Q. **Please provide a copy of the report filed by Mr. George C. Baker in the proceeding relating to the Referral by NLH for the proposed cost of service methodology, which resulted in the 1993 report produced as PUB-NLH-113, Att. 1, as mentioned on pages 61 and 62 of said report.**

A A copy of the direct testimony of G. C. Baker (Revised December 10, 1993) and SUPPLEMENTARY TESTIMONY OF G. C. BAKER filed in the proceeding to the Referral by Newfoundland and Labrador Hydro for the proposed Cost of Service Methodology is attached.

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December 13, 1993

Ms. Carol Horwood
Clerk
Newfoundland & Labrador
Board of Commissioners of Public Utilities
P. O. Box 21040
St. John's, Newfoundland
A1A 5B2

Dear Ms. Horwood:

With this letter I submit 25 copies of revised direct testimony and supplementary testimony in the matter of an inquiry into issues relating to the supply of electricity to isolated rural areas of the Province.

Revisions are as follows:

Page 16, line 14: words added.
Page 23, line 8: words changed.
Page 25, line 14, to page 26, line 3: text revised.
Page 26, line 19: typographical correction.

(The above line references are to the original text.)

The revised direct testimony and the supplementary testimony are consolidated into one document, complete with all exhibits and appendices. To avoid the possibility of confusion, it is requested that recipients destroy the original version of the direct testimony after receipt of the revised text.

Would you please distribute this material to the appropriate parties.

Yours sincerely,

George Baker

G. C. Baker, P. Eng.

GCB/db

PROVINCE OF NEWFOUNDLAND

BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

IN THE MATTER OF:

An inquiry into issues relating to the supply of electricity to isolated rural areas of the Province.

DIRECT TESTIMONY OF G. C. BAKER

(Revised December 10, 1993)

AND

SUPPLEMENTARY TESTIMONY OF G. C. BAKER

HILTZ & SEAMONE CO. LTD.
ENGINEERS
KENTVILLE, N. S.

PROVINCE OF NEWFOUNDLAND

BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

IN THE MATTER OF:

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(Revised December 10, 1993)

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PROVINCE OF NEWFOUNDLAND

BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

IN THE MATTER OF:

An inquiry into issues relating to the supply of electricity to isolated rural areas of the Province.

DIRECT TESTIMONY OF G. C. BAKER

Q. Please state your name and address.

A. My name is George Chisholm Baker. I reside at Kentville, Nova Scotia.

Q. Please outline your qualifications and experience.

A. I am a registered professional engineer in Nova Scotia and have from time to time held licences to practice in other provinces and territories. I am self-employed as a consultant in matters relating to the regulation of electric utilities and have testified before this honourable Board on previous occasions. My experience relative to electric utilities covers about three decades and includes most aspects of utility operation. My clientele has included regulatory agencies in five Canadian jurisdictions, a number of utilities and departments of federal and provincial governments.

Q. What is your involvement in the present matter?

A. I have been engaged by the Board and have been directed to present opinions on any aspects of the present inquiry which lie within my knowledge and experience.

Q. Generally, on what aspects of the inquiry do you wish to testify?

A. My testimony relates to the following four topics:

1. Current Canadian electrical pricing practices relating to urban, rural and isolated customers;

2. Possible options to recover the cost of serving rural customers;

3. Price and non-price measures to limit electrical consumption in isolated rural areas; and

4. Possible rate structures for isolated rural customers.

Q. Are you basing your opinions on regulatory principles and practices?

A. Not entirely. There are two reasons; (1) regulatory practices tend to vary, and (2) as noted by several parties during the recent generic hearing on Hydro's cost of service, some aspects of the present inquiry lie outside the normal scope of regulatory principles.

For both reasons, it seems necessary to apply a broader criterion, and in my opinion the appropriate criterion is the economic welfare of society in general, and Newfoundland in particular.

Q. Please comment on current Canadian pricing practices relating to urban, rural and isolated customers.

A. The applicable regulatory principle is that rates should reflect costs. The cost of service criterion is widely supported, and was favoured by most of the parties involved in the Board's recent generic hearing. It is the basic criterion used by regulating agencies in Manitoba, New Brunswick, Nova Scotia and Prince Edward Island; the jurisdictions with which I am most familiar.

Nevertheless, the degree to which this principle is reflected in rates can, and does, vary from one jurisdiction to another depending on the structure of rate classes. For customers of the same type, it is generally cheapest to serve urban loads and more expensive to serve rural loads. If all the customers of one type (residential, for instance) are placed in the same class, urban customers subsidize rural customers, even though the rate charged may exactly recover the cost of serving the class as a whole.

It is in this respect that practice varies from one jurisdiction to another.

It is of course much more expensive to serve isolated loads. Therefore, if urban, rural and isolated customers of the same type were to be included in a single class, the degree of cross-subsidization would be considerably greater.

In both Manitoba and New Brunswick, residential rates are differentiated on the basis of customer density. Manitoba uses three density groupings; New Brunswick uses two. Fixed charge differentials reflect the differences in distribution cost between the relevant groups.

However, in its most recent rate application Manitoba Hydro stated, "Current rate zone distinctions are intended to reflect real differences in distribution cost. However, they are administratively complex, create difficulties for cost allocation and are not well understood by customers." The utility said that simplification possibilities were currently being examined.

By contrast, residential customers of the dominant utilities in PEI and Nova Scotia pay at the same rate wherever situated. Until recent years, Maritime Electric (MECL) rates in PEI differed for city, town and rural customers, but the regulator approved uniform rates as urged by the provincial government. Uniform rates were established in 1975 by Nova Scotia Power Corporation after it absorbed Nova Scotia Light and Power.

In the Maritime Provinces, and in Ontario as well, rate differentials are maintained in certain areas by virtue of the existence of distribution utilities. Such utilities buy part or all of their requirements at wholesale from the dominant utility and perform the distribution function; usually serving communities where customers are well concentrated. Their rates tend to reflect the inherently lower cost of service.

Winnipeg Hydro is the only such utility in Manitoba. Its rates are set at Manitoba Hydro levels, so in that case the City, not the electric customer, receives the benefit.

Distribution utilities are the norm rather than the exception in Ontario and their rates to customers have been regulated on a cost of service basis by Ontario Hydro. Distributing utilities in the Maritimes include Saint John and Edmundston in New Brunswick, seven municipal utilities in Nova Scotia and Summerside in PEI.

The existence of distribution utilities can generally be ascribed to historical circumstance. However, it may in part owe something to economic circumstance. In this connection, it is interesting to note that the Summerside utility, faced with having to pay a part of the cost of subsidizing rural customers of MECL, applied to the Commission for approval of plans to install enough diesel generation to replace its purchases from that utility. This matter has not yet been resolved.

Q. In your opinion, what causes the differences you have described?

A. There is an inherent conflict between Bonbright's desirable attributes of equity on the one hand and simplicity and understandability on the other. Judgment in any particular case is no doubt based on all the pertinent factors including the extent of the inequity, which is relatively small between urban and rural customers in these examples; and the weight accorded to customer understanding and acceptance. Judgment can be expected to vary from case to case.

Q. What is the situation regarding isolated areas?

A. There are none in the Maritimes. Manitoba Hydro has been providing service in thirteen communities isolated from its main grid. Customers in those communities can purchase limited service at standard rural (Zone 3) rates. This collects about 30% of the cost of service.

For residential customers, limited service had been 15 amperes at 240 volts. However, in two communities the limit was increased to 60 amperes in 1991 and 1992.

General service (GS) customers received limited service (at Zone 3 rates) or full service (with basic monthly charge at Zone 3 level and energy rate recovering allocated cost). The rate varies by community and depends on whether or not the customer had made a capital contribution.

Government agencies, federal and provincial, are served under the GS full cost rate, but in addition pay a surcharge. The surcharge has been calculated so that the proceeds thereof, when added to the revenue from limited service customers, would bring the revenue/cost ratio on limited service up to the level of Zone 3 residential in the interconnected system.

In 1992, Manitoba Hydro adopted new objectives for its diesel zone. By 1997 it expected to have seven of the thirteen communities connected to the main grid. Concomitantly, it planned to increase the service restriction to 60 amperes in communities still served by diesel and to eliminate the rate distinction based on capital contribution. (All new customers have been paying a capital contribution for some years.)

These changes were expected to add to the costs borne by full service customers, both private and government.

Q. What conclusions, if any, do you draw?

A. I believe the Manitoba Hydro approach is instructive. In essence, it involves:

1. Full cost recovery from isolated areas, without burden on the interconnected system.
2. Subsidization of certain isolated system customers.
3. Limitation of service where subsidy exists.
4. Customer option to receive full service at full cost.
5. Recovery of revenue shortfall from federal and provincial government customers.

I conclude that some of these ideas merit consideration by the Board as a possible means of improving the status quo in this province.

Q. Do other jurisdictions supplying electric service to isolated areas use somewhat the same approach as Manitoba?

A. The approaches vary, but there are a few common threads.

There are four rate zones in the Yukon and fifty-three (one for each system) in the Northwest Territories. Rates recover costs in each zone.

Alberta Power says it does not apply a separate rate in remote areas, but does apply a surcharge as a reminder that service in those areas costs more. The surcharge approximately doubles the energy rate.

Ontario Hydro charges government customers 70 to 80 cents/KWh in isolated areas with air access only and 45 to 60 cents/KWh in isolated areas with road or rail access. Residential customers pay standard rates.

Quebec Hydro applies a 26 cents/KWh surcharge on all use over 20 KWh per day for residential service north of the 53rd parallel.

In Saskatchewan, there is only one isolated system. Residential customers pay the same rates as applicable to rural and resort areas, plus a surcharge of about 6 cents/KWh on the first 650 KWh and about 20 cents/KWh on the balance of use. There is also a government surcharge.

The first common thread is that where high-cost isolated systems exist, every jurisdiction applies a surcharge or higher rate in the high cost areas. The higher rates recover all or nearly all the costs except in the case of Hydro Quebec, NLH, and perhaps in Alberta, where zone costs are not tracked. No jurisdiction simply applies universal rates, allowing the whole of the burden to fall on interconnected customers.

While limitations on service are applied in some jurisdictions, they are of a different nature than those applied in Manitoba. For example, Hydro Quebec applies a 1,000 KVA limit on individual loads and Alberta Power a 650 KW limit. Alberta Power also prohibits water heating or space heating loads. Elsewhere, restraint comes mainly from rate levels, not rules.

Again with the possible exception of Alberta Power, in no jurisdiction is the burden of service to isolated areas allowed to create a significant impact on the cost to interconnected customers except in Newfoundland and Labrador.

Q. Why is electric service provided in areas where it is so expensive that consumption needs to be subsidized?

A. The answer derives in part from the history of the electric utility industry in this country. The first electric service was provided by entrepreneurs who hoped to profit from the opportunities presented by growth of electrical technology. Areas served were at first rather random but soon came to include all major population centres and a number of smaller ones.

As electricity became more widely used and appliance availability made it more versatile and useful, governments concluded, as a matter of social policy, that electric service should be universally available, or as nearly so as possible.

The means of achieving that policy varied, but a common strategy was to provide grants to support the capital costs of rural electrification. Another was to create Crown electric utilities. Most of the Crown electrics were created expressly for this purpose.

Where rural electrification grants were provided, utility customers were left to bear the full cost of replacing the original equipment. Where cheap power sources were available, or load growth was sufficient, customers had no difficulty in meeting the subsequent full costs of service. This was the outcome in most cases.

Continuing subsidies were necessary only where social policy encouraged the provision of utility service in areas having adverse geographic and economic conditions.

So the answer to the question is clear and simple: subsidies are required because of social policies adopted by the governments concerned.

Q. Would the need for continuing subsidies have been foreseen when such social policies were adopted?

A. In the case of Newfoundland and Labrador, the record indicates that subsidies were envisaged from the outset, and paid in full from the consolidated revenue fund of the Province until 1989.

Q. Turning to the second area of your testimony, what options exist to recover the cost of serving rural customers?

A. There are only three plausible options:

1. To recover all costs from the customers themselves.

2. To recover partially from customers, with the balance from the consolidated revenue fund.

3. To recover partially from customers, with the balance from other electric customers.

Q. In the case of the second and third options, how much should be recovered from isolated customers?

A. This is a matter of judgment. While it might be in part a matter for regulatory judgment, it certainly involves the question of social policy. As matters stand at present, judgment has been made by the government partially through the provisions of the Electric Power Control Act and partially through its decision not to approve rate increases recommended by the Board in 1992.

However, the fact that this inquiry has been ordered, and the terms of reference thereof, support the inference that present policy is not cast in stone. I am basing my testimony on this assumption.

The portion of cost recoverable from customers is therefore regarded as a variable. Both the level of recovery from customers and the option selected have economic implications. From an economic perspective, the proportion recovered from customers should be as high as possible. Social and regulatory considerations could constrain the result to less than full recovery.

