An Application to the Board of Commissioners of Public Utilities

2006 General Rate Application

FINAL ARGUMENT

PROPOSED POWER RATES

To be charged by

Newfoundland and Labrador Hydro

To

Newfoundland Power,

Island Industrial Customers and

Rural Customers

February 2007

HYDRO
THE POWER OF COMMITMENT

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A. INTRODUCTION

A.1 General

On August 3, 2006, Newfoundland and Labrador Hydro ("Hydro") filed a General Rate Application ("GRA") with the Board of Commissioners of Public Utilities ("the Board") under the *Public Utilities Act*, R.S.N.L. 1990, c. P-47 (the "Act") seeking approval, *inter alia*:

1. pursuant to section 70 of the Act, of changes in the rates to be charged for the supply of power and energy to its Retail Customer, Newfoundland Power ("NP"), its Rural Customers, and its Island Industrial Customers ("IC"), to be effective January 1, 2007; and

2. pursuant to section 71 of the Act, of the Rules and Regulations applicable to the supply of electricity to Rural Customers.

On September 12, 2006 the Board issued a Procedural Order (Order No. P.U. 28 (2006)) under which the hearing was scheduled to commence on October 31, 2006. In September, Hydro and the Registered Intervenors (the Consumer Advocate ("CA"), NP and the IC) entered into negotiations to investigate issues which might be settled prior to the commencement of the hearing.

On October 31, 2006, the Board postponed the commencement of the hearing, having been informed that the parties had reached an agreement on October 20, 2006 on a number of Cost of Service ("COS") issues and other matters, and that further substantive negotiations were in progress. These negotiations continued through to November 23, 2006 at which time the parties to the GRA signed an additional three agreements that, together, comprised a settlement on all quantitative (i.e. revenue requirement) and rate design issues and upon most, but not all, regulatory policy issues. These agreements were expressly stated to be non-severable.

On December 6, 2006 Hydro filed a Revised Application based upon the elements of the four agreements that had been filed with the Board. At that time, Hydro sought rates to be charged to NP, the IC, Rural Labrador Interconnected Customers, and the Isolated Government Departments, pursuant to section 75 of the Act, to become effective on January 1, 2007. Also on December 6, 2006, the Lieutenant-Governor in Council, pursuant to section 5.1 of the *Electrical Power Control Act, 1994*, directed the Board as to rates to be charged by Hydro to its Non-Government Isolated Rural Customers. On December 8, 2006, NP applied for flow-through rates to its customers premised upon Hydro's Revised Application. On December 14, 2006, Hydro sought 2008 to 2011 rates to apply to service provided to Labrador Interconnected Customers, and 2007 rates to apply to service to Island Interconnected and Isolated (Non-Government) Rural Customers. Finally, on December 20, Hydro applied for amendments to the Rules pertaining to the Rate Stabilization Plan ("RSP").

By Order Nos. P.U. 41, 42, 43, 45 and 46 (2006), the Board granted, on an interim basis, Hydro's and NP's Applications for rates for electricity consumption on and after January 1, 2007.

On January 22, 23 and 25, 2007, the Board heard from witnesses from Hydro and the CA concerning Hydro's Revised Application and six unresolved issues.

A.2 Agreements among the Parties

Hydro's Revised Application was based upon and consistent with the principles and settlements found in the four agreements filed with the Board:

- October 20, 2006 Agreement on COS, Rate Design and Rate Stabilization Plan
- November 23, 2006 Agreement on COS, Rate Design and Other Issues
- November 23, 2006 Agreement on Labrador Interconnected Rates
- November 23, 2006 Agreement on Revenue Requirement

While COS and rate setting methodology issues have been settled in previous hearings, for the first time the agreements resulting in the Revised Application reflect agreement on the Test Year revenue requirement. Reaching this resolution required extensive discussions amongst the parties, and Board staff, parallel with an exchange of information through Requests for Information ("RFIs"). Through this process, the rate case was fully tested and analyzed.

A.2.1 October 20, 2006 Agreement on COS, Rate Design and Rate Stabilization Plan

This agreement stated the matters upon which the parties reached agreement in the first round of negotiation, including rate design principles and the basis of a future IC rate design review process. There were four items identified as COS issues that the parties had not agreed upon, all of which were subsequently resolved with the November 23, 2006 COS, Rate Design and Other Issues Agreement.

The issues resolved in the October 20, 2006 agreement include the following:

- Hydro's embedded COS study is in compliance with Board Orders and is acceptable to the parties (with some exceptions that were resolved in a later agreement);
- the rate structure for the wholesale rate charged to NP, including a reduced demand charge to better reflect marginal cost principles;
- IC rate design will continue as a Review Process rather than during the GRA;
- some changes to the RSP were agreed upon, and other issues were deferred; and
- three review processes were deferred to a 2007 review (NP rate design, IC rate design, RSP).

A.2.2 November 23 Agreement on COS, Rate Design and Other Issues

The issues resolved under this agreement include cost allocation issues which required the parties to reach principled conclusions and compromises on matters where Hydro was revenue-neutral. An example of such an issue was the resolution of the NP generation credit, an issue identified by the IC. This was a matter upon which Hydro had its rates and COS consultant, Stone and Webster, provide an opinion and report (Exhibit RDG-2 – *Review of Newfoundland and Labrador Hydro's Treatment of Newfoundland Power's Generation*). This agreement accepts the methodology and outcome recommended by Hydro's consultant.

The parties also agreed that the proposals put forward by Hydro in its August 3, 2006 Application as to: (1) refunding CFB Goose Bay secondary energy revenues to NP through the RSP, and (2) stabilizing diesel related costs through the RSP, be withdrawn. These issues are to be included for subsequent consideration in the RSP Review Process.

Other matters the parties settled in this agreement include:

- retaining the method of determining specifically assigned charges;
- reducing NP's load forecast in the 2007 test year to remove the effect of their Rattling Brook planned outage; and
- adjusting Hydro's Rural Isolated Customers' (excluding Government Departments) rates to reflect periodic adjustments that occur through NP's Rate Stabilization Adjustment ("RSA") and Municipal Tax Adjustment ("MTA").

A.2.3 November 23. 2006 Agreement on Labrador Interconnected Rates

In this Agreement, the parties agreed upon 2007 rates to be charged Rural Labrador Interconnected Customers. Hydro's August 3, 2006 Application, in a manner consistent with Board Order No. P.U. 14 (2004), proposed rates for these customers to be altered over time so that by 2008 (1) similar customers in Labrador West and in the Happy Valley-Goose Bay areas would be paying the same rates; and (2) all of the revenue credit forecast to be collected by Hydro from secondary energy sales to CFB Goose Bay would be assigned to the rural deficit through the Test Year COS and the RSP. Under the Parties' Agreement on Labrador Interconnected Rates, 2007 rates were to be set at 2006 levels; the pace of the phasing-in of uniform rates was reduced, to be completed by 2011 instead of 2008; and the RSP would continue to be used to account for the CFB Goose Bay revenue credit as Labrador Interconnected rates change.

A.2.4 November 23, 2006 Agreement on Revenue Requirement

There are a number of items settled in the Parties' Agreement on Revenue Requirement. These matters can be categorized into changes and updates in forecast costs (including some data corrections); decreases in forecast operating costs used for rate setting purposes; and changes in the manner in which the RSP Hydraulic Production Variation Balance was to be applied.

Some noteworthy items upon which agreement was reached include (as outlined in Schedules A and C of the Revised Application):

- No. 6 fuel forecast costs decreased by $5.6 million.

- The forecast deficit pertaining to providing service in Natuashish was excluded from revenue requirement. Should these costs be incurred, the parties have consented to the principle of Hydro applying to have those costs deferred for recovery at a later time. The agreement does not commit the parties to consenting to the recovery of any or all of these costs; as this matter would be determined by the Board upon an application being filed by Hydro.

- Changes in forecast interest costs and other factors resulted in a reduction in return on rate base of $3 million.

- Hydro agreed to an overall reduction of operating expenses of $1 million which includes an estimated savings in regulatory costs of $250,000 in 2007.

- NP will see a January 1, 2007 rate reduction of 2.53 mills/kWh flowing from the Hydraulic Variation Special Adjustment (Schedule C to the Revised Application (Rate Stabilization Plan)) whereby NP's Historic RSP Balance will be reduced by the NP portion ($17.7 million) of the forecast December 31, 2006 Hydraulic Variation balance of $20.7 million. NP's portion of the December 31, 2006 actual Hydraulic Variation Balance will be included in the Historic Plan at December 31, 2006, and any difference between the forecast and actual balances will affect July 2007 rates in accordance with the normal operation of the RSP.

- For 2007, IC's RSP rates will be reduced, under existing RSP rules, by applying the IC portion of 25% of the December 31, 2006 Hydraulic Variation Balance. The IC portion of the remainder of the December 31, 2006 actual Hydraulic Variation Balance will be applied to reduce the IC Historic RSP Balance, effective with January 2008 RSP rates.

A.3 Marginal Cost Study

An important advance in the rate setting methodologies in this hearing occurred in response to the marginal cost study that Hydro undertook pursuant to the Board's direction in Order No. P.U. 14 (2004) (Item 61). Consideration of marginal costs is a useful tool in setting rates in that it assists in the understanding of the utility's incremental costs, which is important in designing rates that promote economic efficiency. The parties' agreement on NP rates reflects the influence of the marginal cost study, with a decrease of the demand rate to $4.00/kW, a concomitant increase to the first block energy rate and continuation of a tail block energy rate that reflects Holyrood fuel costs. Marginal cost principles will also be considered in the IC Rate Design Review Process and additional rate design consideration for NP rates, in accordance with the October 20, 2006 Agreement.

A.4 Review Processes

There are a number of rate design issues which the parties wish to discuss further. Under the three agreed upon Review Processes, Hydro and the Registered Intervenors will meet throughout 2007 to discuss further the RSP, the design of the IC's rates, and the design of the demand billing component of the wholesale rate charged by Hydro to NP. These Review Processes will, where specified, entail technical conferences and any agreed upon changes to rates or to rate designs will be proposed to the Board.

It is Hydro's expectation that these Review Processes will permit the parties to continue to work constructively toward resolving remaining rate design issues.

A.5 Board's Acceptance of Agreements

Hydro is cognizant that the Board must satisfy itself on the whole of the record that the rates that it orders are just and reasonable and in compliance with the *Public Utilities Act* and the power policy provision (section 3) of the *Electrical Power Control Act, 1994.*

In the present matter, the Board has before it some 650 RFIs, and it heard testimony on six unresolved issues and received a presentation on the content of the agreements. It is recognized that the custom of this jurisdiction is to make a decision based on evidence and information received through a fully contested hearing. Clearly, the Board's review of a proposed settlement of a GRA requires some degree of deference to be paid by the Board to the parties as to the diligence and level of scrutiny and analysis of the issues undertaken in the negotiation process. Hydro submits that the considerable gains in regulatory efficiency, and savings in regulated costs, merit that this deference be given. Hydro requests that these agreements be viewed in their totality as resulting in a joint rates proposal that treats customer groups fairly and similarly while still ensuring that Hydro can earn a rate of return consistent with the methodology approved by the Board for Hydro in Order No. P.U. 14 (2004).

These agreements evince a principled approach to ratemaking by the parties that has resulted in a fair and balanced outcome. The principles applied by the parties in reaching these agreements were consistent with those principles and ratemaking practices that have been applied by the Board in previous Orders. For instance, the deferral of the completion of phasing-in Labrador uniform rates is, in these circumstances, a reasonable application of the gradualism principle whereby uniform rates will be achieved over a period of time.

Hydro submits that the settlement reached amongst the parties respects the goals of the regulatory process and has resulted in a Revised Application which provides a fair, reasonable and just outcome to all concerned. The evidence is that these agreements were reached only after considerable information had been exchanged and extensive negotiations had occurred. All customer groups were represented by counsel throughout the process. In particular, the CA was appointed pursuant to the *Public Utilities Act* to act on behalf of all of Hydro's domestic and general service customers.

Indeed, the Board should take comfort that the parties were represented by able and experienced counsel supported by expert consultants with whom the Board has had the opportunity to interact in prior contested hearings. Further, Mr. Mark Kennedy, who has acted as Board hearing counsel and, in less recent engagements, as counsel for the CA, was retained by the Board as facilitator and he has executed the agreements in that capacity.

There is evidence before the Board that the agreements reached and proposed to the Board may contain some elements that may not have been achievable in a contested hearing (Transcript – testimony on Mr. Glenn Mitchell, January 22, 2007, pages 157 and 158).

Finally, Hydro would refer to the *Supplementary Report* filed on January 12, 2007 by Grant Thornton, the Board's Financial Consultants. That report indicates that the Agreements were reviewed and considered together with the Revised Application to ensure consistency and accuracy of the forecast revenue requirement, forecast rate base, forecast rate of return on rate base, and proposed changes to the RSP. The Board's Financial Consultants raised no concerns about any of the foregoing and observed that:

> "many of the agreed revisions are interrelated and therefore the reasonableness of the proposed revisions are best assessed in an overall context."

(Page 2 of the January 12, *Supplementary Report* of Grant Thornton)

Hydro submits that the Revised Application and the agreements should be accepted by the Board as the bases for setting as final the rates that have been approved by the Board on an interim basis.

A.6 Rate Outcomes

The rate outcomes are, essentially, the status quo. Most domestic and general service customers received little or no increase. For instance, Island Interconnected domestic customers received a 0.08% increase. The only customer groups whose rate changes are significantly different from that level are the IC, who benefit from a $10 million contribution made by the Provincial Government toward the IC RSP Historical Plan balance, and the Isolated Systems Government Departments whose rates are proposed to increase in 2007. The Province's contributions towards the costs of providing electricity to Isolated Rural Customers did not provide relief to the Government customers.

A.7 Rate of Return on Rate Base

Under section 3 of the *Electrical Power Control Act, 1994*, the power policy requires that the rates set by the Board (subparagraph 3(a) (iii)):

> "Should provide sufficient revenue to the producer or retailer of the power to enable it to earn a just and reasonable return as construed under the provisions of the *Public Utilities Act* so that it is able to achieve and maintain a sound credit rating in the financial markets of the world."

The rate of return on rate base proposed in Hydro's Revised Application has been calculated consistent with the methodology required by the Board in Order No. P.U. 14 (2004). Hydro did not seek to revisit that methodology in this GRA. It is submitted that the manner of setting the levels of Return on Equity ("ROE") and on rate base, as prescribed by the Board in Order No. P.U. 14 (2004), be used for this Application.

B. CONTESTED ISSUES

The November 23, 2006 Agreement on Revenue Requirement identified the following unresolved matters to be heard by the Board during this GRA:

- The Automatic Adjustment formula;
- The appropriateness of an Integrated Resource Planning exercise;
- Reliability policy and initiatives;
- Peer Group Benchmarking;
- Oil Purchasing/Hedging; and
- Conservation Initiatives.

As previously stated, the Board heard testimony on these matters from witnesses for Hydro and the Consumer Advocate on January 22, 23 and 25, 2007.

B.1 Automatic Adjustment Mechanism ("AAM")

B.1.1 History of Hydro's Proposal for an AAM

At Hydro's 2003 GRA, the Board's Financial Consultants recommended that the Board consider whether to implement an AAM for Hydro (Grant Thornton Supplementary Evidence Dec. 5, 2003 page 6, lines 6-14).

In Order No. P.U. 14 (2004) the Board noted that NP "has had an AAM since 1998" and that at its 2003 GRA, "considerable effort was directed . . . toward improving its operation". At page 87 the Board reviewed the evidence presented on whether a similar mechanism was appropriate for Hydro and concluded that "in the interests of regulatory consistency and efficiency, an AAM should be considered for NLH."

The Board noted that:

- AAMs were complex;
- it had insufficient evidence to implement an AAM for Hydro;
- NP's AAM had been determined following a full cost of capital hearing (which had been called by the Board on its own motion);
- an AAM for Hydro would be as complex as it had been for NP;
- in light of the return on equity it was granting in 2004, the Board was not convinced that an AAM was necessary or that there were clearly discernable benefits; and
- there was uncertainty concerning Hydro's forecast capital structure in the short term.

The Board determined that it would not, at that time, make an Order implementing an AAM, but directed Hydro to submit a proposal on an AAM at its next GRA. Specifically, the Board held that:

> "NLH be required to submit a report containing a proposal for such a mechanism with analysis as to the impacts for consideration at its next general rate hearing."

The terms proposed for an AAM appropriate for Hydro, together with analysis that would enable the Board to appreciate the differences between NP and Hydro's circumstances, were outlined in Exhibit MGB-1 to Hydro's original Application in August 2006.

In his oral testimony, Mr. Bradbury confirmed that Hydro’s proposed formula had been modeled on the formula approved by the Board for NP. A history of NP’s AAM follows.

B.1.2 History of NP's Automatic Adjustment Mechanism

In a cost of capital hearing called by the Board on its own motion in May 1998, the Board engaged Doane Raymond to review the rate of return and capital structure of NP. When NP proposed adoption of an AAM, the Board expanded the consultant's mandate and requested a review of formulas which had been used in other Canadian jurisdictions to adjust the rate of return on equity. Doane Raymond concluded that all mechanisms then in place had some consistent underlying features. Of relevance to the current Application, no formula then in existence made adjustments to the embedded cost of debt.

Relative to the adoption of an AAM, at page 105 of Order No. P.U. 16 (1998-99), the Board held that:

> "While the Board believes that adoption of an automatic adjustment mechanism is desirable, the evidence heard at this hearing relates primarily to the adjustment of the appropriate rate of return on equity. Before articulating an adjustment formula to set the allowed rate of return on rate base for 1999 and subsequent years, the Board wishes to hear further evidence which bears directly on the derivation of the allowed return on rate base."

Recognizing the conclusions of the Court of Appeal in the "Stated Case", paragraph 61, the Board held that:

> "the analysis of appropriate rates of return on common equity will be undertaken and factored into the conclusion as to what is a just and reasonable return on rate base."

At pages 105-106, the Board ordered that:

> "(a) An automatic adjustment mechanism will be implemented based upon the equity risk premium model, using the long term (30 years) Government of Canada bonds as the risk free rate. The Board will take an average of the daily closing yields on long term Canada bonds for the last five trading days in the month of October and the first five trading days in the month of November….This average of ten trading days will be adopted as

the forecast long term bond rate for the following year to be used in implementation of the formula.

(b) In estimating the appropriate return on common equity the forecast long term bond rate for the following year will be subtracted from the current year's forecast value. The difference will be multiplied by a factor of 0.20 and the resulting product will be used to adjust the risk premium in the opposite direction. The adjusted risk premium will be added to the forecast long term bond rate to produce the rate of return on equity for the following year.

