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April 28, 2014

**COURIER & EMAIL**

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**Attention: Ms. G. Cheryl Blundon, Board Secretary**

Dear Ms. Blundon:

**Re: Newfoundland and Labrador Hydro's 2013 General Rate Hearing – Expert Evidence from Innu Nation**

Please find enclosed the original plus twelve copies of the report of Innu Nation's expert, Philip Raphals, in respect of the above noted Application. A copy of this letter and enclosure will also be couriered directly to the parties listed below.

If you have any questions about the enclosed, please contact the undersigned.

Yours truly,

*Olthuis, Kleer, Townshend LLP*

Stephanie Kearns

SK/ck

Enclosure

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April 28, 2014

# Comments on the 2013 General Rate Application of Newfoundland Labrador Hydro

submitted to the
NL Public Utilities Board

on behalf of

the Innu Nation

by

Philip Raphals
Executive Director

Helios Centre

# Table of Contents

# 1. INTRODUCTION

I have been asked by the Innu Nation to review the aspects of Hydro's General Rate Application (GRA) that most affect the Innu communities of Sheshatshiu and Natuashish.

Sheshatshiu is part of the Labrador Interconnection System (LIS), and so will be affected by the dramatic rate increases for that system proposed by Hydro. These issues are addressed in section 2.

Natuashish is an isolated diesel system but, as we shall see below in section 3, its electric service is subject to prejudicial conditions not found elsewhere in Newfoundland and Labrador.

Should these issues be resolved, Natuashish would be served under the same rates as the other isolated diesel communities. The GRA does not propose a substantial rate increase for these communities. However, due to the interplay between the existing rate structures and the Northern Strategic Plan subsidy, electric bills in these communities would increase substantially as well. Comments about this situation are presented in section 4.

In section 5, I will briefly comment on the failure to move forward with an integrated resource planning (IRP) process for NLH, despite past Board pronouncements in this regard.

Finally, in section 6, I will summarize my conclusions and recommendations.

# 2. LABRADOR INTERCONNECTED RATES

## *2.1. GRA proposal*

Under the GRA proposal, Labrador Interconnected rates would rise dramatically. Residential rates would rise by about 26% and general service rates by 15-30%, as shown in the following table[1]:

Figure 1

Labrador Interconnected – Proposed Rate Increases

| | | |
|---|---|---|
| **Domestic** | | |
| Basic charge | | 26.2% |
| Energy | | 25.9% |
| Minimum monthly charge | | 26.2% |
| **GS 2.1** | | |
| Basic charge | | 28.5% |
| Energy | | 28.5% |
| Minimum monthly charge | Single phase | 28.5% |
| | Three phase | 0% |
| **GS 2.2** | | |
| Energy | | 16.9% |
| Demand | | 15.9% |
| Minimum monthly charge | | 0% |
| **GS 2.3** | | |
| Energy | | 16.7% |
| Demand | | 17.5% |
| Minimum monthly charge | | 0% |
| **GS 2.4** | | |
| Energy | | 21.1% |
| Demand | | 22.9% |
| Minimum monthly charge | | 0% |
| **Street Lights** | | 42.8% |

Expressed in terms of average rates in cents/kWh, the increases are as follows:[2]

[1] CA-NLH-006, pages 3-4.

[2] CA-NLH-007.

Figure 2

Labrador Interconnected

| Rate Class | Percentage Increase | Existing Rates ¢/kWh | Proposed Rates ¢/kWh |
|---|---|---|---|
| Domestic | 26.0% | 3.5 | 4.4 |
| 2.1 G S 0-10 kW | 28.5% | 6.2 | 8.0 |
| 2.2 G S 10-100 kW | 16.6% | 3.1 | 3.6 |
| 2.3 G S 110-1000 kVa | 16.9% | 2.7 | 3.1 |
| 2.4 G S over 1000 kVa | 22.0% | 2.0 | 2.5 |

### *2.2. Drivers for rate increase*

The principal drivers for this rate increase for the LIS can be seen in the following table, which compares the LIS revenue requirement for 2007 and 2013:[3]

Figure 3

**Rural Labrador Interconnected Revenue Requirement**

| **line # (CA-90)** | | **2007** | **2013** | **% increase** | **% of total rev. req. increase** |
|---|---|---|---|---|---|
| 1 | Operating, Maintenance and Admin | 4,747,780 | 6,348,048 | 34% | 24% |
| 3-5 | Fuels | 160,349 | 273,631 | 71% | 2% |
| 21,22 | Return on Rate Base | 3,459,597 | 5,762,760 | 67% | 34% |
| 23 | Total System Revenue Requirement | 14,164,360 | 17,596,591 | 24% | |
| | Rural Deficit Allocation | 4,443,984 | 6,842,261 | 54% | 36% |
| | **Revenue Requirement after Rural Deficit Allocation** | **15,595,763** | **22,316,384** | **43%** | |

Thus, the revenue requirement has risen by 24% before allocation of the rural deficit, and by 43% after that allocation. It is interesting to note that, while the cost of fuels has increased by

[3] Derived from CA-90, Att. 1.

71%, this only accounts for 2% of the overall increase in Labrador Interconnected revenue requirements. (The total exceeds 100% because other posts, not reproduced here, including power purchase costs and various expense credits, show a net decrease.)

The key drivers for the Labrador Interconnected proposed rate increase, which results from a 43% increase in net revenue requirements, are thus:

- Rural deficit allocation (36%),
- Return on rate base (34%), and
- Operating expenses, Maintenance and Administration (24%).

I shall examine each in turn.

### *2.3. Rural deficit*

As seen in Figure 3, the rural deficit cost allocated to Labrador Interconnected increased since 2007 by 54% (an increase of $2.4 million), and accounts for 36% of the proposed rate increase. There has been no change in the methodology of cost allocation since it was established in 1993.

The rural deficit represents the difference between cost of service and revenues collected for several distinct categories of customers. These include:

- Isolated (diesel) communities on the Island and in Labrador,
- Customers of the Anse au Loup system, which are served to a large extent with energy from Hydro-Quebec's Lac Robertson hydro project, and
- Rural interconnected customers on the Island.

It is noteworthy that isolated customers (both on the Island and in Labrador) represent only 55% of the rural deficit, with Island interconnected rural customers representing 40%.[4]

[4] Ignoring the CFB Revenue Credit.

The evolution of the rural deficit since 2007 is shown in the following table, broken down by source:[5]

Figure 4

**Rural Deficit by Rural Deficit Area ($000s)**

| | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 Test Year |
|---|---|---|---|---|---|---|---|
| Island Interconnected | 15,953 | 16,106 | 13,086 | 15,569 | 19,496 | 17,345 | 24,612 |
| Island Isolated | 6,472 | 7,035 | 7,306 | 6,791 | 7,640 | 7,222 | 7,910 |
| Labrador Isolated | 18,323 | 22,379 | 17,801 | 19,252 | 23,067 | 23,179 | 25,663 |
| L'Anse au Loup | 1,986 | 2,987 | 1,958 | 1,967 | 3,140 | 3,037 | 3,402 |
| CFB Revenue Credit | (2,860) | (4,051) | (979) | (3,418) | (3,972) | (1,524) | (863) |
| **Total** | **39,874** | **44,456** | **39,172** | **40,161** | **49,371** | **49,259** | **60,724** |

Adjusting to constant dollars gives the following:[6]

[5] CA-NLH-99.

[6] CA-NLH-208.

Figure 5

**Rural Deficit by Rural Deficit Area in 2013 Dollars ($000)**

| | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 Test Year |
|---|---|---|---|---|---|---|---|
| Island Interconnected | 17,931 | 17,394 | 14,408 | 16,643 | 20,159 | 17,692 | 24,612 |
| Island Isolated | 7,275 | 7,598 | 8,044 | 7,260 | 7,900 | 7,366 | 7,910 |
| Labrador Isolated | 20,595 | 24,169 | 19,599 | 20,580 | 23,851 | 23,643 | 25,663 |
| L'Anse au Loup | 2,232 | 3,226 | 2,156 | 2,103 | 3,247 | 3,098 | 3,402 |
| CFB Revenue Credit | (3,215) | (4,375) | (1,078) | (3,654) | (4,107) | (1,554) | (863) |
| **Total** | **44,818** | **48,012** | **43,128** | **42,932** | **51,050** | **50,244** | **60,724** |
| Cumulative GDP | 12.4% | 8.0% | 10.1% | 6.9% | 3.4% | 2.0% | 0.0% |

Notes:
2008-2011 GDP figures from Stats Canada
2012-2013 GDP figures forecasted by Conference Board of Canada

We see that the constant-dollar rural deficit was relatively stable from 2007 to 2010, but has increased by some 35% from 2007 to 2013. It is striking to note that the rural deficit is projected to increase by more than 20% in 2013, compared to 2012.

The cost of the rural deficit is borne by the customers of Newfoundland Power and of the LIS. Until the end of 1999, Island industrial customers also bore a share of this cost responsibility, but the amendments to *EPCA* absolved them of it. While the number of customers served by diesel systems was reduced by the interconnection of St. Anthony's in 1996, those customers continue to form part of the rural deficit (as "Island Interconnected" rather than Isolated customers), though their contribution to it is smaller than it was before.

### 2.3.1. Regulatory history

The effect of the rural deficit cross-subsidization on Labrador Interconnected rates is substantial: it increases them by 27% to 58% (30.7% on average), depending on the rate class, as seen in the following table.[7]

Figure 6

| Labrador Interconnected rates | proposed increase | w/o rural deficit | net effect |
|---|---|---|---|
| **Domestic** | 26.0% | -12.7% | 38.7% |
| **GS 0-10kW** | 28.5% | -12.7% | 41.2% |
| **GS 10-100 kW** | 16.6% | -10.9% | 27.5% |
| **GS 110-1000 kVA** | 16.9% | -19.2% | 36.1% |
| **GS over 1000 kVA** | 22.0% | -18.9% | 40.9% |
| **Street Lighting** | 42.8% | -15.6% | 58.4% |

Hydro explains this effect as follows:[8]

> The impact of the rural deficit on the Labrador Interconnected System is larger than that of NP mainly because the Labrador Interconnected revenue requirement is much smaller than that of NP, and the rural deficit makes up a larger share of the Labrador Interconnected revenue requirement, than it does for NP. <u>The reallocation of the $6.8 million rural deficit originally allocated to Labrador Interconnected as provided in response to IN-NLH-132, represents an overall reduction in revenue requirement to that system of 30.7%, while the same $6.8 million reallocation to NP represents an increase of 1.5%.</u> [9]

This suggests that, were all of the rural deficit costs borne by Labrador Interconnected customers to be instead assigned to Newfoundland Power (NP) customers, their rates would increase by only 1.5%.

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[7] The second and third columns are from IN-NLH-132.

[8] IN-NLH-222, pp. 1-2.

[9] Unless otherwise noted, underlining in quoted passages in this report has been added by the author.

In its initial hearing on the methodology for the allocation of the rural deficit, the Board stated that, because there is no cost causation at all on the part of the subsidizing groups, “there is no cause and effect relationship upon which to fairly allocate the deficit. … Fairness cannot be assessed as due to the method used, but instead <u>we must assess fairness on the basis of the result,</u> a shared burden among the classes of customers that is fair to all and not discriminatory.”[10]

In an RFI, the Consumer Advocate asked if the use of this method is still “fair” today, 20 years after it was established. Hydro response is unenlightening, simply commenting that:

> Based on the Board’s reasoning in arriving at a decision on the allocation of the rural deficit, there would be no basis to believe that there should be a concern on the "fairness" of using this method today versus 20 years ago.[11]

The question, however, is entirely relevant — especially since the magnitude of the rural deficit has more than doubled since 1993 (from $28 million to $60.7 million[12]), and it is supported by a smaller base (given the exclusion of the Industrial Customers in 1999). As the Board itself acknowledged, fairness in this context can only be judged by the result. One must therefore, first, compare the result of this methodology today with that adopted by the Board in 1993, to judge whether or not there is reason to reopen the methodological question. We will look in detail at that methodology later on.

In response to an RFI, Hydro compared the average rates for each system under each of the three approaches reviewed in the 1993 hearing. The results, expressed in terms of average cost per kWh, are as follows:[13]

---

[10] PUB-NLH-113, Att. 1, page 63 of 83. (Report of the NLPUB on A Referral by NLH for the Proposed Cost of Service Methodology, Feb. 1993, page 60.)

[11] IN-CA-166. A resed and entirely different version of this response, provided later, is discussed in section 2.3.3 , below.

[12] Figures derived from LWHN-NLH-055 and -056.

[13] CA-NLH-228, Att. 1, p. 1 of 4.