Q. Please explain the implications of economic theory.

A. It has been shown that in a free economy, pricing electricity at marginal cost results in optimum allocation of resources and maximizes the economic welfare of society.

This is a provable proposition under certain assumptions, which, however, are invalid or only partially valid in a real-life situation.

One assumption of the theory which does undoubtedly apply in real life is that price influences consumption. The relationship is inverse: that is to say, consumption goes down as the price paid goes up. Economists call this relationship the price elasticity of demand and measure it as the ratio of change in use resulting from a small change in price.

Price elasticity is affected by the time duration of the price signal. It takes years to reach its maximum. Exhibit 1 shows the relationship between price and use for the three Maritime Provinces. Although more than price may be involved, the comparison suggests that long-term elasticity is substantial.

Thus the price signal is important, whether or not marginal cost theory is applicable. If the theory is applicable, then marginal cost gives the correct price signal; if it is not, then allocated cost will be more or less appropriate.

From the economist's viewpoint, if a customer pays only 30% or 40% of the cost, then the signal received is drastically out of step with reality. Full cost would give the correct signal, and failing that, the price should be as close to cost as possible.

If subsidy costs are charged to other electric users, they too will receive wrong price signals. But in their case the signal will be too high and result in consumption below that level which would maximize the economic welfare of the Province.

From the standpoint of economic efficiency, the best approach would involve government payment of a subsidy, maintained at the least possible level consistent with social and regulatory considerations.

Q. That argument is based on theory. Would practical results agree with theoretical predictions?

A. If there were any differences, they would be merely differences of degree.

Customers in isolated areas, with relatively few options, might exhibit a relatively small elasticity of demand. However, higher prices would encourage DSM penetration and the resulting increases in efficiency would tend to offset both the small elasticity and the added cost due to higher prices.

For customers in the interconnected system, the effects could be much greater than might be inferred from the roughly 10% increase in cost incurred to pay the subsidy. For instance, in the case of an industry dependent on export markets, the 10% could well make the difference between continued existence and collapse. Such export markets are highly competitive and foreign buyers are unlikely to make voluntary contributions to support electric customers in the isolated areas of Newfoundland and Labrador.

If the burden of subsidy is placed on the interconnected systems, not every customer would be affected to the extent envisaged in the foregoing example, but every industrial and business customer would to some small extent be rendered less competitive: less able to maintain market share against outside competitors in both internal and external markets.

Q. Why wouldn't paying the subsidy out of tax revenue do the same thing?

A. It would, but to a lesser degree. Taxation correlates at least to some extent with ability to pay and is presumably designed to raise the required revenue with least economic damage. The intensity of electric use correlates with type of industry, not ability to pay.

There is one other difference. Failure to reflect economic cost in prices can, and in the case of utility and municipal services does, lead to locational inefficiencies. Taxation does not in general have this effect.

Q. Have you anything to add regarding options?

A. Yes. My testimony on this point tends to emphasize the conflict between the dictates of economic theory and social considerations. Also, it has focussed narrowly on electric energy. A broader view may lead to an expedient which is to some extent capable of achieving the best of both worlds.

Available information on costs of other commodities tends to support the view that electricity is not the only item which is more expensive in the isolated areas.

For example, a 1984 report[1] shows that food prices were higher in remote and isolated areas, being highest in small coastal Labrador communities. Choice was more limited in these areas as well.

The Committee concluded that:

> ". . . the factors which are most important in influencing differences in food prices across communities in Newfoundland and Labrador are the distance of those communities from larger population centres, the size of food stores serving the consumers of those communities, and the variety of food items available in those stores."

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[1]Report of the Select Committee of the House of Assembly on Food Prices, submitted November 9, 1984 to the House of Assembly.

Price differentials were also evident for fuel in a 1991 report[2]. For example, diesel fuel cost 18% more in the Northern Peninsula, ranging up to 40% more in coastal Labrador, compared to larger centres in the Avalon Peninsula. Price differences for stove oil were less in some areas but amounted to as much as 37% higher in some coastal Labrador communities.

Although not documented, there are grounds for belief that most other commodity prices would be similarly affected by transportation and storage costs, low volume and consequently high overheads.

Based on inquiry, it appears that no subsidy is applied to reduce the price of any of these commodities in isolated areas. Yet for residents of such areas the ability to pay for electricity is the difference between income and the cost of everything else which must be purchased.

Why subsidize electricity and not heating oil? Why pick on one item? If it is accepted that humanitarian, social, jurisdictional, economic or any other grounds justify the maintenance of populations in remote locations, and some such reasons do surely exist, then a general subsidy would appear to be more appropriate.

These considerations suggest that the best solution to the subsidy problem may well be to pay residents a stipend from the consolidated revenue fund for living in such areas and to charge full cost for electricity, like all other commodities and services.

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[2] Cost of Fuel and Utilities, Newfoundland & Labrador, 1991; prepared by Department of Mines & Energy and Newfoundland Statistics Agency Executive Council.

Consumers would "see" costs in true proportion and would then be able to make intelligent purchasing decisions. Conflict between the dictates of economic theory and social necessity would vanish.

The amount of the payment could still be determined as the difference between cost of electric service to isolated areas and the revenue which would accrue therefrom at subsidized rates. The essential feature would be the decoupling of subsidy and electricity consumption.

Such an approach is not without regulatory precedent. It is one of the four major methods set out in the 1992 edition of the NARUC Cost Allocation Manual for the reconciliation of marginal cost rates with the utility revenue requirement.[3] Subject to some modifications suggested by marginal cost considerations and outlined in my supplementary testimony, I recommend this approach for consideration by the Board.

Q. Would you advocate the same approach in the case of non-residential loads?

A. If there is a need and justification for subsidization, then in my opinion the same approach should be used.

Q. What about rural customers in the Island Interconnected System?

A. The same treatment would be appropriate, with the exception that the size of the payment, or stipend, would reflect the higher level of cost recovery and would be proportionately smaller.

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[3]Electric Utility Cost Allocation Manual, 1992; National Association of Regulatory Utility Commissioners; p. 149 and p. 162.

Q. If this approach were deemed inappropriate, what other options do you suggest?

A. Variations of the suggested method are possible. If responsibility for the subsidy were not removed from the shoulders of interconnected customers, Hydro could still set isolated area rates at cost and provide relief in the form of a credit or flat discount.

In either case, a proper price signal would be received by isolated customers. However, in the second case, with responsibility for payment remaining with interconnected customers, these customers would receive a false signal.

Q. The third topic you mentioned is the limitation of electric power and energy used in isolated rural areas. What are your views?

A. This is the final item in the terms of reference for the inquiry as approved by the Lieutenant-Governor in Council.

The proper objective in this context is to minimize the amount of the necessary subsidy. Whether reducing consumption will have this effect may seem self-evident but it is not necessarily true.

It is in my opinion important that this phase of the inquiry be based on a quantitative understanding of the relationship between consumption and revenue shortfall. Otherwise, the remedies proposed may be ineffective or completely counter-productive.

Q. How can the effect of changes in use be analyzed?

A. On the conceptual level, costs go up as loads increase. For an increase in output which does not exceed system capacity, there is an increase in fuel costs and perhaps to a minor extent an increase in the variable portion of maintenance costs. No new plant has to be built to supply the increased load, so fixed costs remain unchanged. The incremental costs under these circumstances are conveniently measured as the ratio of the total increase to the total change in output. This ratio is termed the short-run incremental cost.

If the increment is very small (one KWh in practice) the cost ratio is defined as the short-run marginal cost. Short-run marginal cost varies with the state of the system, so marginal and incremental costs are not necessarily the same. However, the difference is usually small and the terms are often used interchangeably. In isolated systems with diesel generation and three or more prime movers, marginal and incremental cost would be almost synonymous.

If the load increment is large enough to exceed existing capacity, or to affect reliability adversely, then fixed costs as well as variable costs can be expected to change. The incremental and marginal costs, calculated as described above, are in this case termed long-run costs.

The effect of changes in customer usage can be calculated for the isolated systems by comparison of the change in incremental cost with the change in rate revenue. For example, assume the short-run marginal cost is 9 cents/KWh and the rate at which the last KWh is purchased is 12 cents/KWh. Then decreasing consumption by one KWh would decrease Hydro's costs by 9 cents and its revenue by 12 cents, increasing the revenue deficiency and the necessary subsidy by 3 cents in the short term.

Long-run incremental cost is normally stated in dollars per kilowatt, but can be converted to a cents per KWh equivalent. Assume in the foregoing example that long-run marginal cost is 14 cents/KWh. Then in the long term, the reduction in use would yield a 2-cent reduction of subsidy rather than a 3-cent increase.

This example makes it obvious that the effects of reduced consumption can be expected to differ with time. Short-run results would continue until system capacity is fully utilized. So the present amount of surplus capacity in the isolated systems is a factor.

Marginal costs differ from one isolated system to another. If all the systems are grouped, which may be necessary from the standpoint of practicality and rate uniformity, an optimal strategy for the whole group would be considerably less beneficial than an optimal strategy for each isolated system individually.

The rate at which marginal energy is purchased varies from customer to customer. Thus a precise system-by-system calculation would require billing frequency data segregated by system.

While a precise analysis is certainly possible, it would require a major data-gathering and analytical effort. It appears than an overall view represents the limit of practicality at this time.

Q. Have you made any estimates of that nature?

A. Not as yet. Some helpful data being prepared in response to demands for particulars was not available at the time of preparation of this evidence.

Q. Assuming that decreasing consumption in the isolated systems would in fact reduce the subsidy, what price or non-price measures could Hydro employ to limit demand and energy use in isolated rural areas?

A. The most effective price measure would be to charge cost-based rates. This would be feasible if subsidy and rates were decoupled as suggested above. It would be difficult to achieve any significant modification of usage by tinkering with heavily-subsidized rates.

Non-price measures comprise two categories, demand side management (DSM) and arbitrary limitations.

Q. Would DSM be useful?

A. DSM is a flexible and equitable tool. It stands in great favour with regulators, who may have been oversold on its potential.

Some months ago, I reviewed extensive data compiled by EPRI and found that savings by US utilities up to 1990 had amounted to 1.3% of energy use and 3% of summer peak demand. DSM expenditures had been in excess of $25 billions. In simple terms, the purchase of gas turbines of equivalent capacity and the associated energy would have cost about the same as the DSM programs. Projected savings by the end of the century are

3% for energy and 6.7% for peak demand. It appears that in fact, results have been quite modest.

The cost of implementing DSM programs, particularly the incentives offered, depends greatly on the cost of electricity to the customer. So does the penetration achieved. It is easier, and cheaper, to convince customers of the benefits of efficiency if the customer sees the possibility of significant savings.

For many utilities with access to cheap hydro, coal or gas resources, electricity rates remain modest, and this is probably the reason DSM results have been relatively unimpressive.

One could hope and rationally expect that much greater penetration could be achieved in the isolated areas. On the other hand, customer dispersion and remoteness would make it harder to design and carry out effective programs.

On balance, I consider the isolated areas an attractive target for DSM efforts.

Q. Do you have any suggestions about the approach Hydro should take to DSM?

A. Yes, there are two.

The term DSM is usually applied to measures intended to reduce consumption through enhancing the efficiency of end use appliances, equipment, and systems. By contrast, many utilities use it for building desirable loads, shedding undesirable loads, reshaping load curves and other similar measures offering cost reduction, improved reliability or profit.

The first suggestion is that Hydro should use the latter or broader definition of DSM. From the response to GCB-2, it appears that load factors in the isolated system now range from about 59% at Nain to a low of 19% at Norman Bay, with an average of about 38%. This indicates unusually low utilization of the investment in generating plant. I do not for one moment suggest this is the result of poor planning. The situation is no doubt due to small size and number of prime movers and flows from the application of proper system planning procedures. Under the circumstances, DSM programs aimed at reshaping the load curve might well have some cost-saving potential.

Secondly, while the well-known California tests are useful for sifting DSM possibilities, I am firmly convinced that they do not provide a satisfactory criterion for the size and content of the overall DSM effort. In my opinion, DSM should be part of least-cost planning. The overall DSM package should be such that it minimizes the present worth of subsidy required through the planning period. The suggested criterion is strictly in line with Hydro's objective to minimize the degree of cross-subsidization required. The California tests are not. They can be, and have been, applied in such a way as to increase the utility's cost of service.

Q. Please outline your views on service limitation.

A. Service limitation may take a number of forms. Manitoba Hydro limits service entrance capacity, as already noted. another form of limitation is a ban on certain end uses, such as electric heat.

Such limitations are effective in reducing load, or preventing load growth. They have the disadvantage of being arbitrary.

