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December 11, 2014

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Via Electronic Mail and Courier

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

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

Dear Ms. Blundon:

Re: Newfoundland and Labrador Hydro - Amended General Rate Application – Island Industrial Customer rates, effective January 1, 2015

These are the submissions of the Island Industrial Customers or IIC Group (Corner Brook Pulp and Paper Limited, North Atlantic Refining Limited and Teck Resources Limited) regarding the Hydro's request for interim rates for Island Industrial Customers effective January 1, 2015.

Newfoundland and Labrador Hydro filed its Amended General Rate Application ("GRA") on November 10, 2014. The GRA is requesting, among other things, an Order of the Newfoundland and Labrador Board of Commissioners of Public Utilities ("the Board" or "PUB") approving revised interim rates for Island Industrial customers and revised RSP rules, to be effective January 1, 2015.

Compressed process

The Board in its December 4, 2014 correspondence to the parties states that given the proposed effective date, the process for the review of this interim rates application must be compressed, that there will be no requests for information or filing of additional evidence, and that the Board requests the parties to file their submissions by December 11, 2014.

The IIC Group in these submissions has made reference to evidence filed in previous proceedings before the Board, and to the reasoning of other Canadian (and U.S.) utility regulatory bodies in similar or analogous circumstances. Given the compressed process, the IIC Group respectfully submits that it is fair and reasonable for the Board to consider this information in these submissions, in addition to the evidence filed by Hydro.

The Board has specifically requested, in addition to submissions on other issues, that the parties address whether Hydro's proposals are consistent with the Provincial Government's direction in OC2013-089 (as amended)[1]. The IIC Group submit (at greater length below) that the Orders-in-Council do not dictate rates that must inevitably result in "rate shock", and to interpret

[1] OC2013-207; OC2014-319

the Orders-in-Council as leading to this result would be manifestly unfair in the context of the long-delayed GRA process, and would be contrary to the fundamental principles of regulated rate design, which principles continue to provide the necessary context for implementation of the Orders-in-Council, which in and of themselves do not provide sufficient direction to fully guide rate design.

Rationale for Interim Rates

Given the current circumstances, the Island Industrial Customers Group support the implementation of a reasonable increase in interim rates for the Island Industrial Customers, effective January 1, 2015. This position reflects the underlying rationale for interim rates. Interim rates secure a GRA-related cash flow for the utility, thereby establishing conditions necessary to avoid a delayed (and greater) rate shock for customers, while at the same time ensuring that any excess revenue earned by the utility by early implementation of GRA-related interim rates is refundable to the customers, in the event that final rates are less than the interim rates. In the current circumstances, it is acknowledged that interim rates should reflect to a reasonable degree known cost-drivers that will be recognized by the GRA process, such as increases in underlying fuel costs. All of these characteristics are understood to apply to the current situation.

However, the IIC Group submit that it is just as important that interim rates, as well as final rates, should not result in significant rate impacts to utility customers that would classify as "rate shock", particularly where the testing of the underlying evidence is incomplete and where issues such as the appropriate allocation of RSP balances remain undetermined.

Impacts of Interim Rates Proposed by Hydro

Hydro in its Amended 2013 GRA is seeking Board's approval for island industrial customer base rates which would have rate increase impact on the order of 39%[2] (excluding ongoing RSP riders). Hydro is also proposing an RSP Surplus Credit Adjustment which will apply to the difference between the monthly base rate charges, calculated on pre-GRA approved rates and post-GRA approved rates to comply with OC2013-089, in order to reduce the rate impact to the island industrial customers. Absent any other RSP adjustments, the rate impact to the island industrial customers would have been at about 6% effective January 1, 2015 and additional 18% effective September 1, 2015[3], for total (compounded) 2015 rate increase of about 26%. However, Hydro is also proposing to recover an accumulated RSP balance forecast at December 31, 2014 totalling 0.722 cents/kW.h. This would further increase the rate impact to the island industrial customers to 20.7% effective January 1, 2015, and an additional 16.3% effective September 1, 2015, for a total (compounded) 2015 rate increase of about 41%.

Regardless of whether the rate impacts are being measured before the effects of the Orders-in-Council phase-in (54.4%), or including those phase-in impacts (20.7%), the rate changes proposed for island industrial customers can only be characterized as unacceptable rate shock.

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[2] Hydro's Amended 2013 GRA, Section 4: Rates and Regulation, Table 4.15.

[3] Based on Hydro's Amended 2013 GRA, Section 4: Rates and Regulation, Table 4.10 the revenues at proposed rates less RSP Surplus Credit Adjustment (January 1, 2015: $41 million - $9.8 million=$31.2 million over $29.4 million at existing rates results at 6.1% increase; September 1, 2015: $41 million - $4.1 million=$36.9 million over $31.2 million at January 1, 2015 proposed rates results at additional 18.2 increase).

Examples from Other Jurisdictions – Interim Rates

In considering rate impacts, it is well and widely understood that rate stability and minimizing the magnitude of rate changes where possible is a desirable characteristic of any rate design for regulated utilities. "Rate Shock" is a general concept coined to describe rate impacts that exceed reasonable standards and which are to be avoided by reasonable rate design.

Examples of other jurisdictions recognizing and addressing rate shock include:

- In Saskatchewan the 2014-2016 SaskPower GRA proposed rate changes to occur over 3 years, rather than 1 year, "to limit the maximum rate increases to any one class of customers to avoid rate shock". This was needed to keep rate increases below 7.3% for all customers, and to average closer to 5%[4]. Previously, in 2001, the Saskatchewan Rate Review Panel was considering a proposal to allow a 10% impact from "rebalancing" on top of 0.9%-12% increases (depending on the customer load profile) from revenue requirement increases. The Rate Review Panel concluded that "a 22% rate increase for electrical service could be considered to create rate shock" and concluded that the "maximum increase for an individual customer be capped at 13 percent" including all rate components.[5]

- In Minnesota, the regulator has similarly recognized concerns with respect to rate shock, specifically "Avoiding rate shock is a primary ratemaking goal, because sudden, drastic increases in energy costs can be burdensome for residential and non-residential customers alike."[6] The Minnesota Attorney General Utilities Division have provided submissions that increases of 17.1 to 18.0 percent constitute rate shock[7].

- In NWT, a recent GRA for the Northwest Territories Power Corporation was subjected to a special Government-led Due Diligence Review prior to being filed with the regulator. The review was led by a former Chair of the BCUC, Mr. Peter Ostergaard. The review concluded "As NTPC had not filed a General Rate Application (GRA) for five years, we found that there was a significant degree of "catch-up" required with respect to the revenue requirement. The revenue requirement increase from $87.1 million to $101.6 million, is substantial, especially if implemented in one year. At the outset of our review, we were made aware of a proposal being developed by NTPC and the GNWT department of Finance to limit rate increases to no more than 7% per year. This appears reasonable as a fundamental principle of rate design is the avoidance of "rate shock"."[8] Previously the longstanding cap imposed in NWT to avoid rate shock was 15% on the energy component of rates (lower than 15% overall, as this assumes fixed demand charges

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4 http://www.saskpower.com/wp-content/uploads/2014-15-16_rate_application.pdf page 45.

5 Saskatchewan Rate Review Panel Report to the Minister on The Proposal from SaskPower for Changes in Electrical Rates, December 6, 2001, page 15.

6 FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER, In the Matter of Application of Midwest Gas, a Division of Iowa Public Service Company, for Authority to Change its Schedule of Gas Rates for Retail Customers Within the State of Minnesota, Docket No. G-010/GR-90-676 (July 12, 1991) at 35.

7 https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={940E9EF4-47EC-4A30-AC35-48C71D231F27}&documentTitle=20133-84991-03

8 http://www.assembly.gov.nt.ca/sites/default/files/12-06-06td20-173.pdf page 2

and customer charges remain fixed)[9]. The same 15% test has been since adopted in Nunavut.[10]

- In British Columbia, BC Hydro, FortisBC and the BCUC have long applied a "bill impact test" to rate designs. This test is not absolute, as noted by the BCUC in Decision G 124-08:

  > *With respect to BC Hydro's bill impact test the Commission Panel agrees with those Intervenors who submitted that the Commission should not endorse a "one size fits all" approach to "rate - shock" but should evaluate each application on its own merits. In addition, as was noted in the Oral Phase of Argument by virtually all counsel, the Commission has a considerable degree of latitude in determining whether a proposed rate is fair, reasonable and not unduly discriminatory. Counsel for BCOAPO observes that there is no "red light" to go off when a rate crosses into "a zone that's unfair, unreasonable or discriminatory" and that "essentially the question for the Commission is this: Does the structure pass the sniff test?" The Commission Panel agrees.*

  In general, however, the threshold of concern arises with rate impacts which exceed 10 percent, as noted: "FortisBC notes that the 10 percent figure is generally seen as the threshold of "rate shock", though it is not an official position of the Commission."[11] Note however that this standard has traditionally been applied to rate design pressures. Revenue requirement pressures, such as the 2012 proposal for 9.73% increases per year for 3 years have been capped by the BC Government – in that case at 50% of the BC Hydro request[12], and subsequently at a government imposed five year increase caps of 9%, 6%, 4%, 3.5%, 3%[13].

In each case discussed above, the guiding definitions of unacceptable rate shock are set well below the rate impacts proposed for the island industrial customers as part of Hydro's interim rates proposals.

As canvassed above, regulators faced with such circumstances have been prepared to significantly reduce the approved level of rate increase, as compared to what was sought by the utility.

As further examples, as provided in Hydro's response to SIR-IC-NLH-012 (Hydro's 2013 Second Interim Rates Application), the interim rate awarded to Manitoba Hydro was at 2.75% (effective April 1, 2014) compared to 3.95% requested by the utility; the Yukon Utilities Board set interim rates for Yukon Energy effective January 1, 2013 at 3.75% compared to 6.50% requested by the utility; similarly the Northwest Territories Power Corporation interim rate

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9 NWT PUB Decision 8-2002 page 8, Decision 3-2003, pages 27 and 31

10 Utility Rates Review Council report on Qulliq Energy General Rate Application, February 18, 2005

11 http://www.fortisbc.com/About/RegulatoryAffairs/ElecUtility/Documents/FBC_Inc_RIB_Decision_Final.pdf page 13

12 https://www.bchydro.com/news/conservation/2011/rra_amended_message.html

13 http://www.newsroom.gov.bc.ca/2013/11/10-year-plan-means-predictable-rates-as-bc-hydro-invests-in-system.html

applications propose interim rate riders to collect approximately 80% of the test year shortfall subject to a maximum overall rate increase of 15%[14].

It is submitted that the particular circumstances of industrial customers are also a factor to be taken into consideration in relation to the avoidance of rate shock (no more, but no less, so than the circumstances of the retail customer). The Final Report[15] released by the Industrial Electricity Policy Review Task Force appointed by Minister of Energy, Mines and Natural Gas of British Columbia notes that "[i]ndustrial customers are typically price-takers in competitive global commodity markets with limited ability to pass increased costs to customers. Proximity to natural resources, access to capital and market competitiveness have driven, and will continue to drive, investment decisions. Particularly for energy intensive industries, electricity costs heavily influence decisions to invest, expand, contract, or close." The news release[16] by Government of British Columbia on April 28, 2014 regarding BC Hydro rates also notes that "... it's important for BC Hydro's large industrial customers to stay competitive".[17].

Proposed Alternatives

Considering the above noted examples from this jurisdiction and other jurisdictions, the Island Industrial Customer Group submit that the interim rates to be effective January 1, 2015 should be implemented in such a manner so that the overall rate impact to the industrial class does not, to the extent reasonably possible, exceed 15%, including the impacts of any RSP adjustments and specifically assigned charges. It is acknowledged that, even under this submission, some island industrial customers will see increases above 15% (i.e., those island industrial customers who will bear, at least on an interim basis, above average increases in the specifically assigned charges), but the overall class impacts should be limited within the limits of what is reasonably recognized as "rate shock" levels.

The only downside risk to mitigating the interim rate impact for island industrial customers on January 1, 2015 to below rate shock levels is that there is a possibility that the ultimate GRA rate approvals may require the implementation of greater rate increase, and that the funds specifically allocated by the Orders-in-Council for the "phase-in" process may not be sufficient, in themselves, to "smooth" that rate increase. However, in the event this circumstance arises, the Island Industrial Customers Group note that there remain substantial RSP balances that have yet to be allocated, in accordance with Board approved methodology. Such balances have been used in the past to smooth such rate impacts, and are available to be applied for this purpose in the Amended GRA. For example, Hydro in its Amended GRA is proposing that RSP rules related to the allocation of the load variation component be modified such that the year-to-date net load variation for both Newfoundland Power and island industrial customers is allocated among the customer groups based upon energy ratios (effective date for the RSP change is September 1, 2013)[18]. Hydro also notes that the forecast balance in the segregated RSP load variation component as of December 31, 2014 is approximately a $33 million credit to customers[19]. In short, a significant proportion of this segregated RSP load variation balance is proposed to ultimately be allocated for the benefit of island industrial customers, but this has not

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[14] Northwest Territories Public Utilities Board in its decision 11-2012 from May 1, 2012 approved interim rates at 7% requested by the utility considering the fact that it was under 15% rate impact threshold.
[15] http://www.newsroom.gov.bc.ca/downloads/Industrial_Electricity_Policy_Review_Task_Force_Final_Report.pdf
[16] http://www.news.gov.bc.ca/news_releases_2013-2017/2014MEM0013-000539.htm
[17] http://www.newsroom.gov.bc.ca/2014/04/bcuc-review-to-get-commission-back-to-setting-bc-hydro-rates.html
[18] Amended 2013 GRA, Section 4, page 4.36.
[19] Amended 2013 GRA, Section 4, page 4.37.

yet been included in any rate proposals. Furthermore, any potential shortfall regarding the funds in the RSP plan can be recovered over a more extended period to reduce the rate impact to the island industrial customers.

Government direction in OC2013-089

The Board's statutory jurisdiction to make an interim rate order is founded in section 75 of the *Public Utilities Act*:

> ***Interim order***
>
> ***75.*** *(1) The board may make an interim order unilaterally and without public hearing or notice, approving with or without modification, a schedule of rates, tolls and charges submitted by a public utility, upon the terms and conditions that it may decide.*
>
> *(2) The schedule of rates, tolls and charges approved under subsection (1) are the only lawful rates, tolls and charges of the public utility until a final order is made by the board under section 70.*
>
> *(3) The board may order that the excess revenue that was earned as a result of an interim order made under subsection (1) and not confirmed by the board be*
> *(a) refunded to the customers of the public utility; or*
> *(b) placed in a reserve fund for the purpose that may be approved by the board.*

Jurisdictionally, the Board is not limited by what has been proposed by Hydro in its present Application, nor by the absence of full evidence or full testing of evidence, in respect of what the Board may order as interim rates. For the Board to hold otherwise would be, respectfully, an error in law. As stated by the Court of Appeal in *Newfoundland and Labrador Hydro* v. *Newfoundland and Labrador (Board of Commissioners of Public Utilities)*, 2012 NLCA 38:

> *[61] The power of the Board to authorize interim rates is granted in s. 75 of the PUB Act. That section allows the board to set rates expeditiously without full evidence and submissions, such rates being subject to review and possible modification in the final order of the Board, as is expressly provided for in subsections 75(2) and (3).*

As well, it necessarily follows from the Board's decision in P.U. 25 (2010) that the Board has the jurisdiction, when making interim rates, to make interim orders with respect to the operation of the RSP rules. At page 13 of P.U. 25 (2010), the Board stated that:

> *The interim orders clearly provide the Board with the full jurisdiction to, in the words of the Supreme Court of Canada, "modify in its entirety the rate structure" for the Industrial Customer group, which includes all aspects of the Industrial Customers' rate, including the RSP rate. The Board does not accept the position of the Industrial Customers that the Board has no power to change the rules and regulations affecting the RSP.*

The Orders-in-Council do not prohibit or preclude the establishment of interim rates consistent with fundamental principles of regulated rate design, including the mitigation of rate shock. It is Government's direction that: *"... effective January 1, 2014, the Island industrial customers will be subject to Rate Stabilization Plan rate changes in accordance with the Board of*

Commissioners of Public Utilities-approved methodology". The Board-approved RSP methodology, on a go-forward basis from September 1, 2013, is not frozen or dictated by the Orders-in-Council nor by the Board's own orders made since September 1, 2013. The Board has full, and untrammelled, jurisdiction to order interim rates which, *"in accordance with the Board of Commissioners of Public Utilities-approved methodology"*, mitigate rate shock. The Board approved methodology need not be considered final, and may be implemented on an interim basis.

Costs award to the IIC Group

The IIC Group comprise the majority of Hydro's island industrial customers, and are significant consumers of power supplied by Hydro. Since September 1, 2013, the island industrial customers have been subject to an escalating, unstable and unpredictable rate regime. This, unfortunately, promises to remain the case into at least mid-to-late 2015, when the Amended GRA is concluded. The IIC Group submit that these are circumstances in which it is reasonable to award to the IIC Group their legal and consultant's costs of participating in this compressed process, and respectfully request that the Board make an order awarding the IIC Group their costs.

All of which is respectfully submitted on behalf of the Island Industrial Customers Group.

Yours truly,

Stewart McKelvey

Paul L. Coxworthy

PLC/kmcd

c. Geoffrey P. Young, Senior Legal Counsel, Newfoundland and Labrador Hydro
Thomas J. Johnson, Consumer Advocate
Gerard Hayes, Newfoundland Power
Thomas J. O'Reilly Q.C. Cox & Palmer
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Edward M. Hearn Q.C., Miller & Hearn
Yvonne Jones, MP, Labrador

Footnote:

4-Saskatchewan 2014-15-16_rate_application

Attached in a separate document

Saskatchewan

Rate Review Panel

Report to the Minister of Crown Investments Corporation on:

The Proposal from SaskPower for Changes in Electrical Rates

December 6, 2001

Table of Contents

Introduction .... Page 1

Proposal by SaskPower .... Page 3

The Review Process .... Page 9

Panel Conclusions and Recommendations .... Page 13

Summary of Recommendations .... Page 19

Appendix A: Minister's Orders - Saskatchewan Rate Review Panel
SaskPower Rate Change

Appendix B: Dillon Consulting Limited Independent Review of the
SaskPower Rate Proposal of October 2001

Introduction

The Saskatchewan Rate Review Panel (the "Panel") was asked by the Government of Saskatchewan to review Crown corporations' requests for monopoly rate changes.

The Panel consists of Bob Lacoursiere (Chair), Jack Boan (Vice Chair), Tracey Bakkeli, Jo-Ann Carignan-Vallee, Sheldon Craig and Joan Meyer. Each member of the Panel has been appointed until July 25, 2002.

MANDATE

In its general mandate, the Panel is instructed to conduct reviews and provide opinions on the fairness and reasonableness of proposed Crown corporation rate changes referred by the Minister of Crown Investments Corporation, considering the interests of the customer, the corporation and the public.

In conducting its reviews, the Panel is required to:

- receive a rate change submission from a Crown corporation;
- establish procedures for conducting the review and ensure that these procedures are made available to the public;
- engage the services of a consultant(s) to assist the Panel in its review of the fairness and reasonableness of the proposed rate change;
- make available to the public, prior to holding public meetings, the Crown corporation rate change submission, with the exception of commercially sensitive information;
- hold public meetings and provide appropriate notification to the public of the date and location of public meetings, including any rules for public participation and Crown corporation participation;
- provide members of the public with the opportunity to review and comment on the proposed rate changes to the extent reasonably allowed by the mandate of the Panel and by the schedule according to which the Panel is required to complete its work and provide its report to the Minister of Crown Investments Corporation;
- receive presentations of the consultant(s) or the Crown corporation, review any written submissions and receive comments from the public;
- prepare a report on the Crown corporation rate change submission for the Minister of Crown Investments Corporation after considering the material received from the Crown corporation, the consultant(s), the public and its own analysis:
  - where the Panel determines the rate changes as proposed are fair and reasonable, recommend that the changes be implemented; or,
  - where the Panel determines the rate changes are not fair and reasonable as proposed, recommend that the rate changes be adjusted providing reasons for this conclusion;

- provide its report respecting the proposed rate changes to the Minister of Crown Investments Corporation on a date set out in or within any time period after having received the rate change submission that is contained in the specific terms of reference for particular Crown corporation rate reviews; and,
- make its report available to the public.

TERMS OF REFERENCE

On October 11, 2001, the Panel was instructed to conduct a review of the SaskPower proposal for changes in electrical rates effective December 1, 2001.

With respect to the proposal, the Panel was instructed to consider the fairness and reasonableness of the proposed changes considering:

- SaskPower's anticipated cost for fuel (natural gas and coal);
- SaskPower's anticipated hydro facilities availability;
- SaskPower's load forecasts;
- SaskPower's planned maintenance program;
- SaskPower's operating, administrative and maintenance expenses;
- SaskPower's depreciation and finance expenses;
- SaskPower's Corporate Capital Tax; and,
- the revenue requirement resulting from the delivery cost of service.

In reviewing the proposal, the Panel was instructed to take as given:

- the current rate structure (ie. components and classifications);
- the budgeted capital allocation, the rate base, and established corporate policies;
- the Return on Equity target of 10 percent;
- the non-capital spending levels as defined above;
- the existing service levels;
- any existing supply contract;
- the revenue to revenue requirement ratio target range of 0.95 and 1.05 to be achieved by 2004; and,
- the cost of service methodology, which allocates SaskPower's costs between the various rate classes.

The Panel was instructed to include in its report an explanation of how, in its opinion, implementation of the Panel's rate recommendations will allow SaskPower to achieve the performance inherent in the parameters outlined above, where the Panel's recommendations are different from SaskPower's proposed rate changes.

The Panel was instructed to present its report to the Minister of Crown Investments Corporation by December 7, 2001 (**see Appendix A**).

Proposal by SaskPower - Electrical Rates

SaskPower proposed a set of rate changes to generate an overall 5.4 percent revenue increase (6.8 percent excluding long term contracts) effective December 1, 2001. This increase should generate approximately $4.7 million and $56 million in incremental revenue in 2001 and 2002, respectively.

The proposal includes rate changes for all customer classes. SaskPower also proposed the continuation of its rate rebalancing and redesign initiative that started with the rate package approved effective April 1, 2001.

The following table summarizes the major components of SaskPower's rate application, on average, for each customer class.

Customer Class	**Requested Increase (Average % Increase)**	**Current R/RR Ratio* 2002**	**Proposed R/RR Ratio 2002**
Urban Residential	7.1	0.97	0.98
Rural Residential	10.0	0.90	0.94
Farm	8.0	0.96	0.98
Urban Small Commercial	5.0	1.02	1.01
Rural Small commercial	8.0	0.95	0.97
Urban General Service	5.0	1.03	1.03
Rural General Service	6.0	1.01	1.01
Small Manufacturing	12.0	0.82	0.86
Large Manufacturing	12.0	0.83	0.89
Power Rate	4.0	1.04	1.03
Power Rate Contract	0.9	1.01	0.98
Oilfield	4.0	1.13	1.11
Streetlight	4.0	1.12	1.11
Reseller	10.0	0.95	1.00
System Average	5.4	1.00	1.00
System Average without Contracts	6.8	-	-

* R/RR: Revenue to Revenue Requirement ratio

Note: The SaskPower proposal allows a maximum increase for any individual customer of 10 percent above the proposed class average increase. For example, an individual manufacturing customer could have a rate increase of 22 percent (12.0 + 10.0 percent).

REQUEST HIGHLIGHTS

The application consists of three major elements:

1. an increase in revenues to offset fuel and purchased power expenses;
2. a requirement to rebalance rates to improve equity between rate classes and revenues that cover the cost of service; and
3. a rate design adjustment to improve consistency and equity among the components.

A key aspect of rate design is that the cost components are allocated to each customer group in a fair and reasonable manner. That is, each customer class should reflect the share of costs that accurately reflect the cost of providing service to that customer class. Customer classes are based on location (rural or urban), type of customer and consumption attributes. Customer classes are also divided into subcategories, each with a designated rate code.

Rates are composed of three components:

- Basic Monthly Charge;
- Energy Charge; and
- Demand Charge.

The actual charges for specific customer classes will vary with their usage, demand fluctuations and applicable rate codes. The application includes changes to all three components with the goal of bringing into alignment the charges for each cost element for each rate component for each customer class.

Basic Monthly Charge

This component covers certain fixed costs associated with the delivery of service to a customer regardless of the amount of electricity used. These costs include meter reading, billing, customer service, marketing and a component of low voltage lines and associated transformers. The Basic Monthly charge represents the minimum charge for a customer hookup to the system.

Energy Charge

This element covers the costs associated with generating electricity and consists primarily of fuel costs (ie coal, natural gas and water rental). The Energy Charge also includes the cost of providing the energy load as well as any losses due to moving the energy from the generating stations to the point of use.

Demand Charge

This relates to the costs associated with meeting peak load requirements for a given customer class. It consists of much of the generation and all of the transmission infrastructure as well as the operating and maintenance expenses. The Demand Charge also includes most of the distribution infrastructure and associated operating and maintenance costs.

For example, for residential customers, SaskPower proposed to increase the basic monthly charge in cities, towns, villages and urban resorts by $0.61 per month from the current rate of $12.57 to $13.18 per month. At the same time, SaskPower proposed to increase the basic rate for rural residences, rural resorts and those receiving electricity generated from diesel generators by $3.05 per month from $15.41 to $18.46 per month.

For all residential customers, the energy consumption rate would be increased from 7.36 cents/kWh to 7.93 cents/kWh. Residential customers do not have a demand charge component to their bills.

Rate Rebalancing

One fundamental concept of rate rebalancing is an attempt to charge customers more accurately for the actual costs associated with providing that customer electricity. The industry measures this by setting a 'revenue to revenue requirement ratio' (R/RR). Ideally this should have a value of 1.00. This would mean that the revenue gained from the customer class covers all the costs of service for that class.

Simply put, with a R/RR of 1.00, for every $1.00 of costs, the company would receive $1.00 in revenue. If a customer is only paying 0.90 the full cost of supplying electrical service is not being recovered. Conversely, if a customer has a R/RR of 1.10, the customer is paying more than their fair share of costs and is subsidizing other customers.

Because it is difficult to maintain a R/RR exactly at 1.00, most jurisdictions use a R/RR range of 0.95 to 1.05. SaskPower proposes to reach this range over a four-year period, ie by 2004.

If the proposal is approved as presented, only rural residential and manufacturing classes will be below the range and only oilfield and streetlight customer classes will be above the target range.

SaskPower states without rate rebalancing, cross subsidization will continue. This is sustainable only if the customer base remains captive to the utility because of technology or legislation. Given recent industry trends across North America, the concept of jurisdictional monopoly is eroding. In order to retain customer classes, SaskPower must reduce cross-subsidization both among classes and within rate classes.

ISSUES

SaskPower identified the following issues related to its proposal.

Municipalities

SaskPower levies and collects a surcharge on behalf of certain, primarily urban, municipalities. This is a historical obligation and is collected by SaskPower subject to the request of the municipality.

The municipal surcharge is up to 10 percent for cities and up to 5 percent for towns and villages. It is applied to all appropriate customer bills and all eligible municipalities collect the surcharge.

When cost of the increase (est. $1.3 million) is combined with changes to the municipal surcharge and grants in lieu of taxes totaling $2.3 million, SaskPower indicates municipalities will realize a net revenue increase of approximately $1.0 million.

Public Facilities

This sub-category is contained within both urban and rural small commercial customer classes. Public facility rates apply to schools, hospitals, nursing homes, skating and curling rinks, and recreational facilities. The average increase ranges from 5.0 percent to 9.9 percent depending on location and facility size.

Resellers – Saskatoon and Swift Current

A reseller is a wholesale customer who receives power in bulk from SaskPower and then distributes it via its own system to final consumers, either residential or commercial. Both Saskatoon and Swift Current would be subject to a 10 percent increase.

Effective November 1, 2001, the Open Access Transmission Tariff (OATT) was introduced allowing both cities to seek other suppliers if they choose. SaskPower wishes to remain the supplier of choice by offering a reliable supply at a competitive price. Because the R/RR ratio for this group has been significantly impacted by increased fuel costs, the proposed increase is larger than the system average to realign the ratio at an acceptable level of 1.00.

Manufacturing

The manufacturing classes, regardless of location, are the most heavily subsidized within the system, with R/RR ratios of 0.82 for small customers and 0.83 for large customers. As a consequence SaskPower is proposing a rate increase of 12 percent. This is significantly more than the system-wide average increase of 5.4 percent. However an increase of this magnitude is required to reach the four-year rate-rebalancing goal.

Power Rates

This class contains two components: published and contract. The escalation clauses in existing contracts have not kept up with the increases in fuel costs. As a consequence, the R/RR for this customer group will fall from 1.01 to 0.98 after the rate increase. As contracts lapse, SaskPower plans to move these customers to published rates until fuel costs stabilize.

Implications of Deferral

SaskPower believes that deferring the rate increase will promote a decline in the company's financial health. Failure to fund adequately and maintain the established electrical system will place the costs of system failure and repair onto future users.

Insufficient revenues to fund required capital improvements, operating expenses and maintenance can be managed by either postponing investment and accepting the inevitable decline in capabilities or by borrowing with increased debt and interest costs with commensurate pressure to increase rates.

Each month the rate increase is deferred represents a loss of approximately $4.7 million in revenue to the corporation.

IMPACT ON CUSTOMERS

The table on the following page illustrates the average effect on customers in each classification

Customer Class Impact

Class of Service	Current Average Monthly Rate ($)	SaskPower Proposed Average Monthly Rate ($)	Average Increase ($/month)	Average Increase** %	Minimum Increase %	Maximum Increase*** %
Urban Residential	58	62	4	7.1	4.9	7.7
Rural Residential	88	97	9	10.0	8.0	19.8
Total Residential	**62**	**67**	**5**	**7.5**	**-**	**-**
Farms	134	145	11	8.0	0.0	18.0
Small Commercial – Urban	194	204	10	5.0	-15.5	13.1
Small Commercial - Rural	183	198	15	8.0	8.0	15.3
Total Small Commercial	**192**	**203**	**11**	**5.5**	**-**	**-**
General Service – Urban	1,307	1,372	65	5.0	5.0	6.1
General Service – Rural	860	912	52	6.0	6.0	7.0
Total General Service	**1,161**	**1,222**	**61**	**5.2**	**-**	**-**
Small Manufacturing	1,883	2,109	226	12.0	-7.1	21.9
Large manufacturing	95,060	106,467	11,407	12.0	4.5	19.2
Power (Published)	164,647	171,233	6,586	4.0	-	-
Power (Contract*)	351,975	355,086	3,111	0.9	-	-
Oilfields	954	992	38	4.0	-1.7	13.9
Streetlights	397	413	16	4.0	-	-
Reseller	2,330,746	2,563,821	233,075	10.0	-	-
Total (System)	**-**	**-**	**-**	**5.4**	**-**	**-**
Total System (excluding Contracts)	**-**	**-**	**-**	**6.8**	**-**	**-**

* Contract sales are excluded from this review and rates are established through negotiation.
** Differences due to rounding.
***The SaskPower proposal allows a maximum increase for any individual customer of 10 percent above the proposed class average increase. For example, an individual manufacturing customer could have a rate increase of 22 percent (12.0 + 10.0 percent).

EFFECTIVE DATE

SaskPower proposes these increases come into effect December 1, 2001

The Review Process

PUBLIC CONSULTATIONS

In reviewing the SaskPower proposal, the Panel received comments and suggestions from individuals and groups throughout Saskatchewan through a public consultation process that included:

- eight public meetings;
- use of a toll-free telephone message line;
- receipt of submissions by mail;
- receipt of messages by facsimile; and,
- receipt of electronic message correspondence.

These methods of public discussion were advertised in daily newspapers and in weekly newspapers. In addition, radio clips were played on local radio stations.

Panel members were also involved in numerous media interviews and public appearances.

Copies of the SaskPower rate proposal were available to the public at SaskPower offices, at the public meetings and on the Internet.

Public meetings were held on:

- October 29 in Swift Current;
- October 30 in Moose Jaw;
- October 31 in Regina;
- November 1 in Yorkton;
- November 5 in North Battleford;
- November 6 in Prince Albert
- November 7 in Melfort; and
- November 15 in Saskatoon.

The public meetings included:

- an introduction by the Panel Chair with an explanation of the proceedings and the Panel=s mandate for the review;
- an overview by SaskPower of its request;
- an opportunity for submissions by individuals or organizations that had indicated an interest in addressing the Panel; and,
- an opportunity for questions or comments from the floor.

SUBMISSIONS

The Panel received formal submissions from the following organizations:

- City of Swift Current,
- City of Regina,
- Canadian Association of Petroleum Producers,
- Small Explorers and Producers Association of Canada (SEPAC),
- Cameco Corporation and COGEMA Resources Inc.,
- Saskatchewan Wheat Pool,
- Mr. Brian Clavier,
- Saskatchewan Chamber of Commerce,
- Saskatoon and District Chamber of Commerce, and
- Saskatchewan Recreation Facilities Association.

The Panel also received a number of submissions and comments from individuals and organizations at public meetings, via telephone, fax and emails.

PRESENTATIONS

The Panel received presentations from officials of SaskPower and from the Panel's consultant to:

- develop an understanding of the proposed rate changes;
- understand the analyses prepared for the Panel; and,
- develop its recommendations.

CONSULTANT

In conducting its review, the Panel engaged the services of a consultant to examine and advise on the reasonableness and fairness of the SaskPower proposal.

Dillon Consulting Limited was contracted to provide consulting services to the Panel. Staff assigned to the review have extensive experience in utilities regulation and have served as consultants to a variety of regulatory and industry bodies in Canada and internationally.

The Panel met with the consultant and subsequently sought additional information from SaskPower on the rate proposal.

The consultant prepared a report and assessment of the SaskPower proposal (**attached as Appendix B**).

CONSULTANT'S REPORT – HIGHLIGHTS

The Panel reviewed the consultant's findings in detail and particularly noted the following:

- **Overall Requirement** – If SaskPower's assumptions are accepted as presented, the request for incremental revenue of $56 million for 2002 is reasonable. However, a number of assumptions are subject to challenge as noted below. The consultant further noted that these results are **not strictly additive**.

- **Load Growth Forecast** - SaskPower's load growth forecast of 3.1 percent appears to be optimistic. Given economic trends particularly subsequent to September 11, 2001, the consultant suggested a more realistic rate would be in the range of 1.0 to 1.5 percent, for a potential $8 to10 million reduction in revenue requirements.

- **Natural Gas Pricing** - Recent declines in natural gas prices suggest that SaskPower's actual 2002 gas costs may be as much as 1 cent per KiloWatt hour (KWhr) lower, for a revenue requirement reduction of up to $15 million.

- **Hydro Power Availability** – A positive change in stream flow forecasts and water supply outlook could reduce the revenue requirement by up to $14 million. Conversely, a drier than predicted year will increase the need for gas-fueled generation and create incremental costs of up to $14 to 19 million.

- **Import Power** – The consultant suggests, based on the current economic situation, a more positive view of potential import power costs should be considered. For example, off-peak Manitoba Hydro prices are currently running in the 2.5 - 3 cents/KWhr range, compared to the SaskPower forecasted rate of 6 cents/KWhr. In addition, the consultant indicated the potential to buy lower-cost import power in place of increased usage of gas-fired generation. These factors could result in savings of about $18 million.

- **Operations, Maintenance and Administration (OM&A)** – The consultant notes SaskPower is capable of achieving greater productivity based on past performance than it is currently registering. On a unit cost basis, OM&A has increased by approximately 20 percent over the past six years. On this basis the consultant suggests savings of up to $5 million may be achievable in this area if a productivity gain of 2 percent is realized. The consultant also notes it is unlikely that short-term gains are possible.

- **Cost of Service Study** – SaskPower should carry out a detailed Cost of Service study to examine the specific way in which SaskPower's cost allocation methodology is applied, the parameters and controls that are used and the acceptable degree of rate rebalancing measures that should be implemented. This study should be undertaken in the next six months to permit a Panel review well in advance of the next rate increase application.

- **Depreciation Study** – SaskPower is expected to complete a Depreciation Study in the near future. This should be forwarded to the Panel for its review in advance of the next rate increase application.

- **Cost Allocation Methodology and Application** – Cost allocation methodology can be complex. The cost allocation methodology and its application as well as any changes should be provided to the panel for information prior to SaskPower's next rate application.

Panel Conclusions and Recommendations

OVERALL INCREASE

SaskPower proposed an average increase equivalent to 5.4 percent of its revenue from sales of electricity in Saskatchewan with average increases ranging from 0.9 percent to 12.0 percent, depending on the customer class. The overall average increase equates to 6.8 percent of revenue excluding customers who are under long-term contract.

The Panel notes SaskPower is facing increasing costs of electrical generation. This is primarily due to low water levels creating a shortage of hydro generated electricity which is normally replaced by more expensive natural gas-fired generation.

Based on SaskPower's assumptions for a number of factors, their stated revenue requirement of $56 million appeared to be reasonable. However, the Panel notes and accepts the consultant's analysis that a number of these assumptions are subject to challenge and debate. Amendments to these assumptions should provide SaskPower reasonable opportunity to achieve its stated Return on Equity Target of 10 percent.

Load Growth Forecast – The Panel considered a range of options regarding the Load Growth Forecast. While the general economic trend across Canada has not been positive, the Panel notes Saskatchewan has often responded more moderately to both economic upturns and downturns than the rest of the country. The Panel also recognizes the Load Growth Forecast is not fully linked to the economic status of the province. The Panel believes a reduced Load Growth Forecast is appropriate.

Natural Gas Pricing – The Panel noted natural gas prices remain volatile. A significant portion of SaskPower's natural gas prices remains unhedged (approximately 45 percent). If the consultant's outlook for lower gas prices materializes, there is potential for savings to be realized.

Hydro Power Availability – The Panel reviewed the November 1 Outlook provided by SaskWater and noted the return to near normal hydro generation is unlikely. An allowance is necessary to cover the cost of replacement generation.

Import Power – The panel believes current economic conditions warrant the consideration of using cheaper imported power to replace gas-fired generation. It may be possible to achieve savings through such a strategic move.

Operations, Maintenance and Administration (OM&A) – The Panel agrees with the consultant's assessment that productivity improvements are possible within SaskPower's operations. The Panel recognizes an improvement in productivity is most likely to happen if it is determined to be a primary objective.

Depreciation Study – The Panel agrees with the consultant that SaskPower's Depreciation Study should be forwarded to the Panel for its review well in advance of the next rate increase application.

Cost Allocation Methodology and Application – Further to the previous Panel report and consultant's review, the cost allocation methodology and its application as well as any changes should be provided to the panel for information in advance of SaskPower's next rate increase application.

The Panel recommends a set of rate changes that will generate a 4.54 percent revenue increase (5.73 percent excluding contracts) sufficient to generate $47 M increased revenue for 2002.

RATE REBALANCING

The Revenue-to-Revenue-Requirement Ratio (R/RR) is commonly used in the industry as an indicator of the ratio of the revenue generated from a customer or a class of customers to the revenue required from that customer or class of customers to cover the costs associated with providing services to that customer class.

The revenue requirement includes provision for:

- fuel and purchased power costs;
- operating, maintenance and administration costs;
- depreciation, depletion and amortization costs;
- royalties, water rentals and taxes;
- finance charges; and,
- a target return on investment.

In the case of SaskPower, the costs of generating electricity for export sales is also included in calculating the revenue requirement for sales within Saskatchewan.

SaskPower identified a number of customer classes for which the Revenue-to-Revenue-Requirement Ratio was less than 0.95, (ie. Small and Large Manufacturing) as well as customer classes where the R/RR was greater than 1.05 in 2001, particularly Oilfields and Streetlights.

The Panel recognizes that SaskPower must take steps to correct the inequities inherent in the current rate structure and that rate rebalancing is an essential step. The Panel further recognizes that the industry standard for the R/RR is a range rather than a fixed ratio.

Rate and R/RR structures are complex formulae dependent upon a range of factors. There are significant variations of revenue/cost relationships not only between rate classes but also within the classes themselves. The Panel notes time constraints did not allow for an opportunity to review specific goals, allocation methodology and the impact of a four-year rate rebalancing plan. A full review at this time would determine if Rate Rebalancing allocations are on target, or if further shifts of costs are required to reach parity within customer classes. The Panel believes a detailed Cost of Service Study would be beneficial to all parties.

The Panel recommends a detailed Cost of Service Study be completed prior to the next rate application by SaskPower.

LIMITS TO RATE INCREASES FOR CUSTOMER CLASSES

Given the Panel's recommended adjustments to the assumptions leading to the revenue requirement calculation, the Panel felt a cap on maximum increases was warranted. The Panel noted SaskPower's application contained a cap of 10 percent over the class average increase. For example if the class average increase was 12 percent, no individual customer would be subject to an increase exceeding 22 percent.

In the Panel's view this cap, while relevant particularly in the context of rate rebalancing, should be more modest. A 22 percent rate increase for electrical service could be considered to create rate shock and have an extremely negative impact on retaining or advancing any economic growth for the province.

The Panel recommends the maximum increase for an individual customer be capped at 13 percent including Basic Monthly Charge + Energy Charge + Demand Charge.

The table on the following page summarizes the Panel's recommended average rate increase and cap by Customer class compared to SaskPower's application.

SaskPower Requested
Compared to
Panel Recommended Average Increases

Customer Class	SaskPower Requested Increase (Average %)	Panel Recommended Increase (Average %)	Estimated Average $ Increase /Month (Including Cap Effect)	Panel Recommended Maximum Increase (% Cap)
Urban Residential	7.1	7.1	4	13.0
Rural Residential	10.0	10.0	8	13.0
Farm	8.0	7.1	9	13.0
Urban Small Commercial	5.0	5.0	10	13.0
Rural Small Commercial	8.0	8.0	13	13.0
Urban General Service	5.0	5.0	64	13.0
Rural General Service	6.0	6.0	48	13.0
Small Manufacturing	12.0	10.0	164	13.0
Large Manufacturing	12.0	10.0	6,911	13.0
Power Rate	4.0	3.0	4,940	13.0
Power Rate - Contract	0.9	0.9	3,111	-
Oilfield	4.0	2.0	19	13.0
Streetlight	4.0	2.0	8	13.0
Reseller	10.0	7.1	165,483	-
System Average	**5.4**	**4.5**	-	-
System Average without Contracts	**6.8**	**5.7**	-	-

EFFECTIVE DATE

SaskPower proposed to implement the new rate structure December 1, 2001. To meet this implementation date now would require a retroactive application of the new rates to electricity and services provided in the past.

The Panel is of the view that charges should not be increased on past services. The Panel recognizes this will impact on SaskPower's ability to attain its targeted ROE for 2001.

The Panel recommends the increases in SaskPower electrical rates be effective January 1, 2002.

OTHER ISSUES AND CONCERNS

1. SaskPower International

The Panel notes that SaskPower International's (SPI) performance over the short term (five years) potentially impacts the customer rate base, creating pressure for SaskPower to require further rate adjustments. The Panel acknowledges Corporate Structure as a 'given'. However, SPI's activities are having an impact on the targeted Return on Equity and therefore have an impact on both the customer and the public.

The Panel notes the consultant's recommendation that SaskPower should seriously examine its future business relationship with SPI with a view to moving SPI's financial consequences from the responsibility of the SaskPower rate payer.

2. Public Facilities

The Panel received representations, letters and phone calls from a wide range of individuals representing public facility operators across the province. Concerns focused primarily on the impact the rate increases have on their operation and the limited funding many of these organizations have available to them to pay for the increased costs.

The Panel recognizes the pressure these proposed increases will create. However, the Panel notes these issues are outside its mandate and respectfully suggests these concerns would be more appropriately addressed through other mechanisms that can address public policy.

3. Energy Conservation/Consumption

As part of its rate restructuring program, SaskPower appears to be putting more emphasis on increasing those rate components that are 'fixed', eg. Basic Monthly Charge.

The Panel notes with concern that this approach significantly reduces any financial incentive for the customer to conserve energy and/or reduce consumption and suggests that SaskPower revisit this approach and/or provide a more complete explanation of long term plans in this regard. The results of the cost of Service Study may facilitate this review.

4. Rate Rebalancing Schedule

The Panel notes the SaskPower request for rate rebalancing was the second year of a four-year plan. Depending on factors such as the outcome of the Cost of Service Study (see recommendation on page 15), this four-year plan may warrant review and adjustment to a different timeframe.

5. Other Studies/Information

The Panel recommends SaskPower provide the Panel with its Depreciation Study and Cost Allocation Methodology and any associated changes prior to its next rate application.

6. Review Timetable

The Panel wishes to express significant concern regarding the very tight timetable (53 days) available to them for the SaskPower review. SaskPower is a complex operation with many rate components and customer classes requiring thorough review and analysis.

The Panel was further pressed by a concurrent SaskEnergy review.

In future, the Panel strongly recommends it have a minimum of 90 days for any SaskPower review.

Summary of Recommendations

In summary, the Panel recommends:

- a set of rate changes that will generate a 4.54 % revenue increase (5.73 percent excluding contracts) sufficient to generate $47 M increased revenue for 2002;
- a detailed Cost of Service Study be completed prior to the next rate application by SaskPower;
- individual customer increases be capped at 13 percent including Basic Monthly Charge + Energy Charge + Demand Charge;
- electrical rate increases be effective on services beginning January 1, 2002;
- SaskPower provide the Panel with its Depreciation Study and Cost Allocation Methodology prior to its next rate application; and
- in future the Panel be given a minimum of 90 days for any SaskPower Review.

IMPACT ON CUSTOMERS

The Panel recognizes many aspects of the Saskatchewan economy are particularly challenged at this time, ie. agriculture, manufacturing, forestry, mining and oilfields. Utility rate increase must be held to a minimum while establishing strategies to improve economic recovery.

Rate Rebalancing is critical so that customers who may be able to opt for alternative electrical suppliers because of the onset of the Open Access Trade Tariff (OATT) choose to remain with SaskPower. A large-scale departure of these customers would be detrimental to both the remaining customer classes and to SaskPower. Practically, seeking another supplier is not an option for the Resellers or large Power Class customers. This may change as new patterns for wheeling power are established.

The recommended rate changes reflect a closer balance between customer and movement towards SaskPower's goals of rate rebalancing.

IMPACT ON SASKPOWER

The North American economic climate has changed significantly in the four months since the preparation of the SaskPower Rate Proposal. Most of the changes have been of such a nature as to enable SaskPower to potentially reduce their revenue requirements.

The Panel is of the view SaskPower is capable of making these revisions to achieve the recommended reduced revenue levels and still have a reasonable opportunity to earn its target Return on Equity of 10 percent.

IMPACT ON THE PUBLIC

The rate changes will have an effect on several aspects of the public. Municipalities will have the advantage of increased surcharge revenues as a result of the new rates.

The public will benefit from rates that avoid rate shock and offer moderate increases that can be handled through steady growth and economic development. Increased, sustainable development will in turn have an even greater positive impact on the economy and the General Revenue Fund.

As SaskPower's principle shareholder, the restoration of the Return on Equity to a target near 10 percent benefits the public by earning a reasonable return on their investment.

It is the Panel's view, therefore, the rate changes recommended by the Panel are fair and reasonable, considering the interests of the customer, Crown corporation and the public

Appendix A:
Minister's Orders
SaskPower Electrical Rate Change

Minister's Order

Saskatchewan Rate Review Panel SaskPower Rate Change

WHEREAS by an Order dated July 27, 2000, issued pursuant to Section 16 of *The Government Organization Act*, the Minister of Crown Investments Corporation appointed a Ministerial Advisory Committee known as the Saskatchewan Rate Review Panel;

AND WHEREAS that Order provides for specific terms of reference for particular Crown Corporation rate change reviews to be attached by further minister's order;

AND WHEREAS it is desirable to establish terms of reference for a SaskPower rate change review and to attach the Terms of Reference to the previously mentioned Minister's Order;

NOW THEREFORE, I hereby amend the said Order by attaching Appendix A affixed hereunto as **"Schedule F: SaskPower Rate Change Proposal Terms of Reference"** to the said Minister's Order.

Dated at Regina, Saskatchewan this 11th day of October, 2001.
Maynard Sonntag
Minister of Crown Investments Corporation

APPENDIX A
Schedule F:
SaskPower Rate Change Terms of Reference
Terms of Reference

The Saskatchewan Rate Review Panel is requested to conduct a review of SaskPower's request for an increase in its rates effective December 1, 2001.

The Panel shall provide an opinion of the fairness and reasonableness of SaskPower's proposed rate changes, considering the interests of the customer, the Crown Corporation and the public.

In conducting its review, the Panel will consider the following factors:
A) The reasonableness of the proposed changes to the rates in the context of SaskPower's forecasted delivery cost of service, comprised of:

- (i) SaskPower's anticipated costs for fuel (natural gas and coal);
- (ii) SaskPower's anticipated hydro facilities availability;
- (iii) SaskPower's load forecasts;
- (iv) SaskPower's planned maintenance program;
- (v) SaskPower's operating, administrative and maintenance expenses;
- (vi) SaskPower's depreciation and finance expenses; and,
- (vii) SaskPower's Corporate Capital Tax.

B) The revenue requirement resulting from the delivery cost of service.
C) The Panel shall consider the following parameters as given:

(i) the current rate structure (i.e. components and classifications);
(ii) the budgeted capital allocation, the rate base, and established corporate policies;
(iii) the Return on Equity target of 10%;
(iv) the non-capital spending levels as defined in (A) above;
(v) the existing service levels;
(vi) any existing supply contract;
(vii) the revenue to revenue requirement ratio target range of 0.95 to 1.05 to be achieved by 2004; and,
(viii) the cost of service methodology which allocates SaskPower's costs between the various rate classes.

The Panel must include in its report an explanation of how, in its opinion, implementation of the Panel's rate recommendations will allow SaskPower to achieve the performance inherent in the parameters outlined in (C), where the Panel's recommendations are different from SaskPower's proposed rate changes.

The Panel will not publicly release or require SaskPower to publicly release commercially sensitive material including, but not limited to, its fuel purchasing strategies (including hedging activities) and contracts with specific customers.

The Panel will release, as part of its final report, the results of the review of SaskPower's rate request as conducted by an independent third party.

Conduct of Review
The Panel will present its report to the Minister of Crown Investments Corporation no later than December 7, 2001.

Appendix B:
Dillon Consulting Limited
Independent Review
of the SaskPower Rate Proposal
# of October 2001

Saskatchewan Rate Review Panel

Independent Review of the SaskPower Rate Proposal of October 2001

Report

November 2001

Saskatchewan Rate Review Panel
Independent Review of the SaskPower Rate Proposal of October 2001

01-9706-0101

Submitted by

Dillon Consulting Limited

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In reply, please refer to:
Our File: 01-9706-0101

November 30, 2001

Saskatchewan Rate Review Panel
310 – 20th Street East, Suite 400
Saskatoon, Saskatchewan S7K 0A7

Attention: Mr. Bob Locoursiere
Chair – Sask Rate Review Panel

Independent Review of the SaskPower Rate Proposal of October 2001

Dear Mr. Locoursiere:

We are pleased to submit our independent review of SaskPower's Rate Proposal of October 2001.

The Rate Review Panel in their deliberations should note that in the SaskPower Proposal its forecasted revenue and expenditure assumptions are predicted on past trends and economic forecasts. Between the time the proposal was prepared and filed, a number of world economic circumstances have dramatically changed.

Based on these most recent trends and economic forecasts, the results of this review suggest the following:

1. Given the recent economic indicators, SaskPower's target of 3.1% growth in 2002 will not materialize.
2. Gas costs have significantly declined in the fall and are forecasted to remain lower than that presented in the application.
3. Imported power may be a cost-effective alternative to gas-fired generation, particularly if imported power is purchased during off-peak times.

While one cannot forecast the financial results with definitive certainty, it is fair to suggest that there are a number of options available to SaskPower's management team to generate the financial results required to meet their rate of return target of 10% and yet pass on a reduced rate increase for their consumers in this application. Based on our review, a $20 M reduction from the requested $56 M should be readily achievable.

Given SaskPower's plans to ask for a further increase of 1.98% next year, should the Review Panel recommend a lesser increase than that requested by SaskPower, and the suggested results do not materialize, future rate adjustments can then be taken to mitigate the negative or positive consequences.

Should you have any questions, please call.

Yours truly,

Dillon Consulting Limited

L. A. Buhr, M.Sc.
Senior Consultant

Kurt B. Simonsen, M.N.R.M.
Dillon Consulting Limited
Project Manager

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TABLE OF CONTENTS

Page No.

EXECUTIVE SUMMARY

1. INTRODUCTION AND TERMS OF REFERENCE 1

2. THE SASKPOWER RATE PROPOSAL 4

3. SYSTEM OPERATIONAL ANALYSIS 10

3.1. System Description 10

3.2. System Load Forecasts 13

3.2.1. Basic Premise – Economic Growth 13
3.2.2. Electricity Use Forecasts 14
3.2.3. System Load Forecast Summary 16

3.3. System Operation Description 16

3.3.1. Coal-Fired Thermal Generation 16
3.3.2. Hydro Generation 17
3.3.3. Gas/Turbine Generation 19
3.3.4. Energy Imports and Exports 21
3.3.5. Meridian and Cory Co-Generation Plants 23
3.3.6. Wind Generating Facilities 23
3.3.7. Transmission and Distribution 23
3.3.8. Energy Conservation 24

4. SYSTEM OPERATIONAL COSTS 26

4.1. Energy Sales 26

4.2. Fuel and Purchased Power Costs 26

4.3. System Operations Summary and Analysis 29

5. CAPITAL COSTS, OPERATING, MAINTENANCE, ADMINISTRATION, PLUS OTHER FINANCIAL ISSUES 31

5.1. Capital Cost Programs 31

5.2. Operating/Maintenance/Administration 32

5.3. Return on Equity 33

5.4. SaskPower International 33

5.5. Depreciation 35

5.6. Corporate Capital Tax 35

TABLE OF CONTENTS (Cont'd)

Page No.

5.7. *Planned Maintenance* 36

5.8. *Summary of Issues* 36

6. REVENUE REQUIREMENTS 38

6.1. *General* 38

6.2. *Summary* 38

7. REVENUE TO REVENUE REQUIREMENT RATIOS 43

7.1. *Impacts on Various Customer Classes* 43

8. RATE COMPARISONS 46

9. SUMMARY AND CONCLUSIONS 47

9.1. *Revenue Requirements* 47

9.2. *Revenue to Revenue Requirement Issues* 49

9.3. *Comparative Costs* 50

9.4. *Recommendations for Required Studies* 50

LIST OF FIGURES

Page No.

Figure 1 SaskPower - Location of Major Facilities 6

LIST OF TABLES

Table 2.1: Proposed Rate Class Increases 4
Table 2.2: SaskPower Revenue and Expenses 7
Table 2.3: Revenue-to-Revenue Requirement Ratios 8
Table 3.1: SaskPower Approximate Generating Capacity (MW) and Energy Capability (GWhr) 11
Table 3.2: SaskPower Total System Energy Use (GWhr) 15
Table 3.3: SaskPower Peak Demands (MW) 15
Table 3.4: SaskPower Coal-Fired Energy Production 17
Table 3.5: SaskPower Hydraulic Generation Capability 17
Table 3.6: SaskPower Hydraulic Energy Generated (GWhr) 18
Table 3.7: SaskPower Gas/Turbine Generating Capability 19
Table 3.8: SaskPower Gas/Turbine Energy Generated (GWhr) 20
Table 3.9: SaskPower Import/Export Potential 21
Table 3.10: SaskPower Imported Energy Used and Costs 21
Table 3.11: SaskPower Exported Energy Generated (GWhr) 22
Table 3.12: Growth in T & D Facilities from 1995 to 2000 24
Table 4.1: SaskPower Energy Sales Revenue from Annual Reports and Business Plan 26
Table 4.2: SaskPower Summary of Power Supply Costs 27
Table 5.1: SaskPower Capital Expenditures 31
Table 5.2: SaskPower OM&A Costs 32
Table 7.1: Year 2002 Rate Change & R./R.R. Ratios 43
Table 8.1: Typical Electricity Bill Comparisons 46

LIST OF APPENDICES

Appendix A Literature Consulted

EXECUTIVE SUMMARY

On October 11, 2001, the Saskatchewan Rate Review Panel ("the Panel") received Terms of Reference from the Minister responsible for Saskatchewan's Crown Investment Corporation, to conduct a review of SaskPower's request for an increase in rates effective December 1, 2001.

The Terms of Reference supplied by the Minister require the Panel to review the Proposal in light of a number of factors and parameters. These are summarized below:

- The Panel shall provide an opinion of the fairness and reasonableness of SaskPower's proposed rate changes, considering the interests of the customer, the Crown Corporation, and the public.

- In conducting its review, the Panel will consider the following factors:

  - The reasonableness of the proposed changes to the rates in the context of SaskPower's forecasted delivery cost of service, comprised of:

    - SaskPower's anticipated costs for fuel (natural gas and coal).
    - SaskPower's anticipated hydro facilities availability.
    - SaskPower's load forecasts.
    - SaskPower's planned maintenance program.
    - SaskPower's operating, administrative, and maintenance expenses.
    - SaskPower's depreciation and finance expenses.
    - SaskPower's Corporate Capital Tax.

  - The revenue requirement resulting from the delivery cost of service.

As part of the Panel's mandate, the Panel was required to engage the services of a consultant to assist the Panel in its review of the SaskPower Rate Proposal. Dillon Consulting Limited (Dillon) was retained by the Panel in October of 2001.

SaskPower is seeking a set of rate changes that will result in a 5.4% system average increase (6.8% increase, excluding contracts) effective December 1, 2001. The proposed rate increase will result in an additional $56 M in annual revenues.

SaskPower's Rate Proposal is designed to accomplish three objectives:

- Increase revenues to offset increases in fuel and purchased power expenses. These costs are expected to increase $57 M between 2001 and 2002.

- Rebalance rates to ensure that there is more equity between various rate classes and less cross-subsidization.

- Improve the rate design itself for each rate class to improve consistency and equity.

SaskPower has provided substantial documentation to support this revenue requirement. Specific elements that have been suggested as primary contributors to the requested amount are:

- Load growth of 3.1% in 2002, which when supplied by high price natural gas, could result in an increased cost/shortfall of $13 M.
- Lower hydro production than normal (median), which when offset by higher priced natural gas generation, could increase costs by $14 M.
- Higher coal costs due to royalty increases and price escalations could increase costs by $23 M.
- Higher natural gas costs in 2000 and 2001 probably cost SaskPower $12 M and $50 M, respectively. Current gas prices are to a large degree set for 2002, but with slumping prices in late 2001, it is difficult to translate this into an increased cost for 2002.
- Export electricity sales are expected to decline in quantity and unit price for 2002, with a potential 10% reduction in revenue of $10 M.
- Import electricity prices will rise for 2002 and use of import power will be reduced. The cost of natural gas-fired generation to compensate could be in the order of $18 M.
- Operating, maintenance, and administration costs are expected to rise by $13 M in 2002, but spread over a large energy load will mean the unit cost remains unchanged.
- Depreciation charges in 2002 will be up by $9 M.
- Financing charges in 2001 will remain constant for 2002.
- Losses/debt charges flowing from SaskPower International would add $1 M to $2 M to 2002 costs.

Assuming all of the above assumptions are valid, these items, as defined by Dillon, would theoretically add significantly to SaskPower's revenue requirements. However, they are not directly additive and could realistically equate to $40 to $60 M. As such, they appear to support the $56 M additional revenue requirement identified by SaskPower.

However, it is reasonable to re-examine some of the foregoing assumptions. Based on our review and consideration of recent economic circumstances, we are recommending the following alternative short-term scenarios be considered:

- ***Load Growth*** – Recent events and economic forecasts would suggest that SaskPower's 3.1% energy load growth in 2002 is too optimistic. An assumed growth rate of 1.0 to 1.5% would reduce the projected revenue requirement by $6 to $10 M.
- ***Hydro Power Availability*** – A more favourable outlook of normal flow conditions would reduce the revenue requirement by approximately $14 M. Conversely, a less favourable outlook could increase the requirement for gas-fired generation and associated cost increases of approximately $14 M.
- ***Higher Coal Costs*** – Because there are consequences of higher taxes and already negotiated price escalations, no change in additional revenue requirement is likely.
- ***Higher Natural Gas Costs*** – Recent declines in the price of natural gas would suggest that SaskPower's actual costs in 2002 could be as much as ¢1/KWhr lower than indicated in the Rate Proposal. This could equate to a reduction in revenue requirements of approximately $15 M, assuming the indicated gas generated energy is actually used.

- ***Export Electricity Sales*** – A more optimistic viewpoint would suggest that export prices will remain constant with continuing good sales assuming that Alberta's energy needs and current high prices will only drop gradually from their current high levels. This would suggest that an anticipated revenue gain of $15 M for 2002.
- ***Higher Import Prices/Lower Power Availability*** – The current economic situation suggests that a more optimistic view of potential import power may be warranted. SaskPower's interconnections to the US Basin and Manitoba do have significant capabilities for import of power at levels three times SaskPower's 2002 forecast. Prices in Manitoba for off-peak power have been running in the ¢2.5-¢3.0/KWhr range. This is significantly lower than the average import price paid by SaskPower in 2001 of ¢3.95/KWhr and considerably lower than the ¢6/KWhr forecast by SaskPower. This 2001 scenario suggests that SaskPower could reduce costs by at least $18 M in 2002 by increased focus on import power relative to natural gas generation.
- ***Increased Operation/Maintenance/Administration Costs*** - Past performance by SaskPower suggests that higher productivity is achievable. For 2002, with the recent introduction of Queen Elizabeth Gas Turbines, Meridian Co-generation, and Cory Co-generation, it is likely that short-term gains are possible.
- ***Increased Financing Costs*** – SaskPower's forecast of little or no increase in financing costs for the Year 2002 is probably appropriate. However, the longer-term implications of investments in SPI or other generation facilities may see a significant increase in financing costs two to four years from now.
- ***Depreciation*** – Forecasts provided by SaskPower suggest that the depreciation expense will rise by $9.0 M in 2002, presumably reflecting the addition of the Cory facility. If the overall capital program, including SPI ventures taking place, the future depreciation charges will rise significantly.
- ***SPI Ventures*** – SaskPower forecasts suggest that capital investments inside Saskatchewan and elsewhere may add $483 M to the long-term debt by 2006. The result would be interest charges of $30 M/year at that time. This level of financing cost increase will be difficult to absorb if SaskPower's financial situation is below target in 2002.

This review examined a number of operational scenarios which demonstrated potential savings. These scenarios assumed a 1.5% economic growth rate, a shortfall in SaskPower's hydraulic power production of 390 GWhr due to lower water levels, and various increases in the amount of imported energy. Based on this analysis, savings of $27 M to $32 M could be achieved. Our recommendation would be to consider reducing the requested increase by a similar or lesser amount. A $20 M reduction from the requested $56 M should be readily achievable.

SaskPower should carry out a detailed Cost-of-Service study, which examines the specific way in which SaskPower's cost allocation methodology is applied, the parameters and controls that are used, and the acceptable degree of rate rebalancing measures that should be implemented. This should be undertaken within the next six months in order to permit a Rate Panel Review well in advance of the next rate increase proposal.

SaskPower's soon to be completed Depreciation Study should be forwarded to the Rate Review Panel for its review as soon as possible and certainly no later than mid-summer 2002.

SaskPower should seriously examine its future business relationship with SaskPower International with a view to moving SaskPower International's financial consequences from the responsibility of the SaskPower rate payer. It would also reflect on the perceived issue of conflicting business interests of the two organizations in selecting future power supply strategies.

1. INTRODUCTION AND TERMS OF REFERENCE

On October 11, 2001, the Saskatchewan Rate Review Panel ("the Panel") received Terms of Reference from the Minister responsible for Saskatchewan's Crown Investment Corporation, to conduct a review of SaskPower's request for an increase in rates effective December 1, 2001.

The Terms of Reference supplied by the Minister require the Panel to review the Proposal in light of a number of factors and parameters. These are summarized below:

- The Panel shall provide an opinion of the fairness and reasonableness of SaskPower's proposed rate changes, considering the interests of the customer, the Crown Corporation, and the public.

- In conducting its review, the Panel will consider the following factors:

  - The reasonableness of the proposed changes to the rates in the context of SaskPower's forecasted delivery cost of service, comprised of:

    - SaskPower's anticipated costs for fuel (natural gas and coal).
    - SaskPower's anticipated hydro facilities availability.
    - SaskPower's load forecasts.
    - SaskPower's planned maintenance program.
    - SaskPower's operating, administrative, and maintenance expenses.
    - SaskPower's depreciation and finance expenses.
    - SaskPower's Corporate Capital Tax.

  - The revenue requirement resulting from the delivery cost of service.

- The Panel shall consider the following parameters as given:

  - The current rate structure (i.e., components and classifications).
  - The budgeted capital allocation, the rate base, and established corporate policies.
  - The return on equity target of 10%.
  - The non-capital spending levels as defined in the above.
  - The existing service levels.
  - Any existing supply contract.
  - The revenue to revenue requirement ratio target range of 0.95 and 1.05 to be achieved by 2004.
  - The cost of service methodology which allocates SaskPower's costs between the various rate classes.

As part of the Panel's mandate, the Panel was required to engage the services of a consultant to assist the Panel in its review of the SaskPower Rate Proposal. Dillon Consulting Limited (Dillon) was retained by the Panel in October of 2001.

The objective of this report is to review the SaskPower Rate Proposal considering the interests of the customer, the Crown Corporation (SaskPower) and the public, and ascertain the overall fairness and reasonableness of the proposed rate change. To accomplish this objective, Dillon met with officials from SaskPower and the Panel to discuss details of the Rate Proposal and subsequently requested and reviewed supporting documentation.

This report examines the SaskPower Rate Proposal from a number of functional perspectives as outlined below:

- System Operational Analysis
- System Operational Costs
- Load Forecasts
- Capital and Maintenance Programs (including subsidiary companies)
- Annual Revenue Requirements
- Revenue-Revenue Requirements
- Rate Structures/Rate Increases

The methodology used to complete this review involved the following:

- Attendance at a formal presentation by SaskPower of the Proposal to the Panel on October 19, 2001.

- A comprehensive review of the Proposal by the study team.

- The derivation of questions for SaskPower as a result of the study team's review of documentation.

- Meetings with SaskPower officials on October 29, 30, and 31 to discuss questions posed by the study team and review additional documentation.

- Follow-up conference calls and correspondence with SaskPower officials on additional questions.

- Submission of a draft report to the Panel on November 23, 2001, followed by a meeting with the Panel on November 26 and 27, 2001 to discuss the draft report.

- Submission of the final report on November 30, 2001.

Through the course of this review, numerous documents were provided by SaskPower to the study team in support of the Rate Proposal and in response to questions from the study team. A list of documents reviewed for this report is provided in Appendix A.

Dillon would like to acknowledge SaskPower's cooperation in their response to questions and provision of supporting documentation for this review.

The scope of this review was largely to determine the overall fairness and reasonableness of SaskPower's proposed rate change. It was not within the scope of this review to conduct a comprehensive study of SaskPower's operations for the purpose of making specific recommendations. Rather, SaskPower's operations and costs were reviewed to ascertain the fairness and reasonableness of SaskPower's proposed rate change.

2. THE SASKPOWER RATE PROPOSAL

SaskPower is seeking a set of rate changes that will result in a 5.4% system average increase (6.8% increase, excluding contracts) effective December 1, 2001. The proposed rate increase will result in an additional $56 M in annual revenues. The proposed increases by rate class are outlined in Table 2.1 below.

Table 2.1: Proposed Rate Class Increases

Customer Class	Revenue Increase*
Urban Residential Customers	7.1%
Rural Residential Customers	10.0
Farm Customers	8.0
Urban Small Commercial Customers	5.0
Rural Small Commercial Customers	8.0
Urban General Services Customers	5.0
Rural General Service Customers	6.0
Small Manufacturing Customers	12.0
Large Manufacturing Customers	12.0
Power Rate Customers	4.0
Power Rate Contract Customers	0.9
Oilfield Customers	4.0
Streetlight Customers	4.0
Reseller Customers	10.0

Notes to the above table:

1. Revenue increases are weighted averages.
2. The average rate increase is 5.4%, including power rate contract customers and 6.8%, excluding the power rate contract customers.

SaskPower's Rate Proposal is designed to accomplish three objectives:

- Increase revenues to offset increases in fuel and purchased power expenses. These costs are expected to increase $57 M between 2001 and 2002.
- Rebalance rates to ensure that there is more equity between various rate classes and less cross-subsidization.
- Improve the rate design itself for each rate class to improve consistency and equity.

SaskPower's Rate Proposal of October 2001 notes that there has seen a substantial increase in fuel and purchased power expenses. The major cause has been the rise in consumption of natural gas as well as historically high natural gas prices and natural gas price volatility. SaskPower has committed to expanding generating capacity, largely through construction of gas-fired facilities. As of June 2001, SaskPower had the following mix of generation sources:

- Three coal-fired thermal generation plants - 1,653 megawatts:
  - Boundary Dam
  - Poplar River
  - Shand

- Four gas-fired thermal stations - 539 megawatts:
  - Queen Elizabeth
  - Landis
  - Meadow Lake
  - Success

- Seven hydro generation stations - 853 megawatts:

- SaskPower wind - 5 megawatts.

Total Installed Capacity = 3,050 megawatts

In addition, SaskPower also has contracts with the following energy suppliers:

• BEPL Seasonal Diversity	50 megawatts
• Meridian (gas)	232 megawatts
• Cory* (gas) (50% owned by SPI)	263 megawatts
• Sunbridge Wind	11 megawatts
Total Contractual Capacity	556 megawatts
Total SaskPower Capacity (installed and contracts)	3,606 megawatts

* Cory comes on stream in November of 2002.

Figure 1 shows the location of SaskPower's generating facilities, major transmission lines, and interconnects.

Increased Revenues and Costs

With a substantial portion of SaskPower's generating capability relying on natural gas, and the recent volatility in gas prices, fuel and purchased power costs have increased from $172 M in 1996 to an estimated $485 M in 2001. Fuel and purchase power costs are expected to be $441 M in 2002.

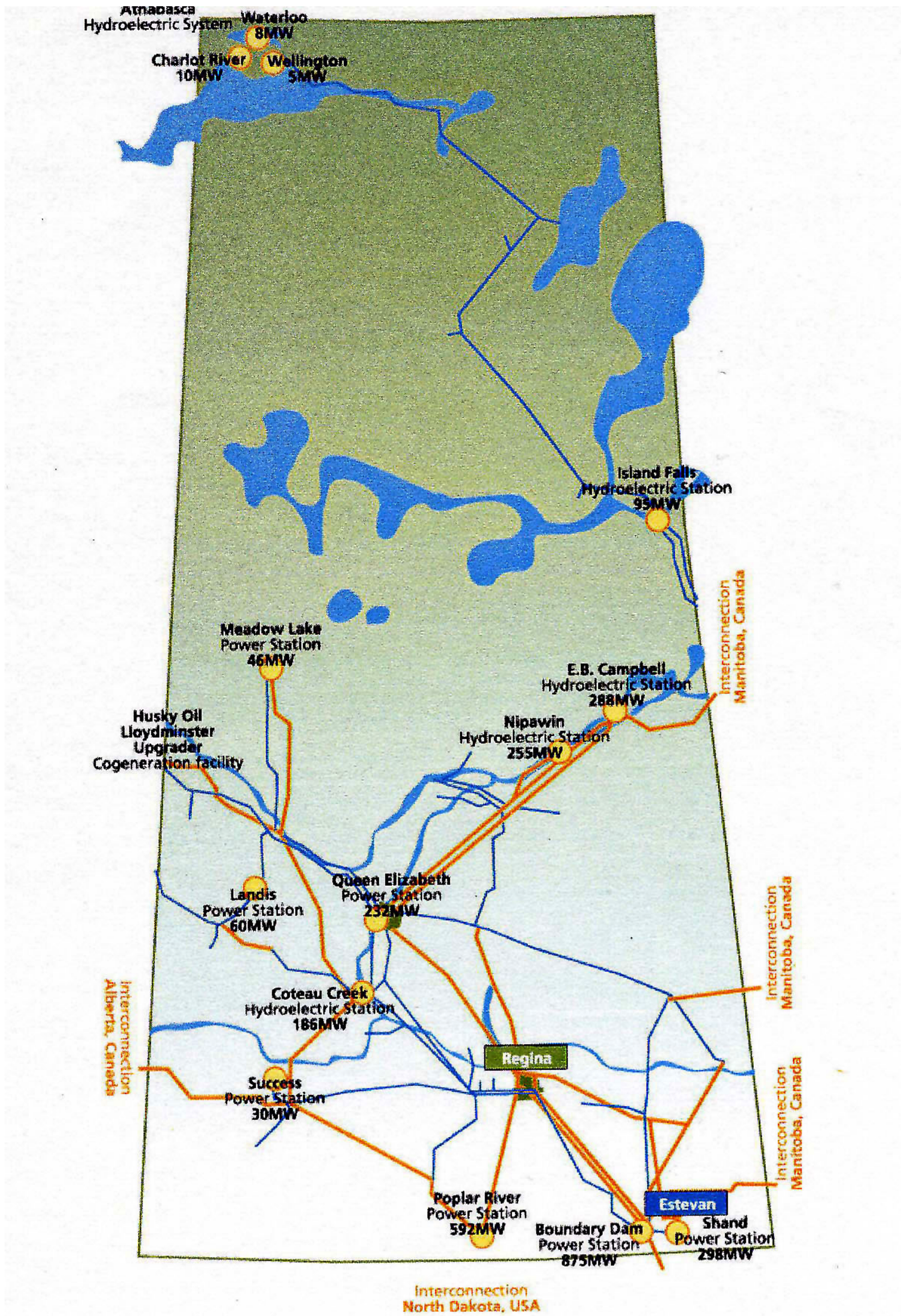

Figure 1: SaskPower – Location of Major Facilities

Revenues at SaskPower have increased from $883 M in 1996 to an estimated $1,124 M in 2001. The increase in revenue of approximately $241 M falls short of offsetting the increase in fuel and purchased power costs.

Table 2.2 summarizes SaskPower's income and expenses.