(c) The resulting rate of return on common equity along with the appropriate rate of return on preferred equity and the embedded cost of debt will be factored into the determination of an allowed return on rate base in a manner to be decided by the Board upon hearing further evidence on accounting methodology in the fall as to how this can best be achieved.

(d) The mechanism will allow any change in the return on rate base to be determined by the Board through an automatic adjustment mechanism in November or December and any rate change would normally be effective on January 1st of the following year.

(e) The Board will issue an Order for revised rates to be filed for the following year if the change in the rate of return on rate base has the effect of moving the rate of return outside the previously approved range.

(f) With regard to a full cost of capital hearing, the Board determines that after the rate of return on rate base has been set for three consecutive years, by application of the formula, and without a hearing, that a hearing will be convened in the following year."

In the GRA that followed in the Fall of 1998, the Board heard evidence from the utility and the Board's financial consultants on the relationship between rate of return on rate base and the cost of various forms of invested capital. The relevant formulae were presented in the pre-filed evidence of Mr. Karl Smith (Exhibits KWS – 9 and 10).

At pages 69-71 of Order No. P.U. 36 (1998-1999), the Board confirmed that the adjustment formula set out in Equation 1 was to be used to set the rate of return on rate base for the forecast year using test year values for each of the dependent variables determining the rate of return on rate base, with the exception of the cost of common equity**,** which was to be estimated pursuant to Order No. P.U. 16 (1998-1999).

The Board also determined that if test year values became inappropriate, the Board would adjust them after a hearing where evidence could be taken respecting the need for adjustments of any of the dependent variables in the adjustment formula.

NP's Automatic Adjustment Formula was used in 1999, 2000 and 2001 to set the rate of return on rate base (and hence rates) for NP for the years 2000, 2001 and 2002. In Order No P.U. 28 (2001-2002) the Board ordered that NP undertake a review of the performance of its formula.

The results of the review were filed as part of the evidence in NP's 2003 GRA and in the hearing that followed, these results led the Board's advisors to alert the Board to the variance between the embedded forecast cost of debt and the actual cost of debt that had occurred between 1999 and 2001 (Grant Thornton Report – NP 2003 GRA, February 4, 2003 page 22 and Order No. P.U. 19 (2003) pages 67-70).

Specifically, Grant Thornton noted that:

> "The decrease in the embedded cost of debt means that actual interest costs are lower than anticipated in the Formula. Generally speaking, assuming other items are constant, as interest costs decrease earnings increase and vice versa. What this means in terms of the operation of the Formula is that because the cost of debt is set at a higher level than actual, the company has the opportunity to increase the return on equity while still staying within the limits of rate of return on rate base."

The Board also heard evidence on behalf of NP's position that the formula yielded a low return on common equity when compared to similar mechanisms adopted by other regulators. NP sought, and the Board ruled on, these changes:

- To adopt the method utilized by the NEB and the BC Commission in the manner of determining the risk free rate. On this point the Board determined that it would continue its existing method for calculating the risk free rate but it would be based on actual yields of three most recent series of CSBs during the trading days (last five in October and first five in November);

- To adopt an equity risk premium of 4.75% at a risk free rate of 6%. Here the Board concluded that a risk premium of 4.15% was appropriate; and

- To expand the range of return on rate base to 50 basis points, and on this change the Board agreed.

The Board considered its options in relation to modifying the formula. One option was to adjust for forecast changes in the embedded cost of debt annually; another was to establish criteria which would trigger a review of the formula and the cost of capital whenever certain variables or returns generated by operation of the formula vary significantly from expectations.

Again, the Board confirmed use of test year values for the embedded cost of debt. At page 68 of Order No. P.U. 19 (2003), it stated:

> "In implementing a formula the Board must select reasonable and justified test year values based on the evidence. In the Board's view this is consistent with the prospective nature of setting rates. Changes in test year values are expected. The primary concern for the Board is to ensure that the components in the Formula remain appropriate."

The Board determined that a monitoring mechanism was appropriate and ordered NP to provide additional information on changes in the embedded cost of debt as part of its annual returns. Specifically, NP was required to prepare and file with the Board:

> "(i) With its annual return until otherwise directed by the Board, a modified schedule calculating the embedded cost of debt for the reporting year to identify specifically the causes of variations in the actual embedded cost of debt from the cost forecast for the test period; and
>
> (ii) With its annual return where in a year the actual rate of return on regulated equity is greater than 50 basis points above the cost of equity as determined by the Formula, a report explaining the circumstances and facts contributing to the difference." (Page 121).

There was no change suggested and none ordered by the Board relative to the use of the embedded cost of debt as the appropriate rate to be applied to the cost of debt in the calculation of return on rate base in the operation of NP's AAM.

B.1.3 Hydro's Proposed AAM

Hydro submits that each of the findings and conclusions of the Board in NP's Order Nos. P.U. 16 (1998-1999), P.U. 36 (1998-1999), P.U. 28 (2001-2002), P.U. 19 (2003) and Order No. P.U. 14 (2004) following Hydro's last GRA, have been incorporated into the proposed AAM reflected in Exhibit MGB-1 with modifications only necessary to reflect matters unique to Hydro.

In his oral testimony, Mr. Mark Bradbury, Corporate Controller and Treasurer, explained that Hydro's proposal had been modeled on the formula that the Board had approved for NP with three key differences:

1. Hydro's rate of return on equity remained tied to the Province's marginal cost of long term debt (unlike NP's which is based on a risk free rate plus a premium);

2. The dates for determination of the Province's marginal cost of long term debt were proposed to be the first ten trading days in October (ahead of those approved for NP) which Mr. Bradbury explained was designed to

give the time required for NP to flow through proposed rate changes to its customers; and

3. The early trigger point proposed was different from that approved for NP (because of the differences in the capital structures of the two utilities).

Otherwise the methodology was consistent with that approved by the Board for NP. The analysis behind this was outlined in Section V of Exhibit MGB-1.

B.1.4 Dr. Cannon’s Suggestions for the Proposed AAM

On behalf of the CA, Dr. William T. Cannon presented pre-filed testimony on October 27, 2006 confirming that he had been engaged to "evaluate, and provide an opinion on the appropriateness of Hydro's proposed automatic adjustment mechanism . . . and recommend changes to [it]" (page 2, lines 22 -25).

In Dr. Cannon's view, the operation of an AAM for determining Hydro's annual allowed return on rate base “should (1) be based on an up-to-date estimate of Hydro's embedded cost of debt for the test year and (2) should incorporate, in the year-by-year calculation of the range for the allowed return on rate base, a weighted average cost of capital ("WACC") value that, subject to forecast error, is as close as possible to the actual WACC likely to be experienced by Hydro in each future year" (page 2, lines 32-37).

Hydro accepted Dr. Cannon's first proposal and on Schedule A, page 5 of 6 of the Revised Application, it recalculated the 2007 Test Year embedded cost of debt at 8.26%. In his oral testimony, Dr. Cannon acknowledged that he accepted this calculation (Transcript January 25, 2007 page 109, line 15 to page 110, line 25).

Hydro did not accept Dr. Cannon's second proposal and in response to CA 219 NLH, explained that it considered Dr. Cannon's proposal to be contrary to ratemaking principles established in this jurisdiction including:

(i) Section 3(a)(ii) of the *Electrical Power Control Act (1994)* SN 1994 Chapter E-5.1 (The “EPCA”) which states the power policy for the Province and specifies that the “rates to be charged for the supply of power should be established wherever practicable, based on forecast costs for that supply of power for one or more years”.

(ii) Section 4 of the EPCA which states that the Board shall “implement the power policy declared in section 3, and in doing so, shall apply tests which are consistent with generally accepted sound public utility practice.”

(iii) Section 80 of the *Public Utilities Act* RSN 1990 Chapter P-47 which establishes the regulatory framework of the Board founded in rate base regulation.

(iv) The Newfoundland Court of Appeal in Newfoundland (Board of Commissioners of Public Utilities) (Re) (1998) 64 N and PEIR 60 stated at para. 77:

> “The process of rate setting is generally prospective by nature. Although the Board must set rates for the future, it only has data from past experience, the evidence from utility officials as to planned changes in operations and the opinions of experts as to future economic trends as a guide to what the revenue requirements of the utility will likely be. It is therefore, necessarily speculative. In developing the utility’s requirements, the Board focuses on a ‘test year’ as the basis for its estimates and adjustments. Traditionally, in North America the test year was chosen as the latest 12 month period for which complete data were available [FN60]. More recently, due largely to inflation, boards adopted a forward-looking test year which in effect amounts to a forecast of what

expenses and costs, and hence revenue requirements, will be. This has been the practice of the Board [FN61], and is supported by the Act [FN62] and the EPC Act [FN63]. Past experience of course remains relevant, however, insofar as it gives insight into the possibility of forecasting error [FN64]".

(v) Order No. P.U. 36 (1998-1999) at pages 69-70 in which the Board determined the parameters of an AAM appropriate for NP and ordered that test year values would be used for each of the dependent variables in determining the rate of return on rate base with the exception of the cost of common equity which would be established pursuant to Order No. P.U. 16 (1998-99);

(vi) Order No. P.U. 19 (2003) at pages 67-70 where the Board addressed its financial advisor's concerns respecting variances between the embedded forecast cost of debt and actual cost of debt for NP in the operation of its AAM over a three-year period, confirmed that it did not want to discourage a utility from seeking efficiencies to lower costs and stated at page 68 that "in implementing a formula the Board must select reasonable and justified test year values based on the evidence. In the Board's view this is consistent with the prospective nature of setting rates. Changes in test year values are expected." To address how the benefit of lower costs (through reduced debt rates) would be passed on to consumers, the Board concluded that a triggering mechanism tied to the overall cost of capital would be appropriate and that NP would be required to provide additional information on changes in the embedded cost of debt as part of its annual returns (page 121);

(vii) Regulatory principles generally as set out by the Board in Order No. P.U. 14 (2004) at pages 23-24. Relative to section 80 of the *Public Utilities Act*, the Board confirmed at page 19 that Hydro's rates were to be based on "forecast costs for the supply of power for one (1) or more years. This timeframe in practice is generally referred to as the 'test year(s)'."

Further at page 25, the Board stated "the focus of return on rate base regulation is on earnings, in particular the allowed return per dollar of investment (rate base). Rates are set to give the regulated utility the opportunity to recover its revenue requirement consisting of its estimated operating costs and a fair return on its rate base. These costs are generally estimated for a test year(s) for which the rates are set."

(viii) The Regulation of Public Utilities, (3rd ed), Phillips, Charles F. Jr., states at page 196:

> "The Company, with the concurrence of the commission or its staff, will generally select a 'test year', frequently the latest twelve-month period for which complete data are available. The purposes of such a test year are as follows. In the first place, the commission's staff must audit the utility's books. For rate-making purposes, only just and reasonable expenses are allowed; only used and useful property (with certain exceptions) is permitted in the rate base. In the second place, the commission must have a basis for estimating future revenue requirements. This estimate is one of the most difficult problems in a rate case. A commission is setting rates for the future, but it has only past experience (expenses, revenue, demand conditions) to use as a guide.
> "Philosophically, the strict test year assumes the past relationship among revenues, costs, and net investment during the test year will continue into the future. To the extent that these relationships are not constant, the actual rate of return earned by a utility may be quite different from the rate allowed by the commission. For many years, commissions have adjusted test year data for 'known changes'; that is, a change that actually took place during or after the test period (such as a new wage agreement that occurred toward the end of the year). More recently, due largely to inflation, a few commissions have modified the traditional historic test-year approach by using a forward-looking test year (either a partial or a full forecast) or by permitting pro forma expense and revenue adjustments."

In paragraph (e) of CA 219 NLH, Hydro further explained that it believed its proposed AAM was consistent with the ratemaking principles established in this jurisdiction particularly since it proposed to adjust only the rate of return on equity and to use single test year values for all other dependent variables of the formula.

Hydro repeats its contention that Dr. Cannon's recommendation to incorporate, at this hearing, different, pre-established values for the embedded cost of debt for three years beyond the test year in Hydro's proposed AAM, is inconsistent with the legislation, Board Orders, Court of Appeal Decision in the Stated Case and regulatory text all referred to in its answer to CA 219 NLH and repeated above.

As Mr. Bradbury explained further in his oral testimony, adjusting the ROE annually (in Hydro's case by the Province's marginal cost of debt) adjusts a rate that can be readily determined in an objective fashion in a non-test year. In stark comparison, the projection of the embedded cost of Hydro's debt beyond the test year requires a detailed calculation that is predicated on many different assumptions that have not been subject to the same scrutiny as test year forecast values (Transcript January 25, 2007 page 12, lines 16 to 21).

In explanation, Mr. Bradbury referred the Board to CA 218 NLH for the calculations of Hydro's forecast embedded cost of debt for the years 2008-2010 (Transcript January 25, 2007 page 12, line 22 to page 13, line 8) and led the Board through the assumptions that lie behind the calculation (page 13, line 11 to page 16, line 19).

Dr. Cannon also testified on January 25, 2007; and Hydro makes the following points relative to his oral evidence:

1. Dr. Cannon acknowledged the accuracy of Hydro's calculation of the forecast embedded cost of debt for the years 2008-2010 as reflected in CA 218 NLH (Transcript January 25, 2007 page 110, lines 10-21).

2. Dr. Cannon acknowledged the differences between the regulatory regimes across the country (Transcript January 25, 2007 page 113, lines 10-17) but admitted to not being able to provide details of such differences for the Board (Transcript January 25, 2007 page 136, lines 9-25). He was specifically unaware that in this Province, the AAM approved for NP used actual and not forecast Government of Canada Bond rates in adjusting the ROE (Transcript January 25, 2007 page 137, lines 1-11).

3. He candidly acknowledged that while it was just as probable that all other costs which combine to make up Hydro's 2007 COS, could also change after the test year (Transcript January 25, 2007, page 152, line 22 to page 163, line 24), he said that he had not been engaged to examine the other components of the COS (Transcript January 25, 2007 page 125, lines 15-22; and page 150, line 18 to page 151, line 15).

4. While Dr. Cannon's proposal was to set, at this hearing, the forecast embedded cost of debt for Hydro for 2008-2010 and use these rates in three separate formulas for adjusting the utility's return between test years, he admitted there was uncertainty inherent in such forecast rates (Transcript January 25, 2007 page 138, line 15 to page 140, line 6).

5. He further confirmed that in his 25 years of experience he had not made a similar recommendation for setting multiple year forecasts for the embedded cost of debt to another regulator (Transcript January 25, 2007 page 132, line 24 to page 133, line 7) and that he did not know of any regulator that followed the practice he was recommending to this Board (Transcript January 25, 2007 page 137, line 22 to page 138, line 14).

6. Additionally, Dr. Cannon's proposal as set out above was based on his concern for the utility's over-earning. In Exhibit MGB-4, with which

calculation Dr. Cannon was also in agreement, Mr. Bradbury had calculated, as an illustration, the difference in earnings in 2010, if the actual embedded cost of debt was 8.21% but the AAM had used the test year embedded cost of debt of 8.26%, as approximately $600,000 on a total revenue requirement of $431.1million (or 0.14%). Dr. Cannon acknowledged that it would not 'take much' for a utility to have a bump of $600,000 in its COS in any given year (Transcript January 25, 2007 page 144, lines 2-6).

7. Finally, in cross examination Dr. Cannon was asked what relevance, if any, it had to his concern for over-earning that Hydro's return on equity was in the range of 4% (and a margin of $8 million). He suggested that, once again, the appropriate return on equity for Hydro was not within the terms of his engagement (Transcript January 25, 2007 page 143, lines 5-23).

B.1.5 Hydro's Position on the AAM

Specific to the conclusions reached by this Board in Order No. P.U. 14 (2004) page 87, NLH submits that:

- There is now sufficient evidence before the Board to enable it to approve terms of an AAM for Hydro;
- A full cost of capital hearing (such as preceded the establishment of NP's formula in 1998) is not necessary as Hydro's ROE is currently tied to the Province's marginal cost of long term debt thus rendering such a hearing unnecessary to determine the variables in the proposed formula;
- The relationship between rate of return on rate base and the cost of the various components of the capital structure of Hydro are fully explained in Exhibit MGB-1;
- The Board has been provided with more certainty surrounding Hydro's forecast capital structure;

- The benefits of an AAM at this time are reduced costs and enhanced regulatory efficiency; and
- Further regulatory principles of fairness and consistency suggests that Hydro should be entitled to an AAM based on the only model already approved in this jurisdiction which regulates on a return on rate base basis.

Hydro therefore seeks approval of an AAM to be based upon the parameters outlined in Exhibit MGB-1. The formula has been filed by Mr. Bradbury as undertaking U Hydro # 1.

B.2 Integrated Resource Plan ("IRP")

During the GRA hearing, the CA and IC indicated (Transcript January 22, page 34, lines 8-13) they would

> "be submitting, at the end, that parties should be given leave to apply to the Board as regards the initiation of an integrated resource planning exercise."

Hydro presents the following discussion to assist the Board in determining what, if any, action needs to be ordered during this GRA on the matter of integrated resource planning.

B.2.1 Jurisdiction

Under Section 4 of the *Electrical Power Control Act* ("EPCA"), the Board is mandated to ensure the management and operation of all sources and facilities for the production, transmission and distribution of power in a manner that would result in power being delivered to consumers in the Province at the lowest possible cost consistent with reliable service.

Under Section 6 of the EPCA, the Board must ensure that adequate planning occurs for the future production, transmission and distribution of power in the Province.

B.2.2 Prior Board Orders

The Board has recognized that in planning for future supply, it has discretion to take appropriate steps to determine that all available options are canvassed and that the options chosen result in least cost service (Order No. P.U. 14 (2004) page 148).

At Hydro's 2003 GRA a "number of witnesses made reference to Integrated Resource Planning, its goals and some of its components." In particular, a marginal cost study was identified by two consultants as being necessary for Integrated Resource Planning (Order No. P.U. 14 (2004) page 149).

At page 149 the Board determined that:

- the implementation of an IRP may present sound opportunities for coordinated planning and improved regulation involving both utilities;
- the process brings together strategic planning, future supply and demand, least cost analysis, demand side management options and environmental considerations;
- it needed more detailed information before it could move forward with IRP; and
- these issues could best be effectively addressed in the context of a generic process involving both utilities and other interested parties at which the Board could address methodologies, benefits, costs and scheduled implementation associated with IRP.

B.2.3 Recommendations for an Integrated Resource Plan

In pre-filed evidence, experts engaged by both the ICs and the CA once again raised the issue of an IRP.

