Q. **(Reference CA-NLH-3) The response states *"In the 1992 cost of service methodology hearing, Mr. Larry Brockman, recommended that hydraulic generation classification be based on the equivalent peaker methodology using a 26% demand component and a 74% energy component."* Please file for the record Mr. Brockman's evidence at the 1992 hearing and the equivalent peaker calculation leading to his recommendation that hydraulic generation be classified as 26% demand and 74% energy. Has Mr. Brockman updated his calculation for this hearing? If so, please file the calculation for the record.**

A. Copies of Mr. Brockman's evidence submitted to the Board in the 1992 generic cost of service proceeding are provided as follows:

1. Attachment A is a copy of *Testimony of Larry Brockman, Hydro 1992 Cost of Service Investigation*, filed with the Board on August 31, 1992.
2. Attachment B is a copy of *Supplemental Evidence of Larry Brockman, Hydro 1992 Cost of Service Investigation*, filed with the Board on September 16, 1992.
3. Attachment C is a copy of revisions to the *Testimony of Larry Brockman* provided in Attachment A, filed with the Board on September 17, 1992.

Mr. Brockman no longer has a record of the equivalent peaker calculations upon which his recommendation in that proceeding was based.

Mr. Brockman has not updated his equivalent peaker calculation for this proceeding.

Testimony of Larry Brockman,
Hydro 1992 Cost of Service Investigation

NEWFOUNDLAND POWER

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1992 08 31

Board of Commissioners of
Public Utilities
2nd Floor, Prince Charles Building
120 Torbay Road
St. John's, Newfoundland
A1A 2X9

Attention: Ms. Carol Horwood, Clerk of the Board

Dear Ms. Horwood:

Re: Generic Hearing on inter alia, the Cost of Service Methodology used by the Newfoundland and Labrador Hydro Electric Corporation

Please find enclosed Newfoundland Power's evidence pertaining to the above hearing. Copies have been sent to the individuals below.

Yours truly,

Tom Conroy For Joan Myles

Joan F. Myles
Legal Counsel

TAC/ct
Encl.

cc Geoffrey Young, Nfld. Hydro
Jeffrey Brace, Consumer Advocate
Janet Henley-Andrews, Stewart Mckelvey Stirling Scales
Edward Hearn, Miller and Hearn
Alvin Hewlett, M.H.A.
George Baker, Hiltz and Seamone
Tom Green, Innu Nation

Newfoundland Power Evidence

Newfoundland & Labrador Hydro 1992 Cost of Service Methodology Hearing

August 1992

NEWFOUNDLAND POWER

Testimony of Larry Brockman

Hydro 1992 Cost of Service Investigation

August 1992

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I. Qualifications

Q. What is your name, address and professional affiliation?

A. My name is Larry B. Brockman. My address is 100 Northcreek, Atlanta, Georgia. I am a Vice President with Energy Management Associates (EMA), the Utilities Division of Electronic Data Systems (EDS). EMA is an industry leader in providing planning and financial software and consulting to the electric and gas industries in Canada, the U.S., the Pacific Rim, the Mid-East, and Europe. I am appearing in this proceeding on behalf of my client, Newfoundland Power.

Q. Have you previously testified before this Board as an expert witness?

A. Yes. I testified as an expert in cost of service, rate design, and utility system planning before this Board in Hydro's 1990 Rate Referral and again in Hydro's 1992 Rate Referral.

Q. Please summarize your professional background.

A. I have over 18 years of experience in the utility industry as a planner, regulator, ratemaker, and consultant. As a Vice President in EMA's consulting department, I specialize in providing planning and regulatory counsel to electric and gas utility clients. Since joining EMA in 1985, I have managed a wide variety of projects involving integrated resource planning, ratemaking and general utility practice. I have reviewed and created numerous least cost plans for Canadian and U.S. clients and have testified on planning and ratemaking before regulatory bodies in Canada and the U.S. I have also worked on several merger and acquisition studies identifying and quantifying the potential planning and operational synergies. I am co-developer and instructor of two internationally recognized courses on least cost planning and ratemaking for Public Utilities Reports Inc. and The Management Exchange.

I graduated from the University of Florida with a Bachelor's Degree in Engineering in 1973 and returned in 1977 to do graduate work in electric engineering and regulatory economics. After graduation from university in 1973, I started my career as a system planning engineer with Jacksonville Electric Authority, a municipal utility in Florida. While there, I performed generation, transmission and distribution studies, including cost effectiveness evaluations of new generation, transmission lines, substations, feeder conversions and the like. I later worked for Gainesville Regional Utilities doing similar work and also performed cost of service and rate design studies.

In 1981, I became the Assistant Director of the Electric and Gas Department of the Florida Public Service Commission, where I had responsibilities for supervising 48 employees engaged in all phases of electric and gas regulation. I was ultimately responsible for making recommendations to the Commission on rate cases, power plant siting, conservation activities, and various public policy matters.

II. Background and Purpose of Testimony

Q. Please provide your perspective on the background behind these proceedings.

A. In its 1992 Rate Referral, Hydro recommended several changes to the cost of service methodology approved by the Board in 1977. The changes proposed by Hydro involved significant shifts of production and transmission plant costs from energy to demand. These changes implied that the method approved in 1977 was too heavily weighted towards energy. In addition, Hydro proposed that certain plant previously treated as dedicated to "Hydro Rurals" be treated as common to all customers. NP argued that insufficient evidence had been submitted to support the changes to the cost of service methodology proposed by Hydro and that the rate referral was not the appropriate forum to fully explore these important issues. NP recommended at that time that the cost of service methodology found to be fair and reasonable in 1977, and in use since that time, be retained unless a more thorough examination of the evidence proved that changes were warranted.

In its April 1992 Report to the Minister, the Board recommended allowing Hydro to use its proposed cost of service methodology on an interim basis, but to submit further justification on its use in a future generic proceeding. In June, 1992 Hydro submitted its evidence seeking justification of the changes sought in the cost of service methodology.

Q. Please provide an overview of your evidence in this proceeding.

A. My evidence in this proceeding will show that the cost allocation methodology approved by the Board in 1977 was not too heavily weighted towards energy, as Hydro's changes would suggest. In fact, it was too heavily weighted towards demand. In addition, the costs allocated to Newfoundland Power, were not too low under the 1977 methodology as Hydro now contends, but were in fact slightly high.

My evidence is presented according to the following main topics:

(1) The purpose of a cost of service study.

(2) The main components of a cost of service methodology.

(3) Criteria for choosing a cost of service methodology.

(4) Cost of service methods appropriate for Newfoundland and Labrador Hydro.

(5) The impact of recommended methods on Hydro's customer classes.

III. Purpose and Principles of Cost of Service Studies

Q. What is the purpose of a cost of service study?

A. Cost of service studies are performed for several reasons. The 1992 NARUC Electric Utility Cost Allocation Manual (page 12) gives the following purposes for cost of service studies:

- To attribute costs to different categories of customers based on how those customers cause costs to be incurred.
- To determine how costs will be recovered from customers within each customer class.

- To calculate costs of individual types of service based on the costs each service requires the utility to expend.
- To determine the revenue requirement for the monopoly services offered by a utility operating in both monopoly and competitive markets.
- To separate costs between different regulatory jurisdictions.

There are two major types of cost of service studies. One is called an embedded cost of service study, the other is called a marginal cost of service study. Embedded cost of service studies deal with the costs of existing utility plant and operating expenses. Marginal cost of service studies deal with the future costs of meeting additional electric energy and demand requirements.

The use of cost of service studies to allocate revenue responsibility derives from the generally accepted principles of good rate design. James Bonbright was one of the first to codify these principles in his classic book, <u>Principles of Public Utility Rates</u>. Bonbright's principles which relate to cost of service studies are:

(1) Effectiveness in yielding total revenue requirements

(2) Fairness in the apportionment of total costs of service among the different ratepayers.

(3) Static efficiency of the rate classes and rate blocks in discouraging wasteful use of 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).

Embedded cost of service studies are done primarily to achieve the goal of fairness and avoidance of undue discrimination in the apportionment of revenue responsibility to rate classes and to individual customers within these classes. Fairness in allocating revenues between individual customers within each class is accomplished by the proper setting of demand, energy and customer charges within those classes. Marginal cost of service studies are performed primarily to assist in designing rates that are economically efficient. The cost of service methods under investigation in this proceeding are embedded methods and are therefore primarily aimed at achieving fairness.

Bonbright's principle of fairness in the apportionment of costs and the NARUC principle of attributing costs based upon how customers cause costs to be incurred, are inextricably inter-twined. In fact, the principle of causality (or cost causation) is almost universally claimed in attempts to justify various cost of service methodologies as fair. The principle of cost causality states that costs should be assigned according to load and customer characteristics that cause the costs to go up or down.

IV. Components of Cost of Service Studies

Q. Please describe how an embedded cost of service study is performed.

A. There are three main steps involved in performing a cost of service study. These steps are called:

(1) functionalization;

(2) classification; and,

(3) allocation.

Each of these steps is a process of sub-dividing the utility's overall costs into smaller and smaller portions, each associated with specific customer classes and load characteristics that cause the costs to occur.

Q. Please describe the functionalization step.

A. Functionalization is a process of deciding what purpose or utility function a utility investment or expenditure serves. Common examples of utility functions are production, transmission, and distribution. As an example of functionalization, consider the cost of fuel burned at a power plant and the cost of carrying the investment in that plant. These costs would be functionalized as production.

Functionalization is performed because it helps identify how costs of providing service to various customers change when the load characteristics of those customers change.

The costs assigned to the major utility functional categories are often broken down further into sub-categories associated with individual customers or groups of customers. For example, if a transmission line was built just to serve a specific group of customers, the costs of that line should be functionalized as transmission whose function is to serve only that group of customers. This will promote fairness by ensuring that the cost of that line will eventually be assigned only to that group of customers.

Q. Please describe the classification step of a cost of service study.

A. Classification is a process of deciding what customer characteristics cause each functionalized cost to increase or decrease as customer load characteristics change. Costs are usually classified as increasing or decreasing because of changes in customer demand, energy or number of customers on the system. The table below shows some commonly accepted ways of classifying the major functional categories:

	Costs Classified As		
Functional Category	Demand	Energy	Customer
Production	yes	yes	no
Transmission	yes	yes	no
Distribution	yes	no	yes

In the classification stage, we must decide not only whether a cost is related to demand, energy or number of customers, but we must also assign percentages for those functions which may be related to more than one of these causal factors.

Even a simple table such as this one can be controversial when we discuss classification, because there is no universally agreed upon method for classifying production, transmission, or distribution related costs.

Q. If there is no agreed upon method for classification of certain costs, please explain how a regulatory body such as this one is to judge how the major functional categories should be classified.

A. The approach I would suggest is to return to the basic principles and purposes of doing a cost of service study in the first place. I previously quoted NARUC's 1992 Cost Allocation Manual on the purpose of a cost of service study as, "to attribute costs to different categories of customers based on how those customers cause costs to be incurred." I also discussed how the principle of cost causation was related to fairness. In teaching hundreds of utility industry personnel about cost of service, the principle of causality is the one I find most helpful in helping them to understand and apply cost of service.

To apply the principle of cost causation at any step in a cost of service study, one simply needs to ask, "What makes this cost go up?" or "What makes it go down?" In the functionalization stage, the causation principle can help determine whether a cost is common to all customers, or whether only a certain group of customers has caused the cost to go up or down. The classification stage cuts to the heart of the matter by asking whether demand, energy, or just being a customer caused a certain cost to rise or fall.

If the functionalization and classification steps are properly done, the allocation step becomes much simpler.

Q. Please describe the allocation step of a cost of service study.

A. In the allocation step, the previously functionalized and classified costs are allocated to the individual customer classes. Allocation to the classes is usually done in proportion to each classes' share of the demand, energy or number of customers depending on how the cost was classified in the prior step. The following example might prove useful in understanding these concepts.

Suppose a utility has spent $50 in a year to provide a generating plant to serve two customer classes. After investigation of the utility's accounting books, it was found that $25 was spent at the power plant for fuel and $25 was associated with carrying the investment in the power plant. The first $25 cost would be functionalized as production-fuel, and the second $25 cost would be functionalized as production-carrying costs.

Next, suppose that consultation with the planners and operators of the plant revealed that the costs of fuel increase primarily as more energy from the plant is used, but one-half of the investment in the plant was spent due to the amount of energy it produced, and the other one-half of the investment in the plant was based on the demand placed on the system. Applying the principle of causality, the $25 production-fuel costs would be classified as energy related, $12.50 of the carrying charges on the plant as demand related, and the $12.50 of the carrying charges as energy related.

To perform the allocation step it must first be determined how much demand and energy requirement each of the two classes places on the system. Suppose in this example that Class 1 places two-thirds the total demand on the system, but uses only one-half the total energy from the plant (Class 1 has a worse load factor than Class 2). Two-thirds of the $12.50 demand related carrying charges on the plant would be allocated to Class 1, because that would be their share of the total demand. (The principle of causality would suggest that they caused two-thirds of the demand costs). Also one-half of the $37.50 energy related costs would be allocated to Class 1 because that is their share of the total energy used from the plant.

V. Criteria for Choosing a Cost of Service Methodology

Q. Please elaborate on why choosing a cost of service methodology and performing a cost of service study can be a subject of controversy.

A. In concept, and theory, cost of service is relatively simple. Unfortunately for someone struggling with choosing a proper cost of service methodology, there are hundreds of cost categories that must be properly functionalized, classified and allocated. Cost of service practitioners have differences of opinion about these items, which partially accounts for the fact that there are so many different methodologies for performing cost of service studies. Other differences occur because utilities have different factors driving the costs up or down.

In addition, there have been both technological changes in production plant equipment and load research improvements in the last 30 years. Both have changed what can and should be done with respect to cost allocation, if capturing cost causation is our goal. Prior to the late 1960's large, inexpensive gas turbines were not available to the electric utility industry for meeting peaking type loads. This meant that in many cases, fossil fueled steam plants were constructed as both base load and peaking plants. Since the same type of plant was constructed to serve both high and low load factor loads, the maximum demand on the plants was all that really drove the cost of installing them. Under such circumstances, classifying all thermal production plant as demand related made causal sense. However, it still offended the ratemakers' sense of fairness that classes using power off peak under such a classification scheme would not pay any of the fixed costs of the generating plants that served them. This led to the use of methods such as the Average and Excess Demand method which allocates a portion of production plant costs on energy and a portion on each classes' non coincident demand.

The fact that good load research data was uncommon prior to the 1960's meant that cost of service methods which required coincident peak data by class could not be used effectively. Since the Average and Excess Demand method required only class energy consumption and non coincident demands, it could be applied with very little load research data. It thus became a popular method with analysts who wanted to recognize the fact that power plant planning involved balancing investment and operating costs that varied with both demand and energy. (For an in depth historical account of this cost of service progression, see Appendix 1.)

VI. Application to Newfoundland and Labrador Hydro

Q. Please explain how the principles you have been discussing apply to the task of choosing an appropriate cost of service study to be used by Newfoundland and Labrador Hydro.

A. I have several areas of disagreement with Hydro's proposal in the present proceeding. Attention to the basic guidelines already discussed will assist the Board in deciding on these matters. The areas of disagreement are:

<u>Issue One</u> - How certain generation, transmission and distribution facilities that serve primarily one group of customers should be functionalized; that is, whether they should be functionalized as common to all customers, or just assigned to that group of customers;

<u>Issue Two</u> - How Hydro's hydraulic and thermal production plant should be classified between demand and energy;

<u>Issue Three</u> - How Hydro's transmission facilities should be classified between demand and energy;

<u>Issue Four</u> - How production, transmission and distribution plant should be allocated to the classes and;

<u>Issue Five</u> - How the Hydro Rural revenue deficit should be allocated.

In addition, a future issue on how to treat interruptible customers in a cost of service study is discussed.

<u>Issue One</u>

Q. Please discuss the issue of how facilities that serve only one group of customers should be treated.

A. This issue refers to whether certain generation, transmission and distribution facilities primarily located on the Great Northern Peninsula, and which were previously functionalized as dedicated to Hydro Rural customers, should now be treated as being common to all customers. In prior cases the entire cost of these lines and associated facilities was assigned to the Hydro Rural class.

Hydro argues that since there is more than one class of rural customer on these facilities, they should be considered as common and allocated to all customers. Hydro also contends that this definition of common facilities is accepted as a mainstream practice. To quote Dr. Sarikas, "Direct assignments are not normally done in cost of service analysis except in the case of large power customers in selected applications, due in part to the time consuming nature and cost of the activity" (Sarikas, June 1992, Page 21, lines 19-22). In the February 1992 Hydro Rate Referral, this theme was also stated as, " Since the rural system is now an integral part of Newfoundland Hydro and consists of individual rate classes, these facilities have been treated as common and are no longer directly assigned" (Sarikas, Nov. 1991, page 19, lines 15-20).

Generally accepted principles state that an assignment of cost to customers should be fair. As I've already discussed, this has come to mean that customers should bear some causal responsibility for the costs being allocated to them. It is an undisputed fact in this case that the facilities in question serve only Hydro Rural customers. The existence of these customers and the fact that they live and work in the Great Northern Peninsula, is the only cause for the cost incurred. The generally accepted principles of good rate design require that the costs of these facilities not be assigned to customers who did not cause them. The principle of practicality that Dr. Sarikas is suggesting here relieves Hydro of the responsibility to be fair only if it is not practical to do so. Since the facilities were specifically assigned to Rural customers in the past, it should still be practical to do so.

If at some future time, these facilities truly do contribute to the benefit of all customer classes, they should be functionalized as common at that time. At the present time, they simply serve one group of customers and should be specifically assigned to this class of customers. The isolated location of these customers makes it unlikely that the facilities serving them will ever contribute to the other classes' benefit.

Q. Was the issue of functionalizing facilities as common versus specifically assigning them addressed by the Board in the 1977 cost of service proceeding?

A. Yes. In that proceeding the Board investigated this issue and found that,

> "For the purpose of resolving the issues between Hydro and the intervenors as to whether certain plant and equipment should be assigned to joint or to specific customers the Board has decided to use the following standard:
>
> (i) plant and equipment which is of substantial benefit to more than one customer will be classified "joint use"; and
>
> (ii) plant and equipment which is of little use or no benefit to two or more customers will be classified as specific use." (Report of the Board of Commissioners of Public Utilities on Rates to be Charged by Newfoundland and Labrador Hydro to Newfoundland Light & Power, dated March 14, 1978, p. 121-122)

Q. Is the above-noted finding in the 1977 Board Report consistent with Hydro's proposal in the current proceeding?

A. No. When the Board referred to one customer in the 1977 report, they meant one customer class, since Hydro had only a few customers at the time. One of these customers was PDD. The fact that PDD or Newfoundland Power had more than one class of customer, was not considered relevant in the Board's determination of what constituted common and joint plant between PDD, NP and the Industrials. From NP's perspective Hydro still has only a few customers (NP, Hydro Rurals, and the Industrials). On that basis, and following similar thinking to the Board's 1977 order, only one customer exists on the facilities on the western side of the Great Northern Peninsula. This matter cannot be fairly resolved by allocating a portion of these costs to customers clearly not responsible for them.

<u>Issue Two</u>

Q. How should Hydro's hydraulic production plant be classified between demand and energy?

A. There are several methods for classifying hydraulic plant between demand and energy. These methods are:

(1) Fixed and Variable

(2) Use of the Facilities

(3) Capacity Factor Methods

(4) Arbitrary Splits

(5) Equivalent Peaker Approach

Method (1) assigns all fixed costs to demand. The philosophy behind this method is that demand causes the utility to add plant and once the decision is made to add plant, the carrying costs on the assets do not vary with energy consumption. This type of philosophy probably made sense when there was essentially only one type of plant available. Where the option exists to spend more money to build plants, either hydro or thermal that are less expensive to operate, clearly the additional fixed costs invested to save on energy costs are not attributable to demand.

Method (2) classifies certain facilities such as dams, reservoirs, canals, etc. to energy. The philosophy is that certain facilities at a hydro plant are constructed in order to get maximum energy cost savings out of the plant. The remainder of the facilities are assumed to be related to demand. This method is fine as far as it goes, but it ignores the fact that hydro plants can be very capital intensive and even the investment left over after subtracting the cost of building reservoirs and dams, may exceed the cost of serving short duration demands by other means, such as combustion turbines. Hydro is now recommending this method.

Method (3) classifies a portion of the hydraulic plants on energy depending on the capacity factor the plant achieves. This method is often modified so that a plant that runs more than the overall system capacity factor is assigned more energy weight than one that runs less.

The method Hydro used until the last rate referral was a variant of this method. In this method, all hydraulic plant was assigned a 50/50 demand/energy split at the capacity factor of the overall system. If the plant ran more than system capacity factor, more energy weight was assigned. This results in a 43% demand and a 57% energy classification on hydraulic plant if this method is used in the 1992 forecast cost of service study.