Customers are deprived of choice. In this respect, the option offered by Manitoba Hydro (accept the limitation and subsidy or pay full cost) appears preferable. Hydro cites disadvantages of scale as one of the underlying reasons for high cost in isolated areas. Service limitations would tend to maximize this particular disadvantage, although there might be compensating benefits to the system.

Between the alternatives, I tend to favour cost-based rates plus well designed, well timed and well executed DSM programs as the best approach from all points of view.

Q. What are your comments on rate structure for rural customers?

A. The task set for the inquiry under the terms of reference is to investigate (and presumably identify) "an appropriate rate structure, with reasons for preferring it to the other identified options".

This might be construed to require the recommendation of actual rates for application in the isolated areas. For two reasons it appears that what might reasonably be expected to result from the inquiry is a general specification of the rate types and forms deemed to be most appropriate.

The design of actual rates requires access to large quantities of billing and other data, suitable computational facilities, painstaking work and extensive testing of results. It is an activity usually best left to the utility.

Moreover, changes of rate structure usually result in changes of impact as between customer and customer. To preserve some degree of stability and avoid rate shock, it is usually found necessary to make the changes in small steps over a period of time. For any really significant changes, several sets of rates over several years would probably be required.

Accordingly, my comments will relate only to rate principles, class structure, rate types and forms.

Q. What principles should apply?

A. The desirable attributes set out by Bonbright[4] have for many years been the regulatory norm, on this continent at least. The major requirements are that rates be accurate in raising the revenue requirement, conducive to efficient use of electricity and equitable as between both customer classes and individuals within each class. The attributes are set out verbatim in Appendix 1 of this testimony.

There is in my view nothing to be gained and much to be lost by departing from these principles in the case of isolated area rates. The high cost of service in these areas makes both equitable sharing of the load and efficient use even more important than is usually the case.

Q. How can these attributes best be realized?

A. Mainly by ensuring that rates reflect responsibility for cost causation.

Unfortunately, this answer, although simple and correct, is open to two interpretations, depending on how "cost" is defined. Most economists might define it as marginal cost.

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[4]Bonbright, Principles of Public Utility Rates, 1961; Bonbright et al., 1988.

From the standpoint of the utility, cost is the embedded cost of service.

If the marginal cost definition is adopted, then marginal cost rates would be applied. For a system optimally designed for the characteristics of the load it supplies, such rates would in theory meet the revenue requirement and conduce to economic efficiency through an appropriate allocation of productive resources.

Real-life utility systems are never optimal for a number of reasons and the application of marginal cost rates does not in general yield the revenue requirement. Also, the conditions under which marginal cost rates would maximize the social welfare are not realized in practice.

Marginal cost rates are often used when load growth would necessitate large additional investment in plant. Under these circumstances, long-run marginal cost signals to customers the consequences of continued growth.

In the isolated systems, generation expansion entails adding a few small diesel units every few years and there is no likelihood of a sudden large increase in the cost of service. A different and somewhat unusual circumstance, which renders long-run marginal cost relevant in the Isolated Systems, will be discussed in my supplementary testimony.

Short-run marginal cost tracks fluctuations from hour to hour. Therefore, unless time-of-use rates were to be used, with consequent large expenditure for metering equipment, short-run marginal cost would be completely irrelevant. Variable cost is more applicable to the Isolated Systems.

Marginal cost might well be used as a floor level for all rates. In that case, one could be confident that the deficit (in constant dollars) would not increase with load growth.

Q. How should rate classes be structured?

A. In order to avoid the sort of cross-subsidization discussed in the first part of this testimony, each rate class should be as nearly as possible homogeneous in terms of unit costs of service. This means that the cost-causative characteristics of electric use should be similar and that the class should be served from the same source of supply.

These requirements result in the segregation of domestic customers in one class and tend to encourage dividing the remainder of customers according to use characteristics and voltage level at which service is provided. The latter is usually determined by the size of load, so large customers are separated from small customers.

Basing class structure on end use (that is, having separate classes for the tinker, tailor and candlestick maker) is now frowned upon, but separation based on end use is correct and logical if there is a real difference in the relevant characteristics of electric use.

For example, the operator of an electric arc furnace taking large power for a short time and a retail establishment with a load likely to be on the system constantly through business hours would not put the same portion of their demands on the system peak and would not bear the same cost responsibility per kilowatt of metered demand. It would be hard to serve them equitably under the same rate.

These considerations often lead to segregation into general service and industrial categories, which may be further segregated by voltage level into secondary, primary and transmission customers.

Often rate "riders" are used to modify a rate in certain cases and to keep the number of classes from expanding beyond reason. For example, industrial customers at various voltage levels may form one class under a rate which has a rider to adjust for the difference in the cost of line losses. In such a case the class is one class for cost of service purposes and the operation of the rider ensures an equitable division of allocated cost between the sub-groups.

Hydro's isolated area cost of service study shows eight classes: one domestic, one school and church, one special, four general service and one street lighting. Apparently Hydro offers only one general service rate (GS Diesel). The other rates in the COS study are to track discounted rates required by order-in-council for a few customers.

The rates established by order-in-council now constitute largesse distributed by the government at the cost of electric customers generally; a somewhat disturbing situation which may well have arisen by inadvertence when the government decided to withdraw its subsidy.

The Board should ask for a government review of the orders in council, and should recommend that if the discounts are still considered appropriate they should be effected by government subsidy with Hydro's standard rates being charged to all customers.

Q. Isn't there some possibility that some customers will not fit well in any given class structure of reasonable simplicity?

A. Yes, there is.

Most utilities have a real concern for their customers, and when this happens, the utility usually will, and should, try to find some method of eliminating the problem.

This can sometimes be accomplished by means of a rate rider, or sometimes may justify some modification of class structure.

If the customer's costs are inordinately high due to unusual circumstances, the utility may be able to get the customer to alter its use characteristics in a way which benefits the utility and justifies a corresponding reduction of rate.

The constraints are that such adjustments should not adversely affect other customers, and that the same treatment should be available to all customers in substantially similar circumstances. That is, the solution must be non-discriminatory.

Q. Is the same type of rate suitable for all classes?

A. Not in general.

The primary question is whether rates are to be based on energy use only or on both energy use and customer peak demand.

Demand metering is considerably more expensive than energy metering, in terms of both first cost and maintenance cost. The latter is inflated, unreasonably in my view, by the requirements of the Electricity and Gas Inspection Branch. For the domestic class, which normally constitutes an overwhelming proportion of total customers, demand metering would be very expensive and, since the demands tend to fall in a narrow bracket, demand metering would add little if anything to the accuracy of cost recovery.

For these reasons, it is normal to apply energy-only rates to the domestic class.

Much the same arguments apply in the case of small commercial loads and in some cases small industrial loads as well.

However, for large loads, demand metering is the norm.

Insofar as the isolated systems are concerned, energy-only metering is certainly most appropriate for the domestic class and General Service customers with small demands. However, it is noted that a few GS customers account for a significant portion of demand in the systems serving them (NP-4). For these customers and perhaps some other of the larger customers, a demand-based rate appears likely to be more suitable.

Usually in the case of energy-only rates, and less frequently where a demand charge is applied, there is also a flat charge per month or billing period to recover distribution customer costs. Hydro includes a customer charge in both its domestic and GS rates.

Q. What are your views on the form of Hydro's isolated area rates?

A. The main options in energy-only rates are blocked or flat rates and if blocked, whether the prices ascend from block to block (inverted block rates) or descend (declining block rates).

The main question in the design of cost-based rates is which of these rate forms best correlates with cost over the whole range of use. The answer depends on the relative coincident loads of small, medium and large domestic users. It emerges from load research.

Hydro's domestic rate is of the inverted block type: 700 KWh at 6.541 cents, 300 KWh at 9.606 cents, and all additional at 13.022 cents.

Inverted block rates flow from the "lifeline" idea. The customer gets what he ought to be able to get along with at minimum cost. If he uses more, it signifies waste or carelessness, which receives the treatment it deserves.

The implicit assumption behind this approach is that all customers are alike: cast like little tin soldiers from the planners' mold. In fact they are not, nor do variations of use necessarily arise from economy or waste. Ontario Hydro research some years ago determined that domestic usage correlated most strongly with the number of persons in the household. In the years since, electric heat has moved into first place in many utilities and number of persons comes second.

Lifeline rates are seldom cost-based, and when they are not, involve significant subsidization of small users by large users.

In the isolated systems, there must be at least a few where oil supplies are not dependable and wood supplies are inadequate. Something like this would be necessary to account for the existence of electric heating loads, even with the high run-off rate. Is it equitable to penalize electric heat if there is no alternative? Is it equitable to force large householders to subsidize small householders?

The GS Diesel rate is also an energy rate of the inverted block type. In this case, and in the absence of demand metering and demand-blocked rates, the inevitable consequence is that large customers subsidize small. (Unless, of course, the large customers get discounted rates by order-in-council).

The existing rates obviously owe much to historical circumstance and the foregoing criticisms are not directed at Hydro. The target is the status quo.

In my opinion, the present domestic rate should be replaced by a cost-based rate. The GS rate should be replaced by a cost-based energy rate for most users, and a demand-blocked rate for the largest users.

Q. Does that conclude your testimony?

A. Yes, at this time.

SUPPLEMENTARY TESTIMONY

OF G. C. BAKER

Q. What is the purpose of your supplementary testimony?

A. The main purpose is to present estimates of the effects on Hydro's revenue, cost and deficit of changes in Isolated System demand and energy requirements. There is some difference between short-run and long-run effects, and estimates of both have been made.

Q. How would the deficit Hydro incurs in operating the Isolated Systems be affected by changes in energy use?

A. As a basis for calculating these effects, a very simple equation is available: the change in deficit equals the change in cost less the change in revenue.

The per-unit change in cost due to change in energy use is calculated in Exhibit 2, page 1, for individual systems and for the Isolated Systems as a group. The figure is 8.38¢ per KWh for all Isolated Systems combined or 9.25¢ per KWh, excluding Roddickton/St. Anthony. These costs are not short-run marginal costs in the strict sense of the word. They represent short-run marginal cost averaged over a full year. However, to ensure that they do not become confused with fully-allocated energy costs they are referred to as marginal costs in this testimony.

If energy use were to decrease by say 1% in every isolated system, the decrease in Hydro's cost would be 919,750 KWh multiplied by marginal cost per KWh (8.38¢), resulting in a total decrease of $77,075.

The exhibit shows that short-run marginal cost varies considerably from one system to another, ranging from a low of less than 7¢ per KWh at Ramea to 28¢ per KWh at Norman Bay. Obviously, if the reduction in energy use does not occur proportionately in all systems, it would be necessary to make a detailed calculation on a system-by-system basis.

The data necessary to calculate changes in revenue is shown in Exhibit 2, pages 2 and 3. For small changes as assumed in this example, a close estimate can be made by considering the proportion of customer bills falling in each block. The loss of revenue per KWh for this case is calculated in Exhibit 2, page 4.

Assuming the 1% decrease to be made entirely by Domestic customers, the revenue loss would be 919,750 KWh multiplied by $.086577, or $79,629 in total. The net effect of the 1% decrease in sales would be to increase Hydro's deficit by $2,554.

In cases involving large reductions, or uneven distribution thereof, a different method of estimating revenue loss, based on separate calculation for each bill size interval, would be required.

It is emphasized that the results are highly dependent on the distribution of the reduction (or increase) between both isolated systems and customer classes. General service customers have higher energy rates than Domestic customers and purchase a larger proportion of their energy at tail block rates.

Q. Your example shows an increase in the deficit. Would that hold true for any reduction in energy use?

A. Results would be somewhat more favourable if the reductions in use could be made selectively in the Isolated Systems with higher marginal cost. Exhibit 2, page 4, item 3, shows the marginal cost for the 23 highest cost systems, in which total energy use is 20,991 MWh per year.

Two further examples may help to outline the potential for deficit reduction. First, assuming a 20% reduction in sales, randomly spread over all Domestic customers excluding those in Roddickton/St. Anthony, the result would be a deficit increase of about $24,000.

Secondly, assuming the same conditions, except that the reductions are secured from the 23 highest cost systems, the result would be a deficit reduction of about $170,000.

In my opinion, the conditions specified in the second example go well beyond the limits of rational expectation. It therefore appears that:

1. While some slight potential for deficit reduction through reduced energy use may exist under Hydro's present rates, it is insignificant in comparison to the size of the deficit; and

2. If rate increases from time to time exceeded contemporary increases in fuel costs, any possible potential for deficit reduction by this means would cease to exist.

Q. What is the situation regarding long-run costs?

A. Based on data supplied by Hydro, I have made an estimate of long-run marginal cost of generation in the Isolated Systems. Because rates in these systems are based on energy only, the estimate has been expressed on a per-KWh base. For the Isolated systems overall, the figure is 1.45 cents per KWh. For the Isolated Systems excluding Roddickton/St. Anthony, it is 2.12 cents per KWh. The assumptions and methods used in estimating are outlined in Appendix 2. Calculations and results are shown in Exhibit 3.