Table 2.2: SaskPower Revenue and Expenses

	2000 Actual	2001 Forecast*	2002 Budget*
Revenue			
SaskPower Customers	$952 M	$1,000 M	$1,092 M
Export Revenues	$128 M	$112 M	$95 M
Ancillary Revenues	$21 M	$17 M	$16 M
Total Revenue	$1,101 M	$1,129	$1,203
Expenses			
Fuel and Purchased Power	$384 M	$485 M	$441 M
Operating, Maintenance, and Administration	$264 M	$273 M	$284 M
Depreciation and Amortization	$151 M	$154 M	$160 M
Taxes	$24 M	$26 M	$27 M
Future Asset Removal and Site Restoration	$14 M	$12 M	$12 M
Finance Charges	$138 M	$151 M	$151 M
Total Expenses	$975 M	$1,102 M	$1,075 M
Net Income	$126 M	$27 M	$128 M

* as at September 7, 2001, with proposed rate increase.

With the proposed rate increase, SaskPower's net income in 2002 is expected to be $128 M. Without the rate increase, net income is forecasted to be $70 M. The return on equity for 2002 is expected to be 10%, with the approved rate increase.

Rate Rebalancing

The second objective of SaskPower's Proposal is to rebalance the rates so there is more equity between the various rate classes and less cross-subsidization. SaskPower is seeking rate rebalancing to ensure that rates better reflect the cost of providing electrical services. The standard that exists throughout the industry holds that revenues for a given class of customer should fall within a range ratio of 0.95 to 1.05 to the cost of serving that class of customer, with 1.00 representing revenues exactly matching costs. SaskPower's current rate structure falls short of this standard and needs to be adjusted accordingly to meet current and future challenges. SaskPower is seeking to establish rates that meet competitive standards for the revenue-to-revenue requirement ratio. SaskPower's objective is to have a revenue-to-revenue requirement ratio of 0.95 to 1.05. It is generally accepted in the industry that achieving a complete range of rates that are all at the ideal ratio is not practically feasible, given all the dynamic variables. Consequently, the range falling on either side of the ideal has been accepted. Table 2.3 illustrates the current status of SaskPower's rate structure showing the cross-subsidization and the impact of the proposed rates.

Table 2.3: Revenue-to-Revenue Requirement Ratios

Class of Service	Year 2002 Revenue/Rev. Req. Ratio (existing rates)	Year 2002 Revenue/Rev. Req. Ratio (proposed rates)
Urban Residential	0.97	0.98
Rural Residential	0.90	0.94
Total Residential	0.96	0.97
Farms	0.96	0.98
Small Commercial - Urban*	1.02	1.01
Small Commercial - Rural*	0.95	0.97
Total Small Commercial	1.01	1.01
General Service - Urban	1.03	1.03
General Service - Rural	1.01	1.01
Total General Service	1.03	1.02
Small Manufacturing	0.82	0.86
Large Manufacturing	0.83	0.89
Power (published rates)	1.04	1.03
Power (contract rates)	1.01	0.98
Oilfields	1.13	1.11
Streetlights	1.12	1.11
Reseller	0.95	1.00
Total (System)	1.00	1.00

* Public facilities included within class.

Note:

A ratio of greater than 1.00 implies that the customer class is paying too much relative to the cost of supplying electricity. A ratio below 1.00 implies that the class is being subsidized.

There are three key factors that are driving SaskPower to design its rates in this direction. The first is the basic issue of fairness in that all customers should pay their fair share of the costs of service, and no more. Fundamentally, customers should not pay for costs attributable to other customers. The second key factor is that properly balanced rates reduce the incentive for uneconomic alternatives for those customers who are providing the subsidy. The final factor is the desire to secure the contribution to fixed costs from those customer classes at risk of leaving the SaskPower system in order to contain the rates across the system. Should such customers abandon SaskPower for self-generation alternatives, there will inevitably be additional upward rate pressure on the remaining customer base to cover those fixed costs that do not vary with demand.

The study team has reviewed the costing methodology adopted by SaskPower. In general, SaskPower has implemented the recommendations of the Foster Report "Review of Costing Methodologies" (Foster, 1998), which examined costing methodologies used by SaskPower. With the absence of a detailed Cost-of-Service-Study and rate allocation process, the study team was unable to specifically address the current rate design and how various parameters would effect individual customers.

Rate Class Improvements

As with the rate balancing proposal, SaskPower also wishes to address the cross-subsidization issue within the rate classes themselves. As a result, not all customers within a rate class will necessarily see the same increase. Some may actually see a rate decrease while others may see up to a 22% increase within a rate class. The actual increase is dependent on energy consumed, the basic charge, and the demand rate.

To generate additional revenues, SaskPower is recommending revenues from each customer class be increased as highlighted in Table 2.1.

3. SYSTEM OPERATIONAL ANALYSIS

3.1. System Description

SaskPower is the principal supplier of electricity in Saskatchewan. Founded as the Saskatchewan Power Commission in 1929, its mandate is to deliver safe, reliable, cost-effective power to the residents of Saskatchewan. SaskPower was incorporated as a provincial Crown Corporation in 1950 and is governed by the Province's Power Corporation Act.

The system currently consists of:

- Three coal-fired thermal plants.
- Seven hydro-electric systems.
- Four natural gas combustion stations.
- More than 150,000 km of electrical transmission and distribution power lines.

Additionally, SaskPower purchases electricity from:

- The Meridian co-generation plant at Lloydminster.
- Alberta, U.S. Basin, and Manitoba electrical utilities.

Coming on-stream in 2001-02 are:

- Cory co-generation facility near Saskatoon (50% owned by SaskPower International).
- Wind generating facilities (Sunbridge).
- SaskPower wind generating facilities (in partnership with the federal government).

The following table identifies the current capacities (MW) and maximum/median energy capabilities (GWhr) based on historical and projected performance of the various coal, gas, hydro, co-generation, wind, and import power sources.

Table 3.1: SaskPower Approximate Generating Capacity (MW) and Energy Capability (GWhr)

	2003	2002	2001	2000	1998
Hydro					
• MW	853	853	853	853	847
• GWhr	Variable year to year (2,400 - 4,400)				
Steam/Coal					
• MW	1,658	1,658	1,658	1,658[1]	1997[1]
• GWhr	11,500± (since 2000)				
Gas Turbine					
• MW	539	539	539	378[1]	136[1]
• GWhr	900 - 2,500 (subject to gas availability)				
Internal Purchase					
• MW	556[3]	232	232	180[2]	--
• GWhr	3,400[3]	1,800	1,800	1,500	--
Out of Province Purchase					
• MW	325[4]	325[4]	325	325	325
• GWhr	900 - 2,000 (subject to transmission constraints during peak and off-peak times)				
Total MW[5]	**3,931**	**3,607**	**3,607**	**3,394**	**3,305**
GWhr	**19,000 - 24,000 (depending on climatic/market/transmission constraints)**				

<u>**Notes:**</u>

1. Queen Elizabeth coal-fired plant switched to gas-fired after 1998.
2. Meridian co-generation plant came on-stream in 2000.
3. Cory co-generating plant will fully come on-stream in 2003.
4. Actual capacity is subject to transmission constraints.
5. Wind Power would add approximately 16 MW, but is not considered firm capacity.

Figure 1 illustrates the location of the various generation facilities and the major transmission network.

Natural Gas Generation

SaskPower's emphasis in satisfying future generating requirements seems to rely largely on expanding gas-fired generation. The recent conversion and repowering of the Queen Elizabeth Station and SaskPower International (SPI's) investment in the Cory Co-generation project reveals this trend. In addition, SaskPower has entered into a contractual arrangement to purchase power from the Meridian Plant in Lloydminster, Saskatchewan.

Total gas generation capability is in the order of 539 MW. The average fuel cost for gas-fired generation is forecasted at approximately ¢5.9/KWhr for 2002.

Thermal (Coal) Generation

SaskPower has no long-term plans for expansion of coal generating facilities due to capital costs and environmental concerns from release of greenhouse gases. The current coal-fired generating capacity at the Boundary Dam, Poplar River, and Shand stations account for approximately 55% of the total installed capacity. Total coal generation capability amounts to approximately 1658 MW. The average reported cost of coal-fired generation is ¢1.6/KWhr.

Hydraulic Generation

SaskPower owns and operates seven hydro generating facilities. Under ideal circumstances, hydro generation can account for approximately 28% of total installed capacity. Future additional hydraulic generating capability is very limited. Hydraulic generating capability is also premised on adequate water flow conditions. The recent low water conditions have resulted in a forecast of hydraulic power accounting for 17% of total forecast production. This loss in available hydraulic capacity results in a reliance on power from gas or coal sources or the importation of electricity. Should water levels improve, the cheaper hydraulic power becomes more attractive. The average cost of hydro generation is ¢0.3/KWhr, primarily for water rental fees.

Wind Generation

SaskPower has also invested in wind power. These are the Sunbridge 11 MW and SaskPower 5 MW projects. Although wind power is a clean source of power, it has a poor reliability factor resulting in the need to have 100% back-up generating capacity.

Purchased Power

Purchased power also forms a large part of SaskPower's overall supply capability. Total purchasing capacity is in the order of 556 MW from either the Meridian, Cory, or Sunbridge Energy facilities within Saskatchewan.

Imported Power

Imports also account for a component of SaskPower's energy supply. In the Year 2000, imports accounted for approximately 12% of total energy sales. Imported energy comes from Manitoba, the United States, and to a lesser less extent from Alberta. The average cost to purchase power from imports was approximately ¢3.5/KWhr in 2000.

3.2. System Load Forecasts

3.2.1. Basic Premise – Economic Growth

System load forecasts for an electrical utility are typically conducted annually. These load forecasts serve as long-term planning tools in an effort to anticipate future electrical generation demands as well as transmission and distribution requirements. One of the fundamental tools used for anticipating future energy demand is projected economic growth.

The Province of Saskatchewan has achieved an increase in GDP of 4.9% over the last ten years, and 2.7% over the last five years. This was achieved with a provincial population growth increase of 1.7% over the last ten years and 1.4% over the last five years. Recent forecasts suggest that the population growth for the next five years could be in the order of 0.10% and 0.16% for the next ten years.

Forecasts of GDP growth rates in current dollars for the province, as used in SaskPower's Business Plan, are 3.5% for the next five years and 4.4% for the next ten years. These growth rates may be somewhat optimistic after the September 11, 2001 terrorist event and the recent downturn in the world economy.

The most recent economic forecasts indicate that there will be a significant decline in economic growth and inflation in the short-term (six to twelve months). The prospects beyond that is very uncertain. The size and duration of the economic consequences of the terrorist attacks of September is difficult to assess. For this reason, the Bank of Canada did not present its usual conventional semi-annual forecast in November but chose instead to present an "economic outlook" based on two assumptions: (1) that there will be no further major escalations of terrorism and (2) that business and consumer confidence will return to normal levels in the second half of 2002. Based on these two assumptions and given the extensive monetary and fiscal stimulus provided, the Bank of Canada is anticipating a 2% growth in the first half of 2002 and a 4% in the second half of 2002. Core inflation is anticipated at 1.5% and total inflation at 2%.

The significant uncertainty on the geopolitical front makes the economic outlook internationally, very difficult. The wildcard in the outlook in the US, as well as in Canada, is the state of confidence, both with consumers and with business. The 11% plunge in equity markets immediately following the terrorist attacks of September 11 and the flurry of layoff announcements speaks further of how companies and individuals are assessing their own near-term prospects. Consumer confidence is at risk and has shown a considerable drop. Layoffs and corporate bankruptcies may add to the gloom. Consumers will likely wait for good news on both fronts; the war and layoffs, before they become a driving force in the economy again.

Canada is the sixth largest exporter of goods in the world. Within Canada, Saskatchewan is the second most export dependent province behind Ontario. Saskatchewan exports more than 60% of all its produce and more than 70% of all its agricultural production. Global overproduction, depressed international prices, both in agriculture and energy, and depressed international economies (especially the US) does not bode well for Saskatchewan for 2002.

The current economic slowdown is almost synchronized globally which means that it is harmful to trade dependent economies and will certainly affect Saskatchewan as a result. Commodity producers may feel the decline keenly; weakness in agricultural output and consumer spending may limit growth.

The drought of 2001 has reduced crop production by 31% compared with 2000. The forecast for 2002 is an increase of 13.9% over 2001, far short of 2000 levels. In the mining sector, low commodity prices for oil and gas will result in fuel output growth of 2.1% and 2.9% for 2001 and 2002 respectively. Net inter provincial migration shows a decline of 0.4% in 2001 and 0.1% growth in 2002. The job count shows a 2.2% decline in 2001 and a 0.2% growth is forecasted for 2002. Real GDP is forecasted to grow 1% in 2001 and 2% in 2002. Based on this data, a 0% growth path is quite possible in the first quarter.

The prospects for global economic growth are not positive. The factors which are driving economic uncertainty – the war and dwindling consumer and business confidence – are not showing any positive signs. For the year 2002 the Province of Saskatchewan could expect minimal growth in its agricultural sector with little changes in the price of oil and gas. A 1-1.5% growth in the economy and an inflation rate of 1.5% may not be unreasonable.

SaskPower's load growth is expected to reflect the influence of overall provincial economic performances, particularly in the short-term (five years) with the recent global economic downturn.

3.2.2. Electricity Use Forecasts

SaskPower is forecasting its total energy requirements (energy sales and losses) to grow by 1.6% per year over the next ten years. This will result in a 3,082 GWhr increase from 18,179 in Year 2001 to 21,261 GWhr in 2011. Of the 3,082 GWhr growth, approximately two thirds is expected by 2006.

SaskPower's forecast of peak system load anticipates a 1.5% per year growth over the next ten years. This equates to a 475 GWhr increase from 2,882 GWhr in 2001 to 3,357 GWhr in 2011. Of the 475 GWhr growth, approximately two thirds is expected by 2006.

These forecasts are based on a compilation of sales forecasts for key account, oilfield, commercial, residential, farm, and reseller customers, including internal use, system losses, etc. Tables 3.2 and 3.3 highlight total system energy and peak demand projections by SaskPower.

Table 3.2: SaskPower Total System Energy Use (GWhr)

	1991	1996	2001	2006 Forecast	2011 Forecast	Ten-Year Forecast	% of Growth in First Five Years
Key Account	3,444	5,267	6,083	6,869	7,246	1.8%/year	68%
Oilfield	623	1,031	1,620	2,375	2,530	4.6%/year	83%
Commercial	3,027	3,135	3,488	3,801	3,973	1.3%/year	67%
Residential	2,243	2,376	2,375	2,466	2,548	0.7%/year	60%
Farm	1,381	1,450	1,327	1,354	1,382	0.4%/year	49%
Reseller	1,081	1,162	1,259	1,343	1,396	1.0%/year	61%
Corporate Use	82	90	120	116	117	-0.3%/year	--
Losses, etc.	1,362	1,847	1,897	2,001	2,068	0.9%	61%
Total Energy Requirements	**13,243**	**16,357**	**18,179**	**Low = 19,096 Most Likely = 20,324 High = 21,442**	**Low = 19,515 Most Likely = 21,261 High = 23,054**	**1.6% (2.3% for first five years)**	**73%**

The above table illustrates SaskPower's most likely forecast of total energy requirements. This amounts to a 2,145 GWhr increase by 2006 and a 3,082 GWhr increase by 2,011 from 2001 levels. The low forecast would see these additional requirements at 954 MW (by 2006) and 1,373 MW (by 2011). A high forecast would see additional requirements at 3,300 MW (by 2006) and 4,911 MW (by 2011).

Table 3.3 shows projected peak electrical demands.

Table 3.3: SaskPower Peak Demands (MW)

	1991	1996	2001	2006 Forecast	2011 Forecast	Five-Year Growth Rate	Ten-Year Growth Rate
Total Grid Demand	--	--	--	3,030 (low)	3,086 (low)	1.5%	0.9%
	2,300	2,650	2,882	3,219 (most likely)	3,357 (most likely)	2.2%	1.5%
	--	--	--	3,402 (high)	3,645 (high)	2.9%	2.1%

From the above, it is apparent that the most likely scenario would require an additional capacity need of 337 MW (by 2006) and 475 MW (by 2011). This additional need could be as low as 118 MW (by 2006) and 204 MW (by 2001) or as high as 520 MW (by 2006) and 763 MW (by 2001).

3.2.3. System Load Forecast Summary

SaskPower has anticipated a GDP growth rate for the province of approximately 3.5% for the next five years and 4.4% for the next ten years. Given today's economic climate, low agricultural and mining commodity prices, and overall population growth, total system energy requirements and peak demand requirements may well favor the low side of forecast expectations. This would result in a total system energy requirement of 19,000 GWhr and a peak demand of 3,030 MW in 2006. The Rate Proposal is predicated on a relatively optimistic growth scenario. This has implications to the corporation on fuel costs and revenue expectations. Given the recent substantial decline in natural gas prices and less optimistic growth scenario, fuel and energy costs could be less than that forecasted by SaskPower.

3.3. System Operation Description

3.3.1. Coal-Fired Thermal Generation

3.3.1.1. General

SaskPower currently operates three coal plants:

- Boundary Dam (six units) - 875 MW capacity/5,600 GWhr/year.
- Shand (one unit) - 298 MW capacity/2,300 GWhr/year.
- Poplar River (two units) - 592 MW capacity/4,600 GWhr/year.

These plants utilize lignite coal from the mines in southern Saskatchewan. They produce relatively inexpensive energy with fuel costs in the range of ¢1.6/KWhr.

The coal plants operate as base load energy suppliers, running almost continuously and provide in excess of 48% of SaskPower's energy needs.

These plants however have considerable outstanding environmental liabilities, which are being addressed in cooperation with Saskatchewan Environment. In recent years, these liabilities have led to energy conversion and upgrading projects that have used 50±% of the annual capital budget.

Table 3.4 highlights historical energy produced by coal-fired thermal generation and forecasted generation potential.

Table 3.4: SaskPower Coal-Fired Energy Production

	Actual						Estimated				
	1996	1997	1998	1999	2000	2001 Forecast	2002	2003	2004	2005	2006
Generation GWhr	11,225	11,256	11,609	11,551	11,436	11,711	11,789	11,448	11,613	11,450	11,541

3.3.1.2. Coal-Fired Thermal Generation Summary and Analysis

As can be seen from Table 3.4, SaskPower is maintaining a "stay-the-course" approach with respect to coal-fired energy production. SaskPower's long-term plans do not see the construction of coal-fired generating stations. Long-term plans continue to see coal servicing the base energy demands. Expenditures in coal-fired energy production are focussed on ongoing operation and maintenance of existing stations and improvements in emission control equipment

3.3.2. Hydro Generation

3.3.2.1. General

SaskPower has a total of seven hydroelectric generation stations. These are outlined in Table 3.5 below.

Table 3.5: SaskPower Hydraulic Generation Capability

	Installed, Capacity[1] (MW)
Saskatchewan River	
▪ EB Campbell Generating Station (eight units)	288
▪ Nipawin Generating Station (three units)	255
▪ Coteau Creek Generating Station (three units)	186
Churchill River	
▪ Island Falls Generating Station	95
Subtotal	824
Athabasca	
▪ Wellington Generating Station	5
▪ Waterloo Generating Station	8
▪ Charlot River Generating Station	10
Subtotal	23
TOTAL	847

[1] Based on 1998 ratings/2000 ratings total is 853.

These generating stations, with the exception of Coteau Creek at the outlet of Lake Diefenbaker, are essentially run of the river plants with little reservoir storage capacity.

The energy generating capability of these stations is stream flow dependent and as such, subject to highs and lows. The following table illustrates the range of available hydro-electric energy:

Table 3.6: SaskPower Hydraulic Energy Generated (GWhr)

	1984	1985	1988	1989	1996	2001 (as per Rate Proposal)	2001 (as per Nov 1/01)	2002 (as per Nov. 1/01)	2003 (median)
Saskatchewan River									
• EB Campbell Generating Station	627	717	603	797	1,180	586	556	676	956
• Nipawin Generating Station	NIL[1]	91	654	859	1,274	667	636	782	1,020
• Coteau Creek Generating Station	301	363	336	404	1,085	345	331	457	601
Subtotal	**928**	**1,170**	**1,594**	**2,060**	**3,539**	**1,598**	**1,523**	**1,915**	**2,577**
Churchill River									
• Island Falls Generating Station	766	762	735	719	688	748	747	872	852
Athabasca									
• Wellington Generating Station	NIL[1]	NIL[1]	6	17	38	NA	33	34	NA
• Waterloo Generating Station	NIL[1]	NIL[1]	4	25	52	NA	44	39	NA
• Charlot River Generating Station	NIL[1]	NIL[1]	5	21	80	NA	65	46	NA
Subtotal	**NIL**	**NIL**	**15**	**63**	**170**	**138**	**142**	**119**	**121**
TOTAL	**1,694**	**1,933**	**2,343**	**2,841**	**4,397[2]**	**2,484**	**2,412**	**2,907[3]**	**3,550**

__Notes:__

1. Not in service.
2. Maximum hydraulic energy generated (theoretically exceeded four times since 1969).
3. The SaskPower 2002 Business Plan was 3,297 GWhr.

As of the time of this review, SaskPower was facing a challenge in terms of available water flows. The recent dry conditions on the prairies have resulted in reduced water flows and therefore a decrease in capacity to generate hydraulic power. Flows in the Saskatchewan and Churchill River Basins are expected to be well below normal into the spring of 2002. Hydraulic power generation during years of median flows is estimated at 3,550 GWhr. Total hydraulic power generation for 2001 is estimated at 2,412 GWhr based on November 1 updates submitted to the review team. The 2002 Business Plan anticipates hydraulic power generation for 2002 at 3,297 GWhr. (This differs from the November 1, 2001 update.) This increases to 3,550 GWhr in 2003 and remains in the order of 3,500 GWhr through to 2006. Given the continued challenge of available water, actual hydraulic production in 2002 may be as little as 2,907 GWhr according to SaskPower officials.

Predicting water flows and availability is a difficult task. Water flows can quickly rebound under the right conditions, such as a heavy winter snowfall and wet spring. History has proven that water conditions do rebound quickly. Under median and above flow conditions, SaskPower has the capacity to generate 3,550 GWhr of cheap electricity.

3.3.2.2. Hydro Generation Summary and Analysis

The Saskatchewan and Churchill River watersheds are experiencing below normal water levels resulting in reduced hydraulic generating capacity for SaskPower. The outlook for 2002 continues to be pessimistic in terms of water supply. Long-term predictions of water supplies and stream flows is an inexact science. History has proven itself that stream flows can recover very quickly given the right circumstances. Therefore, forecasted median flows and resulting hydraulic power generation for the Years 2003 to 2006 may be overly pessimistic. Obviously, the more available hydraulic power, the cheaper the cost of electrical energy production.

3.3.3. Gas/Turbine Generation

3.3.3.1. General

SaskPower currently produces approximately 18% of its energy needs from natural gas-fired plants. These plants are outlined in Table 3.7 below.

Table 3.7: SaskPower Gas/Turbine Generating Capability

	Net Maximum Capacity
• Queen Elizabeth (nine units)	386 MW (since 1999)
• Landis (one unit)	80 MW
• Meadow Lake (one unit)	43 MW
• Success (three units)	30 MW
Total	**539 MW**

As a group, they contribute approximately 18% of SaskPower's total demand capacity capability and because of high variable fuel costs, are used primarily to meet peak load requirements or to meet emergency supply needs.

As peaking plants, the energy generated by these natural gas turbines has been and will continue to be highly variable. The following table illustrates the recent supply history and probable future use.

Table 3.8: SaskPower Gas/Turbine Energy Generated (GWhr)

	Actual								Estimated				
	1995	1996	1997	1998	1999	2000	2001 Budget	2001 September	2002	2003	2004	2005	2006
Queen Elizabeth	--	--	--	--									
Landis	35	49	80	131									
Meadow Lake	84	98	89	205									
Success	Neg.	1	4	12									
Totals	**119**	**148**	**173**	**348**	**995**	**924**	**746**	**990**	**1563**	**1265**	**1368**	**1827**	**1723**

3.3.3.2. Gas Turbine Generation Summary and Analysis

SaskPower's long-term strategy for additional energy production focuses on gas-fired turbine generation. This can readily be seen by the anticipated gas turbine energy production for 2002 increasing by 573 GWhr or 58% from 990 GWhr to 1,563 GWhr. The long-term trend sees a continued reliance on gas for energy production peaking at upwards of 1,827 GWhr in 2005.

The reliance on gas-fired energy generation sources puts SaskPower at some degree of financial risk, given the volatility of natural gas prices as witnessed in the last year. Natural gas purchase hedging practices by SaskPower have resulted in a more stable price guarantee for large volume purchases. The recent economic slowdown and warmer than usual weather patterns have brought the forward price of natural gas down substantially from levels seen in the previous year. At the time of preparation of this review, the December 2001 to October 2002 forward price for natural gas was in the order of \$3.93 per gigajoule. SaskPower has currently hedged approximately 55% of their 2002 gas purchases at a price of approximately \$4.61 per gigajoule. Possible future savings in gas purchases should be realized in 2002 for remaining gas purchases required.

3.3.4. Energy Imports and Exports

3.3.4.1. General

SaskPower's transmission grid system has three interconnections to neighbouring utility systems, as shown on Figure 1. Because of a variety of constraints (energy availability, trip line transmission capacity, and emergency reserves), the actual ability to bring power into Saskatchewan is considerably less. The following table provides a simplistic summary of what is currently achievable under normal circumstances.

Table 3.9: SaskPower Import/Export Potential

	On-Peak Availability (MW)	Off-Peak Capability (MW)
From MAPP (USA and Manitoba)	187.5 (winter) 262.5 (summer)	225 (winter) 225 (summer)
From PPA (Power Alberta)	75 (winter) 75 (summer)	75 (winter) 75 (summer)
Combined Totals	**262.5 (winter)**	**300 (winter)**
	337.5 (summer)	**300 (summer)**

The foregoing would suggest that SaskPower could theoretically import a maximum of 2,700 GWhr/year (assuming there were no conflicting exports).

The actual historical and forecasted power imports are presented in the following table:

Table 3.10: SaskPower Imported Energy Used and Costs

	Actual						Estimated	Forecasted				
	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
PPA	--	--	--	--	--	--	--	--	--			
Basin	--	--	--	--	--	--	--	--	--			
Manitoba	--	--	--	--	--	--	--	--	--			
GWhr	**291**	**741**	**982**	**1,536**	**1,910**	**1,940**	**2,120**	**906**	**618**	**634**	**786**	**903**
Cost ($ Millions)		**12**	**21**	**44**	**51**	**69**	**89**	**54**	**30**	**27**	**36**	**43**

In the past three years, SaskPower has been importing 70 to 75% of the theoretically possible energy. Forecasts which suggest that imports will decline to the 600 to 800 GWhr range seem somewhat pessimistic (e.g., the 2001 budget import forecast was exceeded by 120%).

The same interconnections to external grids that allow import of energy also allow for export of energy when market prices rise. SaskPower has been able to export generally increasing amounts of energy over the last five years. The following table illustrates this and provides the forecasts for future exports.

Table 3.11: SaskPower Exported Energy Generated (GWhr)

	1996	1997	1998	1999	2000	2001 Budget	2001 Estimated	2002 Forecasted	2003 Forecasted	2004	2005	2006
GWhr	467	369	618	801	1143	1176	964	951	1040	936	915	840
Revenue ($ M)					**137**	**97**	**112**	**95**	**88**	**75**	**67**	**56**

It should be noted that the combined total of import and export reached 3,100± GWhr in 2001. Forecasts for 2002 and 2003 show 1,857 and 1,658 GWhr, respectively in combined import and export. This decline may be overly pessimistic.

3.3.4.2. Energy Imports and Export Summary and Analysis

SaskPower's ability to import and export power is constrained by system limitations and both seasonal and daily on-peak and off-peak timing restrictions. In general, however, SaskPower is expecting imported energy to drop in 2002 due to anticipated increases in import energy costs. 2002 imported energy costs are expected to rise from approximately ¢3.9/KWhr in 2001 to $6.0/KWhr in 2002. This unit cost for import energy is anticipated to decrease to ¢4.8/KWhr in 2006.

SaskPower also anticipates export revenues to decline in 2002 due to an anticipated decrease in demand and unit price for energy. Export revenues are expected to decline from $109 M in 2001 to $95 M in 2002. This translates into an average export price of ¢10/KWhr in 2002. This declines to ¢6.7/KWhr in 2006.

This creates somewhat of a paradox since import costs per KWhr are expected to rise while export costs per KWhr are expected to decline. It is considered very unlikely import costs will approach ¢6/KWhr in 2002; especially if imports are purchased during off-peak hours. This would amount to a 70% increase in KWhr costs from a 2000 average price of ¢3.5/KWhr. Average import costs for 2001 to date have been in the order of ¢4.2/KWhr.

Should SaskPower consider the purchase of import power during off-peak times, import power costs of ¢3.5/KWhr to ¢4.5/KWhr should be readily achievable. Recent off-peak import power costs from Manitoba Hydro (November 2001) varied from ¢2.06 to ¢2.54/KWhr. Thus, import costs may compare favorably with local gas generation. For 2001, gas generation costs averaged ¢13/KWhr and ¢6.25/KWhr from co-generation facilities. SaskPower has forecasted 2002 gas generation costs at ¢5.9/KWhr and ¢4.9 to ¢6.8/KWhr from co-generation facilities, assuming gas prices decline somewhat in 2002.

This analysis therefore suggests that the purchase of import power may be the more economical option than the operation of gas generating facilities. This would be especially applicable if import power could be purchased during off-peak time periods.

3.3.5. Meridian and Cory Co-Generation Plants

The Meridian co-generation plant at Lloydminster came on-line in 2000. It is natural gas-fired with an average capacity of 210. With no major overhaul anticipated for at least six years, the full plant capacity should be available for the next six years.

The Cory Co-generation Plant is a 228 MW natural gas-fired co-generation/combined cycle plant scheduled to come on-line after November 1, 2002. SaskPower's initial commitment is to purchase 80 MW of non-dispatchable take or pay capacity and energy for the entire year. The remaining capacity can be purchased by SaskPower at its discretion (in August of each year, the entire plant capacity is available on a dispatchable basis). There has been some indication in this review that SaskPower's obligations may be to purchase most of the dispatchable power.

3.3.6. Wind Generating Facilities

There are two wind generating facilities in SaskPower's system. These are:

- Sunbridge - Seventeen wind turbine towers (coming on stream between July 2001 and December 2001), with an initial capability of 2 MW and a total capability of 11.2 MW.

- SaskPower - Eight wind turbine towers (August 2002 in service) capable of producing 5.3 MW with an assumed energy production of 20 GWhr (43% capacity factor).

These wind generating facilities can be used to complement gas generation, when wind conditions permit. They are not firm energy generators.

3.3.7. Transmission and Distribution

Figure 1 illustrates the major transmission networks for Saskatchewan. These facilities have been progressively improved and expanded over the last five years. Table 3.12 illustrates the growth in transmission and distribution facilities from 1995 to 2000.

Table 3.12: Growth in T & D Facilities from 1995 to 2000

Component/km		1995	2000	% Increase
230 KV		3,457	3,684	6.6%
138 KV		4,116	4,327	5.1%
115 KV		400	400	0
110 KV		190	190	0
72 KV		4,382	4,386	Neg.
72 KV[1]		7	7	0
25 KV		20,914	22,799	9.0
25 KV[1]		420	709	69
14 KV		72,821	72,437	-0.5
14 KV[1]		41,997	42,914	2.2

[1] Underground km

SaskPower appears to have been diligent in keeping transmission capabilities in step with increased generation and load. Presumably, additional transmission requirements will track new generation plants such as the Cory co-generation plant.

3.3.8. Energy Conservation

In May 2001, the Premier of Saskatchewan appointed Peter Prebble (MLA for Saskatoon-Greystone) to coordinate the development of a Saskatchewan GreenPrint for Energy Conservation (provincial conservation strategy). In conjunction with this initiative, Mr. Prebble is working with a government-wide committee to identify conservation program options. These options will be evaluated, interest groups consulted, and a GreenPrint program menu will be presented to cabinet in the September to October period. Some of the organizations contributing to the planning effort include: Saskatchewan Energy and Mines (SEM), SaskPower, SaskEnergy, SaskHousing, SERM, Saskatchewan Research Council, etc. The government has also engaged a consultant from the Pembina Institute, Roger Peters, to work with Mr. Prebble in this undertaking.

Because SaskPower and SaskEnergy are the primary energy providers of electricity and natural gas to the people of Saskatchewan, these organizations have a significant interest in the outcome of this planning process. Existing SaskPower/SaskEnergy programs (like the PowerCheck on-line energy audit, the Energy Performance Contracting (EPC) program, the SaskEnergy high efficiency furnace load programs are being integrated into the GreenPrint plans. As well, other new programs are being considered.

4. SYSTEM OPERATIONAL COSTS

4.1. Energy Sales

SaskPower has seen a general increase in annual energy sales (41% increase since 1991). Only in 2001 does it appear that there was some slippage. Sales revenue on the other hand has increased every year (69% increase since 1991). However, as illustrated in Table 4.1, the average price during this period has increased by 20%, suggesting increased sales revenue is being driven more by increasing energy volume than by unit price gains.

Table 4.1: SaskPower Energy Sales Revenue from Annual Reports and Business Plan

Year	Energy Sales (GWhr)	Revenue ($ Million)	Average Sales Value (¢/KWhr)
1991	12,031	667	5.54
1992	12,657	712	5.63
1993	13,748	790	6.06
1994	13,820	837	6.06
1995	14,383	861	5.99
1996	15,064	886	5.88
1997	15,608	917	5.88
1998	16,187	958	5.92
1999	16,210	977	6.03
2000	17,049	1,080	6.33
2001*	16,981	1,124	6.62
2002*	17,505	1,148	6.78
2003*	18,086	1,240	6.86

*`October 26, 2002 Business Plan

4.2. Fuel and Purchased Power Costs

Table 4.2 (SaskPower Summary of Power Supply Costs) attempts to illustrate the relationships (historical and forecast) that have determined the choice of energy sources.

From careful analysis of this table, a number of observations and trends are apparent:

- Hydro is the preferred supply source at costs of less than ¢0.3/KWhr. It has been and will continue to be the energy choice to the maximum extent available. Unusually low stream flows in the 2000 to 2001 period reduced the hydro percentage of total energy provided from approximately 20% to 16%.

Table 4.2: SaskPower Summary of Power Supply Costs

	1995*	1996*	1997*	1998*	1999*	2000*	Sept. 2001 Update**	2002***	2003***	2004***	2005***	2006***
GWhr Export		464	369	618	801	1,143	964	951	1,040	936	915	840
$ M Revenue		9	8	21	42	128	109.5	95.3	87.5	75.5	67.8	56.4
¢/KWhr		1.93	2.17	3.40	5.24	11.2	11.3	10.02	8.4	8.07	7.41	6.7
GWhr Import	291	741	982	1,536	1,811	1,995	2,120	906	618	634	786	903
$ M Cost					50.5	68.8	83.8	54.1	30.0	27.5	36.0	43.4
¢/KWhr					2.64	3.44	3.95	6.0	4.85	4.33	4.58	4.81
Hydro GWhr	4,137	4,396	4,005	3,668	3,668	3,046	2,424	3,297	3,550	3,562	3,549	3,549
$ M Cost					9.3	7.9	6.6	8.9	9.8	10.0	10.2	10.4
¢/KWhr					0.25	0.25	0.28	0.28	0.28	0.28	0.28	0.28
Coal GWhr	12,669	12,565	13,251	13,584	11,568	11,436	11,711	11,789	11,448	11,613	11,450	11,584
$ M Cost					144.6	167	182.7	185	185	188	174	175
¢/KWhr					1.25	1.42	1.56	1.6	1.6	1.6	1.5	1.5
Gas GWhr	119	148	173	348	995	924	990	1,563	1,265	1,368	1,827	1,723
$ M Cost					42.1	66.8	116.6	92.1	77.5	80.2	102.9	9.25
¢/KWhr					4.7	7.2	11.8	6	6	6	5.5	5.5
Meriden GWhr												
$ M Cost												
¢/KWhr												
Cory GWhr												
$ M Cost												
¢/KWhr												
Wind GWhr												
$ M Cost												
¢/KWhr												
Total Sales GWhr (excludes loss)	**14,400**	**15,000**	**15,600**	**16,200**	**16,200**	**17,050**	**16,981**	**17,509**	**18,090**	**18,449**	**18,753**	**19,051**
$ M Supply Cost					**256**	**387**	**477**	**439**	**474**	**477**	**490**	**502**
¢/KWhr					**1.6**	**2.3**	**2.8**	**2.5**	**2.6**	**2.6**	**2.6**	**2.6**

* Annual Reports ** From SaskPower Third Quarter Report *** SaskPower 2002 Business Plan

- Coal accounted for 80% of the energy supply until 1998, after which the conversion of the Queen Elizabeth generating station to natural gas, reduced the coal share of energy supplied to approximately 67%. Coal costs have risen from ¢1.25/KWhr in 1999 to ¢1.6/KWhr by 2002. However, coal continues to cost ¢2.5 to ¢3.0/KWhr less than gas-supplied energy sources. Environmental liabilities associated with coal-fired generation are continuing to grow and may force progressive movement away from coal generation. or costly environmental control equipment.

- Imported energy has played an increasing role in SaskPower's energy supply reaching a high of 2,120 GWhr or 12% of total energy sold. The Business Plan forecasts suggest that this import level will be reduced to 600 to 800 GWhr in future years as a result of anticipated higher market prices for imported energy. A similar forecast was made for 2001, but proved to be incorrect as natural gas prices rose dramatically while import prices did not rise to the extent anticipated. Import energy costs for 2001 were approximately ¢3.95/KWhr.

- The Cory Co-generation Station is contracted to supply 80 MW on a firm basis to SaskPower. Additionally, there are up to 148 MW available on an as-required/dispatchable basis.

- Export sales prices have increased dramatically to ¢11.2/KWhr in 2000 and ¢11.3/KWhr in 2001 from ¢5.24/KWhr in 1999 and ¢3.40/KWhr in 1998.

4.3. System Operations Summary and Analysis

The following items represent an analysis of system operational practices and possible savings.

- SaskPower's assumptions on future energy generation appear to be predicated on meeting its net income targets in a period when climatic conditions and the natural gas market have created an extremely unfavorable financial condition in 2001 and are likely to do so again in 2002. Unless domestic rates are increased, they expect the same results in 2002. In addition, growth in energy demand is projected at 2.5% to 3% for 2002. Recent events and the declining economy would suggest that SaskPower's load forecasts are overly optimistic. Contrary to expectations that 2001 would see an energy growth of 1.3%, there was little or no growth. Forecasts of a 2.5% to 3% energy growth for 2002 are very optimistic. A growth rate of 1% to 1.5% is more likely. This amounts to approximately 250 GWhr in increased demand rather than 528 GWhr in estimated demands. Savings in electrical generation requirements would therefore be in the order of 250 to 280 GWhr. If we assume this energy savings of say 250 GWhr was produced by gas generation, net savings would be 250 GWhr x (¢6/KWhr for gas generation – the average sale price to the non-residential component in the SaskPower rate table). This amounts to 250 GWhr x (¢6/KWhr - ¢3.7/KWhr) = $5.75 M or approximately $6.0 M.

- The Proposal assumes an anticipated inability to continue to purchase import power at attractive rates (¢3.5 to ¢4.0/KWhr) in sufficient quantities (2000 ± GWhr in 2000 and 2001) to avoid expenditures in gas turbine generation (¢6/KWhr). The experience in 2001 was that SaskPower could buy significant (1000± GWhr) additional power from Manitoba Hydro at lower than budgeted prices. This scenario, if repeated in 2002, would have potential savings of $10 to $20 M (500 to 1,000 GWhr of imported power @ ¢4/KWhr would replace gas turbine generation at ¢6/KWhr). Off-peak surplus energy rates in Manitoba have remained at or below ¢2.5/KWhr during 2001.

  If this import price and availability experience in 2001 is projected into the 2002 and 2003 period, SaskPower could reasonably expect to import an additional 500 to 1,000 GWhr of electricity as a substitute for natural gas-fired turbine energy or SPI's Cory Co-generation dispatchable (or non-firm) energy. Average imported energy prices paid by SaskPower have been increasing over the last three years (from ¢2.64/KWhr in 1999 to ¢3.95/KWhr in 2001). This latter projected value is 0.35¢ lower than the ¢4.30/KWhr use in the 2001 budget. As such, it is not unreasonable to suggest that import costs may be significantly lower than the ¢6.00/KWhr proposed for 2002 in the current SaskPower Business Plan.

- SaskPower anticipates a 10% to 20% below median (normal) forecast hydro generation output, based on a partial recovery from the 30 to 32% below medium hydro energy available in 2001.

  Historically, following drought scenarios, SaskPower's hydro production has returned after two years. An unlikely full recovery to the median energy level would have potential savings of $14 M (approximately 250 GWhr @ ¢6/KWhr for gas minus ¢0.30/KWhr for hydro).

  This saving is a low probability. It can however be rationalized to some extent as it is likely that 50% of future years will be above median and these could theoretically occur within the next five years. SaskPower estimates a three in four chance that their 2002 Business Plan forecast for hydraulic power generation will not be realized. Recent forecasts have budgeted approximately 2,900 GWhr in hydraulic generating capability for 2002.

- Cory energy, over and above the committed firm purchase, could be attractive during peak demand periods.

  Environmental benefits associated with co-generation will continue (in the long-term) to justify Cory production relative to coal energy. High export prices (on-peak) could also encourage Cory production.

- SaskPower currently hedges natural gas purchases to avoid substantial swings in natural gas costs. For 2002, SaskPower estimates a natural gas requirement in the order of 31,300,000 GJ. SaskPower has already hedged in the order of 18,000,000 GJ at a price of $4.61 per GJ. The remaining 13,300,000 GJ will be purchased on the open market. In SaskPower's Business Plan and Rate Proposal, they have assumed a weighted average price for gas of $5.00/GJ, including transportation costs. The recent December to October 2, 2001 forward averaging price for natural gas is now approximately $3.93/GJ. These prices are anticipated to fall even further. If we assume a weighted average price of $4.25/GJ rather than $5.00/GJ, as a result of lower gas costs, a 15% saving in gas purchase price may be realized. This would amount to gas prices in the order of ¢5/KWhr instead of the anticipated ¢6/KWhr. As of November 19, 2001, spot market gas prices were in the order of $2.96/GJ.

5. CAPITAL COSTS, OPERATING, MAINTENANCE, ADMINISTRATION, PLUS OTHER FINANCIAL ISSUES

5.1. Capital Cost Programs

SaskPower has over the last seven years been spending $160 M (on average) per year on Capital Works such as customer access, distribution system upgrades, new transmission facilities, and environmental improvements to generation plants. These actual and anticipated expenditures are outlined in Table 5.1.

Table 5.1: SaskPower Capital Expenditures

	Actual					Budget	Forecast					
	1996	**1997**	**1998**	**1999**	**2000**	**2001**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**
Capital Works ($ M)	117	160	137	185	212	365	302	335	346	354	416	492

These cash requirements include capital investments by SPI.

While the actual dollar investment in capital varies from year to year, the capital expenditures in 2001 were allocated as follows:

	Budget ($ M)	Revised Forecast ($ M)
Corporate Services (Financial/Regulatory/Information Technology)	21.5	12.7
Customer Services	4.7	4.7
Existing Power Production (including Carbon Office)	70.4	75.4
New Generation (Queen Elizabeth and Wind)	103.1	90.3
Transmission and Distribution (including Customer Connects @ $38.2 M and $43.2 M)	115.5	108.0
SPI (Cory Co-generation)	50.0	10.7
Total	**365.2**	**301.7**

Available information does not permit a definitive allocation of revised forecast 2001 generation system upgrade costs to coal, hydro, gas turbine, or co-generation; however, it is suggested that these funds were allocated on the following basis:

- Coal – 67%
- Hydro – 0%.

- Gas Turbine – 30%.
- Co-generation – 3%

Environmental costs (site remediation/air quality improvements) are included in these categories.

SaskPower, with its broad scope of power supply sources, is faced with difficult choices when it comes to new plant investments and also facility decommissioning. SaskPower's current strategy appears to be focussed on:

- Add co-generation facilities while decommissioning older gas turbines.
- Upgrade coal generation plants progressively to meet evolving environmental requirements.
- Enhance hydro production, if possible.
- Add wind power where appropriate.

There does not appear to be a plan to enhance import/export transmission capabilities at this time.

5.2. Operating/Maintenance/Administration

Table 5.2 highlights SaskPower's Operation, Maintenance, and Administration (OM&A) costs.

Table 5.2: SaskPower OM&A Costs

	Actual						Forecast				
	1996	1997	1998	1997	2000	2001 Budget	2002	2003	2004	2005	2006
Cost ($ M)	197	214	238	281	264	276	290	312	322	352	396

SaskPower's operating, maintenance, and administration costs represent 25 to 40% of total operating costs and expenses. On a unit cost basis, these costs have increased from ¢1.3/KWhr in 1996 to ¢1.55/KWhr in 2001 (20% increase over six years compared to an inflation rate of 10%).

In other jurisdictions (e.g., Manitoba Hydro), the OM&A costs account for 20 to 25% of total operating costs/expenses. At Manitoba Hydro, these unit OM&A costs rose from ¢0.79/KWhr in 1996 to ¢0.83/KWhr in 2001 (a 5% increase over six years).

In terms of staff resource efficiencies, SaskPower has generated between 6 and 8 GWhr for each equivalent full-time employee since 1995. In 1995, SaskPower generated 6.7 GWhr/employee. This productivity rose to 7.50 GWhr per employee in 1998 and has since declined to 5.6 GWhr/employee in 2001. Ideally, most utilities strive to achieve a steady increase in productivity. SaskPower is budgeting for an additional 99 full-time equivalent positions in 2002. The resulting increase in employee growth seems excessive in comparison to the load growth. Based on this review, it would seem SaskPower was more efficient in prior years in terms of GWhr generated per employee.

Comparison to industry standards such as the CAE-COPE rating system is difficult because of the considerable variation in the way that different utilities allocate costs.

Operation/maintenance and administration costs are generally allocated as follows at SaskPower:

- Generation - 44%.
- Transmission/Distribution - 25%.
- Customer Service - 10%.
- Corporate/etc. - 21%.

These appear to be reasonable with the possible exception of corporate elements.

5.3. Return on Equity

SaskPower's targeted Return on Equity of 10% may have been appropriate over the last ten years, when interest rates were in the 7.5 to 8% range. Even recognizing that most of the corporation's debt is long-term and subject to interest rates in the 8 to 10% range, it may be appropriate to consider lowering this target, given that new borrowing is achievable at much lower interest rates (e.g., 6%). The fact that the cost of borrowing money has decreased, consideration of a lower return on equity may be warranted.

5.4. SaskPower International

The establishment of SPI (then Commercial) was authorized by the SaskPower Board on December 15, 1993 and ratified by the Crown Investments Corporation Board on February 24, 1994. It was incorporated as a wholly owned subsidiary of SaskPower in September 1994 with a mandate to diversify and enhance SaskPower's revenue base, promote job creation and economic development of the Province, and to achieve a suitable return on invested capital. The declared strategy in SPI's original business plan to achieve those objectives was to market SaskPower's expertise to national and international markets; to market and sell by-products and equipment that is surplus to the needs of the Corporation, and to pursue business opportunities that utilize SaskPower's core business knowledge and networks.

SPI, as a subsidiary of SaskPower, is aligned to contribute to SaskPower's vision of ***excelling in competitive energy markets.*** As such, SPI has been mandated to seek new sources of generation and new sources of corporate and business growth for SaskPower.

In response to this desire to grow the corporation, SPI continues to seek power project investments, including co-generation projects in Saskatchewan and beyond, in conjunction with knowledgeable partners.

SPI's investments outside of Saskatchewan will be targeted in the primary market (North America) with a focus on the region adjacent to the province, other parts of Canada, and subsequently in regions where the culture, language, and business practices are similar to our own.

SPI's primary goals are as follows:

- Market SaskPower's expertise to national and international markets.
- Sell flyash and other by-products.
- Invest in power projects where the Proposal of core skills of SaskPower can add value and where commercial and political risks are acceptable and manageable.

SPI, through a 50-50 joint venture with ATCO Power Canada Ltd. (ATCO), entered the construction phase of the Cory Co-generation Station in 2001.

Investments outside of Saskatchewan by SPI will be targeted in the primary market (North America) with a focus on the region adjacent to the province, other parts of Canada, and subsequently in regions where the culture, language, and business practices are similar to our own (secondary markets).

SPI has budgeted $250 M in equity over five years (to 2006) for such investments. This amounts to SaskPower's equity position in SPI. In addition, SPI has budgeted approximately $233 M in non-recourse financing over the same period.

SPI expects to incur losses of $1 to $2 M/year over the next three to four years.

As a result, SaskPower's net income will be reduced by approximately $4 to $5 M/year (SPI losses plus financing cost estimated at $30 M/year by 2006). These costs form part of the SaskPower revenue requirements to be covered by rate payers.

As SaskPower International grows, capital expenditures are expected to total approximately $483 M by 2006. This is a significant capital investment for a subsidiary company. Based on this review, it would appear that SPI projected revenues by 2006 would potentially not cover interest charges on capital expenditures (estimated to reach $28 to $30 M/year by 2006). This would seem to put the Saskatchewan rate payers at risk to cover the potential costs of SPI investments. As a result, it is suggested SaskPower seriously consider that SPI be treated as a fully cost accounted non-regulated company.

5.5. Depreciation

Depreciation expense is forecasted to increase by approximately $9.0 M over the 2001 forecast. Total depreciation for 2002 is estimated at $175.1 M. It was not within the scope of this review to undertake a depreciation study of SaskPower assets. The last depreciation study was conducted in 1996. SaskPower is scheduled to complete a new depreciation study by November of 2001. Without undertaking a detailed depreciation analysis or being able to review the newest depreciation study, this review is obviously limited as to the overall reasonableness of the depreciation value developed by SaskPower. The individual depreciation rates for assets, and overall depreciation value, appear to be reasonable.

5.6. Corporate Capital Tax

The Corporate Capital Tax is the tax on the Capital of SaskPower. This tax rate is set at 0.6% of "taxable paid-up capital." There is an exemption to Corporations with capital assets less than $10 M. SaskPower's Paid-up Capital (PUC) is made up by adding all balance sheet liabilities with adjustments for short-term accounts payable, and differences between amounts for book and income tax purposes.

SaskPower is allowed to deduct amounts, which represents capital in the form of shares or debt that have been loaned to other corporations or government, including accounts receivable in excess of 90 days.

In addition to the 0.6% regular rate, a resource corporation is subject to a resource surcharge. The surcharge is 3.6% of the corporation's value. However, a corporation is only required to pay the greater of the regular rate or resource surcharge. Corporations that have resource sales are required to pay tax at 3.6% of resource sales that take place in Saskatchewan.

Based on this formula and the legislated requirements, SaskPower's Corporate Capital Tax is estimated at $12.5 M for 2002.

5.7. Planned Maintenance

SaskPower's planned maintenance seems to logically follow their capital spending budget. The majority of SaskPower's maintenance activity is in the Power Production and transmission, as well as distribution business units. The allocation of maintenance expenditures seems reasonable based on this review.

5.8. Summary of Issues

SaskPower Capital Costs are largely focussed on new generation facilities as well as continued upgrading and customer connections to the transmission and distribution system. Future capital expenditure are largely focussed on new generation projects in 2003 to 2006. This also includes a commitment of $50.0 M/year by SaskPower as an equity position in SaskPower International (SPI) projects and an additional $50 M/year by SPI in non-resource financing. This amounts to a $76 M capital investment in 2002 and a budgeted $100 M/year investment commencing in 2003 (total investment to 2006 amounts to $483 M). This represents a significant commitment by SaskPower and SPI in capital expenditures.

SPI is currently functioning as a subsidiary to SaskPower. As such, return on equity flows ultimately to SaskPower. Likewise, SaskPower and their rate payers would seem to absorb the risks from investments made by SPI in new projects. It was not within the scope of this review to attempt to rationalize budgeted capital expenditures and investments by SPI and SaskPower's equity commitment in SPI. This review is designed to bring to the attention of the Panel the significant capital investments planned by SPI and SaskPower in as yet undefined projects. These projects are not necessarily based in Saskatchewan, but represent equity positions deemed to have potential benefits by SPI. As this is a significant departure in investing in more traditional SaskPower-based activities, SaskPower should consider SPI investments and financing as an independent, non-regulated, and fully cost-accounted arm of SaskPower.

Depreciation, corporate capital tax, and planned maintenance activities seem reasonable based on this review.

6. REVENUE REQUIREMENTS

6.1. General

SaskPower has identified total revenue requirements of:

- $1,129 M in 2001, increase of 0.2% over 2000 actual of $1,100 M.
- $1,203 M in 2002, increase of 2.6% over 2001.
- $1,260 M in 2003, increase of 4.7% over 2002.
- $1,283 M in 2004, increase of 1.8% over 2003.
- $1,313 M in 2005, increase of 2.3% over 2004.
- $1,337 M in 2006, increase of 1.8% over 2005.

These revenue requirements are based on:

- Load growth estimates of 0.4% in 2001, 3.1% in 2002, 3.3% in 2003, and 2.0% in 2004. These additional load growth demands must be largely fuelled by natural gas generation, with estimated fuel costs in the order of ¢6/KWhr.

6.2. Summary

- For 2002, the estimated increased energy requirement of 550± GWhr will result in a net income reduction of $13 M (e.g., 550 GWhr @ ¢6.0 – ¢3.7/KWhr of cost-revenue shortfall). **A less optimistic load growth forecast of approximately 1.0% could reduce the negative impact on net income by $8 to $10 M.**

- Lower hydro production – SaskPower has assumed hydro production of 3,297 GWhr in 2002. Hydro production rates are estimated in the order of 2,907 GWhr based on November 1, 2001 updates. The difference of approximately 250 GWhr must be made up by either gas generation or imported energy. The increase in revenue requirements due to gas generation is 250 GWhr x (¢6/KWhr - ¢0.3/KWhr) = $14 M. If imported energy was used, the increased revenue requirement would be 250 GWhr x (¢4 KWhr - ¢0.3 KWhr) or $9 M. A more favourable hydraulic outlook approaching median flows resulting in 3,550 GWhr could provide a comparable saving in the order of $14 M.

- Higher coal costs due to royalty increases and price escalation are expected to increase the unit cost of thermal energy by ¢0.2/KWhr. At an average energy capability of 11,500 GWhr, this translates into a net income reduction of $23 M.

- Higher natural gas costs were a very significant factor in 2000 and 2001 when average unit costs were 7¢ and ¢11/KWhr. The forecast for 2002 and on onward is at or below ¢6/KWhr. As such, there is little direct impact on future net income, even though SaskPower was impacted substantially during the past two years (e.g., as much as $12 M in 2000 and $50 M in 2001). **If supply costs for natural gas were to drop below current prices to ¢5/KWhr, there would be a positive impact on net income of $15 M.**

- A small decline in the export market for SaskPower's surplus power is forecasted for 2002 relative to 2001. This is expected to result in about a 10 to 15% reduction in export revenue (e.g., $14 M) largely as a result of lower unit market prices (10¢/KWhr down from ¢11.3/KWhr). Further similar reductions in future years are forecasted.

- Higher import prices and lower import availability are forecasted for power supply. Average import prices are expected to rise to ¢6/KWhr in 2002 (from ¢3.95/KWhr in 2001), then drop to ¢5/KWhr in 2003. Import power is to drop to 50% of average for last three years because at ¢6/KWhr, it does not really compete with gas generation. The ¢2/KWhr unit price increase raises revenue requirements by $18 M. **If on the other hand average import prices remain at 4¢, imported energy might rise by 500 to 1,000 GWhr to 2001 levels (displacing gas generation) and result in a rise in net income of $10 to $20 M.**

- Increasing operations, maintenance, and administration costs (salaries/inflation/etc.) are expected to rise from $262 M in 2000, $273 M in 2001, $284 M in 2002, $293 M in 2003, $301 M in 2004, $310 in 2005, and $320 M in 2006. This represents a 4% increase in 2002, with subsequent increases declining to 3%±. This cost will remain constant at ¢1.62/KWhr of energy sold. **A productivity gain of 2%, if achieved, would provide approximately $5 M in net income gain.**

- Increasing depreciation charges. Due to substantial capital works in 1999 and 2000, SaskPower's depreciation charges have increased by $9.0 M in 2002. Some of this relates to capitalized interest charges during construction, but is first being paid in the upcoming year. **These charges essentially flow out of past year's commitments and therefore cannot be adjusted in the short-term. In the long-term, the currently forecasted capital works may require scrutiny, because these will eventually lead to requests for rate increases.**

- Increasing finance costs. SaskPower anticipates that because of previous debt reduction measures and low current interest rates, financing costs will be held constant or may be reduced. However, the recent and forecasted capital programs (particularly the SPI investments) will result in increasing debt levels in the short-term and, in the longer-term, increased interest payments. **Again, there is no opportunity for short-term adjustments to reduce revenue requirements. In the long-term, it is important to examine the level of capital expenditures/investment.**

- SPI's investment program has had only modest, if any, impacts to date on SaskPower's net income. However, the addition of $50 M/year over the next five years will progressively increase debt levels and financing charges. By 2006, SaskPower's revenue requirements to service this debt must rise by $28 to $30 M/year. **Given SaskPower's current situation, it may be appropriate to defer/extend this SPI investment process. A one-year delay would potentially reduce revenue requirements in 2002 by $1.5 M and by $3.0 M in 2003.**

- Return on Equity Issues. SaskPower has made a strong case for retaining the current Return on Equity target of 10%, even though current interest rates point to lower expectations in the years to come. The corporation operates in more volatile sections of the energy market than do BC Hydro, Manitoba, or Quebec Hydro, whose cost side is relatively stable. **In the last five years, SaskPower has achieved and exceeded its current return on equity target of 10%, four times (1996, 1997, 1998, and 2000). In the other two years (1999 and 2001), it has fallen short of target, quite substantially in 2001, primarily as a result of lower hydro generation capability leading to gas consumption at high unit costs and to increased imports/reduced exports. Over the six-year period, the average rate of return on equity was just under 10%.**

SaskPower's net income forecasts for the next five years appears to be premised on achieving an average of 9.8% return on equity. Toward this end, they have requested a 5.41% increase as of December 1, 2001 and suggest a further increase of 1.99% for 2003. In general, based on SaskPower's assumptions, the proposed revenue requirements appear appropriate.

However, based on revised assumptions indicated from the above analysis, the following scenarios outlining potential savings should be achievable:

Scenario 1:

- ***1.5% Economic Growth***
- ***906 GWhr of Imported Power***
- ***Gas Purchase Savings***
- ***Shortfall in Hydraulic Power Production is made up with Imports (approximately 3,297 GWhr – 2,907 GWhr = 390 GWhr)***

For this scenario, it is assumed the savings as a result of slower economic growth (of 250 GWhr) is accrued to gas generation resulting in approximately 1,300 GWhr of gas generated power supply in 2002.

Savings from reduced economic growth	= 250 GWhr x (¢6/KWhr - ¢3.7/KWhr) = $5.75 M	say $6.0 M
Gas savings	= 1300 GWhr x (¢1/KWhr saving) =	13.0 M
Imported power savings	= 906 GWhr x (¢2/KWhr saving) =	18.0 M
Additional imported power costs for hydraulic energy shortfall	= 390 GWhr x (¢4/KWhr) =	-15.0 M
Total Savings		**$22 M**

Scenario 2: ***Same as Scenario 1, except imported energy is increased to approximately 1,400 GWhr to replace costlier gas generation.***

Savings from reduced economic growth	= 250 GWhr x (¢6/KWhr - ¢3.7/KWhr) = $5.75 M	say $6.0 M
Import 1,400 GWhr	= 1,400 GWhr x (¢2/KWhr saving) =	28.0 M
Gas savings	= 800 GWhr x (¢1/KWhr saving) =	8.0 M
Additional imported power costs for hydraulic energy shortfall	= 390 GWhr x (¢4/KWhr) =	-15.0 M
Total Savings		**$27 M**

Scenario 3: ***Same as previous scenario, except now SaskPower imports 1,900 GWhr.***

Savings from reduced economic growth	= 250 GWhr (¢6/KWhr - ¢3.7/KWhr) = $5.75 M	say $6.0 M
Import 1,900 GWhr	= 1,900 GWhr (¢2/KWhr saving) =	38.0 M
Gas savings	= 300 GWhr (¢1/KWhr saving) =	3.0 M
Hydraulic energy shortfall is made up by gas generation at ¢5/KWhr	= 390 GWhr (¢5/KWhr) =	-19.0 M
Total Savings		**$28 M**

The above scenarios illustrate potential savings of $22 M to $28 M based on:

- Lower economic growth.
- Greater emphasis on import power during off-peak times.
- Potential gas savings.
- Changes in system operation.
- Unfavorable hydro generation conditions.

In addition to the above three scenarios, the following additional savings could be accrued:

- Operation, Maintenance, and Administration – A productivity increase of 1% would result in a net savings of approximately $1.0 M.

- Timing of Capital Expenditures – A delay of expenditure in capital investments could result in a savings of $2.5 M.

- Actual financing charges related to new investments could be reduced by $1.5 M to reflect recent interest rate reductions.

From the foregoing, it appears that with the proposed rate scenarios, SaskPower's net revenues could increase by at least $27.0 M. Our recommendation would be to consider reducing the rate increase by a similar or lesser amount. A $20 M reduction would be readily achievable.

7. REVENUE TO REVENUE REQUIREMENT RATIOS

7.1. Impacts on Various Customer Classes

SaskPower has provided data on the revenue to revenue ratios for the various customer classes at existing rates and at the proposed new rates. The following table illustrates the wide range of individual customer impacts as defined in Appendix I of the Rate Proposal.

These rate changes were based on an overall approach stipulated by SaskPower, namely:

- Classes above 1.0 R/RR would stay the same or move to a lower RR.
- Classes below 1.0 R/RR would be increased on a levelized basis to minimize impacts and the manufacturing sector would be targeted for a larger increase in order to move it closer to target.
- No classes currently below 1.0 R/RR would be moved above unity.
- Increases would be limited to 10% above class average for any one customer.

Table 7.1: Year 2002 Rate Change & R./R.R. Ratios

Class of Service	Year 2002 R/RR Ratio (Existing Rates)	Year 2002 R/RR Ratio (Proposed Rates)	Proposed % Increase within Class	Probable Range of Increases % Within Class
Urban Residential	**0.97**	**0.98**	**7.1%**	**4.85 to 7.9**
Rate Code E01 – City	0.97			
Rate Code E02 – Town, Village, Urban Resort				
Rural Residential	**0.90**	**0.94**	**10.0%**	**7.97 to 19.79**
Rate Code E03 – Rural, Rural Resort	0.90			
Farms	**0.96**	**0.98**	**8.0%**	**2.14 to 17.49**
Rate Code E19 – Farm – SP Transformers	0.79			
Rate Code E34 – Farm	0.97			
Rate Code E41 – Interruptible (Mains)	0.97			
Rate Code E42 – Interruptible (Pivots)	0.79			
Small Comm. – Urban	**1.02**	**1.01**	**5.0%**	**-15.30 to 14.99**
Rate Code E75 – GSS – SP Transformers	1.02			
Rate Code E77 – GSS – Customer Transformers	1.02			
Rate Code E85 – CS/SP – SP Transformers	1.02			

Class of Service	Year 2002 R/RR Ratio (Existing Rates)	Year 2002 R/RR Ratio (Proposed Rates)	Proposed % Increase within Class	Probable Range of Increases % Within Class
Rate Code E87 – BS/SP – Customer Transformers	1.02			
Small Comm. – Rural	**0.95**	**0.97**	**8.0%**	**0.01 to 17.64**
Rate Code E76 – GSS – SP Transformers	0.95			
Rate Code E78 – GSS – Customer Transformers	0.95			
Rate Code E86 – GS/SP – SP Transformer	0.95			
Rate Code E88 – GS/SP – SP Transformer	0.95			
Gen. Service – Urban	**1.03**	**1.03**	**5.0%**	**-6.60 to 14.79**
Rate Code E05 – GSL – SP Transformers	1.03			
Rate Code E07 – GSL – Customer Transformer	1.04			
Rate Code E15 – GS – Other Unmetered	1.01			
Rate Code E16 – GS – Other – Power Supply Units	1.01			
Rate Code E17 – GS – Other Cable Television	1.01			
Rate Code E18 – GS – LS – SP Transformers	1.01			
Rate Code E95 – GS/LP – SP Transformers	1.03			
Rate Code E97 – GS/LP – Customer Transformer	1.04			
Gen. Service – Rural	**1.01**	**1.01**	**6.0%**	**-0.41 to 15.73**
Rate Code E06 – GSL – SP Transformers	1.03			
Rate Code E08 – GSL – Customer Transformer	0.98			
Rate Code E10 – GSL – Customer Transformer	0.94			
Rate Code E12 – GSL – Customer Transformer	0.97			
Rate Code E90 – GS/LP – Customer Transformer	0.94			
Rate Code E92 – GS/LP – Customer Transformer	0.97			
Rate Code E96 – GS/LP – SP Transformers	1.03			
Rate Code E98 – GS/LP – SP Transformers	0.98			
Manufacturing – Small	**0.82**	**0.86**	**12.0%**	**-7.08 to 21.99**
Rate Code E60 – MFP – Customer Transformer	1.08			
Rate Code E65 – MFP – SP Transformer	0.87			
Rate Code E66 – MFP – SP Transformer	0.80			
Rate Code E67 – MFP – Customer Transformer	0.83			
Rate Code E68 – MFP – Customer Transformer	0.64			
Rate Code E69 – MFP – Customer Transformer	No Customers			
Manufacturing – Large	**0.83**	**0.89**	**12.0**	**4.54 to 19.15**
Rate Code E62 – M/FP – 25 KV Customer Transformer	0.80			
Rate Code E63 – M/FP – 72 KV Customer Transformer	0.89			
Rate Code E64 – M/FP – 138 KV Customer Transformer	0.79			
Power – Published Rates	**1.04**	**1.03**	**4.0%**	**1.40 to 7.86**
Rate Code E22 – Power – 25 KV	1.00			
Rate Code E23 – Power – 72 KV	1.06			
Rate Code E24 – Power – 138 KV	1.06			
Rate Code E46 – Power – 230 KV	No Customers			
Oilfields	**1.13**	**1.11**	**4.0%**	**-1.67 to 13.96**
Rate Code E20 -	1.13			
Streetlights – S01 to S23	**1.12**	**1.11**	**4.0%**	**N/A**
Reseller	**0.95**	**1.00**	**10.0%**	**N/A**
Rate Code E32 – Swift Current – 72 KV	0.96			
Rate Code E33 – Swift Current and Saskatoon – 138 KV	0.95			

SaskPower's proposal will see a 5.4% increase overall for its full slate of customers. If the key account contract customers are excluded, the average increase for the balance of customers is 6.8%.

Based on the proposal, urban customers, not including Saskatoon and Swift Current, will see average rate class increases of 5% to 7%. Non-urban customers and Saskatoon/Swift Current will see rate increases that average 8% to 10% on a class basis. These changes reflect the fact that the R/RR for rural customers were in the 0.86 to 0.96 range. These values suggest that urban customers have, in the past few years, been paying at least their full share of costs, while rural customers have been paying less than their full share of costs.

Within the urban residential classes, proposed rate changes will result in individual customer rate increases between 5% and 7%. Such a narrow range is unusual when a rate rebalancing process is taking place. However, urban commercial will see rate changes between –15% and +15%; this extreme variation is also unusual and could be viewed as inappropriate.

Within the rural/manufacturing/industrial classes, proposed rate changes vary from 8% to 12% (class average). This is intended to move R/RR upward by 0.04 to 0.06 for these classes.

However, the variability of individual customer rate increase is much larger for rural and industrial than for the urban group. Some customers will experience rate increases as high as 22%, while others will see rate decreases of up to 7%. This broad variation in rate change could be considered excessive.

Overall, there appears to have been a general trend by SaskPower towards increasing the fixed cost portion of a customer's bill (e.g., basic monthly charge and/or demand charges), and reducing the customer's sensitivity to energy consumption. This, in conjunction with the historical significantly lower charges for second block energy, does not provide any great incentive for energy conservation.

Within the current rate Proposal process, there has been insufficient time and opportunity to fully address the specific goals, allocation methodology, and progressive results of the four-year rate rebalancing venture. It is suggested that SaskPower undertake a detailed Cost of Service Study well in advance of the next rate increase Proposal (which has been indicated for 2003). This would permit a proper vetting of the objectives/reasonableness of the rebalancing process.

8. RATE COMPARISONS

SaskPower rate structure as of July 2001, provided Saskatchewan consumers (e.g., Regina with power bills at the following percentages of other utilities (Appendix C of Rate Proposal).

Table 8.1: Typical Electricity Bill Comparisons

Service	Manitoba Hydro (Winnipeg)	City of Medicine Hat	ATCO (Alberta)	EpCor (Edmonton)	Enmax (Calgary)	BC Hydro
Residential	148%	120%	64%	109%	98%	147%
Small Commercial						
• Non-Manufacturing	124%	91%	54%	86%	83%	137%
• Manufacturing	117%	86%	52%	82%	79%	130%
Medium Commercial						
• Non-Manufacturing	130%	98%	53%	75%	75%	116%
• Manufacturing	121%	91%	49%	70%	70%	108%
Standard Commercial						
• Non-Manufacturing	147%	126%	N/A	N/A	N/A	151%
• Manufacturing	117%	83%	N/A	N/A	N/A	119%
Standard Grain Farm	131%	100%	97 – 116%	62 – 79%	N/A	144%
Large Grain Farm	120%	89%	73%	N/A	N/A	122%
75 KV Farm						
• Non-Manufacturing	139%	120%	N/A	N/A	N/A	130%
• Manufacturing	119%	103%	N/A	N/A	N/A	111%

Not surprising, SaskPower rates are not competitive with Manitoba or BC utilities. They are however marginally competitive with the City of Medicine Hat in most service classes. As such, the proposed rate may have some impact on export prospects. However, SaskPower enjoys a substantial rate advantage over ATCO and EpCor, which should allow for continued power export at least in the short-term.

Within Saskatchewan, some electricity consumers are likely to see the proposed rate increases as an increasing economic disadvantage to residing/operating businesses in the province. SaskPower is already viewed as a high-price provider of electricity. These rate changes, driven in part by SaskPower's increasing reliance on natural gas as the fuel for on-peak, as well as off-peak power, will stand to confirm this viewpoint.

9. SUMMARY AND CONCLUSIONS

9.1. Revenue Requirements

SaskPower's Rate Proposal of October 2001 has requested an average rate increase of 5.4% (6.8%, excluding contracts) commencing December 1, 2001 and running through the Year 2002. This increases translates into a revenue increase of $56 M for the Year 2002.

SaskPower has provided substantial documentation to support this revenue requirement. Specific elements that have been suggested as primary contributors to the requested amount are:

- Load growth of 3.1% in 2002, which when supplied by high price natural gas, could result in an increased cost/shortfall of $13 M.
- Lower hydro production than normal (median), which when offset by higher priced natural gas generation, could increase costs by $14 M.
- Higher coal costs due to royalty increases and price escalations could increase costs by $23 M.
- Higher natural gas costs in 2000 and 2001 probably cost SaskPower $12 M and $50 M, respectively. Current gas prices are to a large degree set for 2002, but with slumping prices in late 2001, it is difficult to translate this into an increased cost for 2002.
- Export electricity sales are expected to decline in quantity and unit price for 2002, with a potential 10% reduction in revenue of $10 M.
- Import electricity prices will rise for 2002 and use of import power will be reduced. The cost of natural gas-fired generation to compensate could be in the order of $18 M.
- Operating, maintenance, and administration costs are expected to rise by $13 M in 2002, but spread over a large energy load will mean the unit cost remains unchanged.
- Depreciation charges in 2002 will be up by $9 M.
- Financing charges in 2001 will remain constant for 2002.
- Losses/debt charges flowing from SaskPower International would add $1 M to $2 M to 2002 costs.

Assuming all of the above assumptions are valid, these items would theoretically add significantly to SaskPower's revenue requirements. However, they are not directly additive and could realistically equate to $40 to $60 M. As such, they appear to support the $56 M additional revenue requirement identified by SaskPower.

However, it is reasonable to re-examine some of the foregoing assumptions. Based on our review and consideration of recent economic circumstances, we are recommending the following alternative short-term scenarios be considered:

- ***Load Growth*** – Recent events and economic forecasts would suggest that SaskPower's 3.1% energy load growth in 2002 is too optimistic. An assumed growth rate of 1.0 to 1.5% would reduce the projected revenue requirement by $6 to $10 M.
- ***Hydro Power Availability*** – A more favourable outlook of normal flow conditions would reduce the revenue requirement by approximately $14 M. Conversely, a less favourable outlook could increase the requirement for gas-fired generation and associated cost increases of approximately $14 M.
- ***Higher Coal Costs*** – Because there are consequences of higher taxes and already negotiated price escalations, no change in additional revenue requirement is likely.
- ***Higher Natural Gas Costs*** – Recent declines in the price of natural gas would suggest that SaskPower's actual costs in 2002 could be as much as ¢1/KWhr lower than indicated in the Rate Proposal. This could equate to a reduction in revenue requirements of approximately $15 M, assuming the indicated gas generated energy is actually used.
- ***Export Electricity Costs*** – A more optimistic viewpoint would suggest that export prices will remain constant with continuing good sales assuming that Alberta's energy needs and current high prices will only drop gradually from their current high levels. This would suggest that an anticipated revenue drop of $15 M in 2002.
- ***Higher Import Prices/Lower Power Availability*** – The current economic situation suggests that a more optimistic view of potential import power may be warranted. SaskPower's interconnections to the US Basin and Manitoba do have significant capabilities for import of power at levels three times SaskPower's 2002 forecast. Prices in Manitoba for off-peak power have been running in the ¢2.5-¢3.0/KWhr range. This is significantly lower than the average import price paid by SaskPower in 2001 of ¢3.95/KWhr and considerably lower than the ¢6/KWhr forecast by SaskPower. This 2001 scenario suggests that SaskPower could reduce costs by at least $18 M in 2002 by increased focus on import power relative to natural gas generation.
- ***Increased Operation/Maintenance/Administration Costs*** - Past performance by SaskPower suggests that higher productivity is achievable. For 2002, with the recent introduction of Queen Elizabeth Gas Turbines, Meridian Co-generation, and Cory Co-generation, it is likely that short-term gains are possible.
- ***Increased Financing Costs*** – SaskPower's forecast of little or no increase in financing costs for the Year 2002 is probably appropriate. However, the longer-term implications

of investments in SPI or other generation facilities may see a significant increase in financing costs two to four years from now.