B.2.3.1 Mr. Douglas Bowman

At pages 17-19 of his pre-filed testimony, Mr. Douglas Bowman suggested that development of IRPs with full public review is common in the US. He defined IRP as "a planning process . . . that evaluates the full range of alternatives, including new generating capacity, power purchases, energy conservation and efficiency . . . to provide adequate and reliable service to a customer's electric consumers at . . . lowest system cost . . ." and he referred to a Western Area Power Administration (WAPA) website for a checklist for an IRP exercise. However, in response to NLH 10 CA, Mr. Douglas Bowman acknowledged that he did not know the costs associated with the IRP exercise he was recommending.

B.2.3.2 Mr. Patrick Bowman

On behalf of the IC, Mr. Patrick Bowman made a similar recommendation but used as examples Yukon Energy Corporation, Manitoba Hydro and BC Hydro. In reply to NLH 42 IC, Mr. Patrick Bowman declined to provide the Board with a copy of BC's IRP (referred to in that Province as an Integrated Electricity Plan ("IEP")), choosing instead to refer Hydro and the Board to the website.

Hydro submits that the website referred to in this RFI confirms, as a matter of public record, that:

- BC's IEP was filed under section 45(6.1) of the BC Utilities Commission Act (the equivalent provision in this Province is section 6 of the EPCA).

- In Commission Order No. G-103-05 dated October 5, 2005, the Commission approved a Negotiated Settlement in which BC Hydro committed to seek regulatory approval of its Long Term Acquisition Plan ("LTAP") with its 2006 IEP.

- On March 29, 2006, BC Hydro filed its 2006 IEP and LTAP.

- A Procedural Conference was held on May 19, 2006. The IR process and technical workshops occurred between June and August 2006.

- The IEP filing was clearly the result of an enormous undertaking which appears to have taken 24 months to complete (BC filed its last IEP in 2004) and during which the stakeholder input alone took 10 months. See page "2-3", lines 1 to 4.

- The IEP process included (among other things) public involvement through regional workshops, technical resource options workshops, and First Nations engagement. The final report filed by BC Hydro exceeds 2,000 pages.

- Now that the Plan has been filed, hearings will commence.

Similar to Mr. Douglas Bowman, in NLH 42 IC, Mr. Patrick Bowman indicated he had no knowledge of the costs to complete BC's 2006 IEP.

B.2.4 Lack of Sufficient Evidence

In accordance with Order No. P.U. 14 (2004) pages 148-149, a Marginal Cost Study has now been filed with the Board. However, relative to all other factors that the Board wished to consider, neither of the experts at this hearing has addressed the IRP issues identified by the Board in any structured or comprehensive manner. Specifically neither Mr. Douglas Bowman on behalf of the CA nor Mr. Patrick Bowman on behalf of the ICs:

- has made a firm recommendation on methodology;
- has addressed the benefits expected to be achieved from such an exercise;
- has enlightened the Board respecting the costs of such an exercise (not only to the utility but to the other interested parties);
- has given a clear, reliable schedule for such an exercise; and
- has addressed the Board's preference for a generic hearing.

B.2.5 Hydro's Long Term Power System Planning

In support of his recommendation for an IRP, in his pre-filed evidence, Mr. Douglas Bowman suggested that Hydro requires a more comprehensive planning framework to increase confidence that customers are getting maximum value (pages 4-6). Mr. Patrick Bowman made a similar statement at page 42.

Hydro submits that its ongoing system planning analysis and annual Report on Generation Planning Issues assesses the various potential sources of meeting future load requirements. The 2005 report was filed as Schedule JRH - Supplementary 1 to Mr. Jim R. Haynes' Supplemental evidence and the 2006 report was filed on December 8, 2006. This evidence allows the Board to meet its obligations under Section 4 of the EPCA.

B 2.6 Hydro's Position on an IRP

In oral testimony, Mr. Jim R. Haynes, Hydro's VP Regulated Operations, explained that Hydro did not agree that the Board should direct Hydro to prepare and submit to the Board a detailed framework and schedule for undertaking a formal IRP at this time (Transcript January 23, 2007 page 3, line 11 to page 5, line 2; and page 137, line 11 to page 138, line 4).

Specifically, Hydro's position relative to Mr. Douglas Bowman's proposal is reflected in the Supplementary Evidence of Mr. Haynes, pages 2-5, in which it is clarified that:

- Hydro already prepares an annual system planning report, which reviews the latest long term load forecast, generation expansion requirements, options, costs and issues;

- Demand side management is a key element of an IRP and a study of the technical and economic potential for conservation in the Province will be underway in 2007;

- The Board addressed an IRP for Hydro in Order No. P.U. 14 (2004) and expressed its preference for a generic process;

- The BC Hydro model referred to by Mr. Douglas Bowman demonstrates the scope and enormity of the process;

- The Board does not have an accurate estimate of the costs of an IRP; and

- Most importantly the Province's Energy Plan, which will establish provincial policy for the supply of energy, has not yet been released but is anticipated in the coming months.

Hydro's position on the appropriateness of an IRP is that:

1. The Board should await the release of the Province's Energy Plan;

2. It accepts the Board's finding in Order No. P.U. 14 (2004) at page 149 that such an exercise should be coordinated with the involvement of both utilities and is best addressed in the context of a generic process; and

3. Hydro could meet with the Board and Intervenors within a reasonable period following the release of the Province's Energy Plan to discuss the appropriateness of an IRP. If the Board believes an IRP is appropriate, it would discuss the participants, timing and scope of such an exercise.

<u>B.3 Reliability Policy</u>

Mr. Douglas Bowman, on behalf of the CA also made recommendations to the Board concerning reliability targets. This was considered in the oral testimony of Hydro's witness, Mr. Jim Haynes, VP Regulated Operations.

B.3.1 Recommendation of Mr. Douglas Bowman

At page 32, line 15 of his pre-filed testimony, Mr. Douglas Bowman on behalf of the CA suggested that the Board should:

> "direct Hydro to prepare a clear reliability policy or procedure identifying minimum reliability performance benchmarks upon which to evaluate and audit reliability expenditures . . . (that) Hydro should submit the policy . . . to the Board for stakeholder review and Board approval. Following Board approval, Hydro should re-submit for Board approval its reliability improvement plan consistent with the new policy along with a detailed cost estimate and schedule for implementation."

In reply to a question from Vice-Chair Whalen, Mr. Bowman stated that he was recommending establishing a policy against which Hydro could be audited in the context of a hearing, rather than recommending a clear minimum or mandatory criterion for reliability, and that conceptually he would consider Delaware's model as appropriate for a minimum criterion (Transcript January 23, 2007, page 193, line 3 to page 198, line 19).

In answer to a later question from the Vice-Chair he admitted that such minimum reliability policies have been driven largely by de-regulation, privatization and restructuring in North America (Transcript January 23, 2007, page 201, line 1 to line 14).

The following elements of the Delaware model were referred to by Mr. Bowman as possibilities for the policy he suggests the Board require Hydro to prepare and submit for approval:

- minimum benchmarks for SAIDI and SAIFI;
- a power quality program with clearly stated objectives and procedures;
- an inspection maintenance program;
- annual forward looking planning report for reliability;
- annual performance report (to assess if targets were met); and
- suggested penalties and remedies.

(Transcript January 23, 2007, page 194, line 18 to page 198, line 8.)

At page 21, lines 3-7 of his pre-filed testimony, Mr. Douglas Bowman stated that:

> "It is apparent that Hydro does not have a Board-approved policy or procedure including a minimum benchmark of reliability performance beyond which no further reliability expenditures would be required. Other jurisdictions establish such reliability performance procedures and benchmarks".

Mr. Bowman cites in support of this statement the Pennsylvania Code and the Delaware Public Service Commission policy.

B.3.2 Hydro's Response to Mr. Douglas Bowman's Proposal

As confirmed in the pre-filed evidence and oral testimony of Mr. Jim R. Haynes, VP Regulated Operations, Hydro does not agree with Mr. Douglas Bowman's suggestion that the Board require Hydro to prepare and submit a reliability policy as described in his testimony.

Firstly, Hydro has been fully regulated by this Board since 1996 and submits that concerns from other de-regulated jurisdictions that have resulted in the establishment of reliability policies such as described by Mr. Bowman are not entirely relevant in this Province.

Secondly, during his cross examination, Mr. Bowman confirmed that he was not aware of the manner or extent of Hydro's existing reliability reporting requirements to the Board. Specifically, he was not aware:

- that established regulatory oversight requires Hydro to report to the Board on an 'event' basis (i.e. any event which results in greater than 5,000 customer hours of interruption or any event resulting in an isolated diesel community being without service for more than eight hours);

- of Hydro's requirement to report reliability information to the Board on a quarterly basis, including SAIFI and SAIDI statistics; or

- that for capital projects classified as 'normal capital' Hydro must satisfy the Board of need, which can be justified on the basis of reliability.

(Transcript January 23, 2007 page 163, line 3 to page 165, line 7.)

Thirdly, relative to the components of the reliability policy suggested by Mr. Bowman as appropriate, Hydro submits that:

- Hydro has reviewed its performance in Generation, Transmission and Distribution and has established targets for improvement in reliability as reflected in CA 30 NLH (1st Revision) pages 3-9. These targets are reviewed annually, based upon past performance, industry benchmarks, and customer feedback;

- Hydro's President and CEO explained Hydro's philosophy for an inspection maintenance program in cross examination (Transcript January 22, 2007 page 57, line 23 to page 65, line 18). In Mr. Martin's view, the first step is to establish an acceptable band of reliability which would assist in the preparation of a long term comprehensive maintenance plan which would in turn be used to support both capital and operating expenditures. As he explained, this iterative process is currently underway;

- Hydro's KPI Report provides the Board with historic, current and forecast comparisons of eight reliability criteria and seven other key performance measures listed in Table 4.0 on page 23. Subsequently, in CA 30 NLH (1st Revision), Hydro confirmed its 20% improvement targets for distribution and transmission reliability and compared Hydro's performance for D-SAIFI, D-SAIDI, T-SAIFI, T-SAIDI, T-SARI, DAFOR and Weighted Capability Factor against NP and CEA composites;

- Hydro notes that the existence of penalties and remedies converts the policy recommended by Mr. Bowman from a minimum reliability policy to a mandatory reliability policy (Transcript January 23, 2007 page 193, lines 8-14).

B.3.3 Conclusion

The Board has the responsibility to ensure adequate and reliable supply of electricity and in its regulation of Hydro it has established reporting obligations to assist in its oversight of the utility.

Hydro submits that neither Delaware nor Pennsylvania use reliability standards to curtail utility spending. Instead, the regulators use them as mandatory standards, failure to meet which would expose the utilities to monetary penalties. (For example, Exhibit CDB-2 page 14, section 4.2 and page 25, section 13). Hydro submits that the references made by Mr. Bowman are non-supportive of his proposal.

Hydro has complied with the Board's directives on reliability and other KPI reporting. If, in the Board's opinion, it would improve the Board's oversight of the utility and/or improve the efficiency of the regulatory process, Hydro would be prepared to modify its existing reports to provide any available additional information the Board considers appropriate.

However, Hydro submits that modifications to the existing reporting requirements (established by prior Board Orders) should follow only if the Board is satisfied that such changes provide value sufficient to warrant the associated cost.

B.4 Peer Group Benchmarking

At page 33, line 3 of Mr. Douglas Bowman's pre-filed evidence he recommends that:

> "The Board direct Hydro to initiate reporting of key performance indicators in Exhibit JRH-1 with performance externally benchmarked to a comparable peer group as Hydro agreed to do in the Mediation Report (Appendix H of the Decision and Order of the Board No. P.U. 14 2004)".

At pages 28-29 of his pre-filed testimony, Mr. Bowman suggests not only that Hydro is non-compliant with the terms of the Mediation Report but he also questions Hydro's credibility for failure to comply.

B.4.1 Mediation Agreement and Peer Group Benchmarking

Hydro takes issue with the position expressed by Mr. Bowman on behalf of the CA.

The relevant section of the Mediation Report reads as follows:

> "(aa) – Hydro will propose a peer group of utilities and measures upon which to compare its performance not later than six months following the date of the Board Order in this proceeding. Upon approval thereof, Hydro will collect and report such measures for itself and the peer group annually beginning in 2005".

In compliance with this provision, Hydro prepared and filed a report entitled *Defining a Utility Peer Group for Newfoundland and Labrador Hydro* dated December 2004 (the "Peer Group Report") which was also filed in these proceedings as Attachment 1 to Hydro's response to CA 4 NLH.

The Peer Group Report recommended that:

> 'the most cost effective and administratively feasible choice for the selection of a peer group of utilities for Hydro's external benchmarking purposes is the peer groups already established within the CEA and CEA COPE frameworks. Hydro recommends that CEA be used as the means for Hydro to externally benchmark to its industry counterparts operating elsewhere in Canada".

B.4.2 CEA Policy Paper

Subsequent to the filing of the Peer Group Report, CEA finalized a policy paper in October 2005 for its members on the use of benchmarking data in regulatory settings. This policy paper was provided as Attachment 2 to Hydro's response to CA 4 NLH. At page 3 of 6, section 3.1, it states:

> "Appropriate benchmarking performance information (which is accurate, verifiable and verified and includes the proper consideration, caveats, standardized interpretations and collection methodologies) will be developed by CEA for use in Regulatory settings. Participating

> CEA members commit to work towards providing data that meets these criteria, on a yearly basis, that will be used in the development of an agreed-to set of indices."

Section 3.7 of the CEA policy paper restricted the use of existing CEA metrics by member utilities in regulatory settings during the review and development period. Therefore, Hydro awaited further progress by the CEA in developing appropriate benchmarking performance information for use by its member utilities.

In December 2006, Hydro met with CEA for an update on CEA's progress with their performance data review and on performance measurement services generally. The CEA informed Hydro that it had modified its position on the use by its member utilities for reliability-type composite KPIs in public or regulatory settings. It should be noted that reliability KPIs are long and well established products that CEA provides to its members and will likely continue in the future. In response to ongoing requirements by its members, CEA has decided to be less restrictive regarding the use of this data in regulatory settings during the performance data review period.

On December 21, 2006, NP filed its *Peer Group Performance Measures Report* with the Board and referred to CEA distribution reliability composite KPIs. Hydro then confirmed again with CEA that the distribution reliability composite KPIs can be used for its own requirements, as well as the CEA composites covering generation and transmission reliability. Hydro notes that NP is able to report additional CEA composites because it is a direct member of CEA COPE and as such will have access to some additional composites during the continuing review period.

In light of the clarification of CEA policy, Hydro filed CA 30 NLH (1st Revision). Hydro now understands that, on a go-forward basis, it will be able to include in its annual KPI report and other relevant reports to the Board, available CEA industry composite reliability data. However, Hydro also understands that CEA's approach to use of KPIs of an economic or financial nature is not resolved to the same degree and that progress on this aspect of performance measurement will be ongoing for some time. As a result, Hydro's original recommendation to obtain all peer group information from a central source (CEA) is no longer possible. Exploration of other alternatives for KPIs of an economic or financial nature is now required.

As indicated in the testimony of Mr. Jim R. Haynes, VP Regulated Operations, Hydro will now consider other options for reliable information (e.g. the FERC database). However, he confirmed that many sources restrict the use of their data to internal purposes/members and the other challenge is the determination of a peer group that is truly comparable to Hydro's unique circumstances (Transcript January 23, 2007 page 27, line 21 to page 29, line 20).

B.4.3 Hydro's Unique Circumstances

Mr. Douglas Bowman candidly acknowledged the unique circumstances under which Hydro operates and supplies electricity. When asked, he was not able to identify another utility which was truly comparable and confirmed that Hydro "probably has a larger number of isolated systems than most any place else in the world" (Transcript January 23, 2007 page 185, line 11 to page 186, line 15).

In NLH 18 CA, Hydro had asked Mr. Bowman to provide a detailed listing of the numerous other sources for peer group information (besides the CEA) that could provide reliable and consistent performance data. His reply indicated that he had not compiled such a list and made no commitment to do so. In cross examination it was suggested to Mr. Bowman that his answer was not helpful to the Board. He was asked if he was prepared to give an undertaking to assist Hydro in locating such a peer group and ultimately he agreed that he would (Transcript January 23, 2007 page 186, line 25 to page 189, line 14).

B.4.4 Hydro's Position on Peer Group Benchmarking

Hydro has confirmed its ability to access and report in regulatory proceedings, industry composite reliability KPIs for generation, transmission and distribution. Hydro will report all applicable and available industry reliability composite KPIs in its annual KPI reports to the Board commencing with the report for 2006.

While Hydro will remain subject to future changes or modifications to CEA policy, it is confident that reliability performance data will be a key deliverable to CEA members in the future.

Hydro will also utilize applicable KPI data from the NP annual KPI report to the Board and will present such data along with Hydro's own performance (such as for Distribution Operating, Maintenance and Administration expenses per circuit kilometer) in its annual reports to the Board commencing with the report for 2006.

With respect to financial KPIs at the generation and transmission functional level, Hydro will accept whatever assistance may be provided by Mr. Douglas Bowman relative to his undertaking and Hydro will also review the FERC utility database and inform the Board by September 30, 2007 whether it represents a potential source of reliable data and if so, what use can be made of this US data.

Hydro believes that, going forward, these efforts will largely address the Board's requirements, in Order No. P.U. 14 (2004), for external peer group benchmarking.

Relative to Mr. Bowman's criticism of Hydro's failure to provide better peer group benchmarking data, Hydro disagrees and states that it was compliant with both Order No. P.U. 14 (2004) and the Mediation Report which was attached as Appendix H thereto. For reasons beyond its control, there have been delays in reporting reliability composites and a change in policy that now precludes using CEA as a source for non-reliability composites at least in the near future.

B.4.5 Tracking Additional KPIs

At page 32, line 22 of his pre-filed testimony, Mr. Douglas Bowman suggested that the Board should direct Hydro to initiate tracking, reporting and benchmarking additional KPIs in the categories of Customer Service and Costs of Improved Reliability.

These suggestions were addressed respectively, in the oral testimony of Mr. Rob Henderson, Manager, System Operations and Customer Service and Mr. Jim Haynes, VP Regulated Operations (Transcript January 23, 2007 page 15, line 1 to page 24, line 7).

B.4.6 Evidence of Messrs. Haynes and Henderson

While Hydro recognizes the benefit of collecting performance indicators for customer services, before it would embark on collecting data of the type suggested by Mr. Bowman (e.g. percent of customer calls answered within 30 seconds), Hydro believes it is appropriate to assess the costs and potential benefit associated with such an exercise.