Figure 7

| | Allocation based on 1993 method | Allocation based on Rev Requirement | | Allocation based on 50% Rev Req and 50% energy sales | |
|---|---|---|---|---|---|
| | avg. rate | avg. rate | compared to 1993 method | avg. rate | compared to 1993 method |
| **Labrador Interconnected** | | | | | |
| **Domestic** | 4.42 | 3.70 | -16.3% | 3.96 | -10.4% |
| **GS 0-10kW** | 8.00 | 6.06 | -24.3% | 6.16 | -23.0% |
| **GS 10-100 kW** | 3.61 | 2.54 | -29.6% | 2.87 | -20.5% |
| **GS 110-1000 kVA** | 3.13 | 2.28 | -27.2% | 2.63 | -16.0% |
| **GS over 1000 kVA** | 2.88 | 2.18 | -24.3% | 2.53 | -12.2% |
| **Street Lighting** | 24.49 | 19.47 | -20.5% | 18.72 | -23.6% |
| **Unweighted Average** | | | -23.7% | | -17.6% |
| | | | | | |
| **Newfoundland Power** | 8.1 | 8.18 | 1.0% | 8.15 | 0.6% |

The 4th and 6th columns show the percent change, for each group, from the allocation underlying the present GRA. Thus, basing allocation on revenue requirements rather than on the 1993 methodology would result in an increase of 1% for NP customers, and a decrease of 23.7% (non-weighted average) for Labrador Interconnected customers, compared to the proposed rates. This allocation would result in an identical revenue:cost ratio of 1.15 for all groups.[14] Under the GRA proposal, this ratio is 1.14 for NP, and 1.44 for Labrador Interconnected.[15]

The other allocation examined in the 1993 hearing was based 50% on the revenue requirement and 50% on energy sales. This was the approach proposed by NP at the time.[16] It would have a smaller effect: 0.6% increase for NP, and a 17.6% decrease (on average) for Labrador Interconnected.

[14] CA-NLH-228, Att. 1, p. 1 of 4.

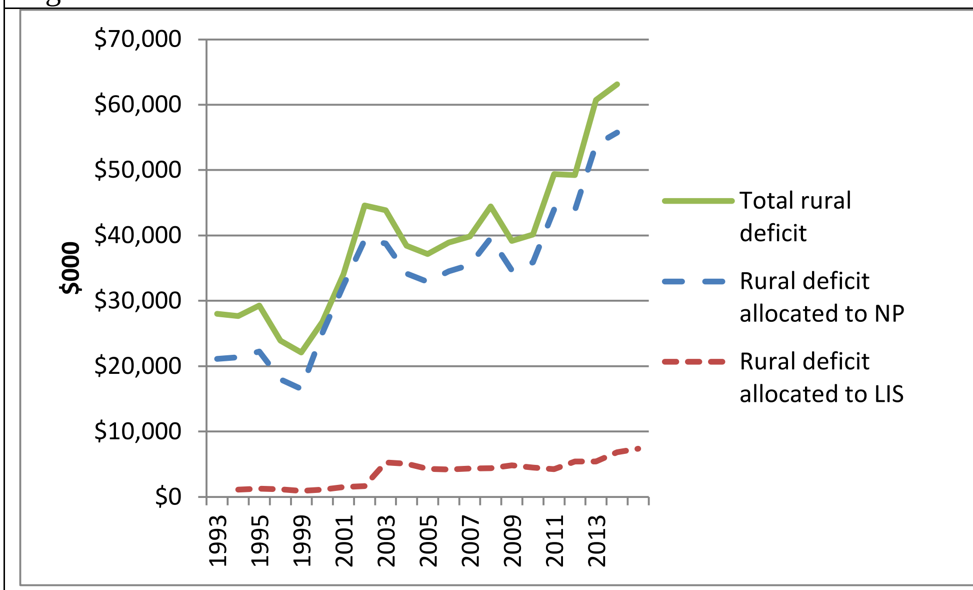
[15] Exhibit 13, Schedule 1.2, p. 1 of 6, col. 8.

[16] PUB-NLH-113, Att. 1, p. 63 of 83, last paragraph.

### 2.3.2. The 1993 Methodology

From 1993 to 2013, the rural deficit has grown from $28,000 to $63,122, an increase of 117%. While the lion's share of the rural deficit is borne by NP, the growth in these costs for LIS during this period has been much greater. NP's allocated rural deficit cost has grown by 155%, while that allocated to LIS has grown by 515%.[17]

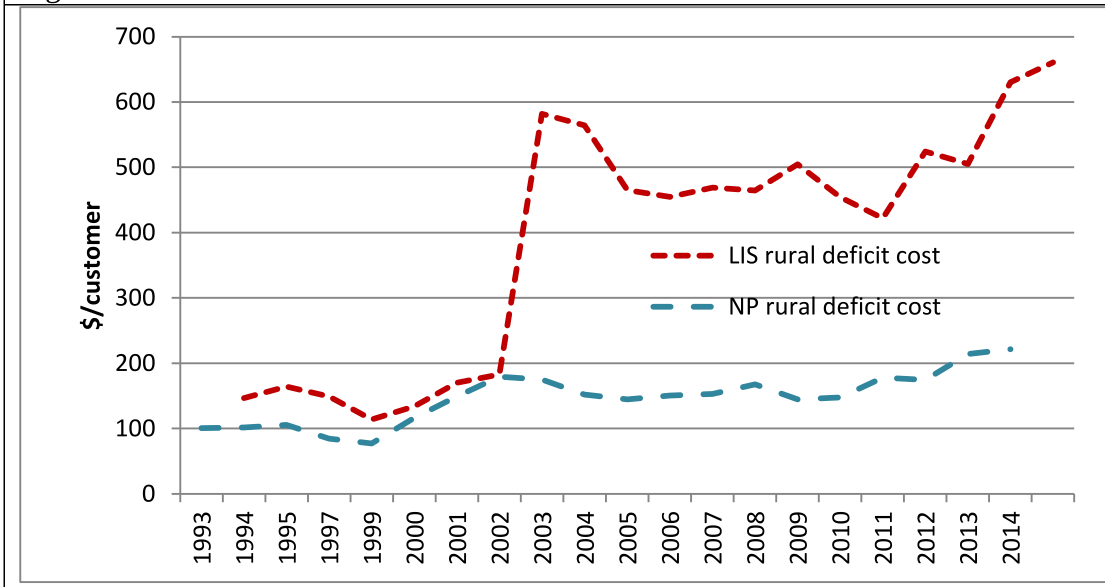
Figure 8




The same effect is seen if we look at cost per customer. For NP, it has grown from $100 to $222, whereas, for the LIS, it has grown from $147 to $661, as seen in Fig. 9.

[17] Derived from LWHN-NLH-055, Att. 1 (1993-1999) and LWHN-NLH-055, Att. 1 (2000-14). Confirming data found CA-NLH-99 for 2007-2014.

Figure 9




It is clear from these graphs that a drastic change took place in 2002. It is possible to identify several contributing reasons for this change. First, the 2002 GRA represented the first time that NLH implemented the Government's 1989 Directive to recover the rural deficit from NLH customers.[18]

In response to RFIs, Hydro provided figures for the rural deficit allocated to each category of customer, including those for the intervening years between 1989 and 2002, without further explanation.[19] Apparently, these allocated amounts were not reflected in rates at the time. However, this does not explain the more-than-tripling of the LIS allocation in 2002 (both on an absolute and a per-customer basis), reported in these same documents.

2002 also represented the first time that the Industrial Customers (IC) contribution to the rural deficit was reassigned to NP and LIS, following the 1999 EPCA amendments. The amount of

[18] P.U. 7 (2002-03), p. 123.

[19] LWHN-NLH-055 and -056.

the IC deficit was forecast to be over $5 million in 2001.[20] This amount is substantial, but not enough to explain the jump in allocation to the LIS.

Comparing the values for 2002 to those for 2000 in LWHN-NLH-56 yields the following observations:

- The rural deficit increased by $18 million;
- $14.3 million of this amount was allocated to NP, and $3.8 million was allocated to LIS;
- The NP rural deficit per customer increased from $149 to $180 (20%), while the LIS rural deficit per customer increased from $183 to $582 (218%).
- Thus, in 2000, LIS customers paid on average 1.2 times as much as NP customers (in current dollars) for the rural deficit. By 2002, this ratio had increased to 3.2.

I have not been able to fully explain these effects, based on the documents in the file. It would be useful to resolve this question, as the effect of this drastic increase in the LIS share of the rural deficit continues to be felt in the present GRA.

There are also conflicting reports as to the magnitude of the rural deficit in 2002. P.U. 7 (2002-03) identified that amount of the rural deficit for 2002 as $31.7 million.[21] A discussion paper prepared for the Minister of Mines and Energy in 2003 identified the amount for 2002 as $38.8 million.[22] However, data provided by Hydro indicate that the rural deficit in 2002 in fact totalled $44.6 million.[23]

The method of allocation of the rural deficit was determined by the Board in its 1993 generic hearing on COS methodology. That method, the results of which were set out in Appendix 1 of

[20] P.U. 7 (2002-03), p. 124. The figure reported in LWHN-NLH-056 is $4.1 million.

[21] Ibid., p. 126.

[22] PUB-NLH-339, Att. 1, p. 2 of 14. A footnote specifies that "2002 data is based on the final forecast Test Year Cost of Service Study filed with the Board during the 2001-2002 rate hearing and reflects the costing methodology approved by the Board resulting from that hearing."

[23] LWHN-NLH-056, Att. 1.

the report, was based on the proposal by the Board's expert witness, Mr. George C. Baker, based on an approach described as a "mini cost-of-service". While not described in detail in the Board's report, based on the calculations presented in the Appendix it appears that this method functions as follows:

1. The costs of the contributing systems are divided into demand, energy and customer cost components.
2. These values are prorated to divide the rural deficit among the same components.
3. Total kW and kWh consumption and adjusted unweighted customer accounts for the contributing systems are divided by the prorated share of the rural deficit, to produce unit costs for each component.
4. These unit costs are multiplied by the corresponding kW and kWh consumption and adjusted customer accounts for each for the Island and for Labrador, to determine the overall cost allocation for each system.[24]

When this method was established in 1993, the rural deficit amounted to $28.5 million. The method resulted in Labrador absorbing 14% of the rural deficit, though its share of total allocated costs was only 6%.

The Baker method includes a surprising feature, which is not explained in the 1993 Board Report or in Mr. Baker's report, namely the source of the figures used for "equivalent unweighted customer accounts" in calculating the deficit unit costs. Table 2 of Exhibit GCB-5.1, from the 1993 Report, gives a value of 9,574 for this category for NP. This is obviously far lower than the actual number of customer accounts. The figure of 7,560 used for Labrador, however, appears to reflect the actual number of customer accounts on the Labrador Interconnected system.

In the present filing, Hydro has presented the detail of its calculation of Equivalent Unweighted Customers for NP. It divides the total of Island Rural Customer Costs by the number of Island

[24] Mr. Baker's description of the method is found at IN-PUB-002, Att. 1, p. 29.

Rural customers.[25] In effect, this resulting figure represents Hydro's average customer cost <u>for Island rural customers.</u> It then divides total NP Customer Costs by this average cost.[26] The result can be thought of, in a sense, as the number of customers that NP would have to have, given its total Customer Costs, if they all had the same Customer Cost as do Hydro's rural customers. The result is only about <u>one twenty-fifth</u> of its actual number of customers.

None of the documents in this file, or in the 1993 Report, explain the necessity for these mental gymnastics, nor does Mr. Baker's expert report submitted to the Board in 1993. The first two steps of the methodology described above produce unit costs (kW, kWh and customer) for the rural deficit. No convincing reason has been proposed why, in allocating that deficit between NP and the Labrador Interconnected system, the LIS share should be based on the actual number of LIS customers, whereas the NP share should be based on a derived "equivalent customer" basis that produces a value of less than 4% of the actual number of NP customers, as seen in the following table.[27]

Figure 10

| **UNIT COSTS OF DEFICIT** | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | | "Equivalent unweighted | % of total | Actual | % of total |
| | line | MW | GWh | customers" | customers | customers | customers |
| NP | 8 | 1,176 | 5,794 | 9,096 | 46% | 251,531 | 96% |
| LIS | 11 | 137 | 659 | 10,854 | 54% | 10,854 | 4.1% |
| Total | 13 | 1,313 | 6,453 | 19,950 | | 262,385 | |
| Deficit unit costs | 14 | 15.27 | 6.09 | 66.78 | | 5.08 | |

[25] LWHN-NLH-013.

[26] There is also an adjustment for specifically assigned distribution costs, but the underlying figures have not been provided.

[27] The line numbers in the second column correspond to those in Exhibit GCB-5.1, Appendix 1 to the 1993 Report. The next three columns are taken from Scheule 1.2.1, p. 1. Actual customer figures from LWHN-NLH-056, Att. 1.

Because customer costs represent only a small portion of total costs, using these customer figures to allocate the deficit results has only a modest effect on the end result. It results in reducing the LIS portion of the rural deficit from 11.3% to 10.2%, as shown in the following table.

Figure 11

| ALLOCATION OF RURAL DEFICIT | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Based on NP "unweighted equivalent customers" (9,096) | | | | Based on NP actual customers (251,531) | | | | |
| | Island | LIS | Island % | LIS % | | Island | LIS | Island % | LIS % |
| Demand | 18.0 | 2.1 | 89.6% | 10.4% | Demand | 18.0 | 2.1 | 89.6% | 10.4% |
| Energy | 35.3 | 4.0 | 89.8% | 10.2% | Energy | 35.3 | 4.0 | 89.8% | 10.2% |
| Customer | 0.6 | 0.7 | 45.6% | 54.4% | Customer | 1.3 | 0.1 | 95.7% | 4.3% |
| Total | 53.9 | 6.8 | 88.7% | 11.3% | Total | 54.5 | 6.2 | 89.8% | 10.2% |

Thus, replacing this derived figure for NP customers with its actual number of customers would result in reducing the LIS share of the deficit by about 10%. To date, no convincing justification for using this very low customer number has been presented.