- ***Depreciation*** – Forecasts provided by SaskPower suggest that the depreciation expense will rise by $9.0 M in 2002, presumably reflecting the addition of the Cory facility. If the overall capital program, including SPI ventures taking place, the future depreciation charges will rise significantly.
- ***SPI Ventures*** – SaskPower forecasts suggest that capital investments inside Saskatchewan and elsewhere may add $483 M to the long-term debt by 2006. The result would be interest charges of $30 M/year at that time. This level of financing cost increase will be difficult to absorb if SaskPower's financial situation is below target in 2002.

This review examined a number of operational scenarios which demonstrated potential savings. These scenarios assumed a 1.5% economic growth rate, a shortfall in SaskPower's hydraulic power production of 390 GWhr due to lower water levels, and various increases in the amount of imported energy. Based on this analysis, savings of $27 M to $33 M could be achieved. Our recommendation would be to consider reducing the requested increase by a similar or lesser amount. A $20 M reduction from the requested $56 M should be readily achievable.

9.2. Revenue to Revenue Requirement Issues

It is apparent that SaskPower is faced with a serious problem, probably not of their making, in the area of revenue/cost relationships for different rate classes and subgroups. Rate balancing, as per their four-year program, is an essential operation.

However, this is complicated by the large discrepancy of R/RR within rate classes. In the absence of a detailed Cost of Service Study, it is not possible to suggest specific modifications to SaskPower's proposed rate schedule.

However, our view is that the proposed rate structure is attempting to move costs from a unit of energy basis to a front end/demand charge scenario. Consequently, high load factor customers will pay comparatively less than low load factor customers. It also benefits high energy users, particularly those using second block energy at significantly lower unit costs. Energy conservation does not appear to have a high priority.

The current review did not have the time frame required, sufficient detailed data, or rate history available to venture specific opinions on the reasonableness and fairness of the currently proposed rebalancing exercise. It would require a much more detailed in-depth study outside of a rate review to adequately address these issues.

To arbitrarily place tighter constraints on the range of increase would not correct imbalances which currently exist, but rather perpetuate these.

9.3. Comparative Costs

SaskPower's proposed rate increases do not appear to significantly harm its position in the import-export market. They do however perpetuate the Province's image as being a high energy cost jurisdiction.

For the domestic customers, the rate increases are no doubt unwelcome for all rate classes. They will be particularly unwelcome for manufacturing and food process customers who must compete in the non-Saskatchewan market as goods and services providers.

9.4. Recommendations for Required Studies

SaskPower should carry out a detailed Cost-of-Service study, which examines the specific way in which SaskPower's cost allocation methodology is applied, the parameters and controls that are used, and the acceptable degree of rate rebalancing measures that should be implemented. This should be undertaken within the next six months in order to permit a Rate Panel Review well in advance of the next rate increase proposal.

SaskPower's soon to be completed Depreciation Study should be forwarded to the Rate Review Panel for its review as soon as possible and certainly no later than mid-summer 2002.

SaskPower should seriously examine its future business relationship with SaskPower International with a view to moving SaskPower International's financial consequences from the responsibility of the SaskPower rate payer. It would also be useful to reflect on the perceived issue of conflicting business interests of the two organizations in selecting power supply strategies.

APPENDIX A

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APPENDIX A

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MPUC Docket No. E002/GR-08-1065
OAH Docket No. 3-2500-20148-2

STATE OF MINNESOTA

OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE

PUBLIC UTILITIES COMMISSION

In the Matter of the Application of
Northern States Power Company d/b/a Xcel Energy
for Authority to Increase Rates for Electric Service In Minnesota

INITIAL BRIEF OF THE RESIDENTIAL AND SMALL BUSINESS UTILITIES DIVISION OF THE OFFICE OF THE ATTORNEY GENERAL

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TABLE OF CONTENTS

Page

I. INTRODUCTION 1

II. PROCEDURAL HISTORY 2

A. Resolved Issues 3

1. The OAG's recommendation for a cap on fuel and purchased power costs. 3

2. NSP's travel, entertainment and related employee expenses. 5

3. The exclusion of unamortized rate case expenses. 8

B. Contested Issues 8

III. ARGUMENT 9

A. Burden of Proof 9

B. NSP's Proposed Change In Accounting For Nuclear Refueling 10

1. NSP seeks to recover nuclear refueling expenses through the deferral and amortization method instead of the direct expense method. 10

2. The commission's reasons for approving the change in accounting methodology for NSP's nuclear refueling expenses. 11

3. The use of the deferral and amortization method for financial reporting purposes does not mean that it should be used for rate setting purposes. 12

4. NSP's nuclear refueling expenses do not qualify for deferred accounting treatment. 13

5. The deferral and amortization method would result in NSP earning a return on the deferred balances of the nuclear refueling expenses, contrary to normal ratemaking. 16

6. The deferral and amortization method would operate like a tracker and virtually guarantee cost recovery of expenses even if they are determined to not be prudent and reasonable. 17

7. The pitfalls of the deferral and amortization method can be avoided if the direct expense method is retained for ratemaking Purposes. 20

C. Rate Case Expense Recovery. 22

1. NSP's rate case expenses should be accounted for as normal operating expenses rather than giving them special accounting treatment. 23

2. A cost control mechanism should be implemented to encourage justifiable rate increase petitions. 25

D. Corporate Cost Allocations. 27

1. History of the commission's concerns related to corporate cost allocations. 27

2. Contrary to NSP's representations, its three-factor general allocator has not been expressly reviewed and approved by the commission. 30

3. The record demonstrates that NSP's preferred general allocator over-allocates corporate costs to Xcel's NSP-Minnesota regulated electric utility jurisdiction. 32

a. Commission precedent instructs that its preferred general allocator is computed by using the ratio of all costs directly assigned or attributed to affiliates and is not limited to expenses directly assigned or attributed. 33

b. The record contains a general allocator calculation that used actual data rather than budgeted data to cure NSP's second concern with the OAG's general allocator calculation. 35

c. NSP obstructed the OAG's ability to fully address NSP's third concern related to Mr. Lindell's general allocator calculation by providing a nonresponsive answer to a follow-up inquiry. 35

d. NSP's general allocator calculations cannot be relied upon because they contain several deficiencies. 36

E. Nuclear Plant Rate Stability Proposal 38

F. Revenue Allocations 39

1. Evidence in this record questions the reliability of using a CCOSS to allocate the revenue requirement. 42

2. Public comments demonstrate the extreme financial difficulties that residential ratepayers are currently experiencing. 43

3. All Classes Should Bear The Same Percentage Rate Increase. 44

IV. CONCLUSION 45

STATE OF MINNESOTA

OFFICE OF ADMINISTRATIVE HEARINGS
FOR THE
PUBLIC UTILITIES COMMISSION

In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota	MPUC Docket No. E002/GR-08-1065 OAH Docket No. 3-2500-20148-2

INITIAL BRIEF OF THE OFFICE OF THE ATTORNEY GENERAL

I. INTRODUCTION

The Office of the Attorney General - Residential and Small Business Utilities Division ("OAG") respectfully submits its Initial Brief addressing Northern States Power Company d/b/a Xcel Energy's ("NSP") request for an approximately $156 million increase in rates for electric service in Minnesota. NSP and the OAG were able to resolve several issues throughout the pendency of this rate case review; however, significant issues that needlessly inflate NSP's requested rate increase remain for Commission consideration. This Brief will address both the resolved and contested issues on which the OAG has taken a position and request that the Commission:

- Approve the proposed Fuel Clause Adjustment Incentive Settlement offered by NSP.
- Approve NSP's proposed Employee Expense Compliance Plan.
- Approve the OAG's proposal for establishing the appropriate test year level of rate case expenses.
- Reject NSP's proposed change in accounting for nuclear refueling.

- Reject NSP's current corporate cost three factor general allocator and require NSP to implement the Commission's preferred general allocator.
- Reject NSP's proposed Nuclear Plant Rate Stability Proposal.
- Approve a revenue allocation that assigns the same percentage rate increase to all rate classes.

II. PROCEDURAL HISTORY

On November 3, 2008, NSP filed its electric general rate case requesting a final base rate increase of $156.065 million, or approximately 6.05 percent annually. As part of that filing, NSP requested an interim rate increase of $155.103 million or approximately 6.0 percent over existing rates. The Commission met on December 16, 2008 to consider this matter. On December 23, 2008, the Commission issued an Order approving a lesser interim rate increase of $132.221 million, effective January 2, 2009.[1]

In a separate, contemporaneous Order, the Commission accepted NSP's November 3, 2008 filing as substantially complete as of the date it was filed and suspended NSP's request for a final rate increase, pending its investigation into the merits of NSP's request.[2] In a third Order issued that same day, the Commission referred the matter to the Office of Administrative

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[1] ORDER SETTING INTERIM RATES, *In the Matter of the Application of Northern States Power Company d/b/a Xcel for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E002/GR-08-1065 (Dec. 23, 2008).

[2] ORDER ACCEPTING FILING, SUSPENDING RATES, AND REQUIRING FILING OF WAIVER, *In the Matter of the Application of Northern States Power Company d/b/a Xcel for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E002/GR-08-1065 (Dec. 23, 2008).

Hearings for a contested case proceeding and gave Notice regarding the preliminary hearing to be held in that proceeding.[3]

Public hearings were held at eight locations throughout NSP's service territory between April 13, 2009 and April 29, 2009. Prefiled testimony was submitted by NSP, the Office of Energy Security ("OES"), the OAG, the Commercial Group,[4] Xcel Large Industrials ("XLI"),[5] the Minnesota Chamber of Commerce ("MCC") and the Suburban Rate Authority ("SRA"). Administrative Law Judge ("ALJ") Kathleen Sheehy conducted evidentiary hearings between June 2 and 9, 2009.

A. Resolved Issues

The OAG's Direct,[6] Rebuttal[7] and Surrebuttal[8] testimony identified and addressed a number of concerns with NSP's initial rate increase petition. While many of these issues remain contested, some of the concerns were resolved between NSP and the OAG through testimony and/or proposed settlements filed for the ALJ's and Commission's approval. The OAG briefly addresses the issues that it considers resolved.

1. The OAG's recommendation for a cap on fuel and purchased power costs.

In the 2009 test year, NSP will automatically recover in rates approximately $1 billion of fuel and purchased power costs annually, an increase in automatic recovery of approximately

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[3] NOTICE AND ORDER FOR HEARING, *In the Matter of the Application of Northern States Power Company d/b/a Xcel for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E002/GR-08-1065 (Dec. 23, 2008).

[4] The Commercial Group is an association of large commercial customers including but not limited to Best Buy Co., Inc., Macy's, Inc., Sam's West, Inc., Target, Inc., and Wal-Mart Stores Inc.

[5] XLI is a group of large industrial customers comprised of Flint Hills Resources, Gerdau Ameristeel Corporation, and Marathon Petroleum Company, LLC.

[6] Ex. 66.

[7] Ex. 67.

[8] Ex. 68.

$110 million over 2008.[9] These costs will be automatically passed to customers through an automatic adjustment, the fuel clause adjustment ("FCA") and collected through customers' bills each month.[10] The costs that are automatically recovered by NSP are not investigated in a rate case proceeding and therefore the revenues associated with these costs are not investigated in this proceeding. Because an increasing percentage of NSP's revenues are being generated through automatic recovery of costs, including the FCA, and are not subject to investigation as part of a rate case proceeding, the OAG recommended instituting a 3 percent cap on NSP's proposed fuel and purchased power costs in order to create an incentive for NSP to minimize or otherwise manage its costs for fuel and purchased power.[11] NSP generally supported the concept of FCA incentives, but argued that an incentive mechanism should be considered outside of a rate case and should be applied to all electric utilities, not just NSP.[12]

In an effort to remove this issue from this rate case proceeding, NSP proposed a FCA Incentive Settlement.[13] Pursuant to the FCA Incentive Settlement, NSP commits to file a FCA incentive proposal in Docket No. E999/CI-03-802 (an open docket investigating the FCA) for consideration by all stakeholders and for potential implementation by all electric utilities.[14] NSP's proposal will include a provision that provides positive and negative financial consequences for controlling fuel and purchased power costs,[15] similar to the mechanism that Wisconsin employs, which the OAG discussed in its Direct Testimony.[16] NSP will file its

[9] Ex. 66, Lindell Direct at 13 and JJL-2.
[10] *Id.* at 7.
[11] *Id.* at 10
[12] Ex. 49, Beuning Exhibit SJB-4, Supplemental Pre-Filed Comments in Response to Surrebuttal Testimony and Settlement Discussions at 4.
[13] Ex. 49 at Schedule 1 ("Proposed FCA Incentive Settlement").
[14] *Id.*
[15] *Id.*
[16] Ex. 66, Lindell Direct at 11-13.

proposal within 90 days of the Commission's final Order in this proceeding. In exchange for NSP's commitment to provide a FCA incentive proposal in the alternative docket, the OAG agrees to withdraw its proposal for a 3 percent cap on fuel and purchased power costs in this proceeding. The OAG may; however, pursue the cap in the alternative FCA docket, Docket No. E999/CI-03-802, for application to all electric utilities.

The OAG agrees that the open FCA investigation docket provides an appropriate alternative forum to address the OAG's concerns related to the management of costs that are automatically passed through the FCA. The OAG believes it is appropriate for all interested parties to work to develop appropriate incentives to ensure that fuel and purchased power costs are adequately managed and all electric ratepayers are protected with appropriate cost controls. NSP's commitment to timely file a FCA Incentive proposal in Docket No. E999/CI-03-802 will initiate the development of an appropriate mechanism in that docket. Therefore, the OAG does not object to deferring this issue to Docket No. E999/CI-03-802 for further development.

2. NSP's travel, entertainment and related employee expenses.

The OAG raised numerous concerns related to Xcel Energy's excessive expenses for travel, entertainment and related employee expenses, particularly those incurred by Xcel's top employees, its Officers and members of the Board of Directors.[17] Many of these excessive corporate expenses, including extravagant hotel fees, expensive restaurant tabs, personal gifts, sporting event tickets and golf expenses were allocated to Xcel Energy's Minnesota regulated utility, NSP-Minnesota, and included on the regulated books of the Minnesota operation to be recovered through NSP's Minnesota electric rates. The OAG objects to rate recovery of these excessive expenses because they are neither reasonable nor necessary in the provision of electric utility service in Minnesota.

[17] Ex. 66, Lindell Rebuttal at 2-23, JJL-1, JJL-2 and JJL-3.

As a result of the OAG's review into Xcel Energy's corporate expenses, NSP agreed to exclude approximately $3.862 million from its revenue requirement for the purposes of the rate case.[18] This revenue requirement adjustment includes, among other things, an exclusion of approximately $437,000 in executive expenses, $300,000 related to purchases of sporting tickets, significant adjustments associated with capping meals at $200 per transaction regardless of how many people attended the meal and a $150 per night cap on hotel stays. The $3.862 million revenue requirement adjustment does not necessarily address all expenses that the OAG characterizes as improper, but given the time constraints of this rate case proceeding and the amount of resources of both NSP and the OAG that would be necessary to conduct further review, the adjustment resolves this issue for the purpose of this rate case proceeding.

In addition to the $3.862 million reduction to the rate case revenue requirement, NSP offers an "Employee Expense Compliance Plan"[19] to improve its employee and Board of Director expense policies going forward. As part of the Compliance Plan, NSP commits to perform a comprehensive review of its policies to determine where changes are necessary to better manage its overall costs.[20] The Compliance Plan requires the Company to provide the OAG and any other interested stakeholders a copy of its proposed policies for employee expenses, as well as its proposal for the appropriate regulatory accounting treatment of those expenses. The policies will include direction on how certain expenses will be treated in subsequent rate proceedings.[21] After receiving feedback from the OAG and other interested stakeholders, the Company will submit a filing to the Commission to initiate a full review and

[18] Ex. 17, Heuer Public Surrebuttal at 33.
[19] Ex. 45, Heuer Supplemental Pre-Filed Comments in Response to Surrebuttal Testimony and Settlement Discussions at Exhibit ____(AEH-4), Schedule 2 ("Compliance Plan").
[20] Ex. 8, Sparby Surrebuttal at 3.
[21] Compliance Plan.

comment process of the appropriateness of the revised employee expense policies and the Company's corresponding proposed regulatory accounting treatment.[22] The filing will outline how those expenses that are included in rates are reasonable and necessary for the provision of utility services for Minnesota ratepayers.[23]

In addition to the $3.862 million revenue requirement adjustment and the proposed Compliance Plan, NSP commits to make the same adjustments to employee and Board expenses that it agreed to in this proceeding in all future natural gas or electric rate case proceedings that may be filed before the results of the new policies are incorporated in future budgets.[24]

NSP's $3.862 million reduction to its revenue requirement, combined with its Compliance Plan and a commitment to make consistent adjustments to any subsequent natural gas or electric rate case proceeding that may be filed before the results of the new policies are incorporated in future budgets are necessary to attempt to address the OAG's concerns related to Xcel Energy's travel, entertainment and other corporate expenses. The $3.862 million rate case adjustment works to eliminate excessive expenses that inflated test year revenue requirement numbers and the accompanying Compliance Plan provides a forum to review and rework, where necessary, NSP's revised employee expense and related policies to ensure that in the future ratepayers are responsible for only those expenses that are reasonable and necessary for the provision of utility service to Minnesotans. The commitment to make consistent adjustments to any subsequent natural gas or electric rate case proceeding that NSP may file before the results of the new policies are incorporated in future budgets provides all parties and the Commission some assurance that the same level of excessive expenses will not be included in subsequent

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[22] *Id.*
[23] *Id.*
[24] Ex. 8, Sparby Surrebuttal at 4.

filings. The OAG respectfully requests that the ALJ and Commission approve NSP's proposed Compliance Plan.

3. The exclusion of unamortized rate case expenses.

In its initial filing, NSP proposed test year rate case expenses that would recover previous unamortized rate case expenses of $99,000 plus an additional $397,000 for the current case.[25] The OAG and the OES objected to NSP's attempt to recover unamortized rate case expenses from NSP's previous rate case.[26] In Rebuttal, NSP agreed to no longer seek annual recovery of $99,000 in unamortized rate case expense.[27] NSP's voluntary adjustment resolves this previously contested issue.

B. Contested Issues

Many issues that the OAG identified in NSP's rate increase petition remain contested. The OAG's remaining contested issues include: (1) NSP's request for a change in accounting for nuclear refueling expenses; (2) the appropriate test year level of rate case expenses; (3) the appropriate corporate cost general allocator consistent with the Commission's directives articulated in Docket No. E,G-999/CI-90-1008;[28] (4) NSP's request for approval of its Nuclear Plant Rate Stability Proposal; and (5) the appropriate revenue allocation of any approved rate increase.

The OAG addresses each remaining contested issue below.

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[25] Ex. 13, Heuer Direct at 103-104.
[26] Ex. 66, Lindell Direct at 48, Ex. 103, Lusti Public Direct at 14-16.
[27] Ex. 15, Heuer Public Rebuttal at 50-51.
[28] ORDER SETTING FILING REQUIREMENTS, *In the Matter of an Investigation into the Competitive Impact of Appliance Sales and Service Practices of Minnesota Gas and Electric Utilities,* Docket No. G,E-999/CI-90-1008 (September 28, 1994).

III. ARGUMENT

A. Burden of Proof

The Legislature has conferred upon the Commission the duty to protect the public interest by ensuring just and reasonable rates for utility service.[29] The goal of the Commission's rate case process is to arrive at just and reasonable rates and it is NSP's burden to demonstrate that its demand for an approximately $156 million rate increase is just and reasonable.[30] Any doubt as to the reasonableness of any rate demanded must be resolved in favor of the consumer.[31]

The Minnesota Supreme Court has instructed that the utility requesting a rate increase must prove the facts necessary to sustain its burden by a "fair preponderance" standard.[32] The Supreme Court further instructs that when weighing the evidence submitted in a rate case proceeding, the Minnesota Public Utilities Commission:

> "is not so much concerned with the sufficiency and credibility of the evidence, as it is concerned with whether the evidence submitted, even if true, justifies the conclusion sought by the petitioning utility when considered together with the Commission's statutory responsibility to enforce the state's public policy that retail consumers of utility service shall be furnished such services at reasonable rates."[33]

It is with this backdrop that NSP's $156 million increase request is evaluated.

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[29] Minn. Stat. § 216B.03. *See also* ORDER ACCEPTING OFFER OF SETTLEMENT, *In the Matter of a Petition by the U.S. Department of Defense, the General Services Administration, and All Other Federal Executive Agencies of the United States Challenging the Reasonableness of the Rates Charged by Northwestern Bell Telephone Company*, Docket No. P-421/CI-86-364 (February 10, 1988) at 3.
[30] Minn. Stat. § 216B.16, subd.4 (2008) ("The burden of proof to show that the rate change is just and reasonable shall be upon the public utility seeking the change.")
[31] Minn. Stat. § 216B.03 (2008).
[32] *In the Matter of the Petition of Northern States Power Company for Authority to Change its Schedule of Rates for Electric Service in Minnesota*, 416 N.W.2d 719, 722 (Minn. 1987).
[33] *Id.*

B. NSP's Proposed Change In Accounting For Nuclear Refueling

1. NSP seeks to recover nuclear refueling expenses through the deferral and amortization method instead of the direct expense method.

NSP owns and operates three nuclear energy generating plants in Minnesota – Prairie Island Units 1 and 2 and Monticello. These reactors must be refueled on a regular basis because the nuclear fuel becomes spent over time. Because the reactors are out of service during refueling, NSP takes those opportunities to perform necessary repairs and inspections. Typical work performed during these outages includes replacement of fuel assemblies, inspections to ensure safety, tests and maintenance that cannot be performed when the reactors are operational, and other repairs.[34] Each reactor requires refueling every 18 to 24 months.

In its petition, NSP requests Commission approval to recover its nuclear refueling expenses using the deferral and amortization accounting method that the Commission allowed for financial reporting purposes in Docket No. E 002/M-07-1489, rather than the direct expense method NSP currently employs. Unlike the direct expense method, where nuclear refueling expenses are reported in the period they are incurred, under the deferral and amortization method these expenses would not be reported as an expense in the period in which they are incurred (*i.e.*, deferral), but instead would be spread over the period between refuelings (*i.e.*, amortization). In its Order,[35] the Commission approved deferral and amortization for accounting purposes only; ratemaking treatment was to be reserved for a ratemaking proceeding:

> The Commission cautions . . . that approval of the proposed accounting methodology in this proceeding does not mean that the Commission is not free to

[34] *See Petition In The Matter Of The Petition Of Northern States Power Company, A Minnesota Corporation, Regarding The Accounting Treatment For Nuclear Refueling Outage Costs,* Docket No. E002/M-07-1489 (November 28, 2007) at 4.

[35] ORDER APPROVING CHANGE IN ACCOUNTING METHODOLOGY WITH CONDITIONS *In the Matter of a Petition by Northern States Power Company, a Minnesota Corporation, for Accounting Treatment for Nuclear Refueling Outage Costs*, Docket No. E-002/M-07-1489 (September 16, 2008).

> employ its normal rate setting procedures when the Company files a rate case. Commission approval of the deferral-and amortization methodology should not be read to suggest that the Commission has pre-approved some form of exact cost recovery in future rate cases.
>
> Instead, the Company will, as always, bear the burden of proof that the proposed cost for re-fueling is reasonable — with those costs clearly subject to a reasonableness and prudence review in a rate case — where the Commission will make its determination of a reasonable cost using standard ratemaking principles.[36]

Under NSP's proposed approach using the "deferral-and-amortization method," refueling expenses would be deferred and amortized during the period between refueling outages, rather than expensed when incurred. If approved for ratemaking purposes, this method would create a "regulatory asset," which operates like an IOU, whereby ratepayers become liable for payment of these expenses at a future time.

The average, or normalized, costs associated with refueling were determined in NSP's previous rate case[37] and are reflected in current rates. The accounting and ratemaking treatment reflected in NSP's last rate case is known as the "direct expense method," where costs are expensed in the year they are incurred. The Commission should continue using this method for ratemaking purposes for the reasons set forth below.

2. The commission's reasons for approving the change in accounting methodology for NSP's nuclear refueling expenses.

Each of NSP's three nuclear plants go through a refueling phase of approximately one month when nuclear refueling is done. The nuclear fuel lasts for approximately 18-24 months. NSP's concern was that in years when two and possibly three refueling events happen in a single year, it raises the costs that it reports on its financial statements, even though the benefits and cost recovery of those refuelings will overlap into another year. The Commission approved the

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[36] *Id.* at 6-7 (footnote omitted).
[37] Docket No. E002/GR-05-1428.

change from the direct expense to the deferral and amortization method of accounting for NSP's nuclear refueling expenses by accepting NSP's arguments that deferral and amortization would spread the costs of nuclear refueling over the 18 to 24 month refueling cycle instead of incurring those costs in a single month and recording them in a single year. The Commission also stated that the benefit of this accounting method would produce a more levelized basis of refueling costs from year to year and allow NSP to show a more levelized refueling outage cost for reporting purposes on its financial statements.

However, for ratemaking purposes, the Commission does not need the deferral and amortization method to achieve levelization of the nuclear refueling costs. Currently, the process for determining refueling costs for ratemaking purposes involves reviewing those costs over a number of years to determine a reasonable or normalized level of costs to reflect future costs going forward. This is the same process that is used for other types of expenses or costs which are high in some years and low in other years. There is no reason to deviate from this approach, and important reasons for not using the deferral and amortization method for ratemaking.

3. The use of the deferral and amortization method for financial reporting purposes does not mean that it should be used for rate setting purposes.

Utilities request approval of accounting changes periodically to conform with Generally Accepted Accounting Purposes ("GAAP") or to change from one acceptable accounting method to another acceptable accounting method. The Commission has authorized NSP to change from one acceptable accounting method (direct expense) to another acceptable method (deferral and amortization) for NSP's nuclear refueling outage expenses. However, changes in accounting for financial statement reporting purposes are not always appropriate for establishing rates. As the Commission held, it is not required to adopt this proposed change in accounting for nuclear refueling outage expenses for ratemaking purposes if it determines that doing so would not be just and reasonable.

An example of using different methods for accounting and ratesetting purposes is found in the recent Minnesota Power rate case. In its Order in that case, the Commission provides an example of different accounting treatment for financial reporting and for ratemaking in its disposition of asset retirement obligations ("ARO"). To be in compliance with GAAP, the accounting for AROs was changed to record current costs that relate to the future obligations to retire assets. The new ARO accounting method established different and generally higher annual expenses to recognize future AROs for companies. Minnesota Power, in its rate case, proposed to also adopt the new ARO accounting change for ratemaking purposes. However, the Commission determined that the accounting change was appropriate for financial reporting purposes to comply with GAAP, but it was not appropriate for ratemaking purposes.[38] Similarly, with regard to NSP's nuclear refueling costs, the Commission should retain the direct expense method for ratesetting purposes even though it has accepted the deferral and amortization method for financial reporting purposes.

4. NSP's nuclear refueling expenses do not qualify for deferred accounting treatment.

A threshold determination with regard to NSP's nuclear refueling expenses is whether they qualify for deferred accounting treatment. The Commission enunciated the parameters for the granting of deferred accounting in NSP's 1992 electric rate case: "Items for which deferred status is sought should be limited to significant and unusual disputed items related to utility

[38] FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER *In the Matter of the Application of Minnesota Power for Authority to Increase Electric Service Rates in Minnesota*, Docket No. E-015/GR-08-415 (May 4, 2009) at 25-28.

operations, for which ratepayers have incurred costs or received benefits."[39] In subsequent decisions,[40] the Commission has allowed deferred accounting treatment where the items are:

- related to utility operations for which ratepayers have incurred costs or receive benefits;
- significant in amount;
- unusual or extraordinary items; and
- subject to review for reasonableness and prudence.

NSP's nuclear refueling expenses only qualify under the Commission's first prong in its test for deferred accounting treatment: the costs are related to utility operations where the utility has incurred costs and ratepayers have received benefits. The refueling costs have always been recognized as necessary in the provision of electric service and that is not disputed. However, none of the remaining standards are met. The second standard, that the costs are significant, is not met. A $25 million to $35 million cost is not significant in relation to NSP's total revenues of approximately $2.5 billion. Refueling expenses are approximately one percent of revenues before tax and less than one percent after tax. Therefore those costs would not be considered significant. The third standard, that the refueling expenses are unusual and extraordinary, is also not met. These costs have been incurred since the 1970's and have consistently been recovered in rates through the direct expense method. There is nothing unusual or extraordinary about these expenses that supports deferral and amortization for rate recovery. Finally, the fourth

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[39] FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER In the Matter of the Application of Northern States Power Company for Authority to Increase Its Rates for Electric Service in the State of Minnesota, Docket No. E-002/GR-92-1185 (September 29, 1993) at 60.

[40] Deferred accounting has been granted for manufactured gas plant pollution cost and related insurance recovery in Docket Nos. G008/M-91-1015, G001/M-94-633, G001/M-95-687, and G002/M- 99-248. Some recent electric utility dockets where deferred accounting was approved for Midwest Independent Transmission system Operator, Inc. (MISO) Day 2 costs are: Docket Nos. E002/M-04-1970, E001/M-05-406, E015/M-05-277 and E017/M-05-284. In addition, the Commission allowed deferred accounting for costs related to time-of-use rates in Docket No. E002/M-03-1462.

standard, that the expenses are subject to review for reasonableness and prudence is questionable. There is a presumption, discussed below, that, according to the accounting rules, by deferring these costs they will be recovered. According to OAG witness Lindell:

> Recoverability should not be presumed without a review for reasonableness and prudence. The Commission will have made that presumption if it determines that this new accounting method should be approved for ratemaking purposes. At the time that refueling expenses are incurred and deferred there will not have been any analysis of their reasonableness and prudence. That argues for continuing to recover the refueling expenses using the direct expense method of accounting, not under the deferral and amortization method. The Commission's standards for deferral of refueling expenses for ratemaking purposes have not been met. Therefore, the direct expense method should continue to be used for cost recovery purposes.[41]

When asked by the OAG how nuclear refueling costs satisfy the requirements for deferred accounting, NSP responded that deferral and amortization would:

> 1) spread the refuel outage costs over the full refueling cycle rather than incurring the costs in a single month; 2) smooth the increasing nuclear refueling outage cost impacts on the Company's financial statements; 3) produce a representative cost level for use in setting customer rates; and 4) during rate proceedings such as this one, refueling outage costs will continue to be subject to review for reasonableness.[42]

Neither in its above-cited response to the OAG nor anywhere in the record in this case does NSP squarely address the Commission's requirement for deferred accounting to support the change in accounting for ratemaking purposes. Further, according to OAG witness Lindell:

> First, I would not agree that the refueling costs are spread out over the refueling cycle rather than being incurred in a single month. Accounting is simply a measurement of economic events. The economic event in this case is the expenditure of money for nuclear refueling. That economic event will not change as a result of this accounting change. Spreading out those costs for accounting purposes does not change when the costs were incurred. They will still be incurred in a single month.

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[41] Ex. 66, Lindell Direct at 26-27.

[42] *See* Ex. 15, Heuer Public Rebuttal at 48; *see also* Xcel's Response to OAG Information Request No. 403 shown in Ex. 66, Lindell Direct at Exhibit JJL-5.

> Second, I would agree that the accounting change will smooth out the refueling outage cost impacts on the Company's financial statements. However, that would not be a reason to establish a new recovery method for these costs. NSP will be recording these costs over the refueling cycle which accomplishes its goal of smoothing out the impact for financial statement reporting purposes. It is not necessary that recovery be accomplished the same way as the Commission explained in its order approving the accounting change.
>
> Third, NSP has not accomplished anything new with this accounting change. The Commission has always used a normalized method to produce a representative level for use in setting customer rates. Analyzing a number of years to determine a normal level of refueling costs allows the Commission to establishing a representative level of that cost for recovery. The change in accounting did not produce that benefit; it already existed.
>
> Finally, the claim is that these costs will continue to be subject to review for reasonableness. The reasonableness evaluation will be more difficult and more time-consuming as a result of this change in accounting. As a result, it is more likely the analysis for reasonableness and prudence will suffer.[43]

NSP has not borne its burden of proof to establish that its nuclear refueling expenses qualify for deferred accounting treatment and its request to accord them such treatment should be denied.

5. The deferral and amortization method would result in NSP earning a return on the deferred balances of the nuclear refueling expenses, contrary to normal ratemaking.

If the Commission were to approve for ratemaking purposes the accounting change from the direct expense method to the deferral and amortization method, a calculated amount would be included in rate base for these expenses. "Including deferred costs in the rate base would provide a return on that amount like capital investments do for NSP. Providing a return on this expense has not been done in the past."[44] According to NSP witness Heuer: "In the case of the outage expense, the Company incurs the cost at the time of the outage. This cost is capitalized like plant and amortized over the 18- to 24-month period until the next outage."[45] Thus, NSP wants an expense that is deferred and amortized to earn a rate of return, as if it were a capitalized

[43] Ex. 66, Lindell Direct at 25-26.
[44] Ex. 68, Lindell Surrebuttal at 18.
[45] Ex. 15, Heuer Public Rebuttal at 47.

asset, which is contrary to normal ratemaking treatment of expenses, and not possible under the current direct expense method.

In the recent Minnesota Power rate case, the Commission ruled that Midwest Independent System Operator ("MISO") Schedule 16 and 17 costs are expenses and are not allowed a return: "The Commission agrees with the OES that the expenditures in question were for administrative costs, not capital costs. Such expenses do not earn a return. It would also be unfair, as the OES argued, to require ratepayers to pay a return on these out-of-period expenses."[46] Thus, not only is it inappropriate to pay a return on out-of-period expenses; it is inappropriate to pay a return on expenses, in general.

In the case of NSP's nuclear plants, nuclear refueling occurs within an approximately one-month period and is not required again for another 18 to 24 months. Until the refueling is done again in 18 to 24 months, that one month of expense would be earning a rate of return, according to NSP's proposal. Nuclear refueling outage expenses would be "out-of-period" expenses in the year after the refueling is done. If the Commission allows the deferral and amortization method for ratemaking purposes, it should deny any rate base treatment, analogous to what the Commission did with MISO expenses for Minnesota Power and the other utilities.

6. The deferral and amortization method would operate like a tracker and virtually guarantee cost recovery of expenses even if they are determined to not be prudent and reasonable.

The deferral and amortization method, if used for ratemaking purposes, would create a regulatory asset with respect to the nuclear refueling costs. According to the FERC Uniform System of Accounts, which has been essentially adopted by Minnesota for regulatory purposes,[47]

[46] FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER *In the Matter of the Application of Minnesota Power for Authority to Increase Electric Service Rates in Minnesota*, Docket No. E-015/GR-08-415 (May 4, 2009) at 25.
[47] *See* Minn. R. Part 7820.0200 - 7820.0400.

regulatory assets are "regulatory-created assets . . . resulting from the ratemaking actions of regulatory agencies."[48] A regulatory asset is essentially an IOU from ratepayers to the utility. If the utility records a regulatory asset, one of the requirements of the accounting standards for recording regulatory assets is that there is a presumption that those costs would be recovered. According to the Financial Accounting Standards Board ("FASB") Statement of Financial Accounting Standards No. 71 ("FAS 71"), with regard to regulatory assets: "It is probable that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for ratemaking purposes."[49] Further, FASB defines "probable" as: "The future event or events are likely to occur."[50] According to OAG witness Lindell: "Once the costs are deferred and then begin to be amortized, there is a presumption that they will be recovered. [However, i]n a rate case setting, under the direct expense method, the refueling costs would be reviewed for reasonableness and prudence."[51] According to FERC standards: "To qualify as a regulatory asset, there must be a showing both (i) that the costs at issue are unrecoverable in existing rates and (ii) that it is probable that such costs will be determined to be recoverable in

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[48] *See* FERC Uniform System of Accounts 182.3:

> Other regulatory assets.
>
> A. This account shall include the amounts of regulatory-created assets, not includible in other accounts, resulting from the ratemaking actions of regulatory agencies. . . .
>
> B. The amounts included in this account are to be established by those charges which would have been included in net income, or accumulated other comprehensive income, determinations in the current period under the general requirements of the Uniform System of Accounts but for it being probable that such items will be included in a different period(s) for purposes of developing rates that the utility is authorized to charge for its utility services.

[49] *Accounting for the Effects of Certain Types of Regulation*, Financial Accounting Standards Board Statement of Financial Accounting Standards No. 71 (2008) at 6 (footnote omitted).
[50] *Id.* n.6.

future rates."[52] The probability of recoverability cannot be presumed, and thus the creation of a regulatory asset of nuclear refueling expenses is inappropriate.

In addition, "it would be inappropriate to create a regulatory asset unless there is a firm commitment by parties to test the prudency of those expenditures."[53] According to NSP witness Heuer: "While deferral creates a regulatory asset, we have no greater expectation that these costs will be found prudent for recovery in a rate case than under the direct expense approach. Our costs were reviewed by both the OES and the OAG and both agencies found those costs reasonable and prudent."[54] Heuer would have us take comfort in the fact that NSP, pursuant to the 07-1489 Order, is "now required to make an annual compliance filing that provides our outage costs and compares those costs using the direct expense method of accounting to the deferral and amortization method of accounting."[55] However, OAG witness Lindell notes: "Contrary to Ms. Heuer's expectations, the OAG will not be reviewing the annual compliance report and does not expect that the OES will either. In the earlier proceeding to change the accounting method for financial reporting purposes, OES indicated that it would not be conducting a prudency review annually."[56, 57] Furthermore, because there is a presumption that these costs are already reasonable under the deferral and amortization method, it is foreseeable

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[51] Ex. 68, Lindell Surrebuttal at 18.
[52] *Midwest Independent Transmission System Operator, Inc.,* 103 FERC ¶ 61,205 at 22 (2003).
[53] *Id.* at 17
[54] Ex. 15, Heuer Public Rebuttal at 46.
[55] *Id.*
[56] Ex. 68, Lindell Surrebuttal at 17 (footnote omitted).
[57] "The OES notes that there is no need for a separate annual audit as the review of prudence and reasonableness of these and other costs occurs in general rate cases, and would continue to occur in the same manner for nuclear outage costs as issues arise in the future." *Reply Comments of the Minnesota Office of Energy Security*, *In the Matter of a Petition by Northern States Power Company, a Minnesota Corporation, for Accounting Treatment for Nuclear Refueling Outage Costs*, Docket No. E-002/M-07-1489 (May 19, 2008) at 3.

that only a limited effort would be made to determine a prudent and reasonable amount for setting rates.

Finally, the creation of a regulatory asset with regard to nuclear refueling expenses, with the presumption that it is probable that the costs involved will be recovered, would tend to subtly shift the burden of proof, or the perception as to which entity bears that burden, from NSP to the reviewing agency. However, pursuant to Minn. Stat. § 216B.16, subd. 4: "The burden of proof to show that the rate change is just and reasonable shall be upon the public utility seeking the change." Retaining the direct expense method would maintain the burden of proof squarely within NSP's domain.

7. The pitfalls of the deferral and amortization method can be avoided if the direct expense method is retained for ratemaking Purposes.

According to OAG witness Lindell: "In a rate case setting, under the direct expense method, the refueling costs would be reviewed for reasonableness and prudence. If, for example, there were years when refueling costs were not reasonable, it would be an opportunity for parties to investigate whether or not the higher costs were prudently incurred."[58] Mr. Lindell calculates the revenue requirement of the expense for nuclear refueling as follows:

($000's) Year	**Prairie Island Unit 1**	**Prairie Island Unit 2**	**Monticello**	**Total**	***Number of Units***
2005 (Actual)	0	18,849	23,568	42,417	*2*
2006 (Actual)	21,991	16,664	0	38,655	*2*
2007 (Actual)	0	0	25,209	25, 209	*1*
2008 (Actual)	22,608	32,442	777	55,827	*2*
2009 (Budget)	26,342	0	25,347	51,689	*2*
				Average	*42,760*
				** 72.9%*	***31,172***

[58] Ex. 66, Lindell Direct at 18.

Mr. Lindell calculated his recommendation of $31,172,000 by utilizing information provided by NSP in response to OAG Information Request 402 shown in Ex. JJL-4 in his Direct Testimony.[59] Using a similar method of averaging a series of several years' nuclear outage expenses, $25,139,022 is the approved amount set in rates for this expense.[60] Thus, the OAG would recommend an increase of approximately $6 million for nuclear refueling expenses.

NSP's deferral and amortization method, if utilized for ratemaking purposes, would embroil regulators in a tangled and convoluted process:

> The total 2009 Test Year revenue requirement associated with all components related to nuclear fuel outage costs is $30,692,218. The analysis includes the impact of the revenue deferral as ordered by the Minnesota Public Utilities Commission in Docket E002/M-07-1489 totaling $13,105,827. The analysis also includes the impact of the basic outage cost accounting change. The 2009 Test Year amortization expense is $30,531,046. The 2009 Test Year outage costs incurred and deferred under the new accounting method total $37,660,773 and represent the amount that would have been expensed prior to the accounting change. Finally, the analysis includes a Test Year adjustment to annualize the amortization expense to include annual costs for all three nuclear units. This adjustment totals $2,308,510.[61]

NSP seeks to cajole us into favoring its deferral and amortization method by claiming that it yields a revenue requirement of $30,692,218, while the amount that would have been expensed prior to the accounting change totals $37,660,773. However, in calculating the latter figure, NSP failed to normalize its costs over a number of years, and thus its purported savings of $7 million is improperly calculated based on a single year, *i.e.*, its budget for 2009.

If the Commission adopts a normalized level for nuclear refueling expense, the calculation of the revenue requirement would not include the calculation of a rate base impact in addition to an income statement impact. In effect, under NSP's methodology and under the new

[59] The data in the table is derived from Xcel's Response to OAG Information Request 402; the italicized portion shows Mr. Lindell's calculations.
[60] Ex. 15, Heuer Public Rebuttal at 47.
[61] Xcel's Response to OAG Information Request 402 shown in Ex. 66, Lindell Direct at Ex. JJL-4.

accounting treatment, a rate of return would be included which, over time, will raise the revenue requirement for these expenses. The normalization approach, would not include a rate base impact which inflates the costs by calculating a return on deferred balances. However, if the Commission were to accept NSP's approach, it should exclude the rate base revenue requirement impact of approximately $1.2 million, which would reduce the revenue requirement amount to $29,487,219 in this case.[62]

Finally, NSP's approach should be rejected because of its unnecessary and confusing complexity. As noted by Mr. Lindell:

> My concern would be that if the deferral and amortization method is adopted for ratemaking purposes, the effort by parties would be devoted to trying to understand the calculation of a simple expense called nuclear refueling expense to try to determine whether the calculation was correct rather than trying to determine whether or not NSP was prudent in its activities and that its refueling costs were reasonable for recovery from ratepayers.[63]

The Commission should hold that of the two approaches for determining the rate component of nuclear refueling expenses, the simplest one, *i.e.*, the direct expense method, is preferable. The Commission should adopt the OAG's approach and find that $31,172,000 should be used to establish the expense level for nuclear refueling costs, with no rate base impact to recover this expense.

C. Rate Case Expense Recovery.

NSP seeks recovery of approximately $1.6 million in rate case expenses that it purportedly incurred developing and attempting to support its request for a $156 million increase in its electric rates. In Direct Testimony the OAG provided three recommendations regarding NSP's recovery of its rate case expenses. First, the OAG recommended no recovery of

[62] *Id.* at 6

[63] Ex. 66, Lindell Direct at 22-23.

unamortized rate case expenses from NSP's prior rate case.[64] As noted above, this issue was resolved when NSP agreed in Rebuttal to no longer seek recovery of prior years unamortized rate case expenses.[65] Two rate case expense related recommendations remain contested.

1. NSP's rate case expenses should be accounted for as normal operating expenses rather than giving them special accounting treatment.

Rate case expenses are normal operating expenses for a regulated utility. These expenses are incurred by a regulated utility for the purpose of presenting its request for a rate increase and include expenses for, among other things, outside legal representation and expert witness testimony. Instead of treating rate case expenses as normal operating expenses, NSP proposes to defer and amortize its rate cases expenses as if they were capital expenditures. This special accounting treatment is unnecessary. The OAG recommends rejecting NSP's proposal because NSP has failed to establish any public interest benefit in giving rate case expenses this special accounting treatment.

There is no rate case dollar adjustment associated with accepting the OAG's recommendation to treat rate case expenses as a normal operating expense. The OAG and NSP are in agreement regarding the amount of rate case expenses assuming NSP is granted 100 percent of its revenue request. Both parties agree that the test year level of rate case expense should be one-fourth of the total costs and that NSP not be allowed a return on its rate case expenses. The only impact of accepting the OAG's recommendation to treat rate case expenses as a normal operating expense rather than accepting NSP's proposal to defer and amortize rate case expenses would be the elimination of a potential future request from NSP to collect any

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[64] *Id.* at 48.
[65] Ex. 15, Heuer Public Rebuttal at 15.

unamortized rate case expenses if NSP files a subsequent electric rate case in less than four years.[66]

As discussed above, NSP attempted to recover unamortized rate case expenses from its prior case in this proceeding. Both the OAG and OES objected to NSP's request[67] and NSP eventually surrendered its efforts to recover these unamortized amounts in Rebuttal.[68] The OES provided several recent Commission decisions where the Commission rejected requests for recovery of unamortized rate case expenses.[69] For example, in Docket No. G004/GR-04-1487, Great Plains Natural Gas Company attempted to recover unamortized rate case expenses from a prior rate case and the Commission held that the unamortized amounts are not recoverable. The Commission noted that the expenses were incurred outside of the test year, and out-of-test-year expenses are generally not recoverable.[70] Normalizing rather than deferring and amortizing these expenses would prohibit NSP from attempting to once again request recovery of an out-of-test year expense.

The OES provides additional support for accepting the OAG's recommendation in its Direct testimony.[71] As the OES notes, ratepayers do not receive a rebate if a utility goes longer than its normalized or amortized recovery period despite the fact that the test year rate case expense is built into rates and therefore perpetually recovered by the utility until it does file a

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[66] Ex. 15, Heuer Public Rebuttal at 51.
[67] Ex. 66, Lindell Direct at 48, Ex. 103, Lusti Public Direct at 14-16.
[68] Ex. 15, Heuer Public Rebuttal at 50-51.
[69] Ex. 103, Lusti Public Direct at 15-16 (citing the Commission's May 1, 2006 Order in Docket No. G004/GR-04-1487, the Commission's November 2, 2006 Order in Docket No. G008/GR-05-1380 and approval of a settlement in Docket No. E001/GR-05-748).
[70] FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER, *In the Matter of a Petition by Great Plains Natural Gas Company, a Division of MDU Resources Group, Inc., for Authority to Increase Natural Gas Rates in Minnesota,* Docket No. G004/GR-04-1487 (May 1, 2006) at 15.
[71] Ex. 103, Lusti Public Direct at 15.

subsequent case.[72] Treating rate case expenses as normal operating expenses, rather than giving them the special deferral and amortization accounting treatment, avoids potentially penalizing ratepayers if NSP decides to file a subsequent rate case in less than four years.

Therefore, while there are public interest benefits in treating rate case expenses like the normal operating expenses that they are, there are only potential ratepayer harms in giving special accounting treatment to these expenses that NSP proposes. The OAG requests that the Commission deny NSP's request to defer and amortize its rate case expenses and instead establish a normalized level of rate case expenses for recovery.

2. A cost control mechanism should be implemented to encourage justifiable rate increase petitions.

The OAG's last rate case expense recommendation relates to the implementation of a cost control mechanism for these expenses. Specifically, the OAG recommends that the Commission adopt a policy that ties the amount of rate case expenses that are recovered from ratepayers to the percentage of the overall rate increase that a utility is ultimately authorized, compared to what it initially requested. For example, as OAG witness Lindell described in his direct testimony,[73] NSP initially requested a $156 million increase. If the Commission authorizes 50 percent of NSP's request, or approximately $78 million, than under the OAG's proposal NSP would be allowed to recover 50 percent of its approximately $1.6 million rate case expenses from its ratepayers. If, on the other hand, NSP were granted all of its requested $156 million rate increase, than it would be permitted to recover all of its claimed rate case expenses in rates.

This recommended cost control mechanism recognizes that utilities should recover only prudently incurred rate case expenses from ratepayers. The mechanism is premised on the fact that it is imprudent for a utility to incur substantial rate case expenses in attempt to justify an

[72] *Id.*
[73] Ex. 66, Lindell Direct at 50.

excessive rate increase, when in actuality the utility can only support a portion of that request. The OAG's recommendation encourages utility's to incur expenses only to support justifiable increases and to limit the time and resources that the petitioning utility, intervening parties, the Commission and its Staff must incur to address red herring issues or issues that clearly do not justify a rate increase.

Moreover, the OAG's rate case expense cost control mechanism is founded on Commission precedent. The Commission has acknowledged that the ultimate determination of the reasonableness of rate case expenses should be dependent on the final rate case determination. In Interstate Power and Light's ("IPL") 2003 rate case the Commission accepted a settlement agreement related to rate case expense recovery, but accepted the settlement subject to potentially reexamining the rate case expense issue on reconsideration. The Commission stated:

> "At this point the dollar amounts slated for recovery for expenses incurred in this case also appear to be just and reasonable, supported by substantial evidence, and in the public interest. This determination could change, however, should the ultimate rate impact of this proceeding prove to be negligible, raising issues of prudence and reasonableness of rate case expenses."[74]

There were only two active parties in the 2003 IPL case, IPL and the Minnesota Department of Commerce. Neither party requested that the Commission reconsider its approval of their rate case expense settlement even though the Commission ultimately granted a rather insignificant percentage of IPL's requested rate increase. Nevertheless, the IPL Order demonstrates that the reasonableness and prudence of rate case expenses is tied to the Commission's ultimate rate increase determination. The OAG's recommendation provides a

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[74] FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER; ORDER MODIFYING SETTLEMENT, *In the Matter of Interstate Power and Light Company for Authority to Increase Electric Rates in Minnesota*, Docket No. E-001/GR-03-767 (April 5, 2004) at 4.

mechanism that the Commission can implement to tie the recoverability of rate case expenses to the Commission's ultimate rate increase determination.

The OAG requests approval of its rate case expense cost control mechanism. Not only will this recommendation control the expenses associated with rate cases, but it also recognizes that if the utility cannot justify its requested rate increase then shareholders must bear some of the expenses associated with the rate increase request.

D. Corporate Cost Allocations.

Each year Xcel Energy's Service Company charges its affiliates millions of dollars for its costs of providing services to its affiliates. Many of the Service Company's costs benefit multiple affiliates and therefore cannot be directly assigned to any one affiliate, but instead are spread among numerous affiliates. Some of Xcel's affiliates are regulated operations and others are nonregulated operations. The regulated affiliates can pass these costs off to their captive ratepayers, while the nonregulated operations must recover these costs through the price of their goods or services. Any time corporate costs are allocated down to both regulated and nonregulated operations concerns arise that the regulated operations are over-allocated corporate costs for the benefit of the nonregulated affiliates. Evidence in this case demonstrates that NSP is over-allocating corporate costs to regulated operations to the detriment of its ratepayers.

1. History of the commission's concerns related to corporate cost allocations.

The Commission is appropriately concerned with the issue of corporate cost allocations in an era of energy utility diversification into both regulated and nonregulated operations. The Commission has expressed its concerns with corporate cost allocations as follows:

> Diversification into affiliated operations…holds the possibility of harm to utility ratepayers. A monopoly utility has a natural impetus to shift costs from the nonregulated to the regulated operation, where costs are covered in rates, or to not acknowledge benefits to the nonregulated entity from joint operations. If

> improper cost or benefit allocations do occur, the result is subsidization of the nonregulated affiliate by the regulated utility.[75]

In addition to the cross-subsidization issue identified by the Commission, an over-allocation of corporate costs to a regulated utility operation compels an inquiry into the reasonableness of the regulated operation's rates. The Commission's concerns related to corporate cost allocations were so great that in 1990 it initiated a four-year, industry-wide investigation that resulted in the development of cost allocation principles to guide Minnesota utilities in apportioning costs between their regulated and unregulated operations.[76] At the end of the investigation, the Commission adopted fully allocated cost accounting principles, based on hierarchical costing principles that the Federal Communications Commission had developed for use in the regulated telecommunications industry. The four hierarchal cost principles that the Commission adopted are as follows:

1) tariff rates shall be used to value tariff services provided to non-regulated activity;
2) costs shall be directly assigned to either regulated or non-regulated activities whenever possible;
3) costs which cannot be directly assigned are considered common costs which shall be grouped into homogenous cost categories and each cost category shall be allocated based on direct analysis of the origin of the cost, whenever possible. If direct analysis is not possible, costs shall be allocated based upon an indirect cost

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[75] *In the Matter of an Investigation into the Competitive Impact of Appliance Sales and Service Practices of Minnesota Gas and Electric Utilities,* Docket No. G,E-999/CI-90-1008, Order Setting Filing Requirements (September 28, 1994) at 2.

[76] *In the Matter of an Investigation into the Competitive Impact of Appliance Sales and Service Practices of Minnesota Gas and Electric Utilities,* Docket No. G,E-999/CI-90-1008, Order Setting Filing Requirements (September 28, 1994); Order Finding Compliance, Exempting Northwestern Wisconsin, Requiring Preparation, and Closing Docket (March 1, 1995); Order Clarifying Commission Order dated September 28, 1994 (March 7, 1995) ("1008 Docket").

causative linkage to another cost category or group of cost categories for which direct assignment or allocation is available; and

4) when neither direct or indirect measures of cost causation can be found, the cost category shall be allocated based upon a general allocator computed by using the ratio of all expenses directly assigned or attributed to regulated and non-regulated activities, excluding the cost of fuel, gas, purchased power and the purchase cost of goods sold.[77]

The Commission encouraged, but did not require, all gas and electric utilities to adopt these four cost allocation principles.[78] In allowing utilities some flexibility to design their own allocation principles, the Commission warned:

> Should a utility wish to base its cost separations on different principles, the burden of proof would be on that utility to prove that its cost allocation principles arrive at fully allocated costs, free of any cross-subsidization. The utility would have to show that the goals of fully allocated costing, as expressed in this and other Orders, are fully realized. The utility would have the burden of demonstrating that it has considered all of its <u>costs</u> and that they are allocated to share burdens and benefits equitably between the regulated and nonregulated operations.[79]

In this case NSP has demonstrated compliance with the first three of the four Commission approved cost allocation principles, but instead of complying with the fourth principle developed in Docket No. G,E-999/CI-90-1008 ("1008 Order"), NSP proposed an alternative general allocator for all costs whose causes cannot be traced. Instead of using the Commission preferred general allocator described in the fourth hierarchical cost principle, NSP

[77] 1008 Docket, September 28, 1994 Order at 4.
[78] 1008 Docket, March 7, 1995 Order at 1.
[79] 1008 Docket, September 28, 1994 Order at 5 (emphasis added).

uses a three-factor general allocator for indirect Service Company costs based on total assets, total revenues and number of employees.[80]

Both the OAG and the OES identified concerns related to NSP's preferred three factor general allocator.[81] The OAG and OES offered evidence demonstrating that NSP's preferred allocator inappropriately allocated more corporate costs to Xcel Energy's regulated operations than non-regulated operations,[82] and according to the OAG's analysis, over-allocated corporate costs to Xcel's NSP-Minnesota regulated electric utility jurisdiction. As a result, NSP has the burden to establish the appropriateness of its preferred methodology. NSP has not met its burden in this case.

2. Contrary to NSP's representations, its three-factor general allocator has not been expressly reviewed and approved by the commission.

NSP attempts to dispel the OAG's and OES's concerns with its alternative three factor general allocator by representing that the Commission has reviewed and approved its allocator in numerous other dockets, including previous rate cases and affiliate interest filings.[83] NSP overstates the Commission's approval. The Commission has permitted NSP to use an alternative general allocator; however, any Commission approval of NSP's general allocator is tacit, at best.

Case in point: Otter Tail Power Company ("OTP") attempted to rely on the Commission's tacit approval of NSP's three factor general allocator in OTP's 2007 electric rate case to support the approval of its "virtually identical" three factor general allocator. The Commission acknowledged that OTP's three factor general allocator was "virtually identical" to

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[80] Ex. 17, Heuer Public Surrebuttal at 34.
[81] Ex. 67, Lindell Rebuttal at 42-49, Ex. 85, Campbell Public Direct at 51-62 and Ex. 101, Campbell Public Surrebuttal at 22-28.
[82] Ex. 85, Campbell Public Direct at 58-59 and Ex. 101, Campbell Public Surrebuttal at 22.
[83] Ex. 17, Heuer Public Surrebuttal at 34-35.

NSP's alternative three factor allocator, but rejected its use to allocate corporate costs.[84] In rejecting OTP's request to use the "virtually identical" alternative general allocator, the Commission noted that OTP's reliance on Commission approval of NSP's alternative general allocator was misplaced because "Xcel's general allocator was not a contested issue in [Xcel's] rate case….It was therefore not expressly addressed by the ALJ or the Commission."[85] The Commission ruled that Xcel's use of a virtually identical general allocator "has no precedential or persuasive value" in the OTP rate case.[86]

Thus, as recently as August 1, 2008, the Commission acknowledged that NSP's proposed alternative general allocator has not been expressly addressed by the Commission. It is therefore inappropriate for NSP to rely on the Commission's previous tacit approval of its three factor allocator to support acceptance of the allocator in this rate case proceeding. The only previously conducted, genuine rate case review of a proposed alternative three factor general allocator occurred in the 2007 OTP rate case where the Commission determined that OTP's "virtually identical" three factor allocator inappropriately allocates corporate costs. As a result, the Commission ordered OTP to implement the Commission's preferred general allocator articulated in the 1008 Order.[87] The record as developed in this case similarly supports the rejection of NSP's alternative three factor general allocator.

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[84] FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER, *In the Matter of the Application of Otter Tail Corporation d/b/a Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in Minnesota*, Docket No. E-017/GR-07-1178 (August 1, 2008) at 15.
[85] *Id.* at 16.
[86] *Id.*.
[87] *Id.* at 17.

3. The record demonstrates that NSP's preferred general allocator over-allocates corporate costs to Xcel's NSP-Minnesota regulated electric utility jurisdiction.

OAG witness Lindell used cost allocation data provided by NSP in response to OAG information requests to calculate the impact of using the Commission's preferred general allocator rather than NSP's preferred alternative general allocator. Applying the data provided by NSP, Lindell calculated that implementing the Commission's preferred general allocator would result in approximately $3.4 million less of Xcel's Service Company costs being allocated to NSP's Minnesota jurisdiction for the budgeted test year ended 2009.[88]

In Surrebuttal, NSP disputed Mr. Lindell's $3.4 million calculation.[89] NSP identified three concerns with his calculation. First, NSP noted that the OAG used costs other than expenses in its general allocator calculation and NSP interprets the Commission's 1008 Order to require the use of only expenses to calculate the general allocator.[90] Second, NSP noted that Mr. Lindell mistakenly included in his calculation of allocated direct costs, $33.3 million in capital labor costs, which for the budgeted 2009 test year had not been directly assigned or attributed to an affiliate. According to NSP, including costs that had not been directly assigned or attributed to an affiliate was inconsistent with the Commission's preferred general allocator.[91] Third, NSP argued that the cost data which Mr. Lindell used to compute his $3.4 million adjustment did not include all Xcel Energy subsidiaries, only those with more than $500,000 of allocated costs.[92] NSP argued that Lindell's $500,000 limit distorted the results.

Commission precedent and further record development addresses NSP's expressed concerns. After NSP's concerns are addressed, the record continues to reflect that NSP has

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[88] Ex. 67, Lindell Rebuttal at 46-47 and Exhibit JJL-6 at 3.
[89] Ex. 17, Heuer Public Surrebuttal at 37.
[90] *Id.*
[91] *Id.* at 38.
[92] *Id.* at 39.

failed to meet its burden "of demonstrating that it has considered all of its costs and that they are allocated to share burdens and benefits equitably between the regulated and nonregulated operations."[93]

a. Commission precedent instructs that its preferred general allocator is computed by using the ratio of all costs directly assigned or attributed to affiliates and is not limited to <u>expenses</u> directly assigned or attributed.

With respect to NSP's first concern, it is undisputed that the Commission's fourth hierarchical cost allocation principle related to the formula for its preferred general allocator developed in the 1008 Docket states:

> when neither direct or indirect measures of cost causation can be found, the cost category *shall be allocated based upon a general allocator computed by using the ratio of all <u>expenses</u> directly assigned or attributed to regulated and non-regulated activities,* excluding the cost of fuel, gas, purchased power and the purchase cost of goods sold.[94]

The Commission, however, did not intend to limit the general allocator computation to only *expenses*, as NSP argues. Instead, a complete reading of the 1008 Order in conjunction with a subsequent Commission Order interpreting the 1008 Order instructs that the Commission's preferred general allocator is computed by using the ratio of all **<u>costs</u>** directly assigned or attributed to regulated and unregulated activities, excluding the cost of fuel, gas, purchased power, and the cost of purchased goods sold.

First, the purpose of the 1008 Docket was to develop <u>cost</u> allocation principles. The Commission's second hierarchical cost allocation principle instructs that <u>costs</u> shall be directly assigned whenever possible, and according to the third principle, those <u>costs</u> that cannot be directly assigned are considered common <u>costs</u> that should be grouped and allocated based on direct analysis if possible, otherwise by indirect <u>cost</u> causative linkage. The fourth principle is

[93] 1008 Docket, September 28, 1994 Order at 5 (emphasis added).
[94] 1008 Docket, September 28, 1994 Order at 4.

intended to allocate those costs that cannot be directly or indirectly allocated. It is inconsistent to allocate these costs based on a formula comprised of only *expenses* directly assigned or attributed to regulated and nonregulated activities when the other cost allocation principles focus on corporate costs, not merely expenses.

Moreover, in the 2007 OTP electric rate case, OTP attempted to demonstrate the appropriateness of its virtually identical three factor general allocator by showing that its general allocator would allocate the same percentage of corporate costs to the utility as the percentage of common costs allocated to the utility under the Commission's preferred 1008 methodology. The Commission was not persuaded by this showing. The Commission stated:

> The Commission approved general allocator is based on a *more comprehensive and broadly representative set of costs* than just common costs; if it were not, the cost-allocations orders would have simply used common costs as the general allocator. Instead, they developed the *much more inclusive formula of the ratio between all costs directly assigned or attributed to regulated operations and all costs directly assigned or attributed to unregulated operations.*[95]

It is this August 1, 2008 Commission interpretation of its own preferred general allocator that OAG witness Lindell used to support his calculations comparing the results of implementing the Commission's preferred general allocator to the results of using NSP's preferred alternative general allocator. NSP's criticism that Lindell's calculation is flawed because it used costs, including capital costs, rather than only expenses is misplaced. The argument fails to consider the Commission's most recent interpretation of its preferred general allocator formula and for this reason its argument should be rejected.

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[95] FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER, *In the Matter of the Application of Otter Tail Corporation d/b/a Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in Minnesota*, Docket No. E-017/GR-07-1178 (August 1, 2008) at 16 (emphasis added).

b. The record contains a general allocator calculation that used actual data rather than budgeted data to cure NSP's second concern with the OAG's general allocator calculation.

The OAG resolved NSP's second concern that Mr. Lindell included in his calculation of allocated direct costs, $33.3 million in capitalized labor costs, which for the 2009 budgeted test year had not been directly assigned or attributed to an affiliate by simply applying NSP's 2008 values.[96] Unlike the data for budgeted year 2009, the 2008 data supplied by NSP in response to OAG IR 130 included the capital costs assigned to each subsidiary. The 2008 values; therefore, contained only costs that had been directly assigned or attributed to regulated and non-regulated activities, consistent with the Commission's preferred general allocator. As Exhibit 69 demonstrates, had the Commission's preferred general allocator been applied in 2008 rather than NSP's preferred allocator, NSP-Minnesota's electric jurisdiction would have been assigned approximately $2.3 million less from the Service Company in 2008.

c. NSP obstructed the OAG's ability to fully address NSP's third concern related to Mr. Lindell's general allocator calculation by providing a nonresponsive answer to a follow-up inquiry.

In attempt to address NSP's third concern that Mr. Lindell's general allocator calculation was skewed because it only included those subsidiaries with greater than $500,000 of costs allocated, Mr. Lindell issued OAG IR 1304, which was accepted into the record as OAG Ex. 47. OAG IR 1304 requested that NSP provide "a follow-up response to OAG 130 with the inclusion of all companies including those with less than $500,000 of Service Company cost or assignment."[97] Rather than providing the requested follow-up information, NSP provided a new schedule which contained all subsidiaries, but only included the cost assignments/allocations of the Service Company's Operating and Maintenance *expenses* for the 2009 budgeted test year.

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[96] Ex. 69, Xcel response to OAG IR 130 with notations by Lindell.
[97] *Id.* at 5.

By inappropriately limiting its response to only Operating and Maintenance *expenses* NSP obstructed the OAG's ability to resolve NSP's final concern.

d. NSP's general allocator calculations cannot be relied upon because they contain several deficiencies.

In response to the additional support for the OAG's recommended general allocator adjustment that was submitted at the evidentiary hearing,[98] NSP offered Exhibit 71. Exhibit 71 contained Service Company Cost Assignments/Allocations for the year ended 2008 and 2009. Exhibit 71; however, contains inaccurate, incomplete and inconsistent data that cannot be relied upon to make a reasonableness determination. The Minnesota Court of Appeals has instructed that if a petitioning utility's evidence is inaccurate, it has failed to meet its burden of proof, and the Commission must either deny the rate increase or make appropriate adjustment to utility's proposal.[99] NSP's evidence used to support the appropriateness of its alternative general allocator contains numerous deficiencies as detailed below and therefore NSP has failed to meet its burden of proof.

First, despite the heading "Service Company Cost Assignments/Allocations," the detail contained in Exhibit 71 is restricted to Service Company operating and maintenance *expenses* that were assigned or allocated in 2008.[100] NSP's general allocator calculation included in Exhibit 71 is similarly limited to a ratio of *expenses* directly assigned or attributed to regulated and non-regulated activities. As discussed above, the Commission's most recent interpretation of its 1008 Order indicates that the ratio should not be limited to only expenses. Instead, it should consist of a "*much more inclusive formula of the ratio between <u>all **costs** directly assigned</u>*

[98] Ex. 69
[99] *Application of Interstate Power Co.,* 500 N.W.2d 501, 504 (Minn. Ct. App. 1993).
[100] Tr. Vol. 3 (June 4, 2009) at 103.

or attributed to regulated operations and all ***costs*** *directly assigned or attributed to unregulated operations."*[101]

Second, Exhibit 71 lists "NSP Nuclear" as an affiliate company that had approximately $1 million of operating and maintenance expenses directly charged to it from the Service Company. NSP's earlier response to OAG IR 130 did not list "NSP Nuclear," as an affiliate that had more than $500,000 of Service Company costs (and not merely operating and maintenance expenses) directly charged to the affiliate. The data for NSP Nuclear appeared for the first time at the evidentiary hearing in Exhibit 71 and is inconsistent with data previously provided by NSP.

Third, Exhibit 71 inexplicably shows that the total operating and maintenance expenses charged to Xcel Energy, Inc. from the Service Company is approximately $9.3 million. However, according to data NSP provided to the OAG in response to OAG IR 130, Xcel Energy, Inc. was allocated approximately $8.7 million in Service Company costs.[102] At the evidentiary hearing the OAG questioned, and continues to question how NSP's Exhibit 71, which is restricted to only operating and maintenance expenses could be greater than the value it supplied the OAG in response to OAG IR 130 which contained capital costs in addition to operating and maintenance expenses.

Because of the numerous deficiencies, inconsistencies and inaccuracies with Exhibit 71, the OAG requests that this exhibit be given no weight. NSP has failed to meet its burden of proof that its alternative general allocator meets the goals established by the Commission in its

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[101] FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER, *In the Matter of the Application of Otter Tail Corporation d/b/a Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in Minnesota*, Docket No. E-017/GR-07-1178 (August 1, 2008) at 16 (emphasis added).

[102] *See* Ex. 69 at 2.

1008 Order. The OAG requests that the Commission make the appropriate adjustment and Order NSP to implement the Commission's preferred general allocator as recommended by the OAG.

E. Nuclear Plant Rate Stability Proposal

In a significant departure from traditional rate setting practice, NSP requests approval of a Nuclear Plant Rate Stability Proposal that attempts to set rates now that are higher than the cost of service, in an apparent effort to cover costs that have not yet been incurred, but are anticipated to be incurred in the future. According to NSP the Nuclear Plant Rate Stability Proposal is necessary to offset the costs from nuclear plant investments that will result from the proposed extension of the life of NSP's Prairie Island ("PI") nuclear plant.[103] If the PI nuclear plant life is extended in 2010 as is projected, then depreciation and decommissioning expenses for the plant would be reduced substantially after rates in this case had been set using the higher depreciation rates.[104] If the Commission allows NSP to continue to collect revenues at the higher 2009 depreciation and decommissioning expense levels, NSP is proposing to defer those revenues and use them to pay for the anticipated life extension investments that NSP will be incurring over the next few years.[105]

In its Direct testimony the OAG recommended that NSP's Nuclear Plant Rate Stability Proposal be rejected because NSP's proposal to create a deferred revenue tracker mechanism to collect and track excess revenues is in effect a proposal to set rates based on its anticipated future cost of service, rather than its actual cost of service as required by Minnesota law.[106]

The OES echoed the OAG's concerns with NSP's proposed Nuclear Plant Rate Stability Proposal. The OES noted that the proposal was in essence a request to require ratepayers to pre-

[103] Ex. 34, Robinson Direct at 10-11.
[104] *Id*. at 10.
[105] *Id*. at 11.
[106] Ex. 66, Lindell Direct at 32-33 (citing Minn. Stat. § 216B.16, subd. 6).

pay for future nuclear power costs by setting rates too high in this proceeding. As the OES noted, "such prepayment would act as an expense account to be used until it runs out and thus would put the entire burden of overruns in nuclear power costs on ratepayers and takes away the incentive for NSP to ensure that costs are minimized."[107]

Despite the concerns with NSP's Nuclear Plant Rate Stability Proposal, the OAG acknowledges NSP's desire to establish rates that match anticipated fluctuations in the revenue requirement related to NSP's nuclear investments. NSP's Nuclear Plant Rate Stability Proposal is not the answer to the matching concern, however. Instead, the OAG supports the OES's alternative proposal to set the depreciable life of PI at ten years in this proceeding to balance the anticipated reduction in depreciation and decommissioning costs and the higher revenue requirement arising from additional nuclear plant investment associated with the life extension of the PI Nuclear Facility.[108] The OES's proposal avoids setting artificially high rates based on anticipated future costs, which the OAG objects to, while at the same time more closely aligning the benefits of additional nuclear investment with the costs and purpose of the investments--extending the useful life of the PI nuclear facilities.[109] The OAG requests Commission approval of the OES's proposal.

F. Revenue Allocations

After the Commission completes the fact-intensive and quasi-judicial process of determining the total revenue requirement of the utility, *i.e.*, the dollar amount of revenue the utility needs in order to pay its operating and maintenance expenses and earn a fair and reasonable return on its investments, the Commission then exercises its policy-intensive

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[107] Ex. 85, Campbell Direct Public at 19.
[108] *See* Ex. 68, Lindell Direct at 8-9 (supporting OES's alternative proposal to address the matching concern).
[109] *Id.* at 9.

legislative function to determine a just and reasonable allocation of the revenue requirement among NSP's customer classes.[110] Regarding the Commission's revenue requirement allocation process, the Minnesota Supreme Court has stated:

> Once revenue requirements have been determined it remains to decide how, and from whom, the additional revenue is to be obtained. It is at this point that many countervailing considerations come into play. **The commission may then balance factors such as cost of service, ability to pay, tax consequences, and ability to pass on increases in order to achieve a fair and reasonable allocation of the increase among consumer classes.** This determination must result in rates which are "just and reasonable" and rates "shall not be unreasonably preferential, unreasonably prejudicial or discriminatory, but shall be sufficient, equitable and consistent in application to a class of consumers."[111, 112]

The Minnesota Supreme Court noted important differences between residential and commercial customers with regard to the allocation of the costs of utility service:

> …it is a matter of common knowledge that the custom of the commercial users is to employ electrical energy profitably, deduct the expense of such energy as a cost of doing business for income tax purposes, and add the residual cost to the price of the service or product which they produce, while it is similarly known that private consumers of electricity cannot so deduct or pass on electrical costs. Such facts allow the inference that in the majority of cases a rate increase must be fully paid for in cash by residential consumers, who may also end up paying for a portion of the commercial rate increase due to the pass-on effect just described. It is not a leap of logic to then say that for the most part commercial users of

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[110] *Hibbing Taconite v. Minnesota Public Service Commission*, 302 N.W.2d 5, 9 (Minn. 1981).

[111] *St. Paul Area Chamber of Commerce v. Minnesota Public Service Commission*, 251 N.W.2d 350, 357 (1977) (emphasis added); *see also* Minn. Stat. § 216B.03.

[112] The Court found support for considering non-cost factors "with the reasoning expressed by the United States Supreme Court in the *Permian Basin Area Rate Cases*, 390 U.S. 747, 815, 88 S. Ct. 1344, 1385 (1968):

> [T]he [Federal Power] Commission's exposition . . . has quite appropriately incorporated in its calculations factors other than producers' costs . . . .The Commission's responsibilities necessarily oblige it to give continuing attention to values that may be reflected only imperfectly by producers' costs; a regulatory method that excluded as immaterial all but current and projected costs could not properly serve the consumer interests placed under the Commission's protection.

Id. at 355. In setting rates, the Commission is also urged to bear in mind the observation of the United States Supreme Court that "[u]tility service is a necessity of modern life . . . ." *Memphis Light, Gas, and Water Div. v. Craft*, 436 U.S. 1 (1978) at 18.

> electricity are more “able to pay” a rate increase than residential users. While such assumptive reasoning would not ordinarily be employed by a court, which must in most cases confine itself to the evidence, it may be legitimately employed by a legislative agency attempting to serve the public interest at large in a way that courts cannot.[113]

The Commission has adopted the Minnesota Supreme Court’s determination on the issue of allocation of the costs of utility service:

> In determining how to apportion responsibility for the revenue requirement among customer classes, the Commission considers both cost and non-cost factors. Traditional non-cost factors include ability to pay, historical continuity, ease of administration, customer acceptance, ability to pass along costs, ability to bypass the utility, and tax deductibility of utility expenses.[114]

The Commission has elaborated on the importance of the non-cost regulatory policy that favors rate stability and disfavors abrupt or significant changes to rates:

> Avoiding rate shock is a primary ratemaking goal, because sudden, drastic increases in energy costs can be burdensome for residential and non-residential customers alike. Avoiding rate shock is particularly important for residential ratepayers, however, because increases in the cost of basic needs can cause hardship for customers on low or fixed incomes.[115]

OAG witness Lindell acknowledged that the Commission generally begins its revenue requirement allocation determination with an examination of the Class Cost of Service Study (“CCOSS”) and then balances the CCOSS results with non-cost factors that the Minnesota Supreme Court and Commission have recognized. Some parties in this case request that the ALJ and Commission give great deference to the results of the CCOSS. However, evidence in this record demonstrates that a CCOSS is an inherently imprecise revenue allocation tool and for this

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[113] 251 N.W.2d at 354-355.

