PRE-FILED TESTIMONY OF
C.F. OSLER
IN REGARD TO NEWFOUNDLAND & LABRADOR HYDRO
GENERAL RATE REVIEW

Submitted to

The Board of Commissioners of Public Utilities

On behalf of

Island Industrial Customers

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1.0 INTRODUCTION

This testimony has been prepared for the four Island Industrial Customers (IC) of Newfoundland and Labrador Hydro (Hydro) by InterGroup Consultants, Ltd. (InterGroup) under the direction of Mr. C.F. Osler. It is evidence for the public hearing into an Application (the "Application") by Hydro to the Board of Commissioners of Public Utilities (Board) dated May 31, 2001.

The Island IC group includes the four large industrial customers operating in Newfoundland and Labrador on Hydro's Island Interconnected System. These companies are:

- Abitibi Consolidated Inc. (Grand Falls)
- Abitibi Consolidated Inc. (Stephenville)
- Corner Brook Pulp and Paper Limited
- North Atlantic Refining Limited

Mr Osler's qualifications are provided in Attachment A. InterGroup was retained at the end of June 2001 and subsequently assisted the Island IC in preparation of the first round of questions submitted by them to Hydro.

In preparing this testimony, the following information has been reviewed:

- The Hydro Application filed May 31, 2001, including pre-filed testimony of Hydro staff and witnesses.

- The responses to the Information Requests of the Consumer Advocate to the Board (CA-1 to CA-12) with the exception of CA-1 which has not been reviewed in detail (Hydro's 1992 Application).

- The Information Requests filed to Hydro from the Board, the IC, Newfoundland Power (NP), and the Labrador Customers (LC).

- To a limited degree, the responses to the Information Requests filed by Hydro; however, given the volume of the responses and the limited amount of time that has been available for us to review them, this review has been severely restricted. Furthermore, several key responses filed to date by Hydro fail to provide sufficient information as yet to usefully answer the questions posed.

Hydro's Application has been filed as required by the Board in Order P.U. 25 (2000-2001). This is the first general review of Hydro's rates by the Board since 1992, and the first general rate review under the new regulatory regime established for Hydro during the mid-1990's. InterGroup has been asked to identify and evaluate issues relating to the following aspects of Hydro's filing, taking into account normal regulatory review procedures and principles appropriate for Canadian electric power utilities:

1. revenue requirements for 2002 as submitted by Hydro; and
2. cost of service and rate structures, particularly insofar as these rates affect the Island IC.

Board Order P.U. 7 (2001-2002) directs that pre-filed testimony by Intervenors is to be filed by August 15, 2001. This testimony has been prepared in response to this direction and based on our review as conducted to date.

As noted, our review to date has been limited by the time available, the availability of responses to the Information Requests filed by all parties, and the complexities associated with the first general rate review of Hydro in almost a decade. Accordingly, this initial testimony focuses on summarizing the contents of the Application, identification of key issues related to the above matters, and a brief overview of these issues. Following our review and clarification as required of Hydro's responses, further analysis and testimony on these issues is expected to be filed.

2.0 INFORMATION ON ISLAND INDUSTRIAL CUSTOMERS

The Island IC group is comprised of four large energy customers who operate with high load factors (i.e. they have relatively comparable levels of energy use throughout the day and throughout the year).

These four customers are forecast to purchase over 1400 GW.h of electricity in 2002, or about 20% of the energy sold by Hydro at rates regulated by the Board, at a cost of about $50 million in 2002. In each case, electricity costs make up a substantial portion of the operating costs of the customer's operation. In two cases, the customers have material hydro self-generation capability which can be from time to time used to supply surplus power to Hydro.

Industrial Customer concerns are focused around the following:

- Long-term stability and predictability in electricity rates
- Fair allocation of costs between the various customer classes to be served, including a fair interpretation of the legislative limitation on industrial customer rates from funding the rural subsidy
- Flexibility to tailor electrical service options to suit their operation to achieve an appropriately firm supply at the lowest cost for the load being served (i.e. using a mix of self-generation, Hydro firm power, Hydro interruptible power, curtailable service, etc.)
- Protection for customers from risky or government-initiated ventures or supply options that are not consistent with the provincial power policy objectives of efficiency and equitable power supply at the lowest possible cost.
- Lowest cost for power that can be achieved within the above considerations.
- Continued reliability of power supply for Island Interconnected customers.

Industrial customer concerns reflect the size of their capital investments in Newfoundland and Labrador, the long-term perspective essential to such investments and the major stake that these investments typically have in continued large-scale power purchases from Hydro. In addition, the industrial customer concerns reflect competitive pressures associated with selling industrial products to external markets.

3.0 OVERVIEW OF HYDRO'S APPLICATION

Hydro's Application requests the Board's approval of matters in the following broad areas:

1) The rates to be charged for the supply of power and energy to Hydro's Wholesale Customer (NP), Hydro's Rural Customers and the IC as of January 1, 2002.

2) The rules and regulations applicable to the supply of electricity to Hydro's Rural Customers.

3) The contracts setting out the terms and conditions applicable to the supply of electricity to the IC.

4) Hydro's 2002 Capital Budget.

The Application is made pursuant to the Public Utilities Act (R.S.N. 1990, Chap P-47) the Electrical Power Control Act 1994 (EPCA, 1994) (S.N. 1994, Chap E-5.1), and the Hydro Corporation Act (R.S.N. 1990, Chap H-16).

3.1 CONTENTS OF THE APPLICATION

The Application includes the rate schedules that Hydro proposes to apply starting in January, 2002, the rules and regulations regarding supply of power that Hydro proposes to apply starting January, 2002, the proposed industrial contracts without reference to the date these contracts are proposed to apply, and a copy of the 2002 Hydro Capital Budget.

Hydro has also filed pre-filed testimony of various staff and experts to address specific items which Hydro has chosen to expand upon.

3.2 ISSUES ARISING FROM THE APPLICATION

A number of key issues arising from the Application have been identified to date. These are reviewed in subsequent sections of this testimony under the following topics:

a) **Context:** The context for the Application and for review of the Application, including the legislative changes that have occurred since 1992 and the recommendations and orders of the Board that have been issued since 1992, merits careful review. This matter is reviewed further in section 4 of this evidence.

b) **Revenue Requirement and Overall Rate Increases:** The overall revenue requirement and level of rate increases requested do not fully reflect the material changes in Hydro's cost structure since rates were last set. These and other matters related to regulated revenue requirements are reviewed further in section 5 of this evidence.

c) **Cost of Service and Rate Design:** The relative rate increases that have been requested from the various classes are calculated using a particular methodology that has changed from previous rate reviews. The collection of each customer's portion of the revenue requirement also assumes a certain structure for rates, which can have substantial impacts on the amounts customers end up paying under various conditions. Further, as set out in Schedule C to the Application, the proposed IC contracts which are to be approved by the Board include changes from the current contracts as well as many material terms and conditions not addressed in the relevant rate schedules set out in Schedule A to the Application. These matters are reviewed further in section 6 of this evidence.

d) **Rate Stabilization Plan (RSP):** Hydro operates and proposes to continue a rate stabilization plan for NP and IC which has a material impact on the amounts charged to customers for power purchases during any year. Terms for operation of the RSP are included under the rate schedules included in Schedule A of the Application. Matters relating to the RSP are reviewed further in section 7 of this evidence.

4.0 CONTEXT FOR THE APPLICATION

Hydro has not appeared before the Board for a general review of revenue requirement, rate design, and rules and regulations applicable to the supply of electricity since early 1992 when rates to be charged to NP and rural customers were approved effective May 1, 1992. Since that time, Hydro has been before the Board for a number of specific reviews, including:

- **1992-1993 Review of Cost of Service Methodology:** This hearing reviewed Hydro's proposed Cost of Service methodology to be applied in future rate Applications, as well as a method to adjust the Rate Stabilization Plan (RSP) to take into account the variation in Hydro's rural revenues resulting from variations in the rates set by the Board to be charged by NP.

- **Various reviews of debenture issuance, capital purchases, construction projects, leases, and contributions in aid of construction:** These proceedings have been held, as required, by section 41 pf the Public Utilities Act.

- **1997/1998 rate adjustments as a result of the Harmonized Sales Tax:** Two Applications were reviewed to adjust rates to reflect the change to the Harmonized Sales Tax and associated implications for NP's rates, Hydro's rural and diesel rates, Hydro's industrial rates and the RSP.

- **Ex-parte Application to reduce Hydro's rates to Island Industrial Customers on an interim basis:** Hydro filed two Applications to adjust IC rates in accordance with the EPCA, 1994. In each case the revisions to rates were left as interim to be finalized in the current proceeding.

- **Reviews of abandonment of works:** A number of reviews of abandonment of works Applications were held pursuant to section 38 of the Public Utilities Act. In particular, the Board reviewed Applications on the Roddickton woodchip generating plant and the Roddickton diesel plant.

Each of the above reviews was carried out on a limited scope basis to address the subject matter at hand. As a result, it is apparent that even in the absence of the legislative changes and changes to regulatory methodologies that have occurred in the interim (discussed below), the current proceeding is required to address material changes in Hydro's operations, capital investments, loads, customer profiles, and changes in financial position that have occurred over the past 9 years.

However, the changes to be reviewed at the current proceeding are further affected by changes in legislation that have occurred in the interim and the changes that have arisen due to Board proceedings (such as the Cost of Service review and Rural Service review). Some of the key factors to be considered in this regard include:

- Regulation of industrial rates by the Board for the first time in a General Rate Application proceeding.
- New direction that industrial customers are not to be allocated any of the charges required to subsidize rural customers.
- New questions about Hydro's fair and reasonable level of return and ability to maintain a sound credit rating.
- A change to a rate base approach to regulation based on tests of the use, usefulness and prudent acquisition of assets to be charged to customers.

4.1 RELEVANT LEGISLATIVE CHANGES AND THEIR IMPACTS

In 1992, when Hydro appeared before the Board for the last general rate review, it was subject to three statutes which differ considerably from the legislation that is in place today. A detailed review of these changes is included in Attachment B to this evidence. A summary of changes that affect the current Hydro proceeding is provided below.

4.1.1 Summary of Changes in Legislation that impact current proceeding

To our current knowledge, the changes highlighted in Attachment B are the sum total of all legislative changes that materially impact on the current proceeding, and that are material to reviewing and approving/amending/rejecting Hydro's Application, in contrast to the approaches and approvals granted in previous Hydro rate reviews.