As Mr. Henderson explained, Hydro relies upon its customer satisfaction index to identify those areas where customers are less satisfied with corporate performance (Exhibit JRH-1 at page 20 and Attachment 1 to CA 1 NLH, page 18). Relying on these documents, in evidence before the Board, Mr. Henderson suggested that Hydro's customers place primary importance on safety, the restoration of electricity promptly and reliability of service (Transcript January 23, 2007 page 17, line 1 to page 18, line 7).

During his oral testimony, Mr. Henderson explained the performance gap chart (CA 1 NLH, Attachment 1, page 25) which indicates the gaps in performance between customers' expectation and customers' perception of Hydro's performance. While supplying electricity at reasonable cost had the greatest gap, it was followed closely by ‘electricity restored promptly’. In comparison, the gap chart suggested that ‘timely response to customer concerns’ (a performance indicator similar to those Mr. Bowman suggest Hydro track) was ranked tenth.

Hydro proposed to concentrate and focus its efforts upon the measures identified by its customers as being of greatest importance to them, or alternatively, had the most serious ‘gap’ in service expectations. Hydro submits that its position in this regard has a sound basis in the Customer Service Index and is reasonable. With respect to the performance indicators in the area of costs of improved reliability as reflected in CA 3 NLH, Mr. Haynes echoed the testimony of Mr. Henderson relative to both the desirability of having such information and also the need to balance the cost of obtaining the information (Transcript January 23, 2007 page 19, line 16 to page 20, line 4).

Mr. Haynes explained that Hydro does not, and could not reasonably be expected to track reliability improvements on an asset by asset basis (Transcript January 23, 2007 page 20, line 18 to page 21, line 25). Instead, Hydro considers a number of different factors in determining system maintenance and capital improvements. Mr. Haynes made the following points in this regard:

- While reliability may not be the justification for a particular operating or capital expense, reliability enhancement may nevertheless result from such an expenditure (Transcript January 23, 2007 page 21, lines 5-13).

- He explained by means of example (the Nain diesel plant) that reliability concerns can often be addressed by either operating or capital expenditures and that solid analysis lies behind the decision made in the approach selected (Transcript January 23, 2007 page 22, line 12 to page 24, line 7).

- Alternatively, an expense may be justified on the basis of improved reliability but the enhancement may not be apparent for a number of years (Transcript January 23, 2007 page 22, lines 1-11).

B.4.7 Hydro's Position

Hydro does not agree with Mr. Bowman's suggestion that the Board should direct Hydro to initiate tracking, reporting and benchmarking of additional KPIs in the areas of Customer Satisfaction and the Costs of Reliability Improvements without first considering the benefits such indicators will provide and the costs to implement.

B.5 Conservation

Another issue left unresolved by the terms of the Agreements is the subject of Conservation.

Hydro notes that there was no firm proposal presented on this topic in the pre-filed evidence supplied on behalf of either of the Intervenors. Therefore, Hydro's written argument on this issue is given without a full appreciation of the positions of the parties on this topic.

Hydro accepts that conservation plays a role in the Board's obligation to ensure the adequate and reliable supply of electricity to consumers in the Province. This was addressed in general in the pre-filed testimony of Mr. Ed Martin, President and CEO and specifics were provided in the pre-filed evidence of Mr. Jim R. Haynes, VP Regulated Operations, adopted as the sworn testimony of Mr. Haynes and Mr. Rob Henderson on January 23, 2007.

Specifically, at pages 18-19 of the Regulated Activities Evidence, it states:

> "Hydro intends to work more closely with partners including NP, the provincial government, and other stakeholders to develop a coordinated approach for conservation education and initiatives for the Province.
>
> To support this initiative, Hydro will have an employee whose sole focus is energy conservation. The Energy Conservation Program Manager will develop programs, in consultation with partners, to bring about change in energy consumption. To start and steward progress in this area, Hydro has included $500,000 in its 2007 operation and maintenance expense budget, in addition to $100,000 for the Hydrowise program for energy conservation."

This was elaborated upon in the testimony of Mr. Rob Henderson in answer to questions from the Chair and Vice-Chair (Transcript January 23, 2007 page 138, line 13 to page 145, line 9; and page 153, line 24 to page 155, line 10).

Hydro has hired an Energy Conservation Program Manager who is tasked with assembling the partners involved in energy conservation, implementing outreach and education initiatives in the short-term and developing a long term conservation strategy.

As the first step in the development of the long term strategy, in conjunction and on a cost-shared basis with NP, Hydro has issued a Request for Proposals ("RFP") for a Conservation and Demand Management ("CDM") Potential Study.

The primary objective of the RFP is to select a consulting firm that will provide expert analysis and advice to Hydro and NP in all areas of conservation and demand management, including cataloguing CDM technologies, identification of applicable technologies, development of program concepts as well as market and economic analysis for the residential, commercial and industrial sectors.

The emphasis will be on best practices from other jurisdictions so that Hydro and NP are provided with an accurate picture of the potential achievements - for example, kilowatt hours saved (Transcript January 23, 2007 page 153, line 24 to page 155, line 10).

While this is ongoing, Hydro also proposes to strengthen recognition and credibility among electricity users around the HydroWise brand and to conduct education and outreach.

It is anticipated that the CDM Potential Study will be completed by mid-year 2007 and the five-year strategic plan will be the focus of the third and fourth quarters.

Once the five-year plan is in development, pilot and small scale initiatives will occur and will ensure the continuation of momentum on CDM in the Province. Hydro anticipates that these will build experience, strengthen partnerships and improve both communication and education.

Hydro submits that the costs associated with this initiative are warranted and consistent with the supply of least cost energy.

B.6 Oil Price Hedging

The last outstanding unresolved issue identified in the parties' agreements is the topic of oil price hedging.

At each of Hydro's 2001 and 2003 GRAs, oil hedging was the subject of evidence and testimony. The Board concluded in Order No. P.U. 14 (2004), page 57, that all things considered, the RSP alone has the greatest impact on fuel price variances and there were at that time no significant benefits from further exploring an oil hedging program. Hydro submits that no evidence has been presented at this GRA to alter that conclusion.

B.6.1 The Purpose of an Oil Price Hedging Program

For utilities, Hydro understands that hedging programs are normally considered in order to reduce a firm's exposure to unfavorable price movements on input costs that cannot be passed on to customers. Thus an oil hedge program can reduce shareholder risk and contribute to a utility's financial stability.

Hydro notes that, as a regulated utility, the Board has approved an RSP which:

- mitigates the financial impact to Hydro from unfavorable fluctuations in the price of oil, and;
- provides both rate stability and predictability to ratepayers.

Given the existence of the RSP, the notion that Hydro should engage in oil hedging usually rests on the tacit assumption that an oil hedge program will effectively 'beat the market' and result in lower average fuel costs than would otherwise be the case. Such a program is considered to be speculative in nature.

Relative to these principles, in cross examination Mr. Martin outlined his experience with oil hedging programs in particular (Transcript January 22, 2007 page 91, line 19 to page 92, line 18).

B.6.2 The Expertise Required

A speculative hedging program requires a corporation to take positions on future supply and demand conditions of a commodity. In Hydro's case, the success of a program would require the utility to correctly speculate on the direction and magnitude of future prices for oil, a task which would be extremely difficult without some informational advantage.

As Mr. Martin explained further in answer to the CA's questions, even the PIRA Energy Group, Hydro's oil market advisory firm, with its extensive staff expertise and resources dedicated to the task of oil market analysis and price forecasting, publishes high and low forecasts suggesting that even such experts do not have a definitive projection for where oil prices are going. As he indicated, oil market expertise is not a core competency of Hydro and should not be expected of the utility (Transcript January 22, 2007 page 91, line 19 to page 93, line 14).

Hydro does not believe that ratepayers and stakeholders would accept the potential risks associated with being on the losing end of an active or speculative hedging program. Hydro does not accept that such an oil hedge program is appropriate or necessarily consistent with the utility's obligation to supply safe and reliable power at least cost (Transcript January 22, 2007 page 93, line 15 to page 94, line 14).

B.6.3 Hydro's Position

Hydro does not support the establishment of a speculative oil price hedging program. The existing RSP appropriately mitigates the financial impacts of volatile fuel oil prices for regulated Hydro while at the same time providing reasonable rate stability and predictability. Hydro believes that the appropriate strategy to manage the exposure to the volatility of international oil markets is to minimize the absolute fuel requirements required for the production of electricity on the Island.

As Mr. Martin explained, it is anticipated that some direction in this regard will be provided in the Province's Energy Plan (Transcript January 22, 2007 page 94, line 15 to page 96, line 23).

C. OTHER ISSUES

C.1 Rules and Regulations for Service

In its Revised Application, Hydro proposed two changes to the Rules and Regulations for Rural Customers. Hydro requests that the Board approve the following changes to:

1. Delete the rate and all references to the Burgeo school and library; and

2. Amend Sections 16 and 17 so that all rates paid by Rural Isolated Customers, excluding Government Departments, be adjusted between Hydro GRAs to reflect changes made to NP's rates, including changes arising from MTA and RSA adjustments.

In Hydro's August 3, 2006 pre-filed testimony of Mr. Glenn Mitchell, Rates Evidence, page 7, lines 18-21, it was stated that references to the Burgeo school and library may be removed because the rate is no longer active as the premises to which the rate previously applied have a new owner. Upon further consideration of the circumstances and of the Order in Council that was filed as Information # 1 in Hydro's 2003 GRA, the preferential rate prescribed by the Order in Council applies to the newly constructed school that became a customer of Hydro very shortly after the issuance of the Order in Council. Hydro undertakes to rectify this matter by reinstating this rate and by ensuring that the billing is adjusted accordingly. The request for changes to the Rules and Regulations regarding the Burgeo school and library is therefore withdrawn.

Rate adjustment for certain Isolated Rural Customers (excluding Government Departments) was agreed upon by the parties and included in the November 23, 2006 Agreement on COS, Rate Design and Other Issues. The purpose of this change in policy is to mitigate the potential for rate shock between GRAs for these customers, by providing an RSP, or fuel-related, annual price change for these Isolated System Customers.

Hydro submits that the changes to the Rules and Regulations attached as Schedule A, reflecting item (2) above should be approved by the Board.

C.2 Rate Stabilization Plan Rules

On December 20, 2006, Hydro filed an Application containing all of the amendments required to the Rate Stabilization Plan to affect the issues agreed upon in the parties' agreements and the Revised Application.

The specific changes are contained within that Application. In Order No. P.U. 46 (2006), the Board ordered, on an interim basis, certain changes to the RSP which were intertwined with the implementation, on an interim basis, of rates contained in Hydro's Revised Application. Hydro submits that the changes to the RSP Rules proposed in the December 20, 2006 Application should be approved by the Board.

C.3 Final Cost of Service

Hydro proposes that the COS filed in its Revised Application be accepted as the Test Year final COS unless there is clear and specific direction received from the Board in its final order to make a change.

C.4 Costs

Section 90 (1) of the *Public Utilities Act* states that the costs of and incidental to a proceeding before the Board are in the discretion of the Board. Clearly, the Board has authority to award costs in appropriate circumstances and it has done so in the past.

Section 117 of the *Public Utilities Act* states that the costs of the Consumer Advocate are to be borne by the Board, which in turn passes these costs on to Hydro as it does its own costs. Hydro is proposing to amortize its hearing costs including the cost of the Board, the costs of the Consumer Advocate and any other costs awarded by the Board, over a three-year period commencing in 2007, an estimate of which has been included in the 2007 Revenue Requirement included in the Revised Application.

C.5 Depreciation Study

In Hydro's August 3, 2006 Application, Hydro endorsed the recommendations of the Gannett Fleming Inc. Depreciation Study, filed by Hydro on December 22, 2005 and suggested that the continued used of sinking fund methodology will result in a burden on future ratepayers in the Province. Hydro did not incorporate the report recommendations into this GRA, but requested approval in principle of the change in depreciation rates and methodology as detailed in the report.

In Order No. P.U. 28 (2006) the Board ordered that the request for approval, in principle, will be addressed after the conclusion of the Application in a process to be established by the Board beginning in 2007. Hydro will await further direction from the Board in this matter, but requests an opportunity be given to engage in dialogue with the Board and the parties before any such process commences.

C.6 Labrador West Presentations

On February 5, 2007, the Board received by teleconference presentations from the Towns of Labrador City and Wabush and the Hyron Corporation. The essence of both presentations was that prior decisions of the Board regarding the determination that there is a single Labrador Interconnected system for COS and rate design purposes, and the level of the Rural Deficit to be paid by Labrador Interconnected customers were, and are, incorrect and do not reflect the historical development of the region. Moreover, the Board was provided with information and evidence to the effect that further increases in rates may cause hardship to the people in Labrador West.

It is Hydro's position that the theory and basis for setting uniform rates for the Labrador Interconnected customers, and for applying the CFB revenue credit to the deficit, are not contrary to regulatory principle. Hydro believes that the more gradual phasing in of rates that has been proposed in the Revised Application and in the Labrador Interconnected Agreement provide a means by which these rate changes will be easier to absorb by the Labrador Interconnected customers.

The rates proposed to be charged these customers have been tested in the negotiation process. Hydro submits that the costs set out in the 2007 COS study are reasonable, prudent and necessary to provide to these customers service that is "reasonably safe and adequate and just and reasonable" as is required by Section 37 of the *Public Utilities Act*.

C.7 Rates Schedules

As a matter of convenience, Hydro has attached, as Schedule A, a complete schedule of rates which Hydro is requesting the Board approve as final as a result of this GRA.

SCHEDULE A

Availability:

This rate is applicable to service to Newfoundland Power (NP).

Definitions:

"Billing Demand"

In the Months of January through March, billing demand shall be the greater of:

(a) the highest Native Load less the Generation Credit, beginning in the previous December and ending in the current Month; and
(b) the Minimum Billing Demand.

In the Months of April through December, billing demand shall be the greater of:

(a) the Weather-Adjusted Native Load less the Generation Credit, plus the Weather Adjustment True-up; and
(b) the Minimum Billing Demand.

"Generation Credit" refers to NP's net generation capacity less allowance for system reserve, as follows:

	kW
Hydraulic Generation Credit	80,104
Thermal Generation Credit	37,826
Total Generation Credit	117,930

In order to continue to avail of the Generation Credit, NP must demonstrate the capability to operate its generation to the level of the Generation Credit. This will be verified in a test by operating the generation at a minimum of this level for a period of one hour as measured by the generation demand metering used to determine the Native Load. The test will be carried out at a mutually agreed time between December 1 and March 31 each year. If the level is not sustained, Newfoundland Power will be provided an opportunity to repeat the test at another mutually agreed time during the same December 1 to March 31 period. If the level is not sustained in the second test, the Generation Credit will be reduced in calculating the associated billing demands for January to December to the highest level that could be sustained.

"Maximum Native Load" means the maximum Native Load of NP in the four-Month period beginning in December of the preceding year and ending in March of the current year.

"Minimum Billing Demand" means ninety-nine percent (99%) of:

NP's test year Native Load less the Generation Credit.

"Month" means for billing purposes, the period commencing at 12:01 hours on the last day of the previous month and ending at 12:00 hours on the last day of the month for which the bill applies.

"Native Load" is the sum of:

(a) the amount of electrical power, delivered at any time and measured in kilowatts, supplied by Hydro to NP, averaged over each consecutive period of fifteen minutes duration, commencing on the hour and ending each fifteen minute period thereafter; and

(b) the total generation by NP averaged over the same fifteen-minute periods.

"Weather-Adjusted Native Load" means the Maximum Native Load adjusted to normal weather conditions, calculated as:

Maximum Native Load
plus (Weather Adjustment, rounded to 3 decimal places, x 1000)

Weather Adjustment is further described and defined in the Weather Adjustment section.

"Weather Adjustment True-up" means one-ninth of the difference between:

(a) the greater of:
- the Weather Adjusted Native Load less the Generation Credit, times three; and
- the Minimum Billing Demand, times three; and

(b) the sum of the actual billed demands in the Months of January, February and March of the current year.

Monthly Rates:

Billing Demand Charge:
Billing Demand, as set out in the Definitions section, shall be charged at the following rate:

$4.00 per kW of billing demand

Energy Charge:
First 250,000,000 kilowatt-hours* .... @ 3.246 ¢ per kWh
All excess kilowatt-hours* .... @ 8.805 ¢ per kWh

Firming-up Charge:
Secondary energy supplied by
Corner Brook Pulp and Paper Limited* .... @ 0.841 ¢ per kWh

RSP Adjustment:
All kilowatt-hours .... @ 0.425 ¢ per kWh

***Subject to RSP Adjustment:**

RSP Adjustment refers to all applicable adjustments arising from the operation of Hydro's Rate Stabilization Plan, which levelizes variations in hydraulic production, fuel cost, load and rural rates.

Adjustment for Losses:

If the metering point is on the load side of the transformer, either owned by the customer or specifically assigned to the customer, an adjustment for losses as determined in consultation with the customer prior to January 31 of each year, shall be applied to metered demand and energy.

Adjustment for Station Services and Step-Up Transformer Losses:

If the metering point is not on the generator output terminals of NP's generators, an adjustment for Newfoundland Power's power consumption between the generator output terminals and the metering point as determined in consultation with the customer prior to the implementation of the metering, shall be applied to the metered demand.

Weather Adjustment: This section outlines procedures and calculations related to the weather adjustment applied to NP's Maximum Native Load.

(a) Weather adjustment shall be undertaken for NP's actual Maximum Native Load.

(b) Weather adjustment shall be derived from Hydro's general NP native peak demand forecasting model.

(c) By September 30th of each year, Hydro shall provide NP with updated weather adjustment coefficient incorporating the latest year of actuals.

(d) The underlying temperature and wind speed data utilized to derive weather adjustment shall be sourced to Environment Canada's weather station data for the St. John's, Gander, and Stephenville airports. NP's regional customer counts shall be used to weight regional weather data. Hydro shall consult with NP to resolve any circumstances arising the availability of, or revisions to, Environment Canada's weather data and/or wind chill formulation.

(e) The primary definition for the temperature weather variable is the average temperature for the peak demand hour and the preceding 19 hours. The primary definition for the wind weather data is the average wind speed for the peak demand hour and the preceding seven hours. Hydro will consult with NP should data anomalies indicate a departure from the primary definition on underlying weather data.

(f) Subject to the availability of Environment Canada weather data, Hydro shall prepare a preliminary estimate of the Weather-Adjusted Native Load by March 15th of each year, and a final calculation of Weather-Adjusted Native Load by April 5th of each year.

General:

This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.

With respect to all matters where the customer and Hydro consult on resolution but are unable to reach mutual agreement, the billing will be based on Hydro's best estimate.