[114] *In re Minnegasco, a Div. of Nor Am Energy Corp.*, 170 P.U.R.4th 193, 1996 WL 361224, Minn.P.U.C., June 10, 1996, (NO. G-008, GR-95-700).

[115] FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER, *In the Matter of Application of Midwest Gas, a Division of Iowa Public Service Company, for Authority to Change its Schedule of Gas Rates for Retail Customers Within the State of Minnesota*, Docket No. G-010/GR-90-676 (July 12, 1991) at 35.

reason, the ALJ and Commission should carefully balance non-cost factors with the questionable merit of the CCOSS.

1. Evidence in this record questions the reliability of using a CCOSS to allocate the revenue requirement.

The OAG provided extensive testimony regarding its concerns with relying on the results of a CCOSS to apportion rate increases and its testimony is supported by evidence in this record that further explains the limited reliability of CCOSS for apportioning an authorized rate increase. Due to the limited reliability of the results of a CCOSS, it is important to give careful consideration to non-cost factors when apportioning rates.

As counsel for XLI demonstrated through the use of the excerpts from the National Association of Regulatory Utility Commissioners ("NARUC") Cost Allocation Manual,[116] there are numerous CCOSS methods, some of which are discussed in the NARUC manual. NSP witness Zins noted through questioning by Commission Staff that there are numerous types of CCOSS because "there's lots of analysts like me to dream them up. And each utility looks at these things differently. Each jurisdiction. The regulatory agencies look at them differently. And in addition to that, the ideas have evolved over time."[117] Further, Mr. Zins acknowledged that the selection of the CCOSS used will impact the cost of service results. In fact, Mr. Zins stated that the implementation of one CCOSS method may produce results that are "materially different" than the results of a different method.[118]

Mr. Zins testimony supports OAG witness Lindell's position that a CCOSS is an arbitrary exercise that has limited value in ratemaking.[119] This testimony also supports Mr. Lindell's

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[116] Ex. 55.
[117] Tr. Vol 2A (June 2, 2009) at 98, lines 2-5.
[118] *Id.* at 98-99.
[119] Ex. 66, Lindell Direct at 41 (citing Baumol, "*How Arbitrary is Arbitrary? - or Toward the Deserved Demise of Full Cost Allocation,*" The Public Utilities Fortnightly (September 3, 1987).

argument that cost studies do not reflect the "actual cost" of providing service to a class of customers[120] and that results of a CCOSS will depend largely on the allocation methods used and data incorporated within the CCOSS.[121] If two different studies applying the same information can produce cost results that are materially different, than it is inappropriate to claim that the results of the chosen study demonstrate the "actual cost" of serving a customer class. Similarly, because results can vary materially depending on the study chosen, it is inappropriate to rely on the results of a study to make a claim that one class of customers is subsidizing another class of customers.

Because of the limited reliability of this cost of service evidence, the OAG requests that the Commission employ great caution in using its results to guide revenue allocation decisions.

2. Public comments demonstrate the extreme financial difficulties that residential ratepayers are currently experiencing.

The ALJ and Commission are undoubtedly aware that the NSP's rate increase request comes in the midst of an economic crisis unlike any experienced in recent times. Minnesotans are experiencing record levels of unemployment rates and many are fighting to make monthly payments for necessities such as food, clothing, shelter and utilities. Public comments provide an applicable litmus test for determining the impacts of a rate increase on the utility's customers and whether the proposed increased rates are "reasonable" given the economic climate that we find ourselves. Numerous customers submitted substantial and thoughtful written remarks regarding the impact and timing of NSP's rate increase request.[122] All customers submitting written public comment opposed NSP's rate increase request.

[120] Ex. 67, Lindell Rebuttal at 26.
[121] *Id.* at 32.
[122] The written public comments were filed in two volumes on May 12, 2009.

Ms. Lois Kelly, a fixed income NSP customer, wrote to express her objection to NSP's rate increase request. Ms. Kelly indicates that she has worked diligently to conserve electricity in an attempt to lower her electric bill. Ms. Kelly further indicates that despite her best efforts to reduce her monthly bill, she continues to pay more for her electricity. Ms. Kelly states that she prides herself on timely paying all her bills, but this proposed electricity rate increase will undoubtedly cause strain on her already fixed budget.

Mr. Thomas Beagan wrote to express his position that no rate increase should be permitted. Mr. Beagan noted that his employer has frozen wages and is not awarding bonuses this year. He noted that currently Minnesotans are experiencing extreme difficulty "keeping their heads above water" and therefore NSP's rate increase request is untimely.

NSP customer Ms. Erika Schaper echoed the sentiments of many other concerned NSP customers when she wrote to express her position that given current economic conditions this is not the right time for ratepayers to experience a rate increase.

These and all other written public comments in the record demonstrate that ratepayers, especially residential ratepayers, are experiencing grave financial circumstances. The prospect of raising rates for this class of customers is frightening, especially when most residential ratepayers will not receive wage increases this year to offset the impact of rising energy rates. The OAG requests that the Commission give appropriate deference to the public comments when making its policy-intensive revenue allocation decision.

3. All Classes Should Bear The Same Percentage Rate Increase.

Given the lack of any reliable evidence to demonstrate the actual cost of serving each customer class or any reliable evidence that residential ratepayers are subsidized by other customer classes, it is highly inappropriate to place a greater percentage of any approved rate increase on the backs of the residential class. NSP's proposal, however, will do just that. As demonstrated in OAG witness Lindell's direct testimony, NSP's proposal would result in a much higher proportion of the overall increase being assigned to the residential class.[123]

The OAG's analysis shows that under NSP's proposal, the residential class will receive 44 percent of the proposed increase even though the residential class only takes 26 percent of NSP's total retail Minnesota power.[124] Conversely, commercial and industrial customers consume 72 percent of the power, but NSP is only proposing that those customers receive 54 percent of the overall increase. The XLI, MCC, and Commercial Group recommend allocating even more of the authorized rate increase to the residential ratepayers than NSP proposes. As the record demonstrates, residential ratepayers should not and cannot be asked to shoulder the burden of this rate increase. Given this record and the dire economic circumstances that all customers find themselves, the OAG requests that Commission apportion any authorized rate increase equally among all customer classes.

IV. CONCLUSION

In summary, the OAG requests that the Commission:

1. Accept the proposed FCA Incentive Settlement that requires NSP to provide a FCA incentive proposal to the workgroup formed in an alternative docket for consideration by all stakeholders and for potential implementation by all electric utilities.
2. Accept of the proposed Employee Expense Compliance Plan which will provide a forum to review and rework, where necessary, NSP's revised policies for employee expenses and to ensure that in the future, ratepayers are responsible for only those expenses that are reasonable and necessary for the provision of utility service to Minnesotans.

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[123] Ex. 66, Lindell Direct Testimony at JJL-1.
[124] *Id.*

3. Accept the OAG's proposal to establish a cost control mechanism to determine the appropriate test year level of rate case expenses to be recovered from ratepayers.
4. Deny NSP's proposed change in accounting for nuclear refueling.
5. Require NSP to adopt the Commission's preferred corporate cost general allocator and set rates on the basis of that general allocator, as recommended by the OAG.
6. Denial of NSP's proposed Nuclear Plant Rate Stability Proposal.
7. Approve a revenue allocation that assigns the same percentage increase to all rate classes.

Dated: July 10, 2009

Respectfully submitted,

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BEFORE THE MINNESOTA OFFICE OF THE ADMINISTRATIVE HEARINGS
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MPUC Docket No. E-002/GR-12-961
OAH 68-2500-30266

In the Matter of the Application of Northern States Power Company, d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota

REBUTTAL TESTIMONY AND SCHEDULES OF ATTORNEY GENERAL ANTITRUST AND UTILITIES DIVISION WITNESS

VINCENT C. CHAVEZ

March 25, 2013

TABLE OF CONTENTS

I. INTRODUCTION AND QUALIFICATIONS 1

II. PURPOSE OF TESTIMONY 1

III. MODIFICATIONS TO CLASS COST OF SERVICE STUDY ("CCOSS") 4
- A. Minnesota Chamber of Commerce ("MCC") 4
- B. Xcel Large Industrial ("XLI") 8
- C. Minnesota Department of Commerce ("DOC") 12
- D. Summary Of OAG's Rebuttal Testimony Regarding CCOSS 13

IV. RATE DESIGN 14
- A. Apportionment of Revenue Responsibility 14
- B. DOC's Proposed Residential Customer Charges 17
- C. Energy Cents Collation's Proposed Residential Inverted Block Rate Structure . 22

V. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS 26

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Vincent C. Chavez. I am employed by the Office of the Minnesota Attorney General as a Financial Analyst in the Antitrust and Utilities Division ("OAG"). My business address is Bremer Tower, Suite 1400, 445 Minnesota Street, St. Paul, Minnesota, 55101-2127.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes, I filed Direct Testimony in this proceeding.

II. PURPOSE OF TESTIMONY

Q. WHAT TOPICS WILL YOU ADDRESS IN YOUR REBUTTAL TESTIMONY??

A. I address:

- Modifications to Xcel's proposed Class-Cost-of-Service Study ("CCOSS") as recommended by the Minnesota Chamber of Commerce ("MCC" or "Chamber"), Xcel Large Industrials ("XLI"), and the Minnesota Department of Commerce ("DOC");
- Modifications to Xcel's proposed apportionment of revenue responsibility as recommended by the DOC;
- Customer charge increases for the Residential and Small General Service customer classes as recommended by the DOC; and
- The recommendation by Energy Cents Collation ("ECC") to implement an Inverted Block Rate structure for Residential ratepayers.

Each is presented below.

Q. BEFORE CONTINUING, DO YOU HAVE ANY QUALIFYING REMARKS?

A. Yes. In Xcel's last rate case (Docket No. E002/GR-10-971 ("Docket 10-971")), the Commission established an apportionment of revenue requirement in which the Residential customer class was assigned 100.1 percent of the costs identified by the CCOSS. Now, due largely to the loss of two major Commercial and Industrial customers ("C&I"), there is a shift of costs to Residential ratepayers. This shift of costs now changes the amount of costs assigned to the Residential ratepayers to 99.1 percent, which Xcel wants to "correct." Residential ratepayers have been paying more than 100 percent of their costs and are now being asked to pay more costs simply due to the loss of C&I customers, and not because the Residential customers impose more costs on the system. The proposed shift in costs due to a shift in revenue is neither fair nor reasonable given that Residential ratepayers have been and are currently paying their costs.

III. MODIFICATION TO CLASS COST OF SERVICE STUDY ("CCOSS")

A. MINNESOTA CHAMBER OF COMMERCE

Q. DO YOU HAVE ANY OBSERVATIONS CONCERNING THE TESTIMONY OF MCC WITNESS KAVITA MAINI?

A. Yes. According to Ms. Maini:

> Xcel is seeking additional revenues due to significant losses in the C&I rate class, and Xcel has seen elimination or reductions in its largest ratepayers. These include closing of the Ford Plant and Verso Paper, switching of sources by the University of Minnesota and Cypress, and an economic retention rate was needed to support expansion at Gerdau Ameristeel.[1]

According to Ms. Maini, these "high load factor businesses are typically energy intensive 24x7 operations and have a stable and predictable load profile. Consequently, such loads

[1] Maini Direct at 24.

impose lesser costs on the system because the utility incurs less load following costs."[2] However, as in the case of the Ford Plant, Verso Paper, and other lost C&I customers, these are only "energy intensive 24x7 operations" when they are in operation. When they are not in operation, their load profile is zero.

Q. **HOW ARE RATES GENERALLY AFFECTED WHEN A UTILITY EXPERIENCES ELIMINATION OF OR REDUCTIONS IN ITS LARGEST C&I RATEPAYERS?**

A. Generally, the costs in a CCOSS are assigned to the cost causer -- an outcome Ms. Maini acknowledges.[3] Here, the C&I class of customers is the cost causer of what Xcel identifies as significant losses in the C&I rate class. Thus, C&I rates would logically increase as a result. It would be contrary to ratemaking principles to increase Residential and Small General Service rates as a result of decreased revenue from C&I customers because Residential and Small General Service customers are no more expensive to serve as a result of the elimination of or reductions in the energy consumption of Xcel's largest C&I ratepayers. Once again, in Docket 10-971, the Commission assigned 100.1 percent of residential costs to the Residential customer class, but MCC wants to shift yet more costs to Residential customers due to the loss of revenue from the C&I customer class.

Q. **HOW DOES MS. MAINI PROPOSE THAT XCEL MAKE UP FOR THE LOST REVENUE FROM THE C&I RATE CLASS?**

A. Ms. Maini skirts the issue by recommending "to change the CCOSS method to one that is not punitive to these high load factor customer classes. . . . [and] that the Peak Demand CCOSS method be used to assign revenue responsibility to customer classes where all

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[2] Maini Direct at 16.
[3] Maini Direct at 18 and 21.

fixed production plant costs are classified as demand or capacity related."[4] In other words, Ms. Maini subjectively picks a CCOSS methodology that assigns more costs to Residential and Small General Service customers. Indeed, she states: "The results comparing Xcel's proposed cost allocation to the Peak Demand method using 1CP as the allocator indicate that the C&I demand metered class should be responsible for revenue deficiency that is $63 million ($158.9 million - $95.9 million) less than what is currently proposed by Xcel . . . ."[5]

Q. WHAT IS THE 1CP ALLOCATOR?

A. The Single Coincident Peak Method ("1CP") is described in the NARUC Electric Utility Cost Allocation Manual[6] ("NARUC Manual") as having the objective of allocating production plant costs to customer classes according to the load of the customer classes at the time of the utility's highest measured one-hour demand in the test year.

Q. WHY DOES MS. MAINI PROPOSE THIS CHANGE IN XCEL'S CCOSS METHODOLOGY?

A. Because the 1CP system peak typically occurs on days with extreme weather, this allocation methodology will allocate more costs to weather sensitive classes and less costs to non-weather sensitive classes than other methodologies. Thus, it allocates more costs to the Residential class than Xcel's CCOSS methodology -- the Equivalent Peaker method.[7] Since "the Chamber's position is that there should be no inter class subsidies and that the revenue apportionment to each class should reflect the cost to serve[,]"[8] Ms. Maini's only recourse is to change the CCOSS to produce a different result that

[4] Maini Direct at 16-17.
[5] Maini Direct at 21.
[6] NARUC (1992).
[7] Peppin Direct at 9.
[8] Maini Direct at 16.

favors her clients, *i.e.*, if you don't like the game, change the rules. This selective, self-serving, results-driven approach must be rejected.

Q. WHAT IS THE IMPACT OF MS. MAINI'S PROPOSED CHANGE IN XCEL'S CCOSS METHODOLOGY?

A. As shown in Table 8, page 22, Ms. Maini's proposed 1CP (peak demand) allocator, the revenue deficiency attributed to the C&I customer class decreases from 10.10 percent to 6.10 percent, while the revenue deficiency attributed to the Residential customer class increases from Xcel's proposed deficiency of 11.70 percent to 18.00 percent. Similarly, the revenue deficiency attributed to the Small General Service customer class increases from Xcel's proposed deficiency of 10.80 percent to 17.10 percent. These changes proposed by Ms. Maini are not fair and not reasonable. Furthermore, such changes inflict rate shock on the Residential and Small General Service customer classes.

Q. DOES XCEL'S PROPOSED CCOSS ALREADY SHIFT COSTS TO RESIDENTIAL CUSTOMERS DUE TO PLANT CLOSING OF LARGE C&I CUSTOMERS?

A. Yes. The OAG requested that Xcel provide the revenue and class cost allocation ramifications of losing the large C&I customers Ford and Verso Paper individually and collectively. In response to the question, Xcel states:

> The Company has not prepared jurisdictional and class cost studies forecast year 2013 with the hypothetical assumption of including the two customers specified in a question, because those loads have been permanently lost due to plant closures. Therefore, an estimated revenue requirement and class cost allocation impact is not available. However, with the exception of both local costs that are directly assigned and directly variable costs such as fuel and purchased power, the remaining fixed costs do not change and continue to have the same revenue requirement after the loss of a customer loads. In isolation, if a customer

> load reduction is limited to a single class, the class cost allocation impact would be to increase the revenue requirement of the other classes.[9]

Thus, Xcel's proposed cost allocation already shifts costs to other customer classes due to the loss of revenue from the plant closures of Large C&I customers.

B. Xcel Large Industrial

Q. Have You Reviewed The Testimony Of Xcel Large Industrials ("XLI") Witness Jeffrey Pollock?

A. Yes. Mr. Pollock wants the Commission to ignore non-cost factors in setting rates. I address Mr. Pollock's recommendations to use a different CCOSS and to ignore non-cost factors in setting rates.

Q. What Type Of CCOSS Does Mr. Pollock Recommend?

A. Mr. Pollock offers a CCOSS using the Average and Excess Demand ("AED") allocation method. The NARUC Manual describes the AED method as a method that allocates production plant costs to rate classes using factors that combine the classes' average demands and non-coincident peak ("NCP") demands. NCP is the individual or actual peak demand of each load in an electrical system; it does not necessarily fall during system peak (or it would be considered coincident peak). This method of allocation favors high load factor customers (*e.g.*, classes with industrial customers), and disfavors customer classes with lower load factor customers (e.g., Residential and Small General customer classes). Like the MCC's witness Ms. Maini, the XLI's witness Mr. Pollock selectively picks a CCOSS that favors his constituents with lower allocated costs and must be rejected.

[9] Xcel's Response to OAG IR No. 109, included as Rebuttal Schedule VCC-1

Q. PLEASE ADDRESS MR. POLLOCK'S RECOMMENDATION TO IGNORE NON-COST FACTORS IN SETTING RATES.

A. Mr. Pollock disagrees with the Minnesota Supreme Court's directive that non-cost factors, including the cost of service, ability to pay, tax consequences, and ability to pass along cost increases, be considered in setting rates, claiming: "The decision dates back to 1977. Circumstances have changed dramatically in the last several decades." [10]

Q. DO YOU AGREE WITH MR. POLLOCK'S STATED POSITION REGARDING THE USE OF NON-COST FACTORS IN SETTING RATES?

A. No. I strongly disagree. XLI joins MCC in their assault on Residential ratepayers, claiming that business customers are subsidizing Residential customers. Repeating the same mantra in virtually every rate case on record, the MCC contends that "there should be no inter class subsidies and that the revenue apportionment to each class should reflect the cost to serve."[11] In this regard, the XLI teamed with MCC in maintaining that interclass subsidies have existed among Minnesota Power's customer classes since the late 1970's. It is of note that MCC has made the same argument in the 2008 MP rate case (08-415), the Xcel Energy electric 2010 rate case (10-971), the 2008 rate case (08-1065) and the 2005 rate case (05-1428), the Otter Tail Power 2007 rate case (07-1178), and many others beginning with the dawn of utility regulation in Minnesota. Indeed, in the 1975 Northern States Power rate case, the participation of MCC (then the St. Paul Chamber of Commerce) is described as follows:

> St. Paul Chamber of Commerce witness Wilson presented his analyses of the load on the NSP system, of a group of five residential feeders, a group of 48 St. Paul large C&I customers and 105 large C&I customers from the

[10] Pollock Direct at 66.
[11] Maini Direct at 16.

> total NSP system, and an analysis of system and class demand growth based upon kilowatt-hours and available data for the period July, 1972, through 1974. Based upon his analyses, he concluded that the large C&I customers have high load factors. He concluded that the contribution to the system peak of these customers is less than proportional to their average demand. He further concluded that these customers contribute more than proportionally to NSP's rate of return.[12]

After the Commission (then the Public Service Commission) rejected a rate design based on the MCC's representations, the MCC appealed the decision to the District Court which agreed with the MCC, but which decision was overturned by the Minnesota Supreme Court in the landmark case, *St. Paul Area Chamber of Commerce v. Minnesota Public Service Commission*, holding in oft-cited language:

> Once revenue requirements have been determined it remains to decide how, and from whom, the additional revenue is to be obtained. It is at this point that many countervailing considerations come into play. The commission may then balance factors such as cost of service, ability to pay, tax consequences, and ability to pass on increases in order to achieve a fair and reasonable allocation of the increase among consumer classes. This determination must result in rates which are "just and reasonable" and rates "shall not be unreasonably preferential, unreasonably prejudicial or discriminatory, but shall be sufficient, equitable and consistent in application to a class of consumers." Minn. St. 216B.03.[13]

Mr. Pollock's opinion that circumstances have changed in the last several decades and that non-cost factors should be now ignored has no bearing on existing law and what the above language directs the Commission to consider in designing rates.

Q. SHOULD THE COMMISSION CONSIDER OTHER NON-COST FACTORS WHEN DETERMINING THE REVENUE RESPONSIBILITY OF THE RESIDENTIAL CLASS

A. Yes. When determining class revenue responsibility, the Commission should consider the low-income Residential ratepayers' ability to pay, including, in particular, those who do

[12] *Re Northern States Power Co.*, 11 P.U.R.4th 385, Mn.P.U.C. 1975 (October 31, 1975).
[13] *St. Paul Area Chamber of Commerce v. Minnesota Public Service Commission*, 251 N.W.2d 350, 357 (Minn.1977).

not qualify or are just above the eligibility requirements of the affordability programs. Minnesota law expressly authorizes the Commission to consider low-income customers' ability to pay in establishing utility rates. Specifically, Minn. Stat. § 216B.16, subd. 15 states:

> Subd. 15. Low-income programs. (a) The Commission may consider ability to pay as a factor in setting utility rates and may establish programs for low-income residential ratepayers in order to ensure affordable, reliable, and continuous service to low-income utility customers.
>
> (b) The purpose of the low-income programs is to lower the percentage of income that low-income households devote to energy bills, to increase customer payments, and to lower the utility costs associated with customer account collection activities. In ordering low-income programs, the Commission may require public utilities to file program evaluations, including the coordination of other available low-income bill payment and conservation resources and the effect of the program on:
>
> (1) reducing the percentage of income that participating household devote to energy bills:
> (2) service disconnections; and
> (3) customer payment behavior, utility collection costs, arrearages, and bad debt.

Thus, in designing rates and establishing revenue allocation procedures, it is appropriate for the Commission to consider low-income customers' ability to pay. This is especially important to low-income customers who do not qualify for the affordability program and must pay the increased cost to support this program. In addition, Xcel's Residential ratepayers are unable to pass the high cost of their electric bills off to other parties through sales of their products or services and cannot take a tax deduction like business customers. The Commission should consider these non-cost factors when setting the revenue responsibility for the Residential customer class.

C. Minnesota Department Of Commerce

Q. Have You Reviewed The Testimony Of Minnesota Department Of Commerce ("DOC") Witness Dr. Samir Ouanes?

A. Yes. Dr. Ouanes recommends:

> First, the classification and allocation methods used by Xcel are generally reasonable and the Commission approved these methods in Xcel's previous rate cases. Second, the correction made to Xcel's CCOSS improves the precision of the revised CCOSS as it relates to the cost causation principle.[14]

The correction to which Dr. Ouanes refers in the above cite is DOC's recommendation that the Commission require the capacity portion of generation plant costs be allocated on the basis of the summer system coincident peak only, rather than a winter/summer coincident peak as proposed by Xcel.

Q. What Are The Results Of Dr. Ouanes' Recommended Change?

A. Dr. Ouanes' proposed change increased allocation from Xcel's proposed allocation by 0.42 percent ($4,469,000) and 0.21 percent ($240,000) for Residential and Small General Service customer classes, respectively. The increase to Residential and Small General Service customer classes results in a decrease to C&I and Lighting customer classes by 0.20 percent ($3,443,000) and 4.18 percent ($1,266,000).

Q. Do You Have Any Observations Regarding Dr. Ouanes' Recommendation?

A. Yes. I understand that the Commission has previously accepted Xcel's CCOSS method in the Company's previous rate case. I also recognize that the DOC is attempting to further refine Xcel's methodology to improve the precision of the CCOSS cost allocations. However, the effort to make any one CCOSS method more precise has

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[14] Ouanes Direct at 24.

limited value. Xcel's CCOSS, even as modified by the DOC, merely provides a rough estimate of cost, not a precise measure of the actual cost of service.

Q. **DO YOU HAVE ANY FURTHER OBSERVATIONS REGARDING THE DOC'S CCOSS TESTIMONY?**

A. Yes. Dr. Ouanes does not acknowledge the role of sales forecasts in the determination of cost allocation. As mentioned above, Xcel's CCOSS increases the cost allocation to the Residential and Small General Service customer classes due to loss of revenue from the plant closings by large C&I customers. The final, approved CCOSS in this case should reflect the changes in the final sales forecasts approved by the Commission. Department witness Adam Heinin recommends a new sales forecast which dramatically increases the revenue attributable to the Residential customer class. The impact of the new sales forecast on the CCOSS should be fully identified prior to the Commission's final decision.

D. SUMMARY OF THE OAG'S REBUTTAL TESTIMONY REGARDING CCOSS

Q. **PLEASE SUMMARIZE YOUR TESTIMONY REGARDING THE CCOSS TESTIMONY PRESENTED IN DIRECT TESTIMONY.**

A. MCC and XLI are proposing different CCOSS methods which predictably decrease the cost allocation to the C&I customer class, while dramatically increasing the costs allocated to Residential and Small General Service customer classes. The DOC recommends corrections to Xcel's proposed CCOSS to make it more precise. However, as noted in my Direct Testimony, the results of CCOSS models can vary significantly, and any single outcome cannot be relied upon as an accurate result.[15] CCOSS methods have basic limitations and present a false impression of precision. Xcel's CCOSS, even

[15] Chavez Direct at 6.

as modified by the DOC, merely provides a rough estimate of cost, not a precise measure of the actual cost of service. Basing rates entirely on costs derived from any one CCOSS method does not recognize the directives of the Minnesota Supreme Court, the Legislature, and the Commission to take non-cost factors into account when establishing the rate design.

IV. RATE DESIGN PROPOSALS PRESENTED IN DIRECT TESTIMONY

A. Apportionment of Revenue Responsibility

Q. Have Other Intervenors In This Proceeding Taken Positions Regarding The Apportionment Of Revenue Requirements?

A. Yes. MCC advocates for revenue apportionment equal to the CCOSS. Under the advice of counsel, XLI witness Pollock understands that the Commission is instructed by the Minnesota Supreme Court to consider "cost of service, ability to pay, tax consequences, ability to pass along cost increases",[16] but recommends that rates be solely based cost. The DOC recommends a "more moderate move toward cost at this time"[17] rather than Xcel's proposal, which is purportedly based on costs.

Q. Do You Have Any Observations Regarding MCC's And XLI Proposed Apportionment of Revenue Responsibility?

A. Yes. Both MCC and XLI propose basing rates entirely on costs derived from their selected CCOSS method, but both parties appear to dismiss the directives of the Minnesota Supreme Court, the Legislature, and the Commission to take non-cost factors into account when establishing the rate design as discussed above. In other words, cost is merely one factor and other factors must be considered in setting rates.

[16] Pollock Direct at 66.
[17] Peirce Direct at 6.

Q. DO YOU HAVE ANY OBSERVATIONS REGARDING DOC'S PROPOSED APPORTIONMENT OF REVENUE RESPONSIBILITY?

A. Yes. DOC witness Ms. Susan Peirce notes that Xcel's proposed increase "is the highest revenue increase the Company has ever proposed"[18] and that "this case is likely to result in rate shock to all customer classes." [19]

Q. WHAT ARE THE RESULTS OF THE DOC'S PROPOSED REVENUE APPORTIONMENT COMPARED TO THE CURRENT REVENUE APPORTIONMENT?

A. A comparison of the current revenue apportionment and DOC's revenue apportionment is shown below.

Rebuttal Table 1
Difference between Current and DOC's Proposed Revenue Apportionment

	Current Percent of Total Revenue	DOC's Percent of Total Revenue	% Revenue Apportionment Difference	% Rate Increase Difference from Xcel's Proposed Increase
Residential	35.90%	36.10%	0.20%	0.50%
Sm Gnrl Srvc	3.90%	3.90%	0.00%	0.10%
C&I Demand	59.21%	59.00%	-0.21%	-0.30%
Lighting	0.98%	1.00%	0.02%	1.90%
Total	100%	100.00%		

As shown above in Rebuttal Table 2, Ms. Peirce's recommended revenue apportionment increases the revenue responsibility from the current apportionment for the Residential customer class and decreases the revenue responsibility from current apportionment for the C&I and Lighting customer classes.

[18] Peirce Direct at 7.
[19] Peirce Direct at 7.

Q. HOW DOES THE DOC'S PROPOSED REVENUE APPORTIONMENT COMPARE TO XCEL'S PROPOSED REVENUE APPORTIONMENT AND THE CURRENT REVENUE APPORTIONMENT?

A. A comparison of the current, Xcel's proposed and DOC's revenue apportionment is illustrated below.

Rebuttal Table 2
Current, Xcel's Proposed, DOC's Proposed Revenue Apportionment

	Current		Xcel		DOC	
	Percent of Total Revenue	Percent Increase	Percent of Total Revenue	Percent Increase	Percent of Total Revenue	Percent Increase
Residential	35.90%	10.70%	36.21%	11.70%	36.10%	11.20%
Sm Gnl Srvc	3.90%	10.70%	3.90%	10.80%	3.90%	10.80%
C&I Demand	59.21%	10.70%	58.88%	10.10%	59.00%	10.40%
Lighting	0.98%	10.70%	1.00%	12.60%	1.00%	12.60%
Total	100%	10.70%	100.00%	10.70%	100.00%	10.70%

As shown above in Rebuttal Table 2, the DOC's recommend apportionment is higher for the Residential customer class than the current apportionment, but is lower than Xcel's proposed apportionment. Using figures from Xcel's initial petition, the DOC recommendation for the Residential customer class results in an increase of 11.20 percent, while Xcel's proposed apportionment results in an increase of 11.70 percent. At the same time, the DOC recommendation for the C&I customer class results in an increase of 10.40 percent, rather than an increase of 10.10 percent.

Q. HOW DOES THE DOC JUSTIFY THE RECOMMENDED CHANGES IN THE REVENUE APPORTIONMENT?

A. Ms. Peirce recommends that the Commission adopt the DOC revenue apportionment because it balances "the goal of moving toward cost to lessen the impact of inter-class subsidies with the goal of moderating the overall revenue increase experienced by each class. . . ."[20]

Q. WHAT IS YOUR RESPONSE TO THE DEPARTMENT'S JUSTIFICATION?

A. First, the best way to achieve the goal of moderating the overall revenue increase experienced by each class is to maintain the current revenue apportionment which has already been determined to be fair and reasonable by the Commission in Docket 10-971. Second, with respect to inter-class subsidies, both the Department's and Xcel's proposed CCOSS already shift costs to the Residential and Small General Service customer classes due to the loss of revenue from the plant closings of large C&I customers. It is unreasonable to continually attempt to move closer and closer to cost, when the Commission's revenue apportionment in Docket 10-971 for the Residential customer class is 100.1 percent. Even accepting that Xcel's CCOSS is "precise" and ignoring every other factor for setting rate design, Residential customers are paying more than 99 percent of their "costs." Residential customers have been and are currently paying their fair share; it is unfair that both Xcel and the DOC are now recommending an increase from the current revenue apportionment. I continue to recommend that the Commission maintain the currently approved revenue apportionment established in Docket 10-971 as a fair and reasonable allocation to customer classes.

[20] Peirce Direct at 8.

B. DOC's Proposed Residential Customer Charges

Q. PLEASE SUMMARIZE DOC'S PROPOSED CHANGES TO RESIDENTIAL CUSTOMER CHARGES.

A. The DOC proposes to increase its monthly customer charges for the Residential customer class. Rebuttal Table 3 below depicts both the present customer charges and the DOC's proposed customer charges:

Rebuttal Table 3
Present Customer Charges and DOC's Proposed Customer Charges

Service Category	Present Customer Charge	DOC's Proposed Customer Charge	Percent Increase from Present Customer Charge	Fixed Monthly Cost of Service	DOC's Proposed Customer Charge as Percent of Cost
Residential Overhead	$7.11	$8.50	19.54%	$17.35	48.99%
Residential Underground	$9.11	$10.50	15.26%	$17.44	60.20%

Q. WHAT IS DOC'S JUSTIFICATION TO INCREASE CUSTOMER CHARGES?

A. DOC states that its proposed Residential customer charge of $8.50 per month is comparable to other Minnesota utilities that received Commission approval to increase the Residential customer charge to $8.00 per month (Minnesota Power) and $8.50 per month (Otter Tail Power and Interstate Power). Ms. Peirce states that her recommendation "seeks to balance the impact that an increase in fixed customer charges has on customer or households with the impact of intra-class subsidies."[21]

Q. DO YOU AGREE THAT DOC'S PROPOSED CUSTOMER CHARGES ARE REASONABLE?

A. No, for two reasons.

[21] Peirce Direct at 11.

Q. PLEASE EXPLAIN THE FIRST REASON WHY THE DOC PROPOSED CUSTOMER CHARGES ARE UNREASONABLE.

A. DOC's proposed customer charges represent almost a 20 percent increase over current customer charges for the Residential customer classes. The DOC's proposed customer charge is less than Xcel's proposed Residential customer charge of $10.00, which represents a 40 percent increase over current customer charges for the Residential class. However, when compared to previous customer charges assessed to the Residential class, as shown page 14 of my Direct Testimony, an increase of such magnitude has only once been instituted by the Commission for Xcel's Residential customer charges. With one exception, DOC's proposed increase in the customer charge from $7.11 per month to $8.50 per month (or approximately 20 percent) is larger than the Xcel's prior Commission-approved Residential customer charges.[22] Moreover, an increase in the monthly increase in customer charge of approximately 20 percent will induce rate shock.

Q. HAS THE COMMISSION OR HAVE OTHER COMMISSIONS PREVIOUSLY RECOGNIZED THE IMPORTANCE OF RATE SHOCK?

A. Yes. The Commission has recognized the importance of a regulatory policy that favors rate stability and disfavors abrupt or significant changes to rates:

> Avoiding rate shock is a primary ratemaking goal, because sudden, drastic increases in energy costs can be burdensome for residential and non-residential customers alike. Avoiding rate shock is particularly important for residential ratepayers, however, because increases in the cost of basic needs can cause hardship for customers on low or fixed incomes.[23]

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[22] Chavez Direct, Table 4, at 14.

[23] FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER, *In the Matter of Application of Midwest Gas, a Division of Iowa Public Service Company, for Authority to Change its Schedule of Gas Rates for Retail Customers Within the State of Minnesota*, Docket No. G-010/GR-90-676 (July 12, 1991) at 35.

Additionally, rate shock is a utility common law concept.[24] Rate shock describes the subjective effect of sudden large rate increases on utility ratepayers. It is recognized by virtually every utility regulatory commission in the nation. A Westlaw search of the Public Utilities Reports and Federal Energy Regulatory Commission ("FERC") databases shows over 2,000 entries that refer to the term "rate shock," representing almost every state, FERC, as well as Manitoba and Ontario provinces.[25] Although the term is often used, it is not formally defined. The Minnesota Commission refers to rate shock as "sudden, drastic increases in energy costs."[26]

Q. PLEASE EXPLAIN THE SECOND REASON WHY THE DOC PROPOSED CUSTOMER CHARGES ARE UNREASONABLE.

A. As noted above, DOC witness Peirce's recommendation to increase customer charges attempts to mitigate the impact of intra-class subsidies.

Q. DO INTRA-CLASS SUBSIDIES MATTER?

A. Yes, to some extent. Intra-class subsidies can provide advantages to one set of consumers and disadvantages to another set of consumers. In this case, due to an associated, higher energy charge resulting from lower-than-cost customer charges, low-use consumers will be

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[24] Rate shock is also used in the context of insurance rates and interest rates, and is akin to such terms as "sticker shock."

[25] The term "rate shock" is used by the following commissions: FERC, Regulatory Commission of Alaska, Ariz.C.C., Ark.P.S.C., Cal.P.U.C., Colo.P.U.C., Conn.D.P.U.C., D.C. P.S.C., Del.P.S.C., Fla.P.S.C., Ga.P.S.C., Hawai'i P.U.C., Idaho P.U.C., Ill.C.C., Indiana U.R.C., Iowa U.B., Kan.S.C.C., Ky.P.S.C, Maine P.U.C., Mass.D.P.U., Md.P.S.C., Mich.P.S.C., Minn.P.U.C., Mo.P.S.C., N.C.U.C., N.H.P.U.C., N.J.B.P.U., N.M.P.S.C., N.Y.P.S.C., Nev.P.U.C., Ohio P.U.C., Okl.C.C., Or.P.U.C., Pa.P.U.C., R.I.P.U.C., S.C.P.S.C., Tenn.P.S.C., Tex.P.U.C., Utah P.S.C., Va.S.C.C., Vt.P.S.B., W.Va.P.S.C., Wash.U.T.C., Wisconsin P.S.C., Wyo.P.S.C., Ontario Energy Bd., and Manitoba P.U.C.

[26] FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER, *In the Matter of Application of Midwest Gas, a Division of Iowa Public Service Company, for Authority to Change its Schedule of Gas Rates for Retail Customers Within the State of Minnesota*, Docket No. G-010/GR-90-676 (July 12, 1991) at 35.

subsidized by higher-use consumers. However, to gain perspective, even if the customer charge were moved completely to Xcel's CCOSS indicated costs, it would still be true that higher (lower) use means higher (lower) bills.

Q. HAS THE COMMISSION PREVIOUSLY ADDRESSED LARGE INCREASES IN RESIDENTIAL CUSTOMER CHARGES?

A. Yes. As I noted in my Direct Testimony,[27] in its Order in Minnesota Power's 2008 rate case (Docket No. E015/GR-08-415), dated May 4, 2009, the Commission stated that it "is convinced that to adopt an increase in the customer charge to $10.00, as the Company proposed, not only would have a significant billing impact on low income customers, but on all residential customers."[28]

Q. HAS THE COMMISSION PREVIOUSLY REJECTED INCREASES TO RESIDENTIAL AND SMALL GENERAL SERVICE CUSTOMER CHARGES?

A. Yes. As I noted in my Direct Testimony,[29] in its 2009 rate case (Docket No. E015/GR-09-1511), Minnesota Power proposed a 60 percent increase in its Residential customer charges. In its Order, dated November 2, 2010, the Commission stated that it would:

> adopt the Administrative Law Judge's recommendation to maintain Residential customer charges at current levels. The Commission is reluctant to increase these charges. Customer charges do not vary with usage, and no amount of conservation permits a customer to reduce these costs -- short of disconnection. And given that the Company has only recently increased the Residential Basic customer charge by 60%, the Commission will decline to authorize another increase at this time.[30]

Similar to Minnesota Power's rate case, the Commission just recently allowed Xcel to increase its Residential and Small General Service customer charge by $1.00 on May 14,

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[27] Chavez Direct at 14.
[28] Commission Order in Docket No. E015/GR-08-15 at 71.
[29] Chavez Direct at 16.
[30] Commission's Order in Docket No. E015/GR-09-1511 at 61.

2012 in Docket 10-971. It is unfair to these customers to once again increase the customer charge.

Q. DO YOU WISH TO CHANGE YOUR RECOMMENDATION REGARDING RESIDENTIAL AND SMALL GENERAL SERVICE CUSTOMER CHARGES?

A. No. I continue to recommend that customer charges to Residential and Small General Service classes not be increased.

C. ENERGY CENTS COLLATION'S ("ECC") PROPOSED RESIDENTIAL INVERTED BLOCK RATE STRUCTURE

Q. HAVE YOU REVIEWED THE DIRECT TESTIMONY OF ECC WITNESS PAM MARSHALL REGARDING THE IMPLEMENTATION OF A RESIDENTIAL INVERTED BLOCK RATE ("IBR")?

A. Yes. Ms. Marshall introduces a five block IBR structure which, she purports, "promotes more affordable utility service for low and fixed income customers"[31] and "ensure[s] affordable energy costs and conservation."[32] Ms. Marshall recommends that the IBR structure be similar to Minnesota Power's IBR.

Q. WHAT IS YOUR RESPONSE TO ECC'S IBR RECOMMENDATION?

A. I oppose the implementation of ECC's recommended IBR structure for two primary reasons.

Q. PLEASE DISCUSS THE FIRST PRIMARY REASON FOR YOU OPPOSITION TO ECC'S RECOMMENDED IBR STRUCTURE.

A. In Docket No. G008/GR-08-1075 ("08-1075"), the Commission authorized CenterPoint to terminate the inverted block rate structure. In so authorizing the termination the Commission stated:

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[31] Marshall Direct at 21.
[32] Marshall Direct at 21.

> CenterPoint's inverted block rate design unexpectedly resulted in significantly increased bills for certain customers. Among the customers adversely effected were low-income customers in poorly-insulated homes, and renters in multi-unit buildings with only one gas meter. Other customers received higher than expected bills because their meters were not read punctually and their natural gas use during the extended billing period lifted them into a higher gas-price block.
>
> The unintended effects of the inverted block rate design on certain customers and the larger bills that were the result of elongated and uneven billing periods were contrary to the public interest. There does not appear to be a way to modify the inverted block rate structure that would be worth the cost to administer, would not result in even greater customer confusion, and would still deliver the intended benefits in a measurable way. Accordingly, this inverted block rate implementation cannot be reinstated.[33]

The Commission's Order followed an unprecedented number of customer complaints and CenterPoint's failure to show any correlation between its IBR and diligent conservation efforts and lower energy bills. In Docket 08-1075, every party that has submitted comments in this period has acknowledged that there were serious problems posed by the inverted block rates and elongated bills that remained unaddressed.

Q. PLEASE DISCUSS THE SECOND PRIMARY REASON FOR YOU OPPOSITION TO ECC'S RECOMMENDED IBR STRUCTURE.

A. In 2011, the public outcry regarding IBR structures prompted the 87th Minnesota Legislature:[34]

- To repeal Minn. Stat. 216B.242, which allowed the Commission to initiate a program designed to demonstrate the effect of inverted rates on promoting conservation by Residential customers of natural gas;

[33] Commission's *Order Terminating Inverted Block Rate Structure, Accepting Evaluation And Workgroup Reports, And Requiring Compliance Filings*, dated August 10, 2012 at 3,4.
[34] S.F. No. 1197, 3rd Engrossment - 87th Legislative Session (2011-2012) Posted on May 23, 2011.

- To strike language in Minn. Stat. 216B.16, subd. 15, which previously stated "Affordability programs may include inverted block rates in which lower energy prices are made available to lower usage customers[;]" and
- To strike language in Minn. Stat. 216B.2401 (Energy Conservation Policy Goal) which previously stated: "It is the energy policy of the state of Minnesota to achieve annual energy savings . . . through energy conservation improvement programs and rate design, such as inverted block rates in which lower energy prices are made available to lower-usage residential customers . . . ."

The Minnesota Legislature's modification demonstrates that the people in the state of Minnesota should no longer be subjected to IBR structures and all references to such structures have been stricken from Minnesota law.

Q. DO YOU HAVE ANY FURTHER DISCUSSION REGARDING YOUR OPPOSITION TO ECC'S PROPOSED IBR STRUCTURE?

A. Yes. The two reasons, discussed above, are just the first of many reasons for opposing ECC's proposed IBR structure. During workshops held and as presented in the IBR Modification Workgroup Report ("*Workshop Report*") in Docket No. G008/GR-08-1075, dated March 1, 2012, the parties conducted in-depth discussions regarding such issues as customer exemptions ("opt-outs"), effectiveness in promoting conservation, impacts on low-income households, and the cost feasibility of administration and customer acceptance.[35] In its *Comments* in response to the *Workshop Report*, the OAG addressed a number of concerns specific to opt-outs and concluded:

[35] IBR Modification Workgroup Report in Docket No. G008/GR-08-1075, dated March 1, 2012, included as Rebuttal Schedule VCC-2.

> Due to a myriad of unfair and unintended consequences, IBR has already been suspended. The parties have met to discuss possible improvements to the IBR program, but have not reached consensus. In fact, after trying to tackle the problems associated with IBR head-on, the only proposal is a system of *opt-outs* which, for the reasons discussed above, results in an ineffectual IBR program, increase in customer confusion, higher rates, additional complexities and unfair and unintended results. The proposed "solution" may be worse than the first attempt.[36]
> (Emphasis added.)

After the workshop was concluded, CenterPoint did not propose to reinstate a modified IBR program "based on the information developed in the workgroup process." [37] The Commission ultimately terminated the IBR structure on August 1, 2012.

Q. WHAT IS YOUR RECOMMENDATION TO THE IMPLEMENTATION OF AN IBR STRUCTURE IN THIS CASE?

A. The CenterPoint IBR pilot has shown unintended and undesirable consequences for certain customers without any evidence that the inverted block rate promotes energy conservation. ECC's proposal does not address or provide solutions to the full array of issues and problems presented in the *Report* and as brought forth in the by the OAG in its *Comments.* Residential consumers do not need yet another IBR pilot program to further determine whether or not IBR structures are in the public interest. I recommend that the Commission reject ECC's proposed IBR structure.

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[36] *Response of the Office of the Attorney General to the IBR modification Workgroup Report and CenterPoint's Revenue Decoupling and Inverted Block Rate Evaluation Report ("Response"),* dated April 2, 2012 at 13. The Response is included as Rebuttal Schedule VCC-3.

[37] IBR Modification Workgroup Report in Docket No. G008/GR-08-1075, dated March 1, 2012, at 16.

V. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY AND RECOMMENDATIONS REGARDING CCOSS MODIFICATIONS PRESENTED IN THE DIRECT TESTIMONY OF MCC, XLI AND THE DOC?

A. In Direct Testimony, both MCC and XLI provide proposed CCOSS models, which are proposed for use as the sole determinant in apportioning revenue responsibility. Both MCC's and XLI's CCOSS models propose to increase the allocated costs to the Residential and Small General Service customer classes. The strict application of MCC's CCOSS as the sole basis to determine rates results in an 18.00 percent increase in rates for Residential customer, which will inflict rate shock. Xcel's proposed cost allocation already shifts costs to other customer classes due to the loss of revenue from the plant closures of Large C&I customers. Both the MCC's and XLI's CCOSS predictably favor only their constituents. I recommend that the Commission reject the CCOSS methods proposed by MCC and XLI.

With respect to the DOC's Direct testimony on CCOSS, the DOC recommends modification to further refine Xcel's CCOSS methodology and to improve the precision of the CCOSS cost allocations. However, the effort to make any one CCOSS method more precise has limited value. Xcel's CCOSS, even as modified by the DOC, merely provides a rough estimate of cost, not a precise measure of the actual cost of service. Additionally, the DOC does not acknowledge that its forecasting witness, Mr. Heinen, recommends a new sales forecast which dramatically increases the revenue attributable to the Residential customer class. The impact of the new sales forecast on the CCOSS has not been provided. I recommend that the impacts of the DOC's new sales on Xcel's proposed CCOSS be fully identified prior to the Commission's final decision.

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY AND RECOMMENDATIONS WITH RESPECT TO THE DOC'S REVENUE APPORTIONMENT AND RESIDENTIAL CUSTOMER CHARGE AS PROPOSED BY THE DOC.

A. The DOC recommends a revenue apportionment and a Residential customer charge, that it considers to be a moderate movement towards cost-based rates. However, the best way to achieve the goal of moderating increases experienced by each customer class is to maintain the current revenue apportionment which has already been determined to be fair and reasonable by the Commission in Docket 10-971. I recommend that the Commission maintain the current revenue apportionment and current customer charges for the Residential and Small General Service customer classes as established in Docket 10-971.

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY AND RECOMMENDATIONS TO ECC'S PROPOSED IBR STRUCTURE.

ECC's proposal did not address or provide solutions to the full array of issues presented in the IBR *Workshop Report* and as brought forth in the by the OAG in its *Comments* in Docket 08-971. Residential consumers do not need to be subjected to another IBR pilot experiment to show whether or not IBR structures are in the public interest. I recommend that the Commission reject ECC's proposed IBR structure.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Xcel Rate Case Rebuttal Testimony

CCOSS, Revenue Apportionment and Rate Design Exhibits

Table of Contents

VCC-1	Xcel's response to OAG IR 109
VCC-2	March 1, 2012 IBR Modification Workgroup Report in Docket No. G008/GR-08-1075, dated
VCC-3	April 2, 2012 *Response of the Office of the Attorney General to the IBR modification Workgroup Report and CenterPoint's Revenue Decoupling and Inverted Block Rate Evaluation Report*

☐ **Non Public Document – Contains Trade Secret Data**
☐ **Public Document – Trade Secret Data Excised**
☒ **Public Document**

Xcel Energy			
Docket No.:	E002/GR-12-961		
Response To:	Office of the Attorney General	Information Request	109
Requestor:	Ron Giteck		
Date Received:	March 8, 2013		

Question:

For all responses show amounts for Total Company and the Minnesota jurisdictional electric company unless indicated otherwise. Total Company is meant to include costs incurred by Xcel Energy Services and NSP Minnesota, both regulated and non-regulated operations.

Provide the revenue requirement and class cost allocation impact of losing the large C&I Demand customers Ford and Verso Paper individual and collectively.

Response:

The Company has not prepared jurisdictional and class cost studies forecast year 2013 with the hypothetical assumption of including the two customers specified in a question, because those loads have been permanently lost due to plant closures. Therefore, an estimated revenue requirement and class cost allocation impact is not available. However, with the exception of both local costs that are directly assigned and directly variable costs such as fuel and purchased power, the remaining fixed costs do not change and continue to have the same revenue requirement after the loss of a customer loads. In isolation, if a customer load reduction is limited to a single class, the class cost allocation impact would be to increase the revenue requirement of the other classes.

Witness:	Steven V. Huso
Preparer:	Steven V. Huso
Title:	Pricing Consultant
Department:	Regulatory Analysis
Telephone:	612-330-2944
Date:	March 12, 2013

CenterPoint Energy

800 LaSalle Avenue
P.O. Box 59038
Minneapolis, MN 55459-0038

March 1, 2012

Dr. Burl Haar, Executive Secretary
Minnesota Public Utilities Commission
121 East 7th Place, suite 350
St. Paul, MN 55101

Re: In the Matter of an Application by CenterPoint Energy for Authority to Increase Natural Gas Rates in Minnesota; Docket No. G-008/GR-08-1075

Dear Dr. Haar:

Pursuant to the Minnesota Public Utilities Commission's October 4, 2011 Order in the above-referenced docket, CenterPoint Energy hereby files the Report of the IBR Modification Workgroup.

Please contact me if you have any questions.

Sincerely,

/s/

Adam Pyles
CenterPoint Energy
Director, Regulatory Activities
(612) 321-4719

Enclosure
C: Service List

AFFIDAVIT OF SERVICE
G-008/GR-08-1075

STATE OF MINNESOTA)
) ss.
COUNTY OF HENNEPIN)

Marie M. Doyle, being first duly sworn on oath, deposes and says she served or caused to be served on behalf of CenterPoint Energy this IBR Workgroup Report.

- Electronic filing using the EDockets system for service to the Minnesota Public Utilities Commission, the Department of Commerce, Division of Energy Resources; and on the Minnesota Office of the Attorney General; and
- Paper copy on persons on the enclosed service list who so requested, by delivering by hand at the respective addresses on the list or by placing in the U.S. Mail at the City of Minneapolis.

/s/ Marie Doyle
Marie M. Doyle, Tariffs Administrator
Regulatory Services
CenterPoint Energy

Subscribed and sworn to before me
this 1st Day of March, 2012

/s/ Linda Bauman
Notary Public
Term expires: 1/31/15

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Rebuttal Schedule
VCC-2, pg. 5

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STATE OF MINNESOTA

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Phyllis Reha	Vice-Chair
David Boyd	Commissioner
J. Dennis O'Brien	Commissioner
Betsy Wergin	Commissioner

In the Matter of an Application by CenterPoint Energy for Authority to Increase Natural Gas Rates in Minnesota

Docket No. G-008/GR-08-1075

IBR MODIFICATION WORKGROUP REPORT

I. Procedural Background

On January 11, 2010, the Commission issued its Order approving, among other things, an Inverted Block Rate (IBR) pricing structure to be charged to CenterPoint Energy's residential and small commercial firm sales service customers. Under this structure, the unit price of gas increased as consumption increased across five consumption blocks. This pricing structure was approved as a three-year pilot program.

On June 1, 2011, the Minnesota Office of the Attorney General (OAG) requested that the Commission suspend the IBR pricing structure. The Minnesota Department of Commerce (Department), the Suburban Rate Authority (SRA), and Community Action Minneapolis (CAM) filed comments supporting suspension of IBR. Through the comments of parties, and public comments filed with the Commission, a variety of practical challenges and unintended hardships affecting various customer groups were identified. On September 16, 2011, CenterPoint Energy (CenterPoint or Company), along with the Energy CENTS Coalition (ECC), Minnesota Center for Environmental Advocacy (MCEA), and the Izaak Walton League of America (IWLA), petitioned to suspend IBR and to convene a workgroup to discuss a new rate design.

On October 4, 2011, the Commission issued its Order which, among other things, ordered the suspension of IBR and authorized the creation of a workgroup to address "whether and how to revise the inverted block rate program". The Order identified a number of possible revisions for the workgroup's consideration. The workgroup was directed to file its report and recommendations no later than March 1, 2012. This filing is the report of the workgroup.

II. Workgroup Activity

In response to the October 4, 2011 Order, CenterPoint contacted the parties that participated in the petition to suspend IBR and solicited their participation in a workgroup to discuss possible modifications to IBR. The following organizations were contacted and each participated in the workgroup: CAM, the Department, ECC, MCEA, OAG, IWLA, and SRA.

The members of the workgroup represented a diverse range of opinions about IBR and related issues. The workgroup focused its efforts on limiting or eliminating the practical challenges and unintended hardships of IBR rather than re-arguing the original points in favor, or not in favor, of IBR. The group acknowledged that consensus on all points might not be possible.

The workgroup met once in December, once in January and once in February to discuss possible modifications to IBR and had various other interactions by correspondence, telephone, and conference call. The workgroup drafted its report in February for submission on March 1, 2012.

III. Discussions of Modifications to the IBR

The workgroup had wide-ranging discussions about IBR including policy, operational, and technical considerations as well as program goals, customer impacts, customer communication, program evaluation and measurement of results. The general points raised in those discussions are described below.

As stated in CenterPoint's tariff, the goals of the original IBR pricing structure were "to lessen the financial burden on low-use customers and to encourage conservation by high-use customers".[1] The identified customer impacts of IBR

[1] Company tariff, Original Page 27.a.

include the magnitude and extent of bill increases for high-use customers or bill decreases for low-use customers, the potential inability of various customer groups to take some or any actions to increase conservation in response to IBR price signals, the bill impacts of longer billing periods under IBR[2], and the perception of fairness or appropriateness of IBR. The workgroup discussed various factors affecting these issues, including the importance of customer acceptance of IBR. Acceptance could be increased by improved customer understanding of IBR through more effective customer communications.

Finally, the group discussed the importance of measurement and evaluation of the impact of IBR on conservation (or affordability). Whether IBR was (or a modified IBR could be) effective at promoting conservation is an important consideration in deciding whether IBR should continue. Equally important is the feasibility of administering a modified IBR in a manner that does not create undue customer confusion or widespread lack of customer acceptance, or that materially increases operating costs. All of these points formed a background against which the subsequent discussions were considered.

With these considerations in mind, the workgroup took up the set of possible program modifications identified in the October 4, 2011 Order. These modifications generally fell into two categories: IBR exemptions for certain customer groups or billing modifications for longer billing periods.

A. Potential IBR Exemption Categories and Administration of Exemptions

Regarding possible IBR exemptions for certain customer groups, the Company attempted to describe what activities would be required to administer exemptions for each identified customer group. These activities included eligibility; applications for, renewal of, and termination of exemption; customer notification; and various internal processes required to bill some customers on an IBR pricing structure and some customers on a flat-rate gas cost pricing structure. The Company also attempted to estimate the potential number of customers that might be eligible and might seek exemption as well as the cost to implement and administer the various exemptions.[3] A detailed description of these activities is

[2] The Company stated that longer billing periods will continue to occur in the future, for some customers, given the currect state of gas operations and metering technology.

[3] The Company estimated the number of customers that might seek exemption based on various assumptions including extrapolations of known data and assumptions about participation rates. More detail about the assumptions is provided in Attachment A. All costs are order-of-magnitude estimates and could vary significantly depending on specific details of the administrative and IT processes that would be required.

included as Attachment A and a summary of each exemption category follows below.

1. Customers with medical conditions requiring additional energy usage

Some customers require a higher temperature in their home for medical reasons These customers may be restricted in their opportunity to conserve energy (e.g., lower the thermostat) and there is an argument they should therefore be exempt from IBR. On the other hand, some of these customers may be able take other steps to conserve energy that do not require a reduction of temperature in their home (e.g., furnace replacement or increased insulation).

The Company has no way of knowing which customers may be in this category. Consequently, the Company would rely on self-declaration to identify customers in this group. The workgroup discussed the idea of requiring a medical doctor's certification that higher temperatures were required for a given customer, but this was deemed impractical due to the subjective and potentially burdensome nature of the request. It would also introduce another layer of administration by the Company. Therefore, the workgroup concluded there should be no verification process other than a customer request.

Such an IBR exemption would be effective with the next monthly bill and be effective until the following June 30th. Customers would renew their exemption annually. The end-date of June 30th was chosen in an attempt to align the IBR exemption period with the annual gas cost period (July 1 through June 30).

As a way to estimate the possible number of customers that might be exempted from IBR in this category, the Company used census data about the percentage of the population over 65 years of age as a proxy. The Company then made assumptions about the percentage of those customers that might face higher bills under IBR and the percentage of those customers that might apply for the IBR exemption. In the end, the Company estimated about 11,000 customers in this category might be exempted.[4] To administer the exemption for this group of customers, the Company estimated cost of about $69,000 for the first year and about $23,000 per year thereafter.

[4] The Company estimated the number of customers that might seek exemption based on various assumptions including extrapolations of known data and assumptions about participation rates. More detail about the assumptions is provided in Attachment A. All costs are order-of-magnitude estimates and could vary significantly depending on specific details of the administrative and IT processes that would be required.

2. Customers in multi-unit housing served by a single meter

Some customers with multi-unit properties served by a single meter may have high consumption on a per-meter basis, but average or low consumption on a per-unit or per-household basis. Since the utility account is established at the meter level and not the unit or person level, the aggregated consumption of two, three, or more households is applied to the IBR pricing structure and may result in consumption being billed in the higher priced blocks of IBR when, in fact, the per-unit consumption may be average or below average.

One possible modification to accommodate this condition would be to increase the size of the IBR blocks based on the number of units in the property. This was deemed impractical by the Company due to the complexity of building and maintaining such capability and data in its billing system. In addition, the dynamic nature of unit vacancy, sub-dividing into more units, and combining into fewer units made the Company deem this approach infeasible. Instead, the workgroup discussed an IBR exemption for this group of customers.

The Company has no way of knowing which customers may be in this category. Consequently, the Company would rely on self-declaration to identify customers in this group. Absent a physical property inspection, there is no practical way for the Company to verify the number of units in a given property. Therefore, there would be no verification.

The application for IBR exemption would be received year-round, but would be held for annual processing and would be effective the next July 1 and be effective until the following June 30th. Customers would renew their exemption every three years. The three-year exemption period was chosen to reflect the fact that properties change over time and the multi-unit condition may not permanent.

As a way to estimate the possible number of customers that might be exempted from IBR in this category, the Company used a report from the City of Minneapolis that indicated the approximate number of duplex, triplex, and four-plex properties in the city. The Company then made assumptions about the percentage of those properties that might be served by a single meter and the number of similar properties in other parts of its service territory. In the end, the Company estimated about 7,500 customers might be exempted in this category. To administer the exemption for this group of customers, the Company estimated about $47,000 in costs for the first year and about $16,000 per year thereafter.

3. Certain renters

Some customers residing in rental properties may be prohibited by their lease from making energy conservation investments that affect the physical structure of the property and equipment (e.g., replacing windows or furnaces or installing programmable thermostats). These customers may have less opportunity to conserve energy than do other customers and there is an argument they should therefore be exempt from IBR. On the other hand, renters may be able to take other conservation steps such as lowering the thermostat and using window coverings to reduce heat loss. The Company is unclear which customers within the renter category might be deemed eligible for an IBR exemption.

Again, the Company has no way of knowing which customers may be in this category. Consequently, the Company would rely on self-declaration to identify customers in this group. The Company could require customers to request the IBR exemption and then require landlords or property managers to verify that the customer resides in a rental property and is prohibited from altering the physical structure or its appliances. Alternatively, landlords or property managers could request the IBR exemption on behalf of all customers in their buildings.

The application for IBR exemption would be received year-round, but would be held for annual processing and would be effective the next July 1 until the following June 30th. Customers or landlords would renew their exemption every three years. The three-year exemption period was chosen to reflect the fact that properties change over time and the rental status of the property may not permanent.

The Company attempts to gather information about which of the properties it serves are rental properties, but this information may not be complete or current. Nonetheless, as of September 2011, the Company had record of about 109,000 rental residential accounts and about 24,000 rental commercial accounts. Given the uncertainty about which customers within the renter category might be deemed eligible for an IBR exemption, the Company did not attempt to estimate the possible number of customers that might be exempted from IBR in this category or the cost of administering the exemption for this group of customers.

4. Customers receiving Low Income Heating Assistance Program (LIHEAP) support or otherwise demonstrating low income

Customers with low incomes may be unable to make investments in capital improvements that could reduce energy usage (e.g., replacing windows or furnaces or installing programmable thermostats). These customers may have less opportunity to conserve energy than do other customers and there is an argument they should therefore be exempt from IBR.

For LIHEAP recipients, the Company could use the receipt of LIHEAP payments as the event triggering the IBR exemption and those customers would not need to request an IBR exemption. The Company has no way of knowing which customers may be low-income but do not receive LIHEAP. Consequently, the Company would rely on self-declaration to identify customers in this group. The Company has existing processes for verifying such information that it uses during the Cold Weather Rule period. These same processes could be extended to administer the IBR exemption request verification.

As with the exemption for medical conditions, the IBR exemption would be effective with the next monthly bill and be effective until the following June 30th. Customers would renew their exemption annually.

As a way to estimate the possible number of customers that might be exempted from IBR in this category, the Company reviewed the number of LIHEAP recipients in the 2010-2011 LIHEAP year (about 41,000) and the number of self-declared low-income customers not receiving LIHEAP in the 2010-2011 LIHEAP period (about 6,300). The Company then assumed that about half of the self-declared low-income customers not receiving LIHEAP might apply for the IBR exemption. In the end, the Company estimated about 43,200 customers might be exempted in this category. To administer the exemption for this group of customers, the Company estimated about $20,000 in costs for the first year and about $7,000 per year thereafter. The Company would incur additional costs to modify its information technology (IT) systems to allow for the automatic triggering of an IBR exemption upon receipt of a LIHEAP payment. Those costs are included in IT costs in the summary below.

5. <u>Customers who have made alternative efforts at energy conservation or participated in conservation programs</u>

Some customers have already made energy conservation efforts (e.g., replacing windows or furnaces or installing programmable thermostats or more insulation). These customers may have less opportunity to conserve energy than do other customers because their energy usage already reflects conservation efforts. There is an argument they should, therefore, be exempt from IBR.

The Company considered using information about which customers participated in Company CIP programs in the past as a basis for identifying customers in this category. Since not all customers that have already made conservation efforts would have also participated in Company CIP programs, this approach was considered unduly restrictive and was discarded. As a result, the Company has no way of knowing which customers may be in this category. Consequently, the Company would rely on self-declaration to identify customers in this group. Absent a physical property inspection, there is no practical way for the Company to verify whether the customer has already made conservation efforts (e.g., furnace of a particular AFUE rating). Therefore, there would be no verification.

The application for IBR exemption would be received year-round, but would be held for annual processing and would be effective with the next July 1 and be effective until the following June 30th. Customers would renew their exemption every three years. The three year exemption period was chosen to reflect the fact that properties change over time and the energy conservation status of the property may not permanent.

As a way to estimate the possible number of customers in this category that might be exempted from IBR, the Company made assumptions about the number of customers that might have already made conservation efforts and the percentage of those customers that might face higher bills under IBR and the percentage of those customers that might apply for the IBR exemption. In the end, the Company estimated about 7,300 customers might be exempted in this category. To administer the exemption for this group of customers, the Company estimated about $46,000 in costs for the first year and about $15,000 per year thereafter.

<u>6. Other customer groups for whom IBR exemptions might be appropriate</u>

Through the course of workgroup discussions, additional groups that might be exempt from IBR were identified and discussed. These groups included: customers with large families (that may use low amounts of energy per person but higher amounts in total), customers that work from home or otherwise spend large portions of the day at home, and senior citizens on fixed income. The issues and process for customers with large families would be similar to the multi-unit housing served by a single meter category. The Company estimated about 18,300 customers might be exempted in this category and the first-year costs to be about $114,000 with subsequent year costs of about $38,000.

The customers that work from home (or that are home due to unemployment) presumably require a higher amount of energy than customers that are not at home during the day and there is an argument they should, therefore, be exempt from IBR. The Company estimated about 7,300 customers in this category might be exempted and the first-year costs to be about $46,000 with subsequent year costs of about $15,000.

Customers that are senior citizens on a fixed income arguably can't afford to pay higher bills under IBR if they are higher usage customers or may not be able to afford to make investments in capital improvements that could reduce energy usage. Presumably these customers would also be eligible for an IBR exemption under the low-income customer group. The Company did not attempt to estimate the number of customers in or the cost to administer this sub-category.

<u>7. Company administration of IBR exemptions</u>

Certain Company actions would be required to support the process of administering IBR exemptions for one or all customer groups. These include: modifications to IT systems, increased activity required to maintain information in the billing system, increased activity for internal control purposes, increased reporting requirements, and increased customer service and customer communication activity. The workgroup discussed the importance of customer acceptance of any modified IBR and the role of customer communications in increasing such acceptance. The discussions did not, however, identify significant new communication tactics that could be employed to improve the overall level of understanding and acceptance of a modified IBR by large numbers of customers.

The table below summarizes the estimated number of exempt customers and the costs to administer IBR exemptions.

Customer Group or Cost Activity	Year one cost	Subsequent annual cost	Estimated number of customers exempt from IBR
Medical conditions	$69,000	$23,000	11,000
Multi-unit/ single meter	$47,000	$16,000	7,500
Certain renters	Not estimated	Not estimated	Not estimated
LIHEAP and other low-income	$20,000	$7,000	43,200
Customers that have already conserved	$46,000	$15,000	7,300
Large families	$114,000	$38,000	18,300
Customers at-home	$46,000	$15,000	7,300
IT costs	$100,000	$10,000	
Internal controls	$50,000	$50,000	
Customer service	$15,000	$15,000	
Customer communication	$50,000-$100,000	$50,000- $100,000	
Total	**$557,000 - $607,000**	**$239,000 - $289,000**	**94,600**

B. Modifications to Accommodate Length of Billing Period Under IBR

Under the IBR pricing structure, the total consumption during the billing period is applied to the IBR rate blocks. Longer billing periods increase the total consumption and can increase the usage charged in higher-priced rate blocks. Customers may have higher total bills in these situations if the consumption for the days of the longer billing period is billed at a rate higher than it would have absent a longer billing period. This issue has been discussed in previous filings in this docket and in the Commission's November 8, 2011 Order. Since longer billing periods would occur under a modified IBR, and in response to the Commission's October 4, 2011 Order, the workgroup discussed this issue briefly.

1. Bill adjustments for length of billing period

CenterPoint indicated that longer billing periods will continue to occur in the future given the current state of metering technology and it would not be possible to ensure that billing periods would be limited to a specific length such as 30 days either through metering operations or billing system changes. Instead, the Company stated that under a modified IBR, it could adjust customer bills for the length of billing period using the calculation method described in its proposal for bill adjustments filed with the Commission on December 7, 2011.[5] Incorporating this adjustment as an ongoing part of the monthly bill calculation would also require displaying an additional line of information on the IBR customer's bill to show any credit for IBR premiums charged on estimated usage after day 35 of the billing period.

2. Daily rather than monthly customer charges

The Company stated that under a modified IBR, it would continue to pro-rate customer charges as it has done under its current tariff. In other words, the customer charge would be prorated on a daily basis for billing periods longer than 35 days and shorter than 25 days. The pro-ration of customer charges occurs whether or not a modified IBR is in place.

IV. Effectiveness of IBR and Possible Modifications

The Commission's October 4, 2011 Order authorized the workgroup to address "whether and how to revise the inverted block rate program". The workgroup discussions about whether to revise IBR centered mainly on the effectiveness of IBR in achieving its stated goals, the possible modifications to address the unintended consequences of IBR, and whether administration of a modified IBR would be feasible.

The effectiveness of IBR in achieving its goals could be assessed by understanding whether IBR lessened the cost of natural gas for low-use customers and whether it encouraged conservation by high-use customers.

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[5] On February 23, 2012, the Commission decided that bill adjustments should be made using the calculation method generally proposed by the Company in its December 7, 2011 filing, but for customers with billing periods longer than 32 days. Under a modified IBR, the Company could incorporate an adjustment mechanism similar to the one adopted by the February 23, 2012 Commision decision, however the Commission has not yet issued its order and the Company could revise its position depending on the specific language of the order.

A. Impact of IBR on Annual Cost for Low-Use Customers and Monthly Cost for All Customers

The consumption and price levels for each of the IBR blocks were designed in such a way that low-use customers would be billed less for gas costs under IBR than they would under flat rates.

To test whether the actual results were consistent with the design of IBR, the Company analyzed a random sample of 490 residential customers to see whether low-use customers were billed less under IBR.[6] Based on discussions in the workgroup, the Company included the effect of the IBR true-up in its analysis. (The group noted that the rate effects of IBR needed to include not only the rates charged in one year but also the IBR true-up factor in the following year; a positive IBR true-up factor would increase the amount billed to customers and reduce the savings from IBR compared to flat-rates.) The results of this analysis showed about 99.5% of customers with twelve-month usage less than 800 therms were billed the same or less under IBR than they would have been billed under flat rates.[7] This result supports the conclusion that IBR lessened the financial burden on low-use customers.[8]

The table below shows the results of this analysis.

Twelve month usage	Percent billed same or less	Percent billed more	Total	Percent of sample
0-799	99.5	0.5	100.0	41.4
800-999	92.1	7.9	100.0	23.3
1000-1199	46.5	53.5	100.0	14.5
1200-1399	4.1	95.9	100.0	10.0
1400+	0	100.0	100.0	10.8
Total				100.0

While it's possible that individual low-use customers could have paid more under IBR than under flat-rates if they had an atypical monthly usage pattern (e.g., all consumption in December-February and no consumption in other months) and

[6] Other members of the workgroup were not involved in this analysis.

[7] This analysis does not consider the impacts of the Commission's February 23, 2012 decision to require bill credits for some IBR customers that were billed for longer billing periods. The decision also allowed for recovery of the total bill credits from all IBR customers in the 2013 gas cost true-up. These impacts could change the percent of customers that were billed the same or less under IBR.

[8] The sample average consumption was 938 therms and the median consumption was 864 therms. While there is no specific definition of low-use customers, customers using 800 therms would have used about 15% less than the average and about 7% less than the median.

it's possible that a different sample or analysis could produce a slightly different set of numbers, the Company believes that IBR lowers the bills of low-use customers.

Another way to examine the impact of IBR on customers is to determine the percentage of customers that were billed more or less under IBR regardless of usage. Some workgroup members believed it is important to understand these impacts on a monthly basis. Using the same sample of residential customers discussed above, the Company computed the percentage of customers that were billed more or less under IBR by month.[9] This shows that from about 40% to about 70% of customers paid more under IBR in the winter months of December through March and about 99% of customers paid the same or less in the months of May through November. Based on the design of IBR consumption blocks and price levels, under normal weather conditions, the Company expected about 78% of residential customers would pay the same or less on an annual basis under IBR compared to flat-rates. On a twelve-month basis, about 70% of customers in the residential data sample paid the same or less under IBR.[10] The table below shows the results of this analysis.

Month	**Percent billed same or less**	**Percent billed more**	**Total**
May 2010 *	99.6	0.4	100.0
June *	99.2	0.8	100.0
July	99.2	0.8	100.0
August	99.4	0.6	100.0
September	99.2	0.8	100.0
October	99.8	0.2	100.0
November	98.8	1.2	100.0
December	58.0	42.0	100.0
January 2011	30.8	69.2	100.0
February	39.2	60.8	100.0
March	54.7	45.3	100.0
April	85.5	14.5	100.0
May – April	69.8	30.2	100.0

* IBR was not in place in May and June 2010, but these months were used as proxies when the data for this analysis was collected in May 2011.

[9] Footnote 7 also applies to this analysis.
[10] The November 2010 – March 2011 period was 5.9% colder than the 20 year average of heating degree days. This may have contributed to higher usage in the upper blocks of IBR thereby lowering the percentage of customers that were billed less under IBR.

B. Impact of IBR on Conservation by High-Use Customers

IBR was intended to send price signals to high-use customers in order to induce those customers to reduce their natural gas usage. The workgroup held considerable discussion about what was known, or may become known, about the effect of IBR on conservation.

At this time, the impact of IBR on conservation by high usage customers is not known and may not be known in the near future. The 2010 decoupling and IBR evaluation report, filed in March 2011 and supplemented in May 2011, included six months of data under IBR and was inconclusive as to the effect of IBR on conservation.

As to whether the impact of IBR on conservation may be known in the future, the 2011 decoupling and IBR evaluation report will be filed March 1, 2012 and will include data from the months IBR was in place, January through mid-October 2011. That report may include information that is helpful in understanding whether IBR contributed to conservation, however it may not be conclusive. If it is correct that the customer groups identified for possible IBR exemption, in fact, were unable to reduce energy use due to physical or economic conditions and if those customers account for a significant number of high-use customers, then the impact of IBR on conservation may be difficult to detect. Some members identified difficulties in measuring the precise effects of IBR on conservation more generally since key data to perform certain statistical tests is not and will not be available. The workgroup discussed the possibility that data on inverted block rate designs from other parts of the country could provide some information about possible impacts on conservation, however no closely-comparable programs were identified.