The figures given combine both the marginal cost of capacity and a correction for the long-run marginal cost of energy, which is below short-run cost because some of the future units will be larger and more efficient than existing units. The overall marginal cost of capacity is 1.57 cents before netting off the energy savings.

Q. What is the significance of these figures for present and future costs in the Isolated Systems?

A. They have absolutely no significance for present costs but considerable significance for future costs.

In 1992, the test year for purposes of this inquiry, all the fixed costs which must be met by rate revenue or subsidy are embedded costs. The 1.45 cents is the present worth, in 1992 dollars, of future fixed costs which will be incurred by an extra KWh of energy use in 1992 at average system load factor and is assumed to be used each year thereafter in perpetuity.

Q. Then will system costs be raised in future if loads increase?

A. Yes. Total future costs will increase, because the cost of owning and operating plant to meet the increased load will be added to the costs associated with meeting existing loads.

However, sales and revenue would also increase due to the new load, and one cannot simply assume that unit costs would increase. That is so for most utilities today, but it is not necessarily so; and it is definitely not so in the case of the Isolated Systems.

Using the same assumptions as for long run marginal cost, the cost of replacing present plant is calculated in Exhibit 4. The answer, which may be regarded as the long-run marginal cost of continuing to use the present energy requirement, is 2.59 cents per KWh as calculated for 1992. However, the present population of generating units is not evenly spaced in terms of in-service date and the stated cost, as computed for 1992, may be slightly distorted on this account. Calculations made at 5-year intervals up to 2012 A.D. have a geometric mean of 2.70 cents per KWh, which is probably a more representative figure.

It follows that additional load would reduce the unit cost of service in future.

Q. How accurate are your estimates of long-run marginal cost?

A. They are based on a large number of assumptions, and certainly contain error. However, the assumptions used in the calculation of marginal cost and replacement cost are uniform, so that substantially the same error will be present in both estimates. The conclusion that growth would reduce future unit costs therefore appears to be reliable.

Q. Why would long-run marginal cost be lower than average embedded cost for the Isolated Systems and higher for most other utilities?

A. Two factors go a long way toward explaining this difference.

In GCB-1, Hydro attributed the high cost of the Isolated Systems in part to disadvantages of scale. The comments under (b), first two sentences, and (c), last sentence, are particularly relevant. Growth tends in some small degree to lessen these disadvantages and therefore to lower costs. Most other utilities do not suffer from disadvantages of scale.

The second factor relates to the type of generation contemplated for future installation. Most utilities plan on meeting load increases with at least a proportion of base-load thermal generation. Environmental requirements have raised the cost of base-load generation proportionately more than the cost of diesel generator units, so long-run marginal cost tends to be higher for such utilities.

Q. As a result of your examination of marginal costs, do you consider that growth offers a better path to deficit reduction than shrinkage?

A. Within limits, yes. One must not overlook the fact that higher sales would require a higher outlay by customers. The extent to which customers in Hydro's Isolated Systems would be able to increase their purchases and the extent to which they would find such increases beneficial is probably very limited.

From an ethical point of view, Hydro should encourage efficiency in the end use of electricity but in view of the fact that LRMC is below embedded cost, I do not consider it appropriate to pursue demand management initiatives simply for the purpose of decreasing sales.

The best strategy in my opinion would be to charge cost-based rates and leave it to customers to decide how much electricity they should buy.

Q. Wouldn't cost-based rates inhibit demand?

A. Yes, to an extent depending on both rate level and rate design. The present inverted block rates are inhibitory and increasing their level would certainly discourage consumption, particularly in the second and third blocks where the rates are already at or above marginal cost and more sales would improve Hydro's cost recovery.

The fact is that most of the costs of service are fixed. To a greater extent than at present, fixed costs could (and should) be recovered through fixed charges, leaving energy rates somewhat above marginal cost and with a declining block structure.

Q. Have you examined the effect of such rates?

A. Yes. The rate used for this purpose was based on the assumption that the subsidy remains at the present level and is used by Hydro to reduce the fixed costs recoverable from customers. The remaining classified costs plus long-run marginal cost were then used to determine the rate elements.

Derivation of the rate, and its yield in comparison to present rates, are outlined in Exhibit 5, page 1. The comparison is made for Domestic and General Service Diesel classes only. Rates, usage and rate yield of the other classes are assumed to remain unchanged.

In essence, the test rate collects all customer costs through the service charge, collects marginal energy cost plus distribution demand cost in the first energy block and both long- and short-run costs in the second block. The Domestic third block rate is the same as the second block rate. In effect, there are only two blocks.

Changes in use expected as a result of changed rate levels are estimated using an assumed elasticity of -0.1, which may be high for first-block use, but is in the general range of investigative results elsewhere. The details are shown at Exhibit 5, page 2.

Q. What are the end results?

A. Revenue is projected to increase by about 6.8% as a result of the generally higher rates and sales are also projected to increase marginally; from 78.2 GWh to 78.6 GWh for the two classes. Domestic sales would drop and General Service sales would increase. The deficit would decrease by about $720,000.

In this case, the effect of adopting a declining block structure is seen to outweigh the inhibiting effect of a rate increase.

Q. Do you recommend adoption of such a rate?

A. The idea illustrated by this example is that a declining block rate structure is appropriate when LRMC is below embedded cost. This is generally recognized to be the case and the idea can in my opinion be applied with advantage to the Isolated Systems.

However, this particular rate was constructed for purposes of illustration and is almost certainly sub-optimal in a number of respects. For example, allocation of classified costs to rate blocks is simplistic and block sizes are not necessarily appropriate. It is not intended as a model rate.

Q. Would rates of this type offset the effect of raising rates to recover the full cost of service?

A. No. To recover full cost, present rates would have to be raised by a factor of 3 or more, based on present sales. While declining block rates would ensure best results possible under any given level of cost recovery, increases of this magnitude would certainly result in shrinkage of the sales base. Such shrinkage has implications for rate policy.

Q. What are the rate implications?

A. My testimony has emphasized the desirability of giving correct price signals to customers. We now see from an examination of long-run costs that the costs of replacing or expanding existing capacity are in fact comparatively modest; that a restrictive policy regarding sales is not in the best interests of any stakeholder; and that massive rate increases would tend to have exactly that effect. Under the circumstances, deciding what constitutes an appropriate price signal is not a trivial problem.

Q. What solution do you suggest?

A. Isolated System fixed costs comprise roughly $26.6 millions or 77% of the total cost of service. Of these, $19.3 millions are related to production demand. This is a huge cost for systems with a total demand of less than 26 MW.

The high cost is mainly due to two factors: (1) the need to staff more than 30 powerhouses, and (2) the need to maintain an 80% capacity reserve. Both are direct consequences of the large number and small size of individual systems.

If these costs were to be recovered in energy rates, the price signal would be incorrect, or at least misconstrued. It would be interpreted as a message to use less energy, an action which would not reduce fixed costs by one iota.

It is therefore reasonable to conclude that generation fixed costs arising solely from the disadvantaged nature of these systems should be collected in the form of fixed charges. They should be offset by subsidy to the extent that subsidy is available. The balance of cost, if assigned to rates, would in my opinion provide a correct price signal.

It would be more practical, if this procedure were to be adopted, to pay the subsidy to the utility rather than to customers as suggested in my original evidence.

At the required filing time for that evidence, it had not been possible to examine system long-run costs and I had envisaged that they would be more or less commensurate with embedded cost levels. It now appears that they are much lower.

Because of this, references to cost-based rates in the original testimony should be interpreted as rates reflecting causal responsibility for embedded costs exclusive of those fixed costs attributable to disadvantages of scale, and having a tail block rate at or moderately above long-run marginal cost.

Q. Do you wish to comment on any other aspects?

A. Yes. The wide variation of short-run marginal cost from system to system raises the question whether it is fair to apply uniform rates to all the Isolated Systems.

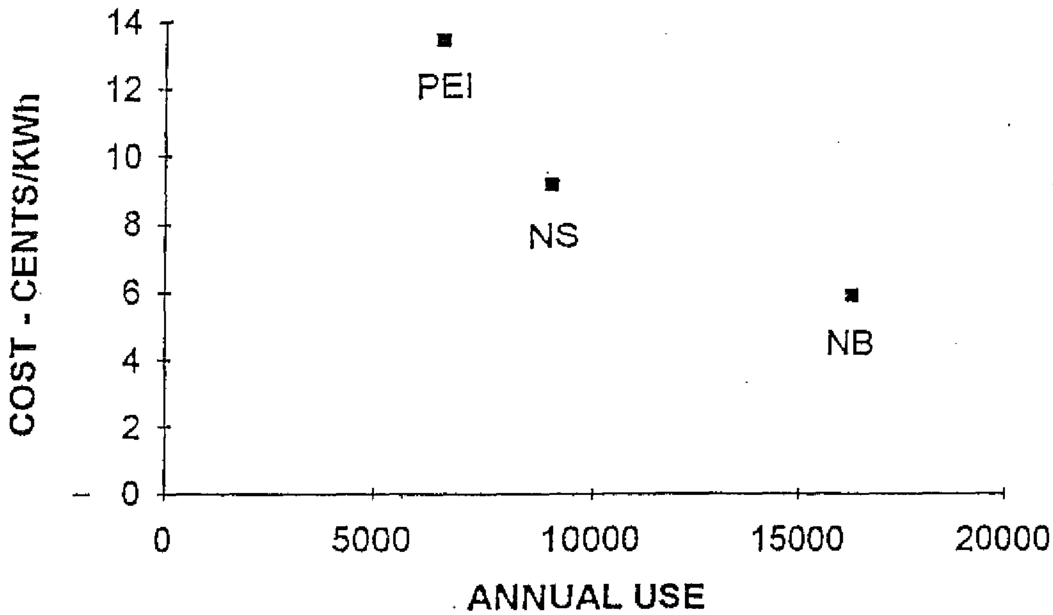
In his testimony during the recent generic hearing, Dr. Sarikas estimated that cost of service variations were within about 10% for all systems. That could well be correct, because the fixed costs relating to generation, transmission, distribution and customer service constitute more than three-quarters of the total cost of service and they probably do not vary much from place to place.

However, there is undoubtedly a large variation in energy costs, and the question I wish to raise is whether this would justify two (or perhaps more) rate zones differentiated by system size.

To do this would raise accounting, cost of service, and perhaps other problems, but would result in rates more reflective of individual system costs. The possibility is mentioned without recommendation in the hope of promoting further discussion.

Q. Does that conclude your testimony?
A. Yes, at this time.

AVERAGE ANNUAL RESIDENTIAL USE VS COST
MARITIME PROVINCES ELECTRIC UTILITIES



NEWFOUNDLAND AND LABRADOR HYDRO
ISOLATED SYSTEMS
Short Run Marginal Cost

		[1] FUEL INPUT	[2] FUEL COST		[3] FUEL COST	[4] SALES 1992	[5] SRMC
	Source or calculation	IC46	IC46		[1]*[2]	NP4	[3]/[4]
	Units	Kl	$/l		$(000's)	MWh	$/KWh
	SYSTEM						
[1]	Black Tickle	406.13	0.244		99.10	1,100	0.0901
[2]	Cartwright	925.14	0.283		261.82	2,766	0.0947
[3]	Charlottetown	366.45	0.254	(a)	164.51	943	0.1745
[4]	Davis Inlet	537.41	0.247		132.74	1,300	0.1021
[5]	Francois	291.43	0.404		117.74	699	0.1684
[6]	Grey river	213.87	0.289		61.81	585	0.1057
[7]	Harbour Deep	315.86	0.238		75.18	760	0.0989
[8]	Hopedale	785.33	0.255		200.26	2,055	0.0975
[9]	La Poile	173.55	0.289		50.16	459	0.1093
[10]	Little Bay Islands	493.94	0.277		136.82	1,375	0.0995
[11]	l'Anse Au Loup	3065.00	0.229		701.89	8,418	0.0834
[12]	Makkovik	979.00	0.242		236.92	2,465	0.0961
[13]	Marys Harbour Diesel	723.55	0.243		175.82	2,370	0.0742
[14]	McCallum	200.94	0.289		58.07	575	0.1010
[15]	Mud Lake	96.00	0.299		28.70	171	0.1679
[16]	Nain	1523.23	0.245		373.19	4,267	0.0875
[17]	Norman Bay	80.91	0.261		21.12	74	0.2854
[18]	Paradise River	116.36	0.259		30.14	207	0.1456
[19]	Petite Forte	164.40	0.289		47.51	365	0.1302
[20]	Petites	128.15	0.289		37.03	296	0.1251
[21]	Port Hope Simpson	523.79	0.303		158.71	1,351	0.1175
[22]	Postville	392.50	0.250		98.13	1,001	0.0980
[23]	Ramea	2476.29	0.218		539.83	7,952	0.0679
[24]	Rencontre East	275.00	0.289		79.48	703	0.1131
[25]	Rigolet	435.00	0.283		123.11	1,110	0.1109
[26]	South East Bight	139.63	0.289		40.35	312	0.1293
[27]	St. Brendans	359.69	0.238		85.61	992	0.0863
[28]	St Lewis	467.10	0.245		114.44	1,293	0.0885
[29]	Westport	477.33	0.220		105.01	1,252	0.0839
[30]	Williams Harbour	161.60	0.249		40.24	319	0.1261
[31]	Subtotals				4,395	47,535	0.0925
[32]	Rod./St. A. (diesel)	6447.57	0.210	(a)	1,351		
[33]	Rod./St. A. (wood)	59.73	31.200	(a)	1,963		
[34]	Rod./St. A. (total)				3,314	44,440	0.0746
[35]	TOTALS				7,709	91,975	0.0838

Note (a): Where data discrepancies occur the total fuel costs shown in column [3] follow NP-1(a).