The changes to legislation can be summarized as being of the following broad types:

1. **Administrative details:** Many of the changes deal with what can be construed as administrative or housekeeping details without substantive material impact on the operation or purpose and intent of the legislation as it applies to regulation or rates. These include:
   a) the changes from Lieutenant-Governor-in-Council (LG-in-C) to shareholder authority in the Hydro Act
   b) the changes in pensions and collective bargaining in the Hydro Act
   c) the removal of certain legislative rights from the Hydro Act where these have been replaced by Hydro gaining similar rights in the Public Utilities Act, such as the right to enter customer's premises, disconnect service, etc.
   d) the removal of sections of the Hydro Act that dealt with change in frequency of power (periodicity of alternations of current) and replacement with similar sections in the EPCA, 1994

2. **Removal of some of Hydro's legislated rights:** The changes remove a number of the

legislated rights from Hydro, such as the rights to access to Crown lands or to request the Minister for Public Works to expropriate land for Hydro. The loss of these legislated rights would appear to be replaced by the need for Hydro to seek such approvals or permission without the benefit of legislation. These changes can be characterized in much the same way as the administrative details above – changes that have been introduced by the legislature to affect how government and its Crown corporations interact but which do not markedly change the nature or structure of the rate regulation issues to be addressed by the Board.

3. **Changes to jurisdiction and authority of Board and new power policy that affect all utilities:** A number of the changes in the legislation change the operation of the Board and the power policy of the Province, but do not affect Hydro differently than any other regulated utility in the Province. Examples include:
   a) no nuclear power
   b) new provisions to address for power emergencies and power planning
   c) new focus on efficiency and equity in management, operation and rate setting
   d) increased requirement for the Board to apply power policy
   e) increased powers for LG-in-C to direct Board

4. **Changes to the funding of the Rural Deficit:** The new legislation provides that Hydro's Rural Deficit will be funded via cross-subsidization between domestic, general service and street and area lighting customers of the Province. The new legislation directs that the former subsidy from the industrial class of customers will no longer be included in rates for the purposes of funding this deficit.

5. **Changes that materially affect the nature of Hydro, its form of regulation and its role in the provision of power in the Province:** These changes appear to fall largely into three categories:

   a) ***Changes that apply normal Newfoundland and Labrador utility regulatory principles and practices to Hydro:*** A number of the changes remove the legislative basis for Hydro to be regulated differently than other utilities under the various Acts, including:
      i. Removal of Hydro's exemption from the jurisdiction of the Board in section 21 of the earlier Hydro Act and limited scope for Board review based on various terms in the EPCA. This has been replaced by review of Hydro's rates and other matters under the Public Utilities Act. This change includes the need for Hydro to have rates set based on their operating costs, rate base, and some measure of a just and reasonable return.
      ii. The requirement under the Provincial power policy to earn a just and reasonable return so as to have a sound credit rating.

   b) ***Changes that are inconsistent with normal Newfoundland and Labrador***

utility regulation: A number of new sections in the legislation provide for terms that are otherwise inconsistent with the regulatory framework for utilities in the Province and which reduce the discretion of the Board with respect to material matters, including:

i. restriction on the Board in setting Hydro's rate base in section 17(2) of the Hydro Act
ii. restriction on the Board regarding review the liabilities of the Corporation under the Hydro Pension Plan and determining whether such expenses are reasonable and prudent
iii. restrictions on the Board regarding review of foreign currency losses and determining whether such expenses are reasonable and prudent
iv. restrictions on the Board regarding review of ongoing amounts paid under contracts to non-utility generators (from Hydro's Request for Proposals 92-195) and determining whether such expenses are reasonable and prudent
v. restrictions on the Board from setting amortization periods in regards to the Hydro Pension Plan expenses and the foreign exchange losses noted above.

c) ***Changes that affect Hydro's operations and rights as a Corporation:*** Only three changes to the legislation appear to change Hydro's nature as a business. These changes do not appear to be material to the current Application:

i. Legislative limitations on Hydro Corporate liability and director's liability
ii. The exclusive legislative franchise to serve certain areas and the exclusive rights to develop hydro-generation.
iii. The ancillary changes to the Freedom of Information Act, the Provincial Preference Act, the Public Tender Act and the Public Service Act.

4.1.2 Impact on Hydro from Changes in Legislation

Hydro's Application, and the pre-filed testimony of Hydro's witnesses and experts in particular, focuses to a great extent on the new requirements that have been imposed on the Board, Hydro and all interveners from the changes in legislation (in such areas as return on equity), in most cases without specific reference to the legislative change that causes such requirements, or without a description of how the change in legislation is being interpreted by Hydro.

Initial review suggests, however, that Hydro has not been substantially changed as a Corporation, or been placed in a substantially different financial position as a result of the changes to legislation. By way of example, none of the legislative changes in any way describes, cites or refers to Hydro as now being equivalent to an investor-owned corporation and none appear to substantially change:

- the risks faced by the Corporation in terms of loads, financing, physical environment, ability to supply power, competition from other utilities or sources of energy, etc.;
- the services that the Corporation is expected to provide;
- the restricted monopoly environment that the Corporation operates in;

- the security of the revenues received by the Corporation;
- the likelihood of the Corporation continuing to meet its debt obligations;
- the expectation that the Corporation will continue to act as an instrument of Government policy (as confirmed by Mr. Wells at page 6 of his evidence);
- the government guarantee on Hydro's current debt and the likelihood of the provision of that guarantee on future debt;
- the ability of the Corporation to continue to use its close relationship with government for the benefit of the Corporation and ratepayers (however, the practical interaction with the specific government departments may change).

The most significant changes for the purpose of the current hearing appear to relate to the method of regulation of Hydro by the Board (item 5 in section 4.1.1 above). As opposed to the limited scope that the Board previously maintained over Hydro's rates, there now appears to be significant additional authority for the Board to regulate Hydro in the best public interests. In this regard, the Board is mandated to have regard for the key facets of the Province's power policy as outlined in the EPCA, 1994, which focus on ensuring efficiency and equity in the supply and availability of power at the lowest possible cost.

In contrast to Hydro's assertion that it is now similar to an investor-owned utility (changes in item 5(a) in section 4.1.1 above), Hydro continues to have substantial additional protections compared to an investor owned-utility, e.g., the government guarantee on debt and associated access to financing. Hydro also continues to operate under restrictions on the Board in terms of their ability to fully regulate the Corporation (as noted in item 5(b) in section 4.1.1 above).

This matter may be considered further after detailed review of Hydro's responses to questions.

4.1.3 Impact on Customers and the Board from the Changes in Legislation

The most apparent impact on customers from the change in legislation is to industrial customers – both in respect of the rates charged to IC being now regulated by the Board, and the rates for IC not to include the rural deficit.

Assessment of the impact on customers and the Board from the changes in legislation will be considered further after detailed review of Hydro's responses to questions.

4.2 CHANGES THAT ARISE FROM PRIOR BOARD PROCEEDINGS

As noted above, the Board has held a number of proceedings with respect to Hydro that materially affect the methodologies and approaches used to determine rates as compared to the approaches used in 1992. These proceedings include the 1993 review of Cost of Service and the proceedings leading to the 1995 and 1996 reports on Rural Service.

The Board's reports in these matters provide detailed descriptions of each of the changes proposed or ordered, and it does not seem to be useful to this proceeding to summarize further here the information provided in those reports. Nonetheless, it is important to note that Hydro's methodologies for cost-of-service, and for allocating the rural deficit are substantively changed from the last review, and the new approaches have never been applied in a rate setting proceeding to date. In addition, only a portion of these changes stem from recommendations that the Board provided in 1993, 1995 or 1996; the others are only now being presented for the first time.

This matter may be considered further after detailed review of Hydro's responses to questions.

5.0 REVENUE REQUIREMENT AND OVERALL RATE INCREASES

The overall revenue requirement and level of rate increases requested do not fully reflect the material changes in Hydro's cost structure since rates were last set. Over 50% of the adjustments in Hydro's fuel costs are excluded from the requested revenue requirement and therefore will continue to be addressed through the Rate Stabilization Plan (RSP) rather than through base rates. Furthermore, although Hydro is asking the Board to send a signal to the financial markets about "normal" debt: equity ratio and return on equity (ROE) financial targets under its new legislative regime[1], the revenue requirement applied for does not reflect any of these adjustments.

The overall changes requested to the revenue requirement are reviewed below. Key issues related to the revenue requirement are noted for further consideration after detailed review of Hydro's responses to questions. Associated issues related specifically to the allocation of revenue requirements to different customer classes (COS), proposed rates and the RSP are addressed in subsequent sections of this testimony.

5.1 OVERVIEW OF PROPOSED REVENUE REQUIREMENT CHANGES

The overall average base rate increase applied for in 2002 is 6.1% before any RSP adjustment is applied.[2] This reflects a $26.3 million increase (8.9%) in revenue requirement from 2001 and a $32.8 million increase (11.3%) in revenue requirement from the 1992 final Cost of Service (COS).[3]

The following cost components for the proposed 2002 forecast showed above average percent increases (greater than 10% from 2001 and greater than 20% from 1992) and accounted for at least $1 million of the revenue requirement changes noted above:

- **No. 6 Fuel and RSP:** Although 2002 forecast cost for No.6 Fuel is down slightly from 2001, the increase since 1992 Final COS is $62.7 million (66%) before RSP allocations. The cost of fuel that is charged to customers through the revenue requirement is net of RSP.[4] Net of RSP, No. 6 Fuel cost included in revenue requirement has increased by 70% since 2001 and 98% since the 1992 final COS. Further comment is provided below on this factor.

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[1] See WEW, page 13 line 4 to page 15, line 10.

[2] See response to IC-206(1).

[3] J.C. Roberts, Schedule 1. As reviewed in response to NP-1, the JCR estimates differ slightly from the revenue requirement applied for in the Application. For example, for 2002 the JCR number exceeds the applied for revenue requirement by approximately $3.45 million before exclusion of COS as expense credits, IOCC revenue adjustment, and differences due to rounding of rates.

[4] IC-113 indicates No. 6 Fuel cost for 2002 net of RSP at $75.49 million. Based on the same adjustments, the No. 6 Fuel cost net of RSP is $ 44.41 million for 2001 and $38.21 million for the 1993 final COS.