Method (4) uses an arbitrary split such as 50/50 demand/energy without detailed scientific calculations. Such a method is often used when it is not feasible to calculate the demand energy splits, but a cost analyst would want to recognize that plants are built to serve both demand and energy.

Method (5) uses the principle of causality to determine how much extra investment was made to construct hydro plants to save on energy costs rather than inexpensive gas (combustion) turbines. The cost of a gas turbine that could have been built to serve short duration demands is subtracted from the cost of the hydraulic plant to determine the additional amount that was spent to save on energy costs. (For a more detailed explanation of this approach see the 1992 NARUC Cost Allocation Manual, Pages 52-55).

The goal of assigning costs to the factors that caused them is best satisfied by Method (5). Hydro clearly built many of the hydraulic plants on its system to save on energy costs. Hydro's own annual reports point this out in several places. For example, "The 120 megawatt hydro-electric development at Cat Arm has a high capital cost of $259 million compared to a 150 megawatt thermal alternative, which costs less than $100 million. However, the subsequent open-ended commitment for oil purchases is highly undesirable" (1979 Annual Report). By these numbers alone, the money spent at Cat Arm for energy considerations was at least 159/259 or 61% of the plant cost.

After examining the various methods available to Hydro for classifying its hydraulic plants between demand and energy, I recommend Method (5), the equivalent peaker approach, as the most sound.

Q. **Have you made calculations to apply such an approach to Hydro's hydraulic plants and can you describe how you did it?**

A. Yes, I have done such a calculation. I first gathered the installed costs of all of Hydro's production plants and the years they were installed. I then converted all the installed costs of both hydraulic and thermal plants to constant 1991 dollars using the Statistics Canada Electric Utility Construction Price Indices for Hydro-Electric and Fossil-Fuel Generating Stations. This removed any bias from inflation in the analysis. The following table summarizes the results:

GENERATING STATION UNIT COSTS

Plant	Rating (MW)	$/kW (1991$)
Hydraulic		
Bay d'Espoir	580	1,112
Upper Salmon	84	2,599
Hinds Lake	75	1,741
Cat Arm	127	2,557
Paradise River	8	2,744
Thermal		
Holyrood	475	766
Gas Turbines		
Stephenville	54	342
Hardwoods	54	338
Overall Gas Turbines	108	340
Diesels		
Overall Island	33	858

The above table shows the $340/kW cost of serving demand with gas turbines, such as those at Stephenville and Hardwoods, is clearly less than the cost of serving demand with steam or hydraulic units ($766/kW to $2,744/kW). The extra investment has been made to achieve cheaper energy supplies, because hydraulic and thermal steam units are cheaper to run.

I next took the cost of the gas turbines at Stephenville and Hardwoods as the equivalent cost of supplying only demand. This amount per kW was divided by the actual cost of building hydro plants, in $/kW in $1991, to arrive at their demand/energy splits. For example, Upper Salmon gives 340/2599 = 13.1%. The following table shows the results.

Plant	Rating (MW)	%Demand
Bay D'Espoir	580	30.6%
Upper Salmon	84	13.1%
Hind's Lake	75	19.5%
Cat Arm	127	13.3%
Paradise River	8[1]	31.3%
Overall Hydraulic	874	18.7%

[1] The Paradise River calculation used $858/kW diesels as the equivalent peaker due to its small size.

The overall result is that only about 19% of the hydraulic plant should be classified as demand related under this method. This contrasts dramatically with Hydro's proposal to move these plants from the old 43% demand to 56% demand. Hydro's proposal is a move in the wrong direction. We should be classifying less, not more, of these plants as demand related.

Q. How should Hydro's thermal production plant be classified?

A. Just as there are many methods to classify hydraulic production plant, there are many methods for classifying thermal production plant between demand and energy. In fact, similar methods can be used as follows:

(1) Fixed and Variable

(2) Use of the Facilities

(3) Capacity Factor Methods

(4) Arbitrary Splits

(5) Equivalent Peaker Approach

Method (1) for the thermal plants again assigns all fixed costs to demand. All variable costs, such as fuel, are assigned to energy. The same problems with the logic apply here as they did to hydraulic plant. This method ignores the fact that fossil steam plants are more expensive than gas turbines and that additional investment is made to provide cheaper energy. Hydro is recommending the use of this method which results in the Holyrood thermal plant classified as 100% demand related.

Methods (2), (3) and (4) work essentially the same way as they did for hydraulic plant and also suffer from similar problems to those pointed out in the hydraulic section.

Method (5) uses the same principle of causality on the thermal plants as was used on hydraulics to determine how much extra investment was made to build efficient fossil plants that save on energy costs, rather than inexpensive gas turbines. In method (5), the cost of a gas turbine that could have been built to serve short duration demands is subtracted from the cost of the fossil steam plant to determine the additional amount that was spent to save on energy costs. Method (5), the equivalent peaker method, again best satisfies the goal of assigning costs to the factors that caused them. Therefore, I recommend its use for Hydro in this cost of service proceeding.

Referring back to the table on installed costs of Hydro's units in the hydraulic section (on page 20), we see that the Holyrood thermal plant cost $766 per kilowatt, while a gas turbine cost about $340 per kilowatt. If we divide the $340/kW by the cost of Holyrood of $766/kW, we see that only 44% of the cost of the plant was spent to serve demand ($340/$766). A proper classification of the investment cost in thermal plant therefore results in a 44% demand classification. All fuel should be classified as energy.

Q. Should there be adjustments to the way fuel is allocated to the rate classes when using an equivalent peaker approach?

A. Yes. The basis of the equivalent peaker approach to classifying generating plant is to assign only the equivalent investment in peaking plant to demand. The remainder of the investment in efficient base load plants is allocated according to each classes' share of the energy on the system. Since fuel costs are higher for peaking units, it is not fair to also ask customers to bear the higher cost of peaking fuel in their energy costs. Some adjustment must therefore be made to account for this effect.

There are two adjustments I am aware of to account for the higher peaker fuel cost under an equivalent peaker method. The first method allocates average hourly fuel costs to every rate class according to that classes' share of the load for each hour of the year. This method requires large amounts of data on class hourly loads and average fuel cost by hour. It is therefore difficult to use this method in many cases.

The second method simply assigns the cost of peaking unit (gas turbine) fuel to demand. That is, not only is the equivalent investment in peakers assigned to classes based on their demands, but so is the higher cost of actual fuel used to operate these units. It has the advantage of being very simple to use. I would recommend its use whenever hourly class load shapes and hourly average fuel costs are not available.

Issue Three

Q. How should Hydro's transmission facilities be classified?

A. To answer this question, we must examine why the transmission facilities were constructed as they were. Applying the principle of causality, we ask what makes the cost of transmission facilities go up or down? The answer is that several factors contribute to the cost of transmission lines and associated substation facilities. One factor is the size or rating of the lines, transformers and breakers. These sizes are often a direct result of the expected peak demands on the transmission system. The other factor is that investments in these facilities are made to save on energy costs.

If we constructed a system to serve only short duration peak demands, we would most likely build gas turbines or diesels close to the load centres. We would still need essentially the same substation facilities, but the lines would be very short. Because larger baseload plants and hydraulic plants are remotely located, much of the cost attributable to the length of the lines is due to the fact that they were constructed over long distances to save on energy costs. Hydro alludes to this fact in commenting on the reasons for building lines to remote locations in its official documents, such as the 1983 Annual report, where they stated,

> "The most notable achievement in the 1983 transmission and terminal program was the completion of 84 kilometres of 138/69 kV transmission line from Hawkes Bay to Flowers Cove on the Great Northern Peninsula. This transmission facility interconnected approximately 30 communities from Castors River to Eddies Cove along the northwest coast of the Island. These communities had previously been supplied from diesel generating systems and their connection with the grid resulted in lower electricity rates for approximately 1800 families and savings of many thousands of gallons of diesel fuel." (Newfoundland and Labrador Hydro, 1983 Annual Report, P. 12)

Transmission lines also have the effect of improving the reliability of power supply in isolated areas. This can be dramatic over all hours, not just at times of system peaks. It therefore means that these reliability improvements are properly more proportional to energy use than to peak demands.

With an interconnected system like Hydro's, it is very difficult to devise a method for fairly determining how much of the cost of each transmission line connecting geographically dispersed areas is related to demand and how much is related to energy. In the final analysis, the fairest approach seems to be one of classifying all substation and terminal equipment as 100% demand related, even though some of the investment in these facilities is for energy savings. The cost of the transmission lines themselves should be classified as 50% demand and 50% energy related.

Issue Four

Q. How should Hydro's hydraulic and thermal generating plants be allocated?

A. If a proper job of functionalization and classification is done as we have done it here, deciding on the proper way to allocate each functionalized and classified cost is much easier. Costs classified as demand related should be allocated to the rate classes in proportion to that classes' share of the demand characteristic causing the costs of hydraulic and thermal production plant to increase or decrease. For the share of the production plant costs we have classified as varying with energy consumption, we should allocate those costs to the classes based upon their share of the energy produced.

That portion of the production plant costs classified as being related to demand should be allocated according to the demand characteristic causing those costs to increase. In the case of Hydro's demand related production costs, the peak demands on the generation system cause Hydro's Loss of Load Probability to increase and therefore cause Hydro to add plant to serve demand. The five winter months of November through March have the highest peaks (all within 80% of the maximum yearly peak) and contribute most to the loss of load probabilities (See response to Demand for Particulars, NP-20, 1992(G)). It is therefore recommended that class coincident peak demands in all five of these months be used to allocate the demand related portions of production plant.

Q. How should Hydro's transmission lines be allocated?

A. The demand related portions of the transmission plant should be allocated on the same 5 month coincident peaking (Hydro's total system 5 CP) methodology as was used to allocate production demand related costs. This is because the same demands that occur on the generation system also occur at the same time on the transmission system. The energy related portions of the transmission system should be allocated on energy plus losses at the transmission system level.

Q. Dr. Sarikas at page 21 of his evidence proposes using the CP method for allocating distribution capacity cost to the Hydro Rural customers. Do you agree with this allocation?

A. This treatment of distribution facilities is inconsistent with the discussion on pages 96-98 of the 1992 NARUC Cost Allocation Manual of how these facilities should be allocated. Dr. Sarikas testified that an examination of the geographic distribution of feeder loads and load characteristics led him to believe that the Hydro distribution facilities are more closely related to Hydro Rural Interconnected rate class coincident peaks (CP) than non-coincident peaks (NCP). Dr. Sarikas also acknowledged that his method "probably isn't a pure Coincident Peak approach" (See Hydro 1992 Referral, transcript page 487). He went on to say that a different geographic dispersion of class loads, which would be more likely in the urban areas served by NP, could dictate an NCP allocator for distribution facilities, and that he had no problem with NP using NCPs to allocate distribution. Therefore, while I fail to see how every rural distribution feeder can be as homogeneous as Dr. Sarikas believes, I have no evidence to the contrary. With all these caveats, I take no issue with Dr. Sarikas' recommendation on Hydro's cost of service approach on this issue.

<u>Issue Five</u>

Q. How should the Hydro Rural revenue deficit be allocated?

A. Unfortunately, there is no causal theory to guide us here. This deficit was not created by demand, energy, or number of customers. Only the principle of fairness can assist in resolving this issue. Hydro has proposed allocating this deficit on the basis of revenues contributed by the various classes. NP pointed out in the last referral that this method does not seem fair, because certain customers, such as the ones in the Labrador Interconnected area have very low rates and would not pick up a fair share of the costs this way. The Board acknowledged in its report on the 1992 Hydro Rate Referral that at least the Labrador portion of this argument was troublesome.

I recently investigated how regulators in the U.S. have allowed costs that have nothing to do with the cost of serving certain classes to be allocated. The states of California, Florida, Iowa, Maryland, Montana, New Hampshire and New Jersey responded that they allocate some social costs, such as uncollectibles or life-line subsidies, on energy.

My evidence in the 1992 Hydro Rate Referral pointed out that there is no scientific way to resolve this question, but that a 50/50 split between energy and revenues seemed more fair to me than the revenue only split.

I therefore respectfully recommend that the Board consider allocating the Rural Revenue Deficit 50% on energy and 50% on revenues.

As an alternative to NP's preferred method described above, the Board may wish to consider another method. In this method, the total deficit would be separated between the Island system and the Labrador system on the basis of energy sales. These distributions would then be allocated to customer classes within each area according to revenues.

Issue Six

Q. How should interruptible load that is expected on Hydro's system in late 1993 be treated in the cost of service study?

A. Interruptible load is by definition, load that is the first shed when the utility is short of capacity. In addition, utilities do not usually plan generation capacity and some portion of their transmission capacity to serve interruptible customers. Because generation and transmission capacity may be avoided for these customers, they expect a lower demand charge than firm customers in exchange for being interruptible.

There are several acceptable ways to treat interruptible customers in the cost of service study. The first way was discussed by Dr. Sarikas in the 1992 Hydro rate referral (on pages 506-508 of the hearing transcript). As Dr. Sarikas pointed out it is not necessary to actually run the cost of service study differently for interruptible customers. Instead, he argues that all demand related generation and transmission costs could be allocated to them, as if they were firm customers. They would simply be given a rate credit representing the annualized savings the utility is expecting from not having to build generation and some transmission to serve them. The rate credit would create a revenue shortfall for the utility, and Dr. Sarikas recommends some type of adjustment clause to collect this shortfall from the firm customers. The use of such a clause would alleviate the need for treating the interruptibles differently in the cost of service study.

Another common method for handling interruptible load is to reduce their demand at the generation and transmission level in the cost of service study. This will in turn reduce the amount of generation and transmission demand related costs allocated to them. Any portion of the interruptible customer load that is not interruptible is treated in the conventional fashion (as firm load).

No matter which method is used, judgement must be used in setting the rate credit, or in deciding how much to reduce the interruptible customer demand. When customers have been interruptible for many years, it is reasonable to assume that some generation and transmission facilities have been avoided by not having to serve them when capacity is short. There may still be a need to construct certain localized transmission facilities to serve them at off peak times so this must be taken into account. If the rate designer can have reasonable assurance that facilities have been avoided by having interruptible customers, their entire demand at that level may be reduced to zero in the cost of service study. This latter practice is sometimes perceived as unfair, especially if the rate designer knows that generation and transmission facilities have large energy cost relationships that have been treated as demand related. For instance, if all generating plant is classified as demand related and allocated that way, reducing interruptible customers demands to zero at the generation level would mean they would not contribute to the fixed generation costs while receiving its benefits.

Another problem exists in deciding how to treat new interruptible customers for which no facilities have yet been avoided. Until such time as new capacity would be needed to serve all customers, these interruptible customers have a smaller capacity related value to the utility, nor is it likely they would be interrupted. A strict application of giving credits only at such time as facilities are avoided would result in no interruptible demand reductions or rate credits. This scheme would not be likely to attract many interruptible customers. Since interruptible customers are desirable to avoid expensive new facilities, most utilities like to attract them. In that sense, they are like other demand side management programs. We must start them now to have them when we need them.

What is often done in the case of interruptible customers, like the future Hydro interruptibles we are discussing here, which will avoid only future facilities, is to calculate the future savings they may create. Some portion of this savings is then present valued and distributed as a credit over the life of the interruptible contract. If the entire value of the future savings is given to the interruptible customers there is little benefit to other customers from having them on the system. For that reason, only some portion of the savings necessary to attract and keep interruptible customers is returned. Any lost revenues in the current period can be accounted for in the cost of service study or could be applied to a recovery clause. Where the lost revenues are uncertain the clause may be preferable.

At the time interruptible customers become a reality, I would recommend that the exact details of the impact on cost allocation among customer classes should be reviewed by the Board.

VII. Impacts of Changes on Customer Classes

Q. Have you calculated the impact of your proposed changes in the cost of service study methodology on the individual Hydro rate classes?

A. Yes. I have. In order to calculate the class revenue impacts of the proposed cost of service changes, NP created a model to replicate Hydro's cost of service study. For simplication, all of Hydro Rural Rate classes were collapsed into one class, Hydro Rural. Also, only the Island Interconnected portion of the model was duplicated, since the breakdown within the Isolated and Labrador Interconnected Systems was not necessary for this analysis. NP's model was used to generate the results for LBB-1. The model was first benchmarked to ensure that it would generate the same results as Hydro's model by using all the assumptions in Scenario 4 (Hydro's recommended method) and verifying that the results were the same as RAB-1, Hydro's results. Both NP's recommended scenario (Scenario 1) and the benchmark to Hydro's RAB-1 (Scenario 4) are attached as Appendices 2 and 3 respectively.

LBB-1 shows the revenue impact on NP and the Industrials under four scenarios. Scenario 1 represents the cost of service methodology I am recommending. It uses the equivalent peaker method to classify generation plant. Hydro's actual historical peaker cost of $340/KW is used as its basis. Fuel is classified as 100% energy related, except combustion turbine fuel, which is 100% demand related. Transmission terminal equipment and substations are classified as 100% demand, with transmission lines themselves 50% demand and 50% energy related. Facilities serving only Hydro Rurals and previously (until Hydro's last referral) assigned to these customers, have been directly assigned to Hydro Rurals here. Finally, the average of each classes' 5 winter month coincident peaks have been used to allocate generation and transmission demand related costs. This scenario, which I recommend as the most causally based, results in a revenue requirement of $189.3 million to NP and $48.4 million for Island Industrials.

Scenario 1 can be contrasted with the revenues allocated to the classes under Scenario 2, the 1977 method approved by the Board (per RAB-2). The 1977 method classified generating plant 50% demand and 50% energy modified by the actual capacity factor of the plant compared to system capacity factor. Plants that have capacity factors which exceeded the system capacity factor received more energy weight under this method. Fuel costs at each generating unit were classified to demand and energy according to this modified 50/50 demand/energy classification method. All transmission plant was classified 50/50 demand/energy, and the facilities serving only Hydro Rurals on the Great Northern Peninsula were directly assigned to them. Both generation and transmission demand related costs were allocated with the average and excess demand (AED) allocator. There was no rural revenue deficit allocated in 1977, but it was allocated 100% on revenue in this scenario to be consistent with RAB-2.

The results for Scenario 2 show $193.6 million and $45.0 million allocated to NP and Island Industrials, respectively. The $3.4 million shift from Island Industrials to NP is caused by the fact that the 1977 method was more heavily weighted towards demand than in Scenario 1, the NP recommended equivalent peaker method. This is true even though generating plant has been classified to demand and energy before using the AED method to allocate costs. Effects such as these are exactly why I disagreed with Hydro's contention in the 1992 Rate Referral that to pre-classify any portion of thermal generating plant as energy related was "double counting". The pre-classification may be semantically "double counting" but the important question is how close we get to a correct result.

Both the AED methodology and the equivalent peaker methodologies are characterized by the 1992 NARUC Manual as energy weighting methods which are required because, "...there is evidence that energy loads are a major determinate of generation plant costs." (NARUC 1992 Electric Utility Cost Allocation Manual, page 49).

Scenario 3 was run to test the sensitivity of the NP recommended approach to the assumptions used in Scenario 1. The philosophy behind Scenario 3 was to create a method which was still causally based, but one in which demand was very heavily weighted. In addition, the allocation of the rural deficit was assumed to go to 100% revenue. In Scenario 3, the cost of the equivalent peaker was doubled from the actual historical costs Hydro reported. All transmission was assumed to be 100% demand related. The facilities previously assigned to Hydro Rural customers were kept that way. The average of the 5 monthly coincident peaks (5 CP) was used to allocate generation and transmission demand related costs.

The results for Scenario 3 show that even giving too much weight to demand in a causally based method does not result in allocations to NP and Island Industrials much different than the 1977 method. The $195 million and $43.8 million allocated to NP and Island Industrials in Scenario 3 compares to $193.6 million and $45 million in the 1977 method, shown in Scenario 2.

Scenario 4 was run using Hydro's recommended methodology. In this method, all generation plant is classified as 100% demand related. All fuel is energy related. Transmission plant is also assumed to be 100% demand related. The rural revenue deficit is allocated 100% on revenue. Facilities serving only Hydro Rurals on the Great Northern Peninsula were treated as common to all customers, and the AED method was used to allocate generation plant. Transmission plant was allocated using single coincident peak (CP). The results of Scenario 4 show that this method results in $8.1 million and $3.8 million more revenue allocated to NP than the more causally based method in Scenario 1, and the Board approved 1977 method in Scenario 2, respectively. The effect occurs because Hydro's recommended method is too heavily weighted towards demand.

Q. Given that the revenue requirements allocated to NP by Hydro's recommended method are less than 5% greater than the method you recommend, should the Board really be concerned about which cost of service method is used?

