NEWFOUNDLAND POWER
A FORTIS COMPANY

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DELIVERED BY HAND

June 4, 2015

Board of Commissioners
of Public Utilities
P.O. Box 21040
120 Torbay Road
St. John's, NL A1A 5B2

Attention: G. Cheryl Blundon
Director of Corporate Services
and Board Secretary

Ladies and Gentlemen:

Re: Newfoundland and Labrador Hydro's Amended General Rate Application

Please find enclosed the original and twelve copies of Expert Evidence of Mr. Larry Brockman of Brockman Consulting.

The enclosure is intended to provide the Board with additional evidence to assist it in considering Hydro's Amended General Rate Application.

We trust the foregoing and enclosed are found to be in order. However, if you have any questions whatsoever, please feel free to contact us.

Copies of the enclosure and this correspondence have been forwarded directly to the parties indicated below.

Yours very truly,

Gerard M. Hayes
Senior Counsel

Enclosures

c. Geoffrey Young
Newfoundland and Labrador Hydro

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IN THE MATTER OF the Public
Utilities Act, R.S.N. 1990, Chapter P-47
(the Act), and

IN THE MATTER OF a General Rate Application (the Amended Application) by Newfoundland and Labrador Hydro for approvals of, under Sections 70 and 75 of the Act, changes in the rates to be charged for the supply of power and energy to Newfoundland Power, Rural Customers and Industrial Customers; and under Section 71 of the Act, changes in the Rules and Regulations applicable to the supply of electricity to Rural Customers.

Prefiled Evidence and Exhibit of Larry Brockman

Testimony on Behalf of Newfoundland Power

Brockman Consulting

NEWFOUNDLAND POWER
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At the hearing into Newfoundland and Labrador Hydro's 2013 Amended General Rate Application, the Rates and Cost of Service Expert Evidence will be adopted by Larry Brockman, President of Brockman Consulting based in Atlanta, Georgia.

A witness profile for Larry Brockman follows.

Larry Brockman

President of Brockman Consulting

Atlanta, Georgia

Larry Brockman has over 36 years experience as a power system planning engineer, rate designer, regulatory staff member and consultant and specializes in regulatory and generation planning assistance and analysis, as well as the analysis of competitive generation markets.

Mr. Brockman has appeared before the Board of Commissioners of Public Utilities of Newfoundland and Labrador on numerous occasions as an expert witness. He has presented evidence on behalf of Newfoundland Power Inc, concerning cost of service, rate design and least cost planning in Newfoundland and Labrador Hydro's 1990, 1992, 2001, 2003 and 2006 general rate referrals, as well as in Newfoundland and Labrador Hydro's 1992 generic cost of service hearing, the 1995 Rural Rate Inquiry and Newfoundland and Labrador Hydro's 2009 and 2013 Applications concerning the Rate Stabilization Plan and Industrial Rates. Mr. Brockman also appeared as an expert witness on cost of service and rate design on behalf of Newfoundland Power in 1996 and 2003 Newfoundland Power General Rate Applications.

A more detailed description of Mr. Brockman's professional background is provided as Exhibit LBB-1 to this evidence.

NEWFOUNDLAND AND LABRADOR HYDRO

2013 AMENDED GENERAL RATE APPLICATION

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1.0 INTRODUCTION

On July 30, 2013, Newfoundland and Labrador Hydro ("Hydro") filed a General Rate Application (the "Application") with the Board of Commissioners of Public Utilities of Newfoundland and Labrador (the "Board") requesting a general rate increase and certain other changes, including changes to Newfoundland Power's rates. On November 10, 2014, Hydro filed an Amended General Rate Application (the "Amended Application") based on a 2015 test year.

Newfoundland Power asked Brockman Consulting to review the Application and I filed evidence with regard to Hydro's proposals in the Application on April 25, 2014. Following the filing of the Amended Application, Newfoundland Power asked Brockman Consulting to review the Amended Application with regard to whether Hydro's proposals are just and reasonable and meet good regulatory practice. The purpose of my testimony is to summarize this review.

In my evidence, I address the following matters:

- Context for Regulatory Decision Making
- Rural Deficit Allocation
- Holyrood Capacity Factor
- Utility Rate Design
- Curtailable Load Credit

This testimony replaces the evidence I filed in relation to the Application in April 2014.

2.0 CONTEXT FOR REGULATORY DECISION MAKING

There are several contextual matters that I believe the Board ought to keep in mind in its consideration of Hydro's Amended Application. These matters relate to the impending Labrador-Island Interconnection; the appropriate consideration of regulatory history; and the difference between cost of service allocation and rate design.

Hydro's evidence filed in support of its Amended Application includes a section entitled Regulatory Outlook. This outlook lists items which Hydro indicates need to be addressed prior to the implementation of customer rates reflecting the costs of the Labrador-Island Interconnection.[1]

Hydro's Regulatory Outlook lists the following three main rate-related matters:[2]

(i) a review of the embedded Cost of Service methodology;

(ii) the completion of a marginal cost study and rate design review; and

(iii) a review of Hydro's regulatory mechanisms for recovery of supply costs.

Hydro states that the review of the embedded cost of service methodology is necessary, in part, because Holyrood Thermal Generating Station ("Holyrood") will soon be essentially shut down and replaced by power supply from the Labrador-Island Interconnection. Hydro indicates the cost of service review is required because "the replacement of fuel costs on the Island Interconnected System with transmission costs and predominately predictable purchase costs

[1] Hydro's Amended Evidence, pages 4.4-4.5.
[2] Ibid. page 4.5, lines 3-5.

also generates questions with respect to cost classification and allocation among customers classes."[3]

Hydro's evidence also acknowledges the current uncertainty of marginal capacity and energy costs. According to Hydro, the results of the marginal cost study to be completed in 2015 "will form a basis for a review of customer rate designs to reflect the new system cost structure" following the Labrador-Island Interconnection. Hydro states that "the transition from an isolated system to a system connected to the North America grid requires a review of the marginal energy costs and marginal capacity costs for both planning and pricing purposes."[4]

I agree that the specific implications of the Labrador-Island Interconnection noted in Hydro's Regulatory Outlook are important. However, I would go further.

In my view, the Labrador-Island Interconnection will dramatically alter the current view of the Labrador Interconnected System as a separate system isolated from the Island. The likely outcome is that the Labrador Interconnected System will be viewed as part of the overall interconnected system of the province.[5] This could have a dramatic effect on rate design and cost allocations. Given that possibility, I think it is unwise to make major changes to allocations and rate design at this time.

[3] Ibid. page 4.5, lines 17-22.

[4] Ibid. page 4.5, lines 25-26 to page 4.6, line 1.

[5] See, for example, the Board's discussion of cost of service considerations related to the Labrador Interconnected System in the 1993 Cost of Service Report at page 10.

One of the main topics in my evidence is Hydro's proposal to change the allocation methodology for the Rural Deficit. In considering that proposal, the impending changes resulting from the Labrador-Island Interconnection should be kept in mind.

I think it is also important to consider regulatory history. We should be cautious about making major regulatory changes based on short-term considerations. Before reversing a prior decision on cost of service methodology, the Board should consider whether there is evidence that the essential underpinnings of the decision have changed. In my view, Hydro's proposal to change the Rural Deficit allocation should be considered in that light. While the magnitude of the deficit has unfortunately continued to increase, the underpinnings of the Board's recommendation following the 1992 generic cost of service hearing (the "1992 COS Hearing"), have not changed.

Hydro's proposal to change the Rural Deficit allocation is based on a fairness assessment.[6] However, there is no scientifically right or wrong way to fairly allocate costs that are not causally related to the customer. When considering fairness in this context, it is important to consider the entire circumstances of the parties involved. For example, Hydro believes it is not fair for the Labrador Interconnected customers to pay a higher share of the Rural Deficit per customer; yet their rate is about half what Newfoundland Power customers pay. There were valid historical reasons for the low rates in Labrador; but, as noted above, major system changes are coming that, in my view, may substantially alter cost of service and rate design for the entire Province.

[6] Hydro's Amended Evidence, page 4.8 ff.