- **Depreciation:** Although Depreciation cost is down slightly since 2001, the increase since 1992 final COS is $6.6 million (26%). This reflects the net impact of capital plant changes, the current methods of depreciation (sinking fund), and any changes in depreciation methods[5]. More detailed review of the Hydro responses is needed to assess this factor.

- **Interest and Margin/ROE:** Based on JCR Schedule 1, the "return on rate base" components (as reflected in Interest and ROE or Margin) in 2002 have declined by over $29 million (22%) compared with the 1992 final COS, and by over $3 million (2.9%) since 2001. Mr. Wells has stated that "taxpayers implicitly are subsidizing ratepayers to some degree" and that Hydro is proposing a 3% ROE in the short-term "to assist in offsetting the rate impacts resulting from increased fuel costs."[6] These factors are commented on further below.

- **Other Costs:** The overall category of Other Costs shows almost no change since 2001, and less than 9% increase since the 1992 final COS. Since 1992, the most significant cost increases have been in system equipment maintenance ($3.5 million or 26%), professional services ($1.5 million or 54%) and miscellaneous ($1.5 million or 52%). Cost decreases in excess of $1.5 million are noted since 1992 in transportation, office supplies expenses, and building rental and maintenance. These factors are not examined further at this time.

Although Hydro references frequently in the Application adjustments that are to be deferred to "the next general rate review", there is no clarity or commitment as to when the next such review will occur. The last time that the Board and intervenors carried out a general rate review of Hydro was in 1992. The results of that review have affected rates, the RSP and Hydro's activities for over 9 years – and the experience suggests a need for the Board in the current hearing to look well beyond the 2002 test year. This perspective is particularly relevant with respect to the implications flowing from fuel prices adopted in the test year (and related RSP implications), the financial target implications for future rates (and related issues as to Hydro/government interactions), and the future rate impact expected from ongoing expansions and new generation plant developments needed for the system to meet customer requirements. In this context it is also relevant to review Hydro's supply planning, including the performance of its hydro-electric generating and storage facilities

The long period since the last general rate review also will require the Board to review revenue requirement matters arising from prior years before 2002. In particular, assets changes during this period as well as interactions with the RSP may merit review to ensure that past actions are approved by the Board when such actions continue to have ongoing rate impact implications for customers.

The balance of this section focuses briefly on a few specific revenue requirement issues arising out of the above review.

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[5] See response to NP-55. Depreciation expense under the sinking fund method increases each year. IC-112 and JAB indicate that depreciation for the Island Interconnected System will increase from 2002 to 2003, assuming that no new assets are acquired, and then decline each year thereafter.

[6] WEW, page 14, line 28 to 31.

5.2 COST OF #6 FUEL

Mr. Wells has testified that "the price of No. 6 fuel is the overriding issue of cost with respect to this Rate Application" (WEW, page 3, lines 1 and 2).

The Application uses a forecast per barrel cost for #6 fuel that is 124% higher than per barrel cost adopted the last time rates were set in 1992.[7] This forecast affects both the base rates required (slightly less than 50% of this fuel cost per barrel increase is included in the applied for base rates), as well as the RSP.[8] The forecast assumes a projected exchange rate for 2002 of 0.701 $US/$CAN.[9]

Detailed review of Hydro responses is needed to assess issues arising from the No. 6 Fuel price.

For example, more recent forecasts suggest a slightly lower $US price in 2002 (at 18.78/bbl) but suggest slightly higher $US prices than previously forecast thereafter.[10] The full cost to Hydro and the RSP will also be affected by actual exchange rates – and the forecast adopted in the Application on this matter may be overly optimistic in at least the short term.[11]

Of more significance, it is necessary to assess the implications for the next several years. In this regard, Hydro has been asked to assess various alternatives as to the base price set in 2002 for No. 6 Fuel. These alternatives need to be reviewed taking into account impacts on base rates levels, the RSP (and rate impacts that flow from the RSP), the financial impacts on the RSP and on Hydro, and the extent to which sound rate design and COS principles are affected with respect to customer rates.

5.3 RETURN ON EQUITY AND DEBT:EQUITY LEVELS

Hydro has requested the Board to send a signal with respect to its proposals to move towards longer-term financial targets, including a return on equity and a target debt:equity structure for its regulated operations which are stated to be consistent with being an investor-owned utility that must raise equity in the global financial markets. This is a major change from the 1992 general rate review approach which

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[7] The forecast price in the Application is 19.88 $US/bbl for 2002, or 28.38 C$/bbl (see RJH, Schedule VIII and IC-189). The price set in the 1992 hearing was 12.5 C$/bbl, which has been used thereafter for annual RSP adjustments.

[8] The price in the Application proposed for setting the revenue requirement (and future RSP adjustments) is 20$C/bbl. In effect, the revenue requirement would absorb 47% of the change in No. 6 Fuel from the price set in the 1992 hearing.

[9] IC-190

[10] See IC-189. The latest forecast based on the July (short term) and June (long term) 2001 PIRA forecast is provided as well as the September 2000 PIRA forecast used for the Application. The latest forecast indicates prices declining to 17.03 $US/bbl; by 2005, and rising to 21.25 $US/bbl by 2010.

[11] The Application assumed an exchange rate of .694 $US/$CAN for 2001 (see IC-190); in contrast, the actual exchange rate in 2001 to June was 0.651 $US/$CAN (see IC-22). If the exchange rate stays at this recent level, and all other aspects of the forecast are met, the cost of No. 6 Fuel in 2002 would be 7.7% higher than projected in the Application.

focused primarily on the ability of Hydro to finance its debt. This change can be expected to increase materially Hydro's overall revenue required to be recovered from its regulated customers.

By way of example, Mr. Wells has testified that if Hydro were to request "a normal 11% to 11.5% ROE, the result would be a further 6% increase in base rates…"[12], which would virtually double the increase currently requested.

In addressing the long term financial targets for the regulated Hydro operations as well as the short-term financial proposals for the 2002 test year, it is relevant to review the implications of the new legislative regime and Hydro's perspective that taxpayers are subsidizing ratepayers in the short term. Several issues need to be addressed in the course of reviewing Hydro's responses to questions, including[13]:

- **Just and reasonable return for Crown-owned Hydro:** Hydro has interpreted the new legislative regime as requiring financial targets for Hydro identical to those required by any other utility that is operated as a commercial entity; further, Hydro has provided expert evidence that the normal financial targets for a utility operating as a commercial entity would be a debt/equity ratio of 60/40 and a ROE of 11% to 11.5%.[14] It is then stated that anything less than this "normal" return implicitly means that "the Government (shareholder) representing taxpayers is not getting an appropriate return on its investment in Hydro."[15] However, the whole matter of Hydro's interpretation of these requirements is a key issue to be dealt with when the Board is actually faced with setting an appropriate rate of return. Hydro has not to date been willing to provide answers to questions that would document the extent to which Government (shareholder) representing taxpayers, rather than the ratepayers (through payment of rates sufficient to develop retained earnings), has in fact provided equity investment that might merit any appropriate return.[16] As noted in Attachment B, the legislative regime as set out before in EPCA and now in EPCA, 1994 also directs that Hydro collect sufficient revenue from rates so as to "achieve and maintain a sound credit rating in the financial markets of the world." Accordingly, it is not readily apparent why the new legislation by itself necessarily leads to any conclusion as to a change in debt/equity ratio requirements or in required margin/ ROE. Hydro's current Application as well as other available evidence indicate that many factors need to be considered.[17] This matter will merit further more detailed review.

[12] WEW, page 15, lines 1 and 2.

[13] Mike Vilbert is providing expert evidence on behalf of IC with respect to return on equity and debt/equity levels.

[14] WEW, page 13 line 27 to page 14, line 9.

[15] WEW, page 14, line 27 and 28.

[16] See, for example, response to IC-48 and IC-122.

[17] For example, WEW notes (page 15, lines 26-29) that the Board in 1992 (before the new legislation) recommended that Hydro "move slowly towards the attainment of an 80/20 debt/equity target". The response to IC-182 notes that in 1992 the Board also recommended that Hydro be allowed to earn an internal interest coverage of 1.08 times gross interest – a target that it may be argued has in effect been pursued with respect to the 2002 test year Application. Addressing the credit rating issue directly (and ignoring other issues potentially relevant to setting any target debt/equity level), the response to IC-65 states:

> "It is impossible to conclude with any degree of precision at what level Hydro's debt ratio would negatively impact on the Province's credit rating. Based on the experience of other Crown Corporations, debt ratios of

- **Provincial Debt Guarantee:** In assessing the financial targets it is relevant to consider the impact of the debt guarantee and the related fee charge by the Province. Hydro understands that the debt guarantee will continue (IC-61), which indicates a continuing ability of Hydro to secure its required debt on reasonable commercial terms plus the 1.0 % fee charged by the Province. It is apparent that Provincial debt guarantee fees have become a material source of revenue for governments. The rationale for such charges appears to be based on capturing for taxpayers the full benefits of reduced borrowing costs associated with the Provincial Guarantee, rather than any need to offset adverse impacts on the credit rating of the Province.[18]

- **Dividends to Province:** Mr. Wells noted: "Commencing in 1995, Government, as shareholder, required Hydro to pay dividends."[19] He went on to state that subsequently "the Board of Directors of Hydro established a dividend policy of payment of 75% of the operating net income, provided it did not negatively impact the debt/equity ratio."[20] The impact of this one new policy implemented since the last general rate review in 1992 is projected to result in dividend payments to the Province of $140.5 million by the end of 2002, with roughly half of this total projected to be paid out in the test year 2002.[21] Hydro's Board has presumably concluded that the debt/equity ratio on utility operations in the Application for 2002 (of 85.5/14.5) is acceptable at this time and that the payment of the projected $70,147,000 dividend in 2002 will not negatively impact the desired debt/equity ratio. If no dividends had been declared to date and none were declared for 2001 and 2002, Hydro's debt/equity ratio on its utility operations in 2002 is projected at 74.89/25.11.[22]

- **Continuing directions from Government and other restrictions:** Mr. Wells has confirmed that Government has indicated that Hydro has a role to play in support of Government policy, or, as an instrument of public policy.[23] As reviewed in section 4 and Attachment B of this evidence, the new legislative regime also provides for terms for Hydro that are not applied to the regulation of other utilities in the Province. These factors merit consideration when assessing the just and reasonable return required for Hydro under the current legislative regime.