Availability:

Any person purchasing power, other than a retailer, supplied from the Interconnected Island bulk transmission grid at voltages of 66 kV or greater on the primary side of any transformation equipment directly supplying the person and who has entered into a contract with Hydro for the purchase of firm power and energy.

Rate:

Demand Charge:

The rate for Firm Power, as defined and set out in the Industrial Service Agreements, shall be $6.68 per month per kilowatt of billing demand.

Firm Energy Charge:

Base Rate* ....@ 3.676 ¢ per kWh

RSP Adjustment

Historic Plan ....@ 1.215 ¢ per kWh**
Current Plan .... @ (2.000) ¢ per kWh
Fuel Rider ....@ 0.000 ¢ per kWh

Total RSP Adjustment...@ (.785) ¢ per kWh

Energy Rate..@ 2.891 ¢ per kWh
**Aur Resources Inc. Energy rate excluding Historic Plan ....@ 1.676 ¢ per kWh

***Subject to RSP Adjustment:**

RSP Adjustment refers to all applicable adjustments arising from the operation of Hydro's Rate Stabilization Plan, which levelizes variations in hydraulic production, fuel cost, load and rural rates.

** Aur Resources Inc. is not subject to Historic Plan component of the RSP Adjustment, in accordance with Order No. P.U. 1 (2007).

Specifically Assigned Charges:

The table below contains the additional specifically assigned charges for customer plant in service that is specifically assigned to the Customer.

	Annual Amount
Abitibi-Consolidated (Grand Falls)	$ 1,244
Abitibi-Consolidated (Stephenville)	$ 104,647
Corner Brook Pulp and Paper Limited	$ 347,167
North Atlantic Refining Limited	$ 150,976
Aur Resources Inc.	$ 186,169

Adjustment for Losses:

If the metering point is on the load side of the transformer, either owned by the customer or specifically assigned to the customer, an adjustment for losses as determined in consultation with the customer prior to January 31 of each year, shall be applied.

General:

Details regarding the conditions of Service are outlined in the Industrial Service Agreements. **This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

Availability:

Any person purchasing power, other than a retailer, supplied from the Interconnected Island bulk transmission grid at voltages of 66 kV or greater on the primary side of any transformation equipment directly supplying the person and who has entered into a contract with Hydro for the purchase of firm power and energy.

Rate:

Non-Firm Energy Charge (¢ per kWh):

Non-Firm Energy is deemed to be supplied from thermal sources. The following formula shall apply to calculate the Non-Firm Energy rate:

$$\{(A \div B) \times (1 + C) \times (1 \div (1 - D))\} \times 100$$

A = the monthly average cost of fuel per barrel for the energy source in the current month or, in the month the source was last used

B = the conversion factor for the source used (kWh/bbl)

C = the administrative and variable operating and maintenance charge (10%)

D = the average system losses on the Island Interconnected grid for the last five years ending in 2005 (2.68%).

The energy sources and associated conversion factors are:

1. Holyrood, using No. 6 fuel with a conversion factor of 630 kWh/bbl
2. Gas turbines using No. 2 fuel with a conversion factor of 475 kWh/bbl
3. Diesels using No. 2 fuel with a conversion factor of 556 kWh/bbl.

Adjustment for Losses:

If the metering point is on the load side of the transformer, either owned by the customer or specifically assigned to the customer, an adjustment for losses as determined in consultation with the customer prior to January 31 of each year, shall be applied.

General:

Details regarding the conditions of Service are outlined in the Industrial Service Agreements. **This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

Availability:

Any person purchasing power, other than a retailer, supplied from the Interconnected Island bulk transmission grid at voltages of 66 kV or greater on the primary side of any transformation equipment directly supplying the person and who has entered into a contract with Hydro for the purchase of firm power and energy and whose Industrial Service Agreement so provides.

Rate:

Energy Charge:

All kWh (Net of losses)* ....@ 0.384 ¢ per kWh

* For the purpose of this Rate, losses shall be 2.68%, the average system losses on the Island Interconnected Grid for the last five years ending in 2005.

General:

Details regarding the conditions of Service are outlined in the Industrial Service Agreements. **This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

The Rate Stabilization Plan of Newfoundland and Labrador Hydro (Hydro) is established for Hydro's Utility customer, Newfoundland Power, and Island Industrial customers to smooth rate impacts for variations between actual results and Test Year Cost of Service estimates for:

- hydraulic production;
- No. 6 fuel cost used at Hydro's Holyrood generating station;
- customer load (Utility and Island Industrial); and
- rural rates.

The formulae used to calculate the Plan's activity are outlined below. Positive values denote amounts owing from customers to Hydro whereas negative values denote amounts owing from Hydro to customers.

References to approved Test Year weighted average cost of capital mean the weighted average cost of capital in Hydro's Test Year Cost of Service study, or as adjusted by the Automatic Adjustment Mechanism.

Section A: Hydraulic Production Variation

1. **Activity:**
   Actual monthly production is compared with the Test Year Cost of Service Study in accordance with the following formula:

$$\{(A – B) \div C\} \times D$$

Where:

A = Test Year Cost of Service Net Hydraulic Production (kWh)
B = Actual Net Hydraulic Production (kWh)
C = Test Year Cost of Service Holyrood Net Conversion Factor (kWh /bbl.)
D = Monthly Test Year Cost of Service No. 6 Fuel Cost ($Can /bbl.)

2. **Financing:**
   Each month, financing charges, using Hydro's approved Test Year weighted average cost of capital, will be calculated on the balance.

3. **Hydraulic Variation Customer Assignment:**[1]
   Customer assignment of hydraulic variations will be performed annually as follows:

$$(E \times 25\%) + F$$

Where:

E = Hydraulic Variation Account Balance as of December 31, excluding financing charges
F = Financing charges accumulated to December 31

[1] Subject to Section F

The total amount of the Hydraulic Customer Assignment shall be removed from the Hydraulic Variation Account.

4. Customer Allocation:
The annual customer assignment will be allocated among the Island Interconnected customer groups of (1) Newfoundland Power; (2) Island Industrial Firm; and (3) Rural Island Interconnected. The allocation will be based on percentages derived from 12 months-to-date kWh for: Utility Firm and Firmed-Up Secondary invoiced energy, Industrial Firm invoiced energy, and Rural Island Interconnected bulk transmission energy.

The portion of the hydraulic customer assignment which is initially allocated to Rural Island Interconnected will be re-allocated between Newfoundland Power and regulated Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the approved Test Year Cost of Service Study.

The Newfoundland Power and Island Industrial customer allocations shall be included with the Newfoundland Power and Island Industrial RSP balances respectively as of December 31 each year. [2] The Labrador Interconnected Hydraulic customer allocation shall be written off to Hydro's net income (loss).

Section B: Fuel Cost Variation, Load Variation and Rural Rate Alteration

1. **Activity**

1.1 Fuel Cost Variations
This is based on the consumption of No. 6 Fuel at the Holyrood Generating Station:

$$(G - D) \times H$$

Where:

D = Monthly Test Year Cost of Service No. 6 Fuel Cost ($Can /bbl.)
G = Monthly Actual Average No. 6 Fuel Cost ($Can /bbl.)
H = Monthly Actual Quantity of No. 6 Fuel consumed less No. 6 fuel consumed for non-firm sales (bbl.)

1.2 Load Variations
Firm: Firm load variation is comprised of fuel and revenue components. The load variation is determined by calculating the difference between actual monthly sales and the Test Year Cost of service Study sales, and the resulting variance in No. 6 fuel costs and sales revenues. It is calculated separately for Newfoundland Power firm sales and Industrial firm sales, in accordance with the following formula:

$$(I - J) \times \{(D \div C) - K\}$$

Where:

[2] Subject to Section F.

C = Test Year Cost of Service Holyrood Net Conversion Factor (kWh /bbl.)
D = Monthly Test Year Cost of Service No. 6 Fuel Cost ($Can /bbl.)
I = Actual Sales, by customer class (kWh)
J = Test Year Cost of Service Sales, by customer class (kWh)
K = Firm energy rate, by customer class

Secondary: Secondary load variation is based on the revenue variation for Utility Firmed-Up Secondary energy sales compared with the Test Year Cost of Service Study, in accordance with the following formula:

$$(J - I) \times L$$

Where:
I = Actual Sales (kWh)
J = Test Year Cost of Service Sales (kWh)
L = Secondary Energy Firming Up Charge

1.3 Rural Rate Alteration

(a) Newfoundland Power Rate Change Impacts:
This component is calculated for Hydro's rural customers whose rates are directly or indirectly impacted by Newfoundland Power's rate changes, with the following formula:

$$(M - N) \times O$$

Where:

M = Cost of Service rate [3]
N = Existing rate
O = Actual Units (kWh, bills, billing demand)

(b) Rural Labrador Interconnected Automatic Rate Adjustments:
This component reflects the impact of the automatic rate adjustments for Hydro's rural customers on the Labrador Interconnected system, which arise from the phase-in of the application of the credit from secondary energy sales to CFB Goose Bay to the rural deficit.

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[3]

- Hydro's schedule of rates for its rural customers not affected by the December 6th, 2006 Government directive.
- For customers affected by the December 6th, 2006 Government directive, the Cost of Service rate equals the phased-in 2007 Forecast Cost of Service Rates for diesel rate classes 1.2D, 2.1D and 2.2D.
- No Rural Rate Alternation will arise from the phase-in of 2007 Forecast Cost of Service rates for the customers affected by the December 6th, 2006 Government directive.
- For the purpose of this section, Test Year Cost of Service Study refers to a Test Year or a Test Year adjusted by the Automatic Adjustment Mechanism.

Monthly adjustments will be subject to revision when a new Test Year Cost of Service is approved by the Public Utilities Board for Hydro. The amount of the automatic rate adjustment is calculated as follows:

$$P = (Q - R) \div 12$$

Where:

P = the monthly amount of the automatic rate adjustment

Q = the CFB Revenue Credit applied to the rural deficit in Hydro's Final 2007 Test Year Cost of Service

R = the CFB Revenue Credit applied to the rural deficit from 2007 to 2011, included in existing rates and outlined in the table below:

	Q	R	Q – R	P
2007	$ 3,380,796	$ 2,270,081	$ 1,110,715	$ 92,560
2008	$ 3,380,796	$2,991,599	389,197	32,433
2009	$ 3,380,796	$3,449,983	(69,187)	(5,766)
2010	$ 3,380,796	$3,954,957	(574,161)	(47,847)
2011[4]	$ 3,380,796	$4,560,334	(1,179,538)	(98,295)

2. Monthly Customer Allocation: Load and Fuel Activity

Each month, the load variation will be assigned to the customer class for which the load variation occurred.

Each month, the year-to-date total for fuel price variation will be allocated among the Island Interconnected customer groups of (1) Newfoundland Power; (2) Island Industrial Firm; and (3) Rural Island Interconnected. The allocation will be based on percentages derived from 12 months-to-date kWh for: Utility Firm and Firmed-Up Secondary invoiced energy, Industrial Firm invoiced energy, and Rural Island Interconnected bulk transmission energy.

The year-to-date portion of the fuel price variation which is initially allocated to Rural Island Interconnected will be re-allocated between Newfoundland Power and regulated Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the approved Test Year Cost of Service Study.

The current month's activity for Newfoundland Power, Island Industrials and regulated Labrador Interconnected customers will be calculated by subtracting year-to-date activity for the prior month from year-to-date activity for the current month. The current month's activity allocated to regulated Labrador Interconnected customers will be removed from the Plan and written off to Hydro's net income (loss).

[4] Monthly adjustments will continue after 2011 until a new Test Year Cost of Service is approved by the Public Utilities Board.

3. Monthly Customer Allocation: Rural Rate Alteration Activity
Each month, the rural rate alteration will be allocated between Newfoundland Power and regulated Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the approved Test Year Cost of Service Study. The portion allocated to regulated Labrador Interconnected will be removed from the Plan and written off to Hydro's net income (loss).

4. Plan Balances
Separate plan balances for Newfoundland Power and for the Island Industrial customer class will be maintained. Financing charges on the plan balances will be calculated monthly using Hydro's approved Test Year weighted average cost of capital.

Section C: Fuel Price Projection

A fuel price projection will be calculated to anticipate forecast fuel price changes and to determine fuel riders for the rate adjustments. For industrial customers, this will occur in October each year, for inclusion with the RSP adjustment effective January 1. For Newfoundland Power, this will occur in April each year, for inclusion with the RSP adjustment effective July 1.

1. **Industrial Fuel Price Projection:**
In October each year, a fuel price projection for the following January to December shall be made to estimate a change from Test Year No. 6 Fuel Cost. Hydro's projection shall be based on the change from the average Test Year No. 6 fuel purchase price, in Canadian dollars per barrel, determined from the forecast oil prices provided by the PIRA Energy Group, and the current US exchange rate. The calculation for the projection is:

$$[\{(S - T) \times U\} - V] \times W$$

Where:

S = the September month-end PIRA Energy Group average monthly forecast for No. 6 fuel prices at New York Harbour for the following January to December

T = Hydro's average Test Year contract discount (US $/bbl)

U = the monthly average of the $Cdn / $US Bank of Canada Noon Exchange Rate for the month of September

V = average Test Year Cost of Service purchase price for No. 6 Fuel ($Can /bbl.)

W = the number of barrels of No. 6 fuel forecast to be consumed at the Holyrood Generating Station for the Test Year.

The industrial customer allocation of the forecast fuel price change will be based on 12 months-to-date kWh as of the end of September and is the ratio of Industrial Firm invoiced energy to the total of: Utility Firm and Firmed-Up Secondary invoiced energy, Industrial Firm invoiced energy, and Rural Island Interconnected bulk transmission energy.

The amount of the forecast fuel price change, in Canadian dollars, and the details of an estimate of the fuel rider based on 12 months-to-date kWh sales to the end of September will be reported to industrial customers, Newfoundland Power, and the Public Utilities Board, by the 10th working day of October.

2. **Newfoundland Power Fuel Price Projection:**
In April each year, a fuel price projection for the following July to June shall be made to estimate a change from Test Year No. 6 Fuel Cost. Hydro's projection shall be based on the change from the average Test Year No. 6 fuel purchase price, in Canadian dollars per barrel, determined from the forecast oil prices provided by the PIRA Energy Group, and the current US exchange rate. The calculation for the projection is:

$$[\{(X - T) \times Y\} - V] \times W$$

Where:

T = Hydro's average Test Year contract discount (US $/bbl)

V = average Test Year Cost of Service purchase price for No. 6 Fuel ($Can /bbl.)

W = the number of barrels of No. 6 fuel forecast to be consumed at the Holyrood Generating Station for the Test Year.

X = the average of the March month-end PIRA Energy Group average monthly forecast for No. 6 fuel prices at New York Harbour for the following July to December, and the most recent long-term PIRA Energy Group average annual forecast for No. 6 fuel prices at New York Harbour for the following January to June.

Y = the monthly average of the $Cdn / $US Bank of Canada Noon Exchange Rate for the month of March.

The Newfoundland Power customer allocation of the forecast fuel price change will be based on 12 months-to-date kWh as of the end of March and is the ratio of Newfoundland Power Firm and Firmed-Up Secondary invoiced energy to the total of: Utility Firm and Firmed-Up Secondary invoiced energy, Industrial Firm invoiced energy, and Rural Island Interconnected bulk transmission energy.

The amount of the forecast fuel price change, in Canadian dollars, and the details of the resulting fuel rider applied to the adjustment rate will be reported to Newfoundland Power, industrial customers, and the Public Utilities Board, by the 10th working day of April.

Section D: Adjustment

1. Newfoundland Power
As of March 31 each year, Newfoundland Power's adjustment rate for the 12-month period commencing the following July 1 is determined as the rate per kWh which is projected to collect:

Newfoundland Power March 31 Balance

less projected recovery / repayment of the balance for the following three months (if any), estimated using the energy sales (kWh) for April, May and June from the previous year

plus forecast financing charges to the end of the 12-month recovery period (i.e., June in the following calendar year),

divided by the 12-months-to-date firm plus firmed-up secondary kWh sales to the end of March.

A fuel rider shall be added to the above adjustment rate, based on the Newfoundland Power Fuel Price Projection amount (as per Section C.2 above) divided by 12-months-to-date kWh sales to the end of March.

When new Test Year base rates come into effect, if a fuel rider forecast (either March or September) is more current than the test year fuel forecast, a fuel rider will be implemented at the same time as the change in base rates reflecting the more current fuel forecast and the new test year values .

Otherwise, the fuel rider portion of the RSP Adjustment will be set to zero upon implementation of the new Test Year Cost of Service rates, until the time for the next fuel price projection.

2. Island Industrial Customers

As of December 31 each year, the adjustment rate for industrial customers for the 12-month period commencing January 1 is determined as the rate per kWh which is projected to collect:

Industrial December 31 Balance

plus forecast financing charges to the end of the following calendar year,

divided by 12-months-to-date kWh sales to the end of December.

A fuel rider shall be added to the above adjustment rate, based on the Industrial Fuel Price Projection (as per Section C.1 above) amount divided by 12-months-to-date kWh sales to the end of December.

When new Test Year base rates come into effect, if a fuel rider forecast (either March or September) is more current than the test year fuel forecast, a fuel rider will be implemented at the same time as the change in base rates reflecting the more current fuel forecast and the new test year values . Otherwise, the fuel rider portion of the RSP Adjustment will be set to zero upon implementation of the new Test Year Cost of Service rates, until the time for the next fuel price projection.

Section E: Historical Plan Balances:

1. August 2002 Balance:

Newfoundland Power and Island Industrial customer balances accumulated in the Plan as at August 2002 will be recovered over a 5-year collection period, with adjustment rates established each December 31, commencing December 31, 2002. Financing charges on the plan balances will be calculated monthly using Hydro's approved Test Year annual weighted average cost of capital.

Newfoundland Power
The adjustment rate for each year of the five-year adjustment period will be determined as follows:

$$A = (B - C + D) \div E \div F$$

where
A = adjustment rate ($ per kWh) for the 12-month period commencing the following July 1.
B = Balance December 31
C = projected recovery to the following June 30 (if any), estimated using the most recent energy sales (kWh) for the period January to June.

D = projected financing charges to the following June 30
E = number of years remaining in the adjustment period
F = energy sales (kWh) (firm and firmed-up secondary) to Newfoundland Power for the most recent 12 months ended December 31

Recovery and financing will be applied to the balance each month. At the end of the five-year recovery period, any remaining balance will be added to the plan then in effect.