NEWFOUNDLAND AND LABRADOR HYDRO
BILLING FREQUENCY DATA
Isolated Domestic diesel customers (Rate 1.2)

Start of Interval	End of Interval	Number of Customer Bills	Killowatt-Hours in Interval	Percent of Customer Bills	Cumulative percent of customer bills		
					Block 1	Block 2	Rem use
0	0	2967	0	3.7038	3.7038		
0	50	3147	3788937	3.9022	7.6061		
51	100	1682	3683981	2.0857	9.6917		
101	150	1575	3602216	1.9530	11.6447		
151	200	1656	3522532	2.0534	13.6981		
201	250	1812	3436173	2.2469	15.9450		
251	300	1991	3341258	2.4688	18.4138		
301	350	2280	3235729	2.8272	21.2410		
351	400	2554	3114506	3.1669	24.4079		
401	450	3054	2973884	3.7869	28.1948		
451	500	3557	2809344	4.4106	32.6055		
501	550	3859	2624897	4.7851	37.3906		
551	600	4048	2426776	5.0195	42.4100		
601	650	4175	2221934	5.1769	47.5870		
651	700	4246	2010814	5.2650	52.8520		
701	750	4373	1792080	5.4225		5.4225	
751	800	4101	1582408	5.0852		10.5077	
801	850	3905	1379722	4.8421		15.3498	
851	900	3602	1193997	4.4664		19.8162	
901	950	3306	1021114	4.0994		23.9156	
951	1000	2880	864635	3.5712		27.4868	
1001	1050	2564	727911	3.1793			3.1793
1051	1100	2156	609176	2.6734			5.8527
1101	1150	1777	512264	2.2035			8.0562
1151	1200	1504	429664	1.8649			9.9211
1201	1250	1247	361053	1.5463			11.4674
1251	1300	1033	304535	1.2809			12.7483
1301	1350	848	257620	1.0515			13.7998
1351	1400	668	219989	0.8283			14.6281
1401	1450	569	188094	0.7056			15.3337
1451	1500	464	162681	0.5754			15.9090
1501	1550	337	142805	0.4179			16.3269
1551	1600	330	125646	0.4092			16.7361
1601	1650	243	111644	0.3013			17.0374
1651	1700	218	100295	0.2703			17.3077
1701	1750	178	90282	0.2207			17.5285
1751	1800	171	81738	0.2120			17.7405
1801	1850	127	74419	0.1575			17.8980
1851	1900	131	67734	0.1624			18.0604
1901	1950	106	61989	0.1314			18.1919
1951	2000	99	56878	0.1228			18.3146
2001	2500	517	395865	0.6411			18.9557
2501	3000	260	208897	0.3224			19.2781
3001	3500	130	118274	0.1612			19.4393
3501	4000	76	67816	0.0942			19.5335
4001	4500	34	42901	0.0422			19.5757
4501	5000	19	29081	0.0236			19.5992
5001	6000	16	40741	0.0198			19.6191
6001	7000	12	26391	0.0149			19.6340
7001	8000	6	19881	0.0074			19.6414
> 8000		16	458150	0.0198			19.6612
Total All Intervals		80646	56721371	100.0000	52.8520	27.4868	19.6612

NEWFOUNDLAND AND LABRADOR HYDRO
BILLING FREQUENCY DATA
General service diesel customers (Rate 2.5)

Start of Interval	End of Interval	Number of Customer Bills	Killowatt-Hours in Interval	Percent of Customer Bills	Cumulative percent of customer bills	
					Block 1	Rem use
0	0	1570	0	12.5070	12.5070	
0	50	1124	514149	8.9540	21.4610	
51	100	535	478943	4.2619	25.7229	
101	150	345	457420	2.7483	28.4713	
151	200	322	440767	2.5651	31.0364	
201	250	312	425845	2.4855	33.5219	
251	300	326	409241	2.5970	36.1189	
301	350	349	393003	2.7802	38.8991	
351	400	376	374291	2.9953	41.8944	
401	450	287	357725	2.2863	44.1807	
451	500	260	344014	2.0712	46.2519	
501	550	272	330861	2.1668	48.4187	
551	600	267	317288	2.1270	50.5457	
601	650	276	303958	2.1987	52.7444	
651	700	212	291435	1.6888	54.4332	
701	750	243	279654	1.9358		1.9358
751	800	185	269501	1.4738		3.4095
801	850	197	260091	1.5693		4.9789
851	900	186	250338	1.4817		6.4606
901	950	171	241393	1.3622		7.8228
951	1000	189	232675	1.5056		9.3284
1001	1050	153	223847	1.2188		10.5473
1051	1100	183	215365	1.4578		12.0051
1101	1150	144	207090	1.1471		13.1522
1151	1200	145	200347	1.1551		14.3073
1201	1250	120	193632	0.9559		15.2633
1251	1300	136	187000	1.0834		16.3467
1301	1350	125	180407	0.9958		17.3425
1351	1400	137	174028	1.0914		18.4338
1401	1450	101	168099	0.8046		19.2384
1451	1500	100	162976	0.7966		20.0351
1501	1550	91	157981	0.7249		20.7600
1551	1600	114	153230	0.9081		21.6681
1601	1650	95	148053	0.7568		22.4249
1651	1700	81	143199	0.6453		23.0702
1701	1750	54	139835	0.4302		23.5004
1751	1800	110	136168	0.8763		24.3766
1801	1850	63	131734	0.5019		24.8785
1851	1900	75	128081	0.5975		25.4760
1901	1950	70	124358	0.5576		26.0336
1951	2000	83	120911	0.6612		26.6948
2001	2500	563	1035152	4.4850		31.1798
2501	3000	312	825101	2.4855		33.6653
3001	3500	235	684120	1.8721		35.5373
3501	4000	185	582335	1.4738		37.0111
4001	4500	142	500374	1.1312		38.1423
4501	5000	83	447534	0.6612		38.8035
5001	6000	145	772809	1.1551		39.9586
6001	7000	115	645771	0.9161		40.8747
7001	8000	78	544765	0.6214		41.4961
>8000		511	5233856	4.0707		45.5668
Total All Intervals		12553	21540750	100.0000	54.4332	45.5668

NEWFOUNDLAND AND LABRADOR HYDRO
ISOLATED SYSTEMS

Comparison of Marginal Revenue and Cost

[1] Marginal Revenue: Domestic Diesel Customers

For a small reduction in use by all customers or by a random selection of all customers the average decrease per KWh at present rates would be:

			Block 1	Block 2	Rem use
Price per KWh; present rates		$	0.0654	0.0961	0.1302
Percent of bills in block			52.8520	27.4868	19.6612
Block reduction per KWh		$	0.0346	0.0264	0.0256
Total reduction: $/ KWh	**0.0866**				

[2] Marginal Revenue: General Service Diesel Customers

For a small reduction in use by all customers or by a random selection of all customers the average decrease per KWh at present rates would be:

			Block 1	Rem use
Price per KWh; present rates		$	0.0858	0.1954
Percent of bills in block			54.4332	45.5668
Block reduction per KWh		$	0.0467	0.0890
Total reduction: $/ KWh	**0.1357**			

[3] Marginal cost of diesel generation (fuel only)

Fuel cost for the isolated systems, ($000's)	$	7,709.5
Sales (MWh), per GCB 2.5		91,975
Short-run marginal cost, overall		**0.0838**
Short-run marginal cost, excluding Roddickton/ St. Anthony		**0.0925**
As above, for the 23 most expensive systems (20,991MWh)		**0.1096**

NEWFOUNDLAND AND LABRADOR HYDRO

ISOLATED AREA GENERATING PLANTS

Calculation of long-run marginal cost

	SYSTEM	[1] Largest present unit KW	[2] Date of next Unit	[3] Scale factor (optimum)	[4] Unit size (optimum) KW	[5] Cost, year of addition $000s	[6] Gross cost, (Note 1) $000s	[7] Deferral value $000s
[1]	Black Tickle	270	2016	0.50	135	293	411.2	27.3
[2]	Cartwright	405	2004	1.25	506	938	1314.6	87.2
[3]	Charlottetown	270	1998	N/A	300	250	350.5	23.3
[4]	Davis Inlet	225	1993	0.55	125	193	270.0	17.9
[5]	Francois	250	1998	0.20	50	87	122.6	8.1
[6]	Grey River	250	1997	0.30	75	130	182.7	12.1
[7]	Harbour Deep	250	2045	1.80	425	2,528	3544.1	235.2
[8]	Hopedale	270	1999	1.00	270	469	657.6	43.6
[9]	La Poile	250	2024	0.20	50	180	251.7	16.7
[10]	Little Bay Islands	450	N/A	N/A	0	0	0.0	0.0
[11]	l'Anse Au Loup	1000	1996	N/A	1100	1,101	1543.4	102.4
[12]	Makkovik	500	2008	1.00	500	986	1382.5	91.7
[13]	Marys Harbour D.	270	1998	1.35	365	601	842.5	55.9
[14]	McCallum	250	2015	0.64	160	439	615.2	40.8
[15]	Mud Lake	55	2010	2.35	130	306	429.5	28.5
[16]	Nain	350	1997	1.45	510	743	1041.3	69.1
[17]	Norman Bay	30	2022	3.33	100	327	458.5	30.4
[18]	Paradise River	55	N/A	N/A	0	0	0.0	0.0
[19]	Petite Forte	136	N/A	N/A	0	0	0.0	0.0
[20]	Petites	200	N/A	N/A	0	0	0.0	0.0
[21]	Port Hope Simpson	350	1994	N/A	450	851	1193.3	79.2
[22]	Postville	225	1995	N/A	300	250	350.5	23.3
[23]	Ramea	1000	2000	1.00	1000	1,419	1988.5	132.0
[24]	Rencontre East	300	2052	0.25	75	564	790.7	52.5
[25]	Rigolet	225	1995	1.35	305	472	661.2	43.9
[26]	South East Bight	136	2006	1.40	190	427	598.5	39.7
[27]	St. Brendans	300	2029	0.67	200	788	1104.5	73.3
[28]	St Lewis	225	2003	1.50	340	644	903.0	59.9
[29]	Westport	250	1996	0.64	160	265	370.8	24.6
[30]	Williams Harbour	125	2148	2.00	250	23,133	32429.1	2,152
[31]	Total							
[32]	Roddickton/ St. Anthony	2000	1994		2600	730	1023.4	67.9
[33]	Total							

Note 1: Gross cost is the capital cost multiplied by infinite series and fixed expense factors.