### 2.3.3. Recent developments

On April 22, 2014, just a few days before the filing deadline for this testimony, NLH submitted a revised response to CA-NLH-166 (quoted earlier), which, strikingly, reverses its position with respect to the fairness of using the Baker methodology today.

Now, Hydro takes the position that:

> Hydro believes that the current methodology [i.e., that found in its own application] does not provide a reasonable sharing of the rural deficit between Labrador Interconnected Customers and Newfoundland Power customers.[28]

This, of course, implies that the rates proposed in its own GRA are also not reasonable or fair.

Hydro proposes two alternate methodologies, one based on the revenue requirements of the two systems, and the other based on the number of customers.

[28] Ibid.

Strikingly, either of these two solutions would apparently result in the elimination of the drastic rate increase for the LIS that is at the heart of the GRA, as shown above in section 2.1.[29]

Figure 12[30]

**Table 6**

**Impact of Rural Deficit Allocation on Rate Change Proposals**

| | Labrador Interconnected | Newfoundland Power | Newfoundland Power Customer |
|---|---|---|---|
| Current Method | 25.1% | -4.8% | -3.2% |
| Revenue Requirement Method | -0.6% | -3.7% | -2.5% |
| Number of Customer Method | 0.6% | -3.8% | -2.5% |

Hydro's first alternate methodology, based on the revenue requirement, is in fact the same one proposed by Hydro in 1993, which was rejected by the Board.[31] The Board had noted NP's position that this approach would be unfair because it would "allow Labrador Customers with low rates to receive a small share of the deficit burden."[32] NP's proposal was that "the deficit be allocated on the basis of 50% energy and 50% revenue requirement."[33]

[29] It is not clear how this finding of a net rate reduction for LIS customers under the alternate allocation methods can be reconciled with the data presented in CA-NLH-090, Att.1, which shows a substantial increase in the LIS revenue requirement prior to rural deficit allocation.

[30] Source: CA-NLH-166 rev.2, p. 7.

[31] PUB-NLH-113, Att. 1, p. 58 of 83.

[32] Ibid., p. 59 of 83.

[33] Ibid.

In making this proposal, NP pointed out:

> the concern the paying classes have for a level playing field where all parties are assessed on the same basis regardless of the rate they are paying.[34]

It should be noted that the second methodology proposed by Hydro, based on an equal payment per customer, respects this criterion.

In his report submitted to the Board in 1993, Mr. Baker pointed out that he was not:

> aware of any generally accepted cost of service methodology for dealing with this particular situation. In finding the best solution, judgment must play a part.[35]

He further explained that his judgment was, in part, based on:

> the inference that public policy at this time requires those who are fortunate enough to enjoy cheap electric service to share their good fortune with those who are not so lucky.[36]

This inference led him to propose his "mini-COS" approach, which would have the result that:

> the percentage increase would be over twice as large for Labrador as for the Island.[37]

This result apparently seemed fair to him, and to the Board, in 1993. Since then, however, two important factors have changed.

First, as we have seen above, the percent increase for Labrador resulting from his proposed method is now more than three times greater than that for the Island.  Its fairness cannot be deduced from the 1993 Report. More important, his inference that public policy favours a levelling of the rate differential between the Island and Labrador has not, to the best of my

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[34] Ibid., p. 64 of 83.

[35] IN-PUB-02, p. 28.

[36] Ibid.

[37] Ibid., p. 30.

knowledge, found support either from government – through its Orders-in-Council and its formal policy documents – or from the Board in its decisions over the last 20 years.

For all these reasons, I believe it is appropriate to put aside the Board's decision of 1993 with respect to the allocation of the rural deficit, and to take a fresh look at the methodology for this allocation, as now proposed by Hydro.

Regarding the second methodology described by Hydro in its revised response — allocation based on the number of customers — it is interesting to note that Hydro's calculations are based on the actual number of customers, not on the "equivalent unweighted customer accounts" used by Baker (and by Hydro in its original filing).

In a report dated April 20, 2014, Dr. Feehan presented an analysis of the rural deficit allocation which in many ways resembles the one presented by Hydro in its revised response (dated April 22, 2014). Like Hydro, he compares costs allocated to NP and to LIS customers based on the unit energy cost to each[38] and on the cost allocated per customer.[39]

Dr. Feehan described four alternate methodologies which overlap, to a certain extent, with those put forward by Hydro. His Alternative A (Every Customer Pays the Same Dollar Amount) closely resembles Hydro's "allocation per customer" approach.[40] His recommended Alternative D, which would allocate the rural deficit between NP and LIS based on the number of customers, and then allocate the deficit between rate classes within each system based on consumption, is also very similar to the suggestion found in note 12 of the NLH's revised response:

> The use of the allocation of the rural deficit using number of customers may be reasonable for allocation between Newfoundland Power and Labrador Interconnected Customers.

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[38] Table 1 of the Feehan report, and Table 1 of the revised response.

[39] Table 3 of the Feehan report, and Table 2 of the revised response.

[40] Feehan, p. 7, and Revised Response, p. 6.

> However, further allocation by rate class would normally consider customer usage characteristics and be allocated based upon a revenue basis.[41]

NLH concludes its revised response with the suggestion that attempts be made to resolve this issue in settlement negotiations. Given the timing of this revised response, this suggestion is to be welcomed.

### *2.4. Return on rate base*

As seen above, return on rate base accounts for 34% of the increase in the Labrador Interconnected revenue requirement ($2.3 million). The highlights of the changes in the Labrador Interconnected rate base are described in s. 3.7.1.1 of the GRA, which identifies an increase of $26.2 million in net book value (reflecting an increase in original cost of $39.0 million) resulting from the conversion of the Labrador City distribution system to 25kV.[42]

#### 2.4.1. Labrador City Distribution Upgrade

In 2012 and 2013, approximately $31 million of transmission and distribution assets relating to this project were placed in service.[43] Additional capital expenditures of $2.5 million are forecast in 2014 and 2015 to complete the project,[44] of which $2.0 million has yet to be requested.[45] In addition, capital expenditures of $2.6 million were made in 2013 for plant which was not yet in-service in 2013, and hence was not included in rate base for that year.[46]

[41] CA-NLH-166, rev. 2, p. 7 of 8, note 12.

[42] Application, page 3.23.

[43] Ibid. and IN-NLH-048

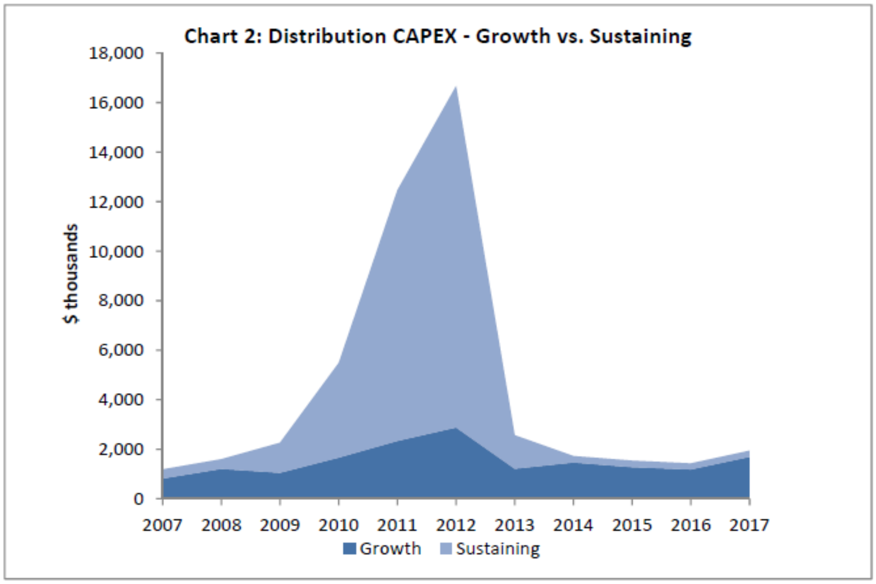
[44] IN-NLH-183, Att. 1, line 1.

[45] IN-NLH-183, p. 1., line 15.

[46] Ibid., note 2.

The following figure shows the capital expenditures for Distribution in the Labrador Interconnected System since 2007.[47]

Figure 13




It seems clear that the vast majority of these expenditures were related to the Labrador City Distribution Upgrade project. It is surprising, however, that they are described here as "sustaining" since, as we shall see in the following sections, they were in fact made necessary by projected load growth in Labrador West.

#### 2.4.1.1.1. Benefits limited to Labrador West

NLH acknowledged in response to an RFI that these investments will not result in any improvements in reliability or any other characteristics of electric service in Labrador East or in

[47] IN-NLH-178, p. 2 of 3.

the Labrador Isolated systems.[48] While the need to upgrade the Lab City distribution system is the result of the ramp up of mining activity in the area, the transmission level customers (IOCC and Wabush Mines) have played no role in financing this upgrade.[49]

Let us presume that these investments have all been duly approved (except for the completion amounts referred to above), and that they are used and useful. The question remains, however, which consumers should bear the costs of these investments, based on the principle of cost causation and relevant precedents. These will be addressed later on. First, we will review the justification for the Labrador City distribution upgrade.

#### 2.4.1.1. Justification

As described in the report, **Labrador City Voltage Conversion Terminals and Transmission Reconfiguration,** presented to the Board as part of the 2009 Capital Budget Application, the Labrador City Upgrading Project would replace the 4.6 kV distribution system in Labrador City with a 25 kV system. The 4.6 kV system was able to support up to 52 MW of load.[50]

At the time, Labrador City loads were forecast to increase by around 0.9% per year, and were projected to reach 55.6 MW by 2027. The gross peak in 2013 was forecast at 53,528 MW.

> The load forecast for Labrador City is based on a combination of historical data since 1992, the effects of increased mining activities, the impacts of the new college and hospital, a modest amount of new residential construction and electric heat conversions.[51]

Furthermore:

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[48] IN-054.

[49] IN-051.

[50] IN-NLH-50, Att. 1, pp. 3-4 of 177.

[51] Ibid., App. B, p. 14.

> While the load forecast represents the expected energy and demand growth on the Labrador City System, the risk of higher load growth exists due to several factors. A fully utilized housing stock along with the changing demographic in the region from retiree retention and new employees for the mining operations, along with the impacts of the IOCC expansion, and the Bloom Lake Development could potentially spawn new residential developments. In combination with approximately 2 MW of electric heat conversion potential in the region, the load could approach 60 MW over the next 20 years.[52]

In fact, Labrador City load growth has been even higher than predicted in this 2008 forecast. Lab City demand for 2017 is currently forecast at 56.7 MW, higher than the level forecast in 2008 for 2027![53]

The 2008 report was unequivocal:

> The status quo is not an option. The 4.16 kV distribution system that currently supplies the customers in Labrador City was designed to supply a peak load of 52 MW. The system load is forecasted to exceed 52 MW in 2009 and to continue to grow to 55 - 60 MW. The distribution system is now at its operational limit. Continuing with the status quo will result in low voltages to customers, lower system reliability, and could compromise the ability to protect people and equipment when faults on the system occur.[54]

In other words, the upgrade of the Lab West distribution system was made necessary by the continuing load growth in that region, which in turn flowed in large part from the increased industrial activity in the region.

#### 2.4.1.2. Increase in Plant in Service, Labrador East and Labrador West

As noted above, NLH has identified an increase of $26.2 million in net book value (reflecting an increase in original cost of $39.0 million) resulting from the Labrador City distribution upgrade

[52] Ibid., p. 17.

[53] LWHN-NLH-004, p. 2.

[54] IN-NLH-50, Att. 1, p. 18 of 177.

project.[55] As also noted above, this project provides no benefits to customers elsewhere in the Labrador Interconnected System. However, NLH has been unable to identify the relative contribution of Labrador East and Labrador West to the changes in the LIS rate base.

> Board Order No. P.U. 14(2004) ruled that there will be a single cost of service study for the Labrador Interconnected System. As a result, Hydro does not track its detailed cost records on a basis that would provide information separately for Labrador East and Labrador West.[56]

As we shall see in the next section, it is in fact common for cost of service studies to track regional cost variations, even if those regional disparities are not currently reflected in rates.

NLH was in fact able to provide variances for each category of distribution assets distinguishing between Labrador East and West.[57] These results are based on Schedule 2.2E of the Cost of Service Study,[58] which presents Functional Classification of Plant in Service for the Allocation of O&M Expense.

According to IN-NLH-186, the increase in Plant in Service for Labrador East between the 2007 and 2013 COS was $3.3 million, compared to $7.4 million for Labrador West. Thus, the increase in Plant in Service directly attributable to Lab West was more than twice that of Lab East.

However, for several significant categories, it was not able to distinguish between the two regions:

> While Hydro does not track all assets by location, Hydro can distinguish certain investments in Labrador East and Labrador West by the location code. However, assets such as transformers, primary conductor, secondary conductor and pole hardware have not been

[55] Application, page 3.23.

[56] IN-NLH-55.

[57] IN-NLH-186, Att. 1.

[58] Application, volume II, page 608 of 720.

> allocated to a specific location within a system and are therefore classified as unallocated for the purpose of this response.[59]

Thus, there is an additional $12.3 million of Plant in Service which Hydro was unable to allocate between the two regions. In other words, less than half of the increase in Plant in Service was allocated in this response.

Of the $12.3 million of unallocated variance, 82% (over $10 million) is found in the categories of distribution poles, pole cribs and other pole hardware (category 390).