In light of the impending major changes, I believe it is preferable not to do things on a piecemeal basis. We don't want to address a problem today with a solution that may not make sense when circumstances change, as I believe they are about to.

Finally, I believe it is important to keep rate design separate from cost of service. A cost of service allocation should not be chosen based on the amount of the resulting cost assignments to a class. As the Board pointed out in its 1993 report arising out of the 1992 COS Hearing (the "1993 COS Report"), the customer impact of cost of service allocations is more properly addressed as a rate design issue.[7]

3.0 RURAL DEFICIT

3.1 Hydro's Proposal on the Allocation of the Rural Deficit

In the Amended Application, Hydro proposes a change in the methodology for allocating the Rural Deficit. Hydro proposes that the Rural Deficit be allocated based on the revenue requirements of each customer class.[8] The existing allocation methodology (the "Existing Methodology") is based on the recommendation of the Board to Government following the 1992 COS Hearing. I presented evidence on behalf of Newfoundland Power in that proceeding.

3.2 Background and History

What is the Rural Deficit?

The Rural Deficit is associated with Hydro's Isolated Diesel Systems, the L'Anse au Loup System and Hydro's customers on the Island Interconnected System (the "Deficit Systems").

[7] 1993 COS Report, page 59 and page 62.
[8] This is essentially the same approach Hydro proposed, and the Board rejected, at the 1992 COS Hearing.

The Rural Deficit is the difference between the cost of providing electrical service to customers on the Deficit Systems and the revenues collected from those customers. Pursuant to Government policy, the rates of customers on the Deficit Systems are set below the cost of serving them.

Prior to 1989, the Government was paying an annual subsidy of approximately $20 million to the Power Distribution Districts to operate the rural system. Government's subsidy was eventually phased out, so that by 1992 responsibility for the entire subsidy was passed directly to electricity ratepayers on Hydro's interconnected systems.

Table 1 shows the revenue collected from customers on the Deficit Systems as a percentage of the costs of serving those customers in Hydro's proposed 2015 test year.

Table 1
Percentage of Cost of Service
Recovered in Rates for
Deficit Systems
(%)

	2015 TY[9] (proposed)
Hydro Island Interconnected (Rural)	67%
Island Isolated	16%
Labrador Isolated	24%
L'Anse Au Loup	45%

Funding of the Rural Deficit was first included in rates in 1990. At that time, the Rural Deficit was borne by all of Hydro's customers, other than the Labrador Interconnected customers and

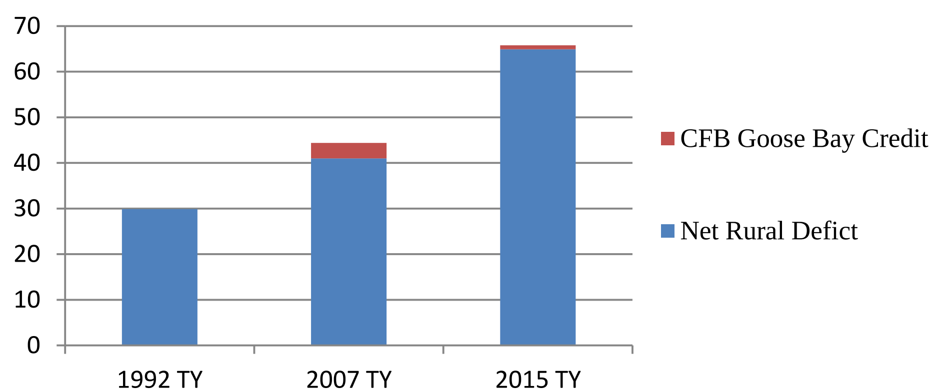
[9] Hydro's Amended Application, Exhibit 13, page 3 of 109.

the customers on the Deficit Systems.[10] In 1991, the legislation was amended to require that Labrador Interconnected customers also bear a portion of the Rural Deficit. In 1998, a legislative change exempted the Industrial Customers from their obligation to fund the Rural Deficit.

Changes in the Rural Deficit

Figure 1 shows the total Rural Deficit for the 1992 Test Year, the 2007 Test Year (amount currently reflected in rates), and the 2015 Test Year. Figure 1 also shows the offsetting effect of the CFB Goose Bay Credit on the total Rural Deficit.[11]

Figure 1
Hydro's Rural Deficit
($ millions)



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10 Newfoundland Power recovers its funding of the Rural Deficit from its customers.

11 A secondary energy rate approved in Hydro's 2001 general rate hearing resulted in revenues from CFB Goose Bay exceeding their cost of service by $3.7 million. To avoid a large increase to Labrador Interconnected customers due to the Rural Deficit and other issues, the Board allowed the surplus revenue to be applied against the cost of service of Labrador Interconnected customers (the "CFB Goose Bay Credit"). The Board also requested that Hydro present at its next general rate hearing a five-year plan to move Labrador Interconnected customers to uniform rates and apply the CFB Goose Bay Credit against the Rural Deficit. This phase-in plan was completed as of January 1, 2011. See Order Nos. P.U. 7(2002-2003), P.U. 14(2004), and Hydro's November 25, 2010 Application for Rates to Certain Labrador Interconnected customers.

Over the 15 years from 1992 to 2007, the total Rural Deficit increased by approximately 2.5% per year. For the 8 years from 2007 to 2015, the rate of increase of the total Rural Deficit increased to approximately 5% per year.

Table 2 shows the sources of funding the Rural Deficit reflected in rates for each of Hydro's 2002 Test Year, 2007 Test Year, and proposed 2015 Test Year.

Table 2
Hydro's Rural Deficit Funding
($ millions)

	2002 TY[12]	**2007 TY**[13]	**2015 TY**[14] **(proposed)**
Newfoundland Power	33.7	36.3	61.7
Island Industrials	-	-	-
Labrador Industrials	-	-	-
CFB Goose Bay	0.1	-	-
Labrador Interconnected	4.9	4.4	2.4
Total	38.7	40.7	64.1

The relative amounts of the Rural Deficit borne by Newfoundland Power's customers and the Labrador Interconnected customers have been relatively stable since 2002. Hydro's proposed 2015 Test Year proposes a 70% *increase* in the funding of the Rural Deficit by Newfoundland Power's customers and a 45% *decrease* in the funding of the Rural Deficit by Labrador Interconnected customers over the amount currently included in rates.

[12] 2002 Forecast Cost of Service dated August 2002 filed in compliance with Order Nos. P.U. 7(2002-2003) and P.U. 16(2002-2003).

[13] See response to Request for Information IC-NLH-002.

[14] Hydro's Amended Application, Exhibit 13, page 3 of 109. In 2015, Hydro is proposing a method based on revenue requirement (i.e. customers pay an equal amount depending on the cost to serve the customer).

Relative Customer Impacts

Figure 2 shows Hydro's cost to serve Newfoundland Power, including the portion of the Rural Deficit allocated to Newfoundland Power's customers.

Figure 2
Cost of Service and Deficit Funding[15]
Newfoundland Power
($ millions)

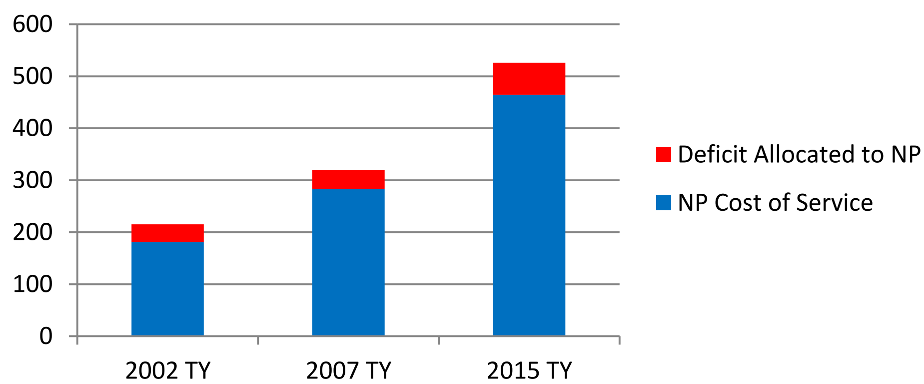


Figure 2 shows that, from the 2002 Test Year to the 2007 Test Year, Hydro's cost to serve Newfoundland Power increased from approximately $181 million to approximately $283 million. The Rural Deficit allocated to Newfoundland Power was approximately $34 million in the 2002 Test Year and approximately $36 million in the 2007 Test Year. For 2015, Hydro proposes that its cost to serve Newfoundland Power will be approximately $464 million. The proposed allocation of the Rural Deficit for Newfoundland Power will increase to approximately $62 million.