A. Yes, even though the differences between the cost of service revenue allocations may appear small in percentage terms on LBB-1, $8 million is still a lot of money. In doing a comparison of this kind, one must remember that NP is by far Hydro's largest customer. This means that any change in revenue responsibility between NP and the Industrials will not represent a large percentage increase to NP's purchase power costs. If we do the same sort of comparison on the Industrials, we see that Hydro's proposal reduces the Industrials revenue responsibility by as much as 13.6%.

Cost of service studies are also used for more than just allocating total revenue requirements to the classes. Another important use for the cost of service studies is in rate design within a class. The starting point for rate design is often times something called the "per unit costs" or "unit costs" from the cost of service study. Unit costs are derived for demand, energy and customers for each class by dividing the associated demand, energy and customer related revenues of the class by the amount of demand and energy sold, and the number of customer bills which will be rendered in the year. These unit costs are then compared to the demand, energy and customer rate components to see the extent to which each rate component reflects cost.

An example of using unit cost for rate design might be instructive. Assume that a cost of service study produces unit costs for demand and energy of $10/kW-month and 4¢/kWh. If the existing rates were $6/kW-month and 6¢/kWh, we could conclude that the demand cost was too low and the energy cost too high.

The per unit costs for demand and energy between Hydro's recommended cost of service method (Scenario 4) and the one recommended by NP (Scenario 1) are quite different as the table below indicates:

COMPARISON OF DEMAND/ENERGY SPLITS

	Demand Unit Cost ($/kW - month)	**Energy Unit Cost (¢/kWh)**
Scenario 1		
NP's Recommended Method [1]		
Newfoundland Power	5.11	2.950
Island Industrials	4.80	3.000
Scenario 4		
Hydro's Recommended Method [2]		
Newfoundland Power	10.95	1.530
Island Industrials	10.52	1.542

[1] Appendix 2, page 2, lines 719-720
[2] RAB-1 (Rev), page 6 of 60, lines 1 - 2

The demand unit costs for Scenario 1 are one-half those of Scenario 4. The unit energy costs, on the other hand, are double in Scenario 1. Demand and energy rates derived from these two approaches would also be very different. The unit energy costs of Scenario 1 are roughly equivalent to the marginal energy costs from Holyrood (about 3¢/kWH). It is a common practice to make sure that the energy run-out rates (rates for the last energy block) are close to short run marginal energy cost. Unit costs from Scenario 1 would certainly come closer to being directly useable for rate design than unit costs from Scenario 4.

Finally, the relationship between demand costs and energy costs may change when Hydro adds new plant. If the Labrador Infeed line from Churchill Falls ever materializes, the large capital expenditure will be justified primarily on energy savings. Therefore, the transmission line from Churchill Falls should have an energy weighting greater than the 50% recommended in Scenario 1. Adopting an approach which is causally based now should ensure that the proper relationship between demand and energy is maintained in the future.

VIII. Recommendations to the Board

Q. Based on your examination, please summarize your final recommendations to the Board on these matters.

A. After examining the evidence, my recommendations on the proper cost of service method for Hydro are as follows:

(1) That Hydro functionalize generation, transmission and distribution plant serving only Hydro Rural customers only to Hydro Rural, and not as common;

(2) That Hydro classify hydraulic and thermal production plant between demand and energy based on an equivalent peaker method;

(3) That Hydro classify transmission lines as 50% related to demand and 50% related to energy, and substation and transmission terminal equipment as 100% related to demand;

(4) That Hydro allocate the demand related portions of hydraulic and thermal production plant and transmission plant to the rate classes based on a 5 CP demand allocator. Energy related costs should be allocated on energy weighted for losses;

(5) That Hydro allocate the Hydro Rural revenue deficit between Labrador and Island Interconnected customer classes, 50% on revenues and 50% on energy; and,

(6) That at the time interruptible customers become a reality, the exact details of the impact on cost allocation among customer classes should be reviewed by the Board.

Newfoundland Light & Power Co. Limited
Summary of Cost of Service Scenarios

Scenario	Revenue Allocated to Classes NP $(000's)	Island Industrials $(000's)	Labrador Industrials $(000's)	Labrador Rural Interconnected $(000's)	Total $(000's)
1. Recommended by NP					
- $340/kW Equivalent Peaker Generation Classification	189.3	48.4	5.0	11.6	254.3
- Fuel 100% Energy except Gas Turbines 100% Demand					
- Transmission Lines 50/50 Demand/Energy; Substation and Terminal Equipment 100% Demand					
- Deficit Allocated 50/50 Revenue/Energy					
- Northern Peninsula Directly Assigned					
- 5CP Allocator Generation/Transmission Plant					
2. Previous (Approved '77 Method)					
- Generation 50/50 Demand/Energy Adjusted for Capacity Factor (including fuel)	193.6	45.0	4.6	11.1	254.3
- All Transmission Plant 50/50 Demand/Energy					
- Deficit Allocated 100% Revenue (per RAB-2) [1]					
- Northern Peninsula Directly Assigned					
- AED Allocator Generation/Transmission Plant					
3. High Sensitivity by NP					
- $680/kW Equivalent Peaker	195.0	43.8	4.3	11.2	254.3
- Fuel 100% Energy except Gas Turbines 100% Demand					
- All Transmission Plant 100% Demand					
- Deficit Allocated 100% Revenue					
- Northern Peninsula Directly Assigned					
- 5CP Allocator Generation/Transmission Plant					
4. Recommended by Hydro					
- Generation Plant 100% Demand	197.4	41.8	4.2	10.9	254.3
- All Fuel 100% Energy					
- All Transmission Plant 100% Demand					
- Deficit Allocated 100% Revenue					
- Northern Peninsula Common					
- AED Allocator Generation Plant					
- CP Allocator Transmission Plant					

[1] Deficit Allocation Method was not an issue in 1977 - 100% Revenue Allocator was used in RAB-2.

APPENDIX 1

Chernick and Meyer

"Capacity/Energy Classifications and Allocations for Generation and Transmission Plant"

Award Papers in Public Utility Economics and Regulation

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Michigan State University
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Capacity/Energy Classifications and Allocations for Generation and Transmission Plant

Paul L. Chernick
and
Michael B. Meyer

In the current ratemaking system, every electric utility rate case necessarily covers three conceptually distinct subjects: estimation of total revenue needs and total revenue deficiency; allocation of total revenue needs and total revenue deficiency to the various customer classes (revenue allocation); and allocation of revenue needs within each customer class to various customers with differing usage patterns (rate design). As a result of many interrelated factors — such as the rapid increase in oil prices since 1973, the passage of the Public Utility Regulatory Polices Act of 1978, and the widespread recognition of the benefits of increased conservation incentives and of prices more accurately reflecting the costs of service — a major reform movement is under way in the United States to modify the way in which the electric utility industry accomplishes the revenue allocations among customers within classes, usually referred to as rate design. Initiatives to institute time-of-use pricing, marginal cost pricing, and lifeline rates are only a few examples of these suggested rate design reforms.

By comparison, although the second step in the ratemaking process, which involves revenue allocations between customer classes, is as important as the rate design step in every respect, it has so far attracted much less attention. This relative lack of attention to interclass revenue allocations exists among regulators, in the academic journal literature, in the industry's efforts and attention, and in the positions taken by would-be rate reformers. In short, the recent flurry of activity, discussion, and controversy over the rate design process has, by and large, not affected the interclass revenue allocation process.

The problem can be briefly stated. Revenue allocations are made to customer classes based upon the estimated costs of serving the classes. However, as the costs being allocated in the current ratemaking system are embedded costs,[1] and as a large percentage of these are joint costs, these allocations are essentially judgmental and cannot be rigorously justified by analytical methods. Furthermore, the present allocation methodologies were designed and adopted in a time when generation plant additions were not usually made for energy cost savings purposes, and when the $/kw costs of the different types of installed generation capacity varied over a much narrower range than do the various generation technologies currently available. Thus the present allocation methodologies require reexamination for two reasons: their lack of a rigorous analytical justification, and their nonresponsiveness to current generation planning considerations.

This paper first describes the traditional solution to the revenue allocation problem as it is widely applied in the United States today. It then recommends an improvement to the current practice, focusing upon the causes for constructing different types of generating capacity in terms of $/kw of capital cost, ¢/kwh of energy cost, and expected capacity factors. The last section offers brief concluding remarks.

The Traditional Solution

The interclass revenue allocation problem (the second of the three ratemaking steps) has traditionally been solved itself in three steps. First, costs are *functionalized* in production, transmission, subtransmission, and distribution cost categories depending upon the purpose served by the operating expense or capital expenditure. Second, these costs are *classified* as energy related, demand related, or customer related. Third, the demand portions of these costs are *allocated* by some method to the various customer classes.[2]

Functionalization can be based upon fairly clear-cut engineering considerations for most capital expenditures. With the exception of the joint cost problem, which appears for some overhead and administrative expenses, functionalization is not very controversial; it is quite uncontroversial as to the capital expenditures under consideration here, for example, for generation and transmission plant.

The steps of classification and allocation, however, are potentially quite arguable, at least as they are currently applied to generation and transmission plant capital expenditures. First, all or essentially all costs for these items are joint costs. With few exceptions, generation plant capital expenditures are usually classified as entirely demand related.[3] Second, once the generation plant capital expenditures are classified as entirely demand related, they are then allocated to the various customer classes by essentially arbitrary (but long-established) methods, such as the contribution to system coincident peak, the non-coincident peak, the average-and-excess, the weighted average of the contributions to summer and winter peaks, or the twelve monthly peaks methods.

The second step, which currently classfies all (or almost all) generation plant to demand, does not appear to be justified in view of the fact that different generating technologies (with different $/kw and ¢/kwh costs) are installed to serve different parts of the load duration curve at different load factors. In other words, a large percentage of generation plant capital costs are currently incurred to minimize total generation costs, including energy costs [Crew and Kleindorfer 1976; Wenders 1976].

The third step, which currently allocates all demand-related generation plant capital costs to peak or some intuitively derived alternate measure of peak, is not justified because it is well established that off-peak demand contributes measurably to total system reliability needs [Vardi and others 1977; compare Kahn 1971 at I:89–103].

Indeed, the traditional solution tends to conflate the problems of classification and allocation. It may be hypothesized that much of the motivation for the use (in step three) of allocation methods other than the contribution to coincident system peak method stems from a desire on the part of electric utilities to correct in some rough and intuitive fashion for the problems caused by the classification (in step two) of all generation plant capital expenditures to demand, which, in fact, appears to understate substantially the energy-related portion of these expenditures. In other words, it seems plausible that the utility industry is attempting to compensate for the under-recognition of energy-related expenses in step two by intuitive means in step three, through the use of allocation methods other than the contribution to system peak method, although no attempt is made to measure the relative size of the "mistake" and the corresponding "correction."

The Minimum-Cost Reliability Serving Method

We believe a set of classification and allocation principles may be derived which can satisfy the concerns raised above. Since cost classifications are more a matter of subjective measures of equity than of objective measures of efficiency, the derivations will not consist of the mathematical progression of equations that characterizes the development of efficient pricing structures. Rather, we will present a series of principles, joined by logical arguments and occasionally restated in the form of equations. We start with our fundamental principles:

> *Principle 1:* The reliability related portion of power supply production investments and nonfuel expenses is the minimum cost associated with providing the desired reliability level, or the actual reliability level, if that is lower. The remaining power supply production costs should be classified as energy.

This principle embodies a "reliability first" conception of system planning. When the utility builds generation capacity it first concentrates on maintaining adequate reliability; only after a reliable system is provided do the planners turn their attention to fuel cost reductions. Since both system reliability and energy costs are designed in simultaneously, the reliability first assumption refers more to a conceptual hierarchy of priorities than to a temporal sequence.[4]

We base our classification technique on the reliability first principle for two reasons. First, we believe it is historically correct. System planners have traditionally been more worried by the prospect of disconnecting customers and shedding load than by an increase in running costs. While attitudes may have changed somewhat in the 1970s, due to large increases in fuel costs, most utility systems probably embody this order of priorities. Second, Principle 1 provides us with fairly specific and tractable directions for deriving a classification scheme. While implementation of the principle is not without complications and controversy, it is relatively easy to determine whether a classification approach is generally consistent with it. We recognize that Principle 1 is not the only contender for a fundamental principle of classification, and we present alternatives in Appendix A.

Principle 1, and other classification principles, are stated in terms of dividing power supply costs into energy-related and reliability related components. The use of reliability in lieu of the more common term demand reflects our concern that the latter has been too long associated with peak load and capacity, and that old habits of thought are hard to break. In reassessing the relationships among capacity, reliability, and load shape, it is advantageous to start with as clean a slate as possible.

The confusion between reliability serving costs and the larger class of capacity costs (or fixed or capital costs) is deeply rooted in the utility industry and often confuses analysis of a variety of issues. For example, a recent article on load management and oil-backout policies concluded that the Long Island Lighting Company (Lilco)

> can justify having higher reserves than required for reliability . . . to substitute nuclear base-loaded plants for oil base-loaded plants. As Lilco's system becomes more heavily nuclear the relationship of its fixed costs to its variable costs will change substantially. Nuclear plants have relatively high-capital costs and low-fuel costs; whereas, oil plants have relatively low-capital costs and high-fuel costs. If we assume that future rates will generally track costs, then demand-related charges will have to rise in relation to energy-related charges. Then assuming all other things being equal for the moment, rates for low-load factor customers will rise faster than rates for high-load factor customers. Since residential customers, as a class, almost always have significantly lower load factors than the industrial customer class, one result from Lilco's converting to a lower cost operating system through installing nuclear plants is likely to be relatively higher residential rates in respect to industrial rates [Koger 1980].

In other words, the implicit assumption that capital costs must be recovered from demand-related charges leads Koger to conclude that residential customers should pay for the nuclear plants that are built to reduce the industrial customers' fuel charges. Clearly, a new mode of thinking about fixed costs is required.

Another set of clear examples of the inadequacy of the prevalent allocation of all fixed costs to demand involves the treatment of fuel storage and treatment facilities. If an oil desulfurization unit, or a coal gasifier, is owned by a supplier who sells the high quality product to the utility, the cost of the treatment facility is rolled into the fuel cost and is therefore treated as an energy charge. If the uility buys is own treatment facilities, they would generally be treated as part of fixed plant and allocated to demand. In either case, the treatment facilities serve exactly the same purpose: to reduce fuel costs. All extra fixed costs incurred to reduce fuel costs are clearly energy related, regardless of whether the extra cost is located at a supplier's plant or beside the utility's generator. The same is true of the additional cost of a coal plant as compared to a less expensive gas-fired plant: The incremental investment is a fuel-saving measure and should be classified as energy serving.[5]

Principle 1 implies that the reliability related portion of a power supply system is the lowest cost system which would provide a particular level of reliability. Certainly, reliability users should not be charged for more reliability than they are actually receiving, so the reliability of the reference, low-cost system need never exceed actual levels. Where the actual reliability is greater than or equal to target reliability, the reference system should generally be designed to the target levels. This follows from the observation that excess capacity is generally the result of the long lead times of base load units (which caused accidental overcapacity starting around 1974 in many parts of the country) and of the effort to replace oil and gas-fired generators with other fuels (which will cause intentional overcapacity in the 1980s). In general, the hypothetical minimum-cost reliability serving system will consist of relatively small units with short lead times and will not consider fuel costs at all. Thus, the reference system should not incorporate overcapacity, unless unusual circumstances (such as a very abrupt drop in load) suggest that the overcapacity would have occurred even to an all-peaking system.

> *Principle 2:* For any generation unit built after 1963, the reliability related cost is generally that of an array of gas turbines with the same contribution to reliability and of the same vintage.

Gas turbines are chosen as the standard reference system because they are cheap and site independent. Under some circumstancs, other types of capacity (building conventional or pumped hydro, retaining obsolete generators, special purchase agreements) may be known to be cheaper for some amount of capacity; this will vary among systems, depending on the extent of current hydro development and purchases and of information on past and future options. Where identified, such cheaper capacity should be used as the basis for reliability/energy classifications. The 1963 cutoff was chosen to reflect the fact that gas turbines were not widely available prior to that date, as evidenced by the fact that the Handy-Whitman price index for gas turbines originated in 1964.

We interpret "the same contribution to reliability" to mean the effective load carrying capability (ELCC) or something quite similar. ELCC [Garver 1965] is the amount of additional firm load that a generating unit allows a system to accommodate without violating its reliability constraint. Thus, if the system can carry 11,000 MW without the unit, and 11,500 MW with it, the unit's ELCC is 500 MW.

Ideally, it would be desirable to model the ELCC of each unit in the utility's actual system to reflect the effect of the utility's load curve, generation mix, and tie lines. Since the ELCC of a large marginal unit increases as the number of such units increases (the sixth 500 MW coal plant has a higher ELCC than the first), the ELCC of each unit should ideally be determined by adding the units in chronological order to the current system of pre-1964 units and peaking units. This level of detail and specificity will not always be possible; we suggest a simplified alternative below.

One might also wish to construct the reference system from the actual system on a unit-by-unit basis, accounting for plant in service, return, non-fuel O&M expense, accumulated depreciation, deferred taxes, depreciation expense, property taxes, and income taxes to develop a total cost in the rate year for each unit. There are three drawbacks to this approach. First, the calculations may be very time consuming for systems with many units and may be virtually impossible if units within a plant (possibly of very different sizes, vintages, and ELCC's) are aggregated in the available accounting data. Second, the components of the reference system must be "aged" to determine accumulated depreciation, deferred taxes, additions to capital cost, and property taxes, which requires assumptions regarding past and present tax treatments, depreciation rates, and capital additions. Third, if accumulated depreciation is reassigned from demand to energy along with the associated plant, the (low load factor) groups who paid for depreciation expense in the past will not generally receive the benefits of the accumulated depreciation they contributed; thus, the detailed accounting does not, in itself, produce as great an increase in equity as might be hoped.

In a previous application [Meyer and Chernick 1980], we simplified the modeling by assuming that all current cost components (except O&M) vary in proportion to initial construction cost, so that for unit *i*,

$$CGT_i = CM(BY) \times \frac{HW(COD)}{HW(BY)} \times ELCF_i \times MW_i \qquad (1)$$

where

CGT_i = cost of a gas turbine equivalent to unit *i* under the terms of Principle 1;

$CM(BY)$ = cost per MW of gas turbine index as of the base year;

$HW(COD)$ = Handy-Whitman gas turbine index as of the commercial operation date of unit *i*;

$HW(BY)$ = Handy-Whitman gas turbine index as of the base year;

$ELCF_i$ = effective load carrying factor, defined as (ELCC/MW for unit *i* ÷ ELCC/MW for gas turbines); and

MW_i = capacity in MW of unit *i*.

For nonfuel O&M expense for unit *i*,

$$OGT_i = OM \times ELCF(i) \times MW(i), \qquad (2)$$

where

OGT_i = O&M expense for unit *i* attributable to reliability; and

OM = current year nonfuel fixed O&M cost/MW for gas turbines.

> *Principle 3:* Steam units built prior to 1964 in primarily thermal systems may be regarded as entirely reliability related, unless a hydroelectric or other specific alternative was available.

Before 1964, units were not so specifically designed for peak or base load service; older units generally served as peaking plants, and the newest units provided the base load. Among today's base load plant types, before 1964 nuclear units were rare and heavily subsidized, while coal units, much less encumbered than at present by environmental regulations, were not much different in terms of initial capital cost per kw of capacity from oil-fired steam units. Before the gas turbine, the only real peaking alternative for thermal systems appears to have been the diesel, which has rarely been used on a large scale. For systems on which a reasonable series of diesel cost estimates can be developed, perhaps the method we suggest for post-1963 units can be pushed back some years. For systems with hydro capacity, the technique discussed in Principle 6 below may be helpful.

In general, the pre-1964 units will not be a large portion of the power production supply costs for three reasons. First, pre-1964 capacity is generally a small portion of total capacity. Second, the original cost of the old units was low; for example, Handy-Whitman all steam generation cost index for the North Atlantic Region in 1960 was 158 versus 505 in 1980. Third, the older units are largely depreciated; even a unit completed in 1963 would be about 50 percent depreciated for ratemaking purposes by 1980, and older units would be even more depreciated. Thus, the classification of old units will not generally be very important to the final allocations.

Exceptions may arise if old units have recently added pollution control or fuel conversion equipment, which would not have been necessary if the unit were a peaking plant for which the cost of fuel was relatively unimportant. Such equipment, especially in the case of coal conversion projects, may have a larger effect on rates than does the remaining balance of the unit and is generally 100 percent energy related.

> *Principle 4:* Where construction work in progress (CWIP) is included in the rate base, only the CWIP which would have accrued on a gas turbine of similar service date is attributable to reliability; the remainder is energy related.

One reason base load plants are so expensive is that they take a long time to build, during which period interest charges must be paid. If the interest portion of the construction cost is to be transferred to the rate payers, then the energy users, who receive most of the benefit from the plant, should also bear most of that interest cost.