Factors used:

Infinite series factor	1.219
Fixed expense factor	1.15
Deferral value factor	0.066

NEWFOUNDLAND AND LABRADOR HYDRO
ISOLATED AREA GENERATING PLANTS
Calculation of long-run marginal cost

		[7] Deferral value	[8] Present Worth 1992	[9] Gross LRMC	[10] Sales at meter 1992	[11] Load at system 1992	[12] Gross LRMC
		$000s	$000s	$/KW	MWh	KW	$/KWh
	SYSTEM						
[1]	Black Tickle	27.3	2.77	25.7	1100	489	0.011
[2]	Cartwright	87.2	27.80	68.7	2766	737	0.018
[3]	Charlottetown	23.3	13.13	54.7	943	387	0.022
[4]	Davis Inlet	17.9	16.29	162.9	1300	325	0.041
[5]	Francois	8.1	4.59	114.8	699	269	0.044
[6]	Grey River	12.1	7.53	125.4	585	237	0.051
[7]	Harbour Deep	235.2	1.51	4.4	760	307	0.002
[8]	Hopedale	43.6	22.39	103.7	2055	604	0.030
[9]	La Poile	16.7	0.79	19.8	459	185	0.008
[10]	Little Bay Islands	0.0	0.00	0.0	1375	604	0.000
[11]	l'Anse Au Loup	102.4	69.96	79.5	8418	2623	0.025
[12]	Makkovik	91.7	19.97	49.9	2465	855	0.017
[13]	Marys Harbour D.	55.9	31.56	108.1	2370	676	0.031
[14]	McCallum	40.8	4.56	35.6	575	202	0.013
[15]	Mud Lake	28.5	5.13	49.3	171	74	0.021
[16]	Nain	69.1	42.91	105.2	4267	913	0.023
[17]	Norman Bay	30.4	1.74	21.8	74	51	0.015
[18]	Paradise River	0.0	0.00	0.0	207	85	0.000
[19]	Petite Forte	0.0	0.00	0.0	365	140	0.000
[20]	Petites	0.0	0.00	0.0	296	132	0.000
[21]	Port Hope Simpson	79.2	65.45	181.8	1351	472	0.064
[22]	Postville	23.3	17.47	72.8	1001	291	0.021
[23]	Ramea	132.0	61.56	77.0	7952	2509	0.024
[24]	Rencontre East	52.5	0.17	2.9	703	243	0.001
[25]	Rigolet	43.9	32.97	135.1	1110	126	0.015
[26]	South East Bight	39.7	10.46	68.8	312	143	0.032
[27]	St. Brendans	73.3	2.16	13.5	992	354	0.005
[28]	St Lewis	59.9	21.00	77.2	1293	330	0.020
[29]	Westport	24.6	16.81	131.3	1252	468	0.049
[30]	Williams Harbour	2,152	0.00	0.0	319	114	0.000
[31]	Total				47535		
[32]	Roddickton/ St. Anthony	67.9	56.13	27.0	44440	11998	0.007
[33]	Total				91975		

NEWFOUNDLAND AND LABRADOR HYDRO
ISOLATED AREA GENERATING PLANTS
Calculation of long-run marginal cost

	SYSTEM	[13] Gross LRMC $/KWh	[14] Energy savings PW (YOA) $000s	[15] Savings % of cap. cost	[16] System Net LRMC $/KWh	[17] Weight Sytem/ (rural total) pu	[18] Rural net LRMC $/KWh
[1]	Black Tickle	0.011	0.0	0.00	0.011	0.012	0.000136
[2]	Cartwright	0.018	153.9	16.41	0.015	0.03	0.000460
[3]	Charlottetown	0.022	30.5	12.21	0.02	0.01	0.000202
[4]	Davis Inlet	0.041	0.0	0.00	0.041	0.014	0.000576
[5]	Francois	0.044	0.0	0.00	0.044	0.008	0.000336
[6]	Grey River	0.051	0.0	0.00	0.051	0.006	0.000323
[7]	Harbour Deep	0.002	1841.0	72.82	5E-04	0.008	0.000004
[8]	Hopedale	0.030	0.0	0.00	0.03	0.022	0.000681
[9]	La Poile	0.008	0.0	0.00	0.008	0.005	0.000040
[10]	Little Bay Islands	0.000	0.0	0.00	0	0.015	0.000000
[11]	l'Anse Au Loup	0.025	25.8	2.35	0.024	0.092	0.002214
[12]	Makkovik	0.017	0.0	0.00	0.017	0.027	0.000464
[13]	Marys Harbour D.	0.031	147.9	24.62	0.023	0.026	0.000599
[14]	McCallum	0.013	0.0	0.00	0.013	0.006	0.000078
[15]	Mud Lake	0.021	235.2	76.77	0.005	0.002	0.000009
[16]	Nain	0.023	246.7	33.21	0.015	0.046	0.000697
[17]	Norman Bay	0.015	357.0	109.15	0	8E-04	0.000000
[18]	Paradise River	0.000	0.0	0.00	0	0.002	0.000000
[19]	Petite Forte	0.000	0.0	0.00	0	0.004	0.000000
[20]	Petites	0.000	0.0	0.00	0	0.003	0.000000
[21]	Port Hope Simpson	0.064	126.7	14.89	0.054	0.015	0.000794
[22]	Postville	0.021	85.4	34.16	0.014	0.011	0.000152
[23]	Ramea	0.024	0.0	0.00	0.024	0.086	0.002099
[24]	Rencontre East	0.001	0.0	0.00	1E-03	0.008	0.000008
[25]	Rigolet	0.015	149.2	31.65	0.01	0.012	0.000127
[26]	South East Bight	0.032	128.4	30.07	0.022	0.003	0.000075
[27]	St. Brendans	0.005	0.0	0.00	0.005	0.011	0.000052
[28]	St Lewis	0.020	271.9	42.20	0.011	0.014	0.000160
[29]	Westport	0.049	0.0	0.00	0.049	0.014	0.000668
[30]	Williams Harbour	0.000	10^8	100.00	0	0.003	0.000000
[31]	Subtotal						0.010953
[32]	Roddickton/ St. Anthony	0.007	0.0	0.00	0.007	0.483	0.003520

[33]	Effective LRMC - Isolated Systems overall	**0.0145**
[34]	Effective LRMC - As above less Roddickton/St. Anthony	**0.02119**

NEWFOUNDLAND AND LABRADOR HYDRO
DIESEL UNIT REPLACEMENT COSTS
Under current planning assumptions

Line	SYSTEM	[1] Unit size KW	[2] 1n service Year	[3] Years to Retire-ment n	[4] Replace-ment cost $000s	[5] Deferral value $000s	[6] present worth 1992 $000s
1	Black Tickle	225	1978	11	440.34	40.96	14.36
2		270	1978	11	521.81	48.54	17.01
3		270	1978	11	521.81	48.54	17.01
4	Cartwright	405	1987	20	957.10	89.04	13.23
5		405	1992	25	1,093.48	101.72	9.39
6		405	1978	11	753.05	70.05	24.55
7		270	1987	20	663.21	61.70	9.17
8	Charlottetown	125	1978	11	251.42	23.39	8.20
9		270	1975	8	481.73	44.81	20.91
10		225	1986	19	544.94	50.69	8.29
11	Davis Inlet	225	1985	18	530.62	49.36	8.88
12		220	1974	7	387.57	36.05	18.50
13		125	1975	8	232.10	21.59	10.07
14		125	1975	8	232.10	21.59	10.07
15	Francois	100	1980	13	213.57	19.87	5.76
16		250	1980	13	512.46	47.67	13.81
17		200	1971	4	327.07	30.43	20.78
18	Grey River	250	1989	22	651.33	60.59	7.44
19		136	1975	8	251.78	23.42	10.93
20		136	1975	8	251.78	23.42	10.93
21	Harbour Deep	136	1975	8	251.78	23.42	10.93
22		136	1979	12	280.09	26.06	8.30
23		136	1980	13	287.65	26.76	7.75
24		250	1974	7	436.76	40.63	20.85
25	Hopedale	180	1980	13	376.19	35.00	10.14
26		270	1975	8	481.73	44.81	20.91
27		270	1975	8	481.73	44.81	20.91
28		225	1974	7	395.83	36.82	18.90
29	La Poile	136	1986	19	337.52	31.40	5.13
30		250	1980	13	512.46	47.67	13.81
31		90	1980	13	192.73	17.93	5.19
32	Little Bay Islands	300	1980	13	606.37	56.41	16.34
33		450	1987	20	1,049.48	97.63	14.51
34		300	1980	13	606.37	56.41	16.34
35		300	1979	12	590.43	54.93	17.50
36	l'Anse Au Loup	720	1981	14	1,316.84	122.50	32.26
37		720	1976	9	1,152.60	107.22	45.47
38		1000	1984	17	1,802.84	167.71	33.18
39		540	1974	7	867.01	80.66	41.39
40		540	1974	7	867.01	80.66	41.39

41	Makkovik	500	1990	23	1,244.44	115.77	12.93
42		500	1990	23	1,244.44	115.77	12.93
43		400	1980	13	785.60	73.08	21.17
44		225	1978	11	440.34	40.96	14.36
45	Marys Harbour D.	165	1980	13	346.25	32.21	9.33
46		270	1974	7	469.06	43.64	22.39
47		225	1975	8	406.51	37.82	17.64
48		225	1975	8	406.51	37.82	17.64
49	McCallum	250	1989	22	651.33	60.59	7.44
50		136	1975	8	251.78	23.42	10.93
51		136	1975	8	251.78	23.42	10.93
52	Mud Lake	55	1975	8	104.05	9.68	4.52
53		45	1980	13	97.52	9.07	2.63
54		45	1982	15	102.86	9.57	2.29
55	Nain	270	1978	11	521.81	48.54	17.01
56		270	1978	11	521.81	48.54	17.01
57		350	1975	8	610.44	56.79	26.49
58		270	1974	7	469.06	43.64	22.39
59		270	1980	13	550.37	51.20	14.83
60	Norman Bay	30	1987	20	78.66	7.32	1.09
61		30	1987	20	78.66	7.32	1.09
62		30	1987	20	78.66	7.32	1.09
63	Paradise River	55	1971	4	93.54	8.70	5.94
64		35	1971	4	59.84	5.57	3.80
65		55	1971	4	93.54	8.70	5.94
66	Petite Forte	55	1971	4	93.54	8.70	5.94
67		136	1978	11	272.73	25.37	8.89
68		136	1980	13	287.65	26.76	7.75
69	Petites	200	1990	23	542.60	50.48	5.64
70		90	1974	7	164.26	15.28	7.84
71		90	1974	7	164.26	15.28	7.84
72	Port Hope Simpson	350	1971	4	548.73	51.05	34.87
73		225	1974	7	395.83	36.82	18.90
74		225	1980	13	464.44	43.21	12.51
75		125	1975	8	232.10	21.59	10.07
76	Postville	75	1976	9	144.95	13.48	5.72
77		75	1976	9	144.95	13.48	5.72
78		225	1978	11	440.34	40.96	14.36
79		155	1987	20	393.02	36.56	5.43
80	Ramea	1000	1971	4	1,275.09	118.62	81.02
81		442	1971	4	674.66	62.76	42.87
82		568	1977	10	979.44	91.11	35.13
83		1000	1980	13	1,620.60	150.76	43.67
84		426	1972	5	670.94	62.42	38.76
85		500	1970	3	730.41	67.95	51.05
86	Rencontre East	136	1980	13	287.65	26.76	7.75
87		300	1,975	8	530.75	49.37	23.03
88		250	1986	19	601.29	55.94	9.15

89	Rigolet	165	1974	7	295.10	27.45	14.09
90		225	1974	7	395.83	36.82	18.90
91		125	1980	13	265.18	24.67	7.15
92		90	1982	15	203.28	18.91	4.53
93	Roddickton/St. A.	350	1975	8	610.44	56.79	26.49
94		1000	1975	8	1,418.48	131.96	61.56
95		1000	1977	10	1,496.11	139.18	53.66
96		850	1980	13	1,450.48	134.93	39.09
97		850	1980	13	1,450.48	134.93	39.09
98		450	1986	19	1,021.89	95.06	15.54
99		1000	1973	6	1,344.88	125.11	70.62
100		1000	1973	6	1,344.88	125.11	70.62
101		1000	1973	6	1,344.88	125.11	70.62
102		2000	1980	13	2,096.52	195.03	56.49
103		2000	1982	15	2,211.26	205.71	49.24
104		850	1980	13	1,450.48	134.93	39.09
105		1000	1975	8	1,418.48	131.96	61.56
106		850	1980	13	1,450.48	134.93	39.09
107	South East Bight	136	1987	20	346.63	32.25	4.79
108		136	1980	13	287.65	26.76	7.75
109		55	1974	7	101.32	9.43	4.84
110	St. Brendans	300	1975	8	530.75	49.37	23.03
111		300	1974	7	516.79	48.08	24.67
112		250	1974	7	436.76	40.63	20.85
113	St Lewis	220	1974	7	387.57	36.05	18.50
114		225	1975	8	406.51	37.82	17.64
115		125	1978	11	251.42	23.39	8.20
116		125	1978	11	251.42	23.39	8.20
117	Westport	250	1974	7	436.76	40.63	20.85
118		250	1980	13	512.46	47.67	13.81
119		250	1974	7	436.76	40.63	20.85
120	Williams Harbour	75	1980	13	161.25	15.00	4.35
121		75	1980	13	161.25	15.00	4.35
122		125	1975	8	232.10	21.59	10.07
123	Totals	40914	241343				2378.36
124	No. of Units	122					
125	Average size	335.3607					
	Average age		13.77869				
126	Marginal replacement cost, $/KW						58.13
127	Marginal replacement cost, $/KWh						0.0259
128	Marginal replacement cost excluding Rod./St. A., $/KW						64.21
	As above, $/KWh						0.0361

NEWFOUNDLAND AND LABRADOR HYDRO
Isolated System Rate yields
Present rates vs marginal cost-based rates