Island Industrial Customers
The adjustment rate for each year of the five-year adjustment period will be determined as follows:

$$G = H \div I \div J$$

where

G = adjustment rate ($ per kWh) for the 12-month period commencing the following January 1.
H = Balance December 31[5]
I = number of years remaining in the adjustment period
J = firm energy sales (kWh) to Industrial Customers for the most recent 12 months ended December 31

Recovery and financing will be applied to the balance each month. At the end of the five-year recovery period, any remaining balance will be added to the plan then in effect.

2. RSP Balance, December 31, 2003:
Newfoundland Power and Island Industrial customer balances accumulated in the Plan as at December 31, 2003 will be consolidated with the outstanding August 2002 customer balances as of December 31, 2003, and will be included with the Newfoundland Power and Island Industrial customer balances respectively for rate-setting purposes as of December 31, 2003.

[5] Subject to Section F.

Section F: Hydraulic Variation Special Adjustment December 31, 2006

1. Hydraulic Variation Customer Assignment

Customer assignment of the December 31, 2006 hydraulic variation account balance will be performed as follows:

E x 100%

Where:

E = Hydraulic Variation Account Balance as of December 31, 2006, including financing charges

The total amount of the Hydraulic Customer Assignment shall be removed from the Hydraulic Variation Account.

2. Customer Allocation

The December 31, 2006 customer assignment will be allocated among the Island Interconnected customer groups of (1) Newfoundland Power; (2) Island Industrial Firm; and (3) Rural Island Interconnected. The allocation will be based on percentages derived from 12 months-to-date kWh for: Utility Firm and Firmed-Up Secondary invoiced energy, Industrial Firm invoiced energy, and Rural Island Interconnected bulk transmission energy.

The portion of the hydraulic customer assignment which is initially allocated to Rural Island Interconnected will be re-allocated between Newfoundland Power and regulated Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the approved Test Year Cost of Service Study.

The Labrador Interconnected Hydraulic customer allocation shall be written off to Hydro's net income (loss).

3. Adjustment Rates

The Newfoundland Power customer allocation shall be included with the Newfoundland Power Historic Plan RSP balance as of December 31, 2006. To implement the affect of the adjustment over the remaining recovery period in the Historic Plan, the adjustment rate is calculated as follows:

January 1, 2007 RSP Adjustment Rate

Newfoundland Power’s adjustment rate for January 1, 2007 will be based on the forecast Hydraulic Variation credit balance of $20,707,844, with Newfoundland Power’s share equal to $17,759,489, calculated using forecast sales to December 31, 2006.

The January 1, 2007 RSP rate Adjustment is calculated as follows:

NP December 2006 Hydraulic Variation Allocation $(17,759,489)
Divided by:

Remaining Historic Plan Recovery Months	18
Equals:	
Forecast Monthly Recovery	$(986,638)
Multiplied by 12 equals	
Annual Adjustment	$(11,839,659)
Divided by	
12 months to date (Jan - Dec) forecast NP Sales (kWh)	4,680,392,181
Equals	
Reduction in Historic Plan Adjustment Rate (mills per kWh), effective January 1, 2007	(2.53)

July 1, 2007 RSP Adjustment Rate

The July 1, Historic Plan will be calculated in accordance with Section E, with the January 1, 2007 RSP adjustment rate calculated above included for the purpose of calculating the projected recovery (Component C) to June 2007 and the projected financing charges (Component D).

The Island Industrial customer allocation shall be allocated between the Industrial Customer current and Historic plans as follows:

Current Plan

The current plan assignment will be equal to the assignment calculated in accordance with Section A.3.

Historic Plan

The difference between the total amount assigned to the Industrial Customers in this section and the amount assigned to the Current Plan above will be included in the Historic Plan. The December 31, 2006 Historic Plan balance used for rate setting in Section E will be adjusted to remove the 2006 Hydraulic Variation amount, so that the impact of the Hydraulic Variation adjustment will not affect Industrial Customer rates until January 1, 2008.

APPLICABILITY:

These general Rules and Regulations apply to all Hydro Rural Customers.

1. INTERPRETATION:

(a) In these Rates and Rules the following definitions shall apply:

(i) "***Act***" means The Public Utilities Act, R.S.N. 1990, c.P-47 as amended from time to time.

(ii) "***Applicant***" means any person who applies for Service.

(iii) ***"Board"*** means the Board of Commissioners of Public Utilities of Newfoundland.

(iv) "***Hydro***" means Newfoundland and Labrador Hydro.

(v) "***Hydro rural customers***" means regulated customers served by Hydro other than industrial customers and Newfoundland Power.

(vi) "***Customer***" means any person who accepts or agrees to accept Service.

(vii) "***Disconnected***" or "***Disconnect***" in reference to a Service means the physical interruption of the supply of electricity thereto.

(viii) "***Discontinued***" or "***Discontinue***" in reference to a Service means to terminate the Customer's on-going responsibility with respect to the Service.

(ix) "***Domestic Unit***" means a house, apartment or other similar residential unit which is normally occupied by one family, or by a family and no more than four other persons who are not members of that family, or which is normally occupied by no more than six unrelated persons.

(x) ***"Service"*** means any service(s) provided by Hydro pursuant to these Regulations.

(xi) "***Serviced premises***" means the premises at which Service is delivered to the Customer.

(xii) ***"Government Departments"*** means electric service accounts of Provincial or Federal government departments, agencies, boards, commissions, and crown corporations but excludes hospitals, fish plants, churches, schools, community halls, municipal buildings and like facilities.

(b) Unless the context requires otherwise these Rates and Rules shall be interpreted such that:

(i) words imparting male persons include female persons and corporations.

(ii) words imparting the singular include the plural and vice versa.

2. CLASSES OF SERVICE:

(a) Hydro shall provide the following classes of Service:

ISLAND INTERCONNECTED AREA

1.1	Domestic
1.3	Burgeo School and Library
2.1	General Service, 0-10 kW
2.2	General Service, 10-100 kW (110 kVA)
2.3	General Service, 110 kVA (100 kW) - 1000 kVA
2.4	General Service, 1000 kVA and Over
4.1	Street and Area Lighting Service

ISLAND AND LABRADOR DIESEL AREA

1.2D	Domestic Diesel - Non-Government
2.1D	General Service Diesel - Non-Government, 0-10 kW
2.2D	General Service Diesel - Non-Government, 10 kW and Over
4.1D	Street and Area Lighting Service Diesel - Non-Government
1.2G	Domestic Diesel - Government Departments
2.1G	General Service Diesel - Government Departments, 0-10kW
2.2G	General Service Diesel - Government Departments, 10kW and Over
4.1G	Street and Area Lighting Service Diesel - Government Departments

HAPPY VALLEY-GOOSE BAY INTERCONNECTED AREA

1.1H	Domestic
2.1H	General Service, 0-10 kW
2.2H	General Service, 10-100 kW (110 kVA)
2.3H	General Service, 110 kVA (100 kW) - 1000 kVA
2.4H	General Service, 1000 kVA and Over
4.1H	Street and Area Lighting Service
5.1H	Secondary Energy

LABRADOR CITY / WABUSH INTERCONNECTED AREA

1.1W	Domestic
2.1W	General Service, 0-10 kW
2.2W	General Service, 10-100 kW (110 kVA)
2.3W	General Service, 110 kVA (100 kW) - 1000 kVA
2.4W	General Service, 1000 kVA and Over
4.1W	Street and Area Lighting Service
4.11W	Street and Area Lighting Service Labrador City - Installed as of Sept. 1, 2002
4.12W	Street and Area Lighting Service Labrador City – Customer Owned

(b) The terms and conditions relating to each class of Service shall be those approved by the Board from time to time.

(c) Service, other than Street and Area Lighting Service, shall be metered except where the energy consumption is relatively low and constant and in the opinion of Hydro can be readily determined without metering.

(d) The Customer shall use the Service on the Serviced Premises only. The Customer shall not resell the Service in whole or in part except that the Customer may include the cost of Service in charges for the lease of space or as part of the cost of other services provided by the Customer.

3. APPLICATION FOR SERVICE:

(a) An Applicant, when required by Hydro, shall complete a written Electrical Service Contract.

(b) An application for Service, when accepted by Hydro, constitutes a binding contract between the Applicant and Hydro which cannot be assigned.

(c) The person who signs an application for Service shall be personally liable for Service provided pursuant thereto, unless that person has authority to act for another Person denoted as the Applicant on the application for Service.

(d) Hydro may in its discretion refuse to provide Service to an Applicant where:

(i) the Applicant fails or refuses to complete an application for Service.

(ii) the Applicant provides false or misleading information on the application for Service.

(iii) the Applicant or the Owner or an Occupant of the Serviced Premises has a bill for any Service which is not paid in full 30 days or more after issuance.

(iv) the Applicant fails to provide the security or guarantee required under Regulation 4.

(v) the Applicant is not the owner or an occupant of the Serviced Premises.

(vi) the Service requested is already supplied to the Serviced Premises for another Customer who does not consent to having his Service Discontinued.

(vii) the Applicant does not pay a charge described in Regulation 9 (b),(c) or (d).

(viii) the Applicant otherwise fails to comply with these Regulations.

(e) A Customer who has not completed an application for Service shall do so within 5 days of a request having been made by Hydro in writing.

4. SECURITY FOR PAYMENT:

(a) An Applicant or a Customer shall give such reasonable security for the payment of charges as may be required by Hydro. When the Customer has established two consecutive years of good credit history, the security deposit will be refunded with simple interest calculated at a Rate equivalent to the Rate paid from time to time by the chartered banks on over-the-counter withdrawal savings accounts.

(b) Hydro may in its discretion require special guarantees from an Applicant or Customer whose location or load characteristics would require abnormal investment in facilities or who requires Service of a special nature.

5. SERVICE STANDARDS - METERED SERVICES:

(a) Service shall normally be provided at one of the following nominal standard secondary voltages depending upon the requirements of the load to be served and the availability of a three phase supply:

Single phase, 3-Wire	-	120/240 volts
Three phase, 4-Wire	-	120/208 volts wye
Three phase, 4-Wire	-	347/600 volts wye

Service at any other supply voltage may be provided in special cases at the discretion of Hydro.

(b) Service shall be supplied at single-phase 120/240 volts where the maximum demand is estimated by Hydro to be less than 75 kW. Where the maximum demand is estimated to be 75kW or greater, service shall normally be supplied at one of the standard three-phase voltages.

Hydro may, if requested by the Customer, provide a three-phase supply where the maximum demand is estimated to be less than 75 kW, if a contribution in aid of construction is paid to Hydro to cover the cost of transformers, equipment and any line extensions or upgrades required to provide the three-phase service.

To determine the contribution required, the cost to provide three-phase service will be reduced by the value of any single-phase plant supported by the projected revenue from the Customer, as calculated in accordance with Hydro's distribution line contribution in aid of construction policy applicable to General Service Customers. Where the necessary equipment and transformer capacity already exist at the location in question, no contribution in aid of construction will be required to provide the three-phase service.

(c) Hydro shall determine the point at which power and energy is delivered from Hydro's facilities to the Customer's electrical system.

(d) Service entrances shall be in a location satisfactory to Hydro and, except as otherwise approved by Hydro, shall be wired for outdoor meters.

(e) Where Hydro has reason to believe that Service to a Customer has or will have load characteristics which may cause undue interference with Service to another Customer, the Customer shall upon written notice by Hydro provide and install, at his expense and within a reasonable period of time, the equipment necessary to eliminate or prevent such interference.

(f) (i) Any Customer having a connected load or a normal operating demand of more than 25 kilowatts, in areas where space limitations or aesthetic reasons make it impractical to use a pole mounted transformer bank, shall, on request of Hydro, install and maintain a padmount transformer and all associated underground wiring, or provide at his expense a suitable vault or enclosure on the Serviced Premises for exclusive use by Hydro for its equipment necessary to supply and maintain service to the Customer.

(ii) Where either the service requirements of a Customer or changes to a Customer's electrical system necessitate the installation of additional equipment to Hydro's system which cannot be accommodated in Hydro's existing vaults or structures, the Customer shall, on request of Hydro, provide at the Customer's expense such additional space in its vault or enclosure as Hydro shall require to accommodate the additional equipment.

(g) The Customer shall not use a Service for across the line starting of motors rated over 10 horsepower except where specifically approved by Hydro.

(h) For Services having rates based on kilowatt demand, the average power factor shall not be less than 90%. Hydro, in its discretion, may make continuous tests of power factor or may test the Customer's power factor from time to time. If the Customer's power factor is lower than 90%, the Customer shall upon written notice by Hydro provide, at his expense, power factor corrective equipment to ensure that a power factor of not less than 90% is maintained.

(i) Hydro shall provide transformation for Service up to 500 kVA where the required service voltage is one of Hydro's standard service voltages and installation is in accordance with Hydro's standards. In other circumstances, Hydro, on such conditions as it deems acceptable, may provide the transformation.

(j) All Customer wiring and installations shall be in compliance with all statutory and regulatory requirements including the Canadian Electrical Code, Part 1 and, where applicable, in accordance with Hydro's specifications. However, the provision of Service shall not in any way be construed as acceptance by Hydro of the Customer's electrical system.

(k) The Customer shall provide such protective devices as may be necessary to protect his property and equipment from any disturbance beyond the reasonable control of Hydro.

6. SERVICE STANDARDS - STREET AND AREA LIGHTING SERVICE:

(a) For Street And Area Lighting Service Hydro shall use its best efforts to provide illumination during the hours of darkness for a total of approximately 4200 hours per year. Hydro shall, subject to Regulation 9 (i) make all repairs necessary to maintain service.

(b) Hydro shall supply the energy required and shall provide and maintain the illuminating fixtures and lamps together with necessary overhead conductors, control equipment and other devices.

(c) Hydro shall not be required to provide Street and Area Lighting Service where, in the opinion of Hydro, the normal Service is unsuitable for the task or where the nature of the activities carried out in the area would likely result in damage to the poles, wiring or fixtures.

(d) Hydro shall provide a range of fixture sizes utilizing an efficient lighting source in accordance with current standards in the industry and shall consult with the Customer regarding the most appropriate use of such fixtures for any specific installation.

(e) The location of fixtures for Street and Area Lighting Service shall be determined by Hydro in consultation with the Customer. After poles and fixtures have been installed they shall not be relocated except at the expense of the Customer.

(f) Hydro does not guarantee that fixtures used for Street And Area Lighting Service will illuminate any specific area.

(g) Where the installation of fixtures is required in a location where there are no existing distribution poles the Customer shall pay any contribution in aid of construction as may be determined under Hydro's policy for the pole line extension required to supply electric service to the location of the fixtures.

(h) Hydro shall not be required to provide additional Street And Area Lighting Service to a Customer where on at least two occasions in the preceding twelve months, his bill for such Service has been in arrears for more than 30 days.

7. METERING:

(a) Service to each building shall be metered separately except as provided in Regulation 7(b).

(b) Service to buildings and facilities on the same Serviced Premises which are occupied by the same Customer may, subject to Regulation 7(c), be metered together provided the Customer supplies and maintains all distribution facilities beyond the point of supply.

(c) Except as provided in Regulation 7(d) Service to each new Domestic Unit shall be metered separately.

(d) Where an existing Domestic Unit is subdivided into two or more new Domestic Units, Service to the new Domestic Units may, in the discretion of Hydro, be metered together.

(e) Where four or more Domestic Units are metered together, the Basic Customer Charge shall be multiplied by the number of Domestic Units.

(f) Where the floor space in the non-domestic portion exceeds 46 sq. meters, the Service shall not qualify for the Domestic Service Rate.

(g) Hydro shall not be required to provide more than one meter per Service, however, sub-metering by the Customer for any purpose not inconsistent with these Regulations is permitted.

(h) Subject to Regulations 7(c) and 7(g) Service to different units of a building may, at the request of the Customer, be combined on one meter or be metered separately.

(i) Maximum demand for billing purposes shall be determined by demand meter or, at the option of Hydro, may be based on:

(i) 80% of the connected load, where the demand does not exceed 100 kW, or

(ii) the smallest size transformer(s) required to serve the load if it is intermittent in nature such as X-Ray, welding machines or motors that operate for periods of less than thirty minutes, or

(iii) the kilowatt-hour consumption divided by an appropriate number of hours use where the demand is less than 10 kW.

(j) When charges are based on maximum demand the metering shall normally be in kVA if the applicable Rate is in kVA and in kW if the applicable Rate is in kW.

If the demand is recorded on a kVA meter but the applicable Rate is based on a kW demand, the recorded demand may be decreased by ten percent (10%) and the result shall be treated as the kW demand for billing purposes.

If the demand is recorded on a kW meter but the applicable Rate is based on a kVA demand, the recorded demand may be increased by ten percent (10%) and the result shall be treated as the kVA demand for billing purposes.

(k) The Customer shall ensure that meters and related equipment are visible and readily accessible to Hydro's personnel and are suitably protected. Unless otherwise approved by Hydro, meters shall be located outdoors and shall not subsequently be enclosed.

(l) If a meter is located indoors and Hydro employees are unable to obtain access to read the meter at the normal reading time for three consecutive months, the Customer shall upon written notice given by Hydro, provide for the installation of an outdoor meter at his expense.

(m) In the event that a dispute arises regarding the accuracy of a meter, and Hydro is unable to resolve the matter with the Customer then either the Customer or Hydro shall have the right to request an accuracy test in accordance with the requirements of the Electricity Inspection Act of Canada. Should the test indicate that the meter accuracy is not within the allowable limits, the Customer's bill shall be adjusted in accordance with the provisions of the said Act and all costs involved in the removal and testing of the meter shall be borne by Hydro. Should the test confirm the accuracy of the meter, the costs involved shall be borne by the party requesting the test. Hydro may require a Customer to deposit with Hydro in advance of testing, an amount sufficient to cover the costs involved.

(n) Metering shall normally be at secondary distribution voltage level but may at the option of Hydro be at the primary distribution level. When metering is at the primary distribution voltage (4-25KV) the monthly demand and energy consumption shall be reduced by 1.5%.

8. METER READING:

(a) Where reasonably possible Hydro shall read meters monthly provided that Hydro may, at its discretion, read meters at some other interval and estimate the reading for the intervening month(s). Areas which consist primarily of cottages will have their meters read four times per year and Hydro will estimate the readings for all other months.

(b) If Hydro is unable to obtain a meter reading due to circumstances beyond its reasonable control, Hydro may estimate the reading.

(c) If due to any cause a meter has not correctly recorded energy consumption or demand, then the probable consumption or demand shall be estimated in accordance with the best data available and used to determine the relevant charge.

9. CHARGES:

(a) Every Customer shall pay Hydro the charges approved by the Board from time to time for the Service(s) provided to the Customer or provided to the Serviced Premises at the Customer's request.