Given that the entire Labrador City distribution system was rebuilt to a higher voltage level between the two COS studies, it is reasonable to presume, in the absence of detailed information, that most of these new poles and related hardware were located in Lab West.

If 80% of these new pole assets are located in Lab West, the ratio of the increase in Distribution Plant in Service in Lab West to that in Lab East increases to 3:1. If 90% are in Lab West, the ratio increase to almost 4:1. If 100% of these new assets are in Lab West, the ratio rises to over 5:1.

Of course, these values do not directly translate to rate base amounts. The utility is best situated to carry out these calculations. One can certainly conclude, however, that if the distribution rate base were calculated on a regional basis, one would observe a substantially greater increase in the Lab West distribution rate base than in the Lab East distribution rate base.

### 2.4.2. Cost responsibility

In IN-NLH-185, it was asked why Hydro considers that it is just and reasonable that consumers in Sheshatshiu or elsewhere in Labrador East pay the costs of the Labrador West distribution system upgrades, which provide them no improvements in reliability or any other characteristic

[59] IN-NLH-186.

of electric service (IN-NLH-054). Hydro did not actually affirm that such cross-subsidization is just and reasonable, but simply responded:

> Hydro is not aware of any precedent in this provincial jurisdiction for assigning costs of a distribution upgrade, such as has occurred in Labrador West, to the specific customers that benefit from it. (IN-185, p. 2)

Of course, the absence of a specific precedent in Newfoundland and Labrador does not in itself dictate the appropriate solution. Is it just and reasonable, and is it fair, that customers in one geographic area (Labrador East) be called upon to share cost responsibility for assets that provide them with no benefits?

In the following sections, we shall look at the underlying regulatory principles that speak to this question, and how they have been applied here and elsewhere.

#### 2.4.2.1. Regulatory principles

In its 1993 report on Cost of Service Methodology,[60] the Board set out its understanding of the fundamental principles underlying a cost of service study and resulting rate design. It is worth quoting this section at length:

> Cost of Service Objective and Principles
>
> Where methodological variations exist, what criteria would be used to make a choice between them? On this question, there were some differences of opinion. Dr. Sarikas' views were stated as follows in response GTCB-14 (a):
>
> > "A cost study is not regarded as an end in itself. Thus the objective is not merely to reflect, as accurately as possible, cost causation in the Newfoundland and Labrador System. Objectives relate to rate design and not to cost analysis. Cost analysis is regarded as a tool for rate design. Rate design involves balancing a number of objectives. The most significant of these objectives is fairness and economic efficiency."

[60] PUB-NLH-113, att. 1, pp. 9-11 of 83.

> In the response, rate design objectives were said to include: meeting the revenue requirement, fairness, economic efficiency, simplicity and ease of understanding, conservation of resources, stability and gradualism, social goals, administrative ease, employment, and protection of the environment.
>
> NP's expert, Mr. Brockman, stated that:
>
> > "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 intertwined. In fact, the principle of causality (cost causation) is almost universally claimed in attempts to justify various cost of service methodologies as fair."
>
> The Board's consultant testified that equity, or fairness, based on causal responsibility or user-pay considerations, would constitute a sufficiently broad criterion for the selection of appropriate methodology. …
>
> The opinions expressed are unanimous in supporting fairness as a criterion, but differ on the extent to which other considerations should be taken into account. …
>
> Within the limits imposed, it is the Board`s opinion that economic efficiency is best promoted by the allocation of costs on a causal basis. If other rate considerations should be imposed for a need for compromise, the required adjustment may best be achieved in the process of rate design.
>
> **Recommendation 1:**
>
> That Hydro`s Cost of Service Study be of the embedded type and that the methodological objective be to allocate costs to rate classes in a fair and equitable manner based on causal responsibility for cost incurrence.[61] (underlining added)

The Board's conclusion, that the objective of a cost of service study is to allocate costs to rate classes in a fair and equitable manner based on causal responsibility for cost incurrence, falls squarely within the North American regulatory tradition.

In P.U. 7 (2002-03), the Board presented in more detail its views regarding fairness in cost allocation, as follows:

> 3. Fair Cost Apportionment

[61] PUB-NLH-113, Att. 1, pp. 10-11 of 83.

> Fairness of specific rates in the apportionment of total costs of service among the different ratepayers so as to avoid arbitrariness, capriciousness, inequities or discrimination. Under this principle, customers in similar situations should be treated equally (horizontal equity), while those in different situations should be treated differently (vertical equity). This principle would not deny cross-subsidization of rates among customers of equal circumstances but such subsidization should not cause undue discrimination. The principle of horizontal equity (i.e. equals treated equally) is set forth in Section 73(1) of the *Act* which requires that *"all tolls, rates and charges shall always, under substantially similar circumstances and conditions in respect of service of the same description, be charged equally to all persons and at the same rate, …".* Furthermore, the aspect of undue discrimination also has statutory reinforcement in Section 3(a)(i) of the *EPCA* which declares it to be "*…the policy of the province that the rates to be charged ………should be reasonable and not unjustly discriminatory."* (P.U. 7, p. 29)

And in P.U. 14 (2004), it reiterated the "fair and equitable" criterion, adding that:

> Cost assignment is not an exact methodology and often requires the exercise of judgment.[62]

These passages raise several important questions:

- Are the customers in Labrador East and in Labrador West "of equal circumstances"?
- Does cross-subsidization between them "cause undue discrimination"?
- Are the resulting rates "fair"?

#### 2.4.2.2. Direct (or Specific) Assignment

Direct assignment — the assigning of the full cost of a given asset to the customer or class of customers on whose behalf it was acquired — is an essential element of determining the cost of service. The Board's 1993 generic report on COS methodology described direct assignment as the first step in COS procedures:

> Cost of service studies are routinely and almost universally used in rate proceedings to determine the cost responsibility of the various customer classes. In broad outline the procedures used have become highly standardized. They comprise (1) identification and segregation of costs directly attributable to any particular **class**, (2) arrangement of the remaining costs so that they can be allocated to the various groups of customers which are

[62] P.U. 14 (2004), p. 94.

> jointly responsible for the incurrence, and (3) allocation of such costs in accordance with physically measurable attributes of the services provided to customer classes.[63] (emphasis added)

Hydro has used two different formulations to explain when direct assignment is appropriate. One formulation states that assets "dedicated to serve one customer should be specifically assigned, and costs of (plant and equipment of) substantial benefit to more than one customer should be apportioned among all customers."[64]

This formulation is found in the Definitions section of Hydro's System Planning Guidelines,[65] along with the definition of Common Plant as "plant that is of benefit to two or more customers." This same formulation was also provided by Hydro in an RFI.[66]

However, in quoting this definition in PU7 (2002-03), the Board saw fit to add a footnote specifying that:

> Specifically assigned costs are costs associated with services or products that are of benefit to a single customer or class of customers. This implies that the facilities can be considered entirely apart from the integrated system. Costs associated with services or products that are of joint benefit to all customers or classes or customers are referred to as common costs.[67]

This footnote was also quoted by NLH in response to another RFI in the present proceeding.[68]

As far back as 1993, the Board applied the notion of direct assignment to classes rather than individual customers:

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63 PUB-NLH-113, Att. 1, p. 4 of 84.

64 NLPUB Rural Electric Service Report (1995), p. 39, quoted in P.U. 7 (2002-03), p. 110.

65 CA-NLH-093, p. 6 of 40.

66 IN-NLH-113, p. 2.

67 P.U. 7 (2002-03), p. 110, note 13.

68 IN-NLH-193, p. 1.

> Direct assignment of cost entails diverting the assigned costs from the normal steps of cost of service analysis and charging them directly to the responsible <u>class</u>.[69]

The distinction is important. Under the first formulation, as soon as an asset is of benefit to two or more customers, its costs must be shared by <u>all</u> customers. In some cases, this would clearly conflict with the principle stated above "that costs should be allocated to classes only for the facilities used by such classes."

Furthermore, the Board pointed out that, when the cost responsibility of a given asset is shared between several classes, "extemporaneous measures" other than Direct Assignment should be used:

> If the cost responsibility is shared by more than one <u>class</u>, and the normal means of splitting such costs have been by-passed, extemporaneous measures would be necessary to distribute the assigned costs between the responsible <u>classes</u>. For this reason, <u>direct assignment should be used only in the case of plant dedicated to the use of a single class.</u>[70]

Thus, the regulator has a broad pallet of solutions available – Direct Assignment to an individual customer, Direct Assignment to a class, or "extemporaneous measures" when more than one class is concerned – to ensure that cost causality is respected in cost allocation.

Thus, the Board clearly has discretion to apply its judgment to ensure that cost allocation, and the resulting rates, are fair and equitable. As we shall see in the following section, it used this discretion to find an equitable solution with regard to the allocation of costs of the Great Northern Peninsula transmission line.

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[69] PUB-NLH-113, Att. 1, p. 16 of 83.

[70] Ibid.

#### 2.4.2.3. Specific assignment of Great Northern Peninsula transmission

In addressing the treatment of the Great Northern Peninsula (GNP) transmission line, the Board addressed many of the issues raised here. In its 1993 Report on Cost of Service Methodology, the Board first addressed the question of how to allocate costs for this transmission line, which provides benefit only to certain distribution customers.[71]

The Board first affirmed that "Hydro's decision to avoid direct assignment was proper," because "direct assignment should be used only in the case of plant dedicated to the use of a single class."[72] It continued:

> However, the Board is not persuaded that the conversion of Rural Customers from one class to several should result in changing the costs allocated to NP and IC.[73]

Instead, in order to permit the allocation of the GNP transmission costs to all rural classes, it created a **unique sub-transmission function**, for this purpose:

> The Board considers that the cost of transmission lines dedicated to the service of Rural classes be included in a sub-transmission function and allocated to such classes. The principle that costs should be allocated to classes only for the facilities used by such classes would justify a second sub-transmission function for common lines used by NP and IC but not by Hydro Rural, provided the costs related thereto were significant.[74]

In doing so, it appears to have followed a path indicated by Mr. Baker, who quoted the NARUC Cost Allocation Manual as follows:

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[71] PUB-NLH-113, Att. 1, pp. 14-18 of 83.

[72] Ibid., p. 13 of 84.

[73] Ibid., p. 14 of 84.

[74] Ibid., p. 17 of 83.

> "By carefully choosing subfunctions within the main functions, the analyst attempts to assign costs within a function to groupings for which particular groups of customers are responsible. "[75]

The Board thus reaffirmed the principle that <u>costs should be allocated to classes only for the facilities used by such classes.</u>

In its 1996 Report on Rural Electric Service, the Board again addressed the question of how to allocate costs for this transmission line, which provides benefit only to certain distribution customers.[76] The question was deferred for further study.

It was deferred again in P.U. 7 (2002-03), where the Board noted:

> that its decision to deny NLH's proposed change in assignment of GNP assets in the COS [to common] will result in … additional costs of over $1,000,000 being assigned to the Labrador Interconnected system due to the allocation of the rural deficit.

The issue was definitively resolved in P.U. 14 (2004), when the Board accepted the "proposed assignment of transmission assets on the GNP to Hydro Rural."[77]

It made this assignment, despite the fact that the GNP generation was assigned as common plant, because the common use of the line (to interconnect the GNP generation) "is not of sufficient magnitude to justify the assignment of the GNP transmission assets to common, given the dominant use of the transmission system to serve NLH's rural customers."[78]

The GNP transmission case demonstrates the Board's commitment to the notion that <u>costs should be allocated to classes only for the facilities used by such classes.</u>

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[75] Baker, IN-PUB-02, Att. 1, p. 14.

[76] LWHN-10, att. 1, pp. 37-38 of 42.

[77] P.U. 14 (2004), p. 93.

[78] Ibid., p. 92.

#### 2.4.2.4. Single cost of service study

Another issue that the Board has returned to several times over the years is the decision to perform a single cost of service study for the Labrador Interconnected system. While this decision has been contested on occasion by the Towns of Labrador City and Wabush, including an unsuccessful appeal to the NL Court of Appeal,[79] the Board has never wavered in its conclusion:

> The Board has already ruled in the 1993 generic COS methodology that there be a single cost of service study for the Labrador Interconnected system and is not persuaded that there is sufficient evidence to reconsider the matter at this time.[80]

The reasons invoked by the Board for this decision — essentially, the commonality of generation and transmission assets throughout the Labrador Interconnected System — are clear and unimpeachable.

The question remains, however, as to whether or not, within the Labrador Interconnected System, it would be appropriate to establish geographically distinct <u>classes</u> of customers. We will address this question in the next section.

#### 2.4.2.5. Distinct classes of service to reflect geographic cost differentials

While many utilities use the same basic rate classes, regulators in fact have considerable discretion in selecting them. As George C. Baker explained in his testimony, as expert witness for the PUB, in a 1993 proceeding on rural electric supply:

> The applicable regulatory principle is that rates <u>should reflect costs</u>.…

[79] Referred to in P.U. 8 (2007), p. 45.

[80] P.U. 7 (2002-03), p. 119.

> Nevertheless, the degree to which this principle is reflected in rates can, and does, vary from one jurisdiction to another depending on the structure of rate classes. For customers of the same type, it is generally cheapest to serve urban loads and more expensive to serve rural loads. <u>If all the customers of one type (residential, for instance) are placed in the same class, urban customers subsidize rural customers</u>, even though the rate charged may exactly recover the cost of serving the class as a whole.
>
> …
>
> It is of course much more expensive to serve isolated loads. Therefore, <u>if urban, rural and isolated customers of the same type were to be included in a single class, the degree of cross-subsidization would be considerably greater.</u>[81]

In other words, though the service provided to residential customers in urban, rural and isolated communities may be identical, the cost of service is radically different, which leads many jurisdictions to establish different rate classes for them.