[1] Classified costs

Gen. demand	19,266,928	Dist. D.	3,005,825	Total	34,593,127
Energy	9,621,705	Dist. Cust.	1,040,173	Subsidy	23,605,508
Transmission	789,679	Cust.	780,883	Net	10,987,619
		St. Ltg.	87,934		

[2] Subsidy set against fixed cost

Gen. demand	0	Dist. D.	1,081,705	Total	10,987,619
Energy	7,996,924	Dist. C	1,040,173	Subsidy	0
Transmission	0	Cust.	780,883	Net	10,987,619
		St. Ltg.	87,934		

[3] Unit classified costs

Customer cost; $/Month	($1,040,173+$780,883)/(6,779x12)=	22.39
Energy cost; $/KWh	$7,996,924/91,975,000KWh=	0.08695
Dist. dmd. cost - domestic; $/KWh	$1,081,705*.6198/42,792,981KWh=	0.01567
Dist. dmd. cost - GS; $/KWh	$1,081,705*.2408/5438940KWh=	0.04789
LRMC; $/KWh		0.0145

[4] REVENUE COMPARISON

		PRESENT RATES			MARGINAL COST RATES		
	ITEM	Rate	Quantity	Yield $	Rate	Quantity	Yield $
Domestic	S.C.	16.67	6,779	1,356,071	22.39	6779	1,821,382
	1 B E	0.06541	42,792,981	2,799,089	0.10261	41,872,969	4,296,744
	2 B E	0.09606	7,833,956	752,530	0.10145	7,729,623	784,145
	3 B E	0.13022	6,094,434	793,617	0.10145	6,579,393	667,479
	Total			5,701,307			7,569,750
General Svc.							
	S. C.	18.97	1,047	238,339	22.39	1,047	281,308
	1 B E	0.0858	5,438,940	466,661	0.13484	5,356,924	722,314
	2 B E	0.1954	16,101,810	3,146,294	0.10145	17,068,515	1,731,545
	TOTAL			3,851,294			2,735,166
Church & Sch.				292,622			
Special				687			
GS 0-10 KW				567			
GS 10-100 KW				39,797			
GS 110-1000				732,556			
St. Ltg.				239,253			
Subtotal				1,305,482			1,305,482
Stabilization & Misc.				129,536			129,536
ALL REVENUE				10,987,619			11,739,934

NEWFOUNDLAND AND LABRADOR HYDRO
Elasticity effects in the isolated systems

In this example the price elasticity of demand is assumed to be -0.1 for all energy blocks.

DOMESTIC CLASS	NO. OF BILLS	BLOCK 1 ENERGY	BLOCK 2 ENERGY	BLOCK 3 ENERGY	TOTAL ENERGY
TOTALS	80646	42,792,981	7,833,956	6,094,434	56,721,371
Block 3 bills	15856	11,099,200	4,756,800	6,094,434	21,950,434
Block 2 bills	22167	15,516,900	3,077,156	0	18,594,056
Block 1 bills	42623	16,176,881	0	0	16,176,881

Elasticity effects:	BLOCK 1	BLOCK 2	BLOCK 3	
Present rate	0.06541	0.09606	0.13022	
New rate	0.10261	0.10145	0.10145	
Change, pu	1.5687204	1.0561108	0.7790662	
Change in sales	-0.056872	-0.005611	0.0220934	
Present block bill totals	16,176,881	18,594,056	21,950,434	
Adjusted block bill totals	15,256,869	18,489,723	22,435,393	56181985

ADJUSTED BLOCK TOTALS		BLOCK 1 ENERGY	BLOCK 2 ENERGY	BLOCK 3 ENERGY	TOTAL ENERGY
Block 3 bills	15856	11,099,200	4,756,800	6,579,393	
Block 2 bills	22167	15,516,900	2,972,823		
Block 1 bills	42623	15,256,869			
Block energy totals		41,872,969	7,729,623	6,579,393	56,181,985

GS CLASS (Rate 2.5)	NO. OF BILLS	BLOCK 1 ENERGY	BLOCK 2 ENERGY	TOTAL ENERGY
TOTALS	12553	5,438,940	16,101,810	21,540,750
Block 2 bills	5720	4,004,000	16,101,810	20,105,810
Block 1 bills	6833	1,434,940	0	1,434,940

Elasticity effects:	BLOCK 1	BLOCK 2
Present rate	0.0858	0.1954
New rate	0.13484	0.10145
Change, pu	1.5715618	0.5191914
Change in sales	-0.057156	0.0480809
Present block bill totals	1,434,940	20,105,810
Adjusted block bill totals	1,352,924	21,072,515

ADJUSTED BLOCK TOTALS		BLOCK 1 ENERGY	BLOCK 2 ENERGY	TOTAL ENERGY
Block 2 bills	5720	4,004,000	17,068,515	21,072,515
Block 1 bills	6833	1,352,924		1,352,924
Block energy totals		5,356,924	17,068,515	22,425,439

	Domestic	GS	Total
Sales under present rates	56,721,371	21,540,750	78,262,121
Sales after rate change	56,181,985	22,425,439	78,607,424

DESIRABLE ATTRIBUTES OF UTILITY RATES

(Reproduced from Bonbright et al.; Principles of Public Utility Rates; 1988)

Revenue-related Attributes:

1. Effectiveness in yielding total revenue requirements under the fair-return standard without any socially undesirable expansion of the rate base or socially undesirable level of product quality and safety.

2. Revenue stability and predictability, with a minimum of unexpected changes seriously adverse to utility companies.

3. Stability and predictability of the rates themselves, with a minimum of unexpected changes seriously adverse to ratepayers and with a sense of historical continuity. (Compare "The best tax is an old tax".)

Cost-related Attributes:

4. Static efficiency of the rate classes and rate blocks in discouraging wasteful use of the service while promoting all justified types and amounts of use:

   (a) in the control of the total amounts of service supplied by the company;

   (b) in the control of the relative uses of alternative types of service by ratepayers (on-peak versus off-peak service or higher quality versus lower quality service).

5. Reflection of all of the present and future private and social costs and benefits occasioned by a service's provision (i.e., all internalities and externalities).

6. Fairness of the specific rates in the apportionment of total costs of service among the different ratepayers so as to avoid arbitrariness and capriciousness and to attain equity in three dimensions: (1) horizontal (i.e., equals treated equally); (2) vertical (i.e., unequals treated unequally); and (3) anonymous (i.e., no rate-payer's demands can be diverted away uneconomically from an incumbent by a potential entrant).

7. Avoidance of undue discrimination in rate relationships so as to be, if possible, compensatory (i.e., subsidy free with no intercustomer burdens).

8. Dynamic efficiency in promoting innovation and responding economically to changing demand and supply patterns.

Practical-related Attributes:

9. The related, practical attributes of simplicity, certainty, convenience of payment, economy in collection, understandability, public acceptability, and feasibility of application.

10. Freedom from controversies as to proper interpretation.

AN OVERALL ESTIMATE OF LONG-RUN MARGINAL COST IN NEWFOUNDLAND & LABRADOR HYDRO ISOLATED RURAL SYSTEMS

1. Summary.

The peaker method of determining long-run marginal cost (LRMC) is used for purposes of this estimate. However, some modifications have been made to adapt it to diesel generation, the only plausible source of new capacity in these small systems.

Separate estimates were made for each isolated system; in most cases by determining the year in which new capacity would be needed, the optimum unit size and cost. There were two exceptions. In the case of systems for which specific expansion plans now exist, Hydro's timing, unit sizes and costs were used [IC-40 and GCB-10(b)]. The other exception involved systems where zero growth was forecast (Little Bay Islands, Paradise River and Petites), and Petite Forte where no future beyond 1993 is forecast. In these cases, marginal cost was taken to be zero.

Estimates for individual systems were then weighted to reflect relative size, and the weighted increments were added to give an estimate of average long-run marginal cost in the Isolated Systems as a whole.

The resulting figures are:

Isolated Rural Systems overall: $.0145 per KWh
As above, but excluding Roddickton/St. Anthony: $.0212 per KWh.

The methods used here were dictated by limitations of both data and resources. The results are inferior to those available through a system planning approach, and estimates for individual systems may contain substantial error. The overall estimate is sensitive to some of the assumptions made but is regarded as a reasonable indication of the true cost of system growth.

2. Economic Assumptions.

The following rates were used:

Interest:	10% per annum.
Construction price escalation:	2.7% per annum.
Fuel price escalation:	5.06% per annum.

The figures are based on Hydro's current system planning assumptions as reported in GCB-10(c). Whether or not they are best estimates of future conditions, they are the figures used in the planning of Hydro's system.

3. Isolated System Data.

Hydro's responses to various demands provided input information for the study. The data and load growth rates calculated therefrom are set out in Schedules 1, 2 and 3 attached.

4. Unit Efficiency versus Size.

The variation of unit efficiency with unit size is an important factor in determining the optimum size of new units. In any actual expansion, manufacturer's data would probably be used, but for present purposes this appeared impractical. Data published by the National Energy Board was used to construct an empirical curve, and the parameters were adjusted to fit reported heat rates in the Isolated Systems with least mean square error. This resulted in the following equation, which was used to calculate operating costs for all scenarios:

Heat rate (KJ/KWh) = 11,246 + 2.627 E+08/[(KW) + 137.97]^2

When applied to Hydro's Isolated Systems, this expression yields estimates with a standard deviation of about 5%.

5. Unit Costs.

Capacity additions necessarily involve the cost of prime mover and generator, but may or may not incur further costs for powerhouse construction, additional fuel storage, increased substation capacity, etc. For purposes of this study it was assumed that the capacity increases now planned by Hydro [IC-40 and GCB-10(b)] would provide a representative view of the average costs incurred in capacity increments. Linear regression of this data resulted in costs of $(1551-.4048(KW)) per KW of added capacity in 1992 dollars and this basis of costing has been used.

6. Criteria and Timing of System Additions.

Hydro's criteria have been followed. Firm capacity has been taken as total installed capacity less that of the largest unit. Capacity additions are assumed to be made in the first year in which system peak demand exceeds existing firm capacity.

In nearly all cases, it was found that application of this rule enabled peak demands to be met with no unit operating at over 80% of rated output. Where any significant increase over 80% was found necessary, the year of addition was advanced to eliminate it.

The rate of load growth assumed for study purposes is the compound rate implied by forecast loads from 1993 to 1997 (NP4). In one or two cases where the rate of increase was high, appeared to result from specific large load additions in specific years and was not paralleled by similar increases in the 1988-92 period, the rate was arbitrarily decreased.

In most cases where rates differed for demand and energy, the average rate was used. The growth rates so determined were assumed to be maintained indefinitely. For most systems, the rate is very modest.

7. Optimum Unit Size.

The unit size for each system was determined on a least-cost basis, considering only unit capital and fuel costs. The latter were determined by simulation of system operation over a 26-year period and taking the present worth at the year of addition.

Simulations were based on load duration curves which accurately reflect peak demand, load factor and energy requirement in each system, but only roughly approximate typical actual load curve shapes.

Defining the size of the additional unit as the ratio of its capacity to that of the largest existing unit, it was found that under the computational framework used, total cost increases as the ratio increases from zero to 1.0, tends to dip to a minimum for some value in excess of 1.0 and then increases indefinitely with further increase in unit size.

The minimum at zero unit size is not a practical solution. In real life the cost of making frequent, small additions to plant would be found prohibitive and the fact that it was not so found in the model used is due to the simple cost function employed. For study purposes an arbitrary minimum size capable of meeting growth through the simulation period was applied. Where lesser cost resulted from unit size ratios above 1.0, the minimum in that region was selected.

Results of applying this procedure are reasonably similar to the pattern of additions actually made in the past as disclosed by unit sizes and dates provided by Hydro (GCB-2.1). In general, addition of unit capacity greater than that of the largest existing unit is more attractive where the existing units are small, where load factor is comparatively high, and where the year of addition lies far in the future. In the latter case energy costs are inflated more than capacity costs and efficiency becomes the most important factor.

The unit capacities selected are detailed in Exhibit 3, page 1, column 4.

8. Application of the Peaker Method.

The present worth in the in-service year of the selected option is converted into the \$1992 long-run marginal cost per KWh of sales by means of the following steps:

1. The capacity cost in the in-service year is grossed up to account for the present worth over life of all other fixed costs associated with the option. In the general case, where the capacity addition is usually a new plant, the factor tends to fall in the range 1.3 to 1.4. Additions to Hydro's Isolated Systems are considered almost always to consist of additional units operating in a single powerhouse, with additional staffing requirements amounting to little or nothing. A factor of 1.15 has therefore been used.

2. The capacity cost determined in step 1 above is grossed up to reflect replacement costs involved in maintaining the added capacity in perpetuity. The factor is

   $$1/[1 - \{(1+I)/(1+x)\}^n]$$

   where I is the inflation rate, x is the interest rate and n is the number of years between successive replacements. Under the assumptions used herein, the factor is 1.219.