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up to 90% in the short-term have been maintained without negative impact on the Province's credit rating. The debt rating agencies would tend to focus on the utility's ability to fully recover its debt service costs without running the risk of having to turn to the Provincial government for assistance. Stated alternatively, as long as Hydro's debt is guaranteed by the Province, the debt rating agencies' concerns are with assurance that Hydro is self-sufficient, i.e. Hydro will cover its total out-of-pocket costs, including interest expenses, from its own revenues, without risk of a short-fall."

[18] See, for example, response to IC-67. The test year Guarantee Fee is currently reported as $11.9 million.

[19] WEW, page 15, lines 20-21.

[20] WEW, page 16, lines 4-7.

[21] See response to IC-66.

[22] See response to IC-66.

[23] WEW, page 6, lines 28-29.

5.4 NEW INTERCONNECTIONS TO THE ISLAND INTERCONNECTED SYSTEM

The Application addresses for the first time the inclusion into rates of the capital and operating costs associated with various expansions of the Island Interconnected System to connect previously isolated diesel communities, the most significant of these being the St. Anthony-Roddickton System (Great Northern Peninsula) interconnection completed in 1996.[24]

The Board has not previously addressed the question of the prudence of these costs, which represent a relatively major adjustment to the Island systems. In 1995, the Board recommended "that the prudence of costs associated with the St. Anthony/Roddickton interconnection be reviewed at the next Hydro rate hearing, following the interconnection, for the purpose of determining recoverable costs."[25] Accordingly, the prudence of these interconnection costs is a revenue requirement issue to be addressed with respect to the Application.

In response to a question on this matter, Hydro has provided various feasibility reports which will need to be reviewed with respect to the interconnection projects.[26] It would also, in our view, be relevant in this regard to assess the actual COS impacts to date from these interconnections. However, Hydro has generally not yet agreed to provide information and estimates on the actual COS impacts to date associated with these new interconnections.[27] Indirectly, it may be inferred that the Great Northern Peninsula Interconnection represents $67.7 million of the 2002 Island Interconnected System rate base; in addition, assignment of the generation and transmission costs for this interconnection to the Rural Interconnected Customers (rather than to all Island Interconnected System customers) would increase the 2002 forecast Rural Deficit by $9.3 million.[28]

In addition to revenue requirement issues, the Great Northern Peninsula Interconnection, in particular, directly affects IC COS to the extent that such expansions act to shift costs from the Rural Deficit (which is not to be allocated in any way to the IC) to the Hydro Island Interconnected System costs allocated to the IC. This matter is relevant to COS allocation issues addressed in section 6 of this evidence.

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[24] See IC-178 and IC-203. Since 1992, interconnections of Isolated Rural Systems to the Island Interconnected System include the Petite Forte community in 1993, St. Anthony-Roddickton System in 1996, the community of Westport in 1996, the community of South Bight in 1998, and the community of La Poile in 1999. Of these, the St. Anthony-Roddickton System clearly constitutes the most significant change, accounting for approximately 94% of the operating load in all of the communities affected by interconnections during this period. Overall, these interconnections have added about 61.0 GWh to the 2002 Island Interconnected System generation requirement (IC-203(e)), representing about 15% of the forecast 2002 generation for Rural customers on this System (IC-202, page 12).

[25] See report filed in response to CA-2, page 189 (R11).

[26] See response to IC-203 (6) as originally filed. A revision has been recently filed, but has not yet been reviewed.

[27] See, for example, responses to IC-96, IC-125(3); and IC-203 (1)(c), (f), (g), and (2).

[28] Compare response to IC-87 and JAB-1, page 2 (line 9, column 3) as regards rate base, and page 3 (line 6, column 5) as regards Rural Deficit.

5.5 OTHER PLANT IN SERVICE

As noted in section 5 of this evidence, Hydro is proposing new specific assignment of costs to certain IC ratepayers for frequency converters that were installed in the past to serve overall common system needs. In contrast, the current Application typically assumes the use and usefulness (and therefore inclusion in rates) of a number of assets which have substantially changed roles or functions since the last rate hearing, such as the St. Anthony's diesel plant, or have come into service since the last rate hearing, such as certain new Non Utility Generator (NUG) assets

It is relevant to review the prudence of Hydro's major capital expenditures since the last hearing, as well as the continued used and useful status of Hydro's existing assets for rate setting purposes. Further comment on this matter requires detailed review of Hydro's responses to questions.

5.6 NEW SOURCES OF GENERATION

The Application includes costs associated with new non-utility generation established since 1992[29], as well as plans to develop additional new base load generation required by 2007[30]. A wind generation feasibility study and demonstration project is also noted.[31] In responding to the need for new capacity and energy on the Island Interconnected System, it will continue to be relevant to assess options involving Industrial Customers able to provide curtailable loads and/or new generation supplies to the grid.

These matters may merit further comment after detailed review of Hydro's responses.

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[29] See response to IC-208.

[30] See response to IC-42 (information on various new generation supply options). WEW noted initiatives undertaken to develop new sources of generation (page 22). HGB noted that based on the latest load forecast beyond the 2003 additions, the Island system is expecting to experience capacity and energy deficits starting in 2006 and 2007 respectively (HGB, page 11, lines 10-14).

[31] HGB, page 11, line 29 to page 12, line 13. Also IC-127.

6.0 COST OF SERVICE AND RATE DESIGN

The relative rate increases that have been requested from the various classes are calculated using a particular methodology that has changed from previous rate reviews. The collection of each customer's portion of the revenue requirement also assumes a certain structure for rates, which can have substantial impacts on the amounts customers end up paying under various conditions. Additional issues arise with respect to the Industrial Contracts that the Board is asked to approve in the Application.

Review of these matters will require detailed review of Hydro's responses. A brief overview of some of the key issues is provided below.

6.1 RELATIVE CHANGES IN RATES AND COST OF SERVICE RATIOS

A summary of the proposed 2002 test year average rate increases as presented in the Application, in percentage terms, for each of the customer classes is provided in the table below:[32]

Customer Class	Base Rates	RSP[5]	Overall Increase
NP	6.7%	5.9%	12.62%
IC	10.4%[1]	7.4%	18.67%
Island Interconnected	3.7%[2]	NA	NA
Labrador Interconnected	-13.1%[3]	NA	NA
Isolated Systems	3.7%[4]	NA	NA

1- The IC base rates for non-firm service are requested to increase by a projected 29.9% (based on 2002 forecasts as set out in response to IC-202)[33] and for wheeling by 7.1%; these non-firm rates are not subject to RSP adjustments.

2- The 3.7% increase is based on the calculated NP increase to retail customers, as rural interconnected customers pay the same rates as NP customers.

3 - The Labrador interconnected rate changes vary considerably by customer class and location reflecting the move to uniform Labrador interconnected rates.

4 - Rates for government customers are requested to increase by 20% on the isolated systems reflecting the move towards 100% COS.

5 - RSP rate increases are projected based on 2001 forecast balances in the RSP.

The rate increases requested by Hydro vary between customer classes and geographic area in a relatively unexpected fashion given the changes such as the removal of Rural Deficit from IC rates. The IC firm

[32] See PRH, Table 2; DWO at page 2; and response to IC-206. All percent increases calculated on basis of forecast 2002 loads. The IC percentages have been derived directly from forecasts.

[33] The non-firm 2002 forecast load has an average load factor (approximately 42 % for the year), which moderates the impact of the non-firm rate increase. By contrast, based on 2001 forecast non-firm IC loads the effective average increase for non-firm rates is 53.2% (see response to IC-30).

service rate increases, including the RSP related increases, are considerably higher than the increases for NP or other customer classes. The IC also face high non-firm service rate increases (29.9% based on 2002 loads and 53.2% based on 2001 loads, reflecting imposition of full fuel costs for this service) and a 7.1% increase for wheeling.

Rate Stability objectives indicate the need to assess the Application in the context of its implications for future years. Hydro has provided information extending the NP and IC rate increases beyond 2002 to 2005, based on current forecasts, the test year rates as set out in the Application, and the impacts flowing from ongoing annual RSP adjustments.[34] It is apparent that the Application presumes significant ongoing rate increases in 2003 and 2004, with only moderate reductions in 2005. This information will be reviewed further, along with various alternative scenarios. The projections are sensitive to assumptions related to the RSP.

Specific COS and rate design issues related to the 2002 test year are noted below, focusing on matters relevant to Island IC ratepayers. It is noted that the overall firm rate design sets rates for IC that reflect 100% of the estimated COS[35]; accordingly, the issues related to firm rate levels for IC reflect COS methods and assumptions issues.

6.2 DIRECT ASSIGNMENT OF CERTAIN ASSETS TO CUSTOMERS

A number of Island assets that were previously allocated to Rural customers are now considered to be of general benefit to the interconnected grid. Other Island assets previously considered to be “common” are now only considered to be useful to only a subset of Island IC customers.

As noted in the previous section, numerous questions have been asked to assess the COS impact and rationale of the treatment given to assets related to new interconnections. Hydro’s responses need to be reviewed in detail. In general, it would appear that the “common” assignment of the Great Northern Peninsula project costs (including generation assets) increased IC COS for 2002 by 3.0%.[36]

Numerous questions have also been asked to assess the COS impact and rationale of the treatment given to frequency converter assets now specifically assigned to IC ratepayers that were previously treated as “common”.[37] Hydro’s responses need to be reviewed in detail. In general, it appears clear that the assets were installed initially by Hydro to meet system needs of “common” benefit to all customers. The only issues today are whether these assets still serve this purpose and, if this is not the case, whether it is fair and reasonable (in accordance with historical events, including any commitments undertaken by Hydro

[34] See response to IC-206 (2). The NP and IC increases indicated from 2002 to 2004 (2 years) approximate a further 13 to 14% above the full increase (including RSP) projected for 2002.

[35] See JAB-1, page 3.

[36] Compare IC-87, page 3, line 2, column 3 ($48.69 million IC COS with Great Northern Peninsula assets assigned a specific to the Rural Interconnected Customers) with JAB-1, page 3, line 2, column 3 ($50.16 million IC COS with these same assets assigned “common” as per the Application.)

[37] See, for example, responses to IC-31, IC-32, IC-41, IC-55. IC-56, IC-117, IC-134, IC-183 and IC-194.

and/or Government at that time, as well as with normal COS and rate design principles) for Hydro today to change the assignment of these costs.