Mr. Baker then pointed out that, in New Brunswick and Manitoba, "residential rates are differentiated on the basis of customer density," and that "fixed charge differentials reflect the differences in distribution cost between the relevant groups." He quoted Manitoba Hydro as stating:

> "Current rate zone distinctions are intended to reflect real differences in distribution cost."[82]

That is, in those two provinces, two or more residential rate classes were established, in order to better reflect cost causation and reduce cross-subsidization.

Like many other analysts, Mr. Baker references the principles set out by Bonbright,[83] and provides them in his Appendix I. He summarizes them as follows:

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[81] G.C. Baker, Direct Testimony, NLPUB, An Inquiry into issues relating to the supply of electricity to isolated rural areas of the Province (rev. Dec. 10, 1993), pp. 3-4. IN-PUB-01, Att. 1.

[82] Ibid., p. 4. He pointed out, however, that Manitoba was considering changing this practice.

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

> The major requirements are that rates be accurate in raising the revenue requirement, conducive to efficient use of electricity and <u>equitable as between both customer classes and individuals within each class</u>.[84] (emphasis added)

When asked how these attributes can best be realized, he responds: "Mainly by ensuring that rates reflect responsibility for cost causation."[85]

Mr. Baker's testimony concerned the rural deficit, but the principles he cites are equally applicable to geographic cross-subsidization within the LIS. The cost increase on the part of interconnected customers to pay the rural subsidy at the time was on the order of roughly 10%.[86] The cross-subsidization from Lab East to Lab West with respect to the Labrador City Distribution Upgrade appears to be considerably greater.

Mr. Baker's testimony in both of these proceedings repeatedly emphasized the importance of cost causality in ratemaking. Describing the general procedure set out in the 1973 NARUC cost allocation manual, he stated:

> NARUC's description suggests, both directly by reference and indirectly as a consequence of the defined procedure, that causal responsibility for the existence of costs is the proper basis for their allocation.[87]

And he approvingly quoted the testimony of Mr. Brockman from an earlier hearing:

> "Causality is the guiding principle of all cost of service work."[88]

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[84] Baker, IN-PUB-01, Att. 1, p. 24.

[85] Ibid.

[86] Ibid., p. 13.

[87] Baker, IN-PUB-02, Att. 1, p. 3.

[88] Ibid., p. 5.

Mr. Baker emphasizes the critical role of judgment in resolving the "inherent conflict between Bonbright's desirable attributes of equity on the one hand and simplicity and understandability on the other."

> Judgment in any particular case is no doubt based on all the pertinent factors including the extent of the inequity, which is relatively small between urban and rural customers in these examples; and the weight accorded to customer understanding and acceptance. Judgment can be expected to vary from case to case.[89]

The clear implication is that — when application of a standard approach leads to an inequitable result — the Board should use its judgment in search of the most equitable solution.

### 2.4.3. Socio-economic differences between Lab East and West

A review of data collected by Statistics Canada in its 2011 National Household Survey reveal significant socio-economic differences between the communities of Labrador West and Labrador East.

In this section, we will compare socio-economic indicators for three communities: Labrador City, Happy Valley-Goose Bay, and Sheshatshiu. As the population of HVGB represents over 90% of that of Labrador East (excluding Sheshatshiu),[90] it is used here as a proxy for Labrador East. As data for Wabush are not available[91] and its population is only 25% of that of Lab City, Lab City data will be used as a proxy for Lab West.

[89] Baker, IN-PUB-01, Att. 1, p. 5.

[90] HVGB's population was reported in 2011 as 7,450, compared to 555 for Northwest River and 1314 for Sheshatshiu.

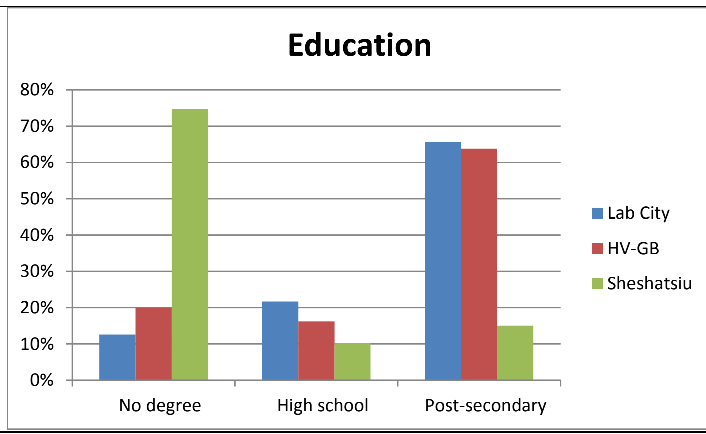
[91] According to the StatsCan website for the National Household Survey, "Data for this area has been suppressed for data quality or confidentiality reasons."

*Education*

In Labrador City, 65.6% of the population over the age of 15 has a post-secondary degree, and only 12.6% do not have a high school diploma. The educational levels in HVGB are only slightly lower: 63.8% have a post-secondary degree, and only 16.2% do not have a high school diploma.

In Sheshatshiu, however, the proportions are reversed: only 15.1% have a post-secondary degree, and 74.7% do not have a high-school diploma.

Figure 14

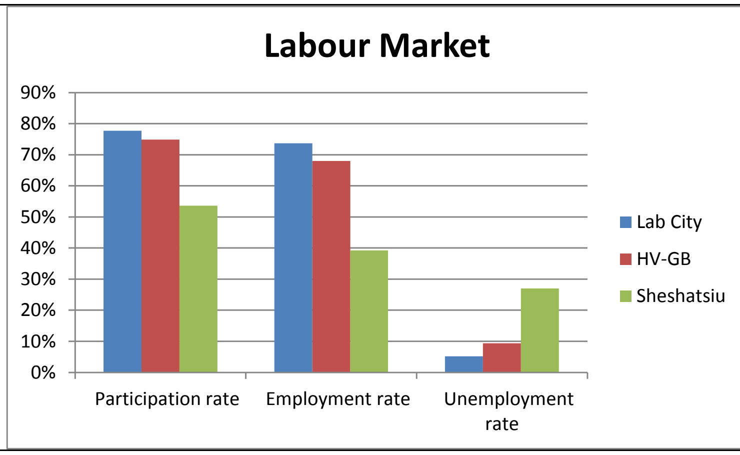



*Employment*

Labrador City has an employment rate of 73.7%, and an unemployment rate of 5.2%. In HVGB, unemployment is almost twice as high (9.4%), and the employment rate is 73.7%.

In Sheshatshiu, on the other hand, the unemployment rate is 27%, and the employment rate is only 39.2%.

Figure 15




*Income*

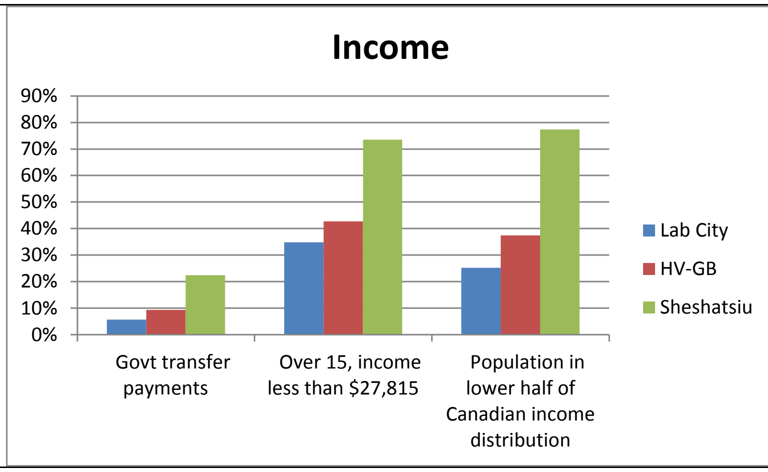
The income disparities between the three communities are substantial.

Government transfers represent 22.4% of total income in Sheshatshiu, but only 5.7% in Labrador City. In HVGB, the figure is 9.3%.

The percentage of Labrador City residents over the age of 15 with an annual income of less than \$27,815 is 34.8% — considerably less than the figures for Canada (50%) or the province of Newfoundland and Labrador (56.1%). For HVGB, the percent of the population with incomes under this level is somewhat higher: 42.7%. However, for Sheshatshiu, it is more than twice as high: 73.5%.[92]

[92] The figure for Sheshatshiu represents incomes under \$29,999.

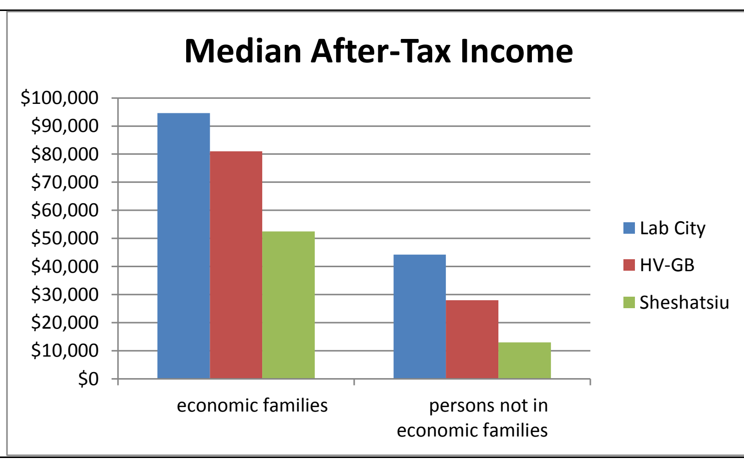
Figure 16




The disparities in after-tax income are even greater. In Lab City, the median after-tax income for people in economic families was $94,967. It was lower (about $81,000) in HVGB, and dramatically lower ($52,502) in Sheshatshiu.

For persons not in economic families, the median after-tax incomes were much lower: $44,173 in Labrador City, about $27,000 in HVGB and only $11,635 in Sheshatshiu.

Figure 17



*Conclusion*

The statistics summarized above demonstrate that there are significant socio-economic disparities between Labrador City (and, presumably, Labrador West as a whole) and Labrador East.[93] Labrador City has much higher levels of income, education, and employment than does Happy Valley-Goose Bay, and vastly higher levels than Sheshatshiu.

To a certain extent, cross-subsidization is a necessary evil of all utility regulation, in that the precise costs of service to any given customer may be higher or lower than the rate charged to the relevant rate class. However, ratemaking involves judgment, and equity considerations are an important component of wise application of that judgment. Standard ratemaking practices should not be applied blindly when the result would be to create substantial cross-subsidization of wealthier communities by poorer ones, as is the case here.

### 2.4.4. Precedents from other jurisdictions

The treatment in the GRA of the Labrador City Distribution Upgrade appears to be based on two principles:

- A cost-of-service study necessarily aggregates costs for all geographic areas covered by the study area; and
- Rates for a given type of electric service must be the uniform all across a cost-of-service study area.

In this section, we will look at several examples from other jurisdictions that demonstrate the contrary.

[93] The population of Northwest River is just 555, compared to 7,450 in HVGB and 830 in Sheshatshiu.

#### 2.4.4.1. Geographical disaggregation in cost-of-service study

##### 2.4.4.1.1. Gaz Métropolitain (Quebec)

In a 1997 decision, the Régie de l'énergie du Québec (the Quebec Energy Board) required that the cost of gas mains be allocated by region. It wrote:

> La Régie est d'opinion que l'allocation par région du coût des conduites principales, à l'aide de demandes quotidiennes maximales par région, est une amélioration importante de la méthode actuellement en vigueur car elle reflète mieux les liens de causalité entre le coût des conduites et les clients pour lesquels elles ont été construites. L'allocation se fait donc en fonction de l'utilisation des conduites principales par les clients actuels des différentes régions. …
>
> En effet, la Régie comprend de la méthode proposée que les coûts des conduites principales seraient alloués aux clients qui les utilisent dans chacune des régions et que les coûts pour desservir chaque classe tarifaire de chacune des régions seraient bien identifiés.
>
> En effet, la Régie comprend de la méthode proposée que les coûts des conduites principales seraient alloués aux clients qui les utilisent dans chacune des régions et que les coûts pour desservir chaque classe tarifaire de chacune des régions seraient bien identifiés.[94]
>
> [The Régie is of the opinion that the allocation by region of the cost of gas mains, based on the maximum daily demand by region, is a significant improvement to the method currently in use, as it better reflects the causal links between the cost of the mains and the clients for whom they were built. The allocation should thus be based on the use of the mains by the current clients in the various regions.
>
> The Régie understands that, under the proposed method, the cost of the mains would be allocated to the clients that use them in each region, and that the costs to serve each rate class in each region would be identified.]

Thus, Gaz Metropolitain's cost-of-service study allocates the cost of these mains differently for different communities, depending on the extent to which they use the mains. To date, the Régie has declined to require that these regional costs be reflected in rates, though it has indicated that, in principle, this would be appropriate.

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[94] Régie de l'énergie, D-97-47 (Dec. 19, 1997), p. 17.

#### 2.4.4.1.1. Pacific Gas & Electric (PG&E)

In its cost of service studies, PG&E distinguishes the cost of service in more than a dozen distinct geographical zones. To understand its approach, some background is necessary.