C. Feasibility of IBR Modifications

As previously mentioned, through the comments of parties and customers, a variety of unintended consequences of IBR were identified. These consequences highlighted the fact that the members of the residential and small business classes of customers are not homogenous in their ability to adjust their energy usage in response to the price signals provided by IBR. This lack of homogeneity is reflected in differences in health, economic situation, housing arrangement and autonomy of control in natural gas usage and led to the unintended consequences of IBR.

The possible modifications to IBR described in section III, above, were developed to address, to the extent possible, the unintended consequences identified in the Commission's Order as well as others raised by some stakeholders. The exemption process for customer categories discussed above would allow certain customers to be exempt from IBR and introduce a bill adjustment mechanism that could prevent higher bills under IBR dues to longer billing periods.

The workgroup considered several issues when discussing whether the IBR modifications would be feasible and effective. These issues included: the complexity of administering the modifications, whether all identified modifications would be necessary, the cost to implement a modified IBR, and customer acceptance of a modified IBR.

The activities required to support the potential IBR modifications described above would result in increased complexity in billing, gas cost recovery true-up calculations, and customer service. The complexity of customer billing operations would increase by billing two separate sets of rates within the affected rate classes. Gas cost recovery calculations complexity would increase by the need to perform separate gas cost true-up calculations for costs recovered under IBR and under flat-rates. The complexity of customer service interactions would increase by requiring the customer service representative to explain the IBR exemption process.

The Company would incur additional costs to support these activities. These would include costs to change and maintain information systems and additional operations expense for IBR exemption request and renewal processing, the billing controls function, and customer service. In future rate cases, the Company would seek to recover these increased costs in base rates to be paid by all customers.

The workgroup discussed whether all of the possible IBR modifications would be necessary and whether the IBR modifications could create their own unintended consequences. Some members of the workgroup believed that addressing fewer than all of the identified categories, such as the exemptions for medical conditions and multi-unit/single meter categories, was a worthwhile step forward for a modified IBR. Other members of the workgroup believed it was necessary to address as many of the customer categories as possible. Some in the workgroup concluded that the steps needed to administer the exemption process (eligibility, billing controls, additional complexity in gas cost true-up proceedings, etc.) might themselves introduce their own unintended consequences. These consequences could include the unknown impact of a comparatively large number of customers that might receive IBR exemptions on the IBR blocks and block premiums and discounts necessary to maintain revenue neutrality.

Customer acceptance of a modified IBR would depend on several factors including an understanding of the IBR program goals and perception of the appropriateness of IBR generally. The IBR modifications would introduce an exemption process which would also need to be understood. Even if it were possible to fully communicate the objective and rationale for a modified IBR to all customers, it seems likely that some customers would not agree with the purpose, process, or results of a modified IBR. This could lead to a lack of customer acceptance that might not be meaningfully different from the experience under the original IBR program.

V. Recommendations

The workgroup, as a whole, did not reach consensus on whether a modified IBR should be proposed at this time. Some parties believed it is premature to forego the conservation potential of IBR without more information about whether IBR is effective at inducing conservation. Some parties believed the bill reductions to low-use customers under IBR should not be abandoned. Some parties believed a modified IBR is infeasible.

Based on the information developed in the workgroup process, the Company is not proposing to reinstate a modified IBR program at this time. As a result, the flat-rate gas cost pricing structure currently in place would remain in effect. Since the Company is not proposing to reinstate a modified IBR program and since current tariffs provide for billing of gas costs at flat-rates, CenterPoint has determined that no tariff revisions are necessary.

The workgroup members did agree they would like the opportunity to file individual comments on this report or other points related to the consideration of IBR modifications.

VI. Conclusion

The Company appreciates the participation of the members of the workgroup and looks forward to additional consideration of these issues by the Commission.

ATTACHMENT A

Possible customer group exemption categories for a modified CPE Inverted Block Rate

Prepared for discussion purposes only

Activity	Medical conditions requiring additional energy usage	Customers living in multi-unit housing that is served by a single meter	People receiving LIHEAP	People not receiving LIHEAP support but otherwise demonstrating low income	People who have already undertaken energy conservation measures		Customers with large families	Customers that work from home or that are home due to unemployment
Eligibility Process – how would eligible customers be identified and/or verified?	• **Customers required to provide statement they are unable to conserve due to medical needs—no verification**	• Customers required to provide statement they reside in a multi-unit property served by a single gas meter—CPE could manually compare this information to billing system data to verify and/or update data.	• **Eligible if customer received LIHEAP (ZQ) payment type within past 12 months.** •	• **Eligible if customer contacts CPE, and is at or below fifty percent of the state median income; income verification would be done the same way it is under the Cold Weather Rule**	• **Customers required to provide statement they have already undertaken energy conservation measures—no verification[1]** • **Need to define "made alternative efforts at conservation measures."**		• **Customers required to provide statement they are unable to conserve due to having a large family—no verification** • **Need to define "large family"**	• **Customers required to provide statement they are unable to conserve because they work from home or are otherwise home all day—no verification** •

[1] An alternative would be to require participation in certain CPE CIP programs within the past ___ years.

3/1/2012

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Notification Process – how would customers be notified of exemption criteria or process?	• all customers notified by new customer brochure and information on web • Annual IBR customer communication	• all customers notified by new customer brochure and information on web • Annual IBR customer communication	• all customers notified by new customer brochure and information on web • Annual IBR customer communication • **exemption described in LIHEAP promo material**	• all customers notified by new customer brochure and information on web • Annual IBR customer communication	• all customers notified by new customer brochure and information on web • Annual IBR customer communication		• all customers notified by new customer brochure and information on web • Annual IBR customer communication	• all customers notified by new customer brochure and information on web • Annual IBR customer communication

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Activity	Medical conditions requiring additional energy usage	Customers living in multi-unit housing that is served by a single meter	People receiving LIHEAP	People not receiving LIHEAP support but otherwise demonstrating low income	People who have already undertaken energy conservation measures		Customers with large families	Customers that work from home or that are home due to unemployment
Enroll/Remove Process & timing – What is potential process to enroll, renew, or remove customers from an IBR exemption? Would the exemption be time-limited or open-ended?	• customer can submit statement to CNP at any time • csr create 'case', inform customer of procedure to submit statement • **exemption effective with next bill, until 6/30** • customer need to renew annually • A customer communication should occur in the month before the exemption expires and account reverts to IBR	• customer can submit statement to CNP at any time • csr create 'case', inform customer of procedure to submit statement • **exemption requests received year-round, but held for annual processing** • **exemption effective with next July bill**[2] • **customer need to renew every 3 years** • A customer communication should occur in the month before the exemption expires and account reverts	• Initial enrollment would be triggered by a report that looks for LIHEAP (ZQ) payments within the past 12 months, those accounts would be placed on exemption. • exemption effective with first bill after LIHEAP payment received • Exemption valid for 12 months after receipt of first LIHEAP payment • A customer communication should occur in the month before the exemption expires and account reverts to IBR	• customer can submit statement to CNP at any time • csr create 'case', inform customer of procedure to submit statement • **exemption effective with next bill, until 6/30** • customer need to renew annually • A customer communication should occur in the month before the exemption expires and account reverts to IBR •	• customer can submit statement to CNP at any time • csr create 'case', inform customer of procedure to submit statement • **exemption requests received year-round, but held for annual processing** • **exemption effective with next July bill** • **customer need to renew every 3 years** • A customer communication should occur in the month before the exemption expires and account reverts to IBR •		• customer can submit statement to CNP at any time • csr create 'case', inform customer of procedure to submit statement • **exemption requests received year-round, but held for annual processing** • customer need to renew annually • **exemption effective with next July bill** • A customer communication should occur in the month before the exemption expires and account reverts	• customer can submit statement to CNP at any time • csr create 'case', inform customer of procedure to submit statement • **exemption requests received year-round, but held for annual processing** • customer need to renew annually • **exemption effective with next July bill** • A customer communication should occur in the month before the exemption

[2] This allows better matching of the exemption period with the annual gas cost year (July – June).

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Activity	Medical conditions requiring additional energy usage	Customers living in multi-unit housing that is served by a single meter	People receiving LIHEAP	People not receiving LIHEAP support but otherwise demonstrating low income	People who have already undertaken energy conservation measures		Customers with large families	Customers that work from home or that are home due to unemployment
		to IBR •					to IBR •	expires and account reverts to IBR •
Account Maintenance – What is the process to initiate an IBR exemption in the billing system? What additional work and/or resources would be required ?	• **Require process to enter exemption from IBR manually** • Require ability to track reason for exemption • Require process to return to IBR at end of exemption eligibility if not 're-qualified' • The rate and exemption code should have a time slice • Nightly program to maintain accounts and add/remove exemptions and perform rate changes; exceptions should automatically create a case for	• Require process to enter exemption from IBR manually • Require ability to track reason for exemption • Require process to return to IBR at end of exemption eligibility if not 're-qualified' • The rate and exemption code should have a time slice • Nightly program to maintain accounts and add/remove exemptions and perform rate changes; exceptions should automatically create a case	• **Require process to 'automatically' exempt from IBR upon receipt of LIHEAP payment** • Require ability to track reason for exemption • Require process to return to IBR at expiration of exemption period if not 're-qualified' • The rate and exemption code should have a time slice • Nightly program to maintain accounts and add/remove exemptions and perform rate changes; exceptions should	• Require process to enter exemption from IBR manually • Require ability to track reason for exemption • Require process to return to IBR at end of exemption eligibility if not 're-qualified' • The rate and exemption code should have a time slice • Nightly program to maintain accounts and add/remove exemptions and perform rate changes; exceptions should automatically create a case for	• Require process to enter exemption from IBR manually • Require ability to track reason for exemption • Require process to return to IBR at end of exemption eligibility if not 're-qualified' • The rate and exemption code should have a time slice • Nightly program to maintain accounts and add/remove exemptions and perform rate changes; exceptions should automatically create a case for back office • Need ability to manually maintain exemption time		• Require process to enter exemption from IBR manually • Require ability to track reason for exemption • Require process to return to IBR at end of exemption eligibility if not 're-qualified' • The rate and exemption code should have a time slice • Nightly program to maintain accounts and add/remove exemptions and perform rate changes; exceptions should automatically create a case	• Require process to enter exemption from IBR manually • Require ability to track reason for exemption • Require process to return to IBR at end of exemption eligibility if not 're-qualified' • The rate and exemption code should have a time slice • Nightly program to maintain accounts and add/remove exemptions and perform

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	back office • Need ability to manually maintain exemption time slices • Cancel/rebills for periods with a change in exemption status are complex.	for back office • Need ability to manually maintain exemption time slices • Cancel/rebills for periods with a change in exemption status are complex.	automatically create a case for back office • Need ability to manually maintain exemption time slices • Cancel/rebills for periods with a change in exemption status are complex.	back office • Need ability to manually maintain exemption time slices • Cancel/rebill sfor periods with a change in exemption status are complex.	slices • Cancel/rebills for periods with a change in exemption status are complex.		for back office • Need ability to manually maintain exemption time slices • Cancel/rebills for periods with a change in exemption status are complex.	rate changes; exceptions should automatically create a case for back office • Need ability to manually maintain exemption time slices • Cancel/rebills for periods with a change in exemption status are complex.

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Additional Reporting – what additional reporting would be required	• Monthly Usage and Count for this group • Gas costs billed to this group. [3] • Time slices complicate reporting • Revenue reports: need monthly detail of revenue, customer count, and throughput by rate (flat vs. IBR) and by exemption code • Report of customer count beginning, added, expired, final billed, and ending exemption	• Monthly Usage and Count for this group • Gas costs billed to this group. • Time slices complicate reporting • Revenue reports: need monthly detail of revenue, customer count, and throughput by rate (flat vs. IBR) and by exemption code • Report of customer count beginning, added, expired, final billed, and ending exemption	• Monthly Usage and Count for this group • Gas costs billed to this group. • Time slices complicate reporting • Revenue reports: need monthly detail of revenue, customer count, and throughput by rate (flat vs. IBR) and by exemption code • Report of customer count beginning, added, expired, final billed, and ending exemption	• Monthly Usage and Count for this group • Gas costs billed to this group. • Time slices complicate reporting • Revenue reports: need monthly detail of revenue, customer count, and throughput by rate (flat vs. IBR) and by exemption code • Report of customer count beginning, added, expired, final billed, and ending exemption	• Monthly Usage and Count for this group • Gas costs billed to this group. • Time slices complicate reporting • Revenue reports: need monthly detail of revenue, customer count, and throughput by rate (flat vs. IBR) and by exemption code • Report of customer count beginning, added, expired, final billed, and ending exemption?		• Monthly Usage and Count for this group • Gas costs billed to this group. • Time slices complicate reporting • Revenue reports: need monthly detail of revenue, customer count, and throughput by rate (flat vs. IBR) and by exemption code • Report of customer count beginning, added, expired, final billed, and ending exemption	• Monthly Usage and Count for this group • Gas costs billed to this group. • Time slices complicate reporting • Revenue reports: need monthly detail of revenue, customer count, and throughput by rate (flat vs. IBR) and by exemption code • Report of customer count beginning, added, expired, final billed, and ending exemption

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Possible customer group exemption categories for a modified CPE Inverted Block Rate

Activity	Medical conditions requiring additional energy usage	Customers living in multi-unit housing that is served by a single meter	People receiving LIHEAP	People not receiving LIHEAP support but otherwise demonstrating low income	People who have already undertaken energy conservation measures		Customers with large families	Customers that work from home or that are home due to unemployment
Controls – what additional controls activity would be required to ensure accurate billing?	• Require process to verify if exempt = flat rate and if not exempt = IBR • Require process to verify return to IBR at end of exemption eligibility if non 're-qualified' • Bill audit needs: daily report of number of exempt accounts by portion and monthly report of number of exempt accounts by town • Daily price key audit • Monthly price key changes for both IBR and flat rate	• Require process to verify if exempt = flat rate and if not exempt = IBR • Require process to verify return to IBR at end of exemption eligibility if non 're-qualified' • Bill audit needs: daily report of number of exempt accounts by portion and monthly report of number of exempt accounts by town • Daily price key audit • Monthly price key changes for both IBR and flat rate •	• Require process to verify if exempt = flat rate and if not exempt = IBR • Require process to verify return to IBR at end of exemption eligibility if non 're-qualified' • Bill audit needs: daily report of number of exempt accounts by portion and monthly report of number of exempt accounts by town • Daily price key audit • Monthly price key changes for both IBR and flat rate	• Require process to verify if exempt = flat rate and if not exempt = IBR • Require process to verify return to IBR at end of exemption eligibility if non 're-qualified' • Bill audit needs: daily report of number of exempt accounts by portion and monthly report of number of exempt accounts by town • Daily price key audit • Monthly price key changes for both IBR and flat rate •	• Require process to verify if exempt = flat rate and if not exempt = IBR • Require process to verify return to IBR at end of exemption eligibility if non 're-qualified' • Bill audit needs: daily report of number of exempt accounts by portion and monthly report of number of exempt accounts by town • Daily price key audit • Monthly price key changes for both IBR and flat rate •		• Require process to verify if exempt = flat rate and if not exempt = IBR • Require process to verify return to IBR at end of exemption eligibility if non 're-qualified' • Bill audit needs: daily report of number of exempt accounts by portion and monthly report of number of exempt accounts by town • Daily price key audit • Monthly price key changes for both IBR and flat rate •	• Require process to verify if exempt = flat rate and if not exempt = IBR • Require process to verify return to IBR at end of exemption eligibility if non 're-qualified' • Bill audit needs: daily report of number of exempt accounts by portion and monthly report of number of exempt accounts by town • Daily price key audit • Monthly price key changes

[3] This implies two gas cost true-up calculations would be required. One for IBR customers and one for flat rate (exempt) customers. IBR customers would still also have a sub-calculation of the over/under due to IBR.

ATTACHMENT A

Prepared for discussion purposes only

Possible customer group exemption categories for a modified CPE Inverted Block Rate

Activity	Medical conditions requiring additional energy usage	Customers living in multi-unit housing that is served by a single meter	People receiving LIHEAP	People not receiving LIHEAP support but otherwise demonstrating low income	People who have already undertaken energy conservation measures		Customers with large families	Customers that work from home or that are home due to unemployment
								for both IBR and flat rate •
What is the potential number of customers likely to be exempted?	• CPE has no way of knowing the number of customers that might be eligible. Census bureau data shows 12.7% of the population in MN was over 65 in 2009. Assuming 15% of CPE customers are elderly and 20% are high or very-high users, and half of those apply for an exemption, **about 11,000** customers are likely to receive an exemption.	• CPE does not know how many individual living units may be served from a single service line or meter. The City of Minneapolis provided a count of buildings with certain use codes and about 31,000 living units may be in duplex, tri- or four-plexes. Assuming one-quarter of these are served by a single service line and an equal number are in other parts of the service territory and about half	• In the 2010-2011 LIHEAP year, about 41,000 CPE customers received LIHEAP. Assume **about 40,000** customers are likely to receive an exemption.	• In the 2010-2011 LIHEAP year, about 6,300 CPE customers demonstrated they were low-income, but did not receive LIHEAP. Assuming about half apply for an exemption, **about 3,200** customers are likely to receive an exemption.	• CPE has no way of knowing the number of customers that might be eligible. Assuming 10% of the customers are eligible and 20% are high or very-high users and half of those apply for an exemption, **about 7,300** customers are likely to receive an exemption.		• CPE has no way of knowing the number of customers that might be eligible. Assuming 10% of the customers are eligible and 50% are high or very-high users and half of those apply for an exemption, **about 18,300** customers are likely to receive an exemption.	• CPE has no way of knowing the number of customers that might be eligible. Assuming 10% of the customers are eligible and 20% are high or very-high users and half of those apply for an exemption, **about 7,300** customers are likely to receive an exemption.

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Possible customer group exemption categories for a modified CPE Inverted Block Rate

Activity	Medical conditions requiring additional energy usage	Customers living in multi-unit housing that is served by a single meter	People receiving LIHEAP	People not receiving LIHEAP support but otherwise demonstrating low income	People who have already undertaken energy conservation measures		Customers with large families	Customers that work from home or that are home due to unemployment
		apply for an exemption, **about 7,500** customers are likely to receive an exemption.						

Rebuttal Schedule
VCC-2, pg. 32

ATTACHMENT A
Prepared for discussion purposes only

Possible customer group exemption categories for a modified CPE Inverted Block Rate

Activity	Medical conditions requiring additional energy usage	Customers living in multi-unit housing that is served by a single meter	People receiving LIHEAP	People not receiving LIHEAP support but otherwise demonstrating low income	People who have already undertaken energy conservation measures		Customers with large families	Customers that work from home or that are home due to unemployment
Cost to implement – what is potential cost? [4] • IT costs • Other fixed costs • Variable costs	• IT: $100,000 one-time and $10,000/yr for maint • $50,000/yr for Controls • $50,000 - $100,000/yr for Communications • $15,000/yr for Call Center inbound call handling • **$69,000 in year one for applications[5]** • **$23,000 in subsequent years for renewals[6]**	• IT: $100,000 one-time and $10,000/yr for maint • $50,000/yr for Controls • $50,000 - $100,000/yr for Communications • $15,000/yr for Call Center inbound call handling • **$47,000 in year one for applications** • **$16,000 in subsequent years for renewals** •	• IT: $100,000 one-time and $10,000/yr for maint • $50,000/yr for Controls • $50,000 - $100,000/yr for Communications • $15,000/yr for Call Center inbound call handling •	• IT: $100,000 one-time and $10,000/yr for maint • $50,000/yr for Controls • $50,000 - $100,000/yr for Communications • $15,000/yr for Call Center inbound call handling • **$20,000 in year one for applications** • **$7,000 in subsequent years for renewals** •	• IT: $100,000 one-time and $10,000/yr for maint • $50,000/yr for Controls • $50,000 - $100,000/yr for Communications • $15,000/yr for Call Center inbound call handling • **$46,000 in year one for applications** • **$15,000 in subsequent years for renewals** •		• IT: $100,000 one-time and $10,000/yr for maint • $50,000/yr for Controls • $50,000 - $100,000/yr for Communications • $15,000/yr for Call Center inbound call handling • **$114,000 in year one for applications** • **$38,000 in subsequent years for renewals** •	• IT: $100,000 one-time and $10,000/yr for maint • $50,000/yr for Controls • $50,000 - $100,000/yr for Communications • $15,000/yr for Call Center inbound call handling • **$46,000 in year one for applications** • **$15,000 in subsequent years for renewals** •

[4] All costs are order-of-magnitude estimates and could vary significantly depending on specific details of the administrative and IT processes that would be required.

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Prepared for discussion purposes only

Possible customer group exemption categories for a modified CPE Inverted Block Rate

Activity	Medical conditions requiring additional energy usage	Customers living in multi-unit housing that is served by a single meter	People receiving LIHEAP	People not receiving LIHEAP support but otherwise demonstrating low income	People who have already undertaken energy conservation measures		Customers with large families	Customers that work from home or that are home due to unemployment
Reason to exempt	• If customers medically require a certain level of "warmth", they may not be able to lower their thermostat.	• Use per person may be low, but aggregated use may be high. • One person in a unit may conserve, but their actions could be offset by residents of other units that do not conserve.	• Customers may not afford to make capital investments to achieve conservation.	• Customers may not afford to make capital investments to achieve conservation.	• Conservation measures have already been taken and "no" further conservation is possible.		• Use per person may be low, but aggregated use may be high.	• Customers may not be able to lower the thermostat during the day to the same extent as those who leave the home.

[5] Based on 15 minutes/application processing labor
[6] Based on 5 minutes/renewal processing labor

STATE OF MINNESOTA

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April 2, 2012

Dr. Burl W. Haar
Executive Secretary
MN Public Utilities Commission
121 Seventh Place East, Suite 35 0
St. Paul, MN 55101

Re: ***In The Matter Of The Office of the Attorney General's Response to the IBR Modification Workgroup Report and CenterPoint's Revenue Decoupling and Inverted Block Rate Evaluation Report***
MPUC Docket No. G-008/GR-08-1075

Dear Dr. Haar:

Enclosed for filing in the above matter, please find the *Response of the Office of the Attorney General to the IBR Modification Workgroup Report and CenterPoint's Revenue Decoupling and Inverted Block Rate Evaluation Report.*

By copy of this letter all parties have been served. An affidavit of service is also enclosed.

Sincerely,

s/Peter S. Shaw

PETER S. SHAW
Assistant Attorney General

(651) 757-1211 (Voice)
(651) 296-9663 (Fax)

Enclosures

cc: Attached Service List (w/ Enclosure)

AG: #2987471-v1

STATE OF MINNESOTA
BEFORE THE PUBLIC UTILITIES COMMISSION

Phyllis Reha	Vice Chair
David C. Boyd	Commissioner
J. Dennis O'Brien	Commissioner
Betsy Wergin	Commissioner

In the Matter of an Application by CenterPoint Energy for Authority to Increase Natural Gas Rates in Minnesota

Docket No. G-008/GR-08-1075

RESPONSE OF THE OFFICE OF THE ATTORNEY GENERAL TO THE IBR MODIFICATION WORKGROUP REPORT AND CENTERPOINT'S REVENUE DECOUPLING AND INVERTED BLOCK RATE EVALUATION REPORT

I. INTRODUCTION

The Office of the Attorney General ("OAG") submits these Comments in response to the IBR Modification Workgroup Report and CenterPoint Energy's ("CenterPoint" or "the Company") Revenue Decoupling and Inverted Block Rate Evaluation Report. For the reasons set forth below, the OAG agrees with CenterPoint's recommendation to maintain a flat rate pricing structure and recommends formal termination of the inverted block rate pricing structure.

II. BACKGROUND

In 2010, the Minnesota Public Utilities Commission ("the Commission") approved a pilot program in which CenterPoint would change its rate design to utilize an inverted block rate pricing structure (sometimes referred to herein as "IBR"). The IBR program went into effect in July, 2010, and was later suspended by the Commission in October, 2011.

Using inverted block rates, customers paid different rates for natural gas depending on how much gas they used; in other words, ratepayers who consumed more gas not only paid more in their total monthly bill because their overall use was higher, but also paid as much as two times more for each unit of energy consumed. The theory behind the pilot program was to incentivize people to lower their energy consumption. *July 22, 2009 Public Comments of CenterPoint Energy*, North Mankato Public Hearing, pp. 29, 30. The premise for the Commission's approval of the pilot program was that inverted block rates should promote energy conservation without adversely affecting ratepayers. The Commission appropriately retained strict oversight over the pilot program, requiring CenterPoint to file annual reports about the impact of the program and specifically retaining the discretion to terminate the program upon "unfavorable review" or "for other cause it shall deem adequate." *June 30, 2010 Order Authorizing Implementation of Final Rates and Approving Refund Plan*, pp. 4, 5.

On June 1, 2011, the OAG filed Comments with the Commission requesting, among other things, the suspension of CenterPoint's inverted block rate program, pending further study and review. *See generally OAG June 1, 2011 Comments*. The OAG's Comments demonstrated that the program was having unfair and unintended consequences on ratepayers of all stripes. For example, the program charged higher rates to many people who had already taken all available steps within their budgets to be energy efficient, or who could not afford energy upgrades in this bad economy. The program also appeared to charge higher rates to certain customers who must use more energy for any number of reasons beyond their control, such as: (1) senior citizens, many of whom are on fixed incomes and consume more energy because they are home all day or need warmer living environments; (2) people with medical conditions who need to stay warm; (3) people who consume more energy because they have larger families; and (4) people whose family members are at home more, such as those with young children, stay-at-home parents, those who work from home and those who are unemployed. The Comments also revealed that IBR may have had a disproportionate adverse impact on some lower-income communities. Lastly, the Comments showed that the inverted block rates were unfairly resulting in higher bills to those ratepayers billed on longer monthly cycles and who were thus pushed or kept in the higher-tier rates for longer periods of time.

Subsequently, every other party to the rate case, including CenterPoint, the Department of Commerce (the "Department"), the Suburban Rate Authority ("SRA"), Energy Cents Coalition ("ECC"), the Izaak Walton League ("IWLA") and the Minnesota Center for Environmental Advocacy ("MCEA"), recommended suspension of the IBR program to the Commission. Community Action of Minneapolis, an organization devoted to helping low-income persons with energy assistance, also submitted a letter to the Commission, supporting the OAG's recommendation to suspend the program.

On October 4, 2011, the Commission ordered suspension of the inverted block rate program. The Order stated:

> Parties have identified unintended hardships arising from the inverted block rate structure, but have yet not [sic] been able to identify appropriate remedies. Based on a review of the record and the unanimous recommendations of the parties, the Commission concludes that the practical challenges posed by the inverted block rate structure require suspension of the program.[1]

October 4, 2011 Order Suspending IBR Structure, Authorizing Workgroup, and Requiring Revised Decoupling Rate Adjustment, p. 3. CenterPoint has since reverted to a flat-rate pricing system.

The Order also authorized the formation of a workgroup to address whether to revise the inverted block rate program. *Id.* at 5. The workgroup consisted of the parties to the rate case and met several times in the winter of 2011-2012 to discuss the IBR program. On March 1, 2012, the

[1] In February, 2012, the Commission voted to order CenterPoint to adjust the bills of certain customers who were impacted by longer billing cycles under IBR. The costs of the bill adjustments will be imposed on CenterPoint's ratepayers via the annual true-up.

workgroup submitted its IBR Modification Workgroup Report. Briefly, the report summarizes the actions of the workgroup and discusses the use of customer exemptions or "opt-outs" as a potential modification to the IBR program. The report also details and discusses the many new challenges and potential pitfalls of a new IBR program utilizing multiple opt-outs. Ultimately the workgroup as a whole did not reach a consensus as to whether and how to modify IBR. In the IBR Modification Workgroup Report, the Company recommends keeping the flat rate system and not returning to an IBR program. *IBR Modification Workgroup Report*, p. 16.

Also on March 1, 2012, CenterPoint submitted its Revenue Decoupling and Inverted Block Rate Evaluation Report. Among other things, the report summarizes certain findings regarding the impact IBR may have had on energy conservation, as well as IBR's impact on certain ratepayer groups, such as those receiving LIHEAP. Of particular relevance to this matter, the report revealed that IBR had no measurable impact on energy conservation and indicates that IBR may not be beneficial to low-income ratepayers. *See infra* pp. 12, 13.

For the reasons set forth below, the OAG agrees with the Company's recommendation to maintain flat rates and requests formal termination of the IBR program.

III. OPT-OUTS COULD NOT EFFECTIVELY ADDRESS THE UNFAIR IMPACTS OF IBR AND MAY LEAD TO ADDITIONAL UNINTENDED CONSEQUENCES.

The unfair impacts of IBR are now well-documented. The workgroup focused its attention on the possibility of addressing these impacts with potential modifications to the IBR structure. The only potential modification discussed at any length during the workgroup sessions was a system of exemptions designed to allow certain categories of CenterPoint ratepayers to avoid the program's harsh impact. *See IBR Modification Workgroup Report*, p. 3. Aside from LIHEAP or other low-income customers, all opt-outs would be achieved via self-declaration, meaning customers would have to take affirmative steps to declare and notify the Company (probably by responding to a bill insert) that they feel they are part of an exempt category of customers. The OAG does not believe an opt-out system could address the harm caused by IBR; in fact, it would lead to further unintended consequences.

A. OPT-OUTS WOULD RESULT IN SUBSTANTIAL CUSTOMER CONFUSION AND FRUSTRATION, AND DECREASED CUSTOMER ACCEPTANCE OF IBR.

The record in this rate case already reflects that the IBR program, as implemented by the Company in 2010-11, lead to substantial customer dissatisfaction and confusion over the program's billing structure, impacts and overall purpose. Public comments filed with the Commission and the OAG's Comments showed that ratepayers who took the time to contact CenterPoint about the program were not able to obtain answers to basic questions and sometimes received conflicting or confusing information. *See OAG's June 1, 2011 Comments*, p. 22. A system of opt-outs would only increase customer confusion and dissatisfaction about IBR, and would be destined to failure.

i. Confusion Regarding Eligibility

Under a modified IBR with opt-outs, customers would be sent a bill insert or notice detailing the IBR program and a list of categories under which they might qualify for an exemption. At least 10 categories of ratepayers who may merit an exemption were discussed in the IBR Modification Workgroup Report. *See IBR Modification Workgroup Report*, pp. 4-10.

As was noted by the Company in the IBR Modification Workgroup Report, customers would experience confusion regarding exemption eligibility. First, a number of customers remain unaware of the program's design and purpose. Many customers were unaware that the program existed, even before its suspension. The first hurdle of an opt-out system would thus be to ensure that all customers know why, *in the first place*, they are being asked to look over a list of exemptions. Experience under IBR has already shown that this would present a challenge, even for those who call the Company to receive answers to basic questions about IBR. *See OAG's June 1, 2011 Comments*, p. 22.

Another important concern relating to the list of exemptions is ensuring that customers are provided with clear and concise information to determine whether or not they are eligible for an exemption. A list with multiple categories of exemptions, many of which would need to contain comprehensive and complex eligibility descriptions, would result in customer confusion. For instance, for an exemption involving customers who have already taken conservation measures, it would seem extremely difficult to define and concisely explain what qualifies as a "conservation effort" and just how much effort needs to be made, by whom and when, before the exemption applies.[2] In the "Certain Renters" category, it would be difficult to convey eligibility criteria in a concise manner and likely impossible for consumers to make a determination as to eligibility without reading the fine print of their lease, which may or may not state whether they are prohibited from making energy conservation efforts. It is foreseeable that, in some cases, the additional time and effort it might require to achieve eligibility information may result in some consumers abandoning exemption attempts and growing dissatisfied with IBR.

The Company agrees that there are justifiable concerns regarding increased customer confusion. It notes that the "activities required to support the potential IBR modifications...would result in increased complexity in billing, gas cost recovery true-up calculations and customer service" and that the "complexity of customer service interactions

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[2] It would be equally difficult for stakeholders and the Commission to determine and come to a consensus as to who should qualify for eligibility under this (and other) categories, and what exactly is meant by "conservation measure."

would increase by requiring the customer service representative to explain the IBR exemption process." *IBR Modification Workgroup Report*, p. 15.

ii. Frustration Regarding Exemptions

Any list of exemptions, no matter how expansive, would still exclude many customers who feel it is unfair they are subjected to IBR. For instance, many families may have difficulty paying their heating bill under a modified IBR, especially in the winter when gas use is highest and more people are subject to high-tier IBR rates. If the family is not considered "low-income," however, they would not be eligible for an opt-out. Additionally, in this economy, many families are experiencing temporary job loss. Last year's tax returns may indicate a "middle-class" income, but temporary unemployment may render their present income zero. It is unclear whether the temporarily unemployed would be eligible for an IBR exemption and for how long. Assuming they are not eligible, these ratepayers would appropriately be dissatisfied with such an opt-out system.

For several reasons, many customers eligible for an opt-out under a modified IBR would not achieve exemption. First, many customers do not and will not read or pay close attention to their bills and accompanying inserts, such as an IBR exemption notification. Many customers simply pay their bills and move on with their lives, having become accustomed to inserts and bill stuffers they feel do not pertain to them. A number of CenterPoint customers pay their bills on-line and do not have or take the time to read the actual on-line statement before paying. *OAG July 21, 2011 Reply Comments*, p. 10. Second, as discussed above, the potential for customer confusion and the steps customers may have to take to determine eligibility will deter many eligible customers from seeking an exemption.

B. A SYSTEM OF EXEMPTIONS WILL REQUIRE MODIFICATIONS TO THE IBR RATE BLOCKS, WHICH COULD RESULT IN HIGHER RATES TO THOSE STILL SUBJECT TO IBR.

An exemption system would decrease the number of customers subject to IBR and would therefore require the restructuring of the IBR tiers, which were set to ensure the company recovers its estimated commodity gas costs. Should a substantial portion of high-use customers exit the IBR program, the IBR rates may have to be increased to ensure that the Company does not substantially under-collect its commodity gas costs from those remaining in the IBR program. As has been illustrated previously in this docket, many customers viewed the very highest tier rates of the IBR program as unacceptably high, to the point where they considered the rates punitive. *See OAG June 1, 2011 Comments*, p. 2. Any increase to the highest tier rates would further diminish customer acceptability and may result in additional harm to those ratepayers who cannot afford such high rates during peak gas-use months.

Additionally, it is not yet known how many customers would actually claim exemptions. The restructured rates would thus, out of necessity, be based on imperfect assumptions regarding the number of customers who may claim an exemption. This would add additional complexities to the IBR program.

C. A SYSTEM OF EXEMPTIONS WOULD LEAD TO MULTIPLE, COMPLEX TRUE-UPS.

A modified IBR featuring an exemption system would likely apply to the residential and small business customer classes and would result in two customer subclasses amongst each affected customer class: those subject to IBR and those not. Thus, there would be four subclasses of ratepayers: two IBR subclasses (one residential and one small business) and two non-IBR subclasses (one residential and one small business). The Company would have to account for these subclasses in any future true-ups, in effect performing a total of four separate true-ups, one for each subclass. CenterPoint has not proposed a system for dealing with these additional true-ups, but it seems safe to say that such a complicated system of multiple, annual true-ups would pose additional questions and burdens for the Company, governmental regulators and the Commission. Indeed, the Company emphasizes that "[g]as cost recovery calculations complexity would increase by the need to perform separate gas cost true-up calculations for costs recovered under IBR and under flat-rates." *IBR Modification Workgroup Report*, p. 15.

D. OPT-OUTS WOULD RESULT IN THE DISCLOSURE OF PERSONAL INFORMATION TO CENTERPOINT.

A system of exemptions would require the collection and storage of a large amount of personal data on individual ratepayers wishing to opt-out of IBR. Some of this information may be sensitive, private or confidential, such as information about an individual user's health or finances. It is unclear whether CenterPoint, an energy utility, is equipped to store and safeguard such private information and what the legal ramifications of this information-sharing might be. It is likely many consumers would have questions and concerns regarding such a system.

Moreover, even if CenterPoint *could* safely store this information, there is the question of whether CenterPoint *should* have access to private information on perhaps thousands of individual ratepayers. Whether it is proper for a utility company to be permitted to seek and collect private and confidential information on a substantial portion of its customer base raises significant privacy concerns and should be carefully considered by the Commission.

E. CENTERPOINT WOULD SEEK TO IMPOSE THE COSTS OF ADMINISTERING AN IBR EXEMPTION ON RATEPAYERS.

In the IBR Modification Workgroup Report, CenterPoint states that certain company actions would be required to support the process of administering IBR exemptions. The Company estimates that the cost of administering the IBR exemptions would range from

\$557,000 to \$607,000 in the first year of a modified IBR program. *IBR Modification Workgroup Report*, p. 10. For each subsequent year under a modified IBR, costs are estimated to be between \$239,000 and \$289,000. *Id.* The Company states that in future rate cases it would seek to recover these increased costs in base rates to be paid by all customers. *Id.* at 15. Sufficient detail regarding the basis of the costs is not provided in the IBR Modification Workgroup Report, but the costs are clearly significant and would be ongoing as long as IBR remains in effect.

Accordingly, a modified IBR program would ultimately result in higher rates to customers, which would likely decrease customer acceptance of the program. It seems ill-advised to impose additional costs to consumers for a program that will continue to result in unfair and unintended consequences and which--as discussed below--has not been shown to impact energy conservation.

IV. A LARGE NUMBER OF OPT-OUTS MAY RESULT IN AN INEFFECTIVE AND MEANINGLESS PROGRAM.

One of the main goals of IBR was to encourage conservation. *See OAG June 1, 2011 Comments*, p. 8. As discussed below in Section VI, IBR has not been shown to lower energy use or increase conservation among ratepayers. IBR usage compared with usage before IBR is unchanged.

Nevertheless, assuming for the sake of argument that IBR could have some effect on conservation, permitting high-use customers to opt-out of the system may completely nullify any potential effect on conservation. According to its promoters, IBR is supposed to send a "conservation signal" to high-use ratepayers to encourage conservation. *Id.* Under a system of exemptions, however, high-use ratepayers (including those who merit exemptions and those who incorrectly claim an exemption) would exit the IBR program and not receive the intended "conservation signal."

V. LONGER BILLS WOULD CONTINUE TO BE A PROBLEM UNDER A MODIFIED IBR.

In the winter of 2010-11, when IBR was in effect, hundreds of thousands of ratepayers received higher gas bills due to longer monthly billing cycles, which kept them in a high-tier rate for a longer period of time or which pushed them into a high-tier rate. This issue has already been the subject of extensive briefing in this docket and was the subject a February, 2012 Commission order. The Commission ruled that CenterPoint should make billing adjustments to certain ratepayers who paid more under IBR as a result of longer billing cycles. The Commission, however, also ruled that the billing adjustments were related to the cost of gas and, thus, could be recovered by the Company in its annual true-up filing. The OAG estimates that the billing adjustments will result in an approximate $1.2 million surcharge to residential and small business class ratepayers.

According to CenterPoint, the problem of longer billing cycles (and the resultant higher gas bills) would continue, even under a modified IBR system. Specifically, in the IBR Modification Workgroup Report, the Company states, "longer billing periods will continue to occur in the future given the current state of metering technology and it would not be possible to ensure that billing periods would be limited to a specific length such as 30 days either through metering operations or billing system changes." *IBR Modification Workgroup Report*, p. 11.

Under a modified IBR program, the Company might be able to adjust customer bills for the length of the billing period using calculation methods which require the assumption of average per day customer usage. As noted by the Company, however, "[i]ncorporating this adjustment as an ongoing part of the monthly bill calculation would also require displaying an additional line of information on the IBR customer's bill…" *Id.* Such a calculation would add yet another layer of complexity to an already cumbersome and unwieldy modified IBR system.

Moreover, the addition of another line item to a customer's bill may result in additional customer confusion regarding the IBR program. Finally, customer usage varies from day-to-day and a calculated, average daily use-per-customer will not necessarily equal the actual, daily use-per-customer for any specific day in the evaluation period. Therefore, any calculation based on an assumed daily use-per-customer could be unfair to ratepayers.

VI. IBR HAS NOT BEEN SHOWN TO ENCOURAGE ENERGY CONSERVATION OR TO ASSIST LOWER-INCOME PEOPLE.

In proposing IBR, parties to the rate case stated that IBR would increase energy conservation and may lead to lower bills for low-use customers, many of whom, they claimed, were low-income. *See OAG June 1, 2011 Comments*, p. 8-9; *OAG July 21, 2011 Response Comments*, p. 4. Thus, two major issues in this docket have been IBR's effects, if any, on energy conservation and low-income ratepayers.

On March 1, 2012, CenterPoint filed its Revenue Decoupling and Inverted Block Rate Evaluation Report. The report attempts to measure the effects of IBR on conservation and also focuses on the usage of LIHEAP customers. A "Key Finding" of the IBR Evaluation Report is that "IBR may have had a limited impact on aggregated usage" and that residential usage was flat when comparing weather normalized therms during the 12 month pre-IBR period and IBR periods. *CenterPoint's Revenue Decoupling and Inverted Block Rate Evaluation Report*, Section J, part 2, p. 21. In fact, CenterPoint's own study notes that while mild price elasticity (flexibility) was observed, the residential class and every residential subclass exhibited such a low level of elasticity that all price-demand relationships were considered inelastic. *Id.* at part 1, p.19. In other words, IBR and its pricing structure has had no measurable impact on conservation or consumption in general.

Another "Key Finding" of the IBR Evaluation Report is that LIHEAP customers tend to use nearly as many therms per customer as non-LIHEAP customers. *Id.* at part 2, p. 21. This finding is consistent with the previous IBR Evaluation Report, filed by CenterPoint in the spring of 2011. *See OAG's June 1, 2011 Comments*, p. 15. Moreover, the OAG has already shown in this docket that IBR has had a disproportionate impact on some lower-income communities, when examining the number of households billed in the fifth-tier rate in January, 2011. *Id.* at 15-16. These findings, along with the recently released report, tend to show that IBR is not beneficial to lower-income people, many of whom may live in older, less efficient houses and do not have the resources to invest in energy-saving measures, such as efficient furnaces.

In sum, the recently released IBR Evaluation Report shows that a primary goal of IBR--energy conservation--has not been met in any measurable way. Moreover, another key goal of IBR--increased low-income affordability--has not been proven.

VII. THE COMMISSION SHOULD TERMINATE IBR.

The Commission retained the discretion to terminate IBR upon "unfavorable review" or "for other cause it shall deem adequate." *June 30, 2010 Order Authorizing Implementation of Final Rates and Approving Refund Plan*, pp. 4, 5. Due to a myriad of unfair and unintended consequences, IBR has already been suspended. The parties have met to discuss possible improvements to the IBR program, but have not reached consensus. In fact, after trying to tackle the problems associated with IBR head-on, the only proposal is a system of opt-outs which, for the reasons discussed above, would result in an ineffectual IBR program, increased customer confusion, higher rates, additional complexities and unfair and unintended results. The proposed "solution" may be worse than the first attempt.

It should be noted that the Company does not recommend returning to IBR, but instead recommends keeping a flat-rate system.

VIII. CONCLUSION

A modified IBR program will not redress the unintended and unfair consequences which led to the suspension of IBR in the first place. In fact, it would result in additional harm, complexity and customer confusion. In addition, the IBR program has not been shown to increase energy conservation or benefit lower-income ratepayers. For these reasons, the OAG recommends that the Commission formally terminate the IBR program at this juncture.

Dated: April 2, 2012

Respectfully submitted,

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AG: #2983341-v1

AFFIDAVIT OF SERVICE

Re: ***In The Matter Of The Office of the Attorney General's Response to CenterPoint Energy's Proposal for Bill Adjustments to Address Impact of Inverted Block Gas Cost Recovery in 2010 and 2011***
MPUC Docket No. G-008/GR-08-1075

STATE OF MINNESOTA)
) ss.
COUNTY OF RAMSEY)

I hereby state that on the April 2, 2012, I efiled the Office of the Attorney General - Antritrust and Utilities Division's Response to the IBR Modification Workgroup Report and CenterPoint's Revenue Decoupling and Inverted Block Rate Evaluation Report, served the same by United States Mail with postage prepaid, and depositing the same in a U.S. Post Office mail receptacle in the City of St. Paul, Minnesota, by email, and/or interoffice mail.

s/Julie Mersch
Julie Mersch

Subscribed and sworn to before me
on April 2, 2012.

s/Sandy Howard
Notary Public

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MARCH 2012

A REVIEW OF COST PRESSURES FACING THE NORTHWEST TERRITORIES POWER CORPORATION

PREPARED BY
OSTERGAARD CONSULTING GROUP

Executive Summary

This report on the Northwest Territories Power Corporation's (NTPC) revenue requirements and cost pressures affirms and augments the relevant findings of earlier utility, policy, and governance reviews. All share the common goal of putting NTPC on a solid financial footing going forward, so it can generate and deliver electricity efficiently, reliably, and at reasonable rates.

It is worth noting that the GNWT considers electricity an essential service for northern communities. The NTPC system operates in a harsh environment, with very small loads in widely dispersed communities. NTPC's ongoing challenge will be to find and implement cost saving measures without affecting safety and reliability.

Through the course of our investigation and analysis, we have found that NTPC's costs are reasonable, given the challenges of providing electricity in the NWT. Electricity utilities across Canada are facing cost pressures, and many are experiencing rate increases that have outpaced those of NTPC over the last five years. The Utility is to be commended for reducing its staff to 2007 levels, and keeping its O&M budget increase in line with inflation.

As NTPC had not filed a General Rate Application (GRA) for five years, we found that there was a significant degree of "catch-up" required with respect to the revenue requirement. The revenue requirement increase from $87.1 million to $101.6 million, is substantial, especially if implemented in one year. At the outset of our review, we were made aware of a proposal being developed by NTPC and the GNWT Department of Finance to limit rate increases to no more than seven per cent per year. This appears reasonable as a fundamental principle of rate design is the avoidance of "rate shock". As well, revenue to cost ratios in all rate zones are reasonable, so simple "across the board" percentage increases to the zone-based rates make sense.

Projected cost impacts for NTPC customers for the next three years (2012-13 to 2014-15) are reflected in the tables below:

Figure I Forecasted Residential Rate Increases

Anticipated Monthly Power Bill Increases (Winter) Residential Ratepayers (1000kWh/month)				
Zone	**2012/13**	**2013/14**	**2014/15**	**Total**
NTPC Thermal	$11	$12	$13	$36
NTPC Taltson	$12	$13	$14	$39
NTPC Snare	$11	$12	$13	$36

*These are projections of monthly bills for January 1st of target years.

Figure II Forecasted Commercial Rate Increases

Anticipated Monthly Power Bill Increases (Winter) Commercial Ratepayers (3000kWh/month)				
Zone	**2012/13**	**2013/14**	**2014/15**	**Total**
NTPC Thermal	$89	$95	$101	$285
NTPC Taltson	$28	$30	$33	$91
NTPC Snare	$66	$70	$75	$211

*These are projections of monthly bills for January 1st of target years.

To keep rate increases to a maximum of seven per cent per year requires a GNWT contribution in the range of $18 million over two years. It should be noted that these figures do not reflect an additional $15 million in diesel costs over the next three years, related to diminishing natural gas supply in Inuvik. Just prior to the finalization of our report, we were informed that there is the potential for these costs to remain ongoing and that they would likely need to be included in the revenue requirement. A discussion of these additional costs was not included in our review. However, the impact on the proposed annual revenue requirement is clear - $107 million will be required. To keep rate increases to a seven per cent maximum and still attain the $107 million revenue requirement, an additional year would need to be added to the annual seven per cent rate increases. As well, GNWT support during this transition phase would need to increase to approximately $33 million.

We understand that government support to this level, accompanied by rate increases of seven per cent for the next four years, is challenging. However, the cost pressures are immediate, and the Utility does need to attain its $107 million revenue requirement, beginning in 2012-13.

In light of these cost pressures, we have presented our recommendations in two streams, short term and long term. The short term recommendations identify some immediate actions that could be considered although we have found that there are few substantive savings to be found. In the long term, our recommendations should be considered as potential strategies to contain future costs and ensure rates keep up with inflation.

Short-term Recommendations

The Petroleum Products Division (PPD) provides diesel fuel to NTPC for electricity generation under a Fuel Services Agreement. As diesel use has increased, so have PPD's revenues from this agreement. These revenues appear to have outpaced costs. Therefore:

1. NTPC, PPD, and other government officials should attempt to reach a consensus on the cost of the service PPD provides to NTPC and whether fuel sales in communities served by PPD are indirectly being subsidized by the PPD charges on diesel fuel used for electricity generation.

We have found that the regulatory process is expensive and have provided a number of suggestions for change to be considered in the long term. Acceptance of these recommendations and reflecting them in the GRA to be filed will reduce costs in the short term.

2. In order to streamline the examination of diesel fuel prices and price forecasts in GRA reviews, NTPC should establish a diesel fuel price forecast methodology and submit it to the Public Utilities Board (PUB) for approval. This methodology should be clear, easy for consumers to understand, and substantially reduce or eliminate detailed discussion on fuel prices during periodic GRA reviews.

   Further, the diesel fuel price forecast should be incorporated into rates on a semi-annual basis in October and April, ensuring that fuel is treated as a "pass through" item. The rider for the Consolidated Stabilization Fund should also be reset each October and April with a two year recovery and there should no longer be a threshold limit before NTPC could apply.

3. In the General Rate Application, NTPC should propose a streamlined process to the PUB that includes no debate of capital structure, return on equity, or development of a detailed cost of service study. The GNWT should consider supporting this position through a submission to the PUB explaining the intent of the proposed government support.

4. Recognizing the 2010 Electricity Policy and the desire to keep rates low, NTPC should consider seeking approval for an Return on equity (ROE) in the 8 to 8.5% range on NTPC's actual equity of just over 40%, to provide a meaningful discount against the benchmark ROE awarded in Alberta.

Finally, consideration could be given to phasing in new depreciation rates for the reasons we discuss in our report. During this time of substantially increased cost pressures, the increased costs associated with a recent depreciation study may not need to be implemented immediately.

5. NTPC should consider advancing its condition assessment for its main assets, use the findings to update its recent depreciation study, and seek PUB approval for its updated depreciation rates through a separate written hearing process for implementation in 2013/14 or later.

Long-term Recommendations (and Strategies)

As found in previous reviews, there needs to be greater communication between the GNWT and the Utility, the mandate and expectations related to NTPC need to be clarified and performance measures will ensure that the interests of the Utility and the government are aligned.

1. The GNWT and NTPC should implement a regular planning and reporting structure centered on a Shareholder's Letter of Expectations, and a subsequent NTPC report back to the GNWT. As well, the GNWT should revisit the Strategic Direction issued in 2002 and the NTPC Act to ensure they are consistent with the current corporate structure of NTPC and there is clarity with respect to NTPC's mandate.
2. NTPC should expand its use of standard industry safety and reliability indexes by setting measurable targets, reporting results at the community, zone, and system level, and comparing its results with those of similar utilities.
3. A comprehensive listing of performance measures should be prepared by NTPC that permit it to assess corporate performance in the context of shareholder expectations, customer interests and corporate priorities.
4. NTPC should calculate "GW.h Produced per Employee" as a useful "Key Performance Indicator" (KPI) to reveal trends at a glance in the future. (Note: This is about 1.89 GW.h/employee with 169 staff in 2012/13, and given recent staff reductions, is trending in a favourable direction).

We have also provided a number of suggestions for the GNWT to consider with respect to the regulatory process. A more detailed review is required.

5. The GNWT should consider undertaking a review of the *Public Utilities Act* and the current GRA process with a view to streamline the process and control costs. This review could either be done by Government or through an undertaking of the Board.

Both NTPC and the GNWT undertake borrowing but ultimately all of the borrowing falls under the GNWT debt limit. We believe there will be efficiencies in combining this approach.

6. GNWT and NTPC should examine the potential savings, advantages, and disadvantages of having GNWT issue debt on NTPC's behalf.

The largest challenge in the NWT is the lack of economies of scale. Increasing sales will reduce the per-unit cost of electricity for everyone.

7. NTPC and the GNWT should explore ways to increase sales where there is a surplus in hydro generation capacity. Electric heating or industrial customers appear to be the greatest opportunity.

While not specifically addressed in this review, continued collaboration among NTPC, GNWT, educators, and unions will be needed to recruit talented staff. Electricity sector retirement rates are among the highest of any Canadian industry: 45,000 new and replacement staff will need to be hired in the next five years. NTPC can attract new workers with favourable career and training opportunities, competitive salaries and benefits, and job security.

TABLE OF CONTENTS

Executive Summary

1.0 Introduction **8**

2.0 Objectives, Approach, and Scope **10**

3.0 Background to NTPC's 2012-14 General Rate Application **14**
3.1 2006-08 Revenue Requirements Application and Decision 14
3.2 Phase II Application and Fuel Riders 14
3.3 Review of Rates, Regulation, and Subsidies 15
3.4 Report of the NTPC Review Panel 15
3.5 Government Response: 2010 Electricity Policy 16

4.0 Cost Pressures, Rates, and Rate Increases: Other Jurisdictions **18**
4.1 Cost Pressures 18
4.2 Rates and Rate Increases 21

5.0 Cost Pressures, Rates, and Rate Increases: NTPC **24**
5.1 Overview 24
5.2 Load Forecast 25
5.3 Breakdown of Cost Components and Overview of Potential Efficiencies 26
5.4 The Proposed "7/7/7" Rate Increase Scenario 27
5.5 Possible GNWT Financial Support 28

6.0 Finding Efficiencies: Strategies to Manage Short Term Rate Increases **29**
6.1 Salaries and Wages 30
6.2 Operations and Maintenance Cost Components 31
6.3 Cost of Production Fuels 31
6.4 Regulatory Considerations 35
6.5 Capital Structure and Return on Equity (ROE) 36
6.6 Fixed Asset Amortization (Depreciation Expense) 38

7.0 Closing the Revenue Gap: Long-Term Cost Containment Strategies **42**
7.1 Governance Structure: the Shareholder-Utility Relationship 42
7.2 Directions to NTPC – Regular Issuance of Shareholder's Letter of Expectations 43
7.3 Long Term Approach to Regulation 44
7.4 Capital Structure and Dividend Policy 46
7.5 Cost of Borrowing 47
7.6 Revenue Growth Opportunities 47
7.7 Demand Side Management 48
7.8 Other Minor Cost Saving Opportunities 48
7.9 Liquefied Natural Gas Potential 49

8.0 Conclusion **52**

Appendices **53**
Appendix 1: Safety and Reliability Indices for Utilities 54
Appendix 2: NTPC Rate Application and Rate Change Chronology Since the 2006/08 GRA 55
Appendix 3: Comparisons of Rates and Costs in Selected Jurisdictions 56
Appendix 4: Selected References 61
Appendix 5: Abbreviations 62
Appendix 6: Consultants' Biographies 63

1

1.0

1.0 Introduction

NOTE: This review and analysis has been prepared at the request of the Government of the Northwest Territories (GNWT) based on the draft General Rate Application (GRA) information compiled by Northwest Territories Power Corporation (NTPC). The information provided for analysis was received no later than mid-February 2012 and, as a result, does not address any changes or adjustments that may have been made to the draft GRA materials after that date.

Northwest Territories Power Corporation (NTPC, the Utility, the Corporation) is a regulated Territorial Crown Corporation serving about 8800 customers directly. It also sells electricity to Northland Utilities for distribution to customers in Hay River and Yellowknife. Revenues in 2010/11 were $82.8 million, close to the average over the last five years of $82.3 million. Seventy-four percent of NTPC's electricity is generated hydraulically; diesel fuel and natural gas account for the remainder. NTPC sells about 314,000 MW.h of electricity annually at an average unit cost in the 26 cents/kW.h range.

There has been no GRA filed by NTPC since 2007/08, when the Utility's revenue requirement was about $80 million. Since then, NTPC's costs have increased significantly in some areas and there have been significant rate changes due to the establishment of rate zones, changes to the Territorial Power Subsidy Program (TPSP), and other GNWT policy decisions.

NTPC is preparing a new GRA that is expected to seek approval for revenues of around $97.3 million in 2012/13 and $101.6 million in 2013/14. Thanks to an anticipated GNWT contribution of about $18.2 million over two years, the rate impact on customers may be reduced to 7% over each of the next three fiscal years, or some variation thereto.

Given the public interest in the cost of living in the Northwest Territories (NWT), the essential role electricity plays in public health and safety, and the substantial government contribution to soften rate impacts, the GNWT decided that a third party review of NTPC's revenue requirements and cost pressures should be completed as a matter of due diligence.

It is important to note that this review does not replace the more detailed GRA examination that will be conducted by the Public Utilities Board (PUB). This being said, we do suggest ways the PUB's review may be streamlined to reduce unnecessary regulatory costs for this and future applications.

We would like to thank staff from NTPC, InterGroup Consultants, the Department of Industry, Tourism and Investment (ITI) and several others who participated in this review, for their cooperation and contributions.

2

2.0

2.0 Objectives, Approach, and Scope

The objective of this report is to evaluate and make recommendations about NTPC's expected revenue requirements, including its main cost drivers, with a view to identifying opportunities for savings. In particular, it is to:

- Provide an overview of cost pressures of other electricity utilities, including utilities similar in size and scope as NTPC;
- Review the cost pressures facing NTPC in the context of historical and projected NTPC budgets, generally identify areas where some operational efficiencies may be realized, and provide an opinion on whether the costs appear to be reasonable, given the challenge of providing electricity services in the NWT;
- Identify strategies to mitigate potential rate increases, including continuing GNWT financial support, approaches to cost drivers, and implementation of identified efficiencies. Specifically:
    - the level of net income
    - dividend and dividend policy
    - the debt/equity ratio
    - depreciation rates of NTPC assets
    - costs associated with PUB reviews
    - fuel costs, including NTPC's contract with the Petroleum Products Division (PPD)
    - the balances in NTPC's deferral accounts

The consultants were supported by a small review team that included representatives from NTPC, InterGroup Consultants Ltd., and ITI. NTPC officials cooperated fully, which was of utmost importance in completing the report in the allotted time.

During our work, we reviewed background government or government-initiated reports, including:

- "Energy For the Future: An Energy Plan for the NWT" (March 2007, 61 pages)
- "A Review of Electricity Regulation, Rates, and Subsidy Programs in the NWT" (December 2008, 11 pages)
- "Electricity Review: A Discussion with Northerners about Electricity" (June 2009, 38 pages)
- "Northwest Territories Energy Report" (May 2011, 52 pages)
- Draft NWT Hydro Strategy Executive Summary (2008, 18 pages) and Draft NWT Hydro Strategy (61 pages)

We also reviewed three additional reports which guide the GNWT's policy direction in relation to the NWT electricity system. These additional reports include: *Creating a Brighter Future: A Review of Electricity Regulation, Rates, and Subsidy Programs in the NWT* (frequently referred to as the "*Electricity Review*", 2009); *The Report of the NTPC Review Panel* (frequently referred to as the "*NTPC Review*", 2010); and the GNWT's policy document "*Efficient, Affordable, and Equitable: Creating a Brighter Future for the NWT Electricity System*" (referred to in this report as the *2010 Electricity Policy*) which summarized the GNWT's response to the earlier independent review documents.

We also:

- Examined NTPC's recent Annual Reports, and NTPC's October 2011 "Strategic Plan 2012—14"
- Met with the President and Chief Executive Officer of NTPC, and the Board's Vice Chairperson, and spoke with the Chairperson of the PUB
- Interviewed senior GNWT finance and public works officials
- Held a workshop with the review team and invited government officials in Yellowknife on January 24 and 25, 2012, to discuss cost pressures, possible ways to reduce NTPC's revenue requirement, options around rate design, regulatory review options, and potential strategies for the future.

Electricity as an Essential Service: Safety and Reliability

As a result of its recent examination of the NWT electricity system, the GNWT has stated that the provision of electricity is seen as essential to the residents of the Northwest Territories. It has also directed NTPC, as a Crown agency, to focus its efforts on ensuring electricity is provided safely and reliably to the communities that it serves. As a result, NTPC has established a vision stating that it wishes to be regarded as an exceptional utility, up to the challenge of delivering safe, reliable, and fairly priced power through a territory-wide system that is efficient and sustainable.

Unlike southern utilities, there is no flexibility in the NTPC system to import power from the North American interconnected transmission grid. Back up generation capacity is in place in communities to meet emergency power demands. Examination of indices used to measure utilities suggest that NTPC's operation is generally reliable and safe when compared to other utilities. (See Appendix1).

Our review and recommendations are not intended to compromise NTPC's safety and reliability priorities and initiatives. Similarly, when considering future proposals for cost reductions or deferrals, the paramount criterion should be to ensure safety and reliability will not be unduly eroded.

3

3.0

3.0 Background to the NTPC's 2012-14 General Rate Application

NTPC's 2012-14 GRA submission represents the first full application submitted for regulatory review since 2006. Since then, there have been material changes in a number of the Utility's cost drivers. As well, as a result of GNWT action, there have been substantial changes to the electricity rate structure.

This chapter briefly summarizes key activities that have occurred since the last GRA filing. A more complete chronology of main GRA related events during this timeframe is attached as Appendix 2.

3.1 2006-08 Revenue Requirements Application and Decision

The 2006-08 NTPC GRA (Phase I) was filed during November, 2006 - 8 months into the test year which began April 1, 2006. NTPC delayed filing the GRA until November as it sought ways to mitigate the rate impacts that were forecast in its initial work. The PUB did not accept a request from NTPC for a negotiated settlement, and a full oral hearing took place.

In its GRA submission NTPC sought increases of:

- $15.9 million for 2006/07 (from $64 million to $79.9 million); and
- $19.9 million for 2007/08 (to $84.3 million).

The final Phase I GRA decision was over 200 pages and had over 50 "directives", many of which were to be addressed at the "next GRA". The PUB's combined decisions reduced the revenue requirement to $76.6 million in 2006/07 and to $81.1 million in 2007/08. The main effect of the PUB's approvals on NTPC's revenue requests were to:

- Reduce return on equity by $1.7 million
- Debt cost recalculation of $0.7 million
- Reduce fuel costs and volumes of $0.2 million
- Reduce salary costs by $0.3 million, by excluding half of bonuses
- Reduce operating and maintenance costs by $0.4 million
- Increase forecast revenues by $0.4 million

The rate riders designed to collect GRA shortfalls and fuel costs were slow to be fully recovered.

3.2 Phase II Application and Fuel Riders

NTPC filed its Phase II application in August 2008 to address cost of service, rate design, and fuel rate riders. ("Rate riders" are meant to capture variances in key cost drivers–usually over which a utility has little or no control between what was forecast when rates were set, and what actually occurs. Amounts either owed back to or owing from ratepayers accumulate in regulatory or stabilization accounts.) Diesel fuel prices had increased dramatically since the 2006 filing and the Phase I GRA shortfalls had not yet begun to be collected.

During Phase II, NTPC sought approval for a revised method to recover stabilization account amounts: in short, it proposed that twice a year the riders would be "trued up" to target a zero balance within twelve months. The PUB generally accepted this new approach, but ordered NTPC to lower the diesel fuel price forecast and target a zero balance over eighteen months, not twelve. Diesel fuel price increases were having a dramatic negative effect on the fuel stabilization account. Subsequently, two payments from the GNWT of $3 million each in 2010/11 and 2011/12 reduced the balance in the Consolidated Stabilization Fund. An additional $1 million contribution in September 2011 reduced the Consolidated

Stabilization Fund balance to $1.5 million. However, given the current fuel price, the balance of this Fund is expected to grow to $4.6 million by March 2012.

In 2009, the GNWT commissioned the NTPC Review and Electricity Review, described below. In consultation with the GNWT, NTPC concluded it could adopt a "zero/zero/zero" percent rate increase plan, with no increase in revenue requirements for 2009/10, 2010/11, and 2011/12. As well, the GNWT also agreed to forego collecting its dividend pending completion of the reviews.

3.3 Review of Rates, Regulation, and Subsidies

The GNWT announced its review of rates, regulation, and subsidies in the 2007 *Energy Plan*. An independent panel completed its work in 2009 and its report (the Electricity Review) was tabled in the Legislative Assembly in November of that year. It called for a renewed focus by all utilities on customer service, and recommended a series of changes to:

- The structure of the electricity system (e.g. consolidation to increase economies of scale)
- The rate structure (e.g. establish three cost of service zones and a thermal zone rate; GNWT to set the rate of return for NTPC's assets in the hydro zones; eliminate the dividend to the GNWT; reduce use of rate riders and replace them with a territorial rider to share costs related to fuel and low water; revise the TPSP and review the subsidy for residents of public housing)
- The regulatory processes (e.g. amend the *Public Utilities Act* to to permit the GNWT to provide policy direction to the PUB; streamline review processes; limit participant funding)
- The role of the GNWT (e.g. improving the lines of authority and accountability for electricity related matters)

This report and its recommendations were reviewed by the Government. A response to the report was issued in 2010 (see sub-section 3.5, below).

3.4 Report of the NTPC Review Panel

The independent NTPC Review Panel was established in 2009 and was tasked with examining the operations, corporate structure, and mandate of NTPC. The Panel did not identify any opportunities for major cost savings in NTPC operations. Their report indicated that NTPC was operating with reasonable efficiency and there were limited opportunities to significantly affect the corporation's cost structure. The Panel made several recommendations concerning operational efficiency (e.g. fuel handling, safety), corporate efficiency (e.g. capital project cost estimation, travel, salaries), and mandate (e.g. NTPC's role in conservation and alternative energy, public engagement, regulatory process delays and costs). Many of the recommendations are currently being implemented.

3.5

3.5 Government Response: 2010 Electricity Policy

The GNWT considered both the NTPC Review and the Electricity Review and issued a comprehensive response in May 2010. As a result of the direction established in the Government's response, rate policy guidelines were issued to the PUB in July 2010 with respect to the approach to NTPC rates. Based upon these guidelines, seven rate zones were established, with no rate increases to any customers (i.e. when rates were compared to what customers paid in October 2009) and significant rate reductions (down to a residential rate of 47.3 cents/kW.h) for NTPC Thermal Zone customers. This was achieved by:

- Ending the 2006/2008 GRA rider that was fully collected by that time;
- A GNWT payment of $6 million to pay down the balances in stabilization funds; and
- The GNWT foregoing the annual NTPC dividend of $3.5 million for 2010/11 and again in 2011/12.

NTPC filed a Rate Rebalancing Application consistent with the rate policy guidelines, and final rates were put in place for December 2010. The rates were designed based on 2007/08 costs and loads, with the exception of items changed by policy, notably a $1.2 million annual decrease in returns from thermal communities. (NTPC returns in thermal communities are now limited to an interest coverage ratio of 1.5 times interest expense, which is very close to simple cost recovery plus a small profit.) The new rates were introduced at the same time as all stabilization fund riders ended.

4

4.0

4.0 Cost Pressures, Rates, and Rate Increases: Other Jurisdictions

As a whole, the electricity utility sector is facing ever increasing cost pressures, with electricity rates rising world-wide due to growing demand, higher fuel costs, operating costs to maintain aging systems, and capital expenditures to sustain and expand them. In fact, many utilities are finding that significant portions of their generation and transmission systems, built during high growth periods in the 1960s and 70s, have reduced reliability, pose safety and environmental risks and are in need of rehabilitation.

NTPC's operations have a number of unique characteristics. However, like NTPC, some utility companies across Canada provide electricity services in locations that are not connected to electricity grids and serve small, often isolated populations.

To assist in the examination of NTPC's proposed GRA we examined the provision of electrical generation, transmission and distribution in Yukon, British Columbia, Alaska, Manitoba and Newfoundland / Labrador. Detailed findings related to these jurisdictions can be found in Appendix 3.

A summary of our findings can be found in the subsections below.

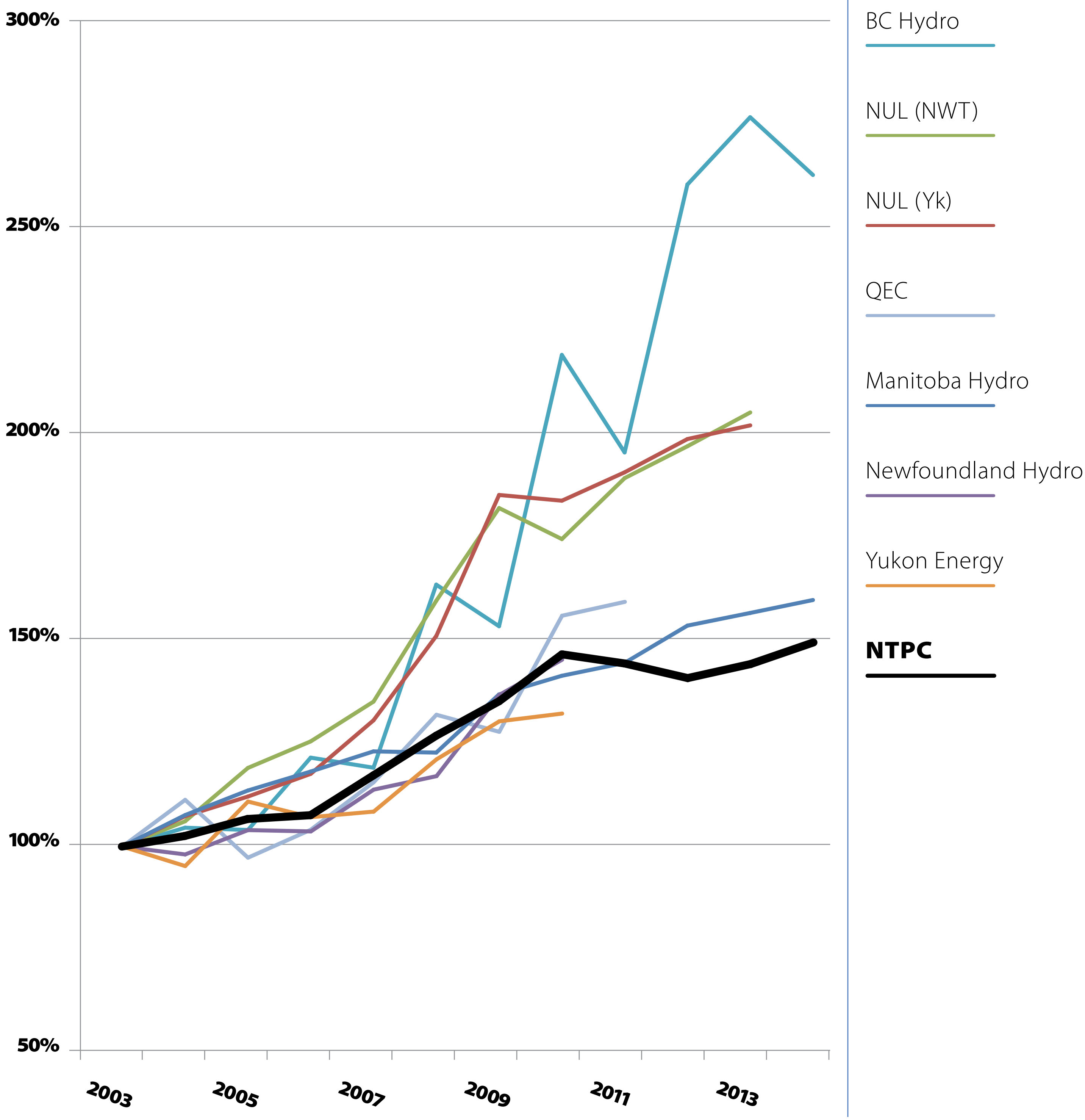
4.1 Cost Pressures

A utility's operating costs relate to day-to-day operations and maintenance activities, such as costs for labour, pension expense, materials, travel, supplies and fuel. Utilities face operating cost pressures due to inflation, customer growth, changing customer service levels, maintenance activities, and public and employee safety.

Operating and maintenance (O&M) costs usually make up between 20 and 40% of a utility's revenue requirements and represent the largest category of "controllable" cost drivers. An example of a largely uncontrollable cost is the price of fuel – in NTPC's case, the cost of diesel fuel for its primary and backup generators.

Comparison of cost pressures, in particular those cost pressures that are controllable, suggests that NTPC has done relatively well in controlling its cost growth. Table 4.1 illustrates that NTPC fares well, particularly when compared to utilities where future year O&M cost information is available.