Where CWIP is an extraordinary measure, permitted only for especially expensive investment, the gas turbine equivalent would have resulted in no CWIP at all, and all CWIP charges may be attributable to energy. This is particularly true when the unit for which CWIP is allowed is not required for reliability in the near future. If CWIP is allowed on all generation, then the amount of the CWIP on unit *i* in year *Y* attributable to reliability is

$$CWGT_i = CM(BY) \times \frac{HW(COD)}{HW(BY)} \times ELCF(i) \times MW(i) \times F(COD - Y) \times P, \quad (3)$$

where

$F(t)$ = the fraction of the final cost of a gas turbine which is invested t years before the COD; and

P = fraction of CWIP allowed in the rate base.

The F function is probably an S-curve, but we approximate it linearly as

$$F(t) = (L-t)/L \text{ for } L > t,\ 0 \text{ for } L \leqslant t, \quad (4)$$

where

L = construction time for gas turbines.

Two problems arise in applying Equation 3. First, COD is an estimate and, especially for nuclear plants, probably an underestimate. Using utility estimates of COD will frequently overestimate F. Second, again because COD is an estimate, $HW(COD)$ must be synthesized from a recent HW and an anticipated inflation rate. Neither difficulty is insurmountable and neither should obscure the basic reality; only a small portion of CWIP is attributable to reliability.

> *Principle 5:* Amortization of the cost of a canceled generation project should only be assigned to reliability to the extent comparable costs would have been incurred for an equivalent gas-turbine addition planned for the same COD.

The same principles apply here as in the case of CWIP. Base load plants require extensive advance preparation which is sometimes lost when events render further development impractical or inappropriate. In the mid-1970s, falling demand and rising oil prices resulted in cancellation of several oil-fired plants on which sizable sums had already been expended. More recently, regulatory actions, budget constraints, and continued conservation have resulted in the cancellation of numerous nuclear units.

In most cases, these cancellations occurred long before a gas-turbine project with the same planned COD would have required much commitment beyond (at most) land acquisition. Since the value of the site is seldom included in the amortization, essentially no amortization would have been necessary if gas turbines had been planned instead of base load units.

> *Principle 6:* For high load factor hydroelectric facilities built prior to 1963, the reliability related portion can be determined from the cost per kw for pumped hydro storage or a low load factor conventional hydroelectric facility of the same vintage.

Just as thermal plants are built more expensively than would be necessary if they were solely designed to meet reliability needs, so are hydroelectric plants. In the case of thermal plants, additional investment (in the form of building steam plants rather than gas turbines) buys lower heat rates (in Btu/kwh) and the ability to use cheaper fuels (in ¢/Btu). In the case of hydroelectric plants, additional investment buys higher capacity factors through such devices as larger capacity storage ponds. In either case, the additional cost is incurred to reduce fuel costs and accommodate high load factor customers and therefore should be classified as energy related.

Isolating the reliability related portion of hydroelectric facility costs involves two problems not encountered in analyzing thermal systems. First, hydroelectric plants exist on a continuum of capacity factors, from base load units (which may operate at 70 percent or greater capacity factors), to peaking units (which operate at capacity factors below 20 percent), to pumped storage hydroelectric units (which contribute no net energy and are designed for varying storage cycles). It is not always obvious what type of hydroelectric plant would represent the portion of the actual plant attributable to reliability. Second, unlike gas turbines, hydroelectric capacity costs ($/kw) are highly site dependent. Thus for each utility system, the cost of an additional kw of hydroelectric capacity varies with the amount of hydroelectric capacity already installed as well as with the capacity factors of the existing system and of the additions to the system. Therefore, some technique must be devised to separate the reliability serving portion of hydroelectric capacity on a utility-specific basis. (In some regions, such as New England, in which utilities commonly own generation outside their service territories, the perspective may be broadened to the region. This ameliorates, but does not remove entirely, the problem).

The first problem may be resolved by reference to the utility's load curves. On a system which experiences sharp, short-duration peaks, very low load factor pumped storage plants might provide adequate reliability; on a system with broader peaks and relatively high off-peak loads (precluding pumping), conventional hydroelectric facilities with higher capacity factors may be needed to carry load. An approximation to the capacity factor needed to replace the hydroelectric portion of a utility system can be determined from the load factor of the portion of the load duration curve corresponding to the installed capacity. Figure 1 illustrates this approach for a utility with 30 percent of its capacity in hydroelectric units. Note that serving the top 30 percent of the load duration curve requires a capacity factor of only about 10 percent. A more rigorous approach to selecting the reliability-serving hydroelectric component would involve the application of simulation models to determine the amount of each type of hydroelectric capacity required to maintain the reliability constraint; the least expensive alternative would be the reliability serving substitute for the existing hydroelectric capacity.

The second problem, relating to the variability of hydroelectric capacity development costs, can be resolved in several ways, depending on the kind of capacity which is being treated as reliability serving and on the extent of specific data about the system. If pumped storage hydroelectric capacity is an appropriate substitute for existing capacity, the cost of that pumped storage capacity may be available from site-specific or from generic regional studies.[6] Similarly, the cost of developing new low load factor hydroelectric facilities, or increasing the installed capacity (while decreasing the capacity factor) at existing sites, may have been previously established.[7]

If such economic studies are not available for enough low capacity factor sites to establish an alternative reliability serving system, or if such studies have excluded the most economical sites, currently occupied by high capacity factor hydroelectric facilities, it may be possible to estimate a general regional relationship between the capacity factor of a hydroelectric development at a site and the $/kw cost for that site. For example, an "economy of intensity" relationship, analogous to the traditional economy of scale, might be estimated as

$$\frac{\text{cost of plant 1 (\$/kw)}}{\text{cost of plant 2 (\$/kw)}} = \left[\frac{\text{capacity factor of plant 1}}{\text{capacity factor of plant 2}}\right]^{m}, \tag{5}$$

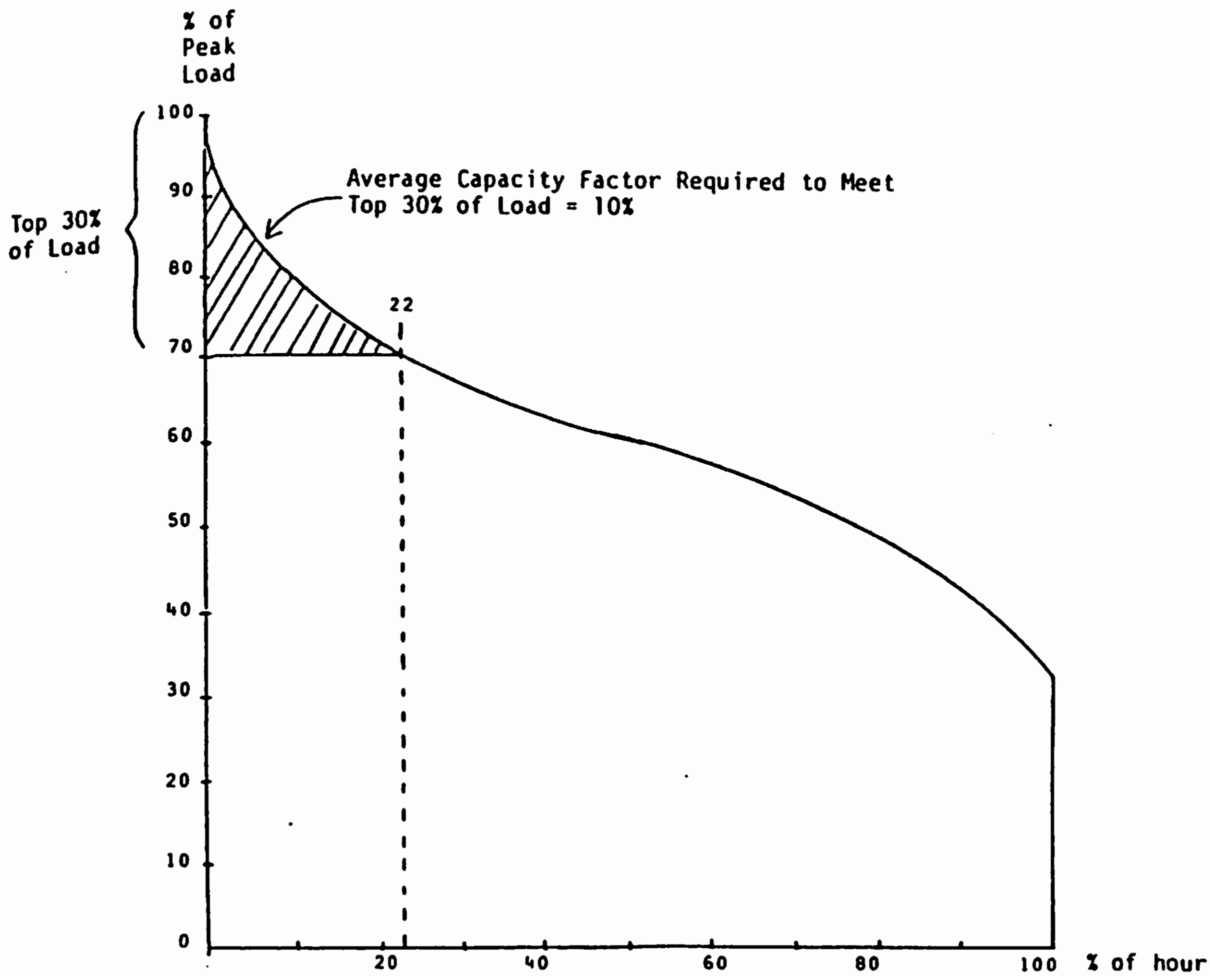

Figure 1. ***Calculation of Required Hydro Capacity Factor for Typical Load Duration Curve and 30 Percent Hydro Capacity***

where plants 1 and 2 are alternative hydroelectric developments at the same site, and *m* is the economy of intensity factor. Once the value of *m* has been determined for a representative set of hydroelectric sites, Equation (5) could then be applied to other representative sites by letting plant 2 be the existing facility (with known cost and capacity factor), assigning plant 1 the desired capacity factor for the reliability serving plant, and solving for the cost of plant 1 at the site of plant 2. Of course, alternative formulations of Equation (5) are possible. Furthermore, to the extent that they are available, detailed site-specific cost studies would be preferable to any such extrapolation.

Whether established through detailed studies or by a generalized relationship, the total low load factor, low cost hydroelectric capacity which could be developed at existing sites will generally exceed the actual installed capacity at those sites. In addition, considerable conventional and pumped hydroelectric capacity may be available at new sites. The cost of this excess of reliability serving hydroelectric capacity, beyond that which would have been required to serve the same reliability as the existing hydroelectric capacity, can be used as the reliability serving component of the pre-1964 steam capacity (assuming the excess hydroelectric capacity is less expensive than the pre-1964 steam plants) and of the post-1964 generating capacity (assuming the excess hydroelectric capacity is less expensive than the gas turbine of equivalent ELCC).

> *Principle 7:* The reliability related cost of the power supply transmission is the cost of the minimum transmission system required to interconnect the minimum-cost reliability serving generation alternative to the utility system's load centers.

For most utilities, large portions of the transmission system exist to minimize total energy costs rather than to maintain reliable service. For example, some transmission lines are required solely to connect remote base load plants to the rest of the transmission grid. These remote base load plants are, of course, largely energy serving, and the motivation for their MW size, fuel type, and remote location are connected to their energy rather than their reliability aspects. Similarly, transmission lines connecting a system's load centers must be reinforced to accommodate the large and variable power flows resulting from the existence of large units and their consequent "lumpy" dispatch patterns and outages. Further reinforcement is typically added to allow for economic dispatch of the base load generation over a variety of load levels, spatial distributions of loads, generation outages, and transmission outages. If the generation system consisted solely of small gas turbines located near load centers, fewer miles of transmission lines would be needed, and the remaining lines would have lower kva capacities. The same result would generally apply for a generation system consisting of old steam units, as these were generally located close to load centers, so long as no provision was made for economic dispatch among the system's various steam generation units.

The minimum reliability serving transmission network will thus be comprised of a set of lines connecting load centers, with some extensions to peaking hydro facilities, if any. The cost of this system can be extrapolated from the cost per kva-mile of the existing system, disaggregated as necessary by area, voltage level, and location of line (overhead versus underground).

> *Principle 8:* The cost of tie lines between utility systems should be considered to be entirely energy serving unless they serve to replace peaking capacity. To the extent that they do replace peaking capacity, the reliability serving portion is that equivalent to minimum-cost reliability serving generation.

In keeping with the reliability first concept of Principle 1, it is appropriate to treat tie lines as entirely reliability serving if they provide ELCC more economically than peaking capacity could provide ELCC. If the tie lines cannot be entirely justified on such a basis, then the reliability serving portion can be identified from Equation (1), where unit i is a tie line or a set of tie lines to another utility.

> *Principle 9:* Reliability related costs should be allocated to customer classes on the basis of class contribution to the system's reliability needs.

An appropriate allocator for reliability related costs will have to reflect what caused the reliability related costs to be incurred. Such costs are not incurred solely to meet one annual system coincident peak, or even a few monthly peaks, but to maintain reliable service throughout the year. Such reliability measures as loss of load probability (LOLP) and loss of energy expectation (LOEE) recognize the overall reliability level at each point of the load duration curve and thus provide the basis for appropriate allocators.

Class contributions to system hourly loads are now estimated by most major utilities for their PURPA §133 filings, and hourly estimates of reliability measures, especially LOLP, are widely available from standard programs. Thus, the class share of reliability serving costs can be determined as

$$S(j) = \sum_{h} M(h) \times L(j,h) \div L(h), \tag{6}$$

where

$S(j)$ = reliability allocator to class j;

$M(h)$ = reliability index, such as LOLP, in hour h;

$L(j,h)$ = load in hour h for class j; and

$L(h)$ = load in hour h for entire system.

If Equation (6) cannot be estimated, due to lack of data, then some arbitrary *ad hoc* allocator may be required. Such an allocator should reflect as much of the system load duration curve as possible, while emphasizing the relatively greater importance of the higher portions of the curve. In general, appropriate allocations will lie somewhere between those based solely on peak demand (which recognize only a few hours at the top of the load duration curve) and those based solely on energy (which recognize all hours on the load duration curve equally).

> *Principle 10:* Energy-related costs for each unit should generally be allocated to customer classes on the basis of class share of energy use (adjusted for losses) at the times of utilization of the unit.

While a reasonable argument can be made that the energy costs should be attributed equally to all periods, it appears fairer to time-differentiate both the fixed and variable components of energy costs. This procedure recognizes that the classes with high off-peak usage allow for the construction and operation of generally less expensive (on a kwh basis) base load plants, while those with heavily on-peak usage require more expensive (per kwh) peaking or intermediate units. The assignment of energy costs to periods may be based on actual or simulated data but should not be unduly sensitive to plant performance or demand patterns peculiar to the test year.

Finally, the relationship between the methodology proposed here and the "marginalist" cost allocation methodologies used by several state commissions (notably California, Montana, and Oregon) should be noted. Interclass revenue allocations based on marginalist principles are neither required nor indicated by efficient pricing theory. *Any* interclass revenue allocation methodology, whether embedded or marginalist in nature, by definition creates class revenue constraints which may require pricing away from "pure" marginal costs. In general, it is not possible to determine which interclass revenue allocation method provides a "better" second-best solution to designing rates; this is true of both embedded and marginalist revenue allocation methods. In sum, the reasons for pricing rates at marginal costs (in rate design) do not necessarily extend to interclass revenue allocations.

In light of this, the embedded cost revenue allocation methodology proposed here is a reasonable alternative to marginalist revenue allocation methodologies, but it cannot be said to be either more or less efficient (due to the second-best problem) than those. It is thus presented as appropriate for commissions which, for one reason or another, do not want to adopt marginalist revenue allocation methodologies but do wish to modify and improve on the traditional embedded cost revenue allocation methodologies widely in use today.

Conclusion

Because of the joint cost nature of many of the costs incurred in the production of electric power, it must be recognized that any interclass revenue allocation method is based upon judgment and not upon principles which can be rigorously derived from efficient pricing theory. However, once this is recognized, equity nevertheless demands that regulators and electric utilities do the best job possible of reflecting the various classes' responsibility for costs in rates. Given this necessity, it is submitted that the alternative interclass revenue allocation method advanced here reflects the realities of present generation planning, in which a large percentage of total generation and transmission capacity costs are incurred to serve most or all of the load duration curve and to minimize the total generation (including fuel) costs. The more traditional methods, which evolved when the capacity costs per kw of the various generation technologies existed in a narrower range, and when most or all capacity costs were in fact incurred in order to serve reliability, do not reflect those realities as well as does our method.

APPENDIX A

Alternatives to Principle I

The reliability-first principle proposed here as Principle 1 is put forth on the basis that it appears best to reflect the realities of current generation planning. However, it is certainly not the only possible basis for revenue allocations. Alternative approaches include energy-first allocation and load curve methods. This appendix briefly describes these two possible alternatives.

Energy-first allocation would allocate as an energy cost the portion of generation unit investment costs and operating and maintenance expenses which is justified on the unit's fuel-cost savings, with the remaining portion allocated to reliability. Some difficulty may arise in the definition of fuel savings; for example, if the generation alternative is an all-gas turbine system, some utility systems would find that their entire generating capacity and associated transmission investments are energy-related by that standard. The methodology may have some appeal for systems with excess capacity, mostly in oil-fired and gas-fired units, which are adding coal or nuclear capacity explicitly to reduce the use of the oil and gas units. In these cases, the energy-serving portion can be determined by comparison with the existing system. Unfortunately, variations in cost (in $/kw) in the new capacity, which is clearly intended as energy-serving, are reflected in the net classification to reliability, which does not seem appropirate.

With respect to load curve allocation methods, some interesting work has been started on allocating production costs by fitting units under the load curve, and allocating responsibility for the generation plant to the customer classes which use them [for example, Charles T. Main, Inc. 1980]. This approach is still quite incomplete: Such elementary concepts as reliability measures and ELCC have not yet been incorporated. Treatment of other issues, such as excess capacity, is still apparently done on an *ad hoc* basis without any substantial foundation. If the conceptual model can be expanded from the current deterministic form to a more reasonable probabilistic form, generalized to recognize the difference between potential contribution to energy supply (such as the capacity factor or the equivalent availability factor) and to reliability (such as ELCC), and made more rigorous, allocations based upon dispatching generators under a load curve may represent a compromise between the energy-first and the reliability-first approaches.

Notes

1. One can conceive of ratemaking systems in the future in which this would not be the case. For example, interclass revenue allocations can be performed using each class's contribution to marginal costs as the basis for allocations. Similarly, a "pure" marginal cost based rate design system would presumably omit the interclass revenue allocation step entirely and would set each class's rates based upon class marginal costs modified by Ramsey pricing, without setting class revenue constraints.
2. See NARUC [1973] at pp. 5–10 (functionalization), pp. 30–39 (classifications between energy-related and demand-related costs), and pp. 40–53 (allocation of demand-related costs).
3. See NARUC [1973] at pp. 30–35, exempting only some hydro generating capacity from the general rule that generation plant capital expenditures are demand related.
4. Applications of this principle in current utility allocation practice are uncommon, but some examples exist. Bonneville Power Administration [1981] applies simple variants of a reliability first approach for allocation of both thermal and hydro generation costs.
5. The coal plant can be thought of as a gas-fired plant with a built-in coal gasifier.
6. For example, NEPOOL has estimated that pumped storage hydroelectric capacity is available in New England for $315/kw, in 1980 dollars, up to at least 7,500 Mw [NEPOOL 1977].
7. Such studies for New England include Campbell [1977]; Acres American, Inc. [1979]; and New England River Basins Commission [1980].

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APPENDIX 2

Scenario 1

Recommended by NP

NEWFOUNDLAND HYDRO — 19-AUG-92 — Base Case

Sch 1.2 — Sch 1.2 — $340/kW Peaker

1992 Forecast — NP-340PE

50% Revenue

Comparison of Revenue & Allocated Revenue Requirement — 50% Energy

Deficit Alloc.