Figure 3 shows Hydro's cost to serve Labrador Interconnected customers, including the portion of the Rural Deficit allocated to those customers. Figure 3 also indicates the portion of the Rural

[15] 2002 Forecast Cost of Service dated August 2002 filed in compliance with Order Nos. P.U. 7(2002-2003) and P.U. 16(2002-2003), page 3 of 98; 2007 Forecast Cost of Service provided in response to Request for Information IC-NLH-002, page 3 of 109; and Hydro's Amended Application, Exhibit 13, page 3 of 109.

Deficit allocation to Labrador Interconnected customers which was effectively offset by the CFB Goose Bay Credit.

Figure 3
Cost of Service and Deficit Funding[16]
Labrador Interconnected
($ millions)

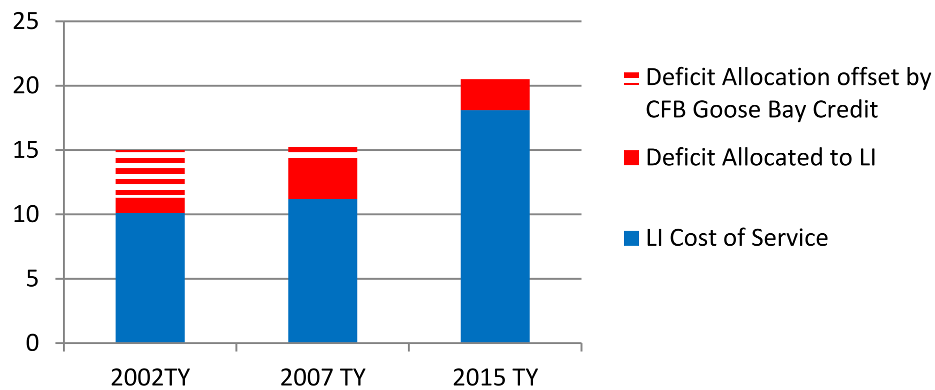


Figure 3 shows that, from the 2002 Test Year to the 2007 Test Year, Hydro's cost to serve Labrador Interconnected customers increased from approximately $10 million to approximately $11 million. The Rural Deficit allocated to Labrador Interconnected customers was approximately $5 million in the 2002 Test Year, of which approximately $3.7 million was offset by the CFB Goose Bay Credit. The Rural Deficit allocated to Labrador Interconnected customers was approximately $5 million in the 2007 Test Year, of which approximately $1.2 million was offset by the CFB Goose Bay Credit. For 2015, Hydro proposes that its cost to serve Labrador Interconnected customers will be approximately $18 million. The proposed allocation of the Rural Deficit for Labrador Interconnected customers will decrease to approximately $2.4 million.

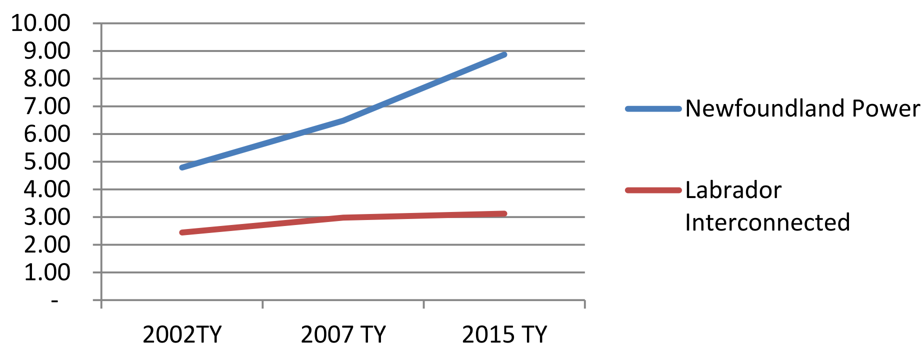
16 2002 Forecast Cost of Service dated August 2002 filed in compliance with Order Nos. P.U. 7(2002-2003) and P.U. 16(2002-2003), page 3 of 98; 2007 Forecast Cost of Service provided in response to Request for Information IC-NLH-002, page 3 of 109; and Hydro's Amended Application, Exhibit 13, page 3 of 109.

Hydro's cost to serve Newfoundland Power together with the Rural Deficit allocation is proposed to increase by approximately 145%, from approximately $215 million in the 2002 Test Year to approximately $526 million in Hydro's proposed 2015 Test Year.

By comparison, Hydro's cost to serve Labrador Interconnected customers together with the Rural Deficit allocation is proposed to increase by approximately 37%, from approximately $15 million in the 2002 Test Year to approximately $20.5 million in Hydro's proposed 2015 Test Year.

Figure 4 shows the relative increases to Newfoundland Power and the Labrador Interconnected customers respectively for Hydro's 2002 and 2007 Test Years and proposed 2015 Test Year expressed as an average cost per kWh.[17]

Figure 4
Average Revenue Requirement
Newfoundland Power and
Rural Labrador Interconnected
(¢/kWh)



[17] The average cost per kWh is derived by dividing Hydro's total forecast cost to serve, including the Rural Deficit allocation and the offsetting effect of the CFB Goose Bay Credit, by the forecast number of kWh delivered.

The overall revenue requirement increase proposed for Newfoundland Power (and ultimately borne by Newfoundland Power's customers) for the 2002 to 2015 period is substantially greater than the overall revenue requirement increase proposed for Labrador Interconnected customers.

The Existing Methodology

In the 1992 COS Hearing, there was a comprehensive review of the allocation of the Rural Deficit to determine who should fund it. The Board recommended a sharing of the Rural Deficit based on equal sharing of the costs by peak demand, energy and by number of customers (the "Unit Cost Method"). This effectively resulted in Labrador Interconnected customers and Newfoundland Power paying an equal amount per kW, per kWh and per customer, independent of whether the customer was on the Island Interconnected System or the Labrador Interconnected system. This method has been used by Hydro in setting customer rates in all their General Rate Applications since 1992.[18] The Unit Cost Method is consistent with the allocation of costs within a system which are typically shared equally depending on the customer use of peak demand (i.e. $/kW), the customer use of energy (i.e. $/kWh) and equal allocation of customer-related costs to customers (i.e. $/customer).

3.3 The General Problem of Allocating the Rural Deficit

Cost of Service Considerations

After consideration of all the evidence in the 1992 COS Hearing, the Board chose a deficit allocation methodology it considered fair and reasonable.

[18] These include Hydro's 2001, 2003, and 2006 GRAs.

Traditional cost-of-service methodologies are generally used to attribute costs to customers based on how those customers cause the cost to be incurred.[19] This is generally thought to be fair. A difficulty with allocating the Rural Deficit is that the Rural Deficit is not causally related to the customers responsible for funding it. For that reason, it is difficult to assess the "fairness" of any allocation methodology for the Rural Deficit from a traditional cost-of-service perspective.

The NARUC Cost-of-Service Allocation Manual addresses the problem of costs that cannot be directly assigned to the traditional cost-of-service categories in the following terms:[20]

> "The administrative and general function includes the management costs, administrative buildings, etc. that cannot be directly assigned to the other major cost functions. These costs may be functionalized by relating them to specific groups of costs or other characteristics of the major cost functions, and then allocated on the same basis as the other costs within the function."

This is similar to what Mr. Baker (the Board's expert witness) did in his "mini-cost-of-service study" upon which the Existing Methodology is based. In essence, the Existing Methodology treats the Rural Deficit as part of the overall cost of doing business, and allocates it using the same allocators used to allocate all the other costs (i.e., demand (kW), energy (kWh), and number of customers).