Like other utilities regulated by the California Public Utilities Commission (CPUC), the rates of Pacific Gas & Electric (PG&E) are based on marginal costs. As noted by Mr. Baker back in 1993, many economists consider marginal costs to be a better basis for ratemaking than embedded costs.[95] The CPUC has relied on marginal costs for its ratemaking processes for since 1981. For distribution assets, PG&E considers only distribution investments related to load growth.

PG&E's service territory has an extremely diverse geography and customer density, resulting in a wide variation in marginal distribution costs among the more than 240 distribution planning areas (DPAs) that comprise its electric system, which are aggregated into 18 divisions. In its cost of service study, PG&E establishes location-specific marginal distribution capacity costs (MDCCs) for each one.

> … MDCCs vary by area to reflect the fact that investments during the planning horizon are needed at different times and in different sizes for different areas depending on the installed capacity and load growth unique to each area.[96]

This approach has for the most part remained stable since 1993, and is meant to reflect cost differences between the 18 geographic divisions.[97]

> Ideally, a DPA has uniform load distribution, uniform load growth rate, a single primary distribution voltage, strong distribution ties among substations inside the area and no ties to

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95 IN-PUB-02, Att. 1, p. 4.

96 Pacific Gas & Electric, General Rate Case 2014, Phase II, Exhibit PG&E-2, p. 1-13.

97 Ibid., p. 5-1.

> substations outside the area. Although ideal DPAs are not encountered in practice, DPAs are defined as nearly as practicable to that ideal.[98]

MDCCs vary greatly between PG&E's 18 geographical divisions. For example, primary distribution marginal costs vary between $13.08 and $78.19/kW.

It should be noted that these MDCCs are not directly reflected in rates at this time, apparently because the current rate structure, based on five tiers and ten climate zones, is already quite complicated. However, the CPUC and PG&E are both committed to "move further toward cost-based rates," implying that regional marginal cost differences will likely eventually be reflected in rates.

#### 2.4.4.2. Alternatives to single-tariff pricing

##### 2.4.4.2.1. Pacific Gas and Electric

As noted above, PG&E's rate structure distinguishes ten climate zones and five tiers. While the ¢/kWh rate for each tier is identical across all zones, the size of the block covered by each tier is not.[99] As a result, the billed amount for a given level of consumption can vary widely across the PG&E service territory.

##### 2.4.4.2.2. Union Gas (Ontario)

Union Gas has distinct distribution rates for its northern and southern regions, based on their different cost structures. Union North (formerly Centra) is served directly from the Trans-

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[98] Ibid., pages 5-2 and 5-3.

[99] The first tier represents a sort of lifeline block – the minimum consumption estimated necessary based on the climate in each of 10 climate zones. Tiers 2-5 consist of percentages above that lifeline block. Thus, Tier 2 consists of 101-130% of the baseline block. In recent years, rate increases have been limited to tiers 3-5, resulting in extremely high rates for these tiers (over 40 cents/kWh in some areas). http://www.pge.com/myhome/saveenergymoney/plans/rateanalysis/howratesset/

Canada mains, and has significantly lower distribution costs than Union South, which requires additional infrastructure, including storage. After the merger with Centra in 1998, Union Gas decided to maintain distinct rates for Union North and South, in order to respect cost causation.[100]

##### 2.4.4.2.3. Massachusetts Department of Public Utilities

The Department of Public Utilities (DPU) in Massachusetts allows utilities to apply a rate rider of up to 2% for municipalities which have opted for underground distribution lines, which are of course far more expensive than overhead lines.[101]

More generally, while the DPU favours single-tariff pricing, it has, on occasion, departed from that practice based on specific facts. It particular, it has approved rates differentiated by zone "in recognition of a specific set of circumstances where cost-causation principles justify a departure from the general rationale behind single-tariff pricing." It has also "approved the use of surcharge mechanisms for utilities to recover the costs associated with particular infrastructure items when traditional ratemaking principles were found to be inadequate for the task."[102]

### 2.4.5. Regulatory mechanisms

In response to an RFI, Hydro wrote:

[100] Personal communication, Chris Ripley, Union Gas.

[101] Personal communication, Paul Osborne, Assistant Director, Rates and Revenue Requirements Division, Massachusetts Department of Public Utilities.

[102] Massachusetts Department of Public Utilities, Decision, Petition of Aquarion Water Company of Massachusetts to the Department of Public Utilities for a General Rate Increase as set forth in M.D.P.U. No. 1, D.P.U. 08-27, March 31, 2009, p. 167.

> To Hydro's knowledge, the Board has never specifically assigned assets to a small group of customers for rate setting purposes. It has either assigned the costs to a single customer or it has treated them as common costs and collected the costs of those assets from the whole rate class, or more than one rate class, in that system. Whether it would be proper for the Board to specifically assign assets to a small group of customers for rate setting purposes is a hypothetical question which cannot be determined absent more factual context.[103]

The question is how best to reflect, in rates, substantial differences in cost of service, due to the costs of particular assets used by one group only, between groups of consumers in different locations which are otherwise similar. One solution is to directly assign those costs to the sub-class of consumers that benefit from them; another solution is to create geographically distinct rate classes. A third, and simpler, solution is to establish a rate rider that applies only to the customers in the area that benefits from the improvement.

In his 1993 testimony in a proceeding relating to the supply of electricity to rural areas, the Board's consultant George C. Baker addressed the question of rate class structure.

> Q. How should rate classes be structured?
>
> A. In order to avoid the sort of cross-subsidization discussed in the first part of this testimony, <u>each rate class should be as nearly as possible homogeneous in terms of unit costs of service</u>. <u>This means that the cost-causative characteristics of electric use should be similar</u> and that the class should be served from the same source of supply.[104]

He recognized, however, that the application of this rule may, under some circumstances, lead to an excessive number of rate classes. To avoid this result, he suggested the use of rate riders:

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

[103] IN-NLH-224.

[104] Baker, IN-PUB-01, att. 1, p. 26.

> operation of the rider ensures an equitable division of allocated cost between the sub-groups.[105]

He reiterated the importance of flexible approach in order to find the best solution for situations where existing rate class structures do not reflect cost causation.

> Q. Isn't there some possibility that some customers will not fit well in any given class structure of reasonable simplicity?
>
> A. Yes, there is.
>
> Most utilities have a real concern for their customers, and when this happens, the utility usually will, and should, try to find some method of eliminating the problem.
>
> This can sometimes be accomplished by means of a rate rider, or sometimes may justify some modification of class structure.[106]

As we have seen, applying the costs of the Labrador City Distribution Upgrade to all distribution voltage ratepayers in the Labrador Interconnected System would result in a substantial cross-subsidization of these costs on the part of the residents of Labrador East, which do not benefit from them in any way. Given the large socio-economic disparities between the two regions, this cross-subsidization is particularly problematic.

As demonstrated above, the regulator has many options to choose from to avoid such an outcome. Under the circumstances, I believe that a rate rider applied to the customers directly benefiting from this upgrade is the best solution. An alternate, but more complex, solution would be to create new rate classes for the Lab West region.

It should be noted that, as we shall see below, customers served under the Labrador Isolated are also indirectly impacted by the LIS rate increase, in that it creates a corresponding reduction in

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[105] Ibid., p. 27.

[106] Ibid., p. 28.

the provincial NSP subsidy. Indeed, the Order-in-Council creating the NSP rebate[107] specifically cites the rates in Happy Valley-Goose Bay, so the application of a rate rider in Labrador West would not affect it.

### 2.5. Operations, Maintenance and Administration (OMA)

As seen above in Fig. 3, Operations, Maintenance and Administration (OMA) expenses for the LIS have increased by 34% since 2007. This increase represents 24% of the total increase in revenue requirement during this period.

The breakdown of revenue requirement and of OMA expenses among the five NLH systems are presented in Exhibit 13, Schedule 1.1. Two lines of this table — OMA expenses and total revenue requirement — are reproduced below.

Figure 18

| | | Total | Island Interconnected | Island Isolated | Labrador Isolated | L'Anse au Loup | Labrador Interconnected |
|---|---|---|---|---|---|---|---|
| 23 | **Total Revenue Requirement** | 567,817,669 | 501,055,017 | 9,516,308 | 33,518,926 | 6,130,827 | 17,596,591 |
| | | | **88.2%** | **1.7%** | **5.9%** | **1.1%** | **3.1%** |
| 1 | **Operating, Maintenance and Administration** | 115,928,304 | 89,425,968 | 5,339,758 | 13,492,944 | 1,321,586 | 6,348,048 |
| | | | **77.1%** | **4.6%** | **11.6%** | **1.1%** | **5.5%** |
| | | | -13% | 175% | 97% | 6% | 77% |

We see here that OMA expense for the Labrador Interconnected System represents 5.5% of Hydro's total OMA expense, but that the Labrador Interconnected revenue requirement represents just 3.1% of Hydro's overall revenue requirement. This could suggest that certain costs may have been misallocated.

The exhibit identifies the Basis of Proration for the OMA expense as "Detailed Analysis" but, to the best of my knowledge, this detailed analysis has not been produced to date in the hearing

[107] OC2007-304, IN-NLH-123, Att. 4.

record. It is thus not possible, at this stage of the proceeding, to determine whether or not the OMA amounts assigned to the Labrador Interconnected System are appropriate, or not.

## 2.6. Other issues

### 2.6.1. Investments required for Muskrat Falls construction

According to CA-NLH-53, "the costs associated with the installation of new facilities to provide construction power for Muskrat Falls was budgeted in the Test Year at $6.1 million and will be fully contributed." The estimates are as follows:

Figure 19.[108]

| Description | Muskrat Falls ($000) |
|---|---|
| Materials Directs Contractor Supplied | 1,700 |
| Labor Direct Contractor | 1,130 |
| Station Equipment Materials Other | 1,700 |
| Total Direct Costs | 4,530 |
| Indirect Costs | 680 |
| Other | 227 |
| Contingency (15%) | 680 |
| **Total Costs** | **6,116** |

However, PUB-NLH-84 shows the Muskrat Falls contribution to be only $3.1 million. At the same time, it notes that "Muskrat Falls Construction transmission assets are fully contributed."

[108] CA-NLH-53.

Figure 20

**Labrador Interconnected Plant in Service ($millions)**

| Function | 2013 Test Year | 2007 Test Year | Difference |
|---|---|---|---|
| Production | 25.9 | 25.9 | - |
| Transmission | | | |
| Distribution Level (46kV) | 11.3 | 0.3 | 11.0 |
| Transmission Level (above 46kV) | | | |
| Muskrat Falls Construction Power[1] | 3.1 | - | 3.1 |
| Other Transmission Level[4] | 23.5 | 21.8 | 1.7 |
| Total Transmission | 37.9 | 22.1 | 15.8 |
| Distribution | 56.3 | 33.2 | 23.1 |
| General[2] | 13.2 | 7.3 | 5.9 |
| Total Plant in Service[3] | 133.3 | 88.5 | 44.8 |
| Muskrat Falls Construction Power[1] | (3.1) | - | (3.1) |
| Adjusted Total Plant in Service | **130.2** | **88.5** | **41.7** |

[1] Muskrat Falls Construction Power transmission assets are fully contributed.
[2] Assets not specific to a given function such as information systems, computer software, corporate office space, etc.
[3] Total Plant in Service before contributions is used in the COS to allocate O&M expense across classes of service.
[4] A portion of the costs related to these assets is assigned to IOCC.

PUB-NLH-297 indicates that "The Labrador Interconnected System transmission assets are assigned to both transmission and distribution levels," in that the costs of terminal stations are divided between "transmission" and "distribution (substations)".

One possible explanation of the gap between the $3.1 million mentioned in PUB-NLH-84 and the $6.1 million mentioned in CA-NLH-53 is that the transmission assets are fully contributed, but the distribution assets are not.

In CA-NLH-168, Hydro pointed out that the modifications increased the transfer capability of the 138 kV line east of Churchill Falls from 63 MW to 76 MW during construction; once it is finished, it will be possible to supply 73.5 MW to HVGB.

In the same response, Hydro identified facilities added at Muskrat Falls to supply construction power for Muskrat Falls that are assigned as common assets, though it did not identify their costs. Based on the responses mentioned above, it would not be unreasonable to expect their cost to be around $3 million.

Hydro justified the allocation of these assets as common as follows:

> As with Hydro's other general service customers, infrastructure before the point at which the customer is metered is common.

This principle differs from the one set out in Hydro's System Planning Guidelines, quoted above, which defines Common Plant as "plant that is of benefit to two or more customers."

It also differs from the criterion set out by the Board:

> Specifically assigned costs are costs associated with services or products that are of benefit to a single customer or class of customers.

Finally, it also differs markedly from the one generally used for transmission assets. The pro forma Open Access Transmission Tariff of the American Federal Energy Regulatory Commission (FERC), which is obligatory in the US and used as a model by most utilities in Canada as well, states:

> Whenever a System Impact Study performed by the Transmission Provider in connection with the provision of Firm Point-To-Point Transmission Service identifies the need for new facilities, the Transmission Customer shall be responsible for such costs to the extent consistent with Commission policy. (s. 27)

More generally, if system upgrades are required before the customer meter which are not useful to other ratepayers, there is no reason why those costs should be allocated as common; they should rather be directly assigned to the customer who requires them.

It is thus important to determine whether or not these upgrades required to serve MFC will be useful, or not, to remaining customers once the Muskrat Falls construction is completed.