($000)

(b) Line No.	(c) Description	(d) Allocated Revenue Reqt	(e) Revenue Before Deficit Alloc	(f) Deficit	(g) Deficit Alloc 50% Rev	(h) Revenue Deficit Alloc 50% Energy	(i) Revenue After Deficit Alloc	(j) Ratio
1	Newfoundland Power	163,996	163,996		13,247	12,066	189,310	1.15
2	Island Industrial	41,566	41,566		3,357	3,518	48,442	1.17
3	Labrador Industrial	3,723	3,723		301	972	4,996	1.34
	Rural							
4	Island Interconnected	34,881	23,112	11,769	(5,884)	(5,884)	23,112	0.66
5	Isolated Systems	34,593	10,988	23,605	(11,803)	(11,803)	10,988	0.32
6	Labrador Interconnected	9,679	9,679	0	782	1,130	11,591	1.20
7	Subtotal Rural	79,153	43,779	35,374	(16,905)	(16,557)	45,691	0.58
	Total	288,438	253,064	35,374	(0)	0	288,438	1.00

Island Interconnected

8	Newfoundland Power	163,996	163,996	0	13,247	12,066	189,310	1.15
9	Industrial	41,566	41,566	0	3,357	3,518	48,442	1.17
10	Rural	34,881	23,112	11,769	(5,884)	(5,884)	23,112	0.66
11	Total	240,443	228,674	11,769	10,720	9,700	260,863	1.08

NEWFOUNDLAND HYDRO 19-AUG-92

Sch 1.3.1 Sch 1.3.1

Island Interconnected NP-340PE

Total Demand, Energy and Customer Amounts

(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		($000)							
		---------Before Deficit Allocation-----------				--------After Deficit Allocation---------			
Line No.	Description	Total	Demand	Energy	Customer	Total	Demand	Energy	Customer
	Island Interconnected								
1	Newfoundland Power	163,996	52,248	109,505	2,243	189,309	60,312	126,407	2,590
2	Industrial	41,565	8,424	32,173	968	48,441	9,818	37,495	1,129
3	Rural	34,881				23,112			
4	Total	240,442				260,862			

Sch 1.3.2 Sch 1.3.2

	Demands, Sales & Bills	Billing Dems	Sales	Bills	Sales Used For Deficit Alloc.	Sales Deficit Alloc. Factor
		(kw)	(mwh)	(Total No)		
	Island Interconnected					
5	Newfoundland Power	11,805,000	4,284,100	12	4,284,100	0.6822
6	Industrial	2,043,300	1,249,200	84	1,249,200	0.1989
7	Rural		273,199			
	Labrador Interconnected					
8	Industrial		345,100		345,100	0.0550
9	Rural		401,373		401,373	0.0639
					6,279,773	1.0000

Sch 1.3 Sch 1.3

		---------Before Deficit Allocation-----------				--------After Deficit Allocation---------			
		Total	Demand	Energy	Customer	Total	Demand	Energy	Customer
			($/kw)	($/kwh)	($/Bill)		($/kw)	($/kwh)	($/Bill)
	Unit Demand, Energy & Customer Amounts								
8	Newfoundland Power		4.43	0.0256	186,956		5.11	0.0295	215,813
9	Industrial		4.12	0.0258	11,529		4.80	0.0300	13,436

NEWFOUNDLAND HYDRO 19-AUG-92

Sch 2.1A Sch 2.1A

Island Interconnected NP-340PE

Functional Classification of Revenue Requirement

(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(L)
		($000)					Distribution			
Line No.	Description	Total Amount	Prod Demand	Prod & Trans Energy	Trans Demand	Rural Trans	Substation Demand	Other	Acct Customer	Spec Assigned Customer
	Expenses									
1	Operating & Maintenance	61,974	16,450	27,952	4,859	2,740	1,228	6,554	1,074	1,116
2	Fuels	38,433	418	38,015		0				
3	Power Purchased	428		428						
4	Depreciation	20,399	8,015	8,486	1,343	608	262	1,316	0	369
	Expense Credits									
5	Sundry	(61)	(16)	(28)	(5)	(3)	(1)	(6)	(1)	(1)
6	Building Rental Income	(131)	(27)	(78)	(11)	(6)	(2)	(5)	0	(2)
7	Tax Refunds	(56)	(15)	(25)	(4)	(2)	(1)	(6)	(1)	(1)
8	Suppilers' Discounts	(75)	(20)	(34)	(6)	(3)	(1)	(8)	(1)	(1)
9	Pole Attachments	(426)						(426)		
10	Subtotal Expenses	120,485	24,805	74,717	6,176	3,334	1,485	7,419	1,071	1,479
11	Interest	110,568	20,878	68,845	9,912	5,360	1,412	2,564	0	1,598
12	Disposal Gain/Loss	186	35	116	17	9	2	4	0	3
13	Subtot Rev Reqt Excl Margin	231,239	45,718	143,677	16,104	8,702	2,899	9,987	1,071	3,080
14	Margin	9,205	1,738	5,731	825	446	118	213	0	133
15	Total Revenue Requirement	240,444	47,456	149,409	16,929	9,148	3,016	10,200	1,071	3,213

Sch 2.2A

NEWFOUNDLAND HYDRO

Island Interconnected

19-AUG-92
Sch 2.2A
NP-340PE

Functional Classification of Plant in Service for the Allocation of O&M Expenses

(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		($000)					Distribution			
Line No.	Description	Total Amount	Prod Demand	Prod & Trans Energy	Trans Demand	Rural Trans	Substation Demand	Other	Acct Customer	Spec Assigned Customer
	Production									
	Hydraulic									
1	Bay D'Espair	170,974	52,284	118,690						
2	Upper Salmon	168,615	22,055	146,560						
3	Hinds Lake	79,068	15,442	63,626						
4	Cat Arm	263,255	35,013	228,242						
5	Paradise River	21,306	6,662	14,644						
6	Snooks Arm/V Bight	99	0	0		99				
7	Subtotal Hydraulic	703,317	131,456	571,762	0	99				
8	Holyrood	164,925	73,210	91,715						
9	Gas Turbines	16,977	16,977	0						
10	Diesel	3,226	0	0		3,226				
11	Subtotal Production	888,445	221,643	663,477	0	3,325				
	Transmission									
12	Lines	193,468	1,317	69,632	69,632	45,766				7,122
13	Terminal Stations	105,729	33,675	0	37,143	8,068	11,820	0	0	15,023
14	Subtotal Transmission	299,197	34,992	69,632	106,775	53,834	11,820	0	0	22,145
15	Total Distribution	49,617	206				3,976	45,435	0	
16	Subtotal Prod Trans Dist	1,237,259	256,841	733,108	106,775	57,159	15,796	45,435	0	22,145
17	General	62,166	12,905	36,835	5,365	2,872	794	2,283	0	1,113
18	Telecontrol - Common	36,476	7,994	22,837	3,326	1,951	368			
19	Telecontrol - Specific	331								331
20	Feasibility Studies	2,232	1997		214	22	0	0	0	
21	Total Plant	1,338,464	279,737	792,780	115,679	62,004	16,958	47,718	0	23,589

NEWFOUNDLAND HYDRO — 19-AUG-92

Sch 2.3A — Sch 2.3A

Island Interconnected — NP-340PE

Functional Classification of Net Book Value

(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		($000)					Distribution			
Line No.	Description	Total Amount	Prod Demand	Prod & Trans Energy	Trans Demand	Rural Trans	Substation Demand	Other	Acct Customer	Spec Assigned Customer
	Production									
	Hydraulic									
1	Bay D'Espair	145,046	44,355	100,691						
2	Upper Salmon	167,332	21,887	145,445						
3	Hinds Lake	77,552	15,146	62,406						
4	Cat Arm	262,415	34,901	227,514						
5	Paradise River	21,219	6,635	14,584						
6	Snooks Arm/V Bight	13	0	0		13				
7	Subtotal Hydraulic	673,577	122,924	550,640	0	13				
8	Holyrood	90,475	40,162	50,313						
9	Gas Turbines	7,546	7,546	0						
10	Diesel	471	0	0		471				
11	Subtotal Production	772,069	170,632	600,953	0	484				
	Transmission									
12	Lines	173,565	1,302	62,658	62,658	42,942				4,005
13	Terminal Stations	90,510	27,161	0	32,671	7,814	11,152			11,712
14	Subtotal Transmission	264,075	28,463	62,658	95,329	50,756	11,152	0	0	15,717
15	Total Distribution	27,837	50				2,512	25,275	0	
16	Subtotal Prod Trans Dist	1,063,981	199,145	663,611	95,329	51,240	13,664	25,275	0	15,717
17	General	42,751	8,002	26,664	3,830	2,059	549	1,016	0	632
18	Telecontrol - Common	24,687	4,734	15,778	2,267	1,643	265			
19	Telecontrol - Specific	40								40
20	Feasibility Studies	2,492	2,240		227	24	0	0	0	
21	Total Plant	1,133,951	214,121	706,053	101,653	54,966	14,478	26,291	0	16,389

NEWFOUNDLAND HYDRO

19-AUG-92
Sch 2.4A
NP-340PE

Sch 2.4A

Island Interconnected

Functional Classification of O&M Expenses

(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		($000)					Distribution			
Line No.	Description	Total Amount	Prod Demand	Prod & Trans Energy	Trans Demand	Rural Trans	Substation Demand	Other	Acct Customer	Spec Assigned Customer
	Production									
1	Hydraulic	7,528	1,407	6,120	0	1				
2	Holyrood	13,907	6,173	7,734	0	0				
3	Gas Turbines	811	811	0	0	0				
4	Diesel	268	0	0	0	268				
5	Subtotal Production	22,514	8,391	13,854	0	269				
	Transmission									
6	Lines	4,389	30	1,580	1,580	1,038				162
7	Terminal Stations	3,324	1,059	0	1,168	254	372	0		472
8	Subtotal Transmission	7,713	1,089	1,580	2,747	1,292	372	0	0	634
9	Total Distribution	4,230	18				339	3,873		
10	Subtotal Prod Trans Dist	34,457	9,498	15,433	2,747	1,561	711	3,873	0	634
11	Customer Accounting	662							662	
	Overheads									
	Plant Related									
12	Production	499	124	373						
13	Transmission	210	25	49	75	38	8			16
14	Production & Trans	201	43	124	18	10	2			4
15	Distribution	168	1				13	154		0
16	Other	3,254	679	1,928	281	150	42	115	0	58
17	Property Insurance	663	167	437	28	10	10			10
18	Expense Related	21,863	5,913	9,608	1,710	972	442	2,411	412	395
19	Subtotal Overheads	26,858	6,952	12,519	2,112	1,179	518	2,681	412	482
20	Tot Oper & Maint Expense	61,977	16,450	27,952	4,859	2,740	1,228	6,554	1,074	1,116

NEWFOUNDLAND HYDRO — 19-AUG-92

Sch 2.5A — Sch 2.5A

Island Interconnected — NP-340PE

Functional Classification of Depreciation Expense

(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		($000)					Distribution			
Line No.	Description	Total Amount	Prod Demand	Prod & Trans Energy	Trans Demand	Rural Trans	Substation Demand	Other	Acct Customer	Spec Assigned Customer
	Production									
	Hydraulic									
1	Bay D'Espair	701	214	487						
2	Upper Salmon	222	29	193						
3	Hinds Lake	241	47	194						
4	Cat Arm	189	25	164						
5	Paradise River	32	10	22						
6	Snooks Arm/V Bight	1	0	0	0	1				
7	Subtotal Hydraulic	1,386	326	1,059	0	1				
8	Holyrood	7,418	3,293	4,125						
9	Gas Turbines	806	806	0						
10	Diesel	56	0	0	0	56				
11	Subtotal Production	9,666	4,424	5,185	0	57				
	Transmission									
12	Lines	1,180	3	445	445	209				79
13	Terminal Stations	1,185	425	0	429	48	83			200
14	Subtotal Transmission	2,365	428	445	874	257	83	0	0	279
15	Total Distribution	1,121	3				105	1,013	0	
16	Subtotal Prod Trans Dist	13,152	4,855	5,629	874	314	188	1,013	0	279
17	General	3,934	1,452	1,684	261	94	56	303	0	83
18	Telecontrol - Common	2,579	1,011	1,173	182	195	17			
19	Telecontrol - Specific	5								5
20	Feasibility Studies	728	696		26	5	0	0	0	2
21	Total Depreciation Expense	20,398	8,015	8,486	1,343	608	262	1,316	0	369

NEWFOUNDLAND HYDRO — 19-AUG-92

Sch 3.1A — Sch 3.1A

Island Interconnected — NP-340PE

Basis of Allocation to Classes of Service

(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		($000)					Distribution			
				Prod &						Spec
Line		Total	Prod	Trans	Trans	Rural	Substation		Acct	Assigned
No.	Description	Amount	Demand	Energy	Demand	Trans	Demand	Other	Customer	Customer
			(5CP kw)	(mwh @ Gen)	(5CP kw)	Direct	Direct	Direct	Direct	
	Amount									
1	Newfoundland Power		951,456	4,397,884	918,660					
2	Industrial		153,408	1,292,104	148,120					
3	Rural		67,631	310,503	65,300					
4	Total		1,172,495	6,000,491	1,132,080					
	Ratios									
5	Newfoundland Power		0.8115	0.7329	0.8115					
6	Industrial		0.1308	0.2153	0.1308					
7	Rural		0.0577	0.0517	0.0577	1.0000	1.0000	1.0000	1.0000	
8	Total		1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	

NEWFOUNDLAND HYDRO 19-AUG-92

Sch 3.2A Sch 3.2A

Island Interconnected NP-340PE

Allocation of Functional Amounts to Classes of Service

(b) Line No.	(c) Description	(d) ($000) Total Amount	(e) Prod Demand	(f) Prod & Trans Energy	(g) Trans Demand	(h) Rural Trans	(i) Distribution Substation Demand	(j) Distribution Other	(k) Acct Customer	(l) Spec Assigned Customer
	Allocated Revenue Requirment Excluding Margin									
1	Newfoundland Power	157,614	37,099	105,304	13,068					2,142
2	Industrial	39,965	5,982	30,938	2,107					937
3	Rural	33,659	2,637	7,435	929	8,702	2,899	9,987	1,071	0
4	Total	231,238	45,718	143,677	16,104	8,702	2,899	9,987	1,071	3,079
	Allocated Margin									
5	Newfoundland Power	6,382	1,410	4,201	670					102
6	Industrial	1,601	227	1,234	108					31
7	Rural	1,222	100	297	48	446	118	213	0	0
8	Total	9,205	1,738	5,731	825	446	118	213	0	133
	Total Allocated Revenue Requirment									
9	Newfoundland Power	163,996	38,510	109,505	13,738					2,244
10	Industrial	41,566	6,209	32,173	2,215					969
11	Rural	34,881	2,737	7,731	977	9,148	3,016	10,200	1,071	
12	Total	240,443	47,456	149,409	16,929	9,148	3,016	10,200	1,071	3,213

NEWFOUNDLAND HYDRO — 19-AUG-92

Sch 3.3A — Sch 3.3A

Island Interconnected — NP-340PE

Allocation of Specifically Assigned Amounts to Classes of Service

(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
		($000)									
			O&M			Depreciation					Subtotal
Line		Total	Transmission		Admin &	Lines &	Telecntr &		Expense	Interest &	Excl
No.	Description	Amount	Lines	Terminals	General	Terminals	Feas Study	General	Credits	Gain/Loss	Margin
			(Plant)	(Plant)	(e + f)	(Direct)	(Direct)			(NBV)	
	Basis of Allocated Amounts										
1	Newfoundland Power		2,950	9,697	12,647			213		12,033	
2	Industrial		4,172	5,327	9,499			66		3,725	
3	Rural		0	0	0			0		0	
4	Total	0	7,122	15,024	22,146	0	0	280	0	15,758	0
	Ratios										
5	Newfoundland Power		0.4142	0.6454	0.5711			0.7627		0.7636	
6	Industrial		0.5858	0.3546	0.4289			0.2373		0.2364	
7	Rural		0.0000	0.0000	0.0000			0.0000		0.0000	
8	Total	0	1.0000	1.0000	1.0000			1.0000		1.0000	
	Amounts Allocated										
9	Newfoundland Power	2,244	67	305	275	213	0	64	(4)	1,222	2,142
10	Industrial	969	95	167	207	66	6	20	(2)	378	937
11	Rural	0	0	0	0	0	0	0		0	0
12	Total	3,213	162	472	482	280	6	83	(6)	1,601	3,079

NEWFOUNDLAND HYDRO 19-AUG-92

Sch 4.1 Sch 4.1

Island Interconnected NP-340PE

Calculation of Generation & Transmission AED Factors

(b) Line No.	(c) Rate Class	(d) Sales+Losses For AED mwhs	(e) Class 5CP AT Generator	(f) Class NCP AT Generator	(g) ----Average Demand--- Amount	(h) Weighted	(i) ----Excess Demand---- Amount	(j) Weighted	(k) --------Total-------- Weighted	(l) Amount
-----	-------------	---------	---------	---------	---------	---------	---------	---------	---------	---------
			(5CP kw)*	(NCP kw)						
	Generation									
1	Newfoundland Power	4,397,884	951,456	1,017,522	502,042	0.4083	515,480	0.3863	0.7945	977,031
2	Industrial	1,276,090	153,408	168,722	145,672	0.1185	23,050	0.0173	0.1357	166,911
3	Rural	310,503	67,631	90,051	35,446	0.0288	54,605	0.0409	0.0697	85,762
4	Subtotal at Generation	5,984,477	1,172,495	1,276,295	683,159	0.5555	593,136	0.4445	1.0000	1,229,704

Line No.	Rate Class	Sales+Losses For AED mwhs	Class 5CP AT Trans	Class NCP AT Trans	----Average Demand--- Amount	Weighted	----Excess Demand---- Amount	Weighted	--------Total-------- Weighted	Amount
		---------	----------	---------	---------	---------	---------	---------	---------	---------
			(5CP kw)	(NCP kw)						
	Transmission									
5	Newfoundland Power	4,284,100	918,660	983,750	489,053	0.4119	494,697	0.3825	0.7944	943,206
6	Industrial	1,243,075	148,120	163,123	141,904	0.1195	21,219	0.0164	0.1359	161,384
7	Rural	302,467	65,300	87,061	34,528	0.0291	52,533	0.0406	0.0697	82,756
8	Subtotal at Transmission	5,829,642	1,132,080	1,233,934	665,484	0.5605	568,450	0.4395	1.0000	1,187,345

Coincident Peaks

		JAN/92	FEB/92	MAR/92	NOV/92	DEC/92	(5CP mw)
	Transmission CP**						
5	Newfoundland Power	970.2	918.7	867.1	867.1	970.2	918.7
6	Industrial	148.4	148.0	148.1	147.7	148.4	148.1
7	Rural	68.7	68.3	61.1	60.0	68.4	65.3
		------	------	------	------	------	------
		1,187.3	1,135.0	1,076.3	1,074.8	1,187.0	1,132.1

* Class 5CP at Generator used the same loss factors as those used to derive class CP at Generator as per response to NP-34 (Page 2 of 2).

** Monthly Class Transmission CP taken from response to NP-1 (Page 4 of 7). Adjustments to Monthly CP related to NP's own generation (See NP-25); other adjustments related to the Industrial class were estimated using the differences between NP-34 and the actuals for Jan/92 as per NP-1.

Sch 4.2 NEWFOUNDLAND HYDRO 19-AUG-92

Base Case Sch 4.2

$340/kW Peaker Island Interconnected NP-340PE

50% Revenue Functionalization and Classification Ratios

50% Energy

Deficit Alloc.