The Existing Methodology incorporates a cost-of-service perspective, to the extent that it attempts to allocate the Rural Deficit with reference to the electricity usage patterns of the Labrador Interconnected customers and Newfoundland Power. In recommending the Existing

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[19] See Exhibit LBB-2 for a summary of cost of service principles and practices.
[20] NARUC Cost Allocation Manual, page 20.

Methodology, the Board indicated that "such an allocation attempts to compensate for the inequities in the other methods proposed."[21]

Hydro's Fairness Assessment

In support of its proposal to change the methodology, Hydro's evidence summarizes a "fairness assessment" of the Existing Methodology.[22] On the basis of this assessment, Hydro says it "believes that the Existing Methodology does not provide a reasonable sharing of the Rural Deficit between customers on the Labrador Interconnected System and customers of NP."[23]

This conclusion appears to be based almost entirely on the fact that the Existing Methodology assigns more cost per customer to the Labrador Interconnected customers than Hydro's proposed methodology.[24] Hydro's explanation for this higher cost per customer is "primarily because [the Labrador Interconnected customers] have higher electricity usage as a result of living in an area of the Province where the climate is materially colder." While that may be the case, Hydro has not provided evidence indicating that the circumstances affecting the electricity usage of the Labrador Interconnected customers are materially different today than they were in 1993, when the Existing Methodology was established.

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21 1993 COS Report, page 62.

22 Hydro's Amended Evidence, page 4.8 ff.

23 Hydro's Amended Evidence, page 4.10.

24 Notwithstanding Hydro's proposed methodology appears based upon the cost borne per customer, Hydro does not propose to allocate the deficit on a per customer basis. Instead, Hydro proposes for cost of service purposes to allocate the deficit over total cost (or revenue requirement). This conceptual inconsistency could result in Hydro having to reassess allocation of the Rural Deficit to Labrador Interconnected customers at each rate case to ensure that the cost borne per customer meets their fairness standard. In addition, the colder temperatures are the only difference in usage patterns between Labrador Interconnected customers and Newfoundland Power customers that appear to be considered in Hydro's proposed methodology.

In considering the fairness of the Existing Methodology, it is not appropriate to consider any single aspect in isolation. A number of comparative factors may be relevant. The circumstances of the Newfoundland Power and Labrador Interconnected customers are different. For example, the Labrador Interconnected customers enjoy the benefits of using roughly twice as much electricity as Newfoundland Power's customers. However, they pay roughly only half as much for the product as Newfoundland Power's customers.

Hydro's proposal to change the allocation methodology at this time seems to be solely motivated by the rate impacts on the Labrador Interconnected customers of the changes in the cost of service reflected in the Amended Application.[25]

In the 1992 COS Hearing, the Board considered the impact of the Rural Deficit allocation on Newfoundland Power's customers in these terms:

> "The Board is also concerned with the fairness to the individual customers of NP who will have this cost passed through to them once the amount is assigned to NP. We do not share the opinion that the allocation of the deficit has little effect on the individual customers of NP. The customers of NP on relative terms are very sensitive to changes in rates."[26]

Hydro's proposed methodology change would simply result in Newfoundland Power's customers picking up a larger share of the Rural Deficit. Newfoundland Power's customers will see the Rural Deficit amount allocated to them increase from $33.7 million in 2002 to $61.7 million in 2015, if Hydro's proposal is approved. By comparison, Labrador Interconnected customers will see the Rural Deficit amount allocated to them decrease from approximately $4.9 million in 2002 to $2.4 million in 2015, if Hydro's proposal is approved.

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[25] Hydro's Amended Evidence, page 4.7, line 18 to page 4.8, line 3.
[26] 1993 COS Report, page 59.

For all of these reasons, Hydro's fairness assessment is not compelling, in my view.

Taking Rates in the Wrong Direction

In the past, the Labrador Interconnected customers have enjoyed rates nearly half of those paid by Newfoundland Power, because their power supply was isolated from the Island system, and it was largely hydraulic. Once the Labrador Interconnection is complete, the Labrador Interconnected System will no longer be electrically separate from the Island. When that occurs, all of Hydro's interconnected customers will be part of a single system. Under that scenario, it is conceivable that all interconnected customers would pay uniform rates. Hydro's proposal to change the Rural Deficit allocation may be taking the Labrador Interconnected rates in the wrong direction.

Rate Design vs. Cost of Service Methodology

After expending great effort in 1992 on this issue, and considering a number of different proposals, the Board recommended the Existing Methodology. Hydro's proposal in this proceeding to change the methodology raises the question of whether circumstances relevant to the Board's 1993 recommendation have changed sufficiently to warrant that the methodology be changed.

Hydro's evidence compares the rate impact on the Labrador Interconnected customers of the proposals in its Amended Application with the rate impact on Newfoundland Power's customers under the Existing Methodology and its proposed methodology. On the basis of that comparison, Hydro's evidence states that "the material rate impact of the Existing Methodology on the customers on the Labrador Interconnected System has ***created a concern*** with respect to the reasonableness of the Rural Deficit allocation methodology."[27] (emphasis added)

However, the greater impact of the Existing Methodology on the Labrador Interconnected customers was clearly within the contemplation of the Board at the time it made its recommendation in 1993. The Board addressed the impact on the Labrador Interconnected customers in the following terms:

> "Since Labrador has not paid the subsidy in the past and has been adjusted in cost, for the purpose of this allocation only, Labrador's increase in costs is twice as large as for the Island. Matters relating to possible rate shock are best addressed in the context of a rate hearing. This report has been restricted to methodology only."[28]

The Board's comment clearly differentiates the issue of methodology from the issue of rate impact, and indicates that the rate impact should be addressed separately.

After giving the matter full consideration in 1992, the Board cautioned against choosing an allocation methodology for the Rural Deficit based on its impact. The report states as follows:

> "Throughout the hearing and as part of final argument fairness was often measured in terms of the impact a change makes. The Board prefers to assess the fairness of the allocation to all parties on its own merits and once this is determined the Board could then consider rate shock implications and the merit of phasing in the change at the time of a full rate hearing."[29]

The amount of the Rural Deficit has increased since 1992. In addition, implementation of the Existing Methodology for the Labrador Interconnected customers was delayed for approximately 10 years. Since implementation, the offsetting effect of the CFB Goose Bay Credit has been

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[27] Hydro's Amended Evidence, page 4.7, line 18 to page 4.8, line 3.
[28] 1993 COS Report, page 62.
[29] 1993 COS Report, page 59.

reduced and the Industrial Customers no longer contribute.[30] These factors have increased the rate impact on the Labrador Interconnected customers. However, none of these factors are specifically related to the allocation methodology. Therefore, in my view, none of the essential underpinnings of the Board's 1993 recommendation on methodology have changed. For that reason, there does not appear to be any new evidence that the ***methodology*** should be changed.

In light of the Board's comments in 1993 regarding "the rate shock implications and the merit of phasing in the change", it may be appropriate at this time for Hydro to consider rate design solutions to moderate the rate impact on the Labrador Interconnected customers.

4.0 COST OF SERVICE AND RATE DESIGN ISSUES

4.1 Holyrood Capacity Factor

The Holyrood capacity factor used in Hydro's 2015 Test Year cost of service study is 28%. This is calculated based on the average of actual Holyrood capacity factors for the years 2010 to 2013 and a forecast capacity factor for 2014. Newfoundland Power believes that a Holyrood capacity factor of 28% is not representative of conditions likely to occur in the test year. In fact, Hydro's forecast of the actual Holyrood capacity factor for 2015 is 39%.[31]

Using Hydro's forecast Holyrood capacity factor of 39% would reduce the 2015 Test Year costs allocated to Newfoundland Power by $228,000.[32]

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[30] The direct offsetting effect of the CFB Goose Bay Credit on the Rural Deficit allocated to the Labrador Interconnected customers was entirely eliminated as of January 1, 2011.

[31] Hydro's Amended Evidence, Table 4.4, page 4.16.

[32] See response to Request for Information NP-NLH-356.

I recommend that Hydro use its 2015 Test Year forecast of 39% for the Holyrood capacity factor in the 2015 Test Year cost of service study.

4.2 Utility Rate Design

The proposed demand and energy rates for Newfoundland Power are shown in Table 3.