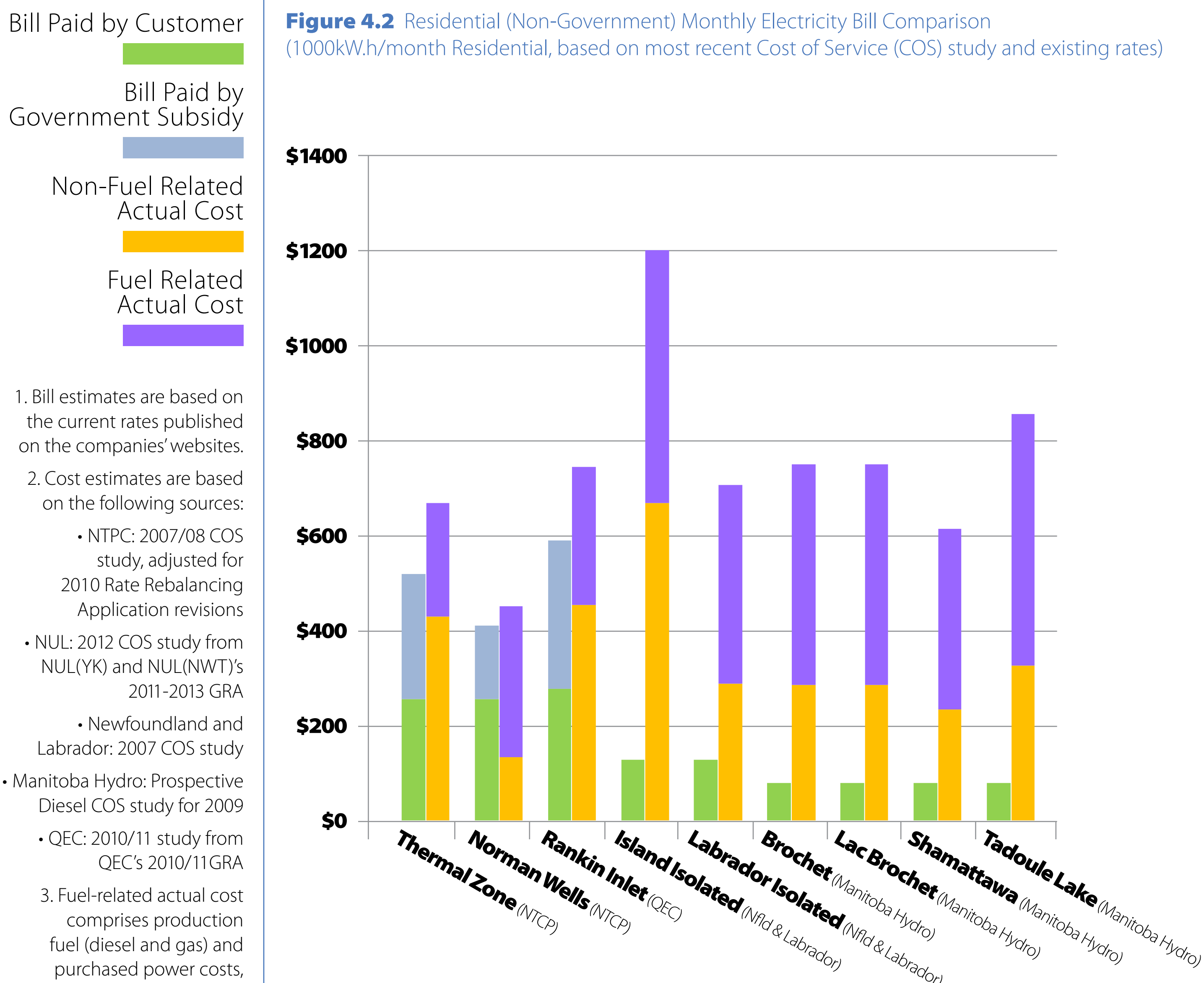
Figure 4.1 Non-Fuel O&M Costs, NTPC and Other Utilities (All costs indexed to 2003)



4.1

Figure 4.2 below compares actual costs and bills for NTPC thermal communities with off-grid diesel communities in Nunavut (Rankin Inlet), Newfoundland, Labrador, and Manitoba. The bottom left (green) portion is the amount a customer pays. The other three portions show the actual cost (broken into non fuel and fuel components), the cross subsidies from other customers, and for the NWT and Nunavut examples, the government subsidies. Newfoundland, Labrador, and Manitoba actual generation costs are higher, and their customers' bills lower, than in NWT communities. Unlike Manitoba and Newfoundland and Labrador where lower cost integrated grid customers subsidize a small minority of diesel off grid customers, in the NWT and Nunavut it falls primarily to governments to help make electricity more affordable.

Figure 4.2 Residential (Non-Government) Monthly Electricity Bill Comparison (1000kW.h/month Residential, based on most recent Cost of Service (COS) study and existing rates)



1. Bill estimates are based on the current rates published on the companies' websites.

2. Cost estimates are based on the following sources:

- NTPC: 2007/08 COS study, adjusted for 2010 Rate Rebalancing Application revisions
- NUL: 2012 COS study from NUL(YK) and NUL(NWT)'s 2011-2013 GRA
- Newfoundland and Labrador: 2007 COS study
- Manitoba Hydro: Prospective Diesel COS study for 2009
- QEC: 2010/11 study from QEC's 2010/11GRA

3. Fuel-related actual cost comprises production fuel (diesel and gas) and purchased power costs, where applicable.

4.2 Rates and Rate Increases

Rates are largely determined by costs associated with the operation of a utility. As electricity rates are regulated, only costs that are approved by the regulator (in the NWT this is the PUB) can be included when the utility revenue requirements are finalized. Approved costs depend, to some extent, on the organizational structure and government policies that define the Utility's operating environment.

Governments also play a significant role in determining the amount that consumers pay for electricity. In other jurisdictions, rates are influenced by government subsidies and cross subsidization between rate zones.

Because of the complexity of approaches taken in various jurisdictions to set electricity rates, it is useful to monitor the changes in rates over time. Examination of rate change provides a perspective on revenue requirement changes and on the changing impact of rates on customers. Table 4.1 compares the monthly residential bill for 1000 kW.h of consumption for Inuvik, Yellowknife, and several cities across Canada in April 2008 and again in April 2011. The Inuvik and Yellowknife bills include the 2006-08 GRA final rates and riders, implemented in January 2008.

4.2

Sources: Hydro Quebec, 2008 and 2011 Comparison of Electricity Prices in Major North American Cities (rates in effect April 1); InterGroup Consultants Ltd. personal communication; www.bankofcanada.ca /rates

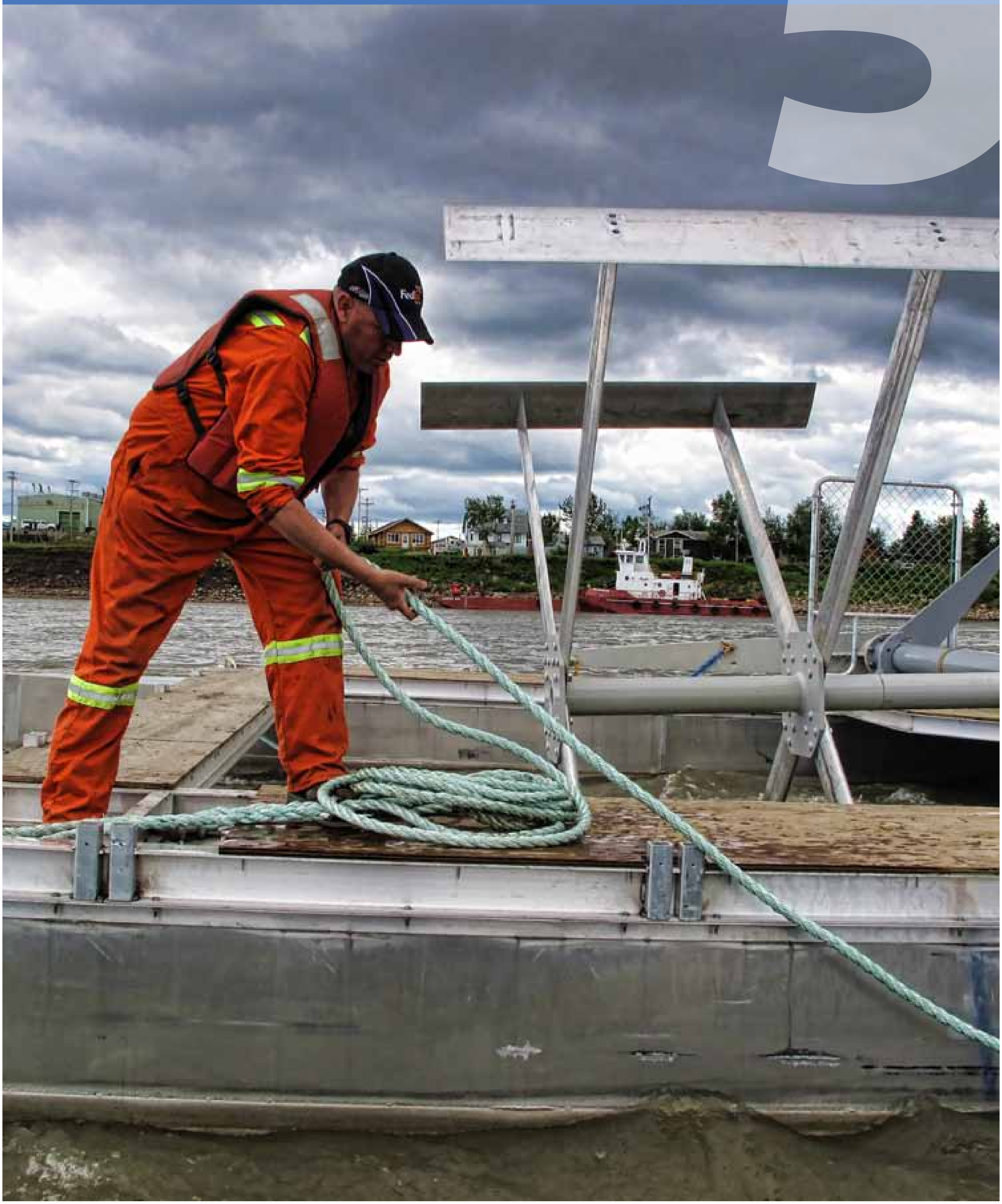
Table 4.1 Comparison of Monthly Bills ($Cdn): 1000 KW.h Consumption

City	April 2008	April 2011	Average Annual Change (%)
Regina	109.11	137.92	8.12%
Edmonton	134.51	164.04	6.84%
Ottawa	106.07	124.37	5.45%
Halifax	117.53	136.23	5.04%
Toronto	111.66	129.01	4.93%
Winnipeg	64.41	73.05	4.29%
Vancouver	69.78	76.81	3.25%
Yellowknife (NUL)	**237.58**	**256.62**	**2.60%**
St. John's	104.31	109.86	1.84%
Moncton	115.13	118.23	0.89%
Montreal	68.12	68.21	0.04%
Charlottetown	148.07	145.07	-0.68%
Inuvik	**425.12**	**246.02**	**-16.67%**
Canadian CPI, All Items (2002=100)	**113.5**	**119.8**	**1.80%**

Note: Inuvik bill is winter season (1000 kW.h TPSP threshold); Yellowknife bill information has been estimated.

For most Canadians, electricity rate increases have exceeded growth in the Consumer Price Index (CPI) during the time period. In fact, only four cities identified in the table have seen rate increases that have been lower than the rise in the CPI. Further, while it is no surprise that Yellowknife's bills are higher than those in southern cities (due to operational costs, limited economies of scale, etc.), the rate of increase over the last three years in Yellowknife is lower than all but Montreal and three cities in Atlantic Canada. It is also important to note that, as a result of the rate restructuring carried out in 2010, the rates for Inuvik have declined by almost 17% per year.

5



5.0

5.0 Cost Pressures, Rates, and Rate Increases: NTPC

The earlier sections of this report have provided a context for the upcoming NTPC GRA. This section examines the main cost drivers described in the 2012-14 GRA, including NTPC's load forecast, the impact of possible GNWT financial support and the proposed approach to rate increases over the next few years.

5.1 Overview

In general, utility sales are influenced by economic growth, population growth, and weather. Economic activity in the NWT has been steady or declining, and prospects for significant new electricity loads are limited. This being said, there may be possibilities for some industrial growth in the mid to long-term.

The recently released 2011 Canada Census reported that the NWT's population did not change between 2006 and 2011. The Census also reported that the number of occupied private dwellings in the NWT has risen by 3.3%, from 14,224 in 2006 to 14,700. This suggests a modest rise in residential customer loads.

NTPC forecasts a 2012/13 revenue requirement of about $97.3 million. While this is a significant increase over the previously approved revenue level, it is clear that NTPC has had recent success in bringing its operating and maintenance costs in line with inflation, which must remain a priority in an operating environment of no or minimal load growth. Most other components of the revenue requirement are harder to influence, or are entirely beyond NTPC's ability to control.

5.2

5.2 Load Forecast

Table 5.1 provides a summary of NTPC's load changes from 2007/08 through to 2013/14. The forecast is broken down by zone (including wholesale sales) and is normalized for recent weather variations.

Table 5.1 Summary of NTPC Load Changes (MW.h)

Zones	2007/08 GRA	2010/11 Actual	% Change 07/08 to 10/11	2013/14 Forecast	% Change 07/08 to 13/14
Snare Zone (includes Yellowknife)	181,740	182,126	+0.2%	186,525	+2.6%
Taltson Zone (includes Hay River)	58,702	58,473	-0.4%	58,987	+0.5%
Thermal Zone	72,729	73,950	+1.7%	74,655	+2.6%
Totals	**313,171**	**314,549**	**+0.4%**	**320,167**	**+2.2%**

Most utilities benefit from system sales growth, but NTPC is facing very low growth overall. As well, based on available information, NTPC is expecting reduced sales for some of the 19 diesel communities in the Thermal Zone. The 2010 establishment of the NTPC Thermal Zone will shield the individual communities with declining sales from further rate increases as long as the overall sales growth in the Thermal Zone remain, as projected, to be slightly positive. If overall sales in the Thermal Zone decline, then rates would rise, as the allocated costs of the Utility would need to be spread over reduced consumption.

We see no reason not to accept NTPC's load forecast for the purpose of this review. However, it is important to remember that actual weather in any year can cause significant variations in actual sales when they are compared to normalized forecasts.

In reviewing the NTPC sales forecast, new revenues will be added starting in 2012/13 to account for interruptible sales to four government customers for electric heating in Fort Smith ($113,000 by 2013/14). Later in this report we have provided additional context and a recommendation aimed at increasing sales.

5.3

5.3 Breakdown of Cost Components and Overview of Potential Efficiencies

Table 5.2 is a summary of the preliminary 2013/14 revenue requirement, compared to the 2007/08 approved revenue requirement and includes actual costs for 2010/11. This table illustrates the trends among the main cost components.

Table 5.2 Preliminary Revenue Requirement Summary ($Millions, Rounded to Nearest $100,000)

Cost Components	2007/08 Test Year	Actual 2010/11	Forecast 2013/14	% Change (Six Years)	% Change (Average Annual)
Salaries and Wages	$18.3	$21.2	$23.5	28%	4.3%
Non Production Fuel	$0.7	$0.9	$1.0	43%	6.1%
Supplies & Services	$10.6	$13.0	$11.9	12%	1.9%
Travel & Accommodation	$2.2	$2.2	$2.2	0%	0%
Total O&M	**$31.8**	**$37.3**	**$38.6**	**21%**	**3.3%**
Production Fuel	$17.3	$17.9	$22.7	31%	4.6%
Depreciation/ Amortization	$12.6	$14.8	$21.5	71%	9.3%
Interest	$10.4	$9.6	$11.6	12%	1.8%
Return on Equity	$9.0	$7.5	$7.2	-20%	-3.7%
Total	**$81.1**	**$87.1**	**$101.6**	**25%**	**3.8%**

NTPC's draft GRA presents cost information that is reasonable and defensible. This being said, there is some room for further examination and the possibility of some policy-based alterations to the reporting of depreciation and return on equity. As well, examination of mitigating actions that could be taken to reduce costs related to the purchase of production fuel and obtaining the best rates when borrowing money also warrant discussion. Sections 6 and 7 provide further discussion of these matters.

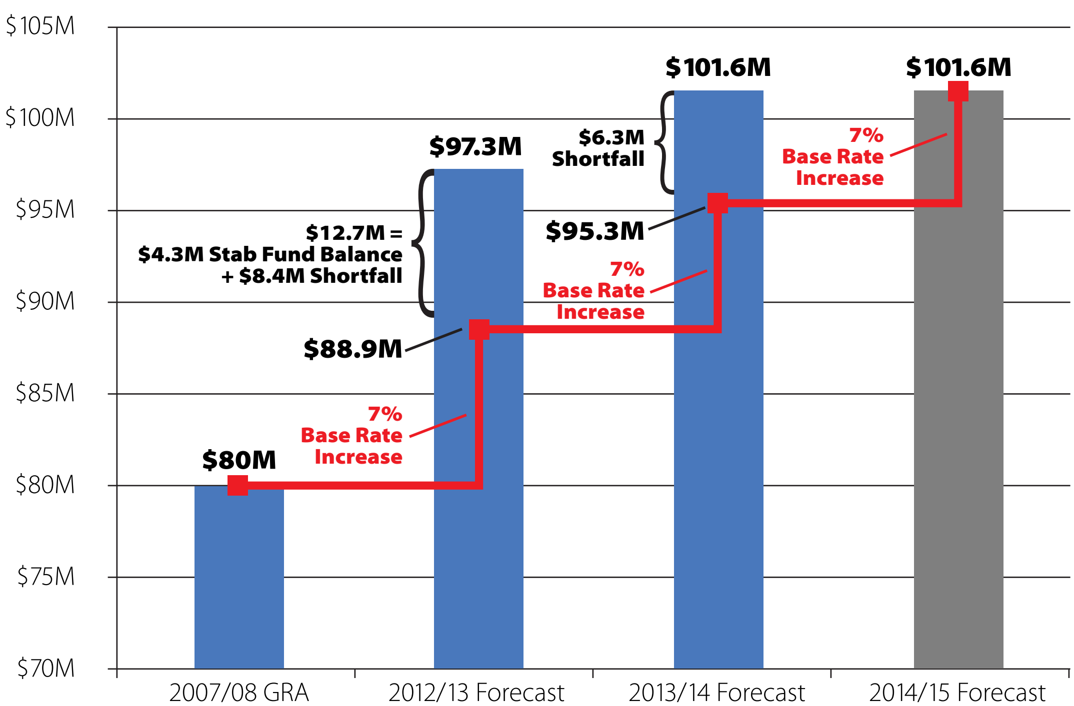
5.4 The Proposed 7/7/7 Rate Increase Scenario

During the course of our review we were informed that the GNWT is considering direct financial support to mitigate the impact of the required rate increases on customers, keeping the impact to no more than 7% per year in most cases. We have developed our report based on the implementation of the proposed 7/7/7 rate increase scenario. This scenario is expected to include the following aspects:

- Energy rates (cents/kW.h) are to increase by 7% in all communities other than Norman Wells – this includes wholesale and retail (residential, general service, and street lighting customers);
- Government customers are expected to face the same 7% rate changes on energy as other customers; and
- No change is expected to customers' demand charges (the fixed $/month component of the bill).

Figure 5.3 below illustrates the revenue forecast from sales under proposed rate increases and the resulting shortfall in relation to the revenue requirement for 2012/13 – 2014/15 fiscal years. The graph is based in part on the information provided in Table 5.2.

Figure 5.3 NTPC Revenue Requirement and Estimated Sales Revenue



While the wholesale energy rate is increasing by 7%, the wholesale demand charge is not. Therefore, the net cost for wholesale power to NUL in Yellowknife is increasing by something less than 7%. In addition, NTPC's cost changes do not affect the distribution component of the Yellowknife bills, which also form the basis for the TPSP calculations. As a result, the net effect on TPSP-eligible bills from NTPC's application is less than 7% each year.

5.5

5.5 Possible GNWT Financial Support

In order to reduce the immediate impacts of the increased revenue requirement on electricity rates, NTPC is proposing a deferred implementation of rate changes over three years. This would result in the smoothing of rate increases. NTPC has therefore proposed that it will seek GNWT contributions of $18.2 million, spread over two years. This contribution, combined with a 7% rate increase in each of the next three years would permit NTPC to generally meet its revenue requirement and eliminate the current balance in the Consolidated Stabilization Fund.

In considering this proposal for financing the revenue requirement of NTPC, it will be important that GNWT decision-makers keep in mind:

- The requirement to establish a timely, efficient way to refund or recover deferral account balances in the future; and
- How inflationary increases will be managed in 2014/15: at this point, there is limited room to address inflation costs within NTPC's cost structure.

The impact on customers is a key issue. The tables below provide an estimate on the impacts of residential (at a thousand kilowatt hours per month) and commercial customers (at 3,000 kilowatt hours per month).

Table 5.4 Electricity Bill Impacts for Residents, 1000 kWh Consumption

Anticipated Monthly Power Bill Increases (Winter) Residential Ratepayers (1000kWh/month)				
Zone	**2012/13**	**2013/14**	**2014/15**	**Total**
NTPC Thermal	$11	$12	$13	$36
NTPC Taltson	$12	$13	$14	$39
NTPC Snare	$11	$12	$13	$36

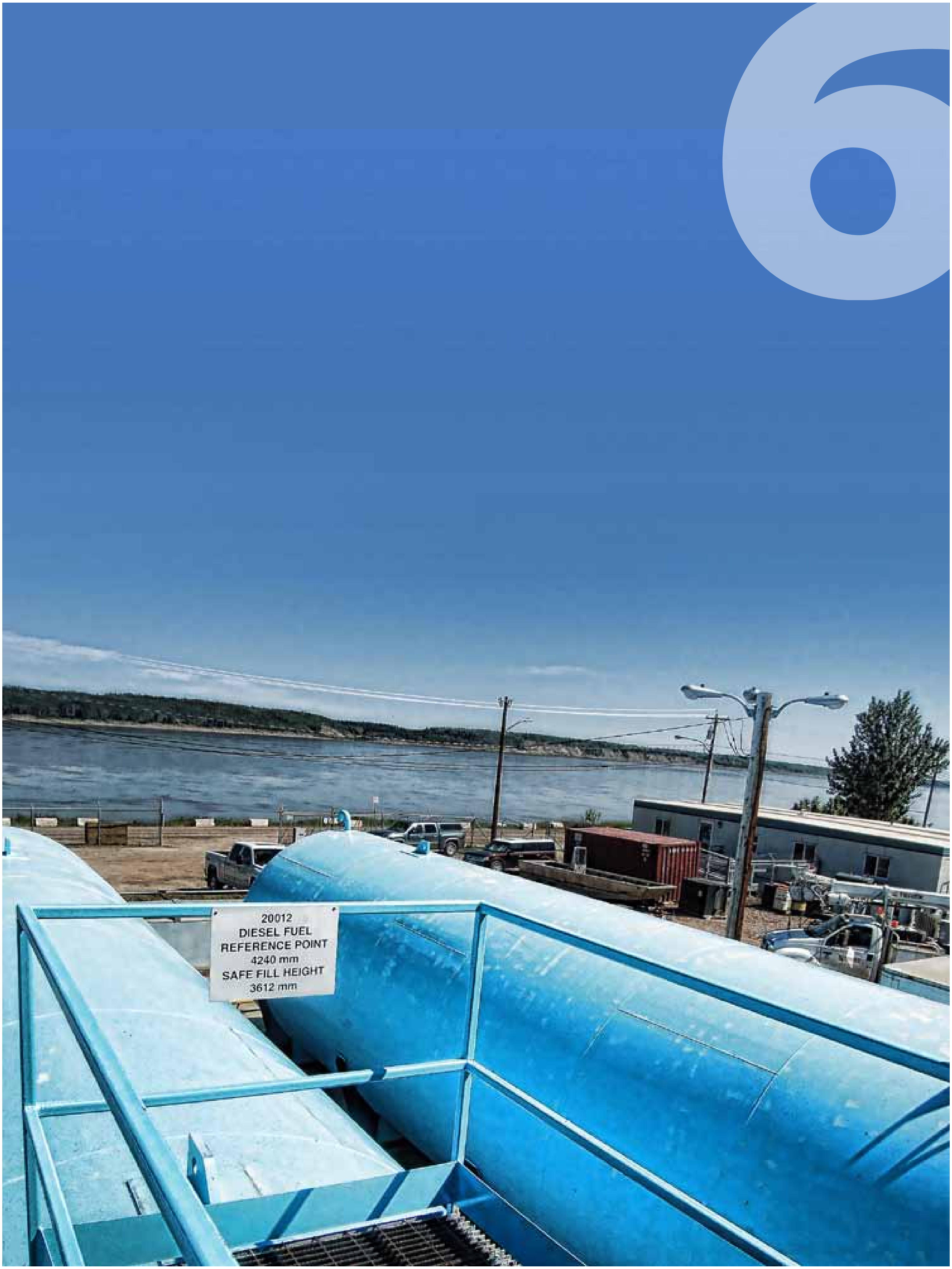
*These are projections of monthly bills for January 1st of target years.

Table 5.5 Electricity Bill Impacts for Businesses, 3000 kWh Consumption

Anticipated Monthly Power Bill Increases (Winter) Commercial Ratepayers (3000kWh/month)				
Zone	**2012/13**	**2013/14**	**2014/15**	**Total**
NTPC Thermal	$89	$95	$101	$285
NTPC Taltson	$28	$30	$33	$91
NTPC Snare	$66	$70	$75	$211

*These are projections of monthly bills for January 1st of target years.

6


20012
DIESEL FUEL
REFERENCE POINT
4240 mm
SAFE FILL HEIGHT
3612 mm

6.0

6.0 Finding Efficiencies: Strategies to Manage Short Term Rate Increases

The next two sections of this report examine NTPC's GRA and the GRA process. Section 6 provides comments and recommendations related to key aspects of NTPC's current draft GRA. Section 7 discusses actions that could be taken in the longer term, to contain NTPC and overall system costs.

Although the GRA submission that we reviewed is preliminary and subject to refinement, there are a number of matters and observations related to NTPC's cost categories that we believe warrant some consideration.

6.1 Salaries and Wages

NTPC has taken significant steps to minimize the impact of salaries and wages on the proposed revenue requirements. It has flattened the organization structure and eliminated nine positions, including three senior management positions. As well, senior management bonuses were not paid in 2010/11, and going forward, all management bonus pay will conform to GNWT bonus program policies.

The net effect of the restructuring actions by NTPC is to reduce staffing approximately to 2007/08 levels, with the exception of apprentices. This would seem appropriate recognizing the minimal growth in sales and customers. It will be important for NTPC to avoid new staffing when the system is static and there are growing cost pressures from capital investment and fuel costs.

The expected increase in NTPC salaries and wages in the six year period since 2007/08 is $5.2 million, or an average of 4.3% per year. This is reasonably good performance in a period when electric utilities throughout Canada have faced a shortage of skilled labour and upward salary cost pressures in excess of inflation. NTPC is hoping to develop a northern apprenticeship program to train northerners to fill future job vacancies, a good objective given the growing shortage of technical personnel within the industry.

There are a couple of additional factors related to salaries and wages that impact the revenue requirement that should receive some further consideration. The first is related to Overhead Capitalized (overhead and administrative costs related to capital projects). For most utilities the trend has been to decrease the Overhead Capitalization Rate as they have fewer new capital expenditures and recent accounting policy changes encourage expensing of overhead rather than capitalization. The draft GRA submission indicates that NTPC has recently increased its Overhead Capitalization Rate from 10% to 18%. While this may be higher than the rate used by some (but not all) other utilities, NTPC's large capital program justifies a higher Overhead Capitalized Rate.

The impact of a higher Capitalization Rate is to decrease the revenue requirement in the near term as more expenses are capitalized. Over the longer term the higher rate base of capital projects (including the Overhead Capitalized) attracts greater depreciation expense and utility return. Therefore, it will be desirable to reduce the Overhead Capitalization Rate in the future if the capital program winds down.

A second issue to consider is the cost of pension and other post-retirement benefits. For most utilities these costs have been growing rapidly in recent years. One large factor driving this growth has been the actuarial reduction in the retirement plan discount rate, the impact of which is to increase the funding obligation of corporations.

An on-going issue for most utilities is whether to include some or all of employee bonus payments in the pension obligations and whether these costs should be funded by ratepayers or shareholders. In the last PUB Decision only 50% of NTPC's management bonuses were allowed for funding by ratepayers. Since then, NTPC has revised its management bonus levels to be consistent with that of the GNWT. It is not clear how this corporate policy change impacts the appropriateness of ratepayer versus shareholder funding of this part of the pension.

6.2 Operations & Maintenance (O&M) Cost Components

The draft GRA also includes Other O&M cost components. Our review of the information provided suggests that estimated costs in O&M are generally well contained. General comments related to these cost components can be found below.

Non Production Fuel is fuel for NTPC's vehicles and for heating NTPC's buildings. The target is to keep fuel consumption volumes the same as the amounts approved in the 2007/08 GRA.

Supplies and Services include materials, insurance, property taxes, and grants in lieu of taxes. These costs have decreased since peaking in 2009/10 to an average increase of 1.9% per year since 2007/08.

Travel and Accommodation costs have stabilized at $2.2 million. Increases in air charter costs to fly power line technicians to trouble spots have been offset by greater use of technology, especially teleconferencing and tele-control, which remotely monitors NTPC's isolated plants.

Taken together, NTPC's estimated expenses for its O&M cost components result in a relatively modest average annual increase of 3.3 % per year between 2007/08 and 2013/14. Based on the research done for this review it is important to note that few utilities are managing to keep O&M cost increases to a level this low.

6.3 Cost of Production Fuels

The cost of fuel (diesel fuel and natural gas) used for the generation of electricity is a major cost category in the NTPC revenue requirements. It is the second largest area of cost increase (following depreciation expense) since the last GRA revenue requirements review in 2007/08. Costs have risen from just over $17.3 million (including Norman Wells) in 2007/08 to a forecast of just under $23 million in the proposed 2012/13 GRA submission. This increased cost creates a shortfall of $5 million that makes up one-third of the total revenue requirements cost difference between 2007/08 and the proposed 2012/13 GRA. (Note: The NTPC forecast does not include impacts that may develop in Inuvik due to reduced natural gas deliverability).

Figure 6.1 shows the changes in diesel production fuel costs to NTPC since 2007, along with the diesel fuel reference price from the 2007/08 GRA.

6.2

Actual Diesel

2007/08 GRA

Figure 6.1 Historical Diesel Fuel Prices since the 2007/08 GRA

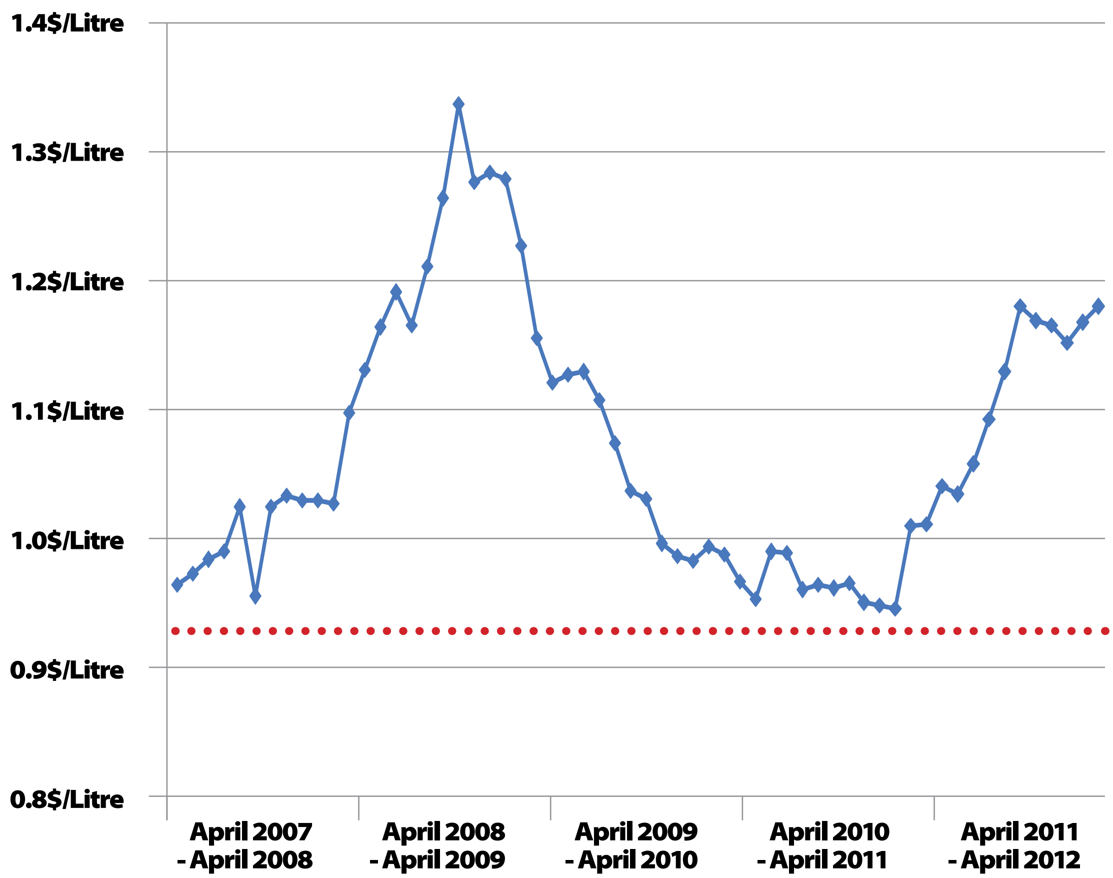


Figure 6.1 demonstrates the extreme volatility in petroleum products costs and the low reference price included in rates back in 2007/08. The impact of not adjusting the reference price quickly enough over the last five years has been large transfers to the diesel rate stabilization fund.

The total of $7 million in payments from the GNWT (and a possible further $4.6 million in future) to pay down the Stabilization Fund balances is a major benefit to ratepayers. The payments have reduced pressure on revenue requirements as well as "clearing" much of the account balances. These payments and a proposed additional $4.6 million payment in 2012/13 will assist in stabilizing rates going forward, as long as an efficient mechanism is established and used in a timely manner to revise the reference price of production fuel.

The Fuel Services Agreement with the Petroleum Products Division

NTPC now purchases all its diesel fuel from the GNWT's Petroleum Products Division (PPD) under a 2005 Fuel Services Agreement. PPD arranges for the purchase and delivery of diesel fuel to the storage tanks in NWT communities, and invoices NTPC for the actual cost of the fuel, plus a charge per litre to cover PPD's own costs for transportation, storage, and administration. The Agreement between NTPC and PPD appears to have been beneficial to both parties as PPD has realized economies of scale in its diesel fuel procurement and transportation, and NTPC receives fuel at competitive prices with low overheads.

When negotiated in 2005, the Agreement identified approximately $400,000 in costs that needed to be recovered by PPD. NTPC's diesel fuel use has increased since the Agreement was signed. As a result, PPD can expect to receive revenues of over $1.1 million per year during the period covered by the draft GRA. This figure includes new revenue of $210,000 that PPD will receive when NTPC reverts to diesel fuel use in Inuvik. The $400,000 in costs identified by PPD in the 2005 Agreement are likely substantially understated in 2012, but they are unlikely to be as high as $1.1 million.

The current Fuel Services Agreement ends in December 2015, but there may be an opportunity to renegotiate it before then. There is significant value to the services PPD provides to NTPC, but it is difficult to see that PPD incurs direct costs of over $1 million. In our view, since both parties benefit from the economies of scale in purchasing, delivery and storage of the diesel fuel, it would seem fair that the PPD mark up should not be more than the actual cost of the service provided to NTPC. If the mark-up is greater than the actual cost of the service being provided by PPD, then electricity rates would be subsidizing PPD fuel sales. This may be the objective of the GNWT, but nonetheless, should be considered from a government policy perspective.

No potential cost saving to NTPC from a renegotiated agreement has been factored into our analysis.

Hedging

Both PPD and NTPC appear to have authority to hedge diesel fuel prices to control volatility. However, an unfortunate hedge in the early 2000s led to considerable criticism of PPD when the hedge went negative, and PPD is now less likely to hedge future purchases. NTPC also has the ability to hedge prices to minimize price fluctuations but is equally reluctant to do so.

NTPC should remain alert to financial hedging options to smooth prices but we agree that fuel price hedges should not be used frequently.

Recommendation

NTPC, PPD, and other government officials should attempt to reach a consensus on the cost of the service PPD provides to NTPC and whether fuel sales in communities served by PPD are indirectly being subsidized by the PPD charges on diesel fuel used for electricity generation.

6.2

Recommendation

In order to streamline the examination of diesel fuel prices and price forecasts in GRA reviews, NTPC should establish a diesel fuel price forecast methodology and submit it to the PUB for approval. This methodology should be clear, easy for consumers to understand, and substantially reduce or eliminate detailed discussion on fuel prices during periodic GRA reviews.

Further, the diesel fuel price forecast should be incorporated into rates on a semi-annual basis in October and April, ensuring that fuel is treated as a "pass though" item. The rider for the Consolidated Stabilization Fund should also be reset each October and April with a two year recovery and there should no longer be a threshold limit before NTPC could apply.

The Consolidated Stabilization Fund

There are many factors that have led to the significant increase in revenue requirements since 2007/08. However, the infrequent updates to the diesel fuel reference price into rates and the build up in the fuel rider, and now the Consolidated Stabilization Fund, are matters that need not reoccur. NTPC had an approved methodology to act on both these diesel fuel price matters, but for various reasons the fund balance has continued to increase. Now that territorial energy policy matters and rate design issues are being resolved, it is timely to address mechanisms to avoid rate shock from diesel fuel price escalation and volatility in the future.

The issue of rising and volatile petroleum and natural gas prices is not new and most jurisdictions in Canada have approved methods to deal with them. For example, in B.C. the natural gas utilities adjust their commodity prices each quarter based on a forward estimate of natural gas prices from NYMEX. At the end of each year the differences in actual versus forecast costs held in a deferral account are set for recovery over a three-year period and a natural gas cost rider is adjusted up or down as necessary. The regulator reviews these applications for accuracy but no regulatory proceeding occurs. The advantage of quarterly price adjustments is that prices reflected in rates are never far out of the market and the benefit of the three-year cost recovery is that the volatility in the market is smoothed out for ratepayers.

The circumstances in NWT are similar and a mechanism could be tailored to the fuel purchase and delivery patterns in NWT. We found, during our review, that the existing mechanism of adjusting prices every six months in October and April will work best with the purchasing practices of PPD. Adjusting the Consolidated Stabilization Fund rate rider also in October and April seems appropriate, although instead of a one year recovery, a two or more year recovery would help to smooth out the volatility that will occur in market prices.

Perhaps the most important feature of a revised approach to diesel fuel price setting and changes to any associated rider is that the mechanism should be automatic - with the regulator reviewing and approving the changes after due diligence checks, but without an extended and formal regulatory process. This approach seems reasonable in that there is no "winning" or "losing" involved in the regulatory review of fuel price changes; the prudently incurred costs will be recovered without profit or loss.

As well, it is important to recognize that automatic semi-annual adjustments, as a regular feature of rate setting, will ensure deferral accounts remain manageable and there would be less need for government intervention.

6.4

6.4 Regulatory Considerations

Everyone we spoke to had views on the state of regulation in NWT. Virtually all are disappointed with the high cost of PUB hearings and the length of time to get Decisions from the Board. The last GRA proceeding in 2007/08 cost approximately $2.5 million in direct costs for consultants, lawyers, intervener funding and proceeding expenses. This is a cost of about $130 for every retail electricity customer, or $60 for every resident in the NWT. For a large utility in the south the cost of a full oral hearing would likely range from one to several dollars per residential customer. In addition to monetary costs, there is a cost to the operating efficiency of the Utility as management attention is diverted to the hearing process.

In its last Decision the PUB issued some 50 Directives to the Utility. Thirty remain outstanding, to be answered in the upcoming GRA. This is a trend that we have also seen by regulatory tribunals across Canada. However, it should be remembered that responding to these directives diverts Utility personnel from their primary task of operating a safe and reliable electricity system. No doubt some directives are necessary but all regulators should weigh the benefit of each directive against its cost in terms of time and expense. In the end the ratepayers will pay for all direct and indirect costs.

The PUB will review many of the critical factors and reach its own conclusion as to whether a streamlined process is appropriate. For example, as discussed in the next section, if NTPC proposes to the PUB a reduced return on equity, there will be little to debate on these issues at a public hearing.

NTPC has also largely reduced staffing to 2007 levels and revised management bonuses so that salaries and wages costs are not much more than inflation since 2007. Fuel costs are largely a pass through from PPD. If there is no change to depreciation rates then the depreciation expense is a matter of verification rather than debate. Add to this the fact that the GNWT intends to provide direct funding to NTPC to reduce the impact of the upcoming GRA on consumers and a very good case can be made to the PUB to implement a streamlined process.

NTPC had forecast $1.6 million as its cost to prepare its application and participate in the regulatory process. This allocation may drop to below $1.2 million assuming the PUB accepts the case for a streamlined process and:

- Removes ROE matters from discussion at a public hearing (savings of at least $300,000);
- Determines that a full Cost of Service study is not required (if the GNWT does propose to provide funding to facilitate "across the board" increases to zone-based rates); and
- Agrees to a combined hearing for Phases I and II (savings of at least $100,000).

With a decline from $1.6 to $1.2 million in GRA regulatory costs, assuming these costs are recovered over four years, the amount being built into rates drops from about $400,000 per year to $300,000 per year.

Government should consider presenting these views to the PUB to support the case for a streamlined process. NTPC, as the agent of GNWT, could make this case in its application, but given its role as proponent, it might not have as much weight with the Board as it would if it is a Government position.

Recommendation

In the General Rate Application, NTPC should propose a streamlined process to the PUB that includes no debate of capital structure, return on equity, or development of a detailed cost of service study. The GNWT should consider supporting this position through a submission to the PUB explaining the intent of the proposed government support.

6.5

6.5 Capital Structure and Return on Equity (ROE)

A regulated investor-owned utility earns its profit based on the awarded ROE on the portion of rate base funded by shareholder equity. The rate base is the depreciated value of all the approved capital assets on the books of the Utility. At the time of the last rate setting for the 2007/08 fiscal year NTPC was awarded an ROE of 9.25% on the actual Capital Structure of 51.4% debt and 48.6% equity. As well, the cost of debt was funded at its actual cost. Since then there have been major energy policy and structural changes that impact NTPC's Capital Structure and effective returns of the Utility.

All of the recent changes result in a new paradigm facing NTPC. The *2010 Electricity Policy* makes it clear that NTPC is to remain owned by GNWT and that reliable and affordable electricity supply is an essential service. The new rate structure creates a new NTPC Thermal Zone with a reduced effective utility return (1.5 times-interest-coverage) while maintaining the existing ROE and Capital Structure rate setting methodology for the hydro zones. Even with these changes, as noted above, the GNWT is facing a significant injection of funds to keep the proposed rate increases to reasonable levels.

In our discussions we heard how NTPC was once structured like an investor-owned utility and that the substantial dividends provided by NTPC to the GNWT were used to fund the Territorial Power Subsidy Program (TPSP). The TPSP subsidizes the initial consumption levels of residents living in what is now the Thermal Zone. However, the link between the amount of the dividend paid and the cost of the TPSP has now been broken as the TPSP now costs far more than the amount provided by the dividend. Further, the 2010 Electricity Policy set new limits to the consumption that will be subsidized by government. As a result of all of these changes it seems fair to say that the TPSP can now be viewed as a social and an economic program of GNWT and not tied to the NTPC dividend.

All of the changes noted above create an opportunity to revisit the Capital Structure and ROE of NTPC. For example, if the dividend is no longer tied to the TPSP, is it reasonable to ask if there is a need for NTPC to have as large a ROE? The ROE drives up the revenue requirement - each percentage point drop in ROE equals a reduction of approximately $0.8 million in the revenue requirement.

Should changes to the ROE structure be contemplated it will be important to recognize the current structure of NTPC rate setting. If one reduces the ROE in the Capital Structure, the impact will be to reduce costs and rates in the hydro zones which then leads to higher costs to government to subsidize the Thermal Zones' initial block consumption down to the now lower "Yellowknife" rate.

In looking at the near term circumstances, we considered the level of equity needed by NTPC and the ROE. In this context we also considered the regulatory costs and time to have the issue adjudicated in an oral public hearing before the PUB. Generally, the issues of Capital Structure and ROE are hotly contested and very expensive when canvassed at a revenue requirements hearing. There are the high costs of experts and an inordinate amount of time consumed in public hearings, often followed by lengthy delays before a tribunal renders a Decision. These issues are usually acrimonious, which reduces opportunities for utilities to work harmoniously with their customers.

Establishing an Appropriate Rate of Return

A suggested in the discussion above, for a Crown utility like NTPC there may be less need to maximize shareholder returns. Rather, there may be a greater desire to keep costs low for ratepayers. An early version of NTPC's draft GRA requests a market ROE of 9% on an actual equity component of just over 40% of rate base. This follows what appears to be a fairly traditional approach. However, there are alternatives. The Alberta regulator has recently awarded its benchmark investor-owned utilities an ROE of 8.75% for 2012.

All parties we spoke to, including NTPC, seem to support setting the ROE below the maximum that could be awarded by the PUB – although no specific level of discount was agreed upon. While reducing NTPC's revenues, this action would likely simplify approval, reduce regulatory costs and provide lower rates to ratepayers.

One option that was suggested was to set the ROE at perhaps 8-8.50%, which is below the level likely to be awarded to a low risk investor-owned utility anywhere in Canada. If the ROE were to be set at this level then there would be no reason to review this in a public hearing since the Utility would be accepting a return less than the regulator would otherwise be obligated to award. With the current low interest rates already existing, the proposed ROE would likely remain below market levels into the future. An alternative could be to prescribe a discount below the annual ROE benchmark set by Alberta's regulator. The discount would need to be meaningful to avoid calls for expert evidence: perhaps a discount of 0.5 to 1.0% would suffice.

The PUB has historically recognized the actual level of equity held by NTPC. Elsewhere it is not uncommon for regulators to deem a level of equity if it is felt that the actual equity component is too high. If the deemed equity for NTPC was set below the actual level of equity, it would mean that NTPC would receive only the weighted average debt percentage return on the portion of equity deemed to be funded by debt. However, in NTPC's case, as the current actual level of equity is close to the 40% there may not be much to be gained by artificially adjusting the equity component.

Interest Coverage

Another area to consider is the mandated 1.5 times-interest-coverage margin that is currently applied to debt servicing costs for assets in the NTPC Thermal Zone. The application of interest coverage, rather than establishing a ROE, helps reduce rates in the thermal communities. The overall result of the application of interest level coverage in the Thermal Zone will also be a lower level of government subsidy.

The use of 1.5 times interest coverage makes some sense when one considers typical debt covenants on borrowings. This being said, it is not clear that the interest level coverage is set at an optimal level, recognizing the ROE and equity thickness in the NTPC hydro zones.

We believe that the 1.5 times interest coverage should be continued for NTPC's thermal zones. This action reduces the overall revenue requirement when compared to a full commercial type ROE.

Recommendation

NTPC should consider seeking approval for an ROE at a level in the 8.0 to 8.5% range on NTPC's actual equity component of just over 40%, to provide a meaningful discount against the benchmark ROE awarded in Alberta.

6.6

6.6 Fixed Asset Amortization (Depreciation Expense)

The depreciation expense on fixed assets is a significant driver in the 2013/14 forecast revenue requirement. Since the last rate setting in 2007/2008, NTPC forecasts that the annual depreciation expense will need to increase by $8.9 million to about $21.7 million. A significant portion of this additional cost relates to increases in the amortization of the deferred costs for things like water licenses and generation plant and equipment overhauls. This deferred cost portion makes up $3.2 million of the $8.9 million increase. Much of the remaining $6.7 million increase can be attributed to new capital additions which result in an increase in the net rate base to which the individual asset's depreciation is applied.

NTPC's draft GRA also provides for the implementation of revised depreciation rates resulting from a recent review of the Corporation's assets by an experienced depreciation firm (the "depreciation study"). No depreciation study was completed for the last GRA, so the most recently completed study is from the year 2000. NTPC's auditors have indicated an updated study is needed. It is our understanding that the net effect of the proposed new depreciation rates is about a $1.6 million increase in depreciation expense compared to the currently approved rates.

The proposed increase in depreciation expense suggested by the depreciation study arises from a combination of changes to estimates of the lives of assets and the treatment of the cost of asset retirement (negative salvage). The largest increases relate to updated estimates of the life of diesel generating assets ($1.7 million, with the remainder of asset classes yielding a net $0.1 million reduction in costs).

Depreciation studies are highly technical and are subject to considerable judgment, so that the approval process for changes to depreciation rates could be involved and lengthy. Changes in depreciation rates are not normally allowed on an interim basis, and it is unlikely the new rates would be approved in time for the upcoming 2012/13 fiscal year.

Negative Salvage

NTPC's depreciation consultants have advised the Corporation that its provision for "negative salvage" is excessive when compared to actual costs for equipment retirement. The negative salvage balance is about $40 million and today's rates include about $2 million/year to build up this balance. The depreciation study concludes the appropriate balance should be $21 million and that $1.5 million should be set aside each year. To remedy this situation, NTPC proposes to stop collecting negative salvage from ratepayers at this time (i.e, put $0/year in rates) until the balance is more appropriate. This reduces overall depreciation expense by about $2 million per year compared to existing rates.

Notwithstanding NTPC's proposed approach to the matter, there are many options for dealing with the issue of negative salvage and the reduction in the "over-collection". In some jurisdictions energy utilities are not approved to collect negative salvage at all. The thinking in support of this perspective is that an asset, like a diesel generator, that has reached its end of life, will be replaced by another generator at the same site and the net cost of removal of the old generator becomes part of the capital cost of installing the new generator. This has not been the practice in NWT.

The options available to the regulator in approving new depreciation rates range from a temporary halt in collecting negative salvage (as proposed by NTPC) to a more aggressive approach based on drawing down some or all of the current negative salvage balance (either the excess or the full amount).

Determining the Life of Assets

The second proposed change in depreciation expense results from an overall reduction in expected asset lives. This change would increase NTPC's depreciation expense by about $3.8 million per year.

A major source of the increased depreciation expense is the proposed reduction in expected life of diesel generation assets in 3 categories:

- Structures (plants) from 40 years to 30 years
- Engines from 25 to 20 years
- Diesel Generation Electrical Equipment from 28 to 21 years.

These changes are very significant and it can be expected that they will be challenged during the regulatory process.

In our view, NTPC should reassess expected diesel life by size of unit and by unit status (i.e. primary use versus back up use units). For example, it is hard to imagine that the average life of the large diesels backing up Yellowknife would only be 20 years. Conversely, a very small primary generator in a small community might have a shorter life. NTPC's 2011 Strategic Plan notes the need to complete a condition assessment for its main assets to help prioritize overhauls, upgrades, and replacements.

NTPC would like to file its depreciation study with the PUB and move forward to regulatory review and approval of updated depreciation rates for implementation in 2013/14. This seems prudent due to the auditor's direction to do so, but this should occur only after the condition assessment is completed. Presumably this could be done as a separate application and reviewed in a written hearing process, perhaps with an initial workshop for the Corporation to explain its study findings and final proposal.

Recommendation

NTPC should consider advancing its condition assessment for its main assets, use the findings to update its recent depreciation study, and seek PUB approval for its updated depreciation rates through a separate written hearing process for implementation in 2013/14 or later.

7

7.0

Recommendation

The GNWT and NTPC should implement a regular planning and reporting structure centered on a Shareholder's Letter of Expectations, and a subsequent NTPC report back to the GNWT. As well, the GNWT should revisit the Strategic Direction issued in 2002 and the NTPC Act to ensure they are consistent with regard to the current corporate structure of NTPC and there is clarity with respect to NTPC's mandate.

7.0 Closing the Revenue Gap: Long-Term Cost Containment Strategies

It is important to recognize that not all opportunities for cost containment and revenue enhancement will be realized immediately. Nevertheless, there is considerable value in identifying those activities that will be of highest priority, in the longer-term, in controlling costs and then establishing a plan for further study and future decisions.

If we consider the period 2012 to 2014 as "transition years", then action related to the subjects discussed below can provide potential ways to reinforce a stable financial foundation for NTPC (and the GNWT) in the post-GRA era.

7.1 Governance Structure: The Shareholder-Utility Relationship

The *NTPC Act* mandates its Board to "act in accordance with the directions and policy guidelines that may from time to time be issued or established by the Executive Council". That *Act* also mandates NTPC to prepare long-term generation and transmission plans, update these plans annually, and to undertake programs to conserve energy.

As well, in 2002 the GNWT issued an "expectations document" to NTPC. The document included a listing of priorities that must now be reconsidered in light of GNWT recent policy changes. The priorities listed in the document included direction that NTPC:

- Aggressively pursue alternative generation technologies
- Aggressively pursue new domestic and export markets with a view to expanding the electrical sales base
- Aggressively pursue partnerships and joint ventures with northern parties
- Maximize the value of NTPC through profitable expansion and diversification

With the subsequent creation of Northwest Territories Hydro Corporation and its business development subsidiaries, NTPC's focus is now correctly on the provision of safe, reliable power at fair, regulated rates. However by doing so it is technically straying from its statutory mandate.

7.2

7.2 Direction to NTPC – Regular Issuance of Shareholder's Letter of Expectations

Long-term efficiencies are more likely to be achieved if there is well developed two-way reporting and communication between GNWT and NTPC. Both the *NTPC Review* and the *Electricity Review* discussed the need to improve this relationship. With new executive leadership in both organizations, changes have already occurred and both are eager to take further positive steps.

NTPC is a corporate structure and the GNWT is its sole shareholder. Both GNWT and NTPC officials expressed support for a "Shareholder's Letter of Expectations" (SLE). Every year or two, a SLE would be prepared by the GNWT and sent to NTPC. The SLE would describe GNWT's perspective on NTPC's priorities and performance expectations for the period covered by the letter. The SLE would provide a way for NTPC to be formally advised of changing government priorities and policies. For the SLE process to be most effective it would be important that NTPC have input into the preparation of the SLE.

NTPC would be expected to submit reports to the GNWT, outlining its successes in achieving stated priorities and describing the corporate results in relation to any performance measures in the SLE. The establishment of a SLE, and an appropriate reporting mechanism, may reduce the temptation for the GNWT to "micromanage" NTPC operations, reduce misunderstandings and miscommunications and encourage cooperation.

Measurement of Corporate Performance

The SLE and NTPC's response should include performance measures and targets. NTPC already refers to the need to develop and implement a set of KPIs in its *2011 NTPC Strategic Plan*. As well, its annual reports have, for some time, summarized trends in customer satisfaction, worker safety and reliability, and may be a source for information leading to the creation of some of the desired KPIs.

NTPC's performance measures should involve target setting by all employees. They should summarize the service, safety, and reliability of the system, and include industry standard measures to enable comparisons with peer utilities. Selected performance measures should also be "SMART": specific, measurable, actionable, repeatable, and targeted. The performance measures could be developed in consultation with the GNWT, industry associations, interested parties and customers.

In addition to the traditional reliability and safety performance measures, we have seen instances where customers want statistics on the average speed with which utility representatives answer complaints or emergency calls and the results of customer satisfaction surveys. Finally, while there is merit in benchmarking to similar utilities, customers often want to see that their utility is improving its performance statistics year over year. In Performance Based Regulation a utility is generally not able to share in financial incentives unless it meets its performance targets.

The performance measures will also prove helpful in communicating with and demonstrating to customers and ratepayers that their utility is providing safe and reliable service at reasonable costs.

Recommendation

NTPC should expand its use of standard industry safety and reliability indexes by setting measurable targets, reporting results at the community, zone, and system level, and comparing its results with those of similar utilities.

Recommendation

A comprehensive listing of performance measures should be prepared by NTPC that permit it to assess corporate performance in the context of shareholder expectations, customer interests and corporate priorities.

Recommendation

NTPC should calculate "GW.h Produced per Employee" as a useful "Key Performance Indicator" (KPI) to reveal trends at a glance in the future. (Note: This is about 1.89 GW.h/employee with 169 staff in 2012/13, and given recent staff reductions, is trending in a favourable direction).

7.3 Long Term Approach to Regulation

While criticisms of the PUB costs and process exist, there appears to be continuing public support for and trust of the PUB. This is an important finding since a regulatory tribunal relies on its independence and public trust to remain effective.

An overall goal of governments, regulators and utilities is to keep GRA review timelines and costs down, while respecting the meaningful role of the regulator. The 2006-08 NTPC GRA review, which cost ratepayers around $2.5 million on an $80 million application, is not a preferred regulatory model to pursue.

Addressing Intervener Costs

The *Public Utilities Act* gives the PUB the authority to require a utility applicant to pay interveners' costs. NTPC paid over $300,000 to fund interveners in the 2006-08 GRA process. As the *Electricity Review* noted, interveners and information requests (over a thousand for the last GRA) are significant expenses and the costs for these elements of the regulatory process are passed on to customers.

The *Electricity Review* recommended that cost awards should be limited to non-tax-based communities and non-profit organizations. The 2010 Electricity Policy (Action 9) stated the PUB would be directed to develop cost recovery guidelines that will outline eligible costs and standard reimbursement rates. Most provincial utility regulators have prepared similar guidelines, which can serve as models to consider.

Addressing the Costs of the Regulatory Process

Upon the completion of the current GRA, the GNWT may wish to undertake a review of the current legislation, the process, and the government's role in that process, and consider additional ways to ensure regulatory costs are low and proceedings are streamlined.

In discussion with the Board Chair, he is open to more efficient regulatory methods while maintaining the integrity of the Board. He has also identified that NTPC is likely to face future pressures as costs of the Bluefish dam enter the rate base and costs are incurred related to declining natural gas in Inuvik and Norman Wells.

With fewer than 9,000 NTPC customers, the regulatory regime must be tailored to minimize regulatory costs while maintaining effectiveness. There are many options that should be considered, including:

- Written hearings and other streamlined application protocols for less substantive applications;
- Establishing intervener budgets and perhaps having Board Counsel assist interveners on procedural matters so that other lawyers are not required;
- Establishing defined time limits for the regulatory process;
- Setting targets for application "turnaround" times and reporting results;
- Establishing multi-year rate setting with some inflationary components; and
- Negotiated settlement processes, and multi-year performance based rate setting.

For example, if NTPC had an on-going mechanism to revise diesel fuel costs and clear out variances, a stretch inflation (inflation less productivity) component for variable costs, a fixed ROE and automatic adjustments to annual depreciation for the completion of previously approved capital projects, NTPC could likely avoid hearings for many years. Most of these items need only be verified by the regulator rather than open to debate.

Establishing a process to adjust rates due to inflation is comparable to the simplified rate adjustment mechanism that was in place in New Brunswick for most of the last two decades. Utilities were required to file a summary package with the PUB for their information within some deadline after the rate change occurred (e.g., 90 days). If so desired by the Minister, the PUB may be asked to provide comments on the package, which would become part of the consideration as to the need for any further adjustments in subsequent years.

A more substantial change could be to adopt some aspects of the Saskatchewan model and change the quasi-judicial approach of the PUB to one more along the lines of an advisory council. The merits of such an approach should be studied in depth as to how it could be applied to the unique circumstances in the NWT. This includes the structure of the industry in the NWT and the fact that there are both public and private utilities, a complicating factor. Changes in regulatory oversight for investor owned utilities are often (justifiably) viewed differently than for government owned utilities.

The recent amendment to the *Public Utilities Act* enables the Minister to request that the Board perform undertakings on behalf of the Government. Therefore, at the Minister's request, the PUB itself could undertake a review and provide recommendations to Government on the opportunities to streamline the GRA process.

The GNWT likely does not have the legislative authority to issue direction specific to a GRA. Section 12 of the *Public Utilities Act* gives the Executive Council the authority to issue directives to the PUB respecting:

> "(1) (a) policies to be applied by the Board in the determination of its orders, decisions and rules; and
>
> (b) the general performance of the duties of the Board.
>
> (2) The Board shall ensure that directives of the Executive Council are implemented promptly and efficiently."

Many jurisdictions have this directive-making power in their utility regulator's enabling legislation. The extent to which such directives can legally intrude on the normal powers of the regulator is a theme visited frequently by legal advisors. Notwithstanding the recent changes made to the PUB legislation, the GNWT should explore making further changes that consider the options for change discussed above.

Recommendation

The GNWT should consider undertaking a review of the Public Utilities Act and the current GRA process with a view to streamline the process and control costs. This review could either be done by Government or through an undertaking of the Board.

7.4

7.4 Capital Structure and Dividend Policy

In the medium to long-term it appears that there may be the need for some substantial policy changes as established in the 2010 Electricity Policy. Most notably, the new Thermal and Hydro Rate Zones have return requirements that seem at odds with each other. Also, breaking the link between the NTPC dividends as a funding source for the TPSP calls into question the need for substantial dividends to government. The two issues are interlinked and should be considered together.

Consideration of recapitalization options may require consideration by the GNWT because of their potential impact on NTPC and GNWT debt ratings - those provided by debt rating agencies. It is well beyond the scope and timing of this review but we offer some comment since it would be to everyone's benefit to simplify the understanding of the Utility funding and rates.

Comparing the Diesel and Hydro Zone Rates of Return

There is currently a difference in the approach to setting a return for the Thermal and Hydro Zones. The current approach does not make much sense except to reduce the overall costs in the Thermal Zone while maintaining higher costs in the Hydro Zones (due to the use of a different approach to return on equity, or setting required reserve levels).

The investor-owned type Capital Structure and ROE structure that existed for NTPC has been mandated for some other Crown-owned energy utilities in Canada, and not for some others. Two examples of alternate approaches can help illustrate the matter.

In the early 1990s the Government of B.C. mandated that the rates of BC Hydro (a Crown Corporation) be set on a notional Capital Structure and that the pre-tax ROE be equal to the return of the most comparable investor-owned energy utility. Prior to that time BC Hydro had been funded almost entirely by government debt and rates were set at cost. BC Hydro had one of the lowest rate structures in Canada and the government saw an opportunity to receive large dividends from BC Hydro by changing its approach. Even now that BC Hydro rates are rising rapidly due to large capital investments and purchased supply contracts, the B.C. government is reluctant to decrease its dividends.

In contrast to B.C., the Province of Manitoba has not created an investor-owned type Capital Structure and ROE for Manitoba Hydro. That Crown utility has traditionally operated on a cost recovery basis with very low reserves or "equity" levels and no dividend paid to the owner (with one exception, in 2003). Starting in the early 1990s, with a ratio of 95% debt and 5% equity or reserves, Manitoba Hydro began to build up equity in order to improve its ability to withstand adverse events such as droughts. Manitoba Hydro generates nearly all of its electricity from hydraulic sources, and exports substantial proportions of this energy (up to 40% of revenues come from export customers). The result is that Manitoba continues to have some of the lowest electricity rates in North America.

One might also wish to consider the effective tax incidence when considering charging an ROE to customers that then becomes a dividend revenue source to government. Typically the income tax system is more progressive than collecting government revenue via the electricity rates.

There are a host of options the GNWT could consider, including maintaining the existing separation between the capital recovery in the Thermal versus Hydro Zones. One radical idea might be to move the NTPC to a debt basis with an interest coverage target and direct that some or all the interest coverage be recovered from the Hydro Zones. This would lower NTPC rates in the thermal communities to a cost only basis and maintain rates in the hydro communities for interest coverage on debt purposes. A reduction in the differential between the zones could reduce the cost of the TPSP subsidy program.

7.5

7.5 Cost of Borrowing

NTPC will need to borrow funds over the next few years to finance its significant capital programs. Crown-owned electricity utilities in western Canada generally borrow money through their provincial government shareholder in an effort to minimize interest payments on utility debt. NTPC's borrowing costs may be reduced if it borrowed through the GNWT's Department of Finance, assuming the GNWT can borrow in capital markets at lower costs than NTPC could achieve on its own. NTPC may also realize some O&M savings by simply utilizing GNWT resources to obtain its financing requirements. As an example, from 2003 to 2010 GNWT's Department of Finance loaned funds to NTPC at short-term floating rates with an interest saving estimated by Finance at $1.2 million over the commercial cost of funds.

As well, centralizing borrowing activities for both NTPC and other government entities may lower the overall cost of GNWT debt by increasing the amount of GNWT debt in the market.

However, the GNWT has its own cash and borrowing constraints, and as NTPC's borrowings are included in the GNWT's debt cap, it is important to ensure NTPC's future debt requirements are well understood. Any further savings from this area may be small as NTPC's debt is already guaranteed by the GNWT.

Recommendation

GNWT and NTPC should examine the potential savings, advantages, and disadvantages of having GNWT issue debt on NTPC's behalf.

7.6 Revenue Growth Opportunities

NTPC receives about $1.2 million per year in non-power revenues, including connection fees, contract work, pole rentals, and heat sales.

NTPC's diesel and natural gas power plants are heated using residual heat, and partnerships have been developed in three NWT communities to heat adjacent buildings. For example, the Fort Liard heat recovery system, funded by GNWT with a contribution from NTPC, connects several buildings to that community's diesel plant.

Residual heat projects often have high up-front costs and extended payback periods, but will become more feasible as oil prices rise. NTPC's ratepayers should share in the revenues from these projects, based on the value of the heat and the way the project was funded. NTPC and GNWT might be able to sell greenhouse gas emission reduction (carbon) credits as a way to improve residual heat recovery project economics: at an emission factor of 0.00276 tonnes of CO2e per litre, the 63,000 litres per year saved at Fort Liard has a value of $4,400 per year at $25 per tonne.

As discussed earlier in this report, NTPC is currently selling interruptible power from the Taltson generation plant to government customers in the Town of Fort Smith. NTPC should ensure these interruptible revenues continue to be included in its revenue forecasts: any such sales in the hydro zones will make a small but positive contribution, given that short-term firm load growth is expected to be minimal.

In the Snare Zone, there is a small surplus capacity of hydro-generated power during the summer months. This is interruptible power, but could be sold through NUL to larger facilities in Yellowknife that wish to install duel fuel heating systems. (As with residual heat, selling carbon credits might help offset costs). Should this occur, NTPC may increase its sales of wholesale power. There are also more lucrative revenue possibilities from the proposed Yellowknife Community Energy System and Giant Mine remediation project.

In the NTPC Taltson Zone there is five to eight megawatts of surplus hydro generation capacity and it is our view that greater efforts should be made to sell this surplus electricity, either through electric heating, or through marketing efforts aimed at potential resource development in the area. Higher sales improve economies of scale, allowing NTPC to spread its overhead across more units of electricity sold, and ultimately reducing the cost of electricity for everyone.

Recommendation

NTPC and the GNWT should explore ways to increase sales where there is a surplus in hydro generation capacity. Electric heating or industrial customers appear to be the greatest opportunity.

7.7 Demand Side Management

Demand Side Management (DSM) encompasses GNWT's and NTPC's initiatives to reduce electricity consumption on the customer's side of the meter. DSM electricity savings are the difference between the actual amount of electricity consumed and the amount that would have been consumed in the absence of DSM programs. For utilities with growing loads, DSM resources are logical alternatives to supply-side additions as the cost per kW.h saved is usually lower than the cost of constructing new generation. In addition, most DSM programs have employment and environmental benefits.

Even though NTPC has a strong public mandate through its legislation to undertake programs to conserve energy, given its flat load growth and modest summer hydro surplus, it is arguably not in NTPC's interest to have its revenues reduced due to DSM investments. Rather, opportunities lie with the GNWT to use DSM programs to reduce the amounts budgeted for electricity subsidies. For example, about $5.2 million is spent annually to reduce NWT Housing Corporation tenants' electricity rates down to six cents/kW.h. Since 2008, NWT Housing has undertaken energy retrofits in about 175 units. The pace of energy retrofits could be expanded and seasonal jobs created, perhaps funded by a redesign of the electricity benefit portion of the Housing Support program. Electricity bills for tenants of retrofitted housing could remain unchanged, with reduced consumption offsetting a reduced subsidy.

A "back to the basics" theme underpins much of NTPC's recent strategic planning and messaging to its shareholder and customers. DSM programs should be evaluated in an effort to balance the costs and benefits among the competing interests of ratepayers, taxpayers, the utilities, and the GNWT. As a general principle, if NTPC is to invest in DSM programs, funding should come from governments, not ratepayers.

NTPC should also continue to pursue initiatives to reduce corporate energy use, examples being gas and diesel generator efficiencies, vehicle fleet fuel consumption, and line losses in its transmission and distribution grids. The 2011 Strategic Plan references NTPC's need to lead by example in a northern conservation culture, noting initiatives to reduce its environmental footprint and proposing a Five Year Environmental Plan. It will be useful to develop performance measures and targets to help fully engage NTPC staff in reducing "in house" energy consumption. As discussed above, the nature and degree of NTPC's responsibilities to promote electricity efficiency and conservation should be clarified.

7.8 Other Minor Cost Saving Opportunities

In 2010/11, NTPC contributed $152,000 to 68 organizations and events around the NWT as an investment in building NTPC's positive reputation in communities. It is important to note that these amounts are not built into the revenue requirements of the Corporation. While this amount is fairly insignificant to the overall revenue requirement (16/100 of one percent) it is proportionately higher than some larger utilities (e.g. BC Hydro's is 4/100 of one percent). This higher proportion may well be justified; nevertheless NTPC should ensure these expenditures are aligned with core operational requirements. NTPC expects to complete an assessment of its Donations and Sponsorship Policy in mid 2012.

As noted in Section 6.2, NTPC's budget for non-production fuel (fuel for vehicles and space heating) is about $1 million per year, up about 5% per year since 2007/08. NTPC expects fuel consumption to stay relatively constant; the increase shown in the cost components of the Corporation is due to the rise in the price per litre.

NTPC may wish to consider joining a fleet management program. "Fleetsmart" is a component of Natural Resources Canada's ecoENERGY for Fleets program, offering free advice. The "E-3 Fleet" (Energy Environment Excellence) is another Canada-wide program that helps 120 public and private organizations operating 50,000 vehicles. It offers fleet reviews, fleet ratings, and ways to help increase fuel efficiency and reduce emissions through driver training, idling reduction, vehicle "right-sizing", maintenance, and trip planning. Fees are scaled by fleet size and designed to be affordable. Cost savings average around 10% per fleet, which could translate into order of magnitude savings of $50,000 per year assuming vehicles account for half of the $1 million non-production fuel budget.

7.9 Liquefied Natural Gas Potential

Liquefied natural gas (LNG) may offer material reductions in long-term electricity rate increases in the larger centres of Inuvik and Norman Wells (which are natural gas ready) and perhaps for smaller Thermal Zone communities that could be converted to natural gas as diesel generators need to be replaced or retrofitted. LNG is natural gas, cooled to minus 160 degrees Celsius to keep it in liquid form. LNG has been safely used and transported around the world for fifty years. It is a relatively stable fuel: if LNG spills, it will warm, rise, and dissipate into the air. Across North America there is renewed interest in LNG as the price differential between natural gas and fuel oil has increased so markedly. For example, at current market prices, LNG fuel costs 40% less than marine diesel fuel. Work is underway in the north to examine LNG as a potential option in Yukon.

Yukon Energy Corporation is examining LNG as a transition fuel away from diesel, and has released a background paper "LNG Transition Option" (www.yukonenergy.ca/energy/public_engagement/lng/) for an LNG workshop in Whitehorse in January 2012. This report concludes:

- LNG liquefaction facilities in Kitimat or Fort Nelson can supply cost competitive LNG by truck to Yukon.
- A potential LNG liquefaction facility at Spectra Energy's Fort Nelson gas processing plant would cost around $26 million, but take advantage of cheaper gas supplies; trucking distances are also lower than Kitimat-sourced LNG.
- Subject to securing LNG supplies, natural gas power plants can be relatively easily integrated into the Yukon grid as conversions or replacements for existing diesel plants.
- At either $9/mmbtu for LNG at Kitimat or $6/mmbtu at Fort Nelson, and diesel at $0.89/litre ($26/mmbtu), LNG is more cost effective than diesel for the various Yukon power generation options and locations that were examined.
- Estimated power generation costs from LNG single or combined cycle generators ranged from 14.2 to 17.9 cents/kW.h (8% cost of capital, capital costs assume a 20 year economic life).

Given the current cost of diesel electricity the potential to introduce LNG solutions at the scale needed for NWT Thermal Communities with either barge or road access merits further study. The cost of permitting and developing the supply chain for sourcing, transporting, storing, re-gasifying and distributing natural gas is unknown, but much can be learned from other jurisdictions.

The Province of BC has released "Liquefied Natural Gas: A Strategy for BC's Newest Industry" (www.gov.bc.ca/ener/natural_gas_strategy.html). The province has committed to having three new LNG facilities in operation by 2020 as part of its goals for clean energy and climate change. Provided the supply chain infrastructure can be put in place, LNG could become the fuel of choice, displacing diesel in stationary power and perhaps transportation uses across the North. As well, Fortis BC Energy Inc. is mid-way through a BCUC-approved pilot program to provide LNG for truck fleets, which could present a viable option for Inuvik, via the Dempster Highway. Barging solutions for communities along the Mackenzie River may also be possible. **To help advance the LNG option, GNWT and NTPC should consider pursuing more detailed feasibility analyses in conjunction with governments, gas industry, and utility interests in BC, Yukon, and Nunavut.**

8

8.0

8.0 Conclusion

This report on NTPC's revenue requirements and cost pressures affirms and augments the relevant findings of earlier utility, policy, and governance reviews. All share the common goal of putting NTPC on a solid financial footing going forward, so it can generate and deliver electricity efficiently, reliably, and at reasonable rates.

All electricity utilities are facing cost pressures, and as detailed in our report, many are experiencing revenue requirement and rate increase percentages outpacing those of NTPC.

For NTPC, there are no "silver bullets". We have identified areas in both the short and long term where savings can be realized. In the short-term:

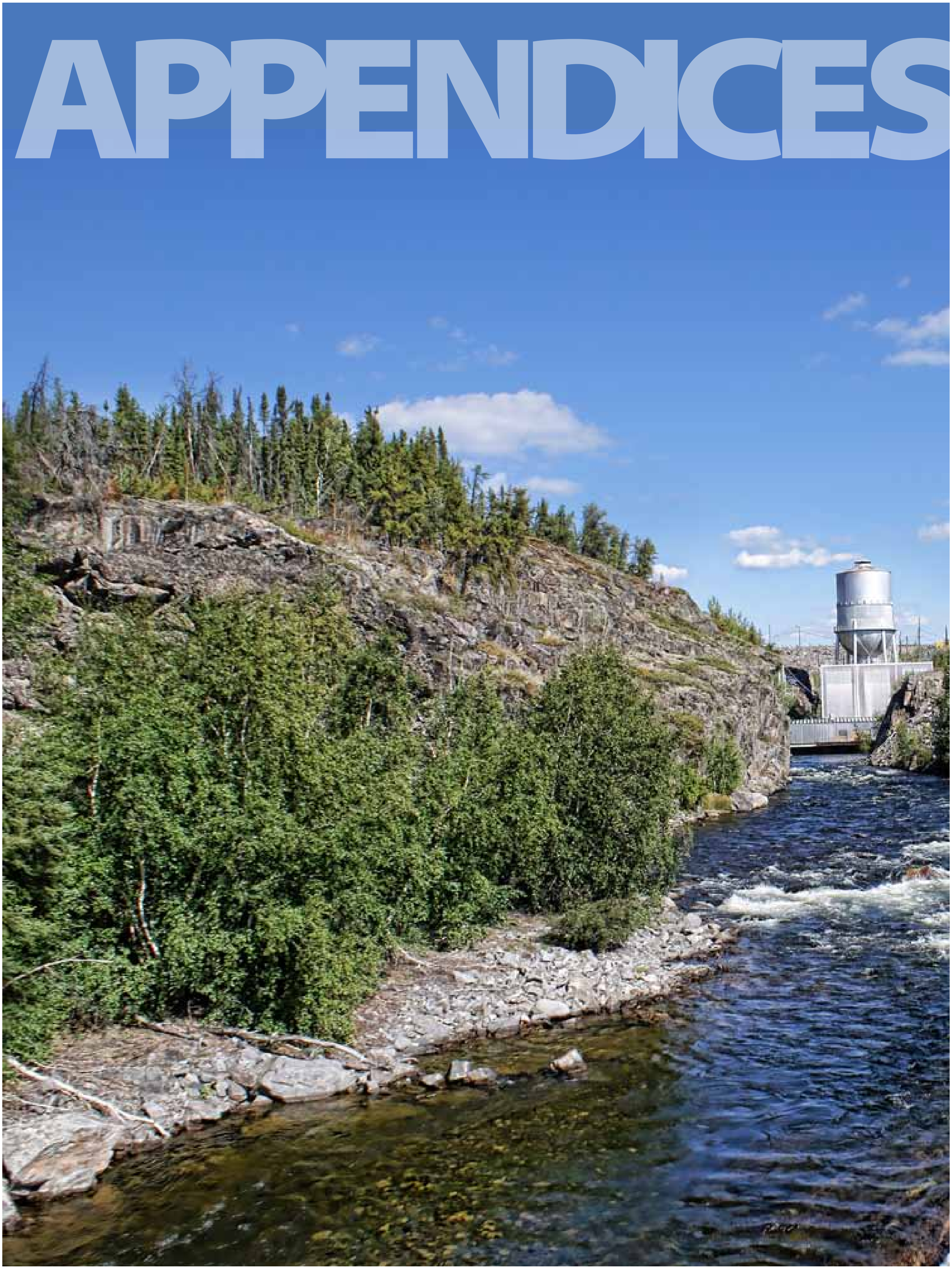
- Reducing the return on equity requested by NTPC and taking other measures to streamline the GRA process will result in savings of several hundred thousand dollars;
- There are likely potential savings from a review of PPD's administration charges to NTPC; and
- There are savings in deferring implementation of the new depreciation rates for at least 2012-13.