(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
							Distribution				
				Prod &			---------------------			Spec	
Line		Total	Prod	Trans	Trans	Rural	Substation		Acct	Assigned	Plant Cost
No.	Description	Amount	Demand	Energy	Demand	Trans	Demand	Other	Customer	Customer	In 1991 $
	Cost of Peaker used for D/E Splits		$340 /kW								$/kW
	Cost of Peaker (Paradise River)		858 /kW								
	Production										
	Hydraulic										
1	Bay D'Espair	100.0%	30.58%	69.42%							1,112
2	Upper Salmon	100.0%	13.08%	86.92%							2,599
3	Hinds Lake	100.0%	19.53%	80.47%							1,741
4	Cat Arm	100.0%	13.30%	86.70%							2,557
5	Paradise River	100.0%	31.27%	68.73%							2,744
6	Snooks Arm/V Bight	100.0%	0.00%	0.00%		100.00%					
7	Subtotal Hydraulic		18.69%	81.30%		0.01%					
8	Holyrood	100.0%	44.39%	55.61%							766
9	Gas Turbines	100.0%	100.00%	0.00%							
10	Diesel	100.0%	0.00%	0.00%		100.00%					
11	Purchase Power Island	100.0%		100.0%							
	Transmission										
12	Lines	100.0%		50.0%	50.0%						
13	Terminal Stations	100.0%		0.0%	100.0%						
14	Subtotal Transmission										
15	Total Distribution	100.0%						100.0%			

APPENDIX 3

Scenario 4

Model of RAB-1
(Recommended by Hydro)

Sch 1.2

NEWFOUNDLAND HYDRO — 19-AUG-92
Sch 1.2

1992 Forecast — RAB-1

Comparison of Revenue & Allocated Revenue Requirement

($000)

(b) Line No.	(c) Description	(d) Allocated Revenue Reqt	(e) Revenue Before Deficit Alloc	(f) Deficit	(g) Deficit Alloc	(h) Revenue After Deficit Alloc	(i) Ratio
1	Newfoundland Power	175,287	175,287		22,107	197,394	1.13
2	Island Industrial	37,166	37,166		4,687	41,853	1.13
3	Labrador Industrial	3,723	3,723		470	4,193	1.13
	Rural						
4	Island Interconnected	27,992	23,112	4,880	(4,880)	23,112	0.83
5	Isolated Systems	34,593	10,988	23,605	(23,605)	10,988	0.32
6	Labrador Interconnected	9,679	9,679	0	1,221	10,900	1.13
7	Subtotal Rural	72,264	43,779	28,485	(27,264)	45,000	0.62
	Total	288,440	259,955	28,485	0	288,440	1.00

Island Interconnected

Line No.	Description	Allocated Revenue Reqt	Revenue Before Deficit Alloc	Deficit	Deficit Alloc	Revenue After Deficit Alloc	Ratio
8	Newfoundland Power	175,287	175,287	0	22,107	197,394	1.13
9	Industrial	37,166	37,166	0	4,687	41,853	1.13
10	Rural	27,992	23,112	4,880	(4,880)	23,112	0.83
11	Total	240,445	235,565	4,880	21,915	262,360	1.09

NEWFOUNDLAND HYDRO — 19-AUG-92

Sch 1.3.1 — Sch 1.3.1

Island Interconnected — RAB-1 (Rev)

Total Demand, Energy and Customer Amounts

($000)

(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Before Deficit Allocation				After Deficit Allocation			
Line No.	Description	Total	Demand	Energy	Customer	Total	Demand	Energy	Customer
	Island Interconnected								
1	Newfoundland Power	175,287	114,824	58,219	2,244	197,394	129,306	65,562	2,527
2	Industrial	37,165	19,092	17,105	968	41,853	21,500	19,262	1,091
3	Rural	27,992				23,112			
4	Total	240,445				262,359			

Sch 1.3.2 — Sch 1.3.2

	Demands, Sales & Bills	Billing Dems (kw)	Sales (mwh)	Bills (Total No)
5	Newfoundland Power	11,805,000	4,284,100	12
6	Industrial	2,043,300	1,249,200	84
7	Rural			

Sch 1.3 — Sch 1.3

		Before Deficit Allocation				After Deficit Allocation			
		Total	Demand ($/kw)	Energy ($/kwh)	Customer ($/Bill)	Total	Demand ($/kw)	Energy ($/kwh)	Customer ($/Bill)
	Unit Demand, Energy & Customer Amounts								
8	Newfoundland Power		9.73	0.0136	186,976		10.95	0.0153	210,558
9	Industrial		9.34	0.0137	11,529		10.52	0.0154	12,983
10	Rural								

NEWFOUNDLAND HYDRO — 19-AUG-92

Sch 2.1A — Sch 2.1A

Island Interconnected — RAB-1

Functional Classification of Revenue Requirement

(b) Line No.	(c) Description	(d) ($000) Total Amount	(e) Prod Demand	(f) Prod & Trans Energy	(g) Trans Demand	(h) Rural Trans	(i) Distribution Substation Demand	(j) Distribution Other	(k) Acct Customer	(L) Spec Assigned Customer
	Expenses									
1	Operating & Maintenance	61,976	35,469	6,583	9,951	0	1,228	6,554	1,074	1,116
2	Fuels	38,433		38,433		0				
3	Power Purchased	428		428						
4	Depreciation	20,399	15,053	981	2,412	0	267	1,316	0	369
	Expense Credits									
5	Sundry	(61)	(35)	(6)	(10)	0	(1)	(6)	(1)	(1)
6	Building Rental Income	(131)	(65)	(33)	(24)	0	(2)	(5)	0	(2)
7	Tax Refunds	(56)	(32)	(6)	(9)	0	(1)	(6)	(1)	(1)
8	Suppilers' Discounts	(75)	(43)	(8)	(12)	0	(1)	(8)	(1)	(1)
9	Pole Attachments	(426)						(426)		
10	Subtotal Expenses	120,487	50,347	46,373	12,308	0	1,490	7,419	1,071	1,479
11	Interest	110,568	52,848	30,473	21,670	0	1,415	2,564	0	1,598
12	Disposal Gain/Loss	186	89	51	36	0	2	4	0	3
13	Subtot Rev Reqt Excl Margin	231,241	103,284	76,897	34,014	0	2,907	9,987	1,071	3,080
14	Margin	9,205	4,400	2,537	1,804	0	118	213	0	133
15	Total Revenue Requirement	240,446	107,683	79,434	35,818	0	3,025	10,200	1,071	3,213

NEWFOUNDLAND HYDRO | 19-AUG-92

Sch 2.2A | Sch 2.2A

Island Interconnected | RAB-1

Functional Classification of Plant in Service for the Allocation of O&M Expenses

(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		($000)					Distribution			
Line No.	Description	Total Amount	Prod Demand	Prod & Trans Energy	Trans Demand	Rural Trans	Substation Demand	Other	Acct Customer	Spec Assigned Customer
	Production									
	Hydraulic									
1	Bay D'Espair	170,974	88,359	82,615						
2	Upper Salmon	168,615	93,497	75,118						
3	Hinds Lake	79,068	38,166	40,902						
4	Cat Arm	263,255	160,454	102,801						
5	Paradise River	21,306	14,884	6,422						
6	Snooks Arm/V Bight	99	56	43		0				
7	Subtotal Hydraulic	703,317	395,417	307,900	0	0				
8	Holyrood	164,925	164,925	0						
9	Gas Turbines	16,977	16,977	0						
10	Diesel	3,226	3,226	0		0				
11	Subtotal Production	888,445	580,545	307,900	0	0				
	Transmission									
12	Lines	193,468	1,317	0	185,029	0				7,122
13	Terminal Stations	105,729	33,868	0	45,018	0	11,820	0	0	15,023
14	Subtotal Transmission	299,197	35,185	0	230,047	0	11,820	0	0	22,145
15	Total Distribution	49,617	206				3,976	45,435	0	
16	Subtotal Prod Trans Dist	1,237,259	615,936	307,900	230,047	0	15,796	45,435	0	22,145
17	General	62,166	30,948	15,470	11,559		794	2,283		1,113
18	Telecontrol - Common	36,476	19,270	9,636	7,200	0	370			
19	Telecontrol - Specific	331								331
20	Feasibility Studies	2,232	1997		214		22	0	0	
21	Total Plant	1,338,464	668,150	333,007	249,019	0	16,982	47,718	0	23,589

NEWFOUNDLAND HYDRO 19-AUG-92

Sch 2.3A Sch 2.3A

Island Interconnected RAB-1

Functional Classification of Net Book Value

(b) Line No.	(c) Description	(d) ($000) Total Amount	(e) Prod Demand	(f) Prod & Trans Energy	(g) Trans Demand	(h) Rural Trans	(i) Distribution Substation Demand	(j) Distribution Other	(k) Acct Customer	(l) Spec Assigned Customer
	Production									
	Hydraulic									
1	Bay D'Espair	145,046	74,960	70,086						
2	Upper Salmon	167,332	92,786	74,546						
3	Hinds Lake	77,552	37,434	40,118						
4	Cat Arm	262,415	159,942	102,473						
5	Paradise River	21,219	14,824	6,395						
6	Snooks Arm/V Bight	13	7	6		0				
7	Subtotal Hydraulic	673,577	379,953	293,624	0	0				
8	Holyrood	90,475	90,475	0						
9	Gas Turbines	7,546	7,546	0						
10	Diesel	471	471	0		0				
11	Subtotal Production	772,069	478,445	293,624	0	0				
	Transmission									
12	Lines	173,565	1,302	0	168,258	0				4,005
13	Terminal Stations	90,510	27,315	0	40,331	0	11,152			11,712
14	Subtotal Transmission	264,075	28,617	0	208,589	0	11,152	0	0	15,717
15	Total Distribution	27,837	50				2,512	25,275	0	
16	Subtotal Prod Trans Dist	1,063,981	507,112	293,624	208,589	0	13,664	25,275	0	15,717
17	General	42,751	20,376	11,798	8,381		549	1,016		632
18	Telecontrol - Common	24,687	12,267	7,104	5,046	0	270			
19	Telecontrol - Specific	40								40
20	Feasibility Studies	2,492	2,240		227		24	0	0	
21	Total Plant	1,133,951	541,995	312,526	222,244	0	14,507	26,291	0	16,389

NEWFOUNDLAND HYDRO

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Sch 2.4A
RAB-1

Sch 2.4A

Island Interconnected

Functional Classification of O&M Expenses

(b) Line No.	(c) Description	(d) ($000) Total Amount	(e) Prod Demand	(f) Prod & Trans Energy	(g) Trans Demand	(h) Rural Trans	(i) Distribution Substation Demand	(j) Distribution Other	(k) Acct Customer	(l) Spec Assigned Customer
	Production									
1	Hydraulic	7,528	4,232	3,296	0	0				
2	Holyrood	13,907	13,907	0	0	0				
3	Gas Turbines	811	811	0	0	0				
4	Diesel	268	268	0	0	0				
5	Subtotal Production	22,514	19,218	3,296	0	0				
	Transmission									
6	Lines	4,389	30	0	4,198	0				162
7	Terminal Stations	3,324	1,065	0	1,415	0	372	0		472
8	Subtotal Transmission	7,713	1,095	0	5,613	0	372	0	0	634
9	Total Distribution	4,230	18				339	3,873		
10	Subtotal Prod Trans Dist	34,457	20,331	3,296	5,613	0	711	3,873	0	634
11	Customer Accounting	662							662	
	Overheads									
	Plant Related									
12	Production	499	326	173						
13	Transmission	210	25	0	161	0	8			16
14	Production & Trans	201	104	52	39	0	2			4
15	Distribution	168	1				13	154		0
16	Other	3,254	1,624	810	605	0	42	115	0	58
17	Property Insurance	663	402	201	39	0	10			10
18	Expense Related	21,863	12,657	2,052	3,494	0	442	2,411	412	395
19	Subtotal Overheads	26,858	15,138	3,288	4,338	0	518	2,681	412	482
20	Tot Oper & Maint Expense	61,977	35,469	6,583	9,951	0	1,228	6,554	1,074	1,116

NEWFOUNDLAND HYDRO 19-AUG-92

Sch 2.5A Sch 2.5A

Island Interconnected RAB-1

Functional Classification of Depreciation Expense

(b) Line No.	(c) Description	(d) ($000) Total Amount	(e) Prod Demand	(f) Prod & Trans Energy	(g) Trans Demand	(h) Rural Trans	(i) Distribution Substation Demand	(j) Distribution Other	(k) Acct Customer	(l) Spec Assigned Customer
	Production									
	Hydraulic									
1	Bay D'Espair	701	362	339						
2	Upper Salmon	222	123	99						
3	Hinds Lake	241	116	125						
4	Cat Arm	189	115	74						
5	Paradise River	32	22	10						
6	Snooks Arm/V Bight	1	1	0	0	0				
7	Subtotal Hydraulic	1,386	740	646	0	0				
8	Holyrood	7,418	7,418	0						
9	Gas Turbines	806	806	0						
10	Diesel	56	56	0	0	0				
11	Subtotal Production	9,666	9,020	646	0	0				
	Transmission									
12	Lines	1,180	3	0	1,098	0				79
13	Terminal Stations	1,185	429	0	473	0	83			200
14	Subtotal Transmission	2,365	432	0	1,571	0	83	0	0	279
15	Total Distribution	1,121	3				105	1,013	0	
16	Subtotal Prod Trans Dist	13,152	9,455	646	1,571	0	188	1,013	0	279
17	General	3,934	2,828	193	470		56	303		83
18	Telecontrol - Common	2,579	2,074	142	345	0	18			
19	Telecontrol - Specific	5								5
20	Feasibility Studies	728	696		26		5	0	0	2
21	Total Depreciation Expense	20,398	15,053	981	2,412	0	267	1,316	0	369

NEWFOUNDLAND HYDRO — 19-AUG-92

Sch 3.1A — Sch 3.1A

Island Interconnected — RAB-1

Basis of Allocation to Classes of Service

(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		($000)					Distribution			
Line No.	Description	Total Amount	Prod Demand	Prod & Trans Energy	Trans Demand	Rural Trans	Substation Demand	Other	Acct Customer	Spec Assigned Customer
			(AED kw)	(mwh @ Gen)	(CP kw)	Direct	Direct	Direct	Direct	
	Amount									
1	Newfoundland Power		977,031	4,397,884	970,174					
2	Industrial		166,911	1,292,104	148,371					
3	Rural		85,762	310,503	68,800					
4	Total		1,229,704	6,000,491	1,187,345					
	Ratios									
5	Newfoundland Power		0.7945	0.7329	0.8171					
6	Industrial		0.1357	0.2153	0.1250					
7	Rural		0.0697	0.0517	0.0579	1.0000	1.0000	1.0000	1.0000	
8	Total		1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	

NEWFOUNDLAND HYDRO 19-AUG-92

Sch 3.2A Sch 3.2A

Island Interconnected RAB-1

Allocation of Functional Amounts to Classes of Service

(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		($000)					Distribution			
Line No.	Description	Total Amount	Prod Demand	Prod & Trans Energy	Trans Demand	Rural Trans	Substation Demand	Other	Acct Customer	Spec Assigned Customer
	Allocated Revenue Requirment Excluding Margin									
1	Newfoundland Power	168,356	82,062	56,360	27,793					2,142
2	Industrial	35,765	14,019	16,559	4,250					937
3	Rural	27,118	7,203	3,979	1,971	0	2,907	9,987	1,071	0
4	Total	231,240	103,284	76,897	34,014	0	2,907	9,987	1,071	3,079
	Allocated Margin									
5	Newfoundland Power	6,931	3,496	1,859	1,474					102
6	Industrial	1,400	597	546	225					31
7	Rural	874	307	131	105	0	118	213	0	0
8	Total	9,205	4,400	2,537	1,804	0	118	213	0	133
	Total Allocated Revenue Requirment									
9	Newfoundland Power	175,287	85,557	58,219	29,267					2,244
10	Industrial	37,166	14,616	17,105	4,476					969
11	Rural	27,992	7,510	4,110	2,075	0	3,025	10,200	1,071	
12	Total	240,445	107,683	79,434	35,818	0	3,025	10,200	1,071	3,213

NEWFOUNDLAND HYDRO — 19-AUG-92

Sch 3.3A — Sch 3.3A

Island Interconnected — RAB-1

Allocation of Specifically Assigned Amounts to Classes of Service

(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
		($000)	O&M			Depreciation					Subtotal
			Transmission								
Line No.	Description	Total Amount	Lines	Terminals	Admin & General	Lines & Terminals	Telecntr & Feas Study	General	Expense Credits	Interest & Gain/Loss	Excl Margin
			(Plant)	(Plant)	(e + f)	(Direct)	(Direct)			(NBV)	
	Basis of Allocated Amounts										
1	Newfoundland Power		2,950	9,697	12,647			213		12,033	
2	Industrial		4,172	5,327	9,499			66		3,725	
3	Rural		0	0	0			0		0	
4	Total	0	7,122	15,024	22,146	0	0	280	0	15,758	0
	Ratios										
5	Newfoundland Power		0.4142	0.6454	0.5711			0.7627		0.7636	
6	Industrial		0.5858	0.3546	0.4289			0.2373		0.2364	
7	Rural		0.0000	0.0000	0.0000			0.0000		0.0000	
8	Total	0	1.0000	1.0000	1.0000			1.0000		1.0000	
	Amounts Allocated										
9	Newfoundland Power	2,244	67	305	275	213	0	64	(4)	1,222	2,142
10	Industrial	969	95	167	207	66	6	20	(2)	378	937
11	Rural	0	0	0	0	0	0	0		0	0
12	Total	3,213	162	472	482	280	6	83	(6)	1,601	3,079

NEWFOUNDLAND HYDRO

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Sch 4.1
RAB-1

Sch 4.1

Island Interconnected

Calculation of Generation & Transmission AED Factors

(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		Sales+Losses	Class CP	Class NCP						
Line		For AED	AT	AT	----Average Demand---		----Excess Demand----		--------Total--------	
No.	Rate Class	mwhs	Generator	Generator	Amount	Weighted	Amount	Weighted	Weighted	Amount
			(CP kw)	(NCP kw)						
	Generation									
1	Newfoundland Power	4,397,884	1,004,786	1,017,522	502,042	0.4083	515,480	0.3863	0.7945	977,031
2	Industrial	1,276,090	153,664	168,722	145,672	0.1185	23,050	0.0173	0.1357	166,911
3	Rural	310,503	71,254	90,051	35,446	0.0288	54,605	0.0409	0.0697	85,762
4	Subtotal at Generation	5,984,477	1,229,704	1,276,295	683,159	0.5555	593,136	0.4445	1.0000	1,229,704

		Sales+Losses	Class CP	Class NCP						
		For AED	AT	AT	----Average Demand---		----Excess Demand----		--------Total--------	
		mwhs	Trans	Trans	Amount	Weighted	Amount	Weighted	Weighted	Amount
			(CP kw)	(NCP kw)						
	Transmission									
5	Newfoundland Power	4,284,100	970,174	983,750	489,053	0.4119	494,697	0.3825	0.7944	943,206
6	Industrial	1,243,075	148,371	163,123	141,904	0.1195	21,219	0.0164	0.1359	161,384
7	Rural	302,467	68,800	87,061	34,528	0.0291	52,533	0.0406	0.0697	82,756
8	Subtotal at Transmission	5,829,642	1,187,345	1,233,934	665,484	0.5605	568,450	0.4395	1.0000	1,187,345

NEWFOUNDLAND HYDRO 19-AUG-92

Sch 4.2 Sch 4.2

Island Interconnected RAB-1

Functionalization and Classification Ratios

(b) Line No.	(c) Description	(d) Total Amount	(e) Prod Demand	(f) Prod & Trans Energy	(g) Trans Demand	(h) Rural Trans	(i) Distribution Substation Demand	(j) Distribution Other	(k) Acct Customer	(l) Spec Assigned Customer
	Production									
	Hydraulic									
1	Bay D'Espair	100.0%	51.68%	48.32%						
2	Upper Salmon	100.0%	55.45%	44.55%						
3	Hinds Lake	100.0%	48.27%	51.73%						
4	Cat Arm	100.0%	60.95%	39.05%						
5	Paradise River	100.0%	69.86%	30.14%						
6	Snooks Arm/V Bight	100.0%	56.42%	43.58%		0.00%				
7	Subtotal Hydraulic	100.0%	56.22%	43.78%						
8	Holyrood	100.0%	100.00%	0.00%						
9	Gas Turbines	100.0%	100.00%	0.00%						
10	Diesel	100.0%	100.00%	0.00%		0.00%				
11	Purchase Power Island	100.0%		100.0%						
	Transmission									
12	Lines	100.0%		0.0%	100.0%					
13	Terminal Stations	100.0%		0.0%	100.0%					
14	Subtotal Transmission									
15	Total Distribution	100.0%						100.0%		

Supplemental Evidence of Larry Brockman,
Hydro 1992 Cost of Service Investigation

Filed Sept 16/92

Supplemental Evidence of Larry Brockman

Hydro 1992 Cost of Service Investigation

August 1992

Q Since filing your original evidence, you have had the opportunity to read the evidence of Mr. Baker. Is there anything in Mr. Baker's evidence that you would like to respond to?

A I would first like to respond to a comment on the equivalent peaker method Mr. Baker makes on page 3, Appendix 2, of his evidence. He states, "There is no certainty that the unit cost as defined by any of the methods here considered is really representative of the cost of pure capacity from a planning perspective at the time when any hydro or base load unit was committed."

There are several conditions where there might be cause for such concern. They are: (1) When the gas turbine costs are based on costs not representative of the region; (2) When the units being classified have significantly different vintages than the gas turbines being used to derive equivalent costs; and, (3) When the size of the equivalent peakers is not representative of the alternatives that might have been installed to meet pure demand. None of these conditions is a problem in the equivalent peaker analysis that I have done for the following reasons.

The equivalent peaker cost I used in my calculations is based on the actual cost of Newfoundland turbines constructed by Hydro at Stephenville and Hardwoods.

The response to NP-35, page 3 of 11, shows that these turbines were installed in 1976 and 1977. The other generating units we are classifying with equivalent peaker costs were all constructed within a band of plus or minus 9 years from these dates. To remove the effects of inflation, all costs were brought to 1991 dollars using Statistics Canada indices for gas turbines.

Finally, the size of the gas turbines at Stephenville and Hardwoods are both 54 MW. They are being used to derive pure demand related costs for units in the 75 MW to 166 MW range. Size can be a problem if the peakers used to derive the pure demand cost are not reasonable equivalents to gas turbine sizes that might have been installed to meet pure demand. In this case, turbines like Stephenville and Hardwoods could have been installed in multiples of 1 to 3 and this type of addition would have been reasonable. If larger turbines were used, the cost per kW would have been even less.