Table 3
Hydro's 2015 Proposed Changes to Newfoundland Power Rate

	Current Rate (set in 2007)	Proposed	Increase (%)
Demand ($/kW/month)	4.00	5.50	37.5%
First Block (GWh)	250	250	-
1st Block (mills/kWh)	32.46	34.11	5.08%
2nd Block (mills/kWh)	88.05	116.22	31.99%

Demand Rate

The demand charge in Table 3 is based on Hydro's estimate of the marginal cost of demand. The 37.5% demand charge increase is a sizable one. It should be noted that Hydro continues to express concerns that their currently estimated marginal costs need to be re-examined, although the recent winter outages indicate demand is quite important in the short run.[33] Given the current uncertainty in marginal costs, a more moderate increase in the Newfoundland Power demand charge may be appropriate. This would be consistent with Hydro's expressed desire to re-examine the costs once the Labrador-Island Interconnection is in service. [34]

[33] Hydro's Amended Evidence, page 4.5, lines 25-26 and page 4.6, lines 1-10.
[34] Hydro's Amended Evidence, page 4.6.

Proposed Energy Rate

Based on Hydro's latest fuel cost estimates, the proposed second block energy charge in Table 3 is close to the marginal energy cost. For that reason, it is difficult to argue with the second block rate in isolation.[35] That said, several facts should be noted. First, the Industrial Customer rate is not set anywhere near Hydro's estimates of the marginal cost of energy. This is also true of the Labrador Interconnected energy rate. Second, once the Labrador Interconnection goes into service, Holyrood will not be on the margin any longer and the marginal energy cost is likely to be lower. In light of these observations, a more moderate rate change may be in order.

4.3 Proposed Newfoundland Power Curtailable Load Credit

The Amended Application proposes that the Board approve use of a curtailable load credit for the calculation of Newfoundland Power's billing demand.[36] Newfoundland Power's billing demand is currently based on the highest peak during the winter season. That gives Newfoundland Power an incentive to reduce its peaks using the curtailable load.

Newfoundland Power and Hydro have acknowledged that, from a system perspective, this is not the most effective use of the curtailable load.[37]

[35] Hydro's latest fuel cost estimate is contained in Hydro's letter to the Board dated April 21, 2015 Re: Rate Stabilization Plan – Fuel Price Projection. Based on Hydro's latest fuel cost estimate, the marginal energy cost may be calculated as follows:

Average No. 6 Fuel Cost per Barrel	$73.35
Conversion Factor (kWh per Barrel)	630
Rate (¢/kWh)	11.64

[36] Order No. P.U. 47(2014) gave interim approval to the proposed curtailable credit for the period December 1, 2014 to March 31, 2015.

[37] As noted in Hydro's Amended Application, Exhibit 11, page 25: "On most peak days, the system has adequate generation available and customer curtailments are not required."

Following a 2008 review, Newfoundland Power and Hydro agreed in principle that the curtailable load should be treated as a generation credit, similar to the treatment of Newfoundland Power's thermal generation. Essentially, a generation credit would reflect the available curtailable load by reducing Newfoundland Power's billing demand. Under that approach, Hydro would have the responsibility for requesting dispatch of the curtailable load when the system needs it.[38]

At the time of the 2008 review, it was agreed that the matter would be addressed in Hydro's next GRA. The Amended Application proposes changes in the treatment of Newfoundland Power's curtailable load that are consistent with the agreement in principle reached as a result of the 2008 review.[39] I recommend Hydro's proposal for the treatment of Newfoundland Power's curtailable load be approved.

[38] Hydro's Amended Application, Exhibit 11, page 25.

[39] Hydro has indicated a willingness to explore options related to the treatment that was agreed to in principle in 2008. See the response to Request for Information CA-NLH-077.

Exhibit LBB-1: Resume of Larry B. Brockman

Larry B. Brockman Resume

Name
Larry B. Brockman

Present Position
President, Brockman Consulting

Qualifications Summary
Mr. Brockman has over 36 years experience as a utility rate designer, planner, consultant, regulator, educator, and expert witness. He specializes in cost of service and rate design, strategic planning, regulatory assistance, competitive market assessments, bid evaluation processes, merger and acquisition analysis, and computer simulation, to help utilities meet their strategic goals and maintain competitive advantage.

Education
Mr. Brockman earned a bachelor's degree in engineering from the University of Florida in 1973. He subsequently completed 35 quarter-hours towards a master's degree in electrical engineering, with a minor in regulatory economics at the University of Florida.

Prior Experience
During his career, Mr. Brockman has performed, and managed a broad range of consulting projects, including:

Cost of Service and Rate Design
Numerous Cost of service and Rate Design projects for Canadian and US utilities, assisting the utilities with marginal and embedded cost-of-service and rate designs for their ability to meet the utilities' strategic and regulatory goals, and pass regulatory scrutiny. In many of these examinations, Mr. Brockman has appeared as an expert witness. These cases are delineated in the Appendix.

Co-Developer and Instructor of the Public Utilities Reports, industry short course on Rates and Regulation for 5 years. In these courses, Mr. Brockman taught hundreds of utility rate designers, regulators, attorneys and Commission staff the principles of rate design and regulation.

Review of a restructured utility's shared services costs of service separation study to allocate the costs between regulated and unregulated subsidiaries, and procedures for tracking the costs in the future.

Financial Analysis and Asset Valuation
Construction of detailed utility financial simulation models to forecast regional bulk-power prices and profits for Utilities and Independent Power Producers to judge market entry positions and create successful negotiating strategies for purchases and sales in unregulated generation markets.

A profitability study for an electric utility to assess effects on shareholder returns and economic value added (EVA), of various marketing activities of the utility. These studies resulted in re-engineering the marketing department to yield higher returns and be more consistent with corporate goals.

Several asset valuation studies for electric utilities to determine whether a market existed to sell existing generating assets, what they were worth, and whether they would be competitive with existing and new generation in the region. Results were presented to senior management and used to revise the strategic planning direction.

Competitive Market Assessments
Expert testimony to the Arkansas and Louisiana Public Service Commissions on the market clearing prices for generation in a competitive market, and the relative competitive positions of many of the generating companies in the SPP and ERCOT regions. To perform this work, Mr. Brockman used sophisticated computer models and a database containing over 120,000 MW of capacity in the region.

A study on the effects of retail competition on the states of North and South Carolina, presented to the South Carolina Legislature and performed for Carolina Power and Light Company. The study required research on the behavior of prices in other formerly regulated industries and detailed modeling of the market prices and financial effects on the utilities, as well as the effects on state and local taxes.

An independent review of the effectiveness and reliability of a large Mid-Western utility's Power Marketing and Purchases Department in deregulated generation markets, performed as a joint project with the utility and the state's attorney general.

Numerous market outlook and generator profitability studies of the ERCOT, Eastern Interconnect, and WSCC markets for merchant plant developers, using the GEMAPS transmission-constrained production cost simulation tool.

An analysis for a large Canadian utility of the profitability of increased transmission line investments to move power into various competitive markets in the US and Canada.

Computer Simulation of Power Systems
Mr. Brockman is an expert in the use of utility simulation software for: planning; operations; and financial analysis including: PROMOD; PROVIEW; PROSCREEN II; PMDAM; PROSYM; EVALUATOR; GEMAPS, IREMM, and several Power Flow programs.

Strategic Planning
A strategic planning project for a large South-Eastern electric utility identifying strengths, weaknesses, opportunities, and threats, in competitive open-access power markets. For each utility in the region, the project identified which customers would be gained and lost, and assessed the impacts of alternative transmission, and contracting strategies. The entire South Eastern US generating and major transmission systems were simulated. Over $1.5 Billion of potential customer revenue migration was identified at the client utility. Strategies for maintaining the utility’s profitability were recommended and accepted by senior management.

Development of several successful strategies and power supply bid evaluation procedures in use at investor owned and rural electric cooperatives, to ensure that winning bids are consistent with the utility’s business goals and objectives.

Operational Studies
A salt dome natural gas storage study for a South Central electric utility. The study identified the hourly operational characteristics necessary for favorable economics of the required storage facility. Estimated savings in excess of $100 Million were identified. The facility was constructed and has been successfully benchmarked against the study results.