6.3 COS METHODOLOGY ISSUES

Hydro has incorporated certain changes in the cost of service (COS) methods due to the 1993 Board review of Cost of Service, and has further amended the methodology in other areas. These factors need to be reviewed in detail. Areas that merit further review include[38]:

- Changes in system load factor since 1993 shift hydraulic generation more substantially to energy from demand.
- Holyrood capacity factor estimates and the use of 5-year averages.
- Load estimates used for COS.
- Use of 2CP allocation for generation demand costs (compared with other alternative allocators).
- Changes in Rural Deficit and RSP allocations related to COS method changes.
- Possible changes in cost causation factors related to the need for new plant to meet capacity constraints in the near future.

6.4 WHEELING RATES

The basis for calculating wheeling rates is an allocation of transmission costs (normally considered to be a capacity-related asset) to the amount of energy supplied by Hydro on the interconnected system.[39] This is different than the normal allocation of transmission costs based on the principles of cost causation, primarily related to demand. Further review of this matter appears to be merited.

It is also relevant to examine Hydro's plans to encourage customer access to the wheeling service and rate.[40]

6.5 ENERGY ONLY RATE FOR NP

Hydro continues to propose an energy-only rate for NP.[41] This rate design appears to result in different impacts on Hydro's risk and on the RSP than a more conventional two-part or three-part rate. Further review appears to be merited, including the impact of this rate on RSP allocations and ongoing rate adjustments.

[38] See responses to IC-6 through 9, IC79, IC-84, IC-91 and 93, IC-136and 137, IC-141 and 142, IC-202 through 204.
[39] See IC-34, IC-118.
[40] See IC-35 and 36, IC-57.
[41] See IC-205(1)

6.6 INTERRUPTIBLE RATES

The Application includes substantial changes to the interruptible rates offered to industrial customers. The Interruptible A rate proposed (as non-firm service) has substantially different cost characteristics than the current offerings.[42] Also, it is relevant to consider future access to Interruptible B and associated rules and regulations.[43]

6.7 TIME OF USE AND OTHER RATE OPTIONS

IC ratepayers are interested in assessing any rate options that may provide added flexibility and/or opportunities for enhanced efficiency. Time of use rates is one option that may merit further consideration.[44] Other issues and options include assessment of possible shared customer/system benefit opportunities (self-generation, underfrequency load shed program, voltage support, and secondary sales).

6.8 INDUSTRIAL CONTRACTS

Details on the contracts proposed by Hydro for the IC are to be reviewed and approved by the Board. As set out in Schedule C to the Application, the proposed contracts include changes from the current contracts as well as many material terms and conditions not addressed in the relevant rate schedules set out in Schedule A to the Application.[45] Issues arising with respect to these contracts, aside from clarification of specific provisions, involve the acceptability of proposed terms in light of normal utility practices. By way of example, provisions defining determination of "billing demands" are often defined in the rate schedules rather than only in the contracts. Provisions for termination, reduction of billing demands and terms for non-firm power services also merit review. These and other issues will be examined after Hydro's responses have been reviewed in more detail.

6.9 DELAYS IN IMPLEMENTING RATE ADJUSTMENTS

The current Application frequently mentions the need for rate changes to reflect Board recommendations and provincial power policy that are not proposed to be initiated until Hydro's ***next*** Application.[46]

It will be relevant to review the rationale for these proposed delays, as well as the potential implications as to when such adjustments are likely to occur.

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[42] See IC-33, IC-119, IC-165, IC-196, IC-202 (page 7).

[43] See IC-166.

[44] Hydro is not looking at this option. See response to IC-205 (2). Cost information provided by Hydro suggests limited opportunity to reduce thermal use during off peak times of the day or week (IC-202 (2)(c)), but some opportunity for seasonal cost differences (see IC-208 (4)).

[45] See response to IC-30, IC-44.

[46] See IC-205 (3).

7.0 RATE STABILIZATION PLAN

The RSP has formed a substantial portion of customer's bills since its inception – in 2002, Hydro forecasts that the RSP will account for 19.5% of the bills paid by island Industrial Customers.[47] Clearly, the RSP is an important element of the Hydro's overall rate structure that is before the Board in the Application. The RSP is included as a specific rate schedule in Schedule A to the Application.

The concept of a rate stabilization mechanism as it is applied in other similar jurisdictions (i.e. non-interconnected grids that generate electricity with a mix of hydro and petroleum, such as Yukon or the Northwest Territories)[48] is to provide protection for both ratepayers and the utility from variations in such uncontrollable variables as water availability and petroleum prices. In each case, the utility and the regulatory body normally set rates based on their best estimation of the costs to provide service over the test year, and the rate stabilization mechanism adjusts for any difference that occurs in utility revenues or costs due solely to these uncontrollable variables. From our understanding of the RSP, this is generally the way it was designed to work with Hydro's wholesale customer (NP) when it was created by the Board. We also understand that the same general principles were intended to be carried over by Hydro into the RSP as it was applied for industrial customers.

In contrast, the current Application proposes to set rates below the level required for cost recovery under current forecasts and to defer certain costs from today into the RSP to be collected from future ratepayers. This appears to be a marked departure from the RSP as it had been used earlier in Newfoundland and Labrador, and a practice not typically encountered in similar regulated rate stabilization mechanisms elsewhere.

In light of this proposal, it is important to review the operating mechanics of the RSP as it applies to each customer group. The application of the RSP to industrial customers (which has not previously been considered by the Board, except on an interim basis) also merits review. Further, any distortions that the RSP imposes on the rate structure need to be clearly identified and corrected.

The following highlights concerns identified to date with respect to the RSP, in addition to the overall concern to assess the impact and significance of the RSP for 2002 and subsequent years within the context of Hydro's overall rate structures. The concerns identified to date are reviewed under the following headings:

- ***Different rules for NP and IC:*** The fund operates under different rules for NP and IC.

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[47] See response to IC 191, page 3.

[48] Contrary to Mr. Wells testimony at page 20, Hydro does not operates the only non-interconnected grid in North America. Similar systems exist in two locations in the Northwest Territories, in one location in Yukon, with another under construction, and in at least one location in Alaska. Observations from some of these other locations provide useful insight into alternative approaches to cost control, allocation and approaches to rate stabilization.

- ***Load variation component:*** The fund includes two components that are fairly consistent with other similar jurisdictions (the hydraulic component and the fuel cost component) and one component that seems to be unique to Newfoundland – the load variation component.

- ***Cost of Fuel:*** Hydro has proposed a cost of No.6 fuel for the purposes of rates and the RSP that is below their forecasts for the next five years. This virtually guarantees substantial operation of the fund to defer fair costs from providing service today (rather than merely stabilizing variations in cost from forecast)

- ***NP's Energy only Rate:*** NP pays a rate which is based on energy only, compared to industrial rates which include demand charges. This affects the revenue forecasts for load variation in the RSP (which appears to be based only on the energy portion of the respective rates).

- ***Allocation of the Fund to IC and NP:*** Variations in hydro generation due to water availability or variations in fuel cost cannot be clearly assigned to a particular group of customers. The fund uses methods to assign these costs to NP and IC and the Rural Interconnected customers which are based on certain not previously tested assumptions.

- ***Proposed changes in RSP Operation:*** Hydro proposes to change some of the operating parameters of the RSP.

The above concerns, and any others that are subsequently noted, will be examined further after detailed review of Hydro's responses to questions.

7.1 DIFFERENT RULES FOR NP AND IC

The RSP is applied differently for NP than for IC in a number of ways. For example, the recovery adjustments are calculated to apply over a 12 month period in each case; however, the NP 12 month period is from July 1 to June 30 of the following year, while the IC recovery period is from January 1 to December 31 of each year. In addition, the balance used to calculate the recovery adjustments is the balance six months prior to the adjustment being implemented in NP's case, and three months prior to the rider being implemented in the IC's case. The materiality of such differences needs to be considered in the context of the fund's operation.

The other immediately apparent difference is that the NP RSP balance is adjusted to reflect the additional revenues received by Hydro when the NP rate (and consequently the rural Hydro rate) is increased outside of a Hydro Application. It does not appear that these revenues are applied to the various components of the fund on a consistent basis.

7.2 LOAD VARIATION COMPONENT

The RSP operates to protect Hydro from errors or misjudgements in its load forecast. Not only does this appear to markedly change the risk profile of the utility and reduce the normal incentives for a utility to correctly forecast its load for the tear year, but it appears to introduce a potential distortion in Hydro's rate design.

For example, we are unclear on the degree to which a customer class would be disadvantaged if Hydro's load forecast overestimated its load during rate design (which could increase the allocations of costs to the customer) and then basically charged the customer additionally via the RSP for not having as high a load as Hydro forecast (due to lost revenue that is greater than reductions in costs) or vice versa.

7.3 COST OF FUEL

In the case of this Application, Hydro is intentionally distorting its rate design to reflect a lower cost of fuel than it forecasts to be required.

Hydro in theory is indifferent to this forecast in that it still collects its costs via the RSP. However, it is not clear that the RSP effectively allocates the fuel cost to customers on the same basis that it would be allocated if it were included in the rate design. Other issues relate to the ongoing stability of the RSP, the extent to which rates are not reflecting current costs, and the ongoing implications for future rates.

7.4 NP'S ENERGY-ONLY RATE

The RSP adjusts the fund monthly for variations in NP and IC loads and the associated increase/decrease in revenue. However, in doing so, it appears to use the energy portion of each customer's rate.

In NP's case this energy portion of the rate reflects 100% of the incremental revenue to Hydro from any load increase. However, in the IC case, the energy portion of the rate only reflects a part of the incremental revenues to Hydro (with the rest of the increased revenues coming from increases in the demand charges to the IC).

7.5 ALLOCATION OF THE FUND TO IC AND NP

At the end of each month, the RSP must be adjusted to allocate the variations in fuel cost and hydro production to each of NP and IC. It is not possible to do this allocation on the basis of causation between NP and IC for such matters as high or low water flows.

Instead, Hydro has developed certain methodologies to do this allocation which do not appear to have been reviewed by the Board or intervenors in the past. It will be important in this hearing to review the actual allocations made to date to each customer group.

7.6 PROPOSED CHANGES IN RSP OPERATION

The current Application proposes certain revisions to the operation of the RSP based on an increased cap ($100 million for the NP portion) and methodological changes (see response to IC 120). These will require review in light of the above concerns.

