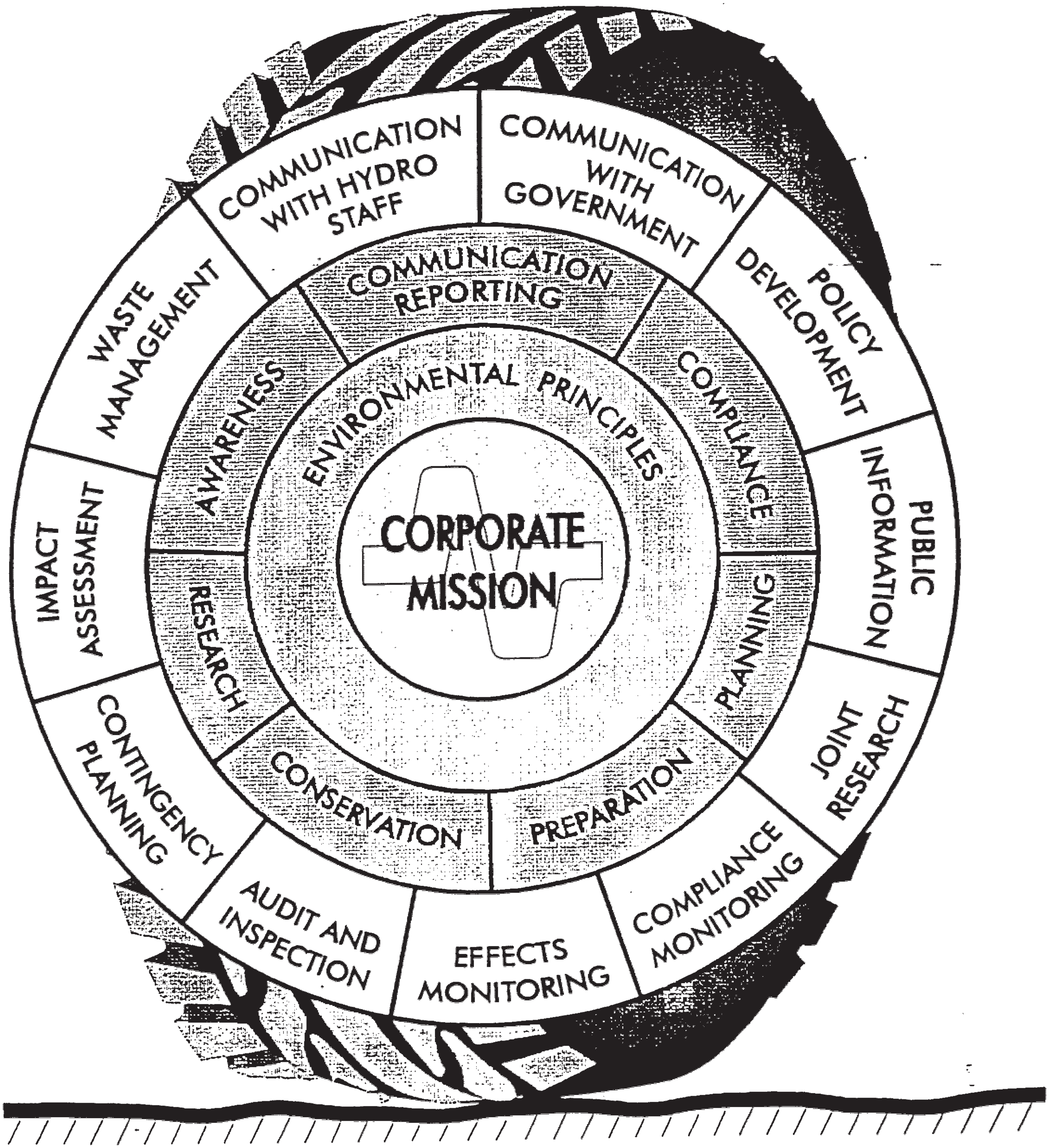
ENVIRONMENTAL PRINCIPLES

The Corporation has adopted 10 principles which will guide the Company's commitment to responsible stewardship of the environment. Adherence to these principles will enhance the Corporation's contribution to the maintenance of a rich and healthful environment for present Newfoundlanders and Labradorians, and for those who will follow.

The Corporation will:

1. integrate environmental considerations into decision-making processes at all levels, and provide sufficient training to its employees to facilitate this;
2. use the Province's natural resources in a wise and efficient manner;
3. undertake use of energy as efficiently as possible during the generation of electricity and the operation of its facilities, and promote efficient use of electricity by customers;
4. comply with all applicable environmental laws and regulations, and exceed these when prudent environmental management dictates;
5. monitor compliance with environmental laws and regulations, and quantify predicted environmental impacts of selected activities on the environment;
6. audit facilities to continuously assess potential environmental risks and improve environmental performance;
7. maintain a state of preparedness in order to respond quickly and effectively to environmental emergencies;
8. respect the cultural heritage of the people of the Province and strive to minimize the potential impact of Corporate activities on heritage resources;
9. reduce, reuse and recycle waste materials whenever feasible; and
10. periodically report to the Board of Directors, Executive Management, employees, government agencies, and the general public which we serve on environmental performance, commitments and activities.

ELEMENTS OF HYDRO'S ENVIRONMENT MANAGEMENT SYSTEM



WHERE THE RUBBER MEETS THE ROAD

Appendix 11
Joint Utilities Coordination Items for Study

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.