The Eastern Labrador load forecast is as follows:

Figure 21

Table 1: Eastern Labrador Load Forecast

| Year | Happy Valley – Goose Bay kW | Muskrat Falls Construction kW |
|---|---|---|
| 2013 | 65,842 | 10,400 |
| 2014 | 66,820 | 12,600 |
| 2015 | 67,801 | 12,400 |
| 2016 | 68,468 | 8,100 |
| 2017 | 69,198 | 7,000 |
| 2018 | 69,648 | 0 |
| 2019 | 70,097 | 0 |

It is indicated that the present transmission system can provide 63 MW to HVGB. In addition, there are two 2.5 MW diesel generators at the North Side Diesel Plant, bringing the capacity that can be served to 68 MW. Additional loads can be served if it is practical for Churchill Falls to increase bus voltage beyond 230 kV.[109]

This suggests that, based on the current load forecast, HVGB loads could be served through 2016, or later, without any system upgrades. Furthermore, the additional loads to be served through 2019, based on this forecast, would require only 2 MW of additional capacity (or less, given the unquantified additional capacity that can be served by increasing transmission voltage from Churchill Falls).

Forecast loads including Muskrat Falls Construction (MFC) will surpass 80 MW in 2015, and one can assume that these upgrades represent the least-cost solution to meet these needs, which exceed existing capacity by 12 MW. However, there is no reason to believe that this major upgrade would have been the least-cost solution for the 2 MW (or less) of additional capacity required by 2019 in the absence of the Muskrat Falls Construction project.

[109] Engineering Brief, Eastern Labrador Transfer Capability, 2013 to 2018, February 1, 2014, p. 3 (CA-NLH-223, Att. 1).

In other words, these upgrades are far out of proportion to the transmission needs through 2019 in the absence of MFC. It is thus clearly inappropriate to impose these costs on other ratepayers, especially since the customer that causes the upgrades will cease to require them in 2018.

Under these circumstances, the costs of these upgrades should be directly assigned to Nalcor.

Alternatively, a system could be designed whereby, rather than contributing the full capital costs of assets that may eventually be used and useful to other customers, Nalcor could assume the annual capital costs of these assets. This annual contribution could be diminished pro rata over time, to the extent that Labrador East loads increase to make use of the assets.

### 2.6.2. Labrador West Transmission Project

The Labrador West Transmission Project (LWTP) consists of a 220 km 230-kV line, a new Flora Lake Terminal Station, and interconnections with the existing Wabush Terminal Station. Under the Labrador West Transmission Exemption Order (Reg. 11/14), NLH is exempt from EPCA and PUA "for all planning, design, construction and contribution activities pertaining to the Labrador West Transmission Project". (s. 3)

The justification of the LWTP is apparently to supply new non-regulated sales. In a news release dated February 13, 2014, Premier Tom Marshall announced that the line's construction would "help to supply power for planned new developments, such as the Kami Iron Ore Project, and improve reliability for all customers in the Labrador region."[110]

[110] http://www.releases.gov.nl.ca/releases/2014/exec/0213n05.htm

New industrial developments in Labrador are served under the Labrador Industrial Rate, established by the NL Government, which became effective in May 2013. The generation component is un-regulated and set by market forces; the transmission component is regulated.[111]

The press release announcing the Labrador Industrial Rate further stated:

> In addition to charges for generation, industrial customers will pay an additional amount based on the costs of required transmission. Under the recommended policy, <u>transmission service and rates would be fully regulated by the PUB beginning in 2015 based on the cost of service principles currently in use on the Island</u>. Transmission owners would be entitled to recover costs and collect a rate of return on their assets in Labrador.[112]

This language could be read to imply that the LWTP will be treated as part of the transmission rate base for the LIS, with its costs shared among all users.

There is, however, no reason to believe the assets will ever be "used and useful" for regulated consumers. Unless it can be demonstrated that the LWTP represents a least-cost solution to a recognized need on the part of regulated consumers, they should bear no cost responsibility for this project.  Given the Project's exemption from the usual controls established by EPCA and PUA are absent, it is hard to see how such a demonstration could be made.

To avoid uncertainty, it is recommended that the PUB make clear that, unless it is demonstrated that the LWTP constitutes the most cost-effective solution to reliability needs caused by growth of regulated loads in the LIS, its costs will not be included in LIS rate base.

[111] IN-NLH-117.

[112] IN-NLH-117, att. 1, p. 2.

# 3. NATUASHISH

## *3.1. The present situation*

Hydro does not at this time provide electric service to consumers in Natuashish. Rather, it provides consulting services to the Mushua Innu First Nation (MIFN).

Electricity consumers served by Hydro in the Labrador Isolated Systems do not pay the full cost of providing their electric service. Those costs are subsidized on the one hand by the rural deficit mechanisms established by the Board − a form of cross-subsidization supported by other classes of electricity consumers – and, on the other hand, by the Northern Strategic Plan subsidy of the provincial government.

To date, Natuashish consumers do not benefit from either of these subsidies, or from any other subsidies or rate reduction programs.[113] To the best of our knowledge, they are they only residents of Newfoundland and Labrador who receive diesel electric service that do not benefit from these subsidy programs.

The following table shows the costs paid to Hydro by MIFN on behalf of Natuashish electricity consumers. Since 2007, these costs have averaged $36.4¢/kWh.

Figure 22

| | | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | average | Source |
|---|---|---|---|---|---|---|---|---|---|
| **MWh used** | (1) | 8400 | 8186 | 8099 | 8319 | 8692 | 8655 | 8452 | IN-NLH-070, Att. 1 |
| **Costs recovered by NLH ($000)** | (2) | $556 | $1,427 | $1,266 | $829 | $847 | $549 | 890 | IN-NLH-096, Att. 1 |
| **Average cost recoveries (cents/kWh)** | (3) = (2) / (1) *100 | 6.6¢ | 17.4¢ | 15.6¢ | 10.0¢ | 9.7¢ | 6.3¢ | 10.6 | calc; also IN-NLH-200, att. 1 |
| **Estimated fuel costs ($000) (based on prices pd by NLH)** | (4) | $1,787 | $2,403 | $1,742 | $2,063 | $2,638 | $2,599 | 2,181 | IN-NLH-202 |
| **Average fuel cost (cents/kWh)** | (5) = (4) / (1) *100 | 21.3¢ | 29.4¢ | 21.5¢ | 24.8¢ | 30.3¢ | 30.0¢ | 25.8¢ | calc; also IN-NLH-200, att. 1 |
| **Total variable costs (cents/kWh)** | (6) = (3) + (5) | 27.9¢ | 46.8¢ | 37.1¢ | 34.8¢ | 40.1¢ | 36.4¢ | 36.4¢ | |

It is important to note that these costs exclude MIFN's own administrative costs, as well as all capital costs related to the plant. These costs are not in the record. However, Hydro indicated that the actual costs for Natuashish are probably **higher** than those reflected in Government rates

[113] IN-NLH-199.

for the Isolated Systems, since "rates in diesel areas are based upon assets which came into service over many years, and the Natuashish infrastructure is relatively new."[114] Government rates for the LIS, which reflect the full cost of service, without any subsidization, are shown in the following table:[115] Furthermore, these estimated diesel costs are based on what NLH would pay for diesel; MIFN's costs may well be higher.

Figure 23

**Isolated Systems - Government**

| Rate Class | Percentage Increase | Existing Rates ¢/kWh | Proposed Rates ¢/kWh |
|---|---|---|---|
| Domestic Government | 17.7% | 80.4 | 94.7 |
| 2.1 G S Government | 22.1% | 74.0 | 90.4 |
| 2.2 G S Government | 27.7% | 68.4 | 87.4 |

It is thus reasonable to presume that the actual costs borne by Natuashish[116] are equal to or greater than the proposed government rates listed above.

It should also be noted that residents of Natuashish apparently have no access to CDM programs.[117]

### *3.2. Should NLH provide electric service in Natuashish?*

Hydro has suggested that because Natuashish is a reserve under Federal jurisdiction, it is not obligated to provide service.

[114] IN-NLH-203.

[115] CA-NLH-7.

[116] Or by the Federal government on its behalf.

[117] PUB-313, Att. 3, Appendix A (Direct install results by community) does not include Natuashish.

> As noted in our previous correspondence, it is clear that INAC/DIAND, either directly or indirectly, fully or partially fund the operational and capital costs of other electrical systems on other Reserves in Canada and accordingly, it has been Hydro's position from the outset that INAC/DIANSD has similar responsibilities in Natuashish since they constructed the system without making any arrangement for the operation of the system once it was built.[118]

The reference to "Hydro's position" apparently refers to the following paragraph:

> We can appreciate your concern that the costs of the electrical system are being paid from the Innu Healing funds but we would consider this to be an issue between MIFN and INAC/DIAND. As noted in the LTOA meetings INAC/DIAND have fully or partially fund [sic] the operation and capital costs of other electrical systems on other Reserves across Canada and it has been Hydro's position that INAC/DIAND should have a similar responsibility here since they are the ones that constructed and currently own the electrical system.[119]

There are three reserves in Newfoundland and Labrador: Natuashish, Sheshatshiu and Samiajij Miawpukek (Conne River).[120] To be best of my knowledge, residences and businesses in the latter two reserves receive electric service from NLH.

Hydro believes that:

> … were it to become the owner and operator of the electrical system in Natuashish and collect rates from the individual customers for the service it provides, it would be required to provide service under the approved rates and rules as set by the Board under Section 70 and other applicable sections of the *Public Utilities Act.*[121]

While that is no doubt true, it is not clear why Hydro would have to own the electrical system in Natuashish in order for it to collect rates from individual customers for the service it provides.

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[118] IN-NLH-205, Att. 14, page 2 of 3. Letter from Wayne D. Chamberlain, NLH General Counsel and Corporate Secretary, to Chief Simon Pokue, Mushuau Innu First Nation, Jan. 18, 2007.

[119] IN-NLH-205, Att. 13, page 1. Letter from Wayne D. Chamberlain, NLH General Counsel and Corporate Secretary, to Chief Simon Pokue, Mushuau Innu First Nation, Nov. 15, 2006.

[120] http://pse5-esd5.ainc-inac.gc.ca/fnp/Main/Search/RVListGrid.aspx?lang=eng

[121] IN-NLH-208.

Hydro has identified a number of situations in which it used transmission and distribution assets owned by third parties to supply electricity to its customers. These include assets owned by Corner Brook Pulp and Paper (CBPP), NP and Twin Falls Power Corp.[122]

Similarly, Hydro does not own all of the generating stations supplying its customers. Hydro purchases electricity produced at generating stations owned by third parties. These include Churchill Falls (Labrador) Corp. (CF(L)Co), CBPP, Star Lake, Corner Brook Cogen, Exploits River Project, St. Lawrence Wind, Fermeuse Wind and others.[123]

There thus appears to be no reason why, even if it did not take ownership of any of the infrastructure in Natuashish, Hydro could not provide service to Natuashish customers – for example, by purchasing electricity from the owner of the Natuashish diesel plant and leasing the existing distribution infrastructure.

In response to an RFI from the Innu Nation, Hydro has indicated the conditions under which it has discretion to refuse to provide service or to connect electric service within its service area.[124] However, it subsequently indicated that the term "service area" is not defined in the *Public Utilities Act* or its regulations.[125] The response appears to suggest that Natuashish is not part of Hydro's service area because "the residents and businesses in that community are not Hydro's customers."[126] The circularity of the argument is self-evident.

NLH concludes the response by indicating:

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[122] IN-NLH-216.

[123] Regulated Activities, Schedule VI.

[124] IN-NLH-124.

[125] IN-NLH-194, p. 1.

[126] Ibid., lines 18-19.

> It could be argued that a customer who is in close proximity to <u>a utility that owns distribution or transmission plant</u> of a suitable nature is within that utility's service territory or service area.

However, we have seen above that ownership is not of itself a determining factor. In the absence of any transfer of ownership of either the diesel plant or the distribution infrastructure, NLH could still provide electric service to residential, commercial and institutional customers in Natuashish, by purchasing power from the owner of the diesel plant and leasing the use of the distribution assets. Doing so would provide dramatic benefits to the community of Natuashish, in reducing the cost of electric service to the level that is applied in all the other isolated communities of Newfoundland and Labrador.

While the purchase by NLH of the diesel plant and distribution infrastructure from MIFN may well be the best solution, it is not a necessary condition for the provision of electric service by NLH in Natuashish.

## 4. LABRADOR ISOLATED RATES

The GRA proposal does not include a significant rate increase the Labrador Isolated systems. However, bills for customers in the Labrador Isolated systems are nevertheless forecast to increase by 20.4%, taking into account the impact of the proposed rate changes for the LIS on the Northern Strategic Plan (NSP) Rebate.[127] Should the residents and businesses of Natuashish become customers of Hydro, they would also be affected by these changes.

The NSP subsidizes rates in the Labrador Isolated Systems (and on the L'Anse au Loup System) to the level of Labrador Interconnected rates for the Lifeline Block of 700-1000 kWh/month). Without this subsidy, they would pay the same rates as NP customers, which are much higher.[128]

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[127] PUB-NLH-107.

[128] IN-NLH-137. Current LIS rates are found at IN-NLH-059.