ATTACHMENT A – RESUME - CAMERON F. OSLER

PRESIDENT AND SENIOR CONSULTANT

EDUCATION:

Simon Fraser University
M.A. (Economics) 1968

University of Toronto Law School
1964-1965

University of Manitoba
B.A. (Philosophy) 1964

PROFESSIONAL HISTORY:

1974 - Present

Founding partner and President of InterGroup Consultants Ltd. (formerly InterGroup Consulting Economists Ltd.). Director, CBT Energy Inc. (2000 - Present)

Strategic planning and multi-disciplinary project team management experience, based on resource and regional economics expertise relating to mining, energy (particularly hydro-electric generation and renewable liquid energy fuels), and downtown tri-government urban development projects.

Detailed project experience is outlined below separately under each of the following headings:

- Utility Regulation – Expert Analysis and Testimony at Hearings
- Strategic Planning & Multi-disciplinary Project Team Management - Resource, Regional and Urban Development Projects
- Socio-Economic and Environmental Assessment & Related Public Consultation – Mining, Hydro-electric, Forestry and Other Major Projects
- Compensation & Monitoring Related to Resource Project Impacts
- Resource Rent, Royalty and Tax Policy – Related Expert Evidence
- Other Strategic Planning and Assessment

Utility Regulation – Expert Analysis and Testimony at Hearings

- **For the Manitoba Industrial Power Users Group (1987-1999),** expert testimony before the Manitoba Public Utilities Board in Manitoba Hydro electricity rate hearings, including rate applications in 1987/88, 1989, 1990, 1991, 1992, 1994, 1995, and 1998, and the Manitoba Hydro Major Capital Projects hearing in 1990. Represented MIPUG at hearings before the Board in 1999 to approve the purchase of Centra Gas by Manitoba Hydro.

- **For the Yukon Energy Corporation (1989-1998)**, expert testimony before the Yukon Utilities Board on planning major capital projects (1992) and on electricity costing and rates related to rate applications by Yukon Energy Corporation (1989, 1991, 1993, 1996, 1997, 1998).

- **For the Bruce Municipal Telephone System in the early 1990's,** expert economic evidence to the Ontario Telephone Service Commission related to the cost of equity capital.

- **For Government of Yukon, expert testimony before the National Energy Board in 1985**, expert testimony on costs and rates pertaining to the Northern Canada Power Commission.

- **For IPSCO during the 1980's**, expert testimony before Saskatchewan Utilities Regulatory Commission hearing on the first and second rate applications by Saskatchewan Power Commission.

- **For Stelco, INCO and the Motor Vehicle Manufacturers' Association of Canada, in the 1977-1979 Ontario Energy Board hearings HR5,** examining Ontario Hydro's electricity costing and pricing principles; provided consulting advice and expert testimony on the issues and options pertaining to that hearing.

- **For a consortium (The Consumers' Gas Company, Union Gas, Northern and Central Gas and the Ontario Ministry of Energy), a 1974 report on natural gas requirements throughout Canada;** provided expert testimony before the National Energy Board on this report.

Strategic Planning & Multi-disciplinary Project Team Management - Resource, Regional and Urban Development Projects

- **For the City of Winnipeg and Neeginan Development Corporation (1998),** project director responsible for preparation of the Development Plan for the Thunderbird House project on Main Street.

- **For Spirit of Manitoba Inc. and Manitoba Entertainment Complex Inc. (1994-1995),** responsible for management of all aspects of a project to develop a new downtown entertainment complex and to retain the Winnipeg Jets Hockey Club in Winnipeg; managed the multi-disciplinary team carrying out negotiations, siting, design, costs, feasibility planning, environmental assessments, and other work required to secure approvals under tight deadlines specifically for the new arena component of the project.

- **For The Forks Renewal Corporation (a corporation owned by Canada, Manitoba and Winnipeg) during the late 1980's and early 1990's,** Development Coordinator responsible for planning and directing initial development and financial activities (1987-1993), including negotiation of land exchange agreements, preparation of a Phase I Concept and Financial Plan, site planning and Stage One projects, roads and services; ongoing financial and strategic planning counsel.

- **For Government of Yukon (Department of Economic Development, Mines & Small Business) (1985-1987),** management of multi-disciplinary team carrying out financial, economic, legal and strategic planning work relating to the devolution and transfer to Yukon of the Northern Canada Power Commission assets and operations in Yukon; participation in all related negotiations.

- **For the East Yard Task Force (comprised of the governments of Canada, Manitoba and Winnipeg) (1985-1986),** general advisor and manager for all consultant work (planning and architectural, engineering, financial and legal) related to the redevelopment of a major rail yard area in downtown Winnipeg.

- **For North Portage Development Corporation (1984-1987),** economics and financial counsel during the initial development phase; coordinator for work relating to corporate financial plans, selection of major developers (retail, housing and office projects), and negotiation of long-term agreements (land lease, development and other related agreements) with each of the selected developers.

- **For Canadian Methanol Canadien during the 1980s**, participation in an executive capacity in a partnership venture involving Inter-City Gas Corporation and The M100 Group to develop methanol vehicle fuel [management of multidisciplinary project team involving engineers, planners, financial, legal, and other professionals to demonstrate and develop hybrid (natural gas and wood feedstock) methanol production facilities as well as different market uses for methanol (including use in flexible fuel passenger vehicles)].

- **For the Government of Canada in the late 1970's,** project director of a major multi-disciplinary study to examine the feasibility of producing liquid fuels (including methanol) from biomass feedstock resources throughout Canada; this study included examination of liquid fuel production options involving the joint use of either electricity or natural gas along with biomass feedstock. The multi-disciplinary consulting team included firms with chemical engineering and forestry expertise.

Socio-Economic and Environmental Assessment & Related Public Consultation – Mining, Hydro-electric, Forestry and Other Major Projects

- **For Manitoba Hydro (1999 – Present),** Study Leader responsible for socio-economic assessment and planning work in a multi-disciplinary Consultant Management Team retained to assist Manitoba Hydro in the conduct of the environmental assessment programs associated with future planning for three potential hydroelectric generating stations in northern Manitoba, including site selection and environmental assessments for the associated transmission facilities.

- **For uranium mining companies in northern Saskatchewan during the 1990's**, project director for consultants regarding socio-economic impact assessment, economic impact and cost-benefit assessments, and public consultation design and implementation for the Rabbit Lake expansions (Cameco Corporation, 1991-1993), the McArthur River developments (Cameco Corporation, 1993-1996), the Cigar Lake developments (Cigar Lake Mining Corporation, 1993-1996), and the Rabbit Lake extension (Cameco Corporation, 1999-); provided related evidence and expert witness testimony for the Rabbit Lake federal environmental review panel hearing and the McArthur River developments federal-provincial environmental review panel hearings. Provided advisory review for InterGroup's similar socio-economic and economic impact assessments, and public consultation work for COGEMA related to Cluff Lake mine projects during this period.

- **For Yukon Energy Corporation (1992-1996**), advisory reviews of environmental impact assessment work for re-licensing of the Aishihik hydro-generation facility.

- **For Cameco, Cigar Lake Mining Corporation and COGEMA (1993-1994),** facilitation of an agreement in principle for an impact management agreement involving seven Athabaska communities (this was one element of the socio-economic/public consultation EIS work related to the McArthur River and CLMC projects).

- **For Repap Manitoba, Inc. (1989-1991)**, project management of the socio-economic impact assessment, and design and implementation of an extensive public consultation program, for the proposed Phase 1 Manitoba expansion.

- **For aggregate producers in Ontario during the 1980's and early 1990's,** socio-economic impact and resource policy evaluations relating to proposed aggregate developments in southern Ontario (Puslinch, Milton and Niagara Escarpment Planning Area); provision of resource economics expert testimony before the Ontario Municipal Board on behalf of TCG Materials Limited and on behalf of Armbro Aggregate.

- **For the City of Winnipeg in the 1990's**, socio-economic impact assessment for the new Charleswood and Main/Norwood bridge developments (two separate assignments; provided advisory review for other InterGroup principals who directed this work, as well as assistance in coordination of hearing testimony for the regulatory review of the Charleswood bridge project.

- **For the Moosonee Development Area Board (early 1990's),** socio-economic counsel in an intervention relating to potential impacts of Ontario Hydro's proposed hydro generation development of the Moose River Basin.

- **For Manitoba Hydro in the late 1980's and 1990's,** senior advisory review as required by other InterGroup principals carrying out the following assignments: socio-economic impact assessment and public consultation program for the Conawapa hydro generating station EIS (1989-1993); socio-economic impact assessment and public consultation program for the Split Lake transmission line project (joint study with the First Nation, early 1990's); socio-economic impact assessment and public consultation program for the siting and the EIS related to the Winnipeg-Brandon transmission line and Neepawa substation projects (1995-1997); study to review environmental externality and compensation cost modeling for hydro-generation and related transmission line projects (1996-1997). Deputy Project Director for initial environmental assessments study for third Bipole Transmission Lines (1986-1987).

- **For Manitoba Hydro in the early-to-mid 1980's,** various investigations with respect to the environmental and socio-economic impacts related to planning of new power generation projects in northern Manitoba, including deputy project director for the Burntwood River Environmental Overview Study (1980-1984), and review of InterGroup's work (carried out by senior staff) to prepare the socio-economic assessment and conduct public consultation for the Limestone hydro-electric generating station EIS.

- **For Alcan in the early 1980's,** management of investigations with respect to the socio-economic impacts of a proposed aluminum smelter in Manitoba.

- **For Key Lake Mining Corporation in the early 1980's,** expert testimony before the Commission of Enquiry on socio-economic impacts associated with the uranium project at Key Lake.

- **For Amok Ltd., in the 1977 Saskatchewan hearings on uranium developments,** provided expert testimony before the Bayda Commission of Enquiry on socio-economic impacts associated with the Amok mining project at Cluff Lake.

Compensation & Monitoring Related to Resource Project Impacts

- **For Manitoba Hydro in the 1990's,** expert socio-economic and resource economics assistance with respect to claims by the community of South Indian Lake (early 1990's) and by Northern Flood Agreement communities, including the Cross Lake First Nation (1999 - Present), related to post-project development impacts from hydroelectric power development.

- **For uranium mining companies (1999),** project director for the preparation of a draft work plan for a community vitality monitoring program for northern communities in Saskatchewan affected by uranium mining development; the work plan requirement arose out of federal-provincial environmental impact panel hearings on the McArthur River and Cigar Lake mining projects; the work plan was prepared for a working committee with representatives from the three uranium mining companies (Cameco Corporation, COGEMA, and Cigar Lake Mining Corporation0, the Saskatchewan Northern Mines Monitoring Secretariat, and the northern Saskatchewan Health Districts.