(b) Where a Customer requires Service for a period of less than three (3) years, the Customer shall pay Hydro in advance a "Temporary Connection Fee". The Temporary Connection Fee is calculated as the estimated labour cost of installing and removing lines and equipment necessary for the Service plus the estimated cost of non-salvageable material.

(c) Where special facilities are required or requested by the Customer or any facility is relocated at the request of the Customer, the Customer shall pay Hydro in advance the estimated additional cost of providing the special facilities and the estimated cost of the relocation less any betterment.

(d) The Customer shall pay Hydro in advance or on such other terms approved by the Board from time to time any contribution in aid of construction as may be determined by the methods prescribed by the Board.

(e) The Customer shall pay Hydro the amount set forth in the Rate for all poles required for Street And Area Lighting Service which are in addition to those installed by Hydro for the distribution of electricity. This charge shall not apply to Hydro poles and communications poles used jointly for Street And Area Lighting Service and communications attachments.

(f) Where a service is Disconnected pursuant to Regulation 12(a), b(ii), (c), or (d) and the Customer subsequently requests that the service be reconnected, the Customer shall pay a reconnection fee. Where a Service is Disconnected pursuant to Regulation 12(g) and an Applicant subsequently requests that the service be reconnected, the Applicant shall pay a reconnection fee. Applicants that pay the reconnection fee will not be required to pay the application fee. The reconnection fee shall be $20.00 where the reconnection is done during Hydro's normal office hours or $40.00 if it is done at other times.

(g) Where a Service, other than a Street and Area Lighting Service, is Discontinued pursuant to Regulation 11(a), or Disconnected pursuant to Regulations 12(a), b(ii), (c) or (d) and the Customer subsequently requests that the Service be restored within 12 months, the Customer shall pay, in advance, the minimum monthly charges that would have been incurred over the period if the Service had not been Discontinued or Disconnected.

(h) (i) Where a Street and Area Lighting Service is Discontinued pursuant to Regulation 11(a), (b), or (c), or 9(i), or when a Customer requests removal of existing fixtures, and/or poles, the Customer shall pay at the time of removal an amount equal to the unrecovered capital cost, plus the cost of removal less any salvage value of only the poles to be Discontinued or removed.

(ii) If a Customer requests the subsequent replacement of the fixture, either immediately or at any time within 12 months by another, whether or not of the same type or size, the Customer shall pay, in advance, an amount equal to the unrecovered capital cost of the fixture removed, plus the cost of removal, less any non-luminaire salvage, as well as the monthly charges that would have been incurred over the period if the Service had not been Discontinued.

(iii) Where a Street and Area Lighting Service is Discontinued, any pole dedicated solely to the Street and Area Lighting Service may, at the Customer's request, remain in place for up to 24 months from the date of removal of the fixture, during which time the Customer shall continue to pay the prescribed monthly charge for the pole.

(i) Where street and area lighting fixtures or lamps are wantonly, wilfilly, or negligently damaged or destroyed (other than through the negligence of Hydro), Hydro, at its option and after notifying the Customer by letter, shall remove the fixtures and the monthly charges for these fixtures will cease thirty days after the date of the letter. However, if the customer contacts Hydro within thirty days of the date of the letter and agrees to pay the repair costs in advance and all future repair costs, Hydro will replace the fixture and rental charges will recommence. If any future repair costs are not paid within three months of the date invoiced, Hydro, after further notifying the Customer by letter, may remove the fixtures. In all such cases the fixtures shall not be replaced unless the Customer pays to Hydro in advance all amounts owing prior to removal plus the cost of removing the old fixtures and installing the new fixtures.

(j) Where a Service other than Street and Area Lighting Service is not provided to the Customer for the full monthly billing period or where Street and Area Lighting Service is not provided for more than seven (7) days during the monthly billing period, the relevant charge to the Customer for the Service for that period may be prorated except where the failure to provide the Service is due to the Customer or to circumstances beyond the reasonable control of Hydro.

(k) Where a Customer's Service is at primary distribution or transmission voltage and the Customer provides his own transformation and all other facilities beyond the designated point of supply the monthly demand charge shall, subject to the minimum monthly charge, be reduced as follows:

For the Island Interconnected, L'Anse au Loup and Isolated service areas:

(i) for supply at 4 KV to 25 KV .... $0.40 per kVA

(ii) for supply at 33 KV to 138 KV .... $0.90 per kVA

For the Happy Valley-Goose Bay, Labrador City and Wabush service areas:

(iii) for supply at 4 KV to 25 KV .... $0.25 per kVA

(iv) for supply at 33 KV to 138 KV .... $0.60 per kVA

(l) Where a Customer's monthly demand has been permanently reduced because of the installation of peak load controls, power factor correction, or by rendering sufficient equipment inoperable, by any means satisfactory to Hydro, the monthly demands recorded prior to the effective date of such reduction may be adjusted when determining the Customer's demand for billing purposes thereafter. Should the Customer's demand increase above the adjusted demands in the following 12 months, the Customer will be billed for the charges that would have been incurred over the period if the demand had not been adjusted.

(m) Charges may be based on estimated readings or costs where such estimates are authorized by these Regulations.

(n) An application fee of $8.00 will be charged for all requests for Customer name changes and connection of new Serviced Premises. Landlords will be exempted from the application fee for name changes at Serviced Premises for which a landlord agreement pursuant to Regulation 11(f) is in effect.

10. BILLING:

(a) Hydro shall bill the Customer monthly for charges for Service. However, when a Service is disconnected or a bill is revised, Hydro may issue an additional bill.

(b) The charges for Street And Area Lighting Service may be included as a separate item on a bill for any other Service.

(c) Bills are due and payable when issued. Payment shall be made at such place(s) as Hydro may designate from time to time. Where a bill is not paid in full by the date that a subsequent bill is issued and the amount outstanding is $50.00 or more, Hydro will charge interest at a rate equal to the prime rate charged by chartered banks on the last day of the previous month plus five percent.

(d) Where a Customer's cheque is not honoured for insufficient funds a charge of $10.00 may be applied to the Customer's bill.

(e) Where a Customer is billed on the basis of an estimated charge, an adjustment shall be made in a subsequent bill should such estimate prove to be inaccurate.

(f) Where between normal meter reading dates, one Customer assumes from another Customer the responsibility for a metered Service or a Service is Discontinued, Hydro may base the billing on an estimate of the reading as of the date of change.

(g) Where a Customer has been under billed due to an error on the part of Hydro or due to an act or omission by a third party, the Customer may, at the discretion of Hydro, be relieved of the responsibility for all or any part of the amount of the under billing.

11. DISCONTINUANCE OF SERVICE:

(a) A Service may be Discontinued by the Customer at any time upon prior notice to Hydro provided that Hydro may require 10 days prior notice in writing.

(b) A Service may be Discontinued by Hydro upon 10 days prior notice in writing to the Customer if the Customer:

(i) provided false or misleading information on the application for the Service

(ii) fails to provide security or guarantee for the Service required under Regulation 4.

(c) A Service may be Discontinued by Hydro without notice if the Service was Disconnected pursuant to Rule 12 and has remained Disconnected for over 30 consecutive days.

(d) When Hydro accepts an application for Service, any prior contract for the same Service shall be Discontinued except where an agreement for that Service is signed by a landlord under Regulation 11(f).

(e) Where a Service has been Discontinued, the Service may, at the option of Hydro and subject to Rule 12(a), remain connected.

(f) A landlord may sign an agreement with Hydro to accept charges for Service provided to a rental premise for all periods when Hydro does not have a contract for Service with a tenant for that premise.

12. DISCONNECTION OF SERVICE:

(a) Hydro shall Disconnect a Service within 10 days of receipt of a written request from the Customer.

(b) Hydro may Disconnect a Service without notice to the Customer:

(i) where the Service has been Discontinued

(ii) on account of or to prevent fraud or abuse

(iii) where in the opinion of Hydro the Customer's electrical system is defective and represents a danger to life or property.

(iv) where the Customer's electrical system has been modified without compliance with the Electrical Regulations.

(iv) where the Customer has a building or structure under Hydro's wires which is within the minimum clearances recommended by the Canadian Standards Association.

(vi) when ordered to do so by any authority having the legal right to issue such order.

(c) Hydro may, in accordance with its Collection Policies, Disconnect a Service upon prior notice to the Customer if the Customer has a bill for any Service which is not paid in full 30 days or more after issuance.

(d) Hydro may Disconnect a Service upon 10 days prior notice to the Customer if the Customer is in violation of any provision of these Regulations.

(e) Hydro may refuse to reconnect a Service if the Customer is in violation of any provisions of these Rules or if the Customer has a bill for any Service which is unpaid.

(f) Hydro may disconnect a service to make repairs or alterations. Where reasonable and practical, Hydro shall give prior notice to the Customer.

(g) Hydro may disconnect the Service to a rental premises where the landlord has an agreement with Hydro authorizing Hydro to disconnect the Service for periods when Hydro does not have a contract for Service with a tenant of that premises.

13. PROPERTY RIGHTS:

(a) The Customer shall provide Hydro with space and cleared rights-of-way on private property for the line(s) and facilities required to serve the Customer.

(b) Hydro shall have the right to install, remove or replace such of its property as it deems necessary.

(c) The Customer shall provide Hydro with access to the Serviced Premises at all reasonable hours for purposes of reading a meter or installing, replacing, removing or testing its equipment, and measuring or checking the connected load.

(d) All equipment and facilities provided by Hydro shall remain the property of Hydro unless otherwise agreed in writing.

(e) The Customer shall not unreasonably interfere with Hydro's access to its property.

(f) The Customer shall not attach wire, cables, clotheslines or any other fixtures to Hydro's poles or other property except by prior written permission of Hydro.

(g) The Customer shall allow Hydro to trim all trees in close proximity to service lines in order to maintain such lines in a safe manner.

(h) The Customer shall not erect any buildings or obstructions on any of Hydro's easement lands or alter the grade of such easements by more than 20 centimetres, without the prior approval of Hydro.

14. HYDRO LIABILITY:

Hydro shall not be liable for any failure to supply Service for any cause beyond its reasonable control, nor shall it be liable for any loss, damage or injury caused by the use of Services or resulting from any cause beyond its reasonable control.

15. GENERAL:

(a) No employee, representative or agent of Hydro has authority to make any promise, agreement or representation, whether verbal or otherwise, which is inconsistent with these Regulations and no such promise, agreement or representation shall be binding on Hydro.

(b) Any notice under these Regulations will be considered to have been given to the Customer on the date it is received by the Customer or three days following the date it was delivered or mailed by Hydro to the Customer's last known address, whichever is sooner.

16. POLICIES FOR AUTOMATIC RATE CHANGES (effective up to and including NP rate changes arising from the flow-through of the final rate changes arising from Hydro's 2006 General Rate Application)

(a) Island Interconnected System:

(i) As Newfoundland Power changes its rates, Hydro will automatically adjust all rates such that these customers pay the same rates as Newfoundland Power customers.

(ii) Rates for Burgeo school and library will increase or decrease by the average rate of change granted Newfoundland Power from time to time, excluding Newfoundland Power's changes for the July 1st Municipal Tax and Rate Stabilization adjustments and for any Fuel Rider adjustments.

(b) L'Anse au Loup System:

(i) As Newfoundland Power changes its rates, Hydro will automatically adjust all rates such that these customers pay the same rates as Newfoundland Power customers.

(c) Isolated Systems:

(i) Isolated Rural Domestic customers, excluding Government departments, pay the same rates as Newfoundland Power for the basic customer charge and First Block consumption (outlined in Rate 1.2D). Rates charged for consumption above this block will be adjusted in accordance with the December 6, 2006 Government directive.

(ii) Rates for Isolated Rural General Service customers, excluding Government departments, will be adjusted in accordance with the December 6, 2006 Government directive.

(iii) As Newfoundland Power changes its rates, Hydro will automatically adjust Rural Isolated street and area lighting rates, excluding those for Government departments, such that these rates are the same as charged Newfoundland Power customers.

17. POLICIES FOR AUTOMATIC RATE CHANGES (to be effective with NP rate changes subsequent to the flow-through of the final rate changes arising from Hydro's 2006 General Rate Application)

(a) Island Interconnected System:

(i) As Newfoundland Power changes its rates, Hydro will automatically adjust all rates such that these customers pay the same rates as Newfoundland Power customers.

(b) L'Anse au Loup System:

(i) As Newfoundland Power changes its rates, Hydro will automatically adjust all rates such that these customers pay the same rates as Newfoundland Power customers.

(c) Isolated Systems:

(i) Isolated Rural Domestic customers, excluding Government departments, pay the same rates as Newfoundland Power for the basic customer charge and First Block consumption (outlined in Rate 1.2D). Rates charged for consumption above this block will be automatically adjusted by the average rate of change granted Newfoundland Power from time to time.

(ii) Rates for Isolated Rural General Service customers, excluding Government departments, will increase or decrease by the average rate of change granted Newfoundland Power from time to time.

(iii) As Newfoundland Power changes its rates, Hydro will automatically adjust Rural Isolated street and area lighting rates, excluding those for Government departments, such that these rates are the same as charged Newfoundland Power customers.

RATE No. 1.1

DOMESTIC

Availability:

For Service to a Domestic Unit or to buildings or facilities which are on the same Serviced Premises as a Domestic Unit and used by the same Customer exclusively for domestic or household purposes, whether such buildings or facilities are included on the same meter as the Domestic Unit or metered separately.

Rate: (Includes Municipal Tax and Rate Stabilization Adjustments)

Basic Customer Charge: .... $15.59 per month

Energy Charge:
All kilowatt-hours .... @ 8.935¢ per kWh

Minimum Monthly Charge $15.59

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales tax (HST) which applies to electricity bills.**

GENERAL SERVICE 0 - 10 kW

Availability[1]:

For Service (excluding Domestic Service) where the maximum demand occurring in the 12 months ending with the current month is less than 10 kilowatts.

Rate: (Includes Municipal Tax and Rate Stabilization Adjustments)

Basic Customer Charge: .... $17.88 per month
Energy Charge:
All kilowatt-hours .... @ 11.462¢ per kWh

Minimum Monthly Charge: Single Phase $17.88
Three Phase $35.76

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales tax (HST) which applies to electricity bills.**

[1] This rate is also available to fish plants in Isolated Rural Systems with a connected load of 30kW or greater.

GENERAL SERVICE 10 - 100 kW (110 kVA)

Availability[1]:

For Service (excluding Domestic Service) where the maximum demand occurring in the 12 months ending with the current month is 10 kilowatts or greater but less than 100 kilowatts (110 kilovolt-amperes).

Rate: (Including Municipal Tax and Rate Stabilization Adjustments**)**

Basic Customer Charge: ....$20.60 per month

Demand Charge:
$8.63 per kW of billing demand in the months of December, January, February and March and $7.88 per kW in all other months. The billing demand shall be the maximum demand registered on the meter in the current month.

Energy Charge:
First 150 kilowatt-hours per kW of billing demand..@ 9.108¢ per kWh
All excess kilowatt-hours..@ 6.102¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 15.9 cents per kWh plus the Basic Customer Charge, but not less than Minimum Monthly Charge.

Minimum Monthly Charge:

Single Phase ....$20.60 per month
Three Phase: ....$35.76 per month

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular Regulation 7 (n)], transformation [in particular Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales tax (HST) which applies to electricity bills.**

[1] This rate is also available to fish plants in Isolated Rural Systems with a connected load of 30kW or greater.

RATE No. 2.3

GENERAL SERVICE 110 kVA (100 kW) -1000 kVA

Availability[1]:

For Service where the maximum demand occurring in the 12 months ending with the current month is 110 kilovolt-amperes (100 kilowatts) or greater but less than 1000 kilovolt-amperes.

Rate: (Including Municipal Tax and Rate Stabilization Adjustments)

Basic Customer Charge: .... $92.73 per month

Demand Charge:
$7.46 per kVA of billing demand in the months of December, January, February and March and $6.71 per kVA in all other months. The billing demand shall be the maximum demand registered on the meter in the current month.

Energy Charge:
First 150 kilowatt-hours per kVA of billing demand,
up to a maximum of 30,000 kilowatt-hours ....@ 8.722¢ per kWh
All excess kilowatt-hours...@ 5.974¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 15.9 cents per kWh plus the Basic Customer Charge.

Discount:

A discount of 1.5% of the amount of the current month's bill, up to a maximum of $500.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular Regulation 7 (n)], transformation [in particular Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales tax (HST) which applies to electricity bills.**

[1] This rate is also available to fish plants in Isolated Rural Systems with a connected load of 30kW or greater.

GENERAL SERVICE 1000 kVA AND OVER

Availability[1]:

For Service where the maximum demand occurring in the 12 month period ending with the current month is 1000 kilovolt-amperes or greater.

Rate: (Including Municipal Tax and Rate Stabilization Adjustments)

Basic Customer Charge: .... $185.46 per month

Billing Demand Charge:
$7.05 per kVA of billing demand in the months of December, January, February and March and $6.30 per kVA in all other months. The billing demand shall be the maximum demand registered on the meter in the current month.

Energy Charge:
First 100,000 kilowatt-hours .... @ 7.334¢ per kWh
All excess kilowatt-hours .... @ 5.866¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 15.9 cents per kWh plus the Basic Customer Charge.

Discount:

A discount of 1.5% of the amount of the current month's bill, up to a maximum of $500.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular Regulation 7 (n)], transformation [in particular Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales tax (HST) which applies to electricity bills.**

[1] This rate is also available to fish plants in Isolated Rural Systems with a connected load of 30kW or greater.

STREET AND AREA LIGHTING SERVICE

Availability:

For Street and Area Lighting Service in the Rural Island Interconnected area and the L'Anse au Loup system, where the electricity is supplied by Hydro and all fixtures, wiring and controls are provided, owned and maintained by Hydro.

Monthly Rate: (Including Municipal Tax and Rate Stabilization Adjustment)

	SENTINEL / STANDARD
MERCURY VAPOUR	
250W (9,400 lumens)	$18.22
HIGH PRESSURE SODIUM [1]	
100W (8,600 lumens)	14.65
150W (14,400 lumens)	18.22
250W (23,200 lumens)	23.92
400W (45,000 lumens)	31.28

For all new installations and replacements.

Special poles used exclusively for lighting service

Wood.. $6.44

General:

Details regarding conditions of service are provided in the Rules and Regulations.
This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.

RATE 1.2D

DOMESTIC DIESEL

Availability:

For all the Island and Labrador diesel service areas of Hydro (excluding Government Departments) for service to a domestic unit or to buildings or facilities which are on the same Serviced premises as a Domestic Unit and used by the same Customer exclusively for domestic or household purposes, whether such buildings or facilities are included on the same meter as the Domestic Unit or metered separately. All churches, schools, and community halls in the diesel service areas are also subject to this rate.