While the proposed rate increase for residential Labrador Isolated Systems customers is only 0.9%, the large increase for the Labrador Interconnected System means that the amount of the provincial NSP subsidy would be very much lower. Thus, the dramatic increase in Labrador Isolated Systems bills will not in fact contribute to meeting Hydro's revenue requirement, but would instead provide a windfall to government, which would see the cost of the NSP subsidy decrease substantially.[129]

It should be noted that the Order-in-Council OC2007-304, which created the NSP subsidy, refers to the costs paid by residential consumers in Happy Valley – Goose Bay.[130] Thus, should the outcome of this hearing result in different rates for residential consumers in Lab West and in Lab East, it is the rates in HVGB (Labrador East) that would determine the level of provincial subsidy to the Labrador Isolated systems.

## 5. INTEGRATED RESOURCE PLANNING

As far back as 1993, it was suggested that the magnitude of the DSM effort should be determined based on least-cost planning principles, in order to minimize the cost of service.

> [W]hile the well-known California tests are useful for sifting DSM possibilities, I am firmly convinced that they do not provide a satisfactory criterion for the size and content of the overall DSM effort. <u>In my opinion, DSM should be part of least-cost planning.</u> The overall DSM package should be such that it minimizes the present worth of subsidy required through the planning period. The suggested criterion is strictly in line with Hydro's objective to minimize the degree of cross-subsidization required. The California tests are not. They can be, and have been, applied in such a way as to increase the utility's cost of service.[131]

Twenty years later, no such process has yet been put in place.

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[129] Annual costs of the NSP subsidy were $1.9 million in 2012 (IN-NLH-137, page 3). Costs of $1.5 million were reported for the first 9 months of 2013.

[130] OC2007-304, IN-123, Att. 4.

[131] G. C. Baker, IN-PUB-01, Att. 1, p. 22.

In its last two orders resulting from NLH GRAs, the Board has addressed the possibility of requiring NLH to carry out Integrated Resource Planning (IRP). In P.U. 14 (2004), it:

> confirmed that it has the authority and responsibility to ensure that adequate planning occurs for the production, transmission and distribution of least cost power in the Province, pursuant to sections 3, 4 and 6 of the *EPCA*. In addressing the question of whether Hydro should be required to undertake an integrated resource planning exercise, the Board noted (pg. 149):
>
> > "…implementation of Integrated Resource Planning may present sound opportunities for coordinated planning and improved regulation involving both utilities. This process brings together strategic planning, future supply and demand, least cost analysis, demand side management options and environmental considerations."
>
> The Board concluded, however, that more detailed information was required before the Board can move forward with an IRP, including a marginal cost study.[132]

Three years later, however, in P.U. 8 (2007), the Board stated that:

> The Board is not prepared to proceed with an IRP exercise <u>given the pending release of the [2007] Energy Plan</u> and completion of the various rate design reviews and conservation and demand management studies currently underway. In the Board's view the province's future policy direction respecting energy supply will be a key ingredient in formulating an IRP. As well these various studies/reviews would also comprise important inputs needed to stimulate informed discussion and debate contributing to a comprehensive IRP acceptable to all stakeholders.

As more than six years have passed since the 2007 Energy Plan was released, there is no apparent reason why the Board should not again pick up the process envisioned earlier for the implementation of IRP.

NLH has indicated that:

> At this time, Hydro does not intend to implement Integrated Resource Planning, unless requested to do so by the Board.[133]

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[132] Quoted in P.U. 8 (2007), pp. 59-60.

[133] IN-NLH-152.

It has also indicated that the Board never convened the "meeting of stakeholders including Hydro and the parties to this proceeding to discuss the scope of an IRP Process", as mentioned in P.U. 8.[134]

It seems clear that, had an IRP process been undertaken earlier, the important decisions of the last few years could have been taken in a more orderly and reflective manner. Similarly, there will undoubtedly be additional system planning decisions to be made in the coming years, which would benefit from the careful analysis that an IRP process entails.

I would therefore encourage the Board to request that NLH initiate an IRP process, and to consult with stakeholders with regard to nature of that process.

# 6. CONCLUSIONS AND RECOMMENDATIONS

## *6.1. Labrador Interconnected Rates*

### 6.1.1. Rural deficit

The methodology for allocating the cost of the rural deficit has not been changed since it was first established in 1993. Use of this methodology leads to results that are clearly inequitable. Since 1993, the cost of the rural deficit per customer in Labrador has increased by a factor of 4.5:1, whereas that for Newfoundland Power customers has only increase by a factor of 2.2:1.[135]

In a revised RFI response, Hydro has belatedly come to the same conclusion. It proposes two alternate methods, both of which have substantially similar results. This change is so significant that it would, alone, practically eliminate the 25% average rate increase for the Labrador Interconnected System in the General Rate Application.

[134] IN-NLH-230.

[135] As seen in Fig. 9, above.

Dr. James Feehan, writing for LWHN, has made a very similar proposal, based on very similar arguments.

Hydro now suggests that this matter be addressed in settlement negotiations. I support this recommendation.

### 6.1.2. Labrador City Distribution Upgrade costs

In the GRA, the return on rate base for the Labrador Interconnected System has increase by 67% compared to 2007, which accounts for 34% of the total revenue requirement increase.[136] It appears that the lion's share of this increase is due to the commissioning of the Labrador City Distribution Upgrade, with a total cost of over $40 million.

This upgrade provides no benefits to consumers in Labrador East. While distribution costs are usually "socialized" within a COS study area, regulators have many tools at their disposal to ensure that results are equitable and respect the principle of cost causation.

Given the magnitude of these costs, the fact that the benefits of the project are unambiguously limited to Labrador West and that socio-economic conditions in that region are substantially superior to those in Labrador East, which will derive no benefit from the project, I recommend that the Board consider assigning those costs to Labrador West. Of the various regulatory mechanisms available, a rate rider appears to be the simplest to apply.

[136] Or more, if the rural deficit allocation methodology is modified in accordance with the suggestions made here, in Dr. Feehan's report and in Hydro's revised response.

### 6.1.3. Other issues

#### 6.1.3.1. OMA expenses

Operations, Maintenance and Administration (OMA) expenses for the LIS have increased by 34% since 2007. This increase represents 24% of the total increase in revenue requirements during this period.

The LIS share of Hydro's total OMA expenses substantially exceeds its share of Hydro's overall revenue requirement (5.5% versus 3.1%). Details of the allocation should be verified, to ensure that costs have not been misallocated.

#### 6.1.3.2. Muskrat Falls Construction

Of the $6.1 million associated with the installation of new facilities to provide construction power for Muskrat Falls, only $3.1 million has been contributed.

The documentation produced to date suggests that, while the transmission components have been fully contributed, and hence have no effect on ratepayers, the distribution components have not.

This is apparently justified by the presumed benefit that these facilities will eventually have for the remaining customers in the LIS, once construction is complete.

However, analysis of the load forecasts for Eastern Labrador show that no additional capacity would be required before 2017 or later, and that only 2 MW or less of additional capacity would be required before 2020. In contrast, the MFC upgrades add over 12.5 MW of additional capacity.

Given this large disparity, it appears unlikely that these distribution upgrades would have constituted the least-cost solution for meeting the very modest forecast load growth in the Labrador East region. It is therefore inappropriate to socialize their $3.1 million cost.

Consequently, I recommend that the costs of these upgrades should be directly assigned to Nalcor.

Alternatively, a system could be designed whereby, rather than contributing the full capital costs of assets that may eventually be used and useful to other customers, Nalcor could assumes the annual capital costs of these assets. This annual contribution could be diminished *pro rata* over time, to the extent that Labrador East loads increase to make use of the assets.

#### 6.1.3.3. Labrador West Transmission Project

The Labrador West Transmission Project (LWTP) consists of a 220 km 230-kV line, apparently meant to supply new non-regulated sales. NLH is exempt from NLPUB jurisdiction "for all planning, design, construction and contribution activities pertaining to the Labrador West Transmission Project".

There is no reason to believe these assets will ever be "used and useful" for regulated consumers. As the Project provides no benefit to regulated consumers and the usual controls established by EPCA and PUA are absent, regulated consumers should bear no cost responsibility for this project.

To avoid uncertainty, it is recommended that the PUB make clear that the costs of this project will not be included in LIS rate base.

## *6.2. Natuashish*

At the present time, Hydro does not provide or offer electric service consumers in Natuashish.

The Mushua Innu First Nation (MIFN) assumes the full cost of providing electric service.[137] As a result, consumers there do not benefit either from the cross-subsidization of the rural deficit or from the direct Northern Strategic Plan rebate provided by the NL government. Based on Hydro's unsubsidized Government rates in the Isolated Systems, it appears that these costs could be close to $1/kWh.

Hydro has indicated that it will not provide electric service in Natuashish unless it becomes owner and operation of that system. Negotiations in this sense were undertaken several years ago, but never resulted in an agreement.

While the purchase by NLH of the diesel plant and distribution infrastructure from MIFN may well be the best solution, it is not a necessary condition for the provision of electric service by NLH in Natuashish. In other circumstances, Hydro has both purchased energy and leased transmission infrastructure from third parties. I see no reason it could not do so in this context.

The residents and business of Natuashish should not have to pay costs for electric service that are far greater than in any other isolated community. I recommend that the Board use the many tools at its disposal to ensure that this issue is resolved promptly.

### 6.3. Labrador Isolated Rates

Under the GRA proposal, bills for customers in the Labrador Isolated systems are forecast to increase by 20.4%, taking into account the impact of the proposed rate changes on the Northern Strategic Plan (NSP) Rebate.

While the proposed rate increase for residential Labrador Isolated Systems customers is only 0.9%, the large increase for the Labrador Interconnected System means that the amount of the

[137] It appears that the capital costs related to the diesel plant are borne by the federal government on behalf of MIFN.

provincial NSP subsidy would be very much lower. Thus, the dramatic increase in Labrador Isolated Systems bills will not in fact contribute to meeting Hydro's revenue requirement, but instead will provide a windfall to government, which will see the cost of the NSP subsidy decrease substantially.

### 6.4. Integrated Resource Planning

In its last two orders resulting from NLH GRAs, the Board has addressed the possibility of requiring NLH to carry out Integrated Resource Planning (IRP). In 2007, however, it declined to proceed with such a process, due to the then-imminent release of the government's energy plan.

As more than six years have passed since the 2007 Energy Plan was released, there is no apparent reason why the Board should not again pick up the process envisioned earlier for the implementation of IRP. Hydro has indicated that it does not intend to implement Integrated Resource Planning, unless requested to do so by the Board.

It seems clear that, had an IRP process been undertaken earlier, the important decisions of the last few years could have been taken in a more orderly and reflective manner. Similarly, there will undoubtedly be additional system planning decisions to be made in the coming years, which would benefit from the careful analysis that an IRP process entails.

I therefore encourage the Board to request that NLH initiate an IRP process, and to consult with stakeholders with regard to nature of that process.

# ATTACHMENT A — QUALIFICATIONS

Cofounder of the Helios Centre, Philip Raphals has extensive experience in many aspects of sustainable energy policy, including least-cost energy planning, utility regulation (including transmission ratemaking) and green power certification.  He is the author of numerous studies and reports and frequently appears as an expert witness in the regulatory arena.

From 1992 to 1994, Mr. Raphals was Assistant Scientific Coordinator for the Support Office of the Environmental Assessment of the Great Whale hydro project, where he coauthored a study on the role of  integrated resource planning in assessing the project's justification.[138]

In 1997, he advised the Standing Committee on the Economy and Labour of the Quebec National Assembly in its oversight hearings concerning Hydro-Quebec. In 2001, he authored a major study on the implications of electricity market restructuring for hydropower developments, entitled *Restructured Rivers: Hydropower in the Era of Competitive Energy Markets*.  In 2005, he advised the Federal Review Commission studying the Eastmain 1A/Rupert Diversion hydro project with respect to project justification. Later, he drafted a submission to this same panel on behalf of the affected Cree communities of Nemaska, Waskaganish and Chisasibi.

Mr. Raphals appeared as an expert witness on behalf of Grand Riverkeeper Labrador Inc. in the hearings of the Joint Review Panel (JRP) on the Lower Churchill Generation Project, which retained many of his suggestions. He also presented testimony to the Newfoundland and Labrador Public Utilities Board in the context of its advisory hearings concerning the Muskrat Falls project.

[138] J. Litchfield, L. Hemmingway, and P. Raphals. 1994.  *Integrated resources planning and the Great Whale Public Review*.  Background paper no. 7, Great Whale Public Review Support Office, 115 pp. *(also published in French).*

Last year, he presented expert testimony to the Nova Scotia Utility and Review Board in the proceedings concerning the Maritime Link, on behalf of the Canadian Wind Energy Association and, for the compliance phase, the Low Power Rates Alliance.

In British Columbia, he testified on behalf of the Treaty 8 Tribal Association before the Joint Review Panel examining the proposal to build the Site C Hydroelectric Project.

For several years, Mr. Raphals chaired the advisory committee for renewable energies of the Low Impact Hydropower Institute (LIHI) in the United States, and he now sits on LIHI's Renewable Markets Advisory Panel. He has also played a role in developing the low impact renewable electricity guideline for the Canadian Ecologo programme.

Mr. Raphals is a frequent expert witness before the Quebec Energy Board (the Régie de l'énergie du Québec). He has been qualified by the Régie de l'énergie as an expert witness with respect to transmission tariffs (FERC), issues related to the integration of wind power, security of supply with respect to hydropower, energy efficiency and avoided costs, and sustainable development criteria. In Nova Scotia, he was recognized as an expert in sustainable energy policy, including least-cost planning and utility regulation.