- **For BC Hydro (early 1990's),** evaluation of a trust fund proposed to compensate five Lillooet Nation Bands for damages from hydroelectric generation and transmission activities.

- **For the Beaufort Sea Steering Committee (early 1990's),** review of wildlife compensation program options in the event of an oil spill in the Beaufort Sea.

- **For Manitoba Hydro (1989-1990),** project management of an independent post-project evaluation of the Grand Rapids Project impacts on Aboriginal communities, including direction of the socio-economic component of the evaluation.

Resource Rent, Royalty and Tax Policy – Related Expert Evidence

- **For Regional Municipality of Ottawa Carleton (RMOC) in the mid-1990's,** expert resource and regulatory economist evidence before the Ontario Municipal Board on By-Law 234/92, which imposed compensation payments on private landfill operators in the Region.

- **For a group of pipeline companies in Ontario (1989-1992),** assistance with coordination of expert evidence in an arbitration, and provision of expert evidence on methodology to determine annual rent for pipeline use of a transmission corridor owned by Ontario Hydro.

- **For Sun Oil in the 1970's,** counsel on preparation of a brief to the Government of Canada on the proposed Federal Land Regulations for Oil and Gas Lands.

- **For the Canadian Potash Producers' Association in the 1970's and early 1980's,** expert assistance with taxation discussions with Saskatchewan authorities, analysis of the proposed government takeover of the potash industry, and liaison with legal counsel.

- **For the Uranerz-Inexco joint venture in the 1970's,** participation in discussions between the Saskatchewan Government and the uranium industry concerning uranium taxation revisions; provided economic counsel for these discussions.

- **For the Mining Association of British Columbia in the 1970's**, expert testimony before the Commission of Enquiry into property taxation in that province.

- **For the Mining Association of Canada in the 1970's**, preparation of analytical models for comparison of different mineral taxation structures.

- **For Canadian Industrial Oil and Gas Ltd. In the 1970's**, analysis of the public policy aspects of Saskatchewan Bill 42 relating to taxation (advice to legal counsel related to a court case).

Other Strategic Planning and Assessment

- **For Manitoba Hydro (1999 – Present),** assistance on various matters, including policy reviews related to debris management programs and planning related to US market consultations.

- **For the Yukon Energy Corporation and the Yukon Development Corporation (1987-ongoing),** financial and strategic planning counsel on major issues, including rate policy planning (see also Utility Regulation), major capital planning issues (see also Environmental Assessment), management agreement arrangements, and negotiations between YEC and various owners of the Faro mine.

- **For the Northern Manitoba Economic Development Commission (1991-1992),** participation in the preparation of two reports, contributing to the Commission's Sustainable Economic Development Plan for Northern Manitoba for the 1990s.

- **For Regional Municipality of Ottawa Carleton (RMOC) during the 1990's,** economic assessments of options to extend the life of the Trail Road Landfill site.

- **For Metropolitan Toronto (late 1980's),** economic analysis of the best available technology for the utilization of the landfill gas resources at the Keele Valley Landfill site.

- **For a western energy company (early 1990's),** preparation of a Cost-Benefit Analysis of a 160 MW co-generation project, assessment of the implications of the project for Manitoba Hydro, and participation in the discussions between the company and Manitoba Hydro.

- **For Western Economic Diversification (late 1980's),** assessment of Winnipeg tri-government development corporation cash flow scenarios.

- **For the Government of Manitoba during the late 1980's and early 1990's,** advice and assistance in the preparation of proposal calls for the redevelopment of a historically significant site in Winnipeg, as well as participation in the developer selection and negotiation process.

- **For the Canadian Electrical Association in the late 1970's,** management of interdisciplinary team investigations with respect to the impacts of proposed federal atmospheric emission control guidelines on Canadian electrical generating industry thermal power stations.

1968 - 1974 MANAGER AND SENIOR CONSULTANT, Hedlin Menzies/Acres Consulting Services (Winnipeg)

RESEARCH ECONOMIST, Hedlin Menzies & Associates Ltd. (Winnipeg)

Project manager of major studies involving regional resource and cost-benefit impact policy issues relating to prairie manufacturing, prairie elevator and transportation rationalization, Manitoba Hydro northern development activities, Canadian energy requirements and research and development priorities, alternative export policies for natural gas, Canadian Merchant Marine development options, alternative rail route options in the Yukon and northern British Columbia, and various mineral resource policy options pertaining to mining development and taxation.

Sessional lecturer on mineral economics for one year at the University of Manitoba's Natural Resources Institute.

RESEARCH PAPERS:

"The Process of Urbanization in Canada, 1600-1961." Simon Fraser University (M.A.) Thesis. 1968.

"Technological Change and the Economics of Agricultural Development." Simon Fraser University (M.A.) Thesis. 1968.

"Economic Analysis of Short-Term Alternatives Regarding Southern Indian Lake in Manitoba" (joint work with Dr. A.M. Lansdown, P.Eng., 1969).

"A New National Development Policy for Canada: The Relevance of Western Canada." Prepared for the Liberal Conference on Western Objectives. 1973.

"Canada's Gains and Losses from Oil Export Taxes" (joint work with Dr. R.W. Fenton, 1973).

"Resource Management Factors Influencing Mineral Development in North Central Canada." Paper presented to the annual western meeting of the Canadian Institute of Mining and Metallurgy, Winnipeg, October 7, 1974.

"Energy, Provincial Rights and Canadian Unity." 1973.

"An Evaluation of 'An Energy Policy for Canada' " (joint work with Dr. R.W. Fenton, 1973).

"Resource Management Factors Influencing Manitoba Mining." Natural Resources Institute, University of Manitoba. 1974.

"Liquid Fuels from Renewable Resources in Canada: Systems Economic Studies." Paper presented to the Institute of Gas Technology Symposium on Energy from Biomass and Wastes, Washington, DC. August 1978.

"Canadian Scenario for Methanol Fuel." Paper presented to the Alcohol Fuels Technology Third International Symposium, California, January 1979.

"Socio-Economic Impacts from Potential Canadian Methanol Fuel Development." Paper presented to the IV International Symposium on Alcohol Fuels Technology, Brazil. October 1980.

"Canadian Methanol Development Using Natural Gas and Wood Feedstocks." Paper presented to the First IEA Conference on New Energy Conservation Technologies and their Commercialization, Berlin. April 1981.

"Methanol as an Alternative Automotive Fuel: CMC's Approach and Experience." Paper presented to the West Coast International Meeting of the Society of Automotive Engineering, Vancouver, BC. August 1983.

"Status of CMC Fuel Methanol Production and Market Development Programs." Paper presented to the VI International Symposium on Alcohol Fuels Technology, Ottawa. May 21-25, 1984.

ATTACHMENT B - CHANGES IN LEGISLATION

Public Utilities Act

The changes that have been made to the Public Utilities Act since 1992 are generally not material to this proceeding. However, the changes to the Hydro Act and the replacement of the earlier Electrical Power Control Act (EPCA) with the Electrical Power Control Act, 1994 (EPCA, 1994) in effect result in a substantially different application of the Public Utilities Act to Hydro. These changes are reviewed below.

Hydro Corporation Act

The Hydro Corporation Act (Hydro Act) has been changed substantially since 1992, but the changes that are relevant to this Application appear to relate to a few key areas:

- **Substantial reduction in the authority of the Lieutenant-Governor-in-Council and increase in the authority of the shareholder and others:** The revised Hydro Act reduces Hydro's requirement to seek Lieutenant-Governor-in-Council (LG-in-C) approval in a number of areas, and changes the approval required in other areas to the shareholders of the Corporation. These areas generally include:
  a) Director's salaries (section 5(4))
  b) Appointment and Terms of Appointment for Chief Executive Officer, and provision of direction to that CEO (section 6(3))
  c) Agreements for appointment of CEO, President and Chairperson (section 8(1))
  d) the By-Laws of the Corporation (section 10)
  e) Oversight of bank deposits (section 16(1)(h))
  f) Establishing authorized share capital (section 25(1))
  g) Approval of borrowings (was LG in C, now can be delegated to Minister of Finance) (section 27(1))
  h) Guarantee of borrowings (was LG in C, now can be delegated to Minister of Finance) (section 28)
  i) Approval of annual borrowing program (section 40(2))
  j) Appointment of Auditors (section 42(3))

- **Removal or revision of many exclusive and legislated rights previously possessed by Hydro:** The new Hydro Act removes a number of rights that had previously been enshrined in legislation. These include:
  a) the right to request the Minister of Public Works to expropriate lands etc. for the Corporation under the Expropriation Act (section 17)
  b) specific legislative provisions relating to the construction, erection and maintenance of assets on Crown lands (section 18)
  c) the ability for the Lieutenant-Governor-in-Council to provide certain rights in land and water to the Corporation notwithstanding any provisions to the contrary in the Crown

Lands Act or any other Act (section 19); also Application of the Crown Lands Act to leases or licences for water power issued to the Corporation (section 20)

d) the legislative basis provided for the Lieutenant-Governor-in-Council to provide all or part of an exclusive right to develop and generate power in Labrador and sell the power (for consumption or resale) (section 26)

e) certain legislatively-based limitations on Corporate liability and director's liability (section 44)

f) rights to enter onto the premises of customers to inspect wiring and to disconnect service to customers whose wiring is below standards (section 49 – Hydro has gained comparable rights under section 45 of the Public Utilities Act)

g) rights to terminate power supply to rural customers for non-payment (section 50 – Hydro has gained comparable rights under section 46 of the Public Utilities Act).

The new Act also removes exclusive rights which were provided in the earlier Act, such as the generally exclusive franchise to serve (for consumption or resale) areas of the Province otherwise not franchised before January 1, 1975, and the exclusive right to develop, generate and sell (for consumption or resale) hydro-electric generated power (section 14).