Merger and Acquisition Analysis
Mr. Brockman has participated in several merger and acquisition studies assessing the production cost and planning and operational synergies arising from the merger. He testified before the FERC on the accuracy and appropriateness of the production costing computer simulations a merger application. He also participated in a regulated/non-regulated cost separation study for a shared services group of a major utility.

Expert Litigation Assistance
Project manager of an anti-trust case involving investigation of all phases of power supply planning covering a 40 year historical period and a successful defense against over $3 Billion damage suit involving alleged actions by an investor owned utility.

Managed a successful defense against a cogenerator seeking to convince regulators that a utility's ratepayers should pay over $1.5 Billion in unnecessary and uneconomic new generation avoided costs by the cogenerator.

Project manager for a precedent setting FERC case defending a utility from an attempt to abrogate a long term bulk power contract worth over $400 Million. Mr. Brockman's team was able to convince the FERC that contract abrogation was not in the public interest, that the plaintiff was not going bankrupt, and that the plaintiff's difficulties were the result of arbitrary and capricious state regulation.

Prior Positions Held
Managing Consultant PA Consulting, 2000-2002. Mr. Brockman managed a group of consultants engaged in the analysis of transmission-constrained competitive generation markets, as well as managing several litigation cases involving electric utilities.

President of Brockman Consulting 1997-2000. Mr. Brockman assisted clients with strategic planning and regulatory assistance.

Managing Director and Vice President 1994-1996, EDS Management Consulting Services (formerly EMA). Responsible for the Atlanta office, engaged in providing technical consulting services in planning, regulatory assistance, marketing, competitive assessments, reliability, bid evaluation, financial simulation, and expert testimony.

Vice President Energy Management Associates (EMA) Consulting Department 1985-1994. Started as lead consultant and rose to position of Vice President. He marketed and provided strategic planning, regulatory assistance, and operational consulting to electric and gas utilities worldwide.

Assistant Director Electric and Gas Department, Florida Public Service Commission 1981-1985. Supervised 48 employees engaged in all phases of electric and gas regulation. Made recommendations to the Commission on rate cases and resource planning dockets for all electric and gas utilities in Florida. Responsible for financial and management audit scopes, prudence reviews of rate base, expenses, revenue requirements, and final rate design. Also advised Commission on economic effects of regulatory and energy policy actions.

Corporate Planning Engineer 1979-1981, Gainesville Regional Utilities. Developed, analyzed, and presented to senior management and the City Council, ideas, plans, and studies affecting the growth, financial well-being and efficient operation of the city owned electric system. Performed detailed simulations and studies of new generation, substations, transmission lines, voltage conversions, re-conductoring, and power factor correction. Mr. Brockman conducted public hearings and testified before the City Council on proposed transmission lines, substations, and rate designs.

Special Consultant 1979-1980, University of Florida Public Utilities Research Center. Under a grant from Florida Power Corporation and the Florida Public Service Commission, performed a detailed review of marginal cost study techniques for electric utilities and completed a marginal cost study for Florida Power Corporation.

Transmission Planning Engineer 1973-1976, Jacksonville Electric Authority. Responsible for bulk transmission planning, including extensive use of power-flow, fault current and transient stability computer programs. Chairman of the Florida Electric Coordinating Group's Long Range Transmission Planning Task Force 1974.

Adjunct Faculty Member 1976, University of North Florida. Taught courses in industrial and commercial building wiring design and conformance with National Electrical Codes.

Expert Witness Appearances

City of Gainesville City Council, 1980, testified on behalf of Gainesville Regional Utilities concerning a joint utility and citizen's collaborative effort on rate design.

City of Gainesville City Council, 1981, testified concerning a Long-Range Transmission and Distribution Plan and proposals to construct a new substation.

Florida Public Service Commission, Florida Power and Light, 1981 Docket No. 810002, Rate Case, testified on cost-of-service.

City of Tallahassee - Surcharge Outside the City Limits, 1983. Testified concerning marginal and embedded costs inside and outside the city limits.

Florida Public Service Commission, 1988, West Florida Natural Gas Company. Testified on cost-of-service and rate design and why the utility needed flexibility to meet competition.

Oklahoma Corporation Commission, 1988, Avoided Cost Proceeding. Testified on the appropriate use of computer models to determine avoided cost of generation.

Nova Scotia Board of Commissioners of Public Utilities, 1989, Nova Scotia Power Rate Case. Testified on cost of service and rate design.

Nova Scotia Board of Commissioners of Public Utilities, 1990, Nova Scotia Power Rate Case. Testified on integrated resource planning, cost of service and rate design.

Nova Scotia Board of Commissioners of Public Utilities, 1993, Nova Scotia Power Rate Case. Testified on cost of service and rate design.

Board of Commissioners of Public Utilities of the Province of Newfoundland and Labrador, 1990. Newfoundland and Labrador Hydro rate case. Testified on integrated resource planning and rate design.

Board of Commissioners of Public Utilities of the Province of Newfoundland and Labrador, 1992, Newfoundland and Labrador Hydro rate case. Testified on Cost of Service and Rate Design.

Board of Commissioners of Public Utilities of the Province of Newfoundland and Labrador, 1992, Generic Hearing on Cost of Service and Rate Design.

Board of Commissioners of Public Utilities of the Province of Newfoundland and Labrador, 1995, In the Matter of an Inquiry Into Issues Relating to Rural Rate Subsidies.

Public Service Commission Colorado, 1994, testified on behalf of Public Service Company of Colorado on the proper use of dynamic programming models in the utility's integrated resource planning process.

Federal Energy Regulatory Commission, 1994, Merger Case, Testified on behalf of Central and Southwest utility concerning production cost merger benefits.

Nova Scotia Board of Commissioners of Public Utilities, 1995, Nova Scotia Power Rate Case. Testified on cost of service and rate design.

Board of Commissioners of Public Utilities of the Province of Newfoundland and Labrador, 1996, Newfoundland Power Rate Case, testified on cost of service and rate design.

Arkansas Public Service Commission, 1997, Arkansas Power and Light Rate Case, testified concerning the market clearing prices for power in deregulated markets and the relative competitive positions of various generators in such markets.

Board of Commissioners of Public Utilities of the Province of Newfoundland and Labrador, 2001, Newfoundland and Labrador Hydro rate case, on behalf of Newfoundland Power concerning Cost of Service and Rate Design.

Board of Commissioners of Public Utilities of the Province of Newfoundland and Labrador, 2003, Newfoundland and Labrador Hydro rate case, on behalf of Newfoundland Power concerning rate design and marginal costs.

Board of Commissioners of Public Utilities of the Province of Newfoundland and Labrador, 2003, Newfoundland Power rate case, concerning Cost of Service and Rate Design.

North Carolina Docket No. E-22, Sub 412. Draft testimony on behalf of Dominion North Carolina, February 2005, concerning rates to a large steel company. Case was settled before final evidence was submitted.

Board of Commissioners of Public Utilities of the Province of Newfoundland and Labrador, 2006, Newfoundland and Labrador Hydro rate case, on behalf of Newfoundland Power concerning rate design and marginal costs.

Board of Commissioners of Public Utilities of the Province of Newfoundland and Labrador, 2009, on behalf of Newfoundland Power concerning Newfoundland and Labrador Hydro's Industrial Rates.

Board of Commissioners of Public Utilities of the Province of Newfoundland and Labrador, 2014, on behalf of Newfoundland Power concerning Newfoundland and Labrador Hydro's proposal for a refund of the Newfoundland Power RSP Surplus.