Rate: (Including Municipal Tax and Rate Stabilization Adjustments)

Basic Customer Charge: .... $15.59 per month

Energy Charge:
First Block (See Table Below) kilowatt-hours per month .... @ 8.935¢ per kWh
Second Block (See Table Below) kilowatt-hours per month .... @ 10.332¢ per kWh
All kWh over 1000 kilowatt-hours per month .... @ 14.007¢ per kWh

	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sept.	Oct.	Nov.	Dec.
First Block	1000	1000	900	900	800	800	700	700	700	800	900	1000
Second Block	0	0	100	100	200	200	300	300	300	200	100	0

Minimum Monthly Charge $15.59

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00, will be allowed if the bill is paid within 10 days after it is issued.

Rate Stabilization Clause:

This Rate is subject to the Rate Stabilization Adjustment arising from the operation of the Rate Stabilization Clause which forms part of the Schedule of Rates. The adjustment is applicable only to the first block kWh per month.

Municipal Tax Clause:

This Rate is subject to the Municipal Tax Adjustment arising from the operation of the Municipal Tax Clause which forms part of the Schedule or Rates.

General:

Details regarding conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales tax (HST) which applies to electricity bills.**

GENERAL SERVICE DIESEL 0-10 kW

Availability:

For all the Island and Labrador diesel service areas of Hydro (excluding Government Departments) for non-domestic services where the maximum demand occurring in the 12 months ending with the current month is less than 10 kilowatts.

Rate:

Basic Customer Charge: .... $19.57 per month

Energy Charge:
All kilowatt-hours .... @ 16.681¢ per kWh

Minimum Monthly Charge: Single Phase.. $19.57
Three Phase.. $35.88

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00 or more than $500.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales tax (HST) which applies to electricity bills.**

GENERAL SERVICE DIESEL OVER 10 kW

Availability:

For all the Island and Labrador diesel service areas of Hydro (excluding Government Departments) for non-domestic services where the maximum demand occurring in the 12 months ending with the current month is 10 kilowatts or greater.

Rate:

Basic Customer Charge: .... $27.40 per month

Demand Charge:
The maximum demand registered on the meter in the current month ....@ $12.16 per kW

Energy Charge:
All kilowatt-hours ....@ 15.459¢ per kWh

Minimum Monthly Charge: Single Phase.. $27.40
Three Phase $59.75

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00 or more than $500.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular Regulation 7 (n)], transformation [in particular Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales tax (HST) which applies to electricity bills.**

STREET AND AREA LIGHTING SERVICE DIESEL

Availability:

For Street and Area Lighting Service (excluding Government Departments) throughout the Island and Labrador diesel service areas of Hydro, where the electricity is supplied by Hydro and all fixtures, wiring and controls are provided, owned and maintained by Hydro.

Monthly Rate: (Including Municipal Tax and Rate Stabilization Adjustment)

	SENTINEL / STANDARD
MERCURY VAPOUR	
250W (9,400 lumens)	$18.22
HIGH PRESSURE SODIUM [1]	
100W (8,600 lumens)	14.65
150W (14,400 lumens)	18.22
250W (23,200 lumens)	23.92
400W (45,000 lumens)	31.28

[1] For all new installations and replacements.

Special poles used exclusively for lighting service

Wood.. $6.44

General:

Details regarding conditions of service are provided in the Rules and Regulations.
This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE No. 1.2G

DOMESTIC DIESEL

GOVERNMENT DEPARTMENTS

Availability:

For Service to Government Departments throughout the Island and Labrador diesel service areas of Hydro, to a Domestic Unit or to buildings or facilities which are on the same Serviced Premises as a Domestic Unit and used by the same Customer exclusively for domestic or household purposes, whether such buildings or facilities are included on the same meter as the Domestic Unit or metered separately.

Rate:

Basic Customer Charge..$41.03 per month

Energy Charge:
All kilowatt-hours ....@ 78.10 ¢ per kWh

Minimum Monthly Charge $41.03

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00 or more than $500.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding conditions of service are provided in the Rules and Regulations.
This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.

Availability:

For Service (excluding Domestic Service) to Government Departments throughout the Island and Labrador diesel service areas of Hydro where the maximum demand occurring in the 12 months ending with the current month is less than 10 kilowatts.

Rate:

Basic Customer Charge..$44.82 per month

Energy Charge:
All kilowatt-hours ....@ 69.701¢ per kWh

Minimum Monthly Charge $44.82

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00 or more than $500.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding conditions of service are provided in the Rules and Regulations.
This rate schedule does not include the Harmonized Sales Tax (HST), which applies to electricity bills.

Availability:

For Service (excluding Domestic Service) to Government Departments throughout the Island and Labrador diesel service areas of Hydro where the maximum demand occurring in the 12 months ending with the current month is 10 kilowatts or greater.

Rate:

Basic Customer Charge: .... $66.37 per month

Demand Charge:
The maximum demand registered on the meter in the current month ....@ $53.68 per kW

Energy Charge:
All kilowatt-hours ....@ 49.554 ¢ per kWh

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00 or more than $500.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular Regulation 7 (n)], transformation [in particular Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales tax (HST) which applies to electricity bills.**

Availability:

For Street and Area Lighting Service to Government Departments throughout the Island and Labrador Diesel service areas of Hydro, where the electricity is supplied by Hydro and all fixtures, wiring and controls are provided, owned and maintained by Hydro.

Monthly Rate:

	SENTINEL / STANDARD
MERCURY VAPOUR	
250W (9,400 lumens)	$63.95
HIGH PRESSURE SODIUM [1]	
100W (8,600 lumens)	51.80
150W (14,400 lumens)	63.95

[1] Only High Pressure Sodium fixtures are available for all new installations and replacements.

General:

Details regarding conditions of service are provided in the Rules and Regulations.
This rate schedule does not include the Harmonized Sales Tax (HST), which applies to electricity bills.

DOMESTIC

Availability:

For Service throughout the Happy Valley-Goose Bay Interconnected service area of Hydro, to a Domestic Unit or to buildings or facilities which are on the same Serviced Premises as a Domestic Unit and used by the same Customer exclusively for domestic or household purposes, whether such buildings or facilities are included on the same meter as the Domestic Unit or metered separately.

Rate:

Basic Customer Charge: .... $7.00 per month

Energy Charge:
All kilowatt-hours ....@ 3.25 ¢ per kWh

Minimum Monthly Charge $7.00

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding conditions of service are provided in the Rules and Regulations.
This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.

RATE No. 2.1H

GENERAL SERVICE 0 - 10 kW

Availability:

For Service (excluding Domestic Service) throughout the Happy Valley-Goose Bay Interconnected service area of Hydro, where the maximum demand occurring in the 12 months ending with the current month is less than 10 kilowatts.

Rate:

Basic Customer Charge: .... $9.10 per month

Energy Charge:
All kilowatt-hours .... @ 4.945 ¢ per kWh

Minimum Monthly Charge: Single Phase $9.10
Three Phase $20.00

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding conditions of service are provided in the Rules and Regulations.
This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.

GENERAL SERVICE 10 - 100 kW (110 kVA)

Availability:

For Service (excluding Domestic Service) throughout the Happy Valley-Goose Bay Interconnected service area of Hydro, where the maximum demand occurring in the 12 months ending with the current month is 10 kilowatts or greater but less than 100 kilowatts (110 kilovolt-amperes).

Rate:

Demand Charge:
The maximum demand registered on the meter in the current month ....@ $2.00 per kW

Energy Charge:
All kilowatt-hours ....@ 2.268 ¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 6.8 ¢ per kWh, but not less than the Minimum Monthly Charge.

Minimum Monthly Charge:

An amount equal to $1.05 per kW of maximum demand occurring in the 12 months ending with the current month, but not less than $20.00 for a three phase service.

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular Regulation 7 (n)], transformation [in particular Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations. **This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

GENERAL SERVICE 110 kVA (100 kW) - 1000 kVA

Availability:

For Service (excluding Domestic Service) throughout the Happy Valley-Goose Bay Interconnected service area of Hydro, where the maximum demand occurring in the 12 months ending with the current month is 110 kilovolt-amperes (100 kilowatts) or greater but less than 1000 kilovolt-amperes.

Rate:

Demand Charge:
The maximum demand registered on the meter in the current month ......@ $1.85 per kVA

Energy Charge:
All kilowatt-hours ....@ 2.014 ¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 6.8 ¢ per kWh, but not less than the Minimum Monthly Charge.

Minimum Monthly Charge:

An amount equal to $1.05 per kVA of maximum demand occurring in the 12 months ending with the current month.

Discount:

A discount of 1.5% of the amount of the current month's bill, up to a maximum of $500.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular Regulation 7 (n)], transformation [in particular Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations. **This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

GENERAL SERVICE 1000 kVA AND OVER

Availability:

For Service (excluding Domestic Service) throughout the Happy Valley-Goose Bay Interconnected service area of Hydro, where the maximum demand occurring in the 12 month period ending with the current month is 1000 kilovolt-amperes or greater.

Rate:

Billing Demand Charge:
The maximum demand registered on the meter in the current month ......@ $1.70 per kVA

Energy Charge:
All kilowatt-hours ....@ 1.729 ¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 6.8 ¢ per kWh, but not less than the Minimum Monthly Charge.

Minimum Monthly Charge:

An amount equal to $1.05 per kVA of maximum demand occurring in the 12 months ending with the current month.

Discount:

A discount of 1.5% of the amount of the current month's bill, up to a maximum of $500.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular Regulation 7 (n)], transformation [in particular Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations. **This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

STREET AND AREA LIGHTING SERVICE

Availability:

For Street and Area Lighting Service throughout the Happy Valley-Goose Bay Interconnected service area of Hydro, where the electricity is supplied by Hydro and all fixtures, wiring and controls are provided, owned and maintained by Hydro.

Monthly Rate:

	SENTINEL / STANDARD
MERCURY VAPOUR	
250W (9,400 lumens)	$ 11.90
HIGH PRESSURE SODIUM [1]	
100W (8,600 lumens)	8.75
150W (14,400 lumens)	11.90
250W (23,200 lumens)	15.95
400W (45,000 lumens)	20.10

[1] Only High Pressure Sodium fixtures are available for all new installations and replacements.

Special poles used exclusively for lighting service

Wood.. $ 3.00

General:

Details regarding conditions of service are provided in the Rules and Regulations.
This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.

SECONDARY ENERGY

Availability:

For Service to Customers on the Labrador Interconnected grid engaged in fuel switching who purchase a minimum of 1 MW load and a maximum of 24 MW, who provide their own transformer and, who are delivered power at primary voltages. Hydro shall supply Secondary Energy to the Customer at such times and to the extent that Hydro has Churchill Falls electricity available in excess of the amount it requires for its own use, and to meet its commitments and sales opportunities, present and future, for firm energy. Moreover, Hydro may interrupt or reduce the supply of Secondary Energy at its sole discretion for any cause whatsoever. The energy delivered shall be used solely for the operation of the equipment engaged in fuel switching.

Energy Charge:

The energy charge shall be calculated monthly based on:

EITHER:

A. The Customer's cost of fuel (cents per litre) most recently delivered to the Customer including fuel additives, if any, in accordance with the following formula:

$$\underline{\text{Secondary Energy Rate} = \text{Constant Factor} \times \text{Fuel Cost/Litre} \times 90\%}$$

$$\text{Constant Factor} = \frac{3413 \text{ BTU/kWh} \times A \times B}{C \times D}$$

Where:

A = Customer's Electric Boiler Efficiency

B = Transformer and Losses Adjustment Factor

C = BTU/Litre of the Customer's fuel

D = Customer's Oil-fired Boiler Efficiency

OR:

B. The price equivalent to that negotiated for the sale of energy to non-regulated customers, as adjusted for losses.

WHICHEVER IS GREATER.

Prior to the commencement of service, the Customer will provide to Hydro the rate component values for insertion in the pricing formula for Secondary Energy. If subsequent changes to any of these rate components are required, the Customer will provide them to Hydro as soon as practicable. Hydro may require that these rate component values be verified.

Communications

The Customer and Hydro shall each designate a position within their respective staffs to be responsible for communications as to changes in the cost of the fuel delivered to the Customer. Hydro will contact the Customer's designate on or before the second working day of each month at which time the Customer's designate will inform Hydro of the fuel cost. If this information is unavailable to Hydro for any reason, Hydro will use the previous month's fuel cost and make the adjustment to the correct cost in the following month's billing.

Power Factor

If the Customer's power factor is lower than 90%, the Customer shall upon written notice by Hydro provide, at the Customer's expense, power factor corrective equipment to ensure that a power factor of not less than 90% is maintained.

General:

Insofar as they are not inconsistent with the forgoing, the conditions of service provided in the Rules and Regulations shall apply to Customers in this rate class.
This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.

DOMESTIC

Availability:

For Service throughout the Labrador City and Wabush Interconnected service area of Hydro, to a Domestic Unit or to buildings or facilities which are on the same Serviced Premises as a Domestic Unit and used by the same Customer exclusively for domestic or household purposes, whether such buildings or facilities are included on the same meter as the Domestic Unit or metered separately.

Rate:

Basic Customer Charge: ....$5.75 per month

Energy Charge:
All kilowatt-hours ....@ 2.290 ¢ per kWh

Minimum Monthly Charge $5.75

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding conditions of service are provided in the Rules and Regulations.
This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.

GENERAL SERVICE 0 - 10 kW

Availability:

For Service (excluding Domestic Service) throughout the Labrador City and Wabush Interconnected service area of Hydro, where the maximum demand occurring in the 12 months ending with the current month is less than 10 kilowatts.

Rate:

Basic Customer Charge: ....$9.10 per month

Energy Charge:
All kilowatt-hours ....@ 3.754 ¢ per kWh

Minimum Monthly Charge: Single Phase... $9.10
Three Phase $20.00

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding conditions of service are provided in the Rules and Regulations.
This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.

RATE No. 2.2W

GENERAL SERVICE 10 - 100 kW (110 kVA)

Availability:

For Service (excluding Domestic Service) throughout the Labrador City and Wabush Interconnected service area of Hydro, where the maximum demand occurring in the 12 months ending with the current month is 10 kilowatts or greater but less than 100 kilowatts (110 kilovolt-amperes).

Rate:

Demand Charge:
The maximum demand registered on the meter in the current month ....@ $2.00 per kW

Energy Charge:
All kilowatt-hours ....@ 2.268 ¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 6.8 cents per kWh, but not less than the Minimum Monthly Charge.

Minimum Monthly Charge:

An amount equal to $1.05 per kW of maximum demand occurring in the 12 months ending with the current month, but not less than $20.00 for a three phase service.

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular Regulation 7 (n)], transformation [in particular Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations. **This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

GENERAL SERVICE 110 kVA (100 kW) - 1000 kVA

Availability:

For Service (excluding Domestic Service) throughout the Labrador City and Wabush Interconnected service area of Hydro, where the maximum demand occurring in the 12 months ending with the current month is 110 kilovolt-amperes (100 kilowatts) or greater but less than 1000 kilovolt-amperes.

Rate:

Demand Charge:
The maximum demand registered on the meter in the current month ......@ $1.85 per kVA

Energy Charge:
All kilowatt-hours ....@ 2.014 ¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 6.8 cents per kWh, but not less than the Minimum Monthly Charge.

Minimum Monthly Charge:

An amount equal to $1.05 per kVA of maximum demand occurring in the 12 months ending with the current month.

Discount:

A discount of 1.5% of the amount of the current month's bill, up to a maximum of $500.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular Regulation 7 (n)], transformation [in particular Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations. **This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

GENERAL SERVICE 1000 kVA AND OVER

Availability:

For Service (excluding Domestic Service) throughout the Labrador City and Wabush Interconnected service area of Hydro, where the maximum demand occurring in the 12 month period ending with the current month is 1000 kilovolt-amperes or greater.

Rate:

Billing Demand Charge:
The maximum demand registered on the meter in the current month ......@ $1.70 per kVA

Energy Charge:
All kilowatt-hours ....@ 1.729 ¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 6.8 cents per kWh, but not less than the Minimum Monthly Charge.

Minimum Monthly Charge:

An amount equal to $1.05 per kVA of maximum demand occurring in the 12 months ending with the current month.

Discount:

A discount of 1.5% of the amount of the current month's bill, up to a maximum of $500.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular Regulation 7 (n)], transformation [in particular Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations. **This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

STREET AND AREA LIGHTING SERVICE

Availability:

For Street and Area Lighting Service throughout the Labrador City and Wabush Interconnected service area of Hydro, where the electricity is supplied by Hydro and all fixtures, wiring and controls are provided, owned and maintained by Hydro.

Monthly Rate:

	SENTINEL / STANDARD
MERCURY VAPOUR[1]	
250W (9,400 lumens)	$ 8.86
HIGH PRESSURE SODIUM [2]	
100W (8,600 lumens)	7.97
150W (14,400 lumens)	11.90
250W (23,200 lumens)	15.95
400W (45,000 lumens)	20.10

[1] Fixtures previously owned by the Town of Wabush as of September 1, 1985, and transferred to Hydro in 1987.

[2] Only High Pressure Sodium fixtures are available for all new installations and replacements installed after September 1, 2002.

Special poles used exclusively for lighting service

Wood ....$ 3.00

General:

Details regarding conditions of service are provided in the Rules and Regulations.
This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.

STREET AND AREA LIGHTING SERVICE

Availability:

For Street and Area Lighting Service throughout the Labrador City service area of Hydro, where the electricity is supplied by Hydro and all fixtures, wiring and controls are provided, owned and maintained by Hydro existing as of September 1, 2002.

Monthly Rate:

	SENTINEL / STANDARD
HIGH PRESSURE SODIUM [1]	
100W (8,600 lumens)	$ 6.02

[1] Any new fixtures added will be at the rates set out in Rate 4.1W.

Special poles used exclusively for lighting service

Wood ....$ 3.00

General:

Details regarding conditions of service are provided in the Rules and Regulations.
This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.

STREET AND AREA LIGHTING SERVICE

Availability:

For Street and Area Lighting Service throughout the Labrador City service area of Hydro, where the electricity is supplied by Hydro and all fixtures, wiring and controls are provided, owned and maintained by the customer.

Monthly Rate:

	SENTINEL / STANDARD
HIGH PRESSURE SODIUM	
100W (8,600 lumens)	$ 3.83

Special poles used exclusively for lighting service

Wood .... $ 3.00

General:

Details regarding conditions of service are provided in the Rules and Regulations.
This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.