- **Removal of previous limitation on jurisdiction of Board, and implementation of new restrictions on the Board:** The new Hydro Act removes the exemption for Hydro from the jurisdiction of the Board previously contained in section 21. The new section 17 addresses the Application of the Public Utilities Act to Hydro, and implements new restrictions on the Board in the Application of that Act. In particular, the new section 17 addresses:

a) the definition of rate base for the Corporation, which "shall include the property and assets of the corporation at their net book value" excluding investments in subsidiaries (section 17(2))

b) inclusion of specific expenses related to the pension plan, foreign currency exchange and all amounts paid to non-utility generators (under Request for Proposals 92-195) and the terms of amortization of these expenses, and restrictions on the Board preventing these expenses from being declared to be not reasonable or imprudent for the purposes of the Public Utilities Act (section 17(3) and 17(4))

c) preventing the Board from making retroactive adjustments to the rates, tolls or charges of Hydro prior to the coming into force of the new Hydro Act (section 17(5))

d) providing that where there is a conflict between the Public Utilities Act and the Hydro Act, the Hydro Act is to prevail (section 17(8)).

Further, the new section 17 effectively replaces a substantial portion of the earlier Electrical Power Control Act that was in place in 1992 and that outlined the method and principles for regulation of Hydro's rates notwithstanding the exemption that existed in section 21 of the earlier Hydro Act.

- **Changes to pensions and collective bargaining:** Repeal of the previous section 22 and addition of new sections 18 and 19 change the provision of pension and collective bargaining in each case to remove the typical public service provisions (the Public Service Pension Plan and the Application of the Public Service Act) and to implement provisions for a Hydro Pension Plan and collective bargaining under the Labour Relations Act.

Electrical Power Control Act, 1994

The predecessor EPCA was the basis for the Hydro Applications prior to the current EPCA, 1994 being proclaimed. The new Act is substantially different in form and content than the old Act. For the purposes of this Application, the following key changes appear to be relevant:

- **Newfoundland Power Policy:** The broad power policy of the Province is set out at section 3 and section 4 of both the EPCA and EPCA, 1994. The changes to power policy as they relate to the current proceeding appear to be focused primarily on the following:

  a) ***Hydro now to earn a just and reasonable return:*** The EPCA, 1994 removes the requirement for Hydro to "recover the cost of service provided by it and a margin of profit sufficient to achieve and maintain a sound financial position" (EPCA, section 3(c)(ii)) and replaces it with a requirement for Hydro to "earn a just and reasonable return as construed under the Public Utilities Act" (EPCA, 1994, section 3(a)(iii)).

  In both the EPCA and the EPCA, 1994 Hydro was required to collect sufficient revenue from rates so as to "achieve and maintain a sound credit rating in the financial markets of the world" so there may not be any change to overall direction from this section.

  No mention is made in the Acts as to what constitutes a sound credit rating or how this requirement is amended (if at all) by the provision of a government guarantee on Hydro's debt. The Public Utilities Act addresses the return to be earned at section 80, but provides no further information on the definition or value of a 'just and reasonable return'. The only section which appears to provide any guidance on the practical definition of a 'just and reasonable return' is section 4 of the EPCA, 1994 which states that the Board shall "apply tests which are consistent with generally accepted sound public utility practice" (EPCA, 1994, section 4).

  b) ***Industrial Customers no longer to subsidize rural customers:*** The EPCA, 1994 adds a new policy of the Province that "...after December 31, 1999 industrial customers shall not be required to subsidize the cost of rural customers in the province, and those subsidies being paid by industrial customers on the date this Act comes into force shall be gradually reduced during the period prior to December 31, 1999" (EPCA, 1994, section 3(a)(iv)). The previous EPCA had required that the forecast costs for supply of power to all Hydro customers include "the difference between the forecast annual revenues and the costs allocated by the Hydro Corporation to serve rural customers" (EPCA, section 3(2)).

c) ***New policies regarding efficiency and equity:*** The EPCA, 1994 includes in section 3(b) new policies that can be categorized as being related to efficiency and equity. These include efficiency of production, transmission and distribution; equitable access for consumers to an adequate supply of power; production and delivery of power at the lowest possible cost consistent with reliable service; and, priority access for power producers to use the power they produce. These provisions appear to be entirely new and not included in the EPCA.

d) ***New emergency provisions:*** The EPCA, 1994 includes new provisions to apply in the case of power supply emergencies at sections 3(c) and 3(d) and outlined in detail in Part III. These provisions are entirely new and were not included in the EPCA.

e) ***Prohibition on nuclear power:*** The EPCA, 1994 prohibits planning for future power supply from including nuclear power (section 3(f)). This provision is entirely new and was not included in the EPCA.

f) ***Board shall implement power policy:*** The EPCA 1994 continues to direct the Board to implement the Provincial power policy (as set out in the Act) but removes clauses which were present in the EPCA which qualified the Board's requirement to implement the power policy "so far as it is practicable" (EPCA, section 4(1)) and which ensured that the Application of the Province's power policy was not to "limit, qualify or derogate" (EPCA, section 4(3)) from the power of the Board under the Public Utilities Act. EPCA, 1994 directs that in implementing the Provincial power policy, the Board "shall apply tests which are consistent with generally accepted sound public utility practice" (section 4). Previously, the direction was to apply such tests with respect to Hydro's rates "so far as it is practicable".

- **Broadening Application of Act to all producers and retailers:** In a number of areas, the EPCA, 1994 expands upon provisions in the EPCA and the Hydro Act to ensure that all producers of power are included in the various sections (except those producers specifically exempted by the Act or Lieutenant-Governor-in-Council), where they were previously limited to Hydro as the only producer, as well as including Hydro within the definition of 'retailer' of power.

  One such example is EPCA, 1994 Part V regarding 'Change of Frequency' (the periodicity of alternations of current) by any retailer where this had been previously only applied to Hydro as it was addressed in the Hydro Act (sections 45-48).

  Another example is the broadening of EPCA section 12 (now EPCA, 1994 section 5) which permits the Lieutenant-Governor-in-Council to refer matters to the Board for a public hearing. This had previously been largely limited to matters regarding the rates charged by Hydro, but it has been changed in the EPCA, 1994 to include any rate or other matters, and it is no longer limited to Hydro.

The other sections where a change of this type is included do not appear to be material to the current Application.

- **New powers for Lieutenant-Governor-in-Council to direct Board policies and procedures and to make regulations:** The EPCA, 1994 provides that the Lieutenant-Governor-in-Council may provide the Board with direction with respect to policies and procedures in determining rate structures and other rate matters under section 5.1. This ability to provide direction was not included in the EPCA. The EPCA, 1994 also provides that the Lieutenant-Governor-in-Council may make regulations in a number of areas to "carry out effectively the purpose and intent of this Act" (section 32(2)(e)) which was not provided in the earlier EPCA.

- **New powers for Board in power planning and allocation:** The EPCA, 1994 includes substantial new powers for the Board in regards to planning the future power supply of the Province, and these powers appear to apply equally to Hydro as to other producers and retailers.

- **Removal of the restrictions on the Board in regards to regulation of Hydro:** The earlier EPCA included a number of sections which provided the Board with a mandate and direction with regards to review of Hydro rates notwithstanding section 21 of the Hydro Act which directed that the Public Utilities Act did not apply to Hydro. These sections included:

  – section 4 (implementing power policy),
  – at various times section 4.1, 4.2, 4.3, 5, 6 and 7 (interim direction on allocation of Hydro's costs and rural deficit for 1989, 1990 and 1991),
  – section 8 (requirement for Board review and report to LG-in-C prior to changes to Hydro rates),
  – section 9 (setting Hydro's rates for rural customers),
  – section 10 (requirement for Hydro to refer proposals for rate changes to the Board),
  – section 11 (public hearings and reporting by the Board on Hydro matters),
  – section 14 (contents of Board report on Hydro matters),
  – section 17 (limitation on Board regarding review of Hydro's rates other than rates to retailers and rural customers), and
  – section 18 (restriction on Application of the Public Utilities Act to reviews of Hydro to only sections 62 to 67, and granting the Board all powers of a commissioner under the Public Inquiries Act).

  In addition, the EPCA included section 15 which provided direction to the LG-in-C regarding implementation of the Board's report under sections 13 and 14.

  Basically all of the above provisions have been replaced by section 30(1) in the EPCA, 1994. This new section provides that the Public Utilities Act is no longer restricted regarding powers over Hydro to only sections 62 to 67 – in essence, all of the earlier detail in the EPCA regarding regulation of Hydro's rates is now replaced by the normal provisions of the Public Utilities Act as adjusted to reflect section 17 of the Hydro Act.

Effect of Removing Exemption from Public Utilities Act

The exemption from the Public Utilities Act that had existed for Hydro in section 21 of the Hydro Act and the Application of specific terms regarding Board review in the EPCA, has been replaced by general Application of the Public Utilities Act to Hydro (except for the restrictions on the Board that continue to exist in section 17 of the Hydro Act). The key effective changes from this revision appear to be:

- **Board Orders as opposed to OIC:** Board reviews of Hydro are now implemented through orders of the Board, rather than via reports to the Lieutenant-Governor-in-Council and subsequent OICs (for example, Public Utilities Act sections 16, 70, 75 and 103).

- **Board approval for capital-related items and borrowing:** The new Application of the Act requires Hydro to seek Board approval for it annual capital budget and contributions in aid of construction (section 41), abandonment (Section 38), and borrowing program (section 91).

- **Board approval of Hydro's rate base:** The Public Utilities Act provides the Board with broad powers over the determination of a utility's rate base (sections 78 and 79) and depreciation policies (section 68 and 69).

- **Board approval of rates and return:** The Public Utilities Act requires Board approval of utility rates (sections 70, 71) and return on rate base (section 80).

- **Franchise and Inter-utility Issues:** The Public Utilities Act requires the Board to approve various franchise-related issues and issue between utilities, such as expansion in territory served by another utility (section 39), interference with other utilities (section 42), restriction on transfer or assignment of franchise (section 49), use of poles (section 53) and construction in municipalities (section 56).

- **Electrical Supply Issues:** The Public Utilities Act specifies requirements in regards to electrical supply, such as voltage and frequency (section 43), maintenance of equipment on customer premises (section 44) and duty to supply (sections 54 and 55).

- **Corporate Transactions and Records:** The Public Utilities Act specifies certain restrictions on corporate transactions and record keeping without Board approval or contrary to Board-directed practices, such as restriction on sale of undertaking (section 48), record keeping and audit (sections 58, 59, 60, and 61) and posting of rates (section 72, 73 and 74).

Ancillary changes to other Acts

Hydro has been exempted from a number of other Acts, including the Freedom of Information Act, the Provincial Preference Act, the Public Tender Act and the Public Service Act. For the purposes of this review, these changes have not been examined in detail; however, they appear to be immaterial to the proceeding at hand.

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