In the long-term, we have identified a number of steps to be taken to ensure NTPC does not "fall behind" again, including:

- A review of the regulatory system to ensure a simplified, predictable regulatory and rate setting regime that secures modest annual inflationary increases and routinely manages deferral accounts;
- The possible transfer of NTPC's borrowing function to GNWT's Department of Finance;
- The development of new sources of revenue from the sale of interruptible hydro and sales to potential industrial developments; and
- A number of recommendations aimed at performance measurement, results reporting, and enhanced communication between the Utility and the GNWT as the shareholder.

While not specifically addressed in this review, continued collaboration among NTPC, GNWT, educators, and unions will be needed to recruit talented staff. Electricity sector retirement rates are among the highest of any Canadian industry: 45,000 new and replacement staff will need to be hired in the next five years. NTPC can attract new workers with favourable career and training opportunities, competitive salaries and benefits, and job security.

APPENDICES



APPENDIX 1

Safety and Reliability Indices for Utilities

The January 2010 Report of the NTPC Review Panel concluded that NTPC's safety policies and procedures rate highly. One measure of safety is the industry standard of accident severity, measured using worker days lost due to accidents. The five year rolling average (2007-2011) of days lost by NTPC employees per 200,000 hours worked is 14.1, very close to the Canadian Electricity Association (CEA) five year rolling average (2007-2010) of 15.5 days lost per 200,000 hours worked. NTPC's 2011 Strategic Plan notes that NTPC already has a strong safety program and now needs to improve the safety "culture" by considering safety as a life value, not as a set of rules to be followed.

Reliability indexes are important in helping to identify aging assets or deficient maintenance: as with all utilities, NTPC needs to invest in its assets so they can continue to provide reliable service. NTPC's outage statistics usually meet or are better than industry averages for two of the three standard reliability indexes:

- Customer Average Interruption Duration Index (CAIDI) is the average interruption in hours per interrupted customer. NTPC fares well, with an average outage duration of 0.44 hours (i.e. 26 minutes) in 2008/09, compared to a CEA average of 2.42 hours.
- System Average Interruption Duration Index (SAIDI) indicates the percent of time in a year the lights are on or out. For the average NTPC customer, power was available 99.93% of the time in 2010/11. Put another way, in 2008/09 the power was out an average of 2.43 hours, comparing favourably with the CEA average of 5.21 hours per year in the last three years, and 7.0 hours for the CEA's "Region 2" utilities in 2010. Region 2 utilities tend to have less favourable SAIDI scores as they have both urban and rural service areas.
- System Average Interruption Frequency Index (SAIFI) measures the number of interruptions per customer per year. In 2008/09, the power went out on 5.6 occasions for the average NTPC customer, compared to the CEA average of 2.2 times and the CEA Region 2 average of 2.5 times.

NTPC's SAIFI index is higher because the system lacks the redundancy of an integrated grid. More importantly though, when a community loses its primary generation source, NTPC has the back-up capability in place to minimize risks to life, health, and public safety.

As noted in the NTPC Strategic Plan, being able to compare NTPC's performance to peer utilities will help meet customer expectations over reliability and cost, and benchmarking will help in discussions with the PUB and GNWT.

APPENDIX 2

Table A2.0 NTPC Rate Application and Rate Change Chronology since the 2006/08 GRA

Fiscal Year	Date	Rates	GNWT
2006/07	APR '06	Start of first 2006/08 GRA test year. Application not yet filled	
	NOV '06	NTPC files 2006/08 Phase I GRA, as well as application to implement interim GRA rates, and increase fuel riders	
	JAN '07	PUB Decision on Interim Refundable GRA rates and Fuel Rider changes; New Fuel Riders implemented	
	FEB '07	2006/07 Interim Refundable GRA Riders implemented	
	MAR '07		Release Energy Plan; indicate intention to review rates, regulation, subsidies
2007/08	MAY '07	2006/08 GRA hearing - 3 days	
	AUG '07	PUB First decision on Phase I GRA matters	
	DEC '07	PUB First decision on Phase I refiling matters	
	JAN '08	Final GRA Phase I rates and riders implemented	
2008/09	MAY '08		Initiate review of rates, regulation, subsidies
	AUG '08	NTPC files 2006/08 GRA Phase II Application	
	NOV '08	Final GRA Phase II rates and riders implemented plus increases to fuel riders	
	DEC '08		Appoint commission and initiate independant review of rates, regulation and subsidies
	FEB '09	Fuel rider application filed - proposed no change - largely on track for March 2010 target	
2009/10	JUN '09		Appoint independent team and initiate review of NTPC operational efficiency
	AUG '09	Fuel rider application filed - proposed no change despite no longer being on track for March 2010 target	Independent team completed review rates, regulation and subsidies
	JAN '10		Independent team completes review of NTPC operational efficiency
	FEB '10	2010/11 Business Plan Prepared - targets 0-0-0; no GRA for 2010/11 or 2011/12	
	APR '10	Fuel rider update filed - not on track for March 2011 - no changes proposed	
2010/11	MAY '10		GNWT releases response to independent review
	JUL '10	PUB received rate policy guidelines; initiates rate rebalancing process	GNWT issues rate policy guidelines to PUB
	AUG '10	NTPC files application for rate rebalancing	
	NOV '10	PUB releases decision on rate rebalancing and recommendations to GNWT regarding revisions to rate policy	
	DEC '10	New "rebalanced" rates in effect; ultimately declared final in March 2011	
	JAN '11	NTPC files rate stabilization fund update - notes no need for riders due to GNWT payment	
	FEB '11		GNWT issues revised rate policy reflecting PUB recommendations
2011/12	APRI '11		Issue final payment of $6 million contribution stabilization fund balances
	SEP '11	Fuel rider update - balance below trigger until January - no rider propsed	

APPENDIX 3

Comparisons of Rates and Costs in Selected Jurisdictions

The sections below describe the current situation in other selected jurisdictions and identify a variety of approaches used by governments and utilities to manage costs and rates.

Yukon

Similar to the NWT, two utilities generate and distribute electricity in Yukon. Yukon Energy Corporation (YEC), owned by the Yukon Government, generates and transmits most of the Territory's electricity. The Yukon Electrical Company Ltd. (YECL), a private utility owned by ATCO Electric Ltd., distributes electricity to most Yukon customers.

Table A3.1 Installed Capacity (MW): Yukon and Northwest Territories

	Yukon	NWT
Hydro	76.7	55.0
Natural Gas	0	22.2
Diesel	53.4	74.3
Wind	0.8	0
Total	130.9	151.5

There are about 17,500 electricity customers in Yukon. YEC directly serves about 1800 of them, mostly in the Dawson City-Mayo area. YECL buys wholesale power from YEC and sells it to retail customers in most other communities, including Whitehorse. YECL generates and distributes its own diesel-generated electricity in five communities away from the Whitehorse-Aishihik-Faro (WAF) transmission grid, a situation similar to the four NWT communities in the NUL (NWT) Thermal Zone.

Many of Yukon's diesel facilities are stand-by or backup plants to the hydro stations that power the WAF and Mayo-Dawson systems. So, while hydro accounts for less than 60% of Yukon's installed capacity, over 93% of its electric energy is generated by hydro. Yukon has reduced its diesel fuel dependence: in the mid 1990s the hydro/diesel energy split was about 60/40. Diesel's contribution is further reduced with the completion of YEC's Mayo-Carmacks-Stewart Crossing Transmission Project, and "Mayo B" hydro expansion project. These two projects are 50% funded by the Federal Government (up to $71 million) as a "Green Energy Legacy Project". The integration of the two hydro grids will allow Yukon to maximize its hydro usage.

Operations of both utilities are regulated by the Yukon Utilities Board (YUB). Each utility filed a GRA in 2008 for forecast revenue requirements for 2008 and 2009. The main components of the 2009 consolidated revenue requirements, totaling $52.3 million, are:

- Fuel $5.8 million.
- Operations and Maintenance $22.2 million.
- Depreciation $9.9 million.
- Income tax $0.2 million.
- Return on rate base-debt $7.4 million.
- Return on rate base-equity $6.8 million.

APPENDIX 3

Yukon is divided into four rate zones: Hydro, Small Diesel; Large Diesel, and Old Crow. Each has its own set of rates for customer classes, although there are very few rate differences across these zones. 2011 rates for the "Non Government Residential" customer class, comprising 98% of the 14,380 residential customers, are set in three inclining blocks. The following rates include all riders, rebates, and GST:

Table A3.2 Yukon Electricity Rates

	Hydro; Small Diesel; Large Diesel	Old Crow
Basic Charge/month	$15.27	$15.27
First 1000 kW.h/month	$0.1023/kW.h	$0.1023/kW.h
1000-2500 kW.h/month	$0.1373/kW.h	$0.1373/kW.h
Over 2500 kW.h/month	$0.1495/kW.h	$0.3244/kW.h

Rates for the 800 customers in the federal and territorial government residential and government general service classes are significantly higher.

The consolidated cost of incremental diesel generation is about 28 cents/kW.h, and is spread across all zones so Hydro Zone customers subsidize those in diesel communities. However the cost of fuel makes up only 11% of the utilities' revenue requirements, so the impact on rates is considerably less than in the NWT, where fuel costs comprise about a quarter of NTPC's revenue requirements. A Fuel Adjustment Rider –currently a surcharge of 0.352 cents/kW.h on all consumption—is meant to cover changes in the cost of fuel. Given the large swings in the account's balance, the YUB has directed the utilities to provide a written policy on how the rider can be better managed and understood by customers.

Rate design is emerging as an issue in Yukon. Under Orders in Council (OIC) since the mid 1990s, the portion of revenue requirements paid by various customer classes was set by government, not the YUB. For example, non-government residential customers pay only about 79% of their true costs; government customers pay 144%. In a December 2010 Decision, the YUB directed the two utilities to file a joint Cost of Service Study and rate design proposals to correct these imbalances after the current OIC expires at the end of 2012. If acceptable to both the regulator and government, residential rates could rise to over $0.15/kW.h, and higher if a government rebate of $0.0266/kW.h on the first 1,000 kW.h per month is discontinued.

Alaska

Diesel fuel powers 16% of Alaska's electricity generation, slightly higher than NTPC's 12%. Hydroelectricity supplies 17%, natural gas 61%, and coal 6%. As in the NWT, generation varies by region, with rural communities in western and interior Alaska relying mostly on diesel fuel. Wood generates both heat and electricity in community-level thermal facilities in about ten communities, mostly in the southeast Alaska panhandle.

There are about 100 separate electricity utilities servicing Alaska, a mixture of investor-owned utilities, municipal utilities, and rural cooperatives. Ownership and size dictate regulatory status with the Regulatory Commission of Alaska (RCA): in general, rates are regulated for co-ops and investor-owned utilities if revenues exceed $50,000 per year.

Communities in southeast Alaska that rely primarily on hydroelectricity from almost fully depreciated assets have rates as low as $0.10/kW.h. Residents of Anchorage and other communities with gas fired generation pay around $0.15/kW.h. Alaskans relying on diesel fuel have the most expensive electricity, mostly between $0.50 and $1.00/kW.h. The State's Power Cost Equalization Program (PCE) subsidizes bills in most diesel communities.

The average rate paid by Alaska residential customers in 2009 was $0.162/kW.h (before PCE subsidies), up from $0.112/kW.h in 1999. This 45% increase over the decade is double the Canadian CPI increase of 23% over the same period.

Alaska's PCE Program was established in 1984 to subsidize rural residents at the same time state funds were being used to subsidize major generation and transmission projects servicing urban communities. In 2010, 183 communities served by 84 utilities benefited from the PCE Program; about 78,000 people live in these communities. Payments totaled $30.6 million, a per capita subsidy of $392. Without PCE, electricity bills would be 2.5 to three times higher. PCE Program rules are complex. The RCA determines utility eligibility and calculates the amount of PCE per kW.h payable to the Utility, which reduces each eligible customer's bill by that amount for up to 500 kW.h per month. A formula is used to determine the PCE rate, to a maximum of $0.82/kW.h. Utilities must meet diesel generation efficiency and line loss standards.

British Columbia

After being frozen by the Provincial Government through the late 1990s, BC Hydro's residential rates have increased from 6.46 cents/kW.h in 2001 to 8.50 cents/kW.h in 2011. This 31.6% increase outpaced the rise of 22.3% in the CPI for the same period.

In March 2011 BC Hydro applied to the BC Utilities Commission (BCUC) for rate increases of 9.73% for each of the next three years, a cumulative total of 32%. Concerns were expressed about the impact the rate increases would have on customers. The B.C. government ordered a review of BC Hydro, seeking recommendations and options for reducing the increases.

The review panel of three Deputy Ministers was supported by a consulting team of twenty, working on site at BC Hydro for several weeks. The 124 page June 2011 report, "Review of BC Hydro" made several recommendations about governance, operating costs, procurement, and electricity policy. It was particularly critical of BC Hydro's operating costs, which make up 22% of BC Hydro's $3.6 billion annual revenue requirement and have been increasing by over 10% per year. Staffing levels rose from 3796 to 5615 employees over the four years ending in 2010.

As recommended by the review panel, BC Hydro filed an amended Application with the BCUC for rate increases of 8%, 3.9%, and 3.9% per year, or 17% over three years. Cost reductions totaling $818 million were comprised of:

- Operating cost decreases, $163 million.
- Deferred capital projects, $54 million.
- Lower than forecast capital projects in service for 2010/11, $61 million.
- Higher export income, $175 million.
- Extended Demand Side Management (DSM) amortization and reduced DSM spending, $127 million.
- Lower than forecast interest rates, $161 million.
- Regulatory account refunds, $27 million.
- Reduced taxes, increased miscellaneous revenues, $50 million.

BC Hydro has eliminated 550 positions and plans to eliminate another 150 over the next three years.

The BCUC has approved interim increases of 8% for 2011/12 and 3.9% for 2012/13. It has also ordered that the deferral accounts rate rider rise from 2.5% to 5.0% for 2012/13. With compounding, this represents an increase in 2012/13 rates of 7.1%. The BCUC concluded that BC Hydro's deferral account balances are continuing to grow, and that doubling the rider is consistent with BC Hydro's approved mechanism to reduce account balances.

Separate from the BC Hydro Review, in October 2011 the Auditor General of British Columbia released a report, "BC Hydro: The Effects of Rate-Regulated Accounting" that criticized BC Hydro's use of regulatory or deferral accounts. It recommended that the Provincial Government determine how BC Hydro will recover the net deferred costs totaling $2.16 billion in 27 regulatory accounts, either through rate increases, operating efficiencies, or cash infusions.

The BC Auditor General's report also recommended that BC Hydro's financial statements be prepared fully in accordance with Canadian Generally Accepted Accounting Principles (GAAP). Rate regulated deferral accounting is not permissible under International Financial Reporting standards (IFRS), and Canada will be adopting IFRS as a Canadian GAAP for business enterprises. Starting in 2012/13, the full costs of operating expenses are to be shown in the year they are incurred, rather than being deferred to future years. The B.C. government has rejected this recommendation, stating that retaining rate regulated accounting is a policy decision made to maintain rate stability, and one that is also being made in other jurisdictions. Regulatory deferral accounts will continue to be used by Manitoba Hydro, Ontario Power Generation, Hydro One, Hydro Quebec, Nova Scotia Power, New Brunswick Power, Newfoundland Power, Fortis BC, Fortis Alberta, Enbridge Gas, and TransCanada.

BC Hydro operates off-grid diesel generation systems in 17 communities, mostly in northern BC. Revenues cover about one-quarter of costs. Rates for the first 1500 kW.h per month are the same as the integrated system (7.84 cents/kW.h for energy) but rise to 13.47 cents thereafter, to discourage electric space heating.

BC Hydro is expanding service to additional communities through its Remote Community Electrification Program. Its goals are to offer BC Hydro electricity to up to forty more communities, and to build sustainable relations with First Nations. Twenty-one First Nations communities receive electricity from diesel generators operated by Aboriginal and Northern Development Canada, which has agreed in principle to transfer funding to BC Hydro where BC Hydro takes over operations and billing. A complementary provincial initiative, the Remote Community Implementation Program, helps subsidize supply and demand side clean energy projects for off grid communities.

NWT electricity interests should keep apprised of BC Hydro activities in the Fort Nelson area. Natural gas producers are planning to install new natural gas gathering and processing capacity in the Horn River region, about 90 km northeast of Fort Nelson and 120 km south of Trout Lake. Industry is increasingly interested in grid-supplied electricity instead of self supply, particularly as expectations rise for mandated or voluntary greenhouse gas emission reductions. BC Hydro is considering a double circuit 287kV line from the south Peace to meet the combined needs of Fort Nelson and Horn River regions.

Manitoba

Manitoba Hydro is a Crown utility serving all electricity customers in Manitoba. Rates have traditionally been low and stable. However, since 2004/05, rates began to steadily increase, rising by approximately 20% by the end of 2010/11, or over 3% per year on average. Going forward, Manitoba Hydro's long term business plan is based on rate increases typically at the 3.5% per year level for the next ten years. Major new generation and transmission is planned over the next decade. Consistent with current practice, Manitoba Hydro is expected to continue to operate on a cost recovery basis, with no dividends being paid to the shareholder over this period.

The recent period of increases in rates has corresponded with major increases in the costs to operate Manitoba Hydro. In the five years from 2007 to 2012, Manitoba Hydro's O&M costs increased by more than 30%. Staff levels have increased by more than 10%, from approximately 6000 staff to almost 6700.

Manitoba Hydro serves four small diesel communities, where costs to serve residential customers average about 15% higher than NTPC's costs to operate in its Thermal Zone. Despite these costs, the rates paid by non-government customers in these communities are the same as those paid by Manitoba Hydro's integrated grid customers.

Newfoundland and Labrador

Crown-owned Newfoundland and Labrador Hydro (NLH) provides power at a wholesale level to the investor-owned distribution utility, Newfoundland Power, and a number of industrial customers, plus provides retail electricity directly to over 36,000 rural customers in Newfoundland and Labrador.

Of the directly served customers, approximately 3500, representing 48 GW.h of generation, are in isolated diesel communities either on the island (900 customers) or in Labrador (2600 customers). Average costs to serve these areas in 2006 was over 70 cents/kW.h (approximately 63 cents/kW.h in Labrador, and $1.07/kW.h on the island). However customers in these isolated areas only pay 17-29% of these costs, with the remainder allocated to non-industrial customers on the interconnected system.

Similar to Manitoba Hydro, NLH was previously (pre-2001) regulated on the basis of a very low equity ratio, and with no formal Return on Equity. This was changed by legislation to require NLH to target a commercial type return in all areas other than the rural and isolated service areas (which have traditionally earned no ROE). At that time NLH had very low levels of reserves that it had begun classifying as equity (below 20%). The Provincial Government suspended dividend payments starting in 2006/07 to aid in bringing the equity levels up to a target range (at that time equity levels were at approximately 14% of total capital, and the company was targeting equity at 20% of total capital). The Government also contributed $100 million as a new equity contribution to NLH. This was the first time such an equity injection had occurred, although Government had played a role in the past by paying off balances in the Rate Stabilization Plan to minimize impacts on customers. At present, NLH has exceeded their new target equity ratio of 25% of total capital, and has resumed paying dividends when this does not drop the equity levels below the target.

APPENDIX 4

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Yukon Utilities Board: www.yukonutilitiesboard.yk.ca

APPENDIX 5

Abbreviations

BCUC: British Columbia Utilities Commission

CAIDI: Customer Average Interruption Duration Index

CEA: Canadian Electricity Association

CO2e: Carbon Dioxide equivalent

CPI: Consumer Price Index

DSM: Demand Side Management

GAAP: Generally Accepted Accounting Principles

GRA: General Rate Application

GNWT: Government of the Northwest Territories

IFRS: International Financial Reporting Standards

ITI: NWT Department of Industry, Tourism and Investment

KPI: Key Performance Indicator

kW.h: Kilowatt hour

LNG: Liquefied Natural Gas

mcf: thousand cubic feet

MW: Megawatt

MW.h: Megawatt hour

NLH: Newfoundland and Labrador Hydro

NTPC: Northwest Territories Power Corporation

NUL: Northland Utilities Ltd.

NYMEX: New York Mercantile Exchange

PCE: Power Cost Equalization Program (Alaska)

PPD: Petroleum Products Division

PUB: Northwest Territories Public Utilities Board

QEC: Quilliq Energy Corporation

RCA: Regulatory Commission of Alaska

ROE: Return on Equity

SAIDI: System Average Interruption Duration Index

SAIFI: System Average Interruption Frequency Index

SLE: Shareholder's Letter of Expectation

TPSP: Territorial Power Subsidy Program

WAF: Whitehorse-Aisihik-Faro

YEC: Yukon Energy Corporation

YECL: Yukon Electrical Company Ltd.

YUB: Yukon Utilities Board

APPENDIX 6

Biographies

Peter Ostergaard, B.A.(Hons.), M.A., MCIP

Peter Ostergaard was an Assistant Deputy Minister with the Government of British Columbia's Ministry of Energy, Mines, and Petroleum Resources for fourteen years, most recently with responsibility for electricity and alternative energy policies, plans, and governance. He was also Chair and Chief Executive Officer of the BC Utilities Commission between 1998 and 2003.

After retiring in 2008, he now consults on energy and land use planning matters, including assignments with the BC Energy Ministry, the Fraser Basin Council, Columbia Basin Trust, and an independent power company. He has also served as Chair of Canada's Electricity Sector Council's "Building Connectivity" Steering Committee, and on the Board of Directors of the Western Electricity Coordinating Council.

Peter has degrees from Queen's and the University of BC, and is a Member of the Canadian Institute of Planners. In the 1970s he spent two summers in the southwestern NWT mapping surficial geology to assist in route selection for the Mackenzie Valley Pipeline. He also completed his graduate thesis in urban geography on Yellowknife's livability.

William Grant, B.Sc. (Eng.), MBA, CFA

Bill Grant was employed by the BC Utilities Commission and its predecessor, the BC Energy Commission, for 30 years. For 15 years he was Executive Director of the Commission. He has consulted to other regulators and governments in Canada, the USA, Australia, and Argentina on regulatory reform, including the Yukon Government on electricity matters. He continues to mediate Negotiated Settlement Processes and Performance Based Regulatory proceedings, primarily for the BCUC.

Bill has initiated or been involved in the development of many energy policy and regulatory initiatives, including:

- Natural gas commodity competition and unbundling of utility tariffs
- An automatic return on equity adjustment mechanism
- A multi year performance –based ratemaking process
- Alternative dispute resolution techniques

Bill completed a Master of Business Administration degree immediately following his undergraduate Bachelor of Science degree. He has been a Professional Engineer in Ontario and British Columbia, and he returned to academic study to obtain a Chartered Financial Analyst designation from the University of Virginia. In 2006 he received the Canadian Association of Members of Public Utility Tribunals award for Innovation in Public Utility Regulation and Process.

THE PUBLIC UTILITIES BOARD

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NORTHWEST TERRITORIES

DECISION 8-2002 **September 16, 2002**

IN THE MATTER OF the Public Utilities Act, being Chapter 110 of the Revised Statutes of the Northwest Territories, 1988(Supp.), as amended.

AND IN THE MATTER OF an application by Northwest Territories Power Corporation for changes in the existing rates, tolls and charges for electrical energy and related services provided to its customers within the Northwest Territories.

THE PUBLIC UTILITIES BOARD

BOARD MEMBERS	John E. Hill	Chairman
	Gene Nikiforuk	Vice-Chairman
	Gabrielle Decorby	Member
BOARD STAFF	Louise Larocque	Board Secretary
	Raj Retnanandan	Board Consultant
	John Donihee	Board Counsel

TABLE OF CONTENTS

1. BACKGROUND 1

2. APPLICATION 6

3. DECISION 7

4. BOARD ORDER 11

1. BACKGROUND

By letter dated July 12, 2002, the Northwest Territories Power Corporation ("**NWTPC**") filed a 2001/02 Revenue Shortfall Rider and 2002/03 Interim Refundable Rates Application ("**Application**"), to collect the revenue requirement for 2001/02 and an increase in the current interim rates to reflect the revenue shortfall of 2002/03.

On May 9, 2001, NWTPC submitted to the Board, its Phase I General Rate Application ("**GRA**") for the fiscal years April 1, 2001 to March 31, 2002 and April 1, 2002 to March 31, 2003 ("**Test Years**"). The GRA requested that the Board:

1. Determine a rate base for NWTPC's property that is used or required to be used in providing energy and related services to the public within the Northwest Territories, including the appropriate allowance for working capital, and fixing return thereon for NWTPC's fiscal years April 1, 2001 – March 31, 2002 and April 1, 2002 – March 31, 2003 (the Test Years);

2. Determine the revenue requirements for the Test Years for the provision of energy to the public in the NWT;

3. Approve NWTPC's application for Required Firm Capacity Planning Criteria for the Snare Yellowknife Zone, Diesel Communities and dual fuel generation communities;

4. Approve NWTPC's application for Alternative Energy Fund;

5. Approve continuation of Rate Stabilization funds, as well as various adjustments to the Funds, to mitigate the impact on rates of changes in fuel prices and deviations in hydro conditions from average water levels;

6. Approve revised Terms and Conditions of Service.

Pursuant to the provisions of section 13. (1) of the Rules of Practice and Procedure, the Board, by letter dated May 10, 2001 directed NWTPC to publish notice of the public hearing of the GRA in newspapers that circulate in the Northwest Territories. The notices were published in May and June 2001, included details of the GRA, and invited interested persons to file a request with the Board for intervenor status (Ex.1)

Those persons who were granted intervenor status were provided the opportunity to make written information requests of NWTPC and to file evidence. The requests elicited written responses from NWTPC. Written evidence was filed on behalf of the Village of Fort Simpson by letter dated 14 September, 2001 and on behalf of the City of Yellowknife and the Town of Hay River by letter dated 24 September, 2001. Further information requests were issued in response to the written evidence. All written information requests by the Board and intervenors together with the responses were made available to all parties before the hearing.

NWTPC, by letter dated October 10, 2001, confirmed its intention to contact all interested parties to determine whether they were receptive to a negotiated settlement conference. NWTPC, by e-mail dated October 23, 2001, provided the Board with a copy of a public notice of the negotiated settlement conference.

The Board, by letter dated October 24, 2001, acknowledged receipt of NWTPC’s letter and e-mail. NWTPC was requested to provide the Board with a list of those interested parties intending to participate in the meeting and to prepare and file a proposed Negotiated Settlement Agreement, if any, by November 16, 2001.

By e-mail dated October 30, 2001, NWTPC informed the Board that notice of the negotiated settlement meeting was published in the News North newspaper of October 29, 2001. The list of participants in the negotiated settlement meeting and a list of the issues identified by the parties were provided to the Board by letter dated November 8, 2001.

The Comprehensive Negotiated Settlement Agreement ("**Agreement**") was dated and filed with the Board on November 20, 2001, together with letters of endorsement from all interested parties and revised GRA schedules.

The Board accepted the Agreement as filed in Decision 1-2002, dated February 15, 2002, subject to a number of Board Directives. In its Decision, the Board determined Rate Base and Revenue Requirement for the two Test Years.

Concurrent with the filing of the GRA, NWTPC filed, separately, an interim refundable rate application, designed to prevent the requirement for a sizeable revenue deficiency rider to be implemented at the same time as the proposed rate increases. Along with the application for an interim refundable rate increase, NWTPC filed under separate cover an application to adjust the Norman Wells Fuel Stabilization Fund, Rider "B" downward, in consideration of the new fuel price that will be reflected in the new interim rate, if approved. The Board approved the interim refundable rate application in Decision 5-2001.

NWTPC's Application of July 12, 2002, states that since the approved 2001/02 interim refundable rates collected only 50% of the revenue requirement shortfall during the 2001/02 fiscal year, NWTPC's final 2001/02 financial results record a substantial under collection of NWTPC's approved 2001/02 revenue requirement. In addition, if the current interim refundable rates were to continue through 2002/03 the result would be a substantial under collection of the approved 2002/03 revenue requirement.

Copies of the Application were distributed to interested parties across the NWT, at the time of filing with the Board. The Board, by letter dated July 22, 2002, advised all parties that it would appreciate receiving any comments with respect to the Application by July 26, 2002. Attached to its letter to the parties, the Board provided a copy of a letter, of the same date, to NWTPC requesting a response to a number of information requests by August 2, 2002.

By letter dated July 22, 2002, the City of Yellowknife/Town of Hay River ("**YK&HR**") expressed its concerns about the Application and requested that the Board direct NWTPC to file additional information in order that the 2001/02 shortfall rider and the 2002/03 interim rates can be based on cost and revenue data by rate zone and major wholesale and industrial customer.

Miramar Mining Corporation ("**Miramar**"), by letter dated July 25, 2002, provided comment with respect to the proposed refund to the Giant Mine, the proposed 2002/03 Interim Refundable rate for the Giant Mine, and the Con Mine contract.

Counsel for the Village of Fort Simpson ("**the Village**"), by letter dated July 25, 2002, in the interest of avoiding duplication, requested a delay in responding to the Application until they had an opportunity to review the response to the Board's information requests. On July 29, 2002, the Board approved the request, subject to the Village responding to the Application no later than August 9, 2002.

NWTPC provided response to the information requests of the Board by letter dated July 31, 2002. NWTPC also responded to YK&HR's letter concerning the Application.

By letter dated August 7, 2002, counsel for the Village advised the Board that the Hamlet of Fort Liard ("**Hamlet**") had authorized him to represent the Hamlet in the proceedings. Separately, the Village/Hamlet enclosed information requests to NWTPC.

The Board, by letter dated August 8, 2002, informed NWTPC that the responses to the information requests will assist the Board in its review of the Application and requested that NWTPC respond to the information requests by August 14, 2002.

YK & HR, by letter dated August 9, 2002, advised that after review of NWTPC's responses to the Board's information requests had further comment with respect to the Application.

NWTPC by letter dated August 14, 2002 responded to the information requests of the Village/Hamlet.

In Decision 6-2002 dated August 15, 2002, the Board rejected NWTPC's July 12, 2002 Application to change non industrial rates. The Board noted that the Application for interim rates applicable to non industrial customers was based on the concept of a single rate zone which remains to be tested. Accordingly, the Board directed NWTPC to refile its Application for interim rate adjustments based on existing rate zones. In Decision 6-2002, the Board approved NWTPC's request to change rates for the Miramar Giant Mine, effective September 1, 2002, on an interim basis.

By letter dated September 5, 2002, NWTPC filed a revised Application for approval of interim rates.

2. APPLICATION

In its July 12, 2002 Application, NWTPC proposed a $0.02 per kwh across the board increase for all non industrial customers to recover the 2001/02 revenue shortfall and a further 10% across the board increase to the energy component of non industrial rates to ensure those rates on a going forward basis are reflective of the 2002/03 approved revenue requirement. NWTPC also proposed carrying charges on the 2001/02 revenue deficiency be approved calculated on the mid year balance of the deficiency over a two year period at the approved rate of return on rate base of 9.477%.

In its September 5, 2002 refiled Application, NWTPC proposed revenue shortfall riders by community to recover the 2001/02 revenue deficiency as well as interim adjustments to 2002/03 rate levels by community to reflect 2002/03 revenue requirement by community. NWTPC states in order to "mitigate the rate impact of higher cost communities and those customers who are not subsidized by the GNWT, the Corporation has set hydro zone communities at 105% Revenue Cost Coverage ("RCC") compared to the measured cost-of-service with non hydro communities at a level reflecting a corresponding reduction below 100% (but greater than or equal to 95%) RCC". Accordingly, the 2001/02 shortfall riders as well as the adjustments to 2002/03 rate levels "are calculated based on a range of revenue/cost from 95% to 105% setting hydro-zone communities at 105% RCC and other communities at an RCC lower than 100%, but greater than or equal to 95%". NWTPC states the corporation will track revenues by community and customer class to ensure the final Phase II decision can be fairly reflected in the final total amounts charged to all customers

NWTPC proposes the interim rates take effect October 1, 2002. The 2001/02 revenue shortfall rider would recover the revenue deficiency from that year over a period of ten months from October 1, 2002 to July 31, 2003. NWTPC notes since the adjusted interim rates for 2002/03 would take effect on October 1, a separate application would be required for recovery of any revenue deficiency for the period April 1, 2002 to September 30, 2002.

In the notes section of the Tables 1 to 4 forming part of the September 5, 2002 Application NWTPC states:

“The total revenue requirement approved by the Board in Decision 1-2002 was $63,566,000 for 2001/02 and $66,639,000 for 2002/03. As a result of the Corporation’s review of cost allocation in preparing the Phase II application, an error in the preparation of the Negotiated Settlement tables was discovered (the lifespan of hydraulic stations were to be changed from 75 to 85 years, which was not fully carried through to the revenue requirement calculation), which reduced the revenue requirement to $63,260,000 in 2001/02 and $66,366,000 in 2002/03.”

NWTPC states the non industrial revenue requirements have accordingly been adjusted to $57,465,000 and $59,754,000 in 2001/02 and 2002/03 respectively.

3. DECISION

The Board notes the adjustments to the Board approved revenue requirement referred to in NWTPC’s Application. The Board will accept these adjustments for purposes of establishing interim rates. However, the Board considers the proposed adjustments to revenue requirement should be tested as part of the forthcoming Phase II proceedings.

The Board considers interim rates should be set so as to minimize rate adjustments on a final basis. Given that NWTPC’s tariffs are presently established on the basis of community revenue requirement, the Board considers it appropriate to allow NWTPC to recover the 2001/02 revenue deficiency and make adjustments to the 2002/03 go-forward rates based on revenue requirements by community.

The Board notes that in the case of certain diesel communities there is considerable variance between revenues at existing interim rates and the community revenue requirement. The Board notes that NWTPC has proposed that the revenue to cost ratios for all hydro communities be increased to 105% to mitigate rate change impact for the diesel communities. This means increasing rates to wholesale customers, namely Northland Utilities (Yellowknife) Limited and Northland Utilities (NWT) Limited, to achieve a revenue cost ratio of 105%.

While rate design issues remain to be tested in the forthcoming Phase II proceedings, the Board considers, for purposes of setting interim rates, the revenue cost ratios for wholesale customers should be set as close to unity as practicable to avoid the possibility for uncompetitive wholesale rates. The Board also considers it is preferable to move the revenue cost ratios of communities served by NWTPC closer to tolerance in gradual steps over a period in order to mitigate rate shock. Accordingly, the Board has modified the rate adjustments proposed by NWTPC to reflect the above considerations. Attachment 1 shows the Board’s calculation of the interim adjustments to 2002/03 rates. For the purposes of these calculations the Board has used the following rules:

-The maximum increase by way of rate adjustment in 2002/03 for any one community will be 15%

-If a 15% maximum adjustment results in a revenue to cost ratio exceeding 105% the increase will be reduced so that the community revenue cost ratio does not exceed 105%

-For those communities where existing revenues exceed the community revenue requirement there will be no further rate adjustment for 2002/03.

For purposes of establishing interim rates effective October 1, 2002, the Board will approve the 2002/03 rate adjustments set out in Attachment 1.

With respect to the 2001/02 revenue deficiency, NWTPC requested that the shortfall rider include carrying costs at the approved rate of return on rate base.

In its August 9, 2002 letter, YK/HR stated:

"As noted above, we estimate the lag in recovery of the shortfall to be approximately 18 months. This estimate is based on ½ of the shortfall occurring during the first 3 months of 2001/02 and the remaining ½ during the last 9 months. The weighted mid-point for the shortfall would hence be August 15. Assuming the shortfall rider commences September 1, 2002 and ends August 31, 2003, the midpoint of recoveries would be March 1, 2003 for an 18 month lag. Although NTPC seeks the weighted average cost of its capital financing rate base, Yellowknife and Hay River submit that the shortfall should be financed at NTPC's short-term cost of debt given the relatively short period over which financing will be required."

The Board considers it appropriate to consider granting carrying costs if there has been a significant regulatory lag and the carrying costs involved are material. Further, the regulatory lag before implementation of the rate adjustment should exceed a period of 12 months as short term situations will normally not involve amounts of material consequence. In regard to the 2001/02 deficiency, the Board is prepared to approve carrying costs for the 16 month period from April 1, 2002 to July 31, 2003 as the amounts involved are material. The Board agrees with YK/HR that the shortfall should be financed at NWTPC's short term cost of debt given the relatively short period over which financing will be required. For purposes of interim rates, the Board has calculated the carrying cost of debt using the average prime rate during the period April to August 2002 as proxy for short term carrying costs (Attachment 3). The Board expects NWTPC to update carrying costs to reflect actual short term debt costs at the time of final reconciliation of rate revenues.

With respect to the 2001/02 revenue shortfall rider, the Board considers it appropriate to adopt similar rate design rules as those used by the Board with respect to 2002/03. The calculation of the 2001/02 revenue shortfall riders reflect the revenue cost ratios used for calculation of the 2002/03 rate adjustment by community with minor modifications to the wholesale classes in order to achieve full recovery of the deficiency. These calculations are provided in Attachment 2.

For purposes of establishing interim rates effective October 1, 2002, the Board will approve the 2001/02 revenue shortfall riders set out in Attachment 2

Attachment 4 provides a comparison of the interim rates requested by NWTPC with those approved by the Board.

4. BOARD ORDER

NOW, THEREFORE IT IS ORDERED THAT:

1. Northwest Territories Power Corporation shall file rate schedules effective October 1, 2002 reflecting the approved 2002/03 rate adjustments and 2001/02 revenue shortfall riders set out in Attachments 1 and 2.

2. Nothing in this Decision and Order shall bind, affect or prejudice the Board in its consideration of any other matter or question relating to Northwest Territories Power Corporation.

ON BEHALF OF THE
PUBLIC UTILITIES BOARD
OF THE NORTHWEST TERRITORIES

____

DATED September 16, 2002
John E. Hill
Chairman

FOLLOWING IS

ATTACHMENTS 1, 2, 3 & 4

ATTACHED TO AND FORMING PART OF

THE PUBLIC UTILITIES BOARD

OF THE NORTHWEST TERRITORIES

DECISION 8-2002

DATED September 16, 2002

Attachment 1

NorthWest Territories Power Corporation 2001/02 & 2002/03 GRA Second Interim Rate Application

2002/03 Rate Adjustments

	Community	2002/03 Rev Req A	Revenue Interim Rates B	2002/03 Deficiency C=A-B	Deficiency Percent D=C/B	Board Appr 2nd Interim E	Board Appr Percent Inc F=E/B-1	Interim RC Ratio G=E/A	2002/03 Energy (Kwh) H	2002/03 Rate Adj I=(E-B)/H
	Hydro Wholesale									
101	**NUL (YK)**	18,174,000	18,184,000	(10,000)	-0.1%	18,251,000	0.4%	100.4%	150720000	0.0004
200	**NUL (HR)**	1,430,000	1,263,000	167,000	13.2%	1,436,000	13.7%	100.4%	30935000	0.0056
	Sub total	19,604,000	19,447,000	157,000	0.8%	19,687,000	1.2%	100.4%	181655000	
	Hydro Communities									
108 109	**RAE DETTAH**	2,249,000	1,869,000	380,000	20.3%	2,149,350	15.0%	95.6%	8058000	0.0348
201 203	**FORT SMITH/RES**	3,487,000	3,193,000	294,000	9.2%	3,661,350	14.7%	105.0%	25238000	0.0186
	Sub total	5,736,000	5,062,000	674,000	13.3%	5,810,700	14.8%	101.3%	33296000	
	Hydro Sub total	25,340,000	24,509,000	831,000	3.4%	25,497,700	4.0%	100.6%	214951000	
	Diesel Communities									
104	**WHA TI**	1,298,000	1,125,000	173,000	15.4%	1,293,750	15.0%	99.7%	1713000	0.0985
105	**RAE LAKES**	908,000	632,000	276,000	43.7%	726,800	15.0%	80.0%	851000	0.1114
110	**LUTSEL K'E**	833,000	721,000	112,000	15.5%	829,150	15.0%	99.5%	1322000	0.0818
	Sub total	3,039,000	2,478,000	561,000	22.6%	2,849,700	15.0%	93.8%	3886000	
301	**INUVIK**	9,490,000	8,396,000	1,094,000	13.0%	9,655,400	15.0%	101.7%	25409000	0.0496
304	**NORMAN WELLS**	2,071,000	1,900,000	171,000	9.0%	2,174,550	14.5%	105.0%	6683000	0.0411
305	**TUKTOYAKTUK**	2,324,000	2,137,000	187,000	8.8%	2,440,200	14.2%	105.0%	3840000	0.0790
306	**FORT MCPHERSON**	1,638,000	1,560,000	78,000	5.0%	1,719,900	10.3%	105.0%	3165000	0.0505
307	**AKLAVIK**	1,530,000	1,398,000	132,000	9.4%	1,606,500	14.9%	105.0%	2599000	0.0802
308	**DELINE**	1,354,000	1,274,000	80,000	6.3%	1,421,700	11.6%	105.0%	2330000	0.0634
309	**FORT GOOD HOPE**	1,456,000	1,398,000	58,000	4.1%	1,528,800	9.4%	105.0%	2409000	0.0543
310	**TULITA**	1,506,000	1,415,000	91,000	6.4%	1,581,300	11.8%	105.0%	1838000	0.0905
311	**PAULATUK**	1,176,000	614,000	562,000	91.5%	706,100	15.0%	60.0%	839000	0.1098
312	**SACHS HARBOUR**	916,000	768,000	148,000	19.3%	883,200	15.0%	96.4%	926000	0.1244
313	**TSIIGEHTCHIC**	676,000	522,000	154,000	29.5%	600,300	15.0%	88.8%	679000	0.1153
314	**COLVILLE LAKE**	575,000	385,000	190,000	49.4%	442,750	15.0%	77.0%	170000	0.3397
315	**HOLMAN**	1,206,000	1,182,000	24,000	2.0%	1,266,300	7.1%	105.0%	1692000	0.0498
	Sub total	25,918,000	22,949,000	2,969,000	12.9%	26,027,000	13.4%	100.4%	52579000	
401	**FORT SIMPSON**	2,670,000	2,671,000	(1,000)	0.0%	2,671,000	0.0%	100.0%	7256000	0.0000
402	**FORT LIARD**	1,254,000	1,399,000	(145,000)	-10.4%	1,399,000	0.0%	111.6%	3368000	0.0000
403	**WRIGLEY**	661,000	549,000	112,000	20.4%	631,350	15.0%	95.5%	748000	0.1101
404	**NAHANNI BUTTE**	497,000	391,000	106,000	27.1%	449,650	15.0%	90.5%	357000	0.1643
405	**JEAN MARIE RIVER**	375,000	199,000	176,000	88.4%	228,850	15.0%	61.0%	218000	0.1369
	Sub total	5,457,000	5,209,000	248,000	4.8%	5,379,850	3.3%	98.6%	11947000	
	Diesel Sub total	34,414,000	30,636,000	3,778,000	12.3%	34,256,550	11.8%	99.5%	68412000	
	Total	59,754,000	55,145,000	4,609,000	8.4%	59,754,250	8.4%	100.0%	283363000	

Attachment 2

NorthWest Territories Power Corporation 2001/02 & 2002/03 GRA Second Interim Rate Application

2001/02 Revenue Shortfall Riders

	Community	2001/02 Rev Req A	Interim RC Ratio B	Target Revenue C=A*B	Revenues Interim Rates D	2001/02 Deficiency E=C-D	Deficiency Incl Interest F	Oct -Jul 03 Energy (Kwh) G	2001/02 Shortfall Rider H=F/G
	Hydro Wholesale								
101	NUL (YK)	17,871,000	100.5%	17,966,610	17,515,000	451,610	469,411	125600000	0.0037
200	NUL (HR)	1,408,000	100.5%	1,415,533	1,189,000	226,533	235,462	25779000	0.0091
	Sub total	19,279,000	100.5%	19,382,143	18,704,000	678,143	704,873	151379000	
	Hydro Communities								
108/109	RAE DETTAH	2,165,000	95.6%	2,069,072	1,786,000	283,072	294,230	6715000	0.0438
201/203	FORT SMITH/RES	3,185,000	105.0%	3,344,250	3,113,000	231,250	240,365	21032000	0.0114
	Sub total	5,350,000	101.3%	5,413,322	4,899,000	514,322	534,595	27747000	
	Hydro sub total	24,629,000	100.6%	24,795,465	23,603,000	1,192,465	1,239,468	179126000	
	Diesel Communities								
104	WHA TI	1,228,000	99.7%	1,223,979	1,003,000	220,979	229,689	1428000	0.1608
105	RAE LAKES	846,000	80.0%	677,173	607,000	70,173	72,939	709000	0.1029
202	LUTSEL K'E	810,000	99.5%	806,256	686,000	120,256	124,996	1102000	0.1134
	Sub total	2,884,000	93.8%	2,707,408	2,296,000	411,408	427,625	3239000	
301	INUVIK	8,954,000	101.7%	9,110,058	7,822,000	1,288,058	1,338,829	21174000	0.0632
304	NORMAN WELLS	1,954,000	105.0%	2,051,700	1,852,000	199,700	207,572	5569000	0.0373
305	TUKTOYAKTUK	2,173,000	105.0%	2,281,650	2,035,000	246,650	256,372	3200000	0.0801
306	FORT MCPHERSON	1,572,000	105.0%	1,650,600	1,510,000	140,600	146,142	2638000	0.0554
307	AKLAVIK	1,470,000	105.0%	1,543,500	1,342,000	201,500	209,442	2166000	0.0967
308	DELINE	1,326,000	105.0%	1,392,300	1,195,000	197,300	205,077	1942000	0.1056
309	FORT GOOD HOPE	1,426,000	105.0%	1,497,300	1,386,000	111,300	115,687	2008000	0.0576
310	TULITA	1,460,000	105.0%	1,533,000	1,333,000	200,000	207,883	1532000	0.1357
311	PAULATUK	1,170,000	60.0%	702,497	601,000	101,497	105,498	699000	0.1509
312	SACHS HARBOUR	857,000	96.4%	826,313	734,000	92,313	95,951	772000	0.1243
313	TSIIGEHTCHIC	636,000	88.8%	564,779	501,000	63,779	66,293	566000	0.1171
314	COLVILLE LAKE	560,000	77.0%	431,200	380,000	51,200	53,218	142000	0.3748
315	HOLMAN	1,163,000	105.0%	1,221,150	1,131,000	90,150	93,703	1410000	0.0665
	Sub total	24,721,000	100.4%	24,806,048	21,822,000	2,984,048	3,101,669	43818000	0.0708
401	FORT SIMPSON	2,608,000	100.0%	2,608,977	2,569,000	39,977	41,553	6047000	0.0069
402	FORT LIARD	1,168,000	111.6%	1,303,056	1,249,000	54,056	56,187	2807000	0.0200
403	WRIGLEY	634,000	95.5%	605,561	531,000	74,561	77,500	623000	0.1244
404	NAHANNI BUTTE	465,000	90.5%	420,699	379,000	41,699	43,342	298000	0.1454
405	JEAN MARIE RIVER	356,000	61.0%	217,255	193,000	24,255	25,211	182000	0.1385
	Sub total	5,231,000	98.6%	5,155,547	4,921,000	234,547	243,792	9957000	0.0245
	Diesel sub total	32,836,000	99.5%	32,669,003	29,039,000	3,630,003	3,773,086	57014000	
	Total	57,465,000	100.0%	57,464,468	52,642,000	4,822,468	5,012,553	236140000	

Attachment 3

NorthWest Territories Power Corporation 2001/02 & 2002/03 GRA Second Interim Rate Application

Calculation of Carrying Costs

		2001/02 Deficiency	Interest Apr-Sep 02	Interest Oct- Jul 03	Deficiency Incl Interest
	Interest Rate		4.3%	4.3%	
	Hydro Wholesale				
101	NUL (YK)	451,610	9,710	8,091	469,411
200	NUL (HR)	226,533	4,870	4,059	235,462
	Sub total	678,143	14,580	12,150	704,873
	Hydro Communities				
108/109	RAE DETTAH	283,072	6,086	5,072	294,230
201/203	FORT SMITH/RES	231,250	4,972	4,143	240,365
	Sub total	514,322	11,058	9,215	534,595
	Hydro sub total	1,192,465	25,638	21,365	1,239,468
	Diesel Communities				
104	WHA TI	220,979	4,751	3,959	229,689
105	RAE LAKES	70,173	1,509	1,257	72,939
202	LUTSEL K'E	120,256	2,586	2,155	124,996
	Sub total	411,408	8,845	7,371	427,625
301	INUVIK	1,288,058	27,693	23,078	1,338,829
304	NORMAN WELLS	199,700	4,294	3,578	207,572
305	TUKTOYAKTUK	246,650	5,303	4,419	256,372
306	FORT MCPHERSON	140,600	3,023	2,519	146,142
307	AKLAVIK	201,500	4,332	3,610	209,442
308	DELINE	197,300	4,242	3,535	205,077
309	FORT GOOD HOPE	111,300	2,393	1,994	115,687
310	TULITA	200,000	4,300	3,583	207,883
311	PAULATUK	101,497	2,182	1,818	105,498
312	SACHS HARBOUR	92,313	1,985	1,654	95,951
313	TSIIGEHTCHIC	63,779	1,371	1,143	66,293
314	COLVILLE LAKE	51,200	1,101	917	53,218
315	HOLMAN	90,150	1,938	1,615	93,703
	Sub total	2,984,048	64,157	53,464	3,101,669
401	FORT SIMPSON	39,977	860	716	41,553
402	FORT LIARD	54,056	1,162	969	56,187
403	WRIGLEY	74,561	1,603	1,336	77,500
404	NAHANNI BUTTE	41,699	897	747	43,342
405	JEAN MARIE RIVER	24,255	521	435	25,211
	Sub total	234,547	5,043	4,202	243,792
	Diesel sub total	3,630,003	78,045	65,038	3,773,086
	Total	4,822,468	103,683	86,403	5,012,553

Attachment 4

NorthWest Territories Power Corporation 2001/02 & 2002/03 GRA Second Interim Rate Application

Comparison of Interim Rate Changes Requested and Approved

	Community	NWTPC's Sept 5, 2002 Application				Interim Per Board			
		Adjustments To 2002/03 Rates	Shortfall Rider 01/02	Total Inc/Dec	% Inc/Dec 1-Oct-02	Adjustments To 2002/03 Rates	Shortfall Rider 01/02	Total Inc/Dec	% Inc/Dec 1-Oct-02
	Hydro Wholesale								
101	**NUL (YK)**	0.60	1.11	1.71	14.2%	0.04	0.37	0.42	3.5%
200	**NUL (HR)**	0.77	1.25	2.02	49.5%	0.56	0.91	1.47	36.1%
	Sub total								
	Hydro Communities								
108/109	**RAE DETTAH**	6.12	8.10	14.22	61.3%	3.48	4.38	7.86	33.9%
201/203	**FORT SMITH/RES**	1.85	1.23	3.08	24.3%	1.86	1.14	3.00	23.7%
	Diesel Communities								
104	**WHA TI**	7.36	14.08	21.44	32.6%	9.85	16.08	25.94	39.5%
105	**RAE LAKES**	28.67	32.72	61.39	82.7%	11.14	10.29	21.43	28.9%
202	**LUTSEL K'E**	6.28	9.71	15.99	29.3%	8.18	11.34	19.52	35.8%
301	**INUVIK**	2.85	4.10	6.95	21.0%	4.96	6.32	11.28	34.1%
304	**NORMAN WELLS**	1.38	0.52	1.90	6.7%	4.11	3.73	7.84	27.6%
305	**TUKTOYAKTUK**	2.81	2.16	4.97	8.9%	7.90	8.01	15.91	28.6%
306	**FORT MCPHERSON**	0.63	0.23	0.86	1.7%	5.05	5.54	10.59	21.5%
307	**AKLAVIK**	3.12	3.97	7.09	13.2%	8.02	9.67	17.69	32.9%
308	**DELINE**	1.37	4.79	6.16	11.3%	6.34	10.56	16.90	30.9%
309	**FORT GOOD HOPE**	0.12	(0.80)	(0.68)	-1.2%	5.43	5.76	11.19	19.3%
310	**TULITA**	2.23	5.55	7.78	10.1%	9.05	13.57	22.62	29.4%
311	**PAULATUK**	62.10	84.12	146.22	199.8%	10.98	15.09	26.07	35.6%
312	**SACHS HARBOUR**	12.31	13.21	25.52	30.8%	12.44	12.43	24.87	30.0%
313	**TSIIGEHTCHIC**	19.29	22.08	41.37	53.8%	11.53	11.71	23.24	30.2%
314	**COLVILLE LAKE**	100.00	126.76	226.76	100.1%	33.97	37.48	71.45	31.5%
315	**HOLMAN**	(1.18)	(0.92)	(2.10)	-3.0%	4.98	6.65	11.63	16.6%
401	**FORT SIMPSON**	(1.39)	(1.12)	(2.51)	-6.8%	-	0.69	0.69	1.9%
402	**FORT LIARD**	(5.79)	(5.06)	(10.85)	-26.1%	-	2.00	2.00	4.8%
403	**WRIGLEY**	11.76	14.13	25.89	35.3%	11.01	12.44	23.45	31.9%
404	**NAHANNI BUTTE**	24.65	25.84	50.49	46.1%	16.43	14.54	30.97	28.3%
405	**JEAN MARIE RIVER**	74.77	92.86	167.63	183.6%	13.69	13.85	27.54	30.2%

THE PUBLIC UTILITIES BOARD
OF THE
NORTHWEST TERRITORIES

DECISION 3-2003 **June 26, 2003**

IN THE MATTER OF the Public Utilities Act, being Chapter 110 of the Revised Statutes of the Northwest Territories, 1988(Supp.), as amended.

AND IN THE MATTER OF an application by Northwest Territories Power Corporation for changes in the existing rates, tolls and charges for electrical energy and related services provided to its customers within the Northwest Territories.

THE PUBLIC UTILITIES BOARD

BOARD MEMBERS	John E. Hill	Chairman
	Gene Nikiforuk	Vice-Chairman
	Gabrielle Decorby	Member
BOARD STAFF	Louise Larocque	Board Secretary
	Raj Retnanandan	Board Consultant
	John Donihee	Board Counsel

APPEARANCES

Stephen Lee, Esq.	Counsel for Northwest Territories Power Corporation
Tom Marriott, Esq.,	Counsel for City of Yellowknife, Town of Hay River, Town of Fort Smith
David Rice, Esq.,	Counsel for the Association of Municipalities for Fair Power Rates

WITNESSES

For Northwest Territories Power Corporation

Judith Goucher	Director and Chief Financial Officer
Patrick Bowman	Consultant
Dan Grabke	Hydro Officer

TABLE OF CONTENTS

1. BACKGROUND 1

2. APPLICATION 6

3. COST OF SERVICE STUDY 9

3.1 Allocation of Head Office Costs 9
3.2 Allocation of Area Office Costs 12
3.3 Allocation of Working Capital to Plants 15
3.4 Allocation of Diesel Plant to Rae Edzo 16
3.5 Allocation of Diesel Fuel and Operating Expenses to Rae Edzo 18
3.6 Miramar Cost Allocation 19
3.7 Allocation of Costs between Fort Smith and Fort Resolution 21
3.8 Bluefish Transmission Line Losses 22
3.9 Retail Community Line Losses on Hydro Systems 23
3.10 Rae Edzo Transmission Gross Plant 24

4. RATE DESIGN 26

4.1 Rate Design Criteria 26
4.2 Evidence of the Association 27

5. REVENUE TO COST RATIOS 32

5.1 Hydro Communities Revenue to Cost Ratio 32
5.2 Hydro Zone Revenue to Cost Ratios 33

6. INDIVIDUAL RATES, TOLLS AND CHARGES 35

6.1 Northland Utilities (Yellowknife) Limited and Giant Mines Energy Rate 35
6.2 Northland Utilities (Yellowknife) Limited Demand Ratchet 38
6.3 Retail Standby Service Rates 41
6.4 Space Heating Rate for Taltson Hydro 42
6.5 Time of Use Rates 44

7. TERMS AND CONDITIONS OF SERVICE 46

7.1 Maximum Corporation Investment 46
7.2 Changes to Terms and Conditions of Service 46

8. FINAL RECONCILIATION 48

9. OTHER MATTERS 51

9.1 Requests for Consultations and Commentary 51

10. SUMMARY OF BOARD DIRECTIVES 56

11. BOARD ORDER 59

1. BACKGROUND

On May 9, 2001, the Northwest Territories Power Corporation ("**NWTPC**", "**the Corporation**") submitted its Phase I General Rate Application ("**Phase I GRA**") for the fiscal years April 1, 2001 to March 31, 2002 and April 1, 2002 to March 31, 2003 ("**Test Years**") to the Northwest Territories Public Utilities Board ("**the Board**").

NWTPC, by letter dated October 10, 2001, advised that it intended to contact all interested parties to determine whether they were receptive to a negotiated settlement conference. NWTPC, by e-mail dated October 23, 2001, provided the Board with a copy of a public notice of the negotiated settlement conference.

The Board, by letter dated October 24, 2001, acknowledged receipt of NWTPC's letter and e-mail. NWTPC was requested to provide the Board with a list of those interested parties intending to participate in the conference and to prepare and file a proposed Negotiated Settlement Agreement, if any, by November 16, 2001.

The Comprehensive Negotiated Settlement Agreement ("**Agreement**") was filed with the Board on November 20, 2001, together with letters of endorsement from all interested parties and revised Phase I GRA schedules.

The Board accepted the Agreement as filed in Decision 1-2002, dated February 15, 2002, subject to a number of Board Directives. In its decision, the Board determined Rate Base and Revenue Requirement for the two Test Years.

Concurrent with the filing of the Phase I GRA, NWTPC filed an interim refundable rate application. NWTPC noted that until both the Phase I and Phase II regulatory proceedings were completed, continuation of the existing approved rates would result in a substantial undercollection of the 2001/02 revenue requirement. NWTPC's justification for the interim refundable rate application was not focused on financial hardship for NWTPC, but rather on a desire to avoid the need for the imposition of a revenue deficiency rider to be implemented at the same time as proposed rate increases were approved.

Along with the application for an interim refundable rate increase, NWTPC filed under separate cover an application to adjust the Norman Wells Fuel Stabilization Fund, Rider "B" downward, in consideration of the new fuel price that will be reflected in the new interim rate, if approved.

The Board approved the interim refundable rate application in Board Decision 5-2001.

In an application dated July 12, 2002, NWTPC advised the Board that the approved 2001/02 interim refundable rates had collected only 50% of the revenue requirement shortfall during the 2001/02 fiscal year. NWTPC's final 2001/02 financial results recorded a substantial under collection of NWTPC's approved 2001/02 revenue requirement. In addition, the Corporation advised that if the interim refundable rates then in effect were to continue through 2002/03 the result would be a substantial under collection of the approved 2002/03 revenue requirement.

Copies of the application were distributed to interested parties across the NWT, at the time of filing with the Board. By letter dated July 22, 2002, the Board advised all parties that it would appreciate receiving comments with respect to the NWTPC application by July 26, 2002. Included with its letter, the Board provided a copy of a letter, of the same date, to NWTPC requesting a response to a number of information requests by August 2, 2002.

By letter dated July 22, 2002, the City of Yellowknife/Town of Hay River ("**YK&HR**") expressed its concerns about the application. YK&HR requested the Board direct NWTPC to file information with respect to the 2001/02 shortfall rider and the 2002/03 interim rates based on cost and revenue data by rate zone and major wholesale and industrial customer.

Miramar Mining Corporation ("**Miramar**"), by letter dated July 25, 2002, provided comment with respect to the proposed refund to the Giant Mine, the proposed 2002/03 Interim Refundable rate for the Giant Mine, and the Con Mine contract.

Counsel for the Village of Fort Simpson ("**the Village**"), by letter dated July 25, 2002, in the interest of avoiding duplication, requested a delay in responding to the application until they had an opportunity to review the responses to the Board's information requests. On July 29, 2002, the Board approved the request, subject to the Village responding no later than August 9, 2002.

NWTPC provided responses to the Board's information requests by letter dated July 31, 2002. NWTPC also responded to YK&HR's letter concerning the Application.

By letter dated August 7, 2002, counsel for the Village advised the Board that the Hamlet of Fort Liard ("**Hamlet**") had authorized him to represent the Hamlet in the proceedings. The Village/Hamlet provided information requests to NWTPC.

YK&HR, by letter dated August 9, 2002, after review of NWTPC's responses to the Board's information requests, provided comment with respect to the application.

NWTPC by letter dated August 14, 2002 responded to the information requests of the Village/Hamlet. In a second letter, dated August 14, 2002, NWTPC responded to the YK&HR letter of August 9, 2002.

In Decision 6-2002 dated August 15, 2002, the Board rejected NWTPC's July 12, 2002 application to change non-industrial rates. The Board noted that the application for interim rates applicable to non-industrial customers was based on the concept of a single rate zone, which remained to be tested. Accordingly, the Board directed NWTPC to refile its application for interim rate adjustments based on existing rate zones. The Board approved NWTPC's request to change rates for the Miramar Giant Mine, effective September 1, 2002, on an interim basis.

By letter dated September 5, 2002, NWTPC filed a revised application for approval of interim rates.

In Decision 8-2002, the Board modified NWTPC's application. The Board stated:

> *"The Board considers interim rates should be set so as to minimize rate adjustments on a final basis. Given that NWTPC's tariffs are presently established on the basis of community revenue requirement, the Board considers it appropriate to allow NWTPC to recover the 2001/02 revenue deficiency and make adjustments to the 2002/03 go-forward rates based on revenue requirements by community.*
>
> *The Board notes that in the case of certain diesel communities there is considerable variance between revenues at existing interim rates and the community revenue requirement. The Board notes that NWTPC has proposed that the revenue to cost ratios for all hydro communities be increased to 105% to mitigate rate change impact for the diesel communities. This means increasing rates to wholesale customers, namely Northland Utilities (Yellowknife) Limited and Northland Utilities (NWT) Limited, to achieve a revenue cost ratio of 105%.*

While rate design issues remain to be tested in the forthcoming Phase II proceedings, the Board considers, for purposes of setting interim rates, the revenue cost ratios for wholesale customers should be set as close to unity as practicable to avoid the possibility for uncompetitive wholesale rates. The Board also considers it is preferable to move the revenue cost ratios of communities served by NWTPC closer to tolerance in gradual steps over a period in order to mitigate rate shock. Accordingly, the Board has modified the rate adjustments proposed by NWTPC to reflect the above considerations."

The Board provided a calculation of interim adjustment to 2002/03 rates, and advised that for the purpose of its calculations, it had used the following rules:

"-The maximum increase by way of rate adjustment in 2002/03 for any one community will be 15%

-If a 15% maximum adjustment results in a revenue to cost ratio exceeding 105% the increase will be reduced so that the community revenue cost ratio does not exceed 105%

-For those communities where existing revenues exceed the community revenue requirement there will be no further rate adjustment for 2002/03."

Accordingly, the Board modified the rate adjustments proposed by NWTPC to reflect the above considerations. NWTPC was directed to file rate schedules to reflect the Board determined 2001/02 revenue shortfall riders and 2002/03 rate adjustment set out in Decision 8-2002.

In Decision 9-2002 dated September 30, 2002, the Board approved the rate schedules on an interim refundable basis.

2. APPLICATION

After NWTPC's Phase I Board Decision was issued in February 2002, NWTPC advised the Board that their Phase II GRA was delayed because of matters being considered by the Executive Council of the Government of the Northwest Territories.

On September 6, 2002, NWTPC filed its Phase II GRA for the fiscal years April 1, 2001 to March 31, 2002 and April 1, 2002 to March 31, 2003 ("**Phase II GRA**"), to determine appropriate rates for their customers. In its Phase II GRA, NWTPC requested approval to levelize the rates across the NWT.

NWTPC, by letter dated October 17, 2002, requested approval to withdraw its Phase II GRA for levelized rates. NWTPC advised that it would re-file its Phase II GRA to apply for community based cost of service rates.

On November 12, 2002, NWTPC re-filed it's Phase II GRA (Ex. 2). The Phase II Application requested an Order or Orders from the Board:

1. Approving NWTPC's proposed retail and wholesale rates for the test years 2001/02 and 2002/03;
2. Approving the revised Terms and Conditions of Service.

Pursuant to section 13. (1) of its Rules of Practice and Procedure, the Board, by letter dated November 12, 2002 directed NWTPC to publish notice of the public hearing of the Phase II GRA in newspapers that circulate in the Northwest Territories. The notices, published in November and December 2002, included details of the Phase II GRA, and invited interested persons to file a request with the Board for intervenor status (Ex. 1).

Intervenors were provided an opportunity to make information requests of NWTPC and to file evidence.

All information requests by the Board and intervenors together with the responses were made available to all parties before the hearing (Ex. 3).

Mayor Peter Clarkson, on behalf of the Association of Municipalities for Fair Power Rates ("**The Association**") representing certain communities located in the Beaufort Delta region filed written evidence by letter dated January 10, 2003 (Ex. 4).

The Board advertised and scheduled the hearing for April 9 – 11, 2003 in Yellowknife and for April 14, 2003 in Inuvik. The Board adjourned the hearing in Yellowknife on April 10th and continued in Inuvik on April 14th.

The interested parties that attended the Yellowknife hearing were NWTPC, City of Yellowknife, Town of Hay River and Town of Fort Smith ("**YK/HR/SM**"), the Association and Mr. Charles Dent, MLA for Yellowknife Frame Lake. At the Inuvik hearing, the parties that attended were NWTPC and the Association. The Association coordinated a number of presentations made to the Board by residents and business people from the eight communities. Mr. Floyd Roland, MLA for Inuvik Boot Lake also made a presentation to the Board at the Inuvik hearing.

During the hearing in Yellowknife, the Board and interested parties agreed on dates for argument and reply argument. For argument, the date was set for May 12, 2003 and for reply argument, the date was set for May 26, 2003.

In this Decision, the Board will address all outstanding matters arising from NWTPC's Phase II Application.

3. COST OF SERVICE STUDY

3.1 Allocation of Head Office Costs

NWTPC provided details of how head office costs were allocated to communities in response to PUB-NTPC-1. Essentially, the Corporation classified the salaries and wages for cost centers (President, Personnel, VP Operations etc.) within the head office function as either customer related or labour related. As a result of this classification, NWTPC proposed 23% of head office costs should be allocated to communities on the basis of number of weighted customers and 77% on the basis of labour.

YK/HR/SM submitted that NWTPC's allocation of entire department salaries and wages to either labor or customer is arbitrary and does not comply with the Board's Directive in Decision 5-95.

In this regard, YK/HR/SM submitted:

> *"Clearly, some of the president's salary, for example, is a function of both plant labor and number of customers rather than just labor. It is submitted that is why separate accounts were required to enable the allocation of head office costs on a rational basis. In the absence of a current cost classification to labor and customer based on separate accounts, it is submitted that 67% of head office general plant and expenses be classified to labor and allocated to individual plants based on plant labor, and, that 33% of head office general plant and expenses be classified to customer and allocated to individual plants based on weighted customers. The 67%/33% classification is derived from Exhibit 13 which, it is submitted, gives effect to the Board's Directive from Decision 5-95. YK/HR submit that NTPC should be directed to refile its cost of service with this change."* [YK/HR/SM Argument PP 2,3]

NWTPC responded to YK/HR/SM's concerns as follows:

> *"Both the 1995/98 and 2001/03 GRA approaches lead to the same result. For example, costs for FERC code 930 Executive-General from the 1995/98 GRA is consistent with the costs for the President and Chairman categories in the 2001/03 GRA. In each case, the costs for these executive functions is considered to be labour-related. In contrast, YK/HR/SM assert that "…some of the president's salary, for example, is a function of both plant labor and number of customers rather than just labor" and therefore the 2001/03 GRA approach is arbitrary.[1] However, all of the time allocated to the executive functions in both the 1995/98 GRA and the 2001/03 GRA is considered 100% labour-related. Contrary to YK's assertion, there is no change in this allocation. Further, Ms. Goucher candidly acknowledged that the allocation of head office costs is not an exact science.[2] Recognizing that costs such as the president's salary are best tracked by the relative amount of activity, it is more accurately allocated relatively equally to NUL(Yk) and Inuvik (i.e. as labour-related), rather than 100 times more to Inuvik than NUL(Yk), which would be the result of a customer-related allocation.*
>
> *With respect to the YK/HR proposal that a 66% labour 33% customer allocation be used, it is clear that that approach is inadequate. The 66:33 allocation is taken from the 1995/98 GRA and based on a 1995/96 timesheet study. The 1995/96 head office timesheet study reflected the Corporation's structure at that point in time, including a substantial number of retail customers served in Nunavut. It does not, however, reflect the Corporation's current structure. For example, at the time of the 1995/98 GRA almost 25% of the head office hours were invested in customer accounting (i.e. billing) and collections.[3] Under the Corporation's current structure, those activities are substantially delivered out of the area offices. Using of a 66:33 allocation in the 2001/03 cost of service study as proposed by YK/HR would be completely arbitrary.*
>
> *The Corporation's head office allocation methodology is consistent with cost causation and appropriately functionalizes costs between labour-related and customer-related categories. The net result is a decrease in the customer-related costs since the 1995/98 GRA (reduced from 33% to 23% of head office costs).[4] This decrease is consistent with the changes*

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1 YK/HR/SM Argument, p. 2.
2 Tr. 1, p. 66, lns. 7-11.
3 See NWTPC 1995/98 Phase II GRA, Ex. 4, BR-NTPC 6.
4 Ex. 13; Ex. 3, PUB-NTPC 1, table 3.

> *that have occurred in the Corporation and the reorganization undertaken since the 1995/98 GRA."* [NWTPC Reply PP 3,4]

NWTPC classified and allocated to the various communities, 5% of operations support plant and operating and maintenance expenses on the basis of weighted number of customers and 95% on the basis of labour. With respect to the allocation of operations support costs, YK/HR/SM submitted:

> *"On cross-examination, it was indicated that the Hay River Warehouse comprises the contracts, purchasing, accounts payable, mail room and logistics functions.*[5] *YK/HR submit that not all of these functions are best classified solely on the basis of labor as NTPC has proposed. Purchasing, accounts payable and logistics are more likely to be a function of the number of invoices and amount of materials and supplies issued by plant rather than labor. NTPC should be directed to review the component costs of the Operations Support function and provide allocators that better reflect the drivers of these costs than primarily labor at the time of its next GRA."* [YK/HR/SM Argument P 3]

In its Reply Argument YK/HR/SM indicated standby generation assets included as part of operations support assets should be allocated equally to all plants, rather than on the basis of 5% of costs based on number of customers and 95% based on labour. [P 2]

The Board is not persuaded by YK/HR/SM's argument the classification of cost related to executive functions as labour related, for purposes of allocating head office costs to zones and communities is necessarily inappropriate. The Board notes YK/HR/SM's submission that the bases used to allocate functions within operations support could be further refined. The Board considers it must strike a reasonable balance between more refinements to the basis of head office and operations support cost allocation and the potential for undue discrimination among zones and communities. The Board notes the proposed method of head office and operations support cost classification and allocations are generally consistent with those previously approved. Given the division of NWTPC, the Board considers the results of allocations from prior years are not necessarily comparable with those in this proceeding. Based on the evidence before the Board, the Board is satisfied the Corporation's proposed allocations of head office and operations support costs will not result in undue discrimination among zones and communities. Given the method of allocation proposed by NWTPC, the Board considers it appropriate to allocate all operations support plant including standby generators on a consistent basis. Accordingly, the Board accepts NWTPC's proposed allocation of head office and operations support costs for purposes of this Decision.

3.2 Allocation of Area Office Costs

In Board Decision number 12-97, NWTPC was directed to carry out a study with regard to a number of topics including the appropriate allocation of area office expenses to the communities served by them. The Corporation undertook a time sheet analysis and an expense analysis for each of the four area offices (Yellowknife, Fort Smith, Inuvik and Fort Simpson) to determine the appropriate proportion of each of the area office expenses that should be allocated to the satellite plants.

NWTPC noted, reflecting the study results would result in relatively minor impacts in revenue requirements for most communities compared to the method used in the 1995/98 GRA. In the 1995/98 GRA, NWTPC allocated 25% of each area office costs to (cost center 8730) the respective plants served by the area office. NWTPC indicated the new method shifts costs away from the area offices

[5] Transcript, April 9, p. 71

and onto the satellite plants. If the new method were used Yellowknife, Inuvik and Fort Simpson would all experience a decrease in net revenue requirement of approximately 1%. Fort Smith would see a 6% decrease. However, the satellite plants would see a range of increases with a median increase of 1% in revenue requirement.

NWTPC states the new method of allocation using time sheet and expense analysis is considerably more complicated whereas the overall impact on most communities is quite small. Accordingly, NWTPC proposed to use the existing, method which allocates 25% of area office costs to satellite plants, for this GRA.