3. A deferral value factor is next applied to convert the total present worth cost resulting from step 2 into an annual cost. The deferral value factor is

   $$(x - I)/(1 + x)$$

   which under the study assumptions amounts to .06636.

4. The deferral value is present-worthed from the in-service year to 1992, using the discount factor 1/(1+x)^(ISY-1992).

5. The annual cost resulting from step 4 is converted to a cost per KW of additional capacity provided. The amount of additional capacity should be taken as the firm capacity in order to reflect the reserve requirements of the system. In the Isolated Systems, an addition smaller than the largest existing unit will usually increase firm capacity by an equal amount, while an addition larger than the largest existing unit will increase firm capacity only by the rating of the largest existing unit. However, as the systems increase in size the .8 unit loading requirement will sooner or later become the ruling factor. For this reason, the capacity addition has been taken as .8 times rated KW in every case.

6. The per-KW costs determined in step 5 are converted to per-KWh costs. To do this, and account for system losses, the conversion factor is the ratio of system sales at meter to system peak demands at generator.

7. Steps 1 through 5 above determine the long-run marginal cost of capacity by means of the peaker method and they would be sufficient if the source of additional capacity was in fact a peaker, or if costs in excess of the cost of gas turbines were to be separately accounted for as energy costs.

   Neither of these conditions is met in the present case. The total capital cost of diesel generation was used and the size of the capacity addition was decided partly on the basis of comparative energy costs. It is therefore appropriate to track the effect of the additional capacity on energy costs and to reflect any changes in the per KWh marginal costs.

   Simulation shows that where the added capacity is small compared to the largest existing unit, it will operate at a comparatively low capacity factor. That is, it will perform a peaking function in the system. Under such circumstances no adjustment to energy costs has been made.

   However, where the new unit is the largest in the system, it will be loaded to the full extent permitted by the system load duration curve. Under this circumstance it will provide a reduction in energy costs, and the per-KWh marginal cost is adjusted to reflect this reduction. The energy savings are computed as the production of the added unit multiplied by the difference in heat rate between the added unit and the largest existing unit and by the fuel cost. This procedure slightly underestimates the energy benefits. Annual savings are present-worthed to the in-service date. Designating the ratio of PW savings to capital cost as F, the per-KWh cost of capacity as calculated in step 6 is reduced to (1 - F) of that amount.

8. <u>Computation of LRMC for all Isolated Systems as a group</u>.

The LRMC calculated for each system is multiplied by its share of the total Isolated Systems energy requirement, to determine its weighted contribution to the overall LRMC. The contributions of all the individual systems are then summed to arrive at the per-KWh LRMC for Hydro's Isolated Systems overall.

9. <u>Results</u>.

The results of applying each of the foregoing steps are set out in Exhibit 3.

APPENDIX GCB - 2
Schedule 1

NEWFOUNDLAND AND LABRADOR HYDRO
ISOLATED AREA GENERATING PLANT DATA

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
		GENERATING UNIT CAPACITIES							TOT. Cap'y	FIRM Cap'y.	PEAK LOAD
	Data source	GCB2.1	GCB2.1	GCB2.1	GCB2.1	GCB2.1	GCB2.1	GCB2.1	GCB2.1	[8]-[1]	GCB2.2
	Units	KW	KW	KW	KW	KW	KW	KW	KW	KW	KW
	SYSTEM										
[1]	Black Tickle	270	270	225					765	495	489
[2]	Cartwright	405	405	405	270				1485	1080	737
[3]	Charlottetown	270	225	125					620	350	387
[4]	Davis Inlet	225	220	125	125				695	470	325
[5]	Francois	250	200	100					550	300	269
[6]	Grey river	250	136	136					522	272	237
[7]	Harbour Deep	250	136	136	136				658	408	307
[8]	Hopedale	270	270	225	180				945	675	604
[9]	La Poile	250	136	90					476	226	185
[10]	Little Bay Islands	450	300	300	300				1350	900	604
[11]	l'Anse Au Loup	1000	720	720	540	540			3520	2520	2636
[12]	Makkovik	500	500	400	225				1625	1125	855
[13]	Marys Harbour Diesel	270	225	225	175	165			1060	790	676
[14]	McCallum	250	136	136					522	272	202
[15]	Mud Lake	55	45	45					145	90	74
[16]	Nain	350	270	270	270	270			1430	1080	913
[17]	Norman Bay	30	30	30					90	60	51
[18]	Paradise River	55	55	35					145	90	85
[19]	Petite Forte	136	136	55					327	191	140
[20]	Petites	200	90	90					380	180	132
[21]	Port Hope Simpson	350	225	225	125				925	575	472
[22]	Postville	225	155	75	75				530	305	291
[23]	Ramea	1000	1000	568	500	442	426		3936	2936	2509
[24]	Rencontre East	300	250	136					686	386	243
[25]	Rigolet	225	165	125	90				605	380	362
[26]	South East Bight	136	136	55					327	191	143
[27]	St. Brendans	300	300	250					850	550	354
[28]	St Lewis	225	220	125	125				695	470	330
[29]	Westport	250	250	250					750	500	468
[30]	Williams Harbour	125	125	75					325	200	114
[31]	Subtotals	8872	7331	5757	3136	1417	426	0	26939	18067	15194
[32]	No of units	1	2	6	4	1	1	1			
[33]	Rod./St. A.	5000	2000	1000	850	450	400	350	19600	14600	11998
[34]	TOTALS								46539	32667	27192

NEWFOUNDLAND AND LABRADOR HYDRO

ISOLATED AREA GENERATING PLANT DATA

		[11] ANNUAL ENERGY	[12] S C LOAD FACTOR	[13] FIRM C. F.	[14] EFFIC-IENCY	[15] FUEL INPUT	[16] FUEL COST	[17] FUEL COST	[18] FUEL COST
	Source or calculation	GCB2.6 NP4			GCB2.1	IC46	IC46	[18]/[11]	NP1(a)
	Units	MWh	pu	pu	KWh/l	Kl	$/l	$/KWh	$(000's)
	SYSTEM								
[1]	Black Tickle	1259	0.2939	0.2903	3.10	406.13	0.244	0.0787	99.1
[2]	Cartwright	3238	0.5015	0.3423	3.50	925.14	0.283	0.0809	261.8
[3]	Charlottetown	1136	0.3351	0.3705	3.10	366.45	0.254	0.1448	164.5
[4]	Davis Inlet	1451	0.5097	0.3524	2.70	537.41	0.247	0.0915	132.7
[5]	Francois	816	0.3463	0.3105	2.80	291.43	0.404	0.1443	117.7
[6]	Grey river	663	0.3193	0.2783	3.10	213.87	0.289	0.0932	61.8
[7]	Harbour Deep	915	0.3402	0.2560	2.90	315.52	0.238	0.0822	75.2
[8]	Hopedale	2356	0.4453	0.3984	3.00	785.33	0.255	0.0850	200.3
[9]	La Poile	538	0.3320	0.2718	3.10	173.55	0.289	0.0932	50.2
[10]	Little Bay Islands	1630	0.3081	0.2067	3.30	493.94	0.277	0.0839	136.8
[11]	l'Anse Au Loup	9807	0.4247	0.4443	3.20	3064.69	0.229	0.0716	701.9
[12]	Makkovik	2937	0.3921	0.2980	3.00	979.00	0.242	0.0807	236.9
[13]	Marys Harbour Diesel	2643	0.4463	0.3819	3.10	852.58	0.243	0.0665	175.8
[14]	McCallum	643	0.3634	0.2699	3.20	200.94	0.289	0.0903	58.1
[15]	Mud Lake	192	0.2962	0.2435	2.00	96.00	0.299	0.1495	28.7
[16]	Nain	4722	0.5904	0.4991	3.10	1523.23	0.245	0.0790	373.2
[17]	Norman Bay	89	0.1992	0.1693	1.90	46.84	0.261	0.2373	21.1
[18]	Paradise River	256	0.3438	0.3247	2.20	116.36	0.259	0.1177	30.1
[19]	Petite Forte	411	0.3351	0.2456	2.50	164.40	0.289	0.1156	47.5
[20]	Petites	346	0.2992	0.2194	2.70	128.15	0.289	0.1070	37.0
[21]	Port Hope Simpson	1519	0.3674	0.3016	2.90	523.79	0.303	0.1045	158.7
[22]	Postville	1099	0.4311	0.4113	2.80	392.50	0.250	0.0893	98.1
[23]	Ramea	8667	0.3943	0.3370	3.50	2476.29	0.218	0.0623	539.8
[24]	Rencontre East	825	0.3876	0.2440	3.00	275.00	0.289	0.0963	79.5
[25]	Rigolet	1305	0.4115	0.3920	3.00	435.00	0.283	0.0943	123.1
[26]	South East Bight	377	0.3010	0.2253	2.70	139.63	0.289	0.1070	40.4
[27]	St. Brendans	1151	0.3712	0.2389	3.20	359.69	0.238	0.0744	85.6
[28]	St Lewis	1448	0.5009	0.3517	3.10	467.10	0.245	0.0790	114.4
[29]	Westport	1432	0.3493	0.3269	3.00	477.33	0.220	0.0733	105.0
[30]	Williams Harbour	405	0.4056	0.2312	2.50	162.00	0.249	0.0994	40.2
[31]	Subtotals	54276	0.4078	0.3429				0.0810	4395.4
[32]	Roddickton/								
[33]	St. Anthony	55733	0.5303	0.4358	3.38	16,489	0.210	0.0595	3314.1
[34]	TOTALS	110009	0.4618	0.3340				0.0701	7709.5

NEWFOUNDLAND AND LABRADOR HYDRO
ISOLATED AREA GENERATING PLANT DATA

		[19]	[20]	[21]	[22]	[23]	[24]	[25]
		GROWTH RATE (D)			GROWTH RATE (E)			S. C.
		1993	1997	RATE	1993	1997	RATE	Load
		KW	KW		MWh	MWh		Factor
	Data source	NP4	NP4	Note1	NP4	NP4	Note1	1997
	Units	KW	KW	pu/yr.	MWh	MWh	pu/yr	pu
	SYSTEM							
[1]	Black Tickle	406	420	1.009	1277	1445	1.031	0.393
[2]	Cartwright	793	897	1.031	3374	3779	1.029	0.481
[3]	Charlottetown	507	610	1.047	1496	1794	1.046	0.336
[4]	Davis Inlet	352	364	1.008	1558	1609	1.008	0.505
[5]	Francois	299	300	1.001	837	842	1.001	0.320
[6]	Grey river	264	274	1.009	689	714	1.009	0.297
[7]	Harbour Deep	272	281	1.008	847	875	1.008	0.355
[8]	Hopedale	573	652	1.033	2280	2595	1.033	0.454
[9]	La Poile	183	188	1.007	554	570	1.007	0.346
[10]	Little Bay Islands	589	589	1.000	1812	1812	1.000	0.351
[11]	l'Anse Au Loup	2538	2716	1.017	10293	10990	1.017	0.462
[12]	Makkovik	596	640	1.018	2430	2585	1.016	0.461
[13]	Marys Harbour Diesel	707	786	1.027	2849	3134	1.024	0.455
[14]	McCallum	198	210	1.015	650	692	1.016	0.376
[15]	Mud Lake	81	83	1.006	210	216	1.007	0.297
[16]	Nain	1046	1118	1.017	4135	4778	1.037	0.488
[17]	Norman Bay	40	42	1.012	96	103	1.018	0.280
[18]	Paradise River	76	76	1.000	234	234	1.000	0.351
[19]	Petite Forte	146	0	0.000	411	0	0.000	0.000
[20]	Petites	124	124	1.000	339	339	1.000	0.312
[21]	Port Hope Simpson	543	625	1.036	1897	2176	1.035	0.397
[22]	Postville	351	380	1.020	1233	1344	1.022	0.404
[23]	Ramea	2227	2775	1.057	7877	8684	1.025	0.357
[24]	Rencontre East	256	263	1.007	873	899	1.007	0.390
[25]	Rigolet	442	481	1.021	1542	1678	1.021	0.398
[26]	South East Bight	152	164	1.019	445	480	1.019	0.334
[27]	St. Brendans	374	390	1.011	1232	1287	1.011	0.377
[28]	St Lewis	399	428	1.018	1563	1667	1.016	0.445
[29]	Westport	485	507	1.011	1480	1548	1.011	0.349
[30]	Williams Harbour	92	94	1.005	365	393	1.019	0.477
[31]	Subtotals	15111	16477	1.022	54878	59262	1.019	0.411
[32]	Roddickton/							
[33]	St. Anthony	11341	12766	1.030	52433	58844	1.029	0.526
[34]	TOTALS	26452	29243	1.025	107311	118106	1.024	0.461

Note 1: Calculated as the compound growth rate from 1993 to 1997.