In summary, none of the conditions concerning the representative nature of the equivalent peakers used to make demand/energy split calculations is present in my use of the technique here. The match between the equivalent peaker costs used and alternatives available to Hydro at the time the baseload plants were being constructed seems to be a good one.

Q **Mr. Baker, in Appendix 2, page 4 of his evidence, states, "If it is appropriate to classify fixed cost to energy where the fixed cost was incurred to avoid excessive fuel cost, then it is equally appropriate to classify fuel cost to demand where fuel cost is incurred to avoid excessive capacity charges. The differential fuel costs associated with gas turbine operation can thus be properly classified to demand." Do you agree with this statement?**

A Yes. Reasoning similar to Mr. Baker's led me to recommend in my evidence that Hydro's fuel costs associated with gas turbine operations be classified as demand. Mr. Baker takes a slightly different approach on page 4 of his Appendix 2, when he recommends that the life cycle fuel costs of a gas turbine should be capitalized and applied to the cost of the equivalent peaker, before it is used to perform the demand energy split on baseload plants. Both methods assign the increased fuel costs to customers based on their demands and would presumably collect the same amount over time. Mr. Baker's method requires knowledge of the gas turbine life cycle fuel costs. My method requires only knowledge of the costs as they occur.

Q **Mr. Baker also suggests (page 4, Appendix 2) that including life cycle fuel costs of the gas turbine would make unit proxy costs dramatically higher. Do you agree?**

A I agree that the proxy costs would be higher, but not necessarily dramatically so. The degree to which proxy costs would be higher depends on the cost of fuel in the future, and how much the gas turbines are operated. Hydro's turbines have operated very little in the past ten years, as indicated in the response to NP-5. The combined average capacity factor of the Stephenville and Hardwoods gas turbines for the last ten years has been about 0.79%. The fuel cost I added was based on the cost of operation in 1991. The combined capacity factor in 1991 was only about 0.25%. I have therefore calculated the sensitivity of the result by multiplying the fuel cost of gas turbines I used by a factor of three. This increased NP's costs by approximately $100,000 and reduced the cost to the Island Industrials. This increased cost is not reflected in Exhibit LBB-1 and Appendix 2. The unit demand and energy cost changed insignificantly. Based on this analysis and Mr. Baker's recommendation I would recommend that cost of turbine fuel added to the demand charge be based on the ten year average gas turbine capacity factor.

Q Are there other questions raised in Mr. Baker's evidence that you would like to respond to?

A Yes. In discussing my statement that, "Causality is the guiding principle of all cost of service work," on page 5 lines 25-27 and page 6, lines 11-13 of his evidence, Mr. Baker states that, "I tend to agree with Mr. Brockman's view, but consider it is a little too restrictive if it is interpreted to exclude user-pay considerations."

I would therefore like to clarify my position on user-pay considerations. The phrase "user-pay" refers to an idea of fairness that if customers use a utility facility they ought to help pay for it. My reliance on causality does not exclude such ideas. The equivalent peaker method for classifying production plant in fact assigns a portion of the fixed cost of baseload plants to energy. When customers use energy they will help pay for these fixed costs. Those portions of the fixed costs of plant classified as demand are only paid for by customers imposing demand at peak times under my 5 CP demand allocation proposal, because that is primarily when customers are using peaking related facilities.

If Coincident Peak (CP) methods are used to allocate fixed costs of plant, without first appropriately classifying some portion of the plants as energy, then a violation of the user-pay idea becomes a serious concern. This is the case for instance in Dr. Olsen's proposal. Dr. Olsen classifies only 3% of production and transmission fixed costs as energy. He then allocates the 97% of the costs he says are demand related on a 1 CP basis. This means that customers using large amounts of relatively cheap base load energy off-peak pay almost none of the fixed costs of providing it. Dr. Olsen's recommendations violate user-pay considerations primarily because they ignore the role of energy consumption in causing base load plants to be constructed.

Q Mr. Baker's discussion of Hydro's treatment of certain facilities serving only Hydro Rural customers, at page 15, lines 5-20 of his evidence, recommends further analysis be done before this issue can be decided. Do you agree that further analysis is necessary?

A The central question which Mr. Baker raises on page 15, lines 1-4, is, "whether the change erodes inter-class equity or whether in fact the pre-existing situation was unfair to the PDD's and the change improves equity." Although the details of the study Mr. Baker proposed are unclear, I am satisfied that there is sufficient data from the responses to demands and the evidence in this proceeding to perform adequate analysis on this issue. Such determination within this proceeding would avoid the need for further study and allow the Board to reach closure on this issue.

In preparing my evidence, I have examined the fairness of the common and specific assignments for every facility Hydro has assigned. After doing so, I agree with all of Hydro's assignments, except for the common designation of facilities serving only the Hydro Rural customer class in the Great Northern Peninsula, the Hydro Rural load from the 69 kV bus at Bay d'Espoir, the transmission facility from Boyd's Cove to Farewell Head, the line from Seal Cove Road to Bottom Waters, and the lines from Howley to Coney Arm.

I made the determination of which facilities should be treated as common and which should be specifically assigned by following the Board's guidelines in the

1977 Hydro Rate Referral. These guidelines, which I find to be sound and fair, are found on pages 121-122 of the Board's order as follows:

(i) plant and equipment which is of substantial benefit to more than one customer will be classified "joint use"; and

(ii) plant and equipment which is of little or no benefit to two or more customers will be classified as specific use.

As I explained in my original evidence (pages 15-16), I interpreted the word customer to mean customer class (ie: NP; Industrials; and, Hydro Rurals), since that is the way the Board was using it in 1977.

The best way to examine the facilities in question is to refer to the Island Interconnected System single Line Diagram - 1992 (Schedule VII of H.G. Budgell's evidence in the February, 1992 Hydro Rate Referral), the response to NP-13, pages 25-26, which indicates what customer classes are served from each of Hydro's interconnected substation busses, and the System Map provided in response to GCB-10. The necessary determinations of fairness can be addressed on a line by line, substation by substation basis, as summarized in Appendix 4.

Q **Mr. Baker also recommends that further study be done to decide the proper demand and energy classification of transmission lines. (Baker p. 22, lines 5-8). Do you agree with this recommendation?**

A No, because I do not believe it would lead to a better answer than the classification system I am recommending. When I first began analyzing the Hydro system, I started down the same road Mr. Baker is suggesting. What I found was that there is really no method that can be used to classify Hydro's transmission lines that will remove the necessity to make large judgements about what is demand and what is energy related. The system is simply too integrated for that. For example, the lines to and from Bay d'Espoir clearly provide both inexpensive energy and some capacity to the system. Because the lines connect the western and eastern sides of the Island, they also provide a large share of reliability benefits which could be related to demand. It is my opinion that no study can truly separate the differences exactly, and further studies would not yield a better answer than what we already have available.

APPENDIX 4

Common and Specific Assignments to Transmission Plants

Common and Specific Assignments to Transmission Plant

Note: It is useful to refer to Budgell's Schedule VII and NP-13 in following this analysis. The analysis begins on the right side of Budgell's map with Holyrood.

Holyrood

Holyrood is a vital generating station benefiting all customers on the interconnected grid. Its transmission and substation facilities should therefore be classified as common, except where extra expenditures were made to benefit only one customer class. The only customer class directly served from the Holyrood substation is NP, which requires approximately 38 MW per NP-13. Facilities used to provide feeds for NP from the Holyrood bus have been properly assigned to NP by Budgell. The rest of the facilities at Holyrood have been properly classified as common.

Hardwoods

The 54 MW gas turbine at Hardwoods and the transmission line loop from Holyrood to Hardwoods and then to Western Avalon provide significant reliability benefits to the interconnected system. The facilities associated with these have been appropriately classified as common. There is NP load served from the Hardwoods bus but only the disconnects indicated as B6B7 and B8B9 on Budgell's Schedule VII are necessary to provide the feeds. The disconnects also provide for significant NP generation support to the interconnected grid from the St. John's area, however and are fairly classified as common.

Oxen Pond

Oxen Pond facilities form a transmission loop with Hardwoods and Holyrood which benefits the entire interconnected grid. Only NP load is served off the Oxen Pond bus, but NP generation support from the St. John's area is also provided just as it is at Hardwoods. The facilities at Oxen Pond and transmission lines to Holyrood and Hardwoods are therefore fairly treated as common.

Western Avalon

The Western Avalon substation is an integral part of the transmission system from Holyrood to the rest of the Island and provides benefits to all customer classes. Facilities necessary to provide these benefits to the system have been appropriately assigned as common. Approximately 6.1 MW of NP load is served from the substation. Facilities necessary to provide for the NP loads have been properly assigned to NP.

Long Harbour

A small amount of Industrial load is fed through facilities from Western Avalon to Long Harbour. The 230 kV line and associated substation equipment at Western Avalon and Long Harbour provides about 3 MW of Albright and Wilson Americas load from Western Avalon and it has been appropriately assigned to A&WA.

Come-By-Chance

A 230 kV transmission link vital to connecting Holyrood and Hardwoods to the rest of the Island runs through Come-By-Chance substation to Sunnyside. This transmission link benefits all customer classes and is appropriately treated as common. The Come-By-Chance substation benefits only Newfoundland Processing and has been properly assigned to them.

A summary of the above analysis of the facilities on the Avalon Peninsula (East of Sunnyside and the right side of Budgell's Map) shows that all facilities in this region have been properly assigned and no class has been unfairly treated by Hydro's proposed treatment.

We now turn our attention to the facilities from Sunnyside to Bay d'Espoir and along the southern shore from Come-By-Chance to Fortune Bay. These facilities are shown in the center of Budgell's Map on his Schedule VII. We begin with the Sunnyside substation.

Sunnyside

The Sunnyside substation is also an integral part of the transmission system connecting the East and West sides of the Island. As such, the lines into the station from Come-By-Chance, Western Avalon and Bay d'Espoir clearly benefit the whole system and are properly treated as common.

Similarly, substation facilities at Sunnyside, which increase system reliability by allowing switching in the event of line failures on the other circuits, benefit all customer classes. Several 138 kV circuits leave the station and connect to NP transmission facilities going to Clarenville and the towns along the Northern Shore all the way to Stony Brook. This northern transmission route contributes to the reliability of the interconnected grid and gives further weight to treating non-dedicated facilities at Sunnyside as common. The lines along the northern route are owned by NP and thus not charged to any of Hydro's customers.

Hydro also has 8 MW of generation at Paradise River connected to the line from Marystown to Sunnyside which is also properly treated as common. It is fair to treat the cost of the substation facilities needed to connect them as common since they benefit all customers.

Where facilities tap off the Sunnyside station merely to serve NP loads and provide no reliability benefits to other Hydro customers, they have been fairly assigned to NP.

Sunnyside - Paradise River and Salt Pond

Hydro's portion of the lines from Sunnyside to Monkstown, Bay L'Argent,and Salt Pond have been treated as common, even though most of the load on the peninsula is NP load. This is appropriate because NP has significant amounts of generation on the Burin peninsula (about 40 MW). This generation can be used to back up generation on the interconnected system. Where additional facilities have been added to serve just NP load, they have been properly assigned to NP.

Bay d'Espoir and Upper Salmon

Bay d'Espoir and Upper Salmon (bottom center of Budgell's map) are the heart of Hydro's generation system on the Island. They benefit all customer classes on the interconnected grid. The only load served from either station is 19.4 MW of Hydro Rural load from the Bay d'Espoir 69 kV bus south to Conne River, English Harbour West and Barachoix. All transmission and substation facilities at Bay d'Espoir and Upper Salmon have been properly treated as common, except those necessary to supply the feed to Conne River and beyond, which should be assigned to Hydro Rurals.

Stony Brook-Buchans-Massey Drive-Deer Lake-Howley-Springdale-South Brook-Stony Brook Loop

The transmission loop from Stony Brook to Buchans, Massey Drive, Deer Lake, Howley, Springdale and back to Stony Brook is a major element in providing reliable power to all customer classes on the northern and western sides of the Island. Except for facilities which tap off this loop to serve only one class of customer, these facilities are fairly treated as common. There are specific facilities for serving NP at Massey Drive and Howley and Budgell properly assigned them to NP. Facilities serving only Hydro Rurals at South Brook have been assigned to them. The Grand Falls Converter connects to Stony Brook and provides access to back up generation. The Hinds Lake facilities and associated line to Howley are properly treated as common since they connect generation to the grid.

The lines from Boyd's Cove to Farewell Head and from Seal Cove Road to Bottom Waters and from Howley to Coney Arm serve only Hydro Rural customers and should be assigned only to them. Hydro has incorrectly classified these lines as common.

Buchans-Massey Drive-Bottom Brook- Loop, Corner Brook and Cat Arm

These facilities provide a southern loop for the integrated system, similar to the northern loop just described. They provide reliability benefits to all classes of customers. They are properly classified as common, except special facilities have been provided to serve one class. At Corner Brook major generation facilities connect to the system and are properly treated as common. Facilities necessary to serve Abitibi Price at Corner Brook have been properly assigned to Abitibi Price.

The line and facilities connecting Cat Arm to Deer lake provides major generation support to the grid and is properly classified as common.

Bottom Brook- Doyles/Grand Bay and to Grandy Brook/Hope Brook

The line and associated substation facilities from Bottom Brook to Doyles and Grand Bay serves only NP load and has been properly assigned to NP only. NP has in the past argued that because of generation in the Port-aux-Basques area, that these facilities should be treated as common. The Board has rejected this idea in the past, presumably because the amount of generation at Port-aux-Basques is fairly small. NP is no longer contesting this issue.

The line and associated facilities to Grandy Brook and Hope Brook serve both Hydro Rural and Industrial customers. It has therefore been properly classified as common.

Deer Lake - Wiltondale and all the way to Plum Point and Bear Cove

These facilities have been incorrectly assigned by Hydro as common. As I explained in my original evidence, there is no other load on these lines except Hydro Rural load. They do not form a loop that contributes to the reliability benefit of other customer classes and generation at Hawkes Bay is small (5 MW). For the same reasons that the line serving NP load at Doyles and Grand Bay is specifically assigned to NP, these facilities should be assigned to Hydro Rural.

In summary, evidence in the record is sufficient to decide the proper specific and common assignments of Hydro transmission and substation plant. Hydro has properly assigned the plant with the exceptions noted on page 44. No further studies are necessary, although other parties may wish to use the evidence present to draw their own conclusions.

Revision to Testimony of Larry Brockman

Filed Sept. 17/92

Direct Testimony of L. B. Brockman
August 1992

Revised September 1992

Revisions Based on Hydro's
Responses to NP's Demands to Particulars

Page 20	See new page 20	
Page 21	See new page 21	
Page 22	Line 24	Change "$766" to $772"
Page 23	Line 1	Change "$340" to "$355"
	Line 2	Change "$766" to "$772"
		Change "$44%" to "$46%"
	Line 3	Change "$340/$766" to $355/$772"
	Line 4	Change "44%" to 46%"
Page 33	Line 4	Change "$340" to $355"
	Line 13	Change "$189.3 million" to $189.4 million"
	Line 13	Change "$48.4 million" to $48.3 million"
Page 34	Line 6	Change "$3.4 million" to "$3.3 million"
Page 35	Line 10	Change "$195 million" to "$195.3 million"
		Change "43.8 million" to "$43.4 million"
	Line 21	Change "$8.1 million" to "$8.0 million"
Page 37	See new page 37	
Exhibit LBB-1	See new LBB-1	
Appendix 2	See new Appendix 2	

GENERATING STATION UNIT COSTS

Plant	Rating (MW)	$/kW (1991$)
Hydraulic		
Bay d'Espoir	580	1,106
Upper Salmon	84	2,602
Hinds Lake	75	1,741
Cat Arm	127	2,561
Paradise River	8	2,786
Thermal		
Holyrood	475	772
Gas Turbines		
Stephenville	54	371
Hardwoods	54	355
Overall Gas Turbines	108	355
Diesels		
Overall Island	33	933

The above table shows the $355/kW cost of serving demand with gas turbines, such as those at Stephenville and Hardwoods, is clearly less than the cost of serving demand with steam or hydraulic units ($772/kW to $2,786/kW). The extra investment has been made to achieve cheaper energy supplies, because hydraulic and thermal steam units are cheaper to run.

I next took the cost of the gas turbines at Stephenville and Hardwoods as the equivalent cost of supplying only demand. This amount per kW was divided by the actual cost of building hydro plants, in $/kW in $1991, to arrive at their demand/energy splits. For example, Upper Salmon gives 355/2602 = 13.6%. The following table shows the results.

Plant	Rating (MW)	% Demand
Bay d'Espoir	580	32.1%
Upper Salmon	84	13.6%
Hind's Lake	75	20.4%
Cat Arm	127	13.9%
Paradise River	8[1]	33.5%
Overall Hydraulic	874	19.6%

[1] The Paradise River calculation used $933/kW diesels as the equivalent peaker due to its small size.

The overall result is that only about 20% of the hydraulic plant should be classified as demand related under this method. This contrasts dramatically with Hydro's proposal to move these plants from the old 43% demand to 56% demand. Hydro's proposal is a move in the wrong direction. We should be classifying less, not more, of these plants as demand related.

Q. How should Hydro's thermal production plant be classified?

A. Just as there are many methods to classify hydraulic production plant, there are many methods for classifying thermal production plant between demand and energy. In fact, similar methods can be used as follows:

(1) Fixed and Variable

(2) Use of the Facilities

(3) Capacity Factor Methods

(4) Arbitrary Splits

(5) Equivalent Peaker Approach

An example of using unit cost for rate design might be instructive. Assume that a cost of service study produces unit costs for demand and energy of $10/kW-month and 4¢/kWh. If the existing rates were $6/kW-month and 6¢/kWh, we could conclude that the demand cost was too low and the energy cost too high.

The per unit costs for demand and energy between Hydro's recommended cost of service method (Scenario 4) and the one recommended by NP (Scenario 1) are quite different as the table below indicates:

COMPARISON OF DEMAND/ENERGY SPLITS

	Demand Unit Cost ($/kW - month)	**Energy Unit Cost (¢/kWh)**
Scenario 1		
NP's Recommended Method [1]		
Newfoundland Power	5.24	2.920
Island Industrials	4.91	2.970
Scenario 4		
Hydro's Recommended Method [2]		
Newfoundland Power	10.95	1.530
Island Industrials	10.52	1.542

[1] Appendix 2, page 2, lines 719-720
[2] RAB-1 (Rev), page 6 of 60, lines 1 - 2

The demand unit costs for Scenario 1 are one-half those of Scenario 4. The unit energy costs, on the other hand, are double in Scenario 1. Demand and energy rates derived from these two approaches would also be very different. The unit energy costs of Scenario 1 are roughly equivalent to the marginal energy costs from Holyrood (about 3¢/kWH). It is a common practice to make sure that the energy

Newfoundland Light & Power Co. Limited
Summary of Cost of Service Scenarios

Scenario	Revenue Allocated to Classes: NP $(000's)	Island Industrials $(000's)	Labrador Industrials $(000's)	Labrador Rural Interconnected $(000's)	Total $(000's)
1. Recommended by NP					
- $355/kW Equivalent Peaker Generation Classification	189.4	48.3	5.0	11.6	254.3
- Fuel 100% Energy except Gas Turbines 100% Demand					
- Transmission Lines 50/50 Demand/Energy; Substation and Terminal Equipment 100% Demand					
- Deficit Allocated 50/50 Revenue/Energy					
- Northern Peninsula Directly Assigned					
- 5CP Allocator Generation/Transmission Plant					
2. Previous (Approved '77 Method)					
- Generation 50/50 Demand/Energy Adjusted for Capacity Factor (including fuel)	193.6	45.0	4.6	11.1	254.3
- All Transmission Plant 50/50 Demand/Energy					
- Deficit Allocated 100% Revenue (per RAB-2) [1]					
- Northern Peninsula Directly Assigned					
- AED Allocator Generation/Transmission Plant					
3. High Sensitivity by NP					
- $710/kW Equivalent Peaker	195.3	43.4	4.3	11.3	254.3
- Fuel 100% Energy except Gas Turbines 100% Demand					
- All Transmission Plant 100% Demand					
- Deficit Allocated 100% Revenue					
- Northern Peninsula Directly Assigned					
- 5CP Allocator Generation/Transmission Plant					
4. Recommended by Hydro					
- Generation Plant 100% Demand	197.4	41.8	4.2	10.9	254.3
- All Fuel 100% Energy					
- All Transmission Plant 100% Demand					
- Deficit Allocated 100% Revenue					
- Northern Peninsula Common					
- AED Allocator Generation Plant					
- CP Allocator Transmission Plant					

[1] Deficit Allocation Method was not an issue in 1977 - 100% Revenue Allocator was used in RAB-2.

NEWFOUNDLAND HYDRO — 9-SEP-92 — Base Case

Sch 1.2 — Sch 1.2 — $355/kW Peaker

1992 Forecast — NEW355PE

50% Revenue

Comparison of Revenue & Allocated Revenue Requirement — 50% Energy

Deficit Alloc.