Clients Mr Brockman has Performed Consulting Services for Include:

Ahlstrom Pyro Power

Alabama Electric Cooperative

Alberta Power Company

Balch and Bingham

Black and Veatch

California Energy Commission

Carolina Power and Light Company

Central and Southwest Company

Central Vermont Power Company

Chugach Electric Cooperative

Cincinnati Gas and Electric Company

Citibank

Commonwealth Edison Company

Duke Power Company

Enron

Entergy

Florida Public Service Commission

Georgia Power Company

Gainesville Gas Company

Hawaiian Electric Company

Howery and Simon

Hydro One

McKinsey and Company

Mission Energy

Nevada Power Company

New Brunswick Power Company

New York State Electric and Gas

Newfoundland Power

Niagara Mohawk

Nova Scotia Power Company

Oklahoma Gas and Electric Company

Ontario Power Generation

Pacific Gas and Electric Company

Public Service Company of Colorado

Public Service Company of New Mexico

Rochester Gas and Electric

SCANA

Southern California Edison

Tampa Electric Company

The City of Austin

The Southern Company

TransEnergie

West Florida Natural Gas Company

The World Bank

Exhibit LBB-2: Cost of Service Principles and Practices

COST OF SERVICE PRINCIPLES AND PRACTICES

1.0 Principles

Cost of service studies are based upon a few basic principles which will be discussed in this section.

1.1 Purpose of Cost of Service Studies

Cost of service studies are performed for several reasons. The *1992 National Association of Regulatory Utility Commissioners Electric Utility Cost Allocation Manual* (the "NARUC Manual") on page 12 gives the following purposes for cost of service studies:

1. to attribute costs to different categories of customers based on how those customers cause costs to be incurred;

2. to determine how costs will be recovered from customers within each customer class;

3. to calculate costs of individual types of service based on the costs each service requires the utility to expend;

4. to determine the revenue requirement for the monopoly services offered by a utility operating in both monopoly and competitive markets; and

5. to separate costs between different regulatory jurisdictions.

The use of cost of service studies to attribute cost responsibility follows logically from the generally accepted principles of good rate design. James Bonbright was one of the first to codify these principles in his classic book *Principles of Public Utility Rates*. The Bonbright principles which relate most to cost of service studies are:

1. effectiveness in yielding total revenue requirements;

2. fairness in the apportionment of total cost of service among the different ratepayers; and

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).

1.2 Embedded and Marginal Cost of Service Studies

There are two basic types of cost of service studies. The first 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 costs of meeting future customer, energy and demand requirements. Embedded cost of service studies look backward; marginal cost of service studies look forward.

1.3 How Cost of Service Studies Achieve Bonbright's Goals

Bonbright's first goal of effectiveness in yielding total revenue requirements applies only to embedded cost of service studies. This is done by first setting the total revenue requirements which are substantially recovered between the customer classes with the guidance of a cost of service study.

The goal of achieving fairness in the apportionment of total cost of service among the different ratepayers and preventing undue discrimination is the stated purpose of most embedded cost of service studies. Fairness in allocating revenues is accomplished by paying attention to one or both of two basic principles. The first principle is "causality"; the second principle is "extent of use."

1.4 The Causality Principle

The causality principle holds that the customer (or customer characteristic) that causes a cost to go up or down should bear that cost in a cost of service study. For example, if demand on the system causes new transmission lines to be built, then transmission lines are causally related to demand and customers should be allocated the costs of those lines based on their respective demands. Most people feel this to be fair. When the costs reflected are marginal costs, it is thought to help achieve economic efficiency.[1]

We can see the principle of causality in other aspects of life as well. When you buy a house, you usually pay an amount based on the cost to build it plus a contractor's commission. Most people would not feel it was fair or efficient to price all houses the same no matter how much they cost to build.

1.5 The Extent of Use Principle

The extent of use principle is grounded in a belief that if you use something you ought to pay for it (whether you caused it to be built or not). For example, extent of use advocates would argue if you use a thermal system's generation on an interruptible basis, you ought to pay some of its fixed costs even though you may not be responsible for its construction. The use of the non-coincident peak in the “average and excess generation demand allocation technique” is based heavily on the extent of

[1] The concept of economic efficiency is based on the notion by an Italian economist, Vilfredo Paredo, who reasoned that if people see what it costs society to produce all goods in society (marginal cost), they will consume exactly the right amount of each good to make everyone as well off as they can be. This principle is known as Paredo Optimality. If all competing goods in society are not priced at marginal cost, then the best that can be hoped for under marginal cost pricing is what is known as "Second Best".

use philosophy. In many ways, the extent of use principle is more of a rate setting principle than a cost of service principle, but it is used so extensively to make decisions in cost of service studies that it is hard to separate the two.

The idea that pricing based on extent of use seems fair to most people can also be illustrated in everyday life. If one person buys a pizza but cannot eat it all, the marginal cost of giving it to someone else is zero. If someone else wants it, however, it would seem fair to most people to have them pay something for it - after all, they are eating it too. However, some economists do not acknowledge such notions of fairness.

1.6 Fairness vs. Efficiency

The principles of fairness (based on past causality and extent of use) and efficiency (based primarily on future causality) are often in conflict.

It is the job of the ratemaker to weigh these goals and decide what best balances people's notions of fairness and society's need for efficiency.

2.0 Practices

Implementing the principles over time has led to fairly widespread agreement on how cost of service studies ought to be conducted. A discussion of the relevant practices follows for both embedded and marginal cost of service studies.

2.1 Embedded Cost of Service Practices

2.1.1 Steps in Performing an Embedded Cost of Service Study

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

(1) functionalization;

(2) classification; and

(3) allocation.

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

2.1.2 Functionalization in Embedded Cost of Service

Functionalization is the process of deciding what purpose or “function” a utility investment or expenditure services. 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 the costs of providing service to various customer classes 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 cost of that line should be functionalized as transmission whose function is to service 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.

2.1.3 Classification in Embedded Cost Service

Classification is the process of deciding what customer characteristics cause each functionalized cost to increase or decrease as customer load characteristics change. Costs are classified as increasing or decreasing because of changes in number of customers, demand on the system or energy consumed.

As an example, the following table shows the commonly accepted ways of classifying production plant costs.

CLASSIFICATION OF PRODUCTION PLANT

FERC Uniform System of Accounts No.	Description	Demand Related	Energy Related
301-303	Intangible Plant	x	-
310-316	Steam Production	x	x
320-325	Nuclear Production	x	x
330-336	Hydraulic Production	x	x
340-346	Other Production	x	-

As the above table shows, production can be classified as demand and/or energy related. Production costs are not usually classified as customer related. The amount of production cost classified to demand (versus energy) is a matter of judgement. In order to decide how to properly classify each item, the analyst must go through each one and ask whether number of customers, demand or energy causes each cost item to increase. If extent of use is to be a criterion, then the analyst must decide whether the extent of use of demand or energy, or simply being a customer, constitutes a fair classification of the item.

Transmission costs are usually classified as demand but may have some energy component. Rarely are transmission costs considered to have a customer component beyond directly assigned costs.

Distribution costs are usually classified as being somewhat related to demand and customers, but not related to energy.

Even in simple tables such as those included in the NARUC Manual, classification can be controversial because no single universally accepted method for classifying production, transmission or distribution related costs exists.

2.1.4 Allocation in Embedded Cost of Service

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 class' 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:
1) the cost of fuel increases only as more energy is used from the plant; and
2) one-half of the investment in the plant was spent due to the system energy requirements and the other one-half of the investment in the plant was due to system demand requirements.

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 place on the system. Suppose in this example that Class 1 is responsible for two-thirds of the total demand at system peak but uses only one-third of the total energy on the overall system. 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 its share of the total demand. (The principle of causality would suggest that they caused two-thirds of the demand costs.) Also, one-third of the $37.50 energy related costs would be allocated to Class 1 because that is its share of the total energy used from the plant.

2.1.5 Final Comments on Embedded Costs

In theory, the embedded cost of service study is relatively simple. However, there are hundreds of cost categories that must be properly functionalized, classified and allocated. Cost of service practitioners have differences of opinion which result in different treatments of different items. Other differences occur because utilities have different factors driving the costs up or down.

In addition, there have been technological changes in production plant equipment and load research capabilities in the last 30 years. If capturing cost causation is the goal, both have changed what can and should be done with respect to cost allocation. Prior to the late 1960s, large inexpensive gas turbines were not available to the electric utility industry for meeting peaking type loads. This meant that in many cases, fossil fuel 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 plants 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 might not be allocated 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 (which is an extent of use idea).

The fact that good load research data was uncommon prior to the 1960s 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. 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.