($000)

(b) Line No.	(c) Description	(d) Allocated Revenue Reqt	(e) Revenue Before Deficit Alloc	(f) Deficit	(g) Deficit Alloc 50% Rev	(h) Revenue Deficit Alloc 50% Energy	(i) Revenue After Deficit Alloc	(j) Ratio
1	Newfoundland Power	163,968	163,968		13,345	12,145	189,458	1.16
2	Island Industrial	41,363	41,363		3,367	3,541	48,271	1.17
3	Labrador Industrial	3,723	3,723		303	978	5,004	1.34
	Rural							
4	Island Interconnected	35,112	23,112	12,000	(6,000)	(6,000)	23,112	0.66
5	Isolated Systems	34,593	10,988	23,605	(11,803)	(11,803)	10,988	0.32
6	Labrador Interconnected	9,679	9,679	0	788	1,138	11,605	1.20
7	Subtotal Rural	79,384	43,779	35,605	(17,015)	(16,665)	45,705	0.58
	Total	288,438	252,833	35,605	(0)	0	288,438	1.00

Island Interconnected

Line No.	Description	Allocated Revenue Reqt	Revenue Before Deficit Alloc	Deficit	Deficit Alloc 50% Rev	Revenue Deficit Alloc 50% Energy	Revenue After Deficit Alloc	Ratio
8	Newfoundland Power	163,968	163,968	0	13,345	12,145	189,458	1.16
9	Industrial	41,363	41,363	0	3,367	3,541	48,271	1.17
10	Rural	35,112	23,112	12,000	(6,000)	(6,000)	23,112	0.66
11	Total	240,443	228,443	12,000	10,712	9,686	260,841	1.08

NEWFOUNDLAND HYDRO — 9-SEP-92

Sch 1.3.1 — Sch 1.3.1

Island Interconnected — NEW355PE

Total Demand, Energy and Customer Amounts

(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		($000)							
		---------Before Deficit Allocation-----------				--------After Deficit Allocation---------			
Line No.	Description	Total	Demand	Energy	Customer	Total	Demand	Energy	Customer
	Island Interconnected								
1	Newfoundland Power	163,968	53,501	108,224	2,243	189,458	61,818	125,048	2,592
2	Industrial	41,363	8,598	31,796	968	48,271	10,034	37,106	1,130
3	Rural	35,112				23,112			
4	Total	240,442				260,840			

Sch 1.3.2 — Sch 1.3.2

Line No.	Demands, Sales & Bills	Billing Dems (kw)	Sales (mwh)	Bills (Total No)	Sales Used For Deficit Alloc.	Sales Deficit Alloc. Factor
	Island Interconnected					
5	Newfoundland Power	11,805,000	4,284,100	12	4,284,100	0.6822
6	Industrial	2,043,300	1,249,200	84	1,249,200	0.1989
7	Rural		273,199			
	Labrador Interconnected					
8	Industrial		345,100		345,100	0.0550
9	Rural		401,373		401,373	0.0639
					6,279,773	1.0000

Sch 1.3 — Sch 1.3

Line No.	Description	Total	Demand ($/kw)	Energy ($/kwh)	Customer ($/Bill)	Total	Demand ($/kw)	Energy ($/kwh)	Customer ($/Bill)
		---------Before Deficit Allocation-----------				--------After Deficit Allocation---------			
	Unit Demand, Energy & Customer Amounts								
8	Newfoundland Power		4.53	0.0253	186,956		5.24	0.0292	216,020
9	Industrial		4.21	0.0255	11,529		4.91	0.0297	13,454

NEWFOUNDLAND HYDRO — 9-SEP-92

Sch 2.1A — Sch 2.1A

Island Interconnected — NEW355PE

Functional Classification of Revenue Requirement

(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(L)
		($000)					Distribution			
Line No.	Description	Total Amount	Prod Demand	Prod & Trans Energy	Trans Demand	Rural Trans	Substation Demand	Other	Acct Customer	Spec Assigned Customer
	Expenses									
1	Operating & Maintenance	61,974	16,951	27,451	4,859	2,740	1,228	6,554	1,074	1,116
2	Fuels	38,433	418	38,015		0				
3	Power Purchased	428		428						
4	Depreciation	20,399	8,217	8,284	1,343	608	262	1,316	0	369
	Expense Credits									
5	Sundry	(61)	(17)	(27)	(5)	(3)	(1)	(6)	(1)	(1)
6	Building Rental Income	(131)	(28)	(77)	(11)	(6)	(2)	(5)	0	(2)
7	Tax Refunds	(56)	(15)	(25)	(4)	(2)	(1)	(6)	(1)	(1)
8	Suppilers' Discounts	(75)	(21)	(33)	(6)	(3)	(1)	(8)	(1)	(1)
9	Pole Attachments	(426)						(426)		
10	Subtotal Expenses	120,485	25,505	74,016	6,176	3,334	1,485	7,419	1,071	1,479
11	Interest	110,568	21,624	68,099	9,912	5,360	1,412	2,564	0	1,598
12	Disposal Gain/Loss	186	36	115	17	9	2	4	0	3
13	Subtot Rev Reqt Excl Margin	231,239	47,165	142,230	16,104	8,702	2,899	9,987	1,071	3,080
14	Margin	9,205	1,800	5,669	825	446	118	213	0	133
15	Total Revenue Requirement	240,444	48,966	147,900	16,929	9,148	3,016	10,200	1,071	3,213

NEWFOUNDLAND HYDRO 9-SEP-92

Sch 2.2A Sch 2.2A

Island Interconnected NEW355PE

Functional Classification of Plant in Service for the Allocation of O&M Expenses

(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		($000)					Distribution			
Line No.	Description	Total Amount	Prod Demand	Prod & Trans Energy	Trans Demand	Rural Trans	Substation Demand	Other	Acct Customer	Spec Assigned Customer
	Production									
	Hydraulic									
1	Bay D'Espair	170,974	54,883	116,091						
2	Upper Salmon	168,615	22,999	145,616						
3	Hinds Lake	79,068	16,122	62,946						
4	Cat Arm	263,255	36,487	226,768						
5	Paradise River	21,306	7,135	14,171						
6	Snooks Arm/V Bight	99	0	0		99				
7	Subtotal Hydraulic	703,317	137,626	565,592	0	99				
8	Holyrood	164,925	75,833	89,092						
9	Gas Turbines	16,977	16,977	0						
10	Diesel	3,226	0	0		3,226				
11	Subtotal Production	888,445	230,436	654,684	0	3,325				
	Transmission									
12	Lines	193,468	1,317	69,632	69,632	45,766				7,122
13	Terminal Stations	105,729	33,675	0	37,143	8,068	11,820	0	0	15,023
14	Subtotal Transmission	299,197	34,992	69,632	106,775	53,834	11,820	0	0	22,145
15	Total Distribution	49,617	206				3,976	45,435	0	
16	Subtotal Prod Trans Dist	1,237,259	265,634	724,316	106,775	57,159	15,796	45,435	0	22,145
17	General	62,166	13,347	36,393	5,365	2,872	794	2,283	0	1,113
18	Telecontrol - Common	36,476	8,268	22,563	3,326	1,951	368			
19	Telecontrol - Specific	331								331
20	Feasibility Studies	2,232	1997		214	22	0	0	0	
21	Total Plant	1,338,464	289,246	783,272	115,679	62,004	16,958	47,718	0	23,589

NEWFOUNDLAND HYDRO 9-SEP-92

Sch 2.3A Sch 2.3A

Island Interconnected NEW355PE

Functional Classification of Net Book Value

(b) Line No.	(c) Description	(d) ($000) Total Amount	(e) Prod Demand	(f) Prod & Trans Energy	(g) Trans Demand	(h) Rural Trans	(i) Distribution: Substation Demand	(j) Distribution: Other	(k) Acct Customer	(l) Spec Assigned Customer
	Production									
	Hydraulic									
1	Bay D'Espair	145,046	46,560	98,486						
2	Upper Salmon	167,332	22,824	144,508						
3	Hinds Lake	77,552	15,813	61,739						
4	Cat Arm	262,415	36,371	226,044						
5	Paradise River	21,219	7,106	14,113						
6	Snooks Arm/V Bight	13	0	0		13				
7	Subtotal Hydraulic	673,577	128,674	544,890	0	13				
8	Holyrood	90,475	41,600	48,875						
9	Gas Turbines	7,546	7,546	0						
10	Diesel	471	0	0		471				
11	Subtotal Production	772,069	177,820	593,765	0	484				
	Transmission									
12	Lines	173,565	1,302	62,658	62,658	42,942				4,005
13	Terminal Stations	90,510	27,161	0	32,671	7,814	11,152			11,712
14	Subtotal Transmission	264,075	28,463	62,658	95,329	50,756	11,152	0	0	15,717
15	Total Distribution	27,837	50				2,512	25,275	0	
16	Subtotal Prod Trans Dist	1,063,981	206,333	656,423	95,329	51,240	13,664	25,275	0	15,717
17	General	42,751	8,291	26,375	3,830	2,059	549	1,016	0	632
18	Telecontrol - Common	24,687	4,905	15,608	2,267	1,643	265			
19	Telecontrol - Specific	40								40
20	Feasibility Studies	2,492	2,240		227	24	0	0	0	
21	Total Plant	1,133,951	221,768	698,406	101,653	54,966	14,478	26,291	0	16,389

Sch 2.4A

NEWFOUNDLAND HYDRO

Island Interconnected

9-SEP-92
Sch 2.4A
NEW355PE

Functional Classification of O&M Expenses

(b) Line No.	(c) Description	(d) ($000) Total Amount	(e) Prod Demand	(f) Prod & Trans Energy	(g) Trans Demand	(h) Rural Trans	(i) Distribution Substation Demand	(j) Distribution Other	(k) Acct Customer	(l) Spec Assigned Customer
	Production									
1	Hydraulic	7,528	1,473	6,054	0	1				
2	Holyrood	13,907	6,394	7,513	0	0				
3	Gas Turbines	811	811	0	0	0				
4	Diesel	268	0	0	0	268				
5	Subtotal Production	22,514	8,679	13,566	0	269				
	Transmission									
6	Lines	4,389	30	1,580	1,580	1,038				162
7	Terminal Stations	3,324	1,059	0	1,168	254	372	0		472
8	Subtotal Transmission	7,713	1,089	1,580	2,747	1,292	372	0	0	634
9	Total Distribution	4,230	18				339	3,873		
10	Subtotal Prod Trans Dist	34,457	9,785	15,146	2,747	1,561	711	3,873	0	634
11	Customer Accounting	662							662	
	Overheads									
	Plant Related									
12	Production	499	129	368						
13	Transmission	210	25	49	75	38	8			16
14	Production & Trans	201	45	123	18	10	2			4
15	Distribution	168	1				13	154		0
16	Other	3,254	703	1,905	281	150	42	115	0	58
17	Property Insurance	663	173	431	28	10	10			10
18	Expense Related	21,863	6,091	9,429	1,710	972	442	2,411	412	395
19	Subtotal Overheads	26,858	7,166	12,304	2,112	1,179	518	2,681	412	482
20	Tot Oper & Maint Expense	61,977	16,951	27,451	4,859	2,740	1,228	6,554	1,074	1,116

NEWFOUNDLAND HYDRO | 9-SEP-92

Sch 2.5A | Sch 2.5A

Island Interconnected | NEW355PE

Functional Classification of Depreciation Expense

(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		($000)					Distribution			
Line No.	Description	Total Amount	Prod Demand	Prod & Trans Energy	Trans Demand	Rural Trans	Substation Demand	Other	Acct Customer	Spec Assigned Customer
	Production									
	Hydraulic									
1	Bay D'Espair	701	225	476						
2	Upper Salmon	222	30	192						
3	Hinds Lake	241	49	192						
4	Cat Arm	189	26	163						
5	Paradise River	32	11	21						
6	Snooks Arm/V Bight	1	0	0	0	1				
7	Subtotal Hydraulic	1,386	341	1,044	0	1				
8	Holyrood	7,418	3,411	4,007						
9	Gas Turbines	806	806	0						
10	Diesel	56	0	0	0	56				
11	Subtotal Production	9,666	4,558	5,051	0	57				
	Transmission									
12	Lines	1,180	3	445	445	209				79
13	Terminal Stations	1,185	425	0	429	48	83			200
14	Subtotal Transmission	2,365	428	445	874	257	83	0	0	279
15	Total Distribution	1,121	3				105	1,013	0	
16	Subtotal Prod Trans Dist	13,152	4,989	5,495	874	314	188	1,013	0	279
17	General	3,934	1,492	1,644	261	94	56	303	0	83
18	Telecontrol - Common	2,579	1,039	1,145	182	195	17			
19	Telecontrol - Specific	5								5
20	Feasibility Studies	728	696		26	5	0	0	0	2
21	Total Depreciation Expense	20,398	8,217	8,284	1,343	608	262	1,316	0	369

NEWFOUNDLAND HYDRO 9-SEP-92

Sch 3.1A Sch 3.1A

Island Interconnected NEW355PE

Basis of Allocation to Classes of Service

(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		($000)					Distribution			
Line No.	Description	Total Amount	Prod Demand	Prod & Trans Energy	Trans Demand	Rural Trans	Substation Demand	Other	Acct Customer	Spec Assigned Customer
			(5CP kw)	(mwh @ Gen)	(5CP kw)	Direct	Direct	Direct	Direct	
	Amount									
1	Newfoundland Power		954,563	4,390,777	921,660					
2	Industrial		153,408	1,290,017	148,120					
3	Rural		67,735	319,697	65,400					
4	Total		1,175,706	6,000,491	1,135,180					
	Ratios									
5	Newfoundland Power		0.8119	0.7317	0.8119					
6	Industrial		0.1305	0.2150	0.1305					
7	Rural		0.0576	0.0533	0.0576	1.0000	1.0000	1.0000	1.0000	
8	Total		1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	

Island Interconnected

Allocation of Functional Amounts to Classes of Service

(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		($000)					Distribution			
Line No.	Description	Total Amount	Prod Demand	Prod & Trans Energy	Trans Demand	Rural Trans	Substation Demand	Other	Acct Customer	Spec Assigned Customer
	Allocated Revenue Requirment Excluding Margin									
1	Newfoundland Power	157,586	38,294	104,075	13,075					2,142
2	Industrial	39,770	6,154	30,577	2,101					937
3	Rural	33,881	2,717	7,578	928	8,702	2,899	9,987	1,071	0
4	Total	231,238	47,165	142,230	16,104	8,702	2,899	9,987	1,071	3,079
	Allocated Margin									
5	Newfoundland Power	6,382	1,462	4,149	670					102
6	Industrial	1,593	235	1,219	108					31
7	Rural	1,230	104	302	48	446	118	213	0	0
8	Total	9,205	1,800	5,669	825	446	118	213	0	133
	Total Allocated Revenue Requirment									
9	Newfoundland Power	163,968	39,756	108,224	13,745					2,244
10	Industrial	41,363	6,389	31,796	2,209					969
11	Rural	35,112	2,821	7,880	975	9,148	3,016	10,200	1,071	
12	Total	240,443	48,966	147,900	16,929	9,148	3,016	10,200	1,071	3,213

NEWFOUNDLAND HYDRO — 9-SEP-92

Sch 3.3A — Sch 3.3A

Island Interconnected — NEW355PE

Allocation of Specifically Assigned Amounts to Classes of Service

(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
		($000)									
			O&M			Depreciation					Subtotal
Line		Total	Transmission		Admin &	Lines &	Telecntr &		Expense	Interest &	Excl
No.	Description	Amount	Lines	Terminals	General	Terminals	Feas Study	General	Credits	Gain/Loss	Margin
			(Plant)	(Plant)	(e + f)	(Direct)	(Direct)			(NBV)	
	Basis of Allocated Amounts										
1	Newfoundland Power		2,950	9,697	12,647			213		12,033	
2	Industrial		4,172	5,327	9,499			66		3,725	
3	Rural		0	0	0			0		0	
4	Total	0	7,122	15,024	22,146	0	0	280	0	15,758	0
	Ratios										
5	Newfoundland Power		0.4142	0.6454	0.5711			0.7627		0.7636	
6	Industrial		0.5858	0.3546	0.4289			0.2373		0.2364	
7	Rural		0.0000	0.0000	0.0000			0.0000		0.0000	
8	Total	0	1.0000	1.0000	1.0000			1.0000		1.0000	
	Amounts Allocated										
9	Newfoundland Power	2,244	67	305	275	213	0	64	(4)	1,222	2,142
10	Industrial	969	95	167	207	66	6	20	(2)	378	937
11	Rural	0	0	0	0	0	0	0		0	0
12	Total	3,213	162	472	482	280	6	83	(6)	1,601	3,079

NEWFOUNDLAND HYDRO — 9-SEP-92

Sch 4.1 — Sch 4.1

Island Interconnected — NEW355PE

Calculation of Generation & Transmission AED Factors

(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		Sales+Losses	Class 5CP	Class NCP	----Average Demand---		----Excess Demand----		--------Total--------	
Line		For AED	AT	AT						
No.	Rate Class	mwhs	Generator	Generator	Amount	Weighted	Amount	Weighted	Weighted	Amount
			(5CP kw)*	(NCP kw)						
	Generation									
1	Newfoundland Power	4,390,777	954,563	1,015,791	501,230	0.4076	514,561	0.3856	0.7932	975,372
2	Industrial	1,274,029	153,408	168,436	145,437	0.1183	22,999	0.0172	0.1355	166,629
3	Rural	319,697	67,735	92,068	36,495	0.0297	55,573	0.0416	0.0713	87,703
4	Subtotal at Generation	5,984,503	1,175,706	1,276,295	683,162	0.5556	593,133	0.4444	1.0000	1,229,704

		Sales+Losses	Class 5CP	Class NCP	----Average Demand---		----Excess Demand----		--------Total--------	
		For AED	AT	AT						
		mwhs	Trans	Trans	Amount	Weighted	Amount	Weighted	Weighted	Amount
			(5CP kw)	(NCP kw)						
	Transmission									
5	Newfoundland Power	4,284,100	921,660	983,750	489,053	0.4119	494,697	0.3825	0.7944	943,206
6	Industrial	1,243,075	148,120	163,123	141,904	0.1195	21,219	0.0164	0.1359	161,384
7	Rural	302,467	65,400	87,061	34,528	0.0291	52,533	0.0406	0.0697	82,756
8	Subtotal at Transmission	5,829,642	1,135,180	1,233,934	665,484	0.5605	568,450	0.4395	1.0000	1,187,345

Coincident Peaks

		JAN/92	FEB/92	MAR/92	NOV/92	DEC/92	(5CP mw)
	Transmission CP*						
5	Newfoundland Power	970.2	921.7	873.1	873.1	970.2	921.7
6	Industrial	148.4	148.0	148.1	147.7	148.4	148.1
7	Rural	68.8	68.4	61.2	60.1	68.5	65.4
		1,187.4	1,138.1	1,082.4	1,080.9	1,187.1	1,135.2

* Class 5CP at Transmission and Generator as per response to NP-38 (Page 3 & 4 of 25)

Sch 4.2 NEWFOUNDLAND HYDRO 9-SEP-92

Base Case Sch 4.2

$355/kW Peaker Island Interconnected NEW355PE

50% Revenue Functionalization and Classification Ratios

50% Energy

Deficit Alloc.

(b) Line No.	(c) Description	(d) Total Amount	(e) Prod Demand	(f) Prod & Trans Energy	(g) Trans Demand	(h) Rural Trans	(i) Distribution Substation Demand	(j) Distribution Other	(k) Acct Customer	(l) Spec Assigned Customer	(m) Plant Cost In 1991 $
	Cost of Peaker used for D/E Splits		$355 /kW								$/kW
	Cost of Peaker (Paradise River)		933 /kW								
	Production										
	Hydraulic										
1	Bay D'Espair	100.0%	32.10%	67.90%							1,106
2	Upper Salmon	100.0%	13.64%	86.36%							2,602
3	Hinds Lake	100.0%	20.39%	79.61%							1,741
4	Cat Arm	100.0%	13.86%	86.14%							2,561
5	Paradise River	100.0%	33.49%	66.51%							2,786
6	Snooks Arm/V Bight	100.0%	0.00%	0.00%		100.00%					
7	Subtotal Hydraulic		19.57%	80.42%		0.01%					
8	Holyrood	100.0%	45.98%	54.02%							772
9	Gas Turbines	100.0%	100.00%	0.00%							
10	Diesel	100.0%	0.00%	0.00%		100.00%					
11	Purchase Power Island	100.0%		100.0%							
	Transmission										
12	Lines	100.0%		50.0%	50.0%						
13	Terminal Stations	100.0%		0.0%	100.0%						
14	Subtotal Transmission										
15	Total Distribution	100.0%						100.0%			