2.2 Marginal Cost of Service Practices

2.2.1 Purpose of Marginal Cost of Service Studies

Marginal cost of service studies attempt to calculate how the future costs of a utility change with a change in demand, the number of customers or the amount of energy used. This basic concept can be written as the change in cost, divided by the change in quantity demanded or:

$$\mathbf{MC = \Delta Costs / \Delta Quantity}$$

Since the changes in costs in the above equation are changes in future costs, they cannot be determined by examining the books and records of a company. Instead, they must be determined from engineering studies or estimated from past trends.

2.2.2 Differences Between Marginal and Embedded Costs

Marginal cost of service study practice is different from embedded cost of service study practice in several ways. One difference already alluded to is that marginal cost of service studies look forward to how costs change in the future rather than backward as in embedded cost of service studies. Marginal cost of service studies are mostly concerned with what causes the costs to change rather than extent of use notions of fairness. Marginal cost of service studies do not usually go through the steps of functionalization, classification and allocation in the same way as embedded cost of service studies. Instead, they rely more on engineering calculations and hypothetical studies which ask "if the utility experiences an increase in the number of customers, demand or energy how will future costs increase?" Marginal cost of service studies usually recognize that time of use can be important in how the costs change and are usually performed for on-peak and off-peak time periods. There is not as much of a focus on customer classes except for the differences in losses, metering and billing. Marginal cost of service studies are usually time differentiated. That is, they calculate marginal costs on-peak and off-peak. Marginal cost of service studies generally are performed to determine the marginal customer, demand and energy costs.

2.2.3 Difficulties in Determining Marginal Costs

Marginal costs can be difficult to determine for several reasons. First, since they are determined by doing engineering calculations or simulations of the future, the results are heavily dependent on the assumptions about how costs will change in the future. The last 20 years of electric utility history is replete with examples of how poorly these future costs were estimated, either because of inaccurate input data, or simulation models which did not capture the changes in costs accurately.

There is also a basic timing dilemma that must be addressed when dealing with marginal cost studies. For example, if more energy is demanded from most power systems in the next hour, there is no time and usually no need to build additional plant to supply the energy. The change in costs to serve the additional requirements is therefore just the change in fuel and variable operating costs of certain power plants. When the time period or the quantity is small enough so that additional plant is not needed, the resulting change in costs is known as short run marginal cost. A simple small spike in demand would have no effect on the costs of the system in the short run. The short run marginal costs on such a system would therefore be said to be the variable fuel and operating costs for energy and zero for demand. To relate these costs to the individual classes losses would be factored in at various voltage levels at which the customers are served.

When the time period for which the marginal cost study is performed is longer, change in demand and energy requirements will generally be larger and additional generating, transmission and distribution plant may need to be built to serve the increase. When this becomes the case, the resulting marginal costs are known as long run marginal costs. Because the changes we are dealing with over longer periods are larger, they are often called incremental costs rather than marginal costs and are often simulated by adding a fixed amount of demand and energy to the utility load curve and studying what happens to the costs in the planning process. The amount of incremental load to be added in these studies can effect the outcome because it affects the type of plant that may be added.

In the end, it is the use to which the marginal costs are to be put that determines whether we should use long run or short run marginal costs and for how long into the future we want to calculate them. Some regulators believe that when marginal costs will be low for a long time into the future they should reflect those low costs in the tail blocks of the rates and let the customers enjoy the advantages of low cost power for that time. Others believe that because customers are making long run equipment purchasing decisions the long run marginal costs should be brought back to the present and reflected in the rates.

2.2.4 Marginal Customer Related Costs

The basic question to be answered by a marginal customer related cost study is "how do the costs change in the future if we add another customer?" This question is usually answered by asking the planning engineers what they would add if a new customer was connected to the system. A new meter and service drop would obviously be required and additional billing costs would be incurred. Instead of assigning the average embedded costs of such devices as we did in embedded cost studies we would assign the costs of all new equipment. As new customers are added, system standards would require additions and upgrades to the distribution system to meet the increased demands. This is the same argument used in the minimum size distribution system in the embedded cost of service studies. One way of capturing how the fixed costs of the distribution system change when a customer is added is the *Natural Economic Research Associates* ("NERA") facilities charge method, this method was used by Newfoundland Power in their 1997 Marginal Cost Study.

2.2.5 Marginal Energy Related Costs

There is relatively little controversy over the short run marginal energy costs of a power system. They are usually taken to be the fuel and variable operating costs of the generating unit which will supply the next kilowatt hour in any given hour. For time of use pricing purposes they are often averaged over the off-peak and on-peak times. In the long run, some systems will have marginal energy costs that include some fixed costs because the increases in energy may cause the utility to invest in new plant simply because more energy is required. An example is pollution equipment that would need to be added to power plants to keep the utility below emissions caps. For isolated systems relying on water power, firm energy criteria may mean that increases in energy will require system expansion whether peak demands increase or not.

To determine the short run marginal energy costs on complicated systems, production cost computer simulations are performed. To determine the long run marginal costs on systems where firm energy criteria may be controlling, system generation expansion studies should be performed. The long run marginal energy costs can then be calculated by taking the changes in costs divided by the energy that caused them. The time value of money must be appropriately treated in such analyses

2.2.6 Marginal Demand Related Costs

The marginal demand related costs are the change in costs for a change in demand. In the short run, these costs are zero as we discussed above. However, in the long run increases in demand cause additional distribution, transmission and generation plant to be built. Determining the marginal cost of demand is usually done by examining all parts of the system separately.

The marginal demand related costs of the distribution system can be determined in several ways. The first is to simply do a regression analysis of the expenditures on the distribution system over some past period of time with demand as an independent variable. The second way is to do engineering "what if?" studies where the planning engineers are asked to calculate the difference in costs of a hypothetical system with different levels of demand. The two methods yield similar results if inflation is accounted for and distribution technology does not change much.

The marginal demand related costs of transmission are calculated in much the same way as distribution the difference being that "number of customers" would not be an independent variable in any historical regressions. It is important to make sure that any costs of transmission lines directly associated with new power plants be treated in the same way as the plants. That is, if the plants were built primarily to satisfy firm energy criteria they should not be included in the marginal demand related costs.

Several methods have been devised to calculate the marginal demand related costs of the generation system. They can be lumped into three major categories: system planning methods, proxy unit methods or regression models. The regression methods are not often used on generation systems and I shall not discuss them further.

The system planning methods use some sort of generation expansion planning tools to examine the effect an increase in demand has on the future generation expansion plans of the utility. A base case is often created, then demand is increased by 50 to100 MW and a new plan is produced. The difference in the costs of these two plans is taken to be the marginal demand related cost of the system.

The proxy unit method does not use a full planning simulation. It simply assumes that the cost of deferring the lowest cost way of meeting future demand is the marginal demand related cost. This is often the cost of deferring a simple cycle combustion turbine divided by its capacity.

The situation is complicated to a large degree by the complex interaction between increases in demand and increases in energy. Increases in demand usually cause the addition of combustion turbines; however, on systems with high energy costs this may not be the case. Increasing demand on these systems may accelerate the construction of base load plants because the fuel savings from such actions more than justifies building them instead of the combustion turbine. In that case, the marginal demand related cost is often taken to be the cost of the base load plant minus the fuel savings.

Systems with firm energy criteria can also make it difficult to calculate the marginal generation demand related costs. With these systems, the generation expansion plan sometimes appears not to change when demand is increased or reduced. This is because the firm energy criteria is controlling the expansion plan. In such cases, the marginal cost of demand on the generation system may be close to zero.

The best method for calculating the marginal demand related cost of generation depends on the system. For simple systems that are close to having the optimal generation mix, the proxy unit method yields good results. For more complicated systems, or those with firm energy criteria, it is best to perform planning studies to determine the effects of changing demand.

2.2.7 Final Comments on Marginal Costs

There are additional costs not captured in the marginal customer, demand and energy techniques described. These are administrative and general (“A&G”) costs. In the long run, some of these costs will also increase if more customers, demand or energy occurs. They are usually accounted for by calculating a historical percentage, known as A&G loading, and adding them to the costs for demand and customer related marginal costs.