YK/HR/SM acknowledged that the NWTPC proposal results in reasonable results elsewhere but submitted that it does not work for the Yellowknife system. YK/HR/SM submitted NWTPC considered the communities of Rae Edzo and Dettah as satellite plants whereas they are part of the Yellowknife system. This resulted in over allocation of area office costs to the Yellowknife system:

> *"While this methodology appears to work for the Inuvik system, it does not appear to work for the Yellowknife system.[6] . The reason offered by NTPC is that it considered that there were six plants in the Yellowknife area, three satellite plants plus Yellowknife, Rae/Edzo and Dettah. With all due respect, Rae/Edzo and Dettah are not satellite plants but rather part of the Yellowknife system. Yellowknife submits that 25% of the Yellowknife area costs or $364,829 should be allocated equally between the Yellowknife plant and the three satellites. Therefore, $91,207 should be allocated to each of Wha Ti, Rae Lakes and Lutsel Ke and $1,185,694 should be allocated to the Yellowknife system."* [YK/HR/SM Argument P4]

NWTPC provided the following comparison of the impact of the different methods of area cost allocation on each of the communities:

[6] Transcript, April 9, pgs. 38-39,

Total Revenue Requirement per Community ($)				
	2001/03 Timesheet Study	NTPC Proposed Approach	YK Proposed Approach	Difference between YK Proposed Approach and 2001/03 Timesheet Study
104 Wha Ti	1,310,310	1,299,755	1,330,157	19,847
105 Rae Lakes	930,008	919,686	950,088	20,080
110 Lutsel K'e	818,925	833,641	864,043	45,118
101/108/109 Snare/YK	24,598,098	24,604,257	24,513,051	-85,047

Source: NWTPC Reply P5

NWTPC submitted:

> *"YK is proposing to have the communities of Yellowknife, Rae/Edzo and Dettah pay approximately $85,000 less than is warranted, at the expense of the 3 diesel communities in the area, who will pay as much as $45,000 over the properly measured revenue requirement (or almost 6% over their revenue requirement). There is simply no basis to push costs properly borne by the Snare/Yellowknife system onto the diesel communities in the area."* [NWTPC Reply P5]

The Board considers the question whether a community is a satellite plant or not, is not determined by the fact it is part of an integrated system, but rather, by the location of the plant in relation to the area office. To the extent the Rae Edzo and Dettah communities are located away from the area office they must be considered satellite offices. The Board notes the 25% allocation of area office costs to satellite plants produces results that are not materially different from that based on the time sheet and expense analysis, for most communities. The Board therefore accepts NWTPC's proposed allocation of area office costs for purposes of this Decision.

3.3 Allocation of Working Capital to Plants

YK/HR/SM raised the concern the proposed allocation of fuel costs to plants in the Snare/Yellowknife system based on energy would not reflect the particular fuel arrangements and costs associated with different plants.

YK/HR/SM also submitted the materials and supplies for the Yellowknife system include $3.6 million which is the balance in the Snare Cascades deferral account. This should be allocated on the basis of hydro plant allocation rather than total plant allocation

NWTPC responded to these concerns as follows:

> *"YK claims that it was not clear "…whether the fuel component of working capital reflects the fuel arrangements at individual plants."*[7] *The Corporation confirms that the fuel component of working capital was indeed derived from measured inventory levels at each individual plant.*
>
> *YK also claims that the balance of the Snare/Cascades deferral account ($3.6 million) should be allocated based on hydro production plant rather than total plant in service, which in their view improperly includes an allocation of diesel assets to Rae/Edzo.*[8] *As discussed in section 2(d) below, the Corporation has properly allocated diesel assets to Rae/Edzo. In any event, the Snare/Cascades deferral account, whether allocated based on hydro production plant or otherwise, has no effect on the final cost of service study.*

[7] YK/HR/SM Argument, p. 5.
[8] YK/HR/SM Argument, p. 5.

> *The Snare/Cascades deferral account was established pursuant to the 1995/98 Phase I negotiated settlement approved by the Board in Decision 1-97.*[9] *It was noted in the Corporation's 2001/03 Phase I application that each year's draw down of the Snare/Cascades deferral account is offset by a corresponding amount attributed to miscellaneous revenue which is netted off of the Snare/Yellowknife revenue requirement. Consequently, the Snare/Cascades deferral account does not have any effect on the final cost of service study."* [NWTPC Reply PP5,6]

The Board notes NWTPC's confirmation the fuel inventory component at each plant reflects the measured inventory at the plant. Accordingly, the Board accepts NWTPC's assignment/ allocation of fuel inventory.

The Board agrees with YK/HR/SM that it is more appropriate to allocate the working capital component of the Snare Cascades deferral account and the miscellaneous revenue associated with Snare Cascades deferral on the basis of hydro plant. NWTPC is directed to change the method of allocation of these accounts for purposes of the refiling.

3.4 Allocation of Diesel Plant to Rae Edzo

NWTPC proposed allocation of the Jackfish diesel plant to all customers except Rae Edzo, in the Snare Yellowknife zone.

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[9] NTPUB Decision 1-97, *NWTPC 1995/98 Phase I GRA* (January 14, 1997) at 8. The following phase-in was agreed to and approved by the Board in negotiated settlement:

a) the entire Snare Cascades project would be placed into rate base in 1996/97;
b) the Corporation would collect the difference between the full revenue requirement for the project and the annual variable savings resulting from the project for five years (1996/97 to 2000/01) in a deferral account;
c) the balance of the deferral account would earn a rate of return similar to AFUDC;
d) the amount in the deferral account would be amortized over ten years commencing April 1, 2001; and
e) the balance in the deferral account would earn a cash return during the ten year amortization period.

YK/HR/SM submitted NWTPC should be directed to allocate all diesel production plant including Jackfish plant to all customers including Rae Edzo as this is consistent with the way NWTPC plans the Snare Yellowknife system. YK/HR/SM argued all of the resources, including both Jackfish and Frank's Channel units, are utilized to meet the Yellowknife system peak load of all customers from a planning perspective and therefore it is appropriate to allocate diesel plant to all customers.

NWTPC stated the Rae Edzo does not rely on the Jackfish plant for its capacity requirements:

> *"From a community planning perspective, the relevant measure to Rae/Edzo is not the Jackfish installed capacity. Rather, the relevant measure is the installed capacity at Frank's Channel, which has to be sufficient to supply those communities in times of outages. It is not relevant to Rae/Edzo if Yellowknife grows and requires larger units at Jackfish, as it did in 1994/95,[10] or if Yellowknife is able to reduce load and retire some units. Under either scenario Rae/Edzo continues to be planned for a local diesel complement that must be able to carry those communities' peak loads. As noted in the Corporation's 2001/03 Phase I Application "Capacity Planning Criteria" section cited in the YK/HR/SM Argument:*
>
> > [w]hile Yellowknife can receive energy generated at the Frank's Channel plant in Rae/Edzo, the flow of energy can not be reversed. Therefore, Customers in Rae/Edzo can not access energy produced at the Jackfish diesel plant or the Bluefish hydro site. As a result, a deterministic planning criteria is more appropriate for Rae/Edzo than the probabilistic method proposed for the balance of the Snare Yellowknife Zone.[11]
>
> *There is no basis to say that Rae/Edzo supply was planned in any way whatsoever with the Jackfish units in mind – the Jackfish units are simply irrelevant to Rae/Edzo.*" [NWTPC Reply PP 7,8]

10 Ex. 17.
11 NWTPC 2001/03 Phase I GRA dated May 9, 2001 at 2-93.

The Board notes NWTPC's assertion Rae Edzo does not rely on the Jackfish diesel plant for its capacity requirements. Accordingly, the Board considers NWTPC's proposed allocation of the Frank's channel plant only to Rae Edzo and the Jackfish plant to all customers except Rae Edzo to be reasonable.

3.5 Allocation of Diesel Fuel and Operating Expenses to Rae Edzo

NWTPC proposed to allocate fuel and operating costs of the Frank's Channel units to all customers while the fuel and operating expenses for the Jackfish plant were allocated to all customers except those in Rae-Edzo. YK/HR/SM expressed concern that:

> *"…Yellowknife submits that NTPC should be directed to allocate all diesel fuel and all other operating and maintenance expenses*[12] *to all customers based on the coincident peak demand and energy of all customers in the refiling of its cost of service study."* [YK/HR/SM Argument P 7]

NWTPC opposed the above recommendation stating the Jackfish plant does not supply Rae Edzo:

> *"The result of the differences between Jackfish and Frank's Channel is that, from both a planning and operational perspective, the Frank's Channel station can and does provide supply to Yellowknife while the Jackfish diesel plant does not supply Rae/Edzo whatsoever."* [NWTPC Reply P8]

In view of NWTPC's evidence noted above, the Board accepts NWTPC's proposed allocation of diesel fuel and operating expenses to Rae Edzo for purposes of this Decision.

[12] Page 7 of 25, Tab 26

3.6 Miramar Cost Allocation

In Decision 12-2002 dated November 12, 2002, NWTPC's request for approval of a project permit to purchase the Bluefish generating plant was approved. In this Decision, the Board stated:

> *"The Board is of the view that the terms of the second restated power sales agreement between NWTPC and Miramar are more appropriately dealt with as part of the upcoming Phase II proceedings. Accordingly, the Board will not deal with NWTPC's request for approval of the second power purchase agreement in this Decision."* [P9]

NWTPC explained how the Miramar demand used for the Phase II cost allocation purposes was developed:

> *"MR. PATRICK BOWMAN: No, the -- the five (5) year averages are measured gross Con load, to come up with the load factor and a coincidence factor. And then those load factors and coincidence factors are applied to the net number of kilowatt hours, ignoring peak and time, but to the net number of kilowatt hours to come up with a calculated peak. And then, subsequently, a calculated coincident peak for Miramar.*
>
> *That's where the five (5) year averages come in. So one doesn't actually look at a certain number, subtract Bluefish, to come up with any of the numbers in the cost of service Study. One starts with the number of kilowatt hours and then uses these accepted calculated numbers, using a particular methodology, to -- to come up with the measured peak."* [T187, lns 1-15]

YK/HR/SM indicated it was satisfied the Corporation has used consistent approaches with respect to the Miramar Net load for planning and cost allocation purposes.

> *"Yellowknife is now satisfied that NTPC was using the Nerco peak demand net of Bluefish generation rather than the 6,500 kVA dedicated contract demand capacity for planning purposes."* [YK/HR/SM Argument P 8]

The Board notes Mr. Bowman's explanation that the 5 year average load factors and coincidence factors developed from the gross Miramar Con Mine Load are applied to the Miramar Kilowatt hours net of bluefish generation Kilowatt hours to calculate the Miramar peak demand used for cost allocation purposes. This approach to cost allocation reflects the assumption that the Bluefish capacity would be relied upon by the entire Snare Yellowknife system for capacity planning purposes. In contrast, if the Bluefish capacity were considered as entirely dedicated to the Miramar mine load the Bluefish load at the time of system peak would have been deducted from the mine load for cost allocation purposes. The Board notes under the second restated power sales agreement Miramar would receive a credit of 7200 KVA per month regardless of the Bluefish plant's generation; further the Corporation would have dispatch control over the Bluefish plant. The second restated power sales agreement is consistent with the assumption the Bluefish capacity would be relied upon by the entire Snare Yellowknife system for capacity planning purposes.

The Board accepts the proposed cost allocation method for Miramar as it appears to be consistent with the current planning and operating assumptions for Miramar load and Bluefish generation.

3.7 Allocation of Costs between Fort Smith and Fort Resolution

YK/HR/SM expressed the concern the Corporation was proposing the same rates for customers in Fort Smith and Fort Resolution whereas if the cost of service methodology approved by the Board in Decision 5-95 been consistently followed, the cost of service for Fort Smith would be lower than for Fort Resolution.

> *"Fort Smith does not consider that NTPC has necessarily followed the Board's directions in Decision 5-95 when it developed zonal rates for Fort Smith and Fort Resolution. The Board clearly indicated that it was appropriate to average generation costs and generation integration costs over all customers in the zone. However, the Board specifically identified that, differences in distribution costs would result in differing cost of service. One of the more significant remaining differences relates to the transmission grid costs allocated to each community. It should be noted that NTPC has specifically allocated transmission grid costs to Rae/Edzo, and, all communities excluding Rae/Edzo, on the Yellowknife system in determining the cost of service for those customers. Although NTPC determined the transmission grid costs separately for each of Fort Smith and Fort Resolution, it then ignored that information in its rate design. Fort Smith is directly subsidizing the cost of serving Fort Resolution, unlike any other community served by NTPC."* [YK/HR/SM Argument P 10]

NWTPC indicated a substantial portion of the difference in cost of service is attributable to the Pine Point mine legacy assets:

> *"There is no basis for dividing Fort Smith and Fort Resolution for rates setting purposes. Both of those communities continue to be served by the same generation and transmission grid. Both are served on a consistent basis by the same Corporation staff. While there may be some differences in the distribution costs in each community, a substantial portion of those cost differences is likely related to the Pine Point mine*

> *legacy assets and not to any inherently higher costs to serve Fort Resolution versus Fort Smith."* [NWTPC Reply P 10]

The Board notes NWTPC's assertion that a substantial portion of the difference in cost of service between Fort Smith and Fort Resolution is attributable to the Pine Point mine legacy assets. However, in the Board's assessment, based on the response to YK, HR, SM-NTPC 16, there are also material cost differences between Fort Smith and Fort Resolution at the diesel plant, distribution plant and general plant levels.

The Board considers it appropriate to share the cost of any stranded assets related to Pine Point mine among all customers on the system. The Board directs NWTPC to identify the cost of any stranded Pine Point legacy assets and address the appropriate allocation of these assets in the Phase II refiling. Consistent with the cost allocation principles used for the Snare/ Yellowknife system, the separate costs based on the cost of service study for each of Fort Smith and Fort Resolution should be used to develop cost based rates for each of those communities. The Board directs NWTPC to revise the cost allocations for the Taltson system in accordance with the foregoing findings.

3.8 Bluefish Transmission Line Losses

With respect to the Bluefish transmission line losses reflected in the cost of service study, NWTPC stated:

> *"Decision 12-97 also directed the Corporation to conduct a study respecting losses on the Bluefish transmission line. In compliance with that direction, the Corporation analysed meter data from September 2000*

> *to December 2001 and has determined that Bluefish transmission line losses are 7.1%.*[13]
>
> *As noted in the Application and by Ms. Goucher, it was the Corporation's intent to use a 7.1% loss factor for the Bluefish transmission line in its cost of service study.*[14] *The Corporation has since determined that 5.7% (not 7.1%) was inadvertently used. The Corporation has undertaken to use a 7.1% loss factor for the Bluefish transmission line in the final cost of service subject to directions from the Board.*[15]*"* [NWTPC Argument P 8]

The Board directs NWTPC to reflect the corrected line loss percentage for the Bluefish transmission line in its refiling.

3.9 Retail Community Line Losses on Hydro Systems

NWTPC used distribution loss factors of 26.9% for the communities of Dettah and Rae Edzo and 25.1% for the communities of Fort Smith and Fort Resolution, for purposes of cost allocations. [PUB-NTPC 4 and PUB-NTPC 11] The Corporation indicated the loss percentages are those used in the 1995/98 GRA and have not been updated.

With respect to the loss percentages used for Fort Smith, YK/HR/SM submitted:

> *"As noted by NTPC, it is the differential in losses as between customer classes that is relevant for cost allocation purposes. For purposes of cost of service, Fort Smith submits that the distribution losses should be limited to the 8% cap set by the Board in Decision 1-97 so as not to unduly influence the energy and coincident peak for allocation of hydro and generation integration assets."* [YK/HR/SM Argument PP 11,12]

[13] Ex. 2, p. 9-5, table A.
[14] Tr. 1, p. 35, lns. 9-25; Ex. 2, p. 9-6.
[15] Tr. 1, p. 28, lns. 13-16.

In response to YK/HR/SM's comments, NWTPC stated:

> *"In retrospect, the Corporation could have applied an 8% cap to distribution losses for all retail customers in the hydro zones in its cost of service study. However, if the Board accepts SM's recommendation to limit distribution losses to 8%, it must be recognized that doing so will not affect recovery of the Corporation's revenue requirement; rather it will impact cost allocations to other communities."* [NWTPC Reply PP 10,11]

The Board notes NWTPC has not carried out any studies to determine the loss percentages for the retail communities on the hydro systems. However, the loss percentages used for these communities for cost of service purposes appear to be materially high in relation to loss percentages considered reasonable by the Board in the past. In accordance with the YK/HR/SM's recommendation, the Board is prepared to limit the loss percentages for these communities to a maximum of 8% for purposes of this Decision. Accordingly, the Board directs NWTPC to use a maximum line loss percentage of 8% for cost allocation purposes for the retail communities of Dettah, Rae Edzo, Forth Smith and Fort Resolution.

3.10 Rae Edzo Transmission Gross Plant

NWTPC proposed the following correction to the Rae Edzo transmission gross plant:

> *"In preparing its response to that Undertaking, the Corporation determined that the Rae/Edzo transmission gross plant direct assigned assets did not include any costs related to FERC account code 354 (Transmission Poles). Even though the $448,000 original cost of the Rae/Edzo transmission poles has been essentially fully depreciated, there could be some additional costs allocated to Rae/Edzo through the operating and maintenance allocation. The Corporation has undertaken to make that*

> *correction in the final cost of service subject to directions from the Board.*[16]*"* [NWTPC Argument P 10]

The Board directs NWTPC to correct the Rae Edzo transmission gross plant in accordance with the above submission.

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16 Ex. 24; Tr. 3, p. 16, ln. 9 to p. 17, ln. 5.

4. RATE DESIGN

4.1 Rate Design Criteria

With respect to its approach to rate design, NWTPC stated:

> *"The broad rate design criteria previously adopted by the Board continue to be appropriate for the Corporation today. In developing its rate design principles, the Corporation took guidance from the Bonbright criteria and the Board's findings in the Corporation's prior GRAs, as well as the 2001/02 and 2002/03 Interim Rates and the 2001/02 Shortfall Rider decisions.[17] Further, the Corporation was cognizant of the developments in its operating environment and the GNWT's directions and work toward an energy strategy, both as discussed in section 2 above.*
>
> *The Corporation applied the following rate design principles:*
>
> - *continue elimination of government customer classes;*
> - *establish wholesale, industrial and streetlighting rates as close to unity as practical;*
> - *move all residential and general service customer classes toward 100% cost of service subject to a 15% maximum rate class increase over current interim rates; and*
> - *ensure that no community is above approximately 105% revenue to cost ratio.[18]"* [NWTPC Argument PP 12,13]

The Corporation acknowledged it could have applied a 105% cost of service limit at the community level before adjusting individual customer classes. However,

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[17] NTPUB Decision 5-2001 *NTPC 2001/02 Interim Refundable Rates* (June 22, 2001); NTPUB Decision 8-2002 *NWTPC 2001/02 Revenue Shortfall Rider and 2002/03 Interim Refundable Rates* (September 16, 2002); NTPUB Decision 9-2002 *NTPC 2001/02 Revenue Shortfall Rider and 2002/03 Interim Refundable Rates* (September 30, 2002).

[18] Ex. 10, pp. 1-2.

NWTPC noted that the Corporation prioritized rate class adjustments over community revenue to cost ratios for the following reason:

> *"By starting at the customer level, what we've effectively said is that if there were two (2) general service customer groups in two (2) different communities, both paying a 115 percent, both would see the same opportunity for rate decreases, rather than them seeing different opportunities for rate decreases, depending on what the residential customers in that community were sitting at."*
> [T142, lns 15-21]

The Board accepts the above rate design criteria as they are generally consistent with those previously accepted by the Board subject to the following. The Board considers in order to be consistent with the interim rate adjustments approved in Decision 8-2002, the 15% maximum increase and 105% cost of service limit should be applied at the community level before adjusting individual customer classes. The Board considers this approach would provide a higher degree of rate stability as it is consistent with the approach used for interim rates approved in Decision 8-2002. The Board directs NWTPC to design its proposed rates in accordance with the foregoing findings for purposes of the refiling.

4.2 Evidence of the Association

The Association's presented evidence expressing concern over the existing community based rates.

The Association argued that although the Corporation has expressed the its intention to or design rates that would avoid rate shock, the cumulative effect of the increases, have had or will have that very effect on many of the Corporation's customers in general and the customers in the communities represented by the

Association in particular. The Association suggested the 15% maximum increase proposed by the Corporation would be considered high in relation to maximum increases considered reasonable in other jurisdictions such as British Columbia and Alberta.

The Association submitted much of the reason for the rate shock is attributable to the practice of establishing rates based on community cost of service. The Association expressed its concern over the strict application of community cost based rates principles. In this regard it stated:

> *"Merely because the residents of the larger southern communities are able to benefit from the good fortune of being near Hydro generators does not warrant such a disproportionate skewing of the rates between different communities. A relatively minimal increase in the rates of the large population centers will make available to the Corporation a significant sum which if applied to the costs of the diesel communities, would allow a significant reduction in the rates of customers in these communities."* [Association Argument P17]

The Association recommended the Corporation's rate design should explicitly take into account the Territorial Power Support Program ("**TPSP**") as described below in order to shield residential consumption up to 700 kWh per month and commercial and street lighting customer classes.

> *"The Association's solution is that for all residential customers in the NWT, there would be two rates. The first rate would apply to the first 700 kilowatts of energy consumed in the month. The rate for this first "block" of 700 kilowatts of energy per month would be equal to the current residential rate for that community plus an amount sufficient to recover the fixed costs of the Corporation (general plant, administration and general expense costs) in providing service to general service and streetlighting customers. The rates for general service and streetlighting customers would be reduced accordingly.*

> *Obviously, it is fundamental to this proposal that the TPSP remain in place and that it remain unchanged so that the residential customers can receive an increased subsidy for the increased cost of up to 700 kilowatts of energy per month. The second or trailing block rate would be equal to the rates proposed by the Corporation so that there would be cost-recovery for the non-subsidized block.*
>
> *The portion of the fixed costs to be transferred or reallocated from general service and streetlighting customers to the first block of residential customers should be calculated so that the general service and streetlighting rates for all such customers of the Corporation would be equal to the rates paid by general and streetlighting customers of NUL(YK) in Yellowknife."* [Association Argument PP 23, 24]

With respect to the Association's concern over the strict application of the community cost based rates principle, YK/HR/SM submitted:

> *"It is no part of the Board's mandate to engage in social engineering or fundamental policy making on its own initiative. As the Board has recognized in the past, that is the function of the Territorial government which must in such a pursuit, weigh all the competing interests rights and equities. These include not only those spoken to by the speakers for the Association, but also the equally valid and compelling viewpoints of the Hydro communities as given a voice through such representatives as Mr. Charles Dent, who presented to the Board on April 10 in Yellowknife."* [YK/HR/SM Argument P 21]

NWTPC responded to the Association's concerns about rate stability as follows:

> *"The Association has alleged that rates for its communities have increased over 50% in the last fifteen months.*[19] *With respect, it is important to put the Association's allegation into context. It appears that the Association has included in its calculation the 2001/02 shortfall riders approved by the Board in Decisions 8-2002 and 9-2002. It must be recalled, however, that the 2001/02 shortfall rider is a temporary rider that expires once the Corporation's entire 2001/02 revenue shortfall has been collected.*[20] *Similarly, any 2002/03 shortfall rider and fuel riders approved by the Board*

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[19] Tr. 3, p. 77, lns. 12-14.
[20] Tr. 2, p. 55, lns. 6-9.

> *will also be temporary. Focusing on a rate increase calculated over a short time frame that includes temporary riders is misleading and does not recognize the longer term rate stability achieved by the Corporation. Further, shortfall riders are put in place to allow the Corporation to collect revenues that would have been collected had the rates in effect reflected the approved revenue requirement. It is not appropriate to compare rates that collect current period revenues against rates that collect both current and past period revenues."* [NWTPC Argument P 21]

With respect to the Association's comments respecting the proposed maximum increase of 15%, NWTPC stated:

> *"Unlike the British Columbia and Alberta integrated electric systems, the Corporation's system is significantly smaller and largely made up of remote, small communities served by isolated diesel generation. Absent the economies of scale enjoyed in other jurisdictions, a 15% rate cap is appropriate for the Northwest Territories. Further, a significant portion of rate increases in the Northwest Territories is directly attributable to fuel price increases. As noted at pages 22 and 23 of the Corporation's Written Argument, the Northwest Territories does not have the luxury of being able to apply a lower definition of rate shock as other jurisdictions.[21]"* [NWTPC Reply P 17]

With respect to the Association's proposal for rate design giving explicit recognition to the TPSP, NWTPC stated:

> *"The Association's proposal does not reflect sound rate making principles because it is entirely dependant upon continuation of the TPSP at its current levels and would not be robust enough to withstand future changes to the TPSP or to address residential customers that do not qualify for the TPSP."* [NWTPC Reply P 17]

The Board notes the Association's concern over the potential for rate shock resulting from rates established on the basis of community cost of service.

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[21] Tr. 2, p. 93, ln. 5 to p. 95, ln. 14.

However, given the absence of a physical system integrating hydro and diesel communities, the creation of any form of cost averaging between hydro and diesel communities would be contrary to the principles of cost causation and rate making. This means, explicit subsidies among rate zones would be contrary to the principles of rate making and the Board cannot act on the recommendations of the Association unless directed otherwise as stated in Decision 5-95:

> *"It is the view of the Board that if unaffordable power rates in diesel communities are to be subsidized by ratepayers in hydro communities or lower cost diesel communities, this can only be achieved by way of a policy direction from the GNWT, keeping in mind the existing subsidy program."* [P 57]

The Board notes the rate design criteria discussed in Section 4.1 are intended to balance the move towards cost based rates while mitigating rate shock. The Board considers that the particular circumstances of the Corporation including cost based rates by community and the relatively high fuel costs must be considered in establishing the maximum increase. The Board considers the proposed maximum 15% increase proposed by the corporation to be reasonable under the circumstances.

The Board notes the Association's proposed rate design giving explicit recognition to the TPSP. However, the Board considers the Association's proposal would not be consistent with cost based rates. Accordingly, the Board does not accept the Association's proposed rate design.

5. REVENUE TO COST RATIOS

5.1 Hydro Communities Revenue to Cost Ratio

YK/HR/SM submitted the revenue cost ratios for the communities within the Taltson zone as well as Northland (NWT) Utilities Limited can and should be designed to recover as close to 100% of costs as practical.

In response, NWTPC stated:

> *"In effect, SM argues that Fort Smith, Fort Resolution and NUL(HR) rate classes should be given preference over other rate classes that are also above a 100% revenue to cost ratio. The Corporation strongly disagrees with that position. Subject to the Corporation's other rate design principles, any potential rate decrease must be equally available to all rate classes with a revenue to cost ratio over 100%. SM's proposal would result in the Corporation unduly prefering Taltson zone rate classes over other rate classes. There are ten diesel zone residential rate classes and nine diesel and hydro zone general service rate classes that have higher revenue to cost ratios than Fort Smith, Fort Resolution and NUL(HR).[22] There is no reasonable basis for unduly preferring Fort Smith, Fort Resolution and NUL(HR) over those 19 customer classes. The Corporation's position is that all customer classes with a revenue to cost ratio over 100% are equally entitled to rate decreases to the extent that any are available and subject to the Corporation's other rate design principles."* [NWTPC Reply PP 15,16]

The Board considers it appropriate to move all communities toward cost recovery. However, this move must be tempered by other rate design considerations including the potential for rate shock for communities seeing cost

22 Ex. 3, SP,FL,LKFN-NTPC 2(f), table 3.

increases. The rate design criteria accepted by the Board as set out in Section 4.1 are designed to balance the conflicting objectives of cost recovery while mitigating rate shock.

The Board notes NWTPC's observation that subject to the Corporation's other rate design principles, any potential rate decrease must be equally available to all rate classes with a revenue to cost ratio over 100%. Given the objective of moving all rates towards cost recovery, the Board considers there is merit in allocating any rate reductions such that communities and classes with relatively higher revenue to cost ratios in relation to the upper limit of the tolerance range of 105% receive a proportionately higher reduction relative to those with relatively lower ratios, subject to all other rate design criteria discussed in section 4.1. The Board directs NWTPC to take this into consideration in designing rates for purposes of the refiling.

5.2 Hydro Zone Revenue to Cost Ratios

YK/HR/SM submitted based on principles established by the Board in Decision 5-95 that each of the Yellowknife, Taltson and Norman Wells rate zones should only recover their respective cost of service. Decision 5-95 states:

> *"It is the view of the Board that if unaffordable power rates in diesel communities are to be subsidized by ratepayers in hydro communities or by lower cost diesel communities, this can only be achieved by way of policy direction from the GNWT, keeping in mind the existing subsidy program." [P 57]*

In response NWTPC submitted:

> *"YK's complaint is that the Corporation has not designed its Snare/Yellowknife and Taltson zone rates to reflect exactly 100% revenue to cost ratio. There is no support for that position. In fact, the Board has approved a range of tolerance in recognition of the fact that rates will not always be set at unity for a particular rate class, community or zone.*
>
>> *Recognizing the judgemental nature of cost allocations reflected in the cost of service study, the Board has generally accepted a revenue cost ratio tolerance range of 95% to 105%. The Board considers this range to be a useful guide for the establishment of revenues and revenue cost ratios by rate class, community and zone.*[23]
>
> *Both the Snare/Yellowknife rate zone (99.83%) and the Taltson rate zone (104.89%) are within the tolerance range and the Board should approve them as such.*[24] *Any reduction of the rates in these two zones as compared to the Application will require additional increases in other communities (i.e. diesel communities) in excess of the proposed 15% rate cap."* [NWTPC Reply P 14,15]

The Board is not persuaded the hydro zones should be treated differently from communities within the diesel zone for the purposes of applying the rate design criteria discussed in Section 4.1. The Board considers the Corporation should have the flexibility to apply the rate design criteria to all zones within its service territory. The Board is not persuaded the Yellowknife, Taltson and Norman Wells rate zones should only recover their respective cost of service as proposed by YK/HR/SM.

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[23] NTPUB Decision 5-95, *NTPC 1993/94 Phase II GRA* (June 9, 1995) at 60-61. See also NTPUB Decision 12-97, *NTPC 1995/98 Phase II GRA* (June 16, 1997) at 24-25; NTPUB Decision 2-98, *NTPC 1998/99 Rates* (March 19, 1998); NTPUB Decision 2-99, *NTPC 1999/2000 Rates* (March 2, 1999); and NTPUB Decision 8-2002 *NTPC 2001/02 Revenue Shortfall Rider and 2002/03 Interim Refundable Rates* (September 16, 2002) at 8.

[24] Ex. 3, table C.

6. INDIVIDUAL RATES, TOLLS AND CHARGES

6.1 Northland Utilities (Yellowknife) Limited ("NUL(YK)") and Giant Mines Energy Rate

NWTPC proposed a two block energy rate for NUL(YK) and Giant mines. NWTPC explained the need for the two block energy rate as follows:

> *"As sales vary beyond the levels used to set the average rate, additional load is met by higher cost diesel generation. The cost of diesel generation is 13.88 cents per kwh while the proposed blended rate for NUL (YK) and Giant Mine is 10.55 and 7.58 cents per Kwh, respectively, resulting in a net loss on increased sales."* [Application P 7-3, lns. 22 - 27*]*

NWTPC explained the specific cut off between the first block and the second block is set at the annual energy in the 2002/03 approved load forecast. This means all load growth above the approved forecast for either customer would be serviced at the higher second block rate. NWTPC stated failure to address this rate design issue in this proceeding could lead to more frequent GRAs for the Snare/Yellowknife zone.

NWTPC stated it does not need a second energy block to recover incremental diesel generation expenses attributable to higher than forecast sales in Rae/Edzo or Dettah because the energy rates for retail and general service in those communities are higher than the incremental cost of diesel. A second energy block has only been proposed for those Snare/Yellowknife customer classes whose energy rate is less than the incremental cost of diesel because the very purpose of the rate modification is to track those costs going forward.

YK/HR/SM opposed the proposed change. YK/HR/SM submitted the proposed rate is asymmetrical in that it allows NWTPC to recover any additional costs incurred due to higher than forecast load growth and increased diesel generation while allowing NWTPC to retain the benefits of lower than forecast load growth and decreased diesel generation for only these two customers. YK/HR/SM submitted it is inappropriate to focus on one component of increased costs in isolation; costs for the Snare Yellowknife system could change as a result of the corporation assuming control of the Bluefish plant and revenues could change as a result of higher demand revenues through load growth. YK/HR/SM submitted the Corporation would need to be back before the Board in any event as a result of changes to the Miramar contract and there is no urgency to approval of the proposed rate.

NWTPC, in reply, stated:

> *"Implicit in YK's position is the assumption that a benefit in the form of a 13.88¢ per kWh avoided cost will accrue to the Corporation if NUL(Yk) annual consumption is less than the load forecast. That assumption is incorrect. The Corporation's approved revenue requirement is based on the load forecast priced at a blended energy rate reflecting both hydro and diesel generation. To the extent that the negotiated settlement load forecast is not met (i.e. consumption is less than 150,720,446 kWh), the avoided costs are blended costs (not simply incremental diesel costs) because there will always be some diesel generation supplying the first block energy.[25]"* [NWTPC Reply P 13]

> *"The Corporation acknowledges that integration of the Bluefish station will eventually allow for more coordinated operations and perhaps operating efficiencies. However, such efficiencies are not forecast to occur until 2007 or 2008.[26] Further, future hydro operational efficiencies are not relevant to the proposed rate modification. It does not matter how the*

[25] Tr. 1, p. 48, lns. 2-10.
[26] Tr. 1, p. 57, ln. 1 to p. 58, ln. 2.

hydro system is operated or what cost efficiencies may be eventually gained through integration of the Snare and Bluefish facilities. Rather, the increase in diesel generation expense is substantiated because energy consumed above the load forecast will be generated by diesel, not a blend of diesel and hydro.[27]

Respecting YK's implicit request for an assessment of incremental demand charge revenues, it is noted in section 3(a) above that the current rate does not recover all of the demand related costs attributable to NUL(Yk). To the extent that the Corporation collects any incremental demand charge revenues, such revenues would appropriately recover more of NUL(Yk)'s demand related costs. The proposed 13.88¢ per kWh rate is designed to only recover the incremental cost of supplying energy and not the incremental cost of demand growth which will recovered by the demand charge." [NWTPC Reply PP 13,14]

With respect to the mechanics of how the second block energy rate would be applied to the second block energy consumption NWTPC stated:

"In terms of whether it's paid at year end
or -- or on a monthly basis, that's simply a mechanics

question of how the -- how the billing is applied. One could
come up with proxy numbers for each month and do the
adjustments and then just do a true-up at year end.
But to the extent that these numbers could
vary up or down, you'd want to make sure there would be
annual reconciliation reflects the costs that it's the annual
number of kilowatt hours that matter. Having a high month
and a low month doesn't necessarily drive more diesel. It
may just allow the water to be moved, it's only have a high
year that drives more diesel.
So it's the annual number that matters. On a
practical basis, it could be applied monthly on a bill, but
that's -- that's more of a -- a detail, if I can put it that
way." [T189, lns 24,25 - T190, lns 1-14]

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27 Tr. 1, p. 46, lns. 2-18.

The Board notes YK/HR/SM's concerns respecting the asymmetric nature of the two block energy rate. The Board agrees if the Corporation has the ability to recover increased fuel costs when load is higher than forecast it should also be required to refund any decrease in fuel costs due to load reduction relative to forecast. The Board also notes the proposed rate would require year end reconciliations to ensure the second block energy consumption is determined correctly. This means there is little difference between the proposed mechanism and establishment of a separate deferral account. Given these considerations, the Board is not prepared to approve the two block energy rate for NUL(YK). However, Board recognizes as valid the reasons the two block energy rate was proposed. The Board will not preclude the Corporation from proposing some other mechanism of cost recovery that takes into account the asymmetry concern noted above. NWTPC's request for approval of a two block energy rate for NUL(YK) and Giant Mines is denied.

6.2 Northland Utilities (Yellowknife) Limited Demand Ratchet

NWTPC proposed to increase the demand ratchet for the NUL(YK) rate from 85% of peak demand to 100% of peak demand established by the customer. NWTPC stated this matter of raising the ratchet percent was considered during the 1995/98 GRA Phase II negotiated settlement and it was agreed that a move to a 100% ratchet might be too abrupt and that movement to an 85% ratchet would be more appropriate at the time. NWTPC submitted a move to a 100% ratchet will result in the NUL(YK) ratchet being the same as that for other large customers and commercial customers in all communities.

YK/HR/SM submitted there are significant differences between other large customers and NUL(YK) which is a wholesale customer. For example, each mining or industrial customer would have considerable direct control over its peak demands, while NUL(YK) would have very little control.

YK/HR/SM submitted the Corporation has not provided any evidence as to the extent to which the NUL(YK) peak coincides with system peak:

> *"Mr. Bowman testified that it is a customer's peak over the course of the year that drives the amount of generation plants that are required[28]. It is self-evident this is only true to the extent that customer's peak coincides with the system peak. On this point NTPC bears the onus of proof and has provided no evidence."* [YK/HR/SM Argument P 13]

YK/HR/SM questioned whether the 100% ratchet in fact strikes the right balance in terms of providing appropriate price signals:

> *"In view of the demand ratchet practices of Northland and other utilities in Alberta, SM questions the appropriateness of NTPC's 100% demand ratchet as it applies to General Service Customers. The purpose of a demand ratchet is to provide a price signal to customers to control their peak demand[29]. The question is whether a 100% demand ratchet provides a price signal to customers or whether it is punitive to those customers who occasionally have a load excursion. It appears that other utilities have struck a balance in coming to what appears to be a fairly universal 85% demand ratchet for wholesale, industrial and general service customers."* [YK/HR/SM Argument P 13]

NWTPC responded to YK/HR/SM as follows:

> *"As noted by SM, it is the extent that a customer's peak coincides with the system peak over the course of the year that drives the amount of generation plant required.[30] Contrary to SM's assertion, however, the Corporation has provided relevant evidence and met its onus of proof on that point. In the case of NUL(Yk), its coincidence factor was 0.96 from*

[28] Transcript, April 9, p. 38 lines 3- 18
[29] Transcript, April 9, p.39
[30] YK/HR/SM Argument, p. 13.

> *1999 to 2001.[31] Clearly NUL(Yk)'s peak is driving the system peak. When the Miramar Con and Giant mines suspend mining operations, NUL(Yk) will be primarily responsible for the Snare/Yellowknife system peak."* [NWTPC Reply P 12]

With respect to the practical application of the rider, NWTPC stated:

> *"SM appeared to express some concern that NUL(Yk)'s demand ratchet may be triggered by "...an artificial peak arising from the cold load pick up following a prolonged outage".[32] The Corporation confirms that it will adjust demand readings for NUL(Yk), as well as Miramar Con and Giant mines, in the event of abnormal operating conditions lasting in excess of 48 hours caused by unanticipated events on the interconnected electric system."* [NWTPC Reply P12]

The Board notes the coincidence factor of 96% for the NUL(YK) load. Given the high coincidence factor, the Board considers the Corporation's proposal to move the NUL(YK) demand ratchet percentage to 100% reasonable. Accordingly, the Board approves NWTPC's proposed 100% demand ratchet for NUL(YK).

The Board notes YK/HR/SM's concern whether the 100% demand ratchet for commercial customers strikes the right balance between providing the right price signals to control peak demand and being punitive to those customers who occasionally have a load excursion. The Board has addressed this matter in Section 9.1 of this Decision.

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[31] Ex. 2, p. 9-4, table A.
[32] YK/HR/SM Argument, p. 12-13.

6.3 Retail Standby Service Rates

NWTPC proposed a new retail standby rate primarily to respond to demand for such a rate from customers with access to self generation from natural gas in Norman Wells and Inuvik. Under the proposed rate, customers would be charged a monthly customer charge equal to the full monthly general service customer cost calculated from the cost of service study. Customers would also be charged a demand charge equal to the full cost of demand reflected in the cost of service study.

Although the Corporation has proposed standby rates, it does not appear to have looked at the cost characteristics of serving standby loads. The Corporation indicated the standby rates were being proposed at this time in order to provide potential self generation customers an indication of what it would cost to provide standby service, in order to assist them in their evaluation of potential self generation opportunities.

The Corporation submitted:

> *"The proposed retail stand-by service rates will not shift costs between communities or customer classes.*[33] *Further, the Corporation does not have any existing stand-by customers and has not forecast any revenue from those rates.*[34] *It is important to note that the Corporation will develop a stand-by service agreement that addresses interconnection standards, subscription periods, exit fees and re-subscription fees. The Corporation will seek Board approval of that agreement.*[35]*"* [NWTPC Argument P 19]

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33 Ex. 10, p. 2; Tr. 1, p. 27, lns. 22-23; Tr. 2, p. 171, lns. 22-23.
34 Ex. 3, SP,FS,LKFN-NTPC 7(b) & (c).
35 Tr. 2, p. 173, lns. 12-25.

The Board notes the Corporation has done very little analysis to ascertain the cost characteristics of standby service customers. The Board considers it is appropriate to provide realistic estimates of standby service costs to potential self generation customers by undertaking further analysis in this regard. The Board directs the Corporation to file the results of a study assessing the cost of providing standby service together with a proposed standby service agreement including proposals for interconnection standards, subscription periods, exit fees and re-subscription fees within 90 days of this Decision. NWTPC's request for approval of standby rates in this application is not approved.

6.4 Space Heating Rate for Taltson Hydro

YK/HR/SM submitted the Corporation should review the feasibility of offering a firm economically discounted rate for space heating or other use to increase utilization of the Taltson plant:

> *"While no electrical system is 100% reliable, it must be noted that NTPC has not evaluated the incremental cost of diesel generation required to support the hydro and transmission system to bring it to an acceptable level of reliability such that it could offer a firm rate that could take advantage of up to the 94 GWh of energy that was spilled at Taltson in 1999/2000, for example. Given that any incremental energy from Taltson is essentially free and even if 5% diesel were required for outages (at the 13.88 cents per kWh proposed for the NUL (Yk) second block), the average cost would still only be 0.7 cents per kWh. Based on Exhibit 16, it appears that NTPC could market up to 9 MW of <u>firm energy</u> at a relatively low cost.*
>
> *It appears that the prospects for interruptible load or export of energy have not and may not materialize for some time. HR/SM submit that the Board should direct NTPC to review the feasibility of offering a <u>firm economically discounted rate</u> for space heating or other use in an attempt to increase*

> *revenues from the Taltson hydro plant which is grossly under-utilized."* [YK/HR/SM Argument PP 18,19]

With respect to a space heating rate, NWTPC stated:

> *"The Corporation is pleased to discuss with potential customers the use of surplus Taltson system power. The Corporation is concerned, however, that all potential customers fully appreciate the circumstances under which surplus Taltson system power could be supplied. Any rate developed would have to be an interruptible rate because it will be served from surplus hydro and the rates for that type of service would not cover diesel generation in the event of a transmission line outage, maintenance to a hydro unit or additional load coming on to the system, such as the Pine Point Mine reopening.[36] Further, the customer's load requirement may come at a time when the system has its least surplus. As Mr. Grabke explained, hydro surplus does not occur throughout the year. Rather, "[i]t occurs in opposition to the load of Fort Resolution, Fort Smith, and Hay River. So in other words, you have left very little surplus energy during the winter, and an awful lot during the summer. So some projects like heating and that, are in conflict to when the surplus is occurring."[37]* [NWTPC Argument P 20]

The Board notes NWTPC's statement that firm rates cannot be offered due to limitations imposed by transmission reliability. However, the Board considers diesel generation if strategically located close to loads may perhaps be used to overcome the transmission reliability problems. This is how the Board understands YK/HR/SM's suggestion. The feasibility of this option has not been explored by NWTPC. The Board also notes the Corporation's willingness to discuss with potential customers the use of surplus Taltson system power. The Board directs the Corporation to investigate the feasibility of these options and provide a report at the time of the next GRA.

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36 Tr. 1, p. 114, ln. 14 to p. 115, ln. 13.
37 Tr. 1, p. 115, lns. 20-25

6.5 Time of Use Rates

The Association submitted in its evidence that the Board should require NWTPC to investigate time of use rates:

> *"More generally, the Board ought to require NTPC to investigate time-of-use rates since many general service customers can likely shift load to non-peak hours, which ought to reduce demand-related costs."* [EX 4,P 4]

NWTPC stated only a very small number of its customers could make use of time of use rates and even for those customers there should be a tie to the potential cost savings resulting from time of use rates:

> *"so, what we're really talking about is the peaks, can you move the peaks. Time-of-use rates would be relevant to send a price signal to customers, to the extent that the customers can respond to those price signals.*
>
> *In most cases the types of customers served by the Power Corporation are not the types that one would normally identify as being able to respond to price signals. A -- supermarket or a hotel doesn't have a lot of potential to shift their load. Their load is driven by the hours of day when the lights need to be on and their refrigerators need to be on.*
>
> *So, it's a very small number of customers who actually have loads, on a practical basis, that they can move around to take use of -- to gain the benefit of a – of a time-of-use rate.*
>
> *Even for those customers who can move the load, the savings that would result from shifting it would have to be tied to the fact that there's actually a savings in costs on the system.*
>
> *And a savings in the costs on the system would arise when the peak in the community is driving the need for*
>
> *new investment in a larger diesel plant, or a larger capacity.*
>
> *In those cases, given that there's a very*

> *small number of customers that we're talking about who can – who can even take benefit from that, a much more straight-forward proposal would be for the Corporation, when it reviews the plant that it needs to add, to consider not only a passive capital addition, to say our peak is currently 2 megawatts, we have 1.9 installed and we need to add one (1), but also to say what can we do to curb that 2 megawatt peak.*
>
> *And in those cases go to directly talk to the customer who may have the ability to shed load at those times or shift load and just individually arrange a means to have that customer shift -- use their load to address the – the – -load pattern."* [T157, lns 5-25 - T158, lns 1-15]

The Board considers there is merit in the Association's proposal even though it may have limited application at the present time. The Board believes it is appropriate to provide the right price signals that would result in delaying new plant additions. The Board directs NWTPC to investigate the benefits and market potential for time of use rates and address this matter at the time of the next GRA.

7. TERMS AND CONDITIONS OF SERVICE

7.1 Maximum Corporation Investment

In response to PUB-NTPC 22 (d), NWTPC indicated the Corporation's maximum investment level in customer facilities has stayed the same over the last 10 years. NWTPC confirmed it has not carried out any assessments to confirm whether or not these investment levels remain appropriate. The Corporation stated as follows in its Reply Argument:

> *"YK/HR/SM request that the Corporation be directed to "…review its current connection costs as compared to its investment levels and file that information at its next GRA, at the latest."*[38] *The Corporation concurs with that request.*[39]*"* [NWTPC Reply P 19]

The Board directs NWTPC to carry out an assessment of maximum corporation investment levels for the next GRA.

7.2 Changes to Terms and Conditions of Service

The revisions proposed to the Terms and Conditions of Service in NWTPC's application are hereby approved subject to revisions and deletions identified by the Corporation and to the following reservations and changes:

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38 YK/HR/SM Argument, p. 23.
39 NWTPC Written Argument, pp. 2, 33 and 35.

Section 2.8: the words "(including, without reservation, individual members of such association)" are struck out.

Section 10.2: the words "with the exception of residential areas" are inserted after the word "property" in the first sentence of the first paragraph.

Section 13.2: largely duplicates the effect of section 13.3 and is not approved

Section 13.3: The subheading above this section should read "Limitation of Corporate Liability".

Section 14.1: Is not approved. The Board is not convinced that a customer should be exposed to liability for losses or damages to third parties arising from the use of the Corporations' Service. The Board does not feel that Customers could reasonably be expected to be aware of this kind of liability imposed thorough Terms and Conditions of Service.

8. FINAL RECONCILIATION

In its opening statement provided at the commencement of the Yellowknife hearing, NWTPC indicated it had detected a linking error in the Phase I negotiated settlement tables and consequently in the Phase I approved revenue requirement for each of the test years. Correction of the error results in a lower revenue requirement for both test years. In response to Exhibit 27, NWTPC provided a reconciliation of the Phase I negotiated settlement revenue requirement with the corrected revenue requirement. Based on Exhibit 27, the Board approves the corrected revenue requirement for 2001/02 and 2002/03 as follows:

Board Approved Revenue Requirement 2001/02	$63,236,000
Board Approved Revenue Requirement 2002/03	$66,344,000

With respect to finalization of rates resulting from these proceedings, NWTPC requested the following of the Board:

(i) directing the Corporation to file with the Board within 30 days of its decision a final cost of service report for the test years 2001/02 and 2002/03 incorporating the updates to the cost of service discussed in section 3 below and revisions to the approved revenue requirement discussed in Exhibit 27;

(ii) approving the rate design principles discussed in section 4 below and directing the Corporation to file with the Board within 30 days of its decision final rates for 2002/03 based on the final cost of service and approved rate design principles, to be effective as soon as practical following a final Board decision;

(iii) ordering that the 2001/02 interim rates and shortfall riders approved by the Board in Decisions 5-2001, 8-2002 and 9-2002 are final and directing the Corporation to file with the Board within 30 days of its

decision a final calculation of the 2001/02 revenue shortfall collected by community consistent with the principles set out in Decision 8-2002, the final cost of service and revisions to the approved revenue requirement discussed in Exhibit 27;

(iv) directing the Corporation to file with the Board within 30 days of its decision a final calculation of the 2002/03 revenue shortfalls by community and customer class based on the final cost of service and revisions to the approved revenue requirement discussed in Exhibit 27;

(v) directing the Corporation to file with the Board within 30 days of its decision a recommendation respecting finalization of the 2002/03 interim rates based on the final cost of service and revisions to the approved revenue requirement discussed in Exhibit 27; [NWTPC Argument P 2]

Having considered the above request, the Board directs NWTPC as follows with respect to finalization of rates:

i) to file within 30 days of this Decision a final cost of service study for the test years 2001/02 and 2002/03 incorporating the changes to the cost of service discussed in section 3 of this Decision and revisions to the revenue requirement discussed above;

ii) to file within 30 days of this Decision final rates for 2002/03 based on the final cost of service and approved rate design principles, to be effective as soon as practical following a final Board Decision;

iii) to file within 30 days of this Decision a final calculation of the 2001/02 revenue shortfall collected by community consistent with the principles set out in Decision 8-2002, the final cost of service and revisions to the approved revenue requirement discussed above;

iv) to file with within 30 days of this Decision a final calculation of the 2002/03 revenue shortfalls by community and customer class based on the final cost of service and revisions to the approved revenue requirement discussed above;

v) to file within 30 days of this Decision a recommendation respecting finalization of the 2002/03 interim rates based on the final cost of service and revisions to the approved revenue requirement discussed above

9. OTHER MATTERS

9.1 Requests for Consultations and Commentary

The Village of Fort Simpson, Hamlet of Fort Liard and Liidlii Kue First Nation, in a letter to the Board dated April 7, 2003, indicated the Board should direct the Corporation to increase its level of consultations with communities in the planning of capital expenditures that would have a significant effect on power rates. They also indicated their desire to be kept informed of any changes to the TPSP that may have an impact on electricity rates. They expressed the desire for increased participation in the development of Government and NWTPC policy as it affects end users of electricity through initiatives such as the paper on energy strategy.

In its Argument, NWTPC submitted:

> *"With respect to the first concern that the Board direct more community consultation respecting capital expenditures, it is the Corporation's position that such a direction from the Board is both unnecessary and not supported by the record in this proceeding. Ms. Goucher stated in the Corporation's opening statement that the Corporation is:*
>
> > *…not aware of any specific issues that Mr. Ackroyd or his clients would like to bring to the attention of the Corporation in this regard.*
> >
> > *However, I will commit to getting in touch with each of those communities to see if I can find out where their concerns lie. In my experience, however, particularly in the last few years, I would suggest that the Corporation has made considerable improvements in its efforts to communicate with communities.*[40]

[40] Tr. 1, p. 30, ln. 23 to p. 31, ln. 4.

> *Given the uncertainty as to the exact nature of the expressed concern and the Corporation's commitment to contact each of the Village of Fort Simpson, Hamlet of Fort Liard and Liidlii Kue First Nation, it is clear that a direction from the Board on this matter is not warranted."* [NWTPC Argument P 32]

The Association recommended in its Argument the Board ought to comment on the vagaries that a cost based rate design imposes on small diesel communities:

> *"It is submitted that the PUB has a unique opportunity to articulate the unique circumstance of the Northwest Territories and to indicate how those unique circumstances have created a rate methodology that must be adjusted. This decision could give vital and sophisticated information to the government's energy strategy forum. The anticipated public debate regarding rate adjustments leading to fairness, i.e. levelized or postage stamp rates, will be more useful and productive and lead to a viable solution if the debate has the foundation of knowledge that the expertise of the Board can provide. The Board in our submission should articulate in this decision the vagaries that a cost based rate design imposes upon small diesel communities."* [Association Argument P 27]

The Association also recommended the Corporation should investigate the possibility of extending the TPSP to cover renters:

> *"It is submitted that the Board should recommend that the Corporation investigate and facilitate a programme whereby renters, including especially those in homes and apartments, would pay rates as residents and qualify for the TPSP. This would alleviate the current inequity whereby apartment building owners, who do not have individual metering and who are general service customers, do not qualify for the TPSP."* [Association Argument P 28]

The Association recommended the Corporation should conduct system wide discussions explaining the demand charge to general service customers:

> *"At Transcript 3, pages 104 to 116, is a discussion regarding the Inuvik Rec Centre and the high demand charge of $2,000/month based on six to eight hours of peak use in the year when the chillers are operating in the Fall to freeze the ice surfaces for the first time in months.*
>
> *At page 114, the Corporation offered to have one of its representatives speak to a representative of Inuvik to discuss the demand charges. The Association submits that the Board should make a recommendation that such discussions occur system wide, especially for general service customers."* [Association Argument P 28]

NWTPC submitted the matters concerning TPSP and Government Energy strategy are beyond the scope of this proceeding.

With respect to the Association's request for consultations on demand charges NWTPC stated:

> *"The only customers that expressed a concern in this proceeding about not understanding the basis for a demand charge were Inuvik, in respect of its recreation centre, and the Hamlet of Tuktoyaktuk.*[41] *The Corporation has already undertaken to consult with Inuvik and any other customer that is unclear respecting the basis for demand charges and how they may be able to control those charges.*[42] *A requirement that the Corporation consult on a system wide basis is far too broad given the concerns expressed in this proceeding."* [NWTPC Reply P 18]

The Board notes the concern of the Village of Fort Simpson, Hamlet of Fort Liard and Liidlii Kue First Nation that the Corporation should increase its level of consultations with communities in the planning of capital expenditures that would have a significant effect on power rates. The Board considers this to be a useful recommendation particularly if the consultations can lead to better planning of resource additions. The Board notes one of the major drivers of rate change at

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41 Tr. 2, p. 105; Tr. 3, p. 133.
42 Tr. 2, p. 107, lns. 3-20.

the community level is capital additions. Systematic consultations with customers when planning future capital projects could potentially result in the identification of alternatives including demand side management initiatives. The Association has identified time of use rates as a potential demand side management initiative.

The Board notes the Association's concern that the Corporation consult with general service customers on a system wide basis with respect to the management of demand charges. The Board recognizes the need for educating customers with respect to the wise use of electricity including the purpose of demand charges and demand ratchets.

The Board also notes YK/HR/SM's concern that a 100% demand ratchet may not strike the right balance between providing the right price signals and being a punitive rate for certain customers. The Board believes these are matters that should be subject to consultations with affected customers and if necessary NWTPC should consider changes to the design of demand charges for commercial customers at the time of the next GRA.

The Board considers NWTPC should give priority to the foregoing matters as part of its communication and consultation strategy. Accordingly, NWTPC is directed to file a proposal as part of its phase 2 refiling describing how the Corporation intends to communicate with its customers in regard to future resource planning and capital additions, as well as, on the wise use of electricity by commercial customers with particular emphasis on demand charges and ratchets.

The Board notes the Association's comment with regard to the vagaries that a cost based rate design imposes on small diesel communities. The Board considers the foregoing directions on the need for consultations particularly when large capital projects are being planned, may help address the Association's concerns in some respects although not in all. The Board also notes the fuel stabilization accounts that have been in place for sometime were designed to mitigate rate shock resulting from fuel price changes.

The Board will not comment on matters relating to the TPSP or the Government Energy strategy as these matters are considered to be outside the Board's jurisdiction.

10. SUMMARY OF BOARD DIRECTIVES

1. The Board directs NWTPC to identify the cost of any stranded Pine Point legacy assets and address the appropriate allocation of these assets in the Phase II refiling.

2. The Board directs NWTPC to revise the cost allocations for the Taltson system in accordance with the cost allocation principles used for the Snare/Yellowknife system. The separate costs based on the study for each of Fort Smith and Fort Resolution should be used to develop cost based rates for each of those communities.

3. The Board directs NWTPC to reflect the corrected line loss percentage for the Bluefish transmission line in its refiling.

4. The Board directs NWTPC to use a maximum line loss percentage of 8% for cost allocation purposes for the retail communities of Dettah, Rae Edzo, Fort Smith and Fort Resolution.

5. The Board directs NWTPC to correct the Rae Edzo transmission gross plant in accordance with the submission made in page 10 of its Argument.

6. The Board considers that the 15% maximum increase and the 105% cost of service limit should be applied at the community level before adjusting individual customer classes and directs NWTPC to design its proposed rates in accordance with this finding for purposes of the refiling.

7. The Board notes NWTPC's observation that subject to the Corporation's other rate design principles, any potential rate decrease must be equally available to all rate classes with a revenue to cost ratio over 100%. Given the objective of moving all rates towards cost recovery, the Board considers there is merit in allocating any rate reductions such that communities and classes with relatively higher revenue to cost ratios in relation to the upper limit of the tolerance range of 105%, receive a proportionately higher reduction relative to those with relatively lower ratios, subject to all other rate design criteria discussed in section 4.1. The Board directs NWTPC to take this into consideration in designing rates for purposes of the refiling.

8. The Board directs the Corporation to file the results of a study assessing the cost of providing standby service together with proposed standby service agreement including proposals for interconnection standards, subscription periods, exit fees and re-subscription fee within 90 days of this Decision.

9. The Board notes NWTPC's statement that firm rates cannot be offered due to limitations imposed by transmission reliability. However, the Board considers diesel generation if strategically located close to loads may perhaps be used to overcome the transmission reliability problems. This is how the Board understands YK/HR/SM's suggestion. The feasibility of this option has not been explored by NWTPC. The Board also notes the Corporation's willingness to discuss with potential customers the use of surplus Taltson system power. The Board directs the Corporation to investigate the feasibility of these options and provide a report at the time of the next GRA.

10. The Board directs NWTPC to investigate the benefits and market potential for time of use rates and address this matter at the time of the next GRA.

11. The Board directs NWTPC to carry out an assessment of maximum corporation investment levels for the next GRA.

12 The Board directs NWTPC as follows with respect to finalization of rates:

i) to file within 30 days of this Decision a final cost of service study for the test years 2001/02 and 2002/03 incorporating the changes to the cost of service discussed in section 3 of this Decision and revisions to the revenue requirement discussed in section 8 of this Decision;

ii) to file within 30 days of this Decision final rates for 2002/03 based on the final cost of service and approved rate design principles, to be effective as soon as practical following a final Board Decision;

iii) to file within 30 days of this Decision a final calculation of the 2001/02 revenue shortfall collected by community consistent with the principles set out in Decision 8-2002, the final cost of service and revisions to the approved revenue requirement in section 8 of this Decision;

iv) to file with within 30 days of this Decision a final calculation of the 2002/03 revenue shortfalls by community and customer class based on the final cost of service and revisions to the approved revenue requirement discussed in section 8 of this Decision;

v) to file within 30 days of this Decision a recommendation respecting finalization of the 2002/03 interim rates based on the final cost of service and revisions to the approved revenue requirement discussed in section 8 of this Decision.

11. BOARD ORDER

NOW, THEREFORE IT IS ORDERED THAT:

1. NWTPC shall prepare and file with the Board that information required to comply with the directions contained in this Decision.

2. The interim rates and shortfall riders approved by the Board in Decisions 5-2001, 6-2002, 8-2002 and 9-2002 are approved as final rates.

3. The Terms and Conditions of Service attached hereto as Appendix 1 are approved with the revisions and deletions identified at section 7.2 of this Decision. Sections 13.2 and 14.1 are not approved.

4. Nothing in this Decision and Order shall bind, affect or prejudice the Board in its consideration of any other matter or question relating to Northwest Territories Power Corporation.

ON BEHALF OF THE
PUBLIC UTILITIES BOARD
OF THE NORTHWEST TERRITORIES

____

DATED June 26, 2003
John E. Hill
Chairman

FOLLOWING IS

APPENDIX 1

ATTACHED TO AND FORMING PART OF

THE PUBLIC UTILITIES BOARD

OF THE NORTHWEST TERRITORIES

DECISION 3-2003

DATED June 26, 2003

NUNAVUT

UTILITY RATES REVIEW COUNCIL

Final Report
to the
Minister Responsible for the Qulliq Energy Corporation
On:

The 2004/05 General Rate Application
by the
Qulliq Energy Corporation

February 18, 2005

THE UTILITY RATES REVIEW COUNCIL

MEMBERS	Ray Mercer	Chairman
	Gordon Rennie	Member
	Louie Qingnatuq	Member
	Peter VandenBrink	Temporary Member
	Adla Itorcheak	Temporary Member

SUPPORT		
	Kirk Janes	Secretary
	Raj Retnanandan	Consultant

TABLE OF CONTENTS

Minister Responsible for Qulliq Energy Corporation's
Letter of February 8, 2005 ______ 1

Qulliq Energy Corporation:
Comments on some Aspects of the January 27, 2005
Report of the URRC ______ 8

Utility Rates Review Council Response to:
Minister Responsible for Qulliq Energy Corporation's
Letter of February 8, 2005 ______ 25

Utility Rates Review Council Response to:
Qulliq Energy Corporation:
Comments on some Aspects of the January 27, 2005
Report of the URRC ______ 28

APPENDIX Report to the Minister Responsible for the Qulliq Energy Corporation On: The 2004/05 General Rate Application by the Qulliq Energy Corporation

January 27, 2005 Report in its Entirety

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Hon. Edward Picco

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Minister of Energy

February 8, 2005

Mr. Raymond Mercer
Chair
Nunavut Utility Rate Review Council
PO Box 1000, Stn 200
Iqaluit, Nunavut
X0A 0H0

Dear Mr. Mercer:

Re: Report to the Minister of Energy on the 2004/05 General Rate Application by the Qulliq Energy Corporation dated January 27, 2005

Thank you very much for your comprehensive initial report, received in this office January 28, 2005. I appreciate the obvious effort put into the materials provided.

There are three items which I would like to ask you to review and incorporate into the final report you will make:

1. Although not yet finally approved or public, the Financial Management Board of the Government of Nunavut has authorized that a bill be put before the Legislative Assembly at its next session, appropriating sums for the following uses:

    a. $8 million as a contribution to QEC in lieu of a fuel rate rider for 2004/05
    b. $10 million as a contribution to QEC corresponding to the impacts of capital funding for the financial year 2004/05
    c. $4 million as an extraordinary contribution to QEC in response to declining equity ratios

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Hon. Edward Picco

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Minister of Energy

The corporation has been instructed that these sums are to be used to immediately pay down the outstanding fuel account to PPD, so that a year end balance of zero is achieved. To this end QEC will be required to inject approximately 5 million dollars from its cash assets.

I would appreciate your taking a look at the **Draft 2004/05 Year End Projections** of the Qulliq Energy Corporation provided with this letter which incorporate these still-pending payments, and advise how this change would impact on your recommendations;

2. In order to more evenly distribute cost among all energy users *within communities*, the GN is considering increasing the current monthly basic service charge of $18 per residential customer (see page 51 of GRA) to a monthly base fee in the range of $20.00 to $40.00 per residential customer. Electricity usage would be calculated in addition to this base sum, reflecting the base cost of providing electricity to each customer.

   Can you advise from your community consultations any comments or presentations either supporting or opposing the idea of base rate increases.

3. The GN has identified that it wishes to have new rates in place for April 1, 2005. Many of your Recommendations and suggestions reference events which are in a different time frame and cannot be implemented between now and April 1, 2005.

   It would be most useful to me if the URRC could separate its current materials into two documents:

   a. A Report under Section 13 of the Act on those items which constitute an immediate rate recommendation (including Section 16.0 and items in 17.0 such as disallowing $1.745 from the utility plant in service, the rate stabilization process or the treatment of alternative energy studies and others), and items 1 and 2 above;

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Hon. Edward Picco

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Minister of Energy

b. A second report equivalent to a management letter or supplementary advice containing those items which relate to those issues on a longertime frame (such as the need for a detailed study of site restoration costs, an external review of the corporation or potential new approaches to capital stabilization)

Other Matters

In addition, at various points during the hearing, the URRC Members commented informally on the review process itself and identified issues which might require change. I recognize that this legislation significantly adapts the mandate of what was once a Public Utility Board. .

It would be of assistance if you also provided, at this time, or within the next months, an indication of the process and mandate issues you have identified during this first URRC hearing.

I have also included a document entitled "Comments on some Technical Aspects of the January 27, 2005 Report of the URRC". This document incorporates comments from sources within GN and the Corporation on some of the technical elements of your report and its recommendations. I would appreciate your reviewing these comments with the possibility of clarifying some elements of the original report.

The URRC Act s. 13 (3) requires that I set a date for the return of what will be your Final Report. I am anxious to proceed with the rate setting process and I know that you are also anxious to have these matters resolved. Consistent with the Act,

1. I am asking for a Final Report on Rate Based Issues for Immediate Implementation, including the item identified as 2) and as set out in a) above within 10 days, being on February 18, 2005.

2. I am asking for a Final Report on Remedial and Longer Term Issues as set out in b) above. I would suggest a return date of February 18, 2005.

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Hon. Edward Picco

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Minister of Energy

Thank you for your continuing contributions in delivering affordable energy to Nunavummiut.

Edward Picco
Minister of Energy

Enclosures:

QEC Draft 2004/05 Year End Projections using new figures
Comments on some Technical Aspects of the January 27, 2005 Report of the URRC

cc. Minister Responsible for the Utility Rate Review Council

Qulliq Energy Corporation

Projected Monthly Statement of Income and Retained Earnings

For the year ending March 31

Unaudited
($000)

	Draft Unaudited Year to Date Actual Nov 2004	Projected Dec 2004	Projected Jan 2005	Projected Feb 2005	Projected Mar 2005	Projected Mar 2005	Audited Restated Mar 2004
Revenue							
Sale of power	$ 35,341	$ 5,407	$ 5,526	$ 5,073	$ 5,348	$ 56,695	$ 53,337
Other	708	90	90	90	90	1,068	1,157
	36,049	5,497	5,616	5,163	5,438	57,763	54,494
Expenses							
Fuel and lubricants	15,473	2,277	2,326	2,143	2,257	24,476	22,561
Fuel and lubricants - August 1 fuel price increase	-	352	360	331	349	1,392	-
Salaries and wages	11,681	1,441	1,399	1,262	1,444	17,227	17,785
Supplies and services	7,452	876	1,284	1,596	1,331	12,539	10,902
Amortization of property, plant and equipment	3,493	437	437	437	437	5,239	4,941
Interest expense	3,208	400	400	400	400	4,808	4,694
Travel and accommodation	1,408	221	272	225	282	2,408	2,559
	42,715	6,004	6,478	6,393	6,499	68,089	63,442
Operating income (loss)	(6,666)	(507)	(862)	(1,230)	(1,061)	(10,326)	(8,948)
Gain on settlement of due to NTPC	535					535	
Net loss before GN contributions	(6,131)	(507)	(862)	(1,230)	(1,061)	(9,791)	(8,948)
GN contributions					22,000	22,000	14,000
Adjusted net income (loss)	(6,131)	(507)	(862)	(1,230)	20,939	12,209	5,052
Retained earnings, beginning of period	40,448	34,317	33,810	32,948	31,718	40,448	35,396
Retained earnings, end of period	**$ 34,317**	**$ 33,810**	**$ 32,948**	**$ 31,718**	**$ 52,657**	**$ 52,657**	**$ 40,448**

Qulliq Energy Corporation

Projected Monthly Statement of Financial Position

As at March 31

Unaudited

($000)

	Draft Unaudited Year to Date Actual	Projected	Projected	Projected	Projected	Audited Restated
	Nov 2004	**Dec 2004**	**Jan 2005**	**Feb 2005**	**Mar 2005**	**Mar 2004**
Assets						
Property, plant and equipment	$ 115,389	$ 116,302	$ 117,216	$ 118,129	$ 119,044	$ 112,911
Current						
Bank	2,594	2,531	3,354	6,994	1,646	1,800
Accounts receivable	13,868	15,712	16,368	16,276	16,217	16,171
Funding in lieu of fuel rider receivable	7,534	7,534	7,534	4,460	4,460	10,000
Inventories	11,977	10,748	9,462	8,388	7,182	7,074
Prepaid expenses	835	829	769	707	643	592
	36,808	37,354	37,487	36,825	30,148	35,637
	$ 152,197	$ 153,656	$ 154,702	$ 154,954	$ 149,192	$ 148,548
Liabilities						
Long term debt	$ 77,000	$ 77,000	$ 77,000	$ 77,000	$ 77,000	$ 77,000
Current						
Accounts payable and accrued liabilities	6,402	6,968	7,476	7,558	7,118	8,234
Due to PPD	22,061	23,461	24,861	26,261	-	9,914
Due to GN (previously due to NTPC)	5,111	5,111	5,111	5,111	5,111	5,646
	33,574	35,540	37,448	38,930	12,229	23,794
Deferred credits and other liabilities	7,306	7,306	7,306	7,306	7,306	7,306
Retained Earnings	34,317	33,810	32,948	31,718	52,657	40,448
	$ 152,197	$ 153,656	$ 154,702	$ 154,954	$ 149,192	$ 148,548

Qulliq Energy Corporation

Projected Monthly Statement of Cash Flow

For the year ending March 31

Unaudited

($000)

	Draft Unaudited Year to Date Actual	Projected	Projected	Projected	Projected		Audited Restated
	Nov 2004	**Dec 2005**	**Jan 2005**	**Feb 2005**	**Mar 2005**	**Mar 2005**	**Mar 2004**
Cash provided (required) by operations							
Cash received from customers	$ 38,022	$ 3,653	$ 4,960	$ 5,255	$ 5,497	$ 57,387	$ 56,995
Cash paid to suppliers and employees	(31,207)	(2,312)	(2,733)	(3,285)	(29,364)	(68,901)	(47,567)
Cash received for funding in lieu of fuel rider 2003/04	2,466	-	-	3,074	-	5,540	4,000
Cash received for funding in lieu of fuel rider 2004/05	-	-	-	-	8,000	8,000	-
Cash received for capital expenditure funding	-	-	-	-	10,000	10,000	-
Cash received for equity restoration	-	-	-	-	4,000	4,000	-
Interest received (paid)	(2,516)	(54)	(54)	(54)	(2,130)	(4,808)	(4,694)
	6,765	1,287	2,173	4,990	(3,997)	11,218	8,734
Cash provided (required) by investing activities							
Addition to property, plant and equipment	(5,971)	(1,350)	(1,350)	(1,350)	(1,351)	(11,372)	(6,146)
Cash provided (required) by financing activities							
Cash inflow (outflow) long term debt	-	-	-	-	-	-	8,638
Increase (decrease) in cash	794	-63	823	3,640	-5,348	-154	11,226
Cash (overdraft) – beginning of period	1,800	2,594	2,531	3,354	6,994	1,800	(9,426)
Cash (overdraft) - end of period	$ 2,594	$ 2,531	$ 3,354	$ 6,994	$ 1,646	$ 1,646	$ 1,800

Qulliq Energy Corporation

Comments on some Aspects of the January 27, 2005 Report of the URRC

Executive Summary

If the Report could be reorganized into two separate reports, one report would be the recommendations to the Minister on rates and the second report would be on other matters identified during the course of the URRC review and future direction.

If this approach were to proceed, then the following and similar text would belong in the second report on other matters and future direction.

> The URRC has recommended that a review of the corporation be carried out with the objective of streamlining the power corporation into a well run utility and regaining the confidence of its customers and stakeholders. The URRC has recommended that a series of reports supporting the level of non fuel O&M expenses be filed following the review. Upon receipt of the foregoing reports the URRC will make a further recommendation to the responsible Minister confirming or varying its preliminary determinations respecting salaries and wages, supplies and services and travel and accommodation expenses as well as recommend any resulting adjustments to rates effective April 1, 2006 to recover the final amount of the shortfall for 2004/05.
>
> The URRC has recommended that in place of the territorial rate structure proposed by QEC the existing community based rate structure be continued in the interest of rate stability. The URRC has provided directions to QEC to come forward with proposals for gradual movement towards some form of rate averaging among communities.
>
> The URRC has recommended that the additional riders proposed by QEC made up of the Alternative Energy Rate of $0.005 per Kwh to facilitate alternative energy initiatives in Nunavut, the Environmental initiatives rate of $0.005 per Kwh to fund the Corporation's share of future removal and site restoration costs and the Beneficiary employment rate of $0.0125 per Kwh to fund the cost of complying with the Nunavut Land Claims Agreement, be denied. Instead the URRC has provided alternative directions to the corporation for dealing with the issues raised.

1.0 Background

1.1 Regulatory History

Represents anticipated content for the rates recommendation

1.2 Corporate Organization and Duties

Represents anticipated content for the rates recommendation

1.3 Jurisdiction and Mandate of URRC

Represents anticipated content for the rates recommendation

2.0 Application

2.1 Requested Approvals of QEC

Represents anticipated content for the rates recommendation
Cut and paste from the GRA

2.2 Requirement for Application

Represents anticipated content for the rates recommendation
Cut and paste from the GRA

3.0 Process for Hearing of the Application

3.1. Community Consultations

The following portion of the Report relates to the provision of future direction to the Corporation.

> As part of the technical meetings conducted between the URRC and QEC, QEC provided its view that it expects to consult with customers prior to the filing of its next Application. The URRC expects that prior to QEC filing its next GRA, QEC will have community consultations with its customers and directs QEC to provide, as part of its next GRA, commentary concerning the process and results of these community consultations. While the URRC recognizes that QEC has overall management responsibility to operate

the utility, input from its customers is also an important element of the management of the utility.

3.2 Consultations with Business and Community Customers

The sections relating to the expansion of the URRC mandate might appear in a report on other matters and future direction; see below.

URRC notes that a number of the submissions from parties, over and above providing comments on the costs, revenues and rates structure of the proposed Application, requested that the URRC be expanded in its mandate beyond that which is currently in place. These comments included:

- An expanded mandate beyond the current legislative role of the URRC in the determination of the revenue requirement, rates and terms and conditions of QEC and its affiliates including additional responsibility for Petroleum Products, the Territorial Power Support Program and the ability for the URRC to make a final determination of the rates rather than the GN or alternatively have the URRC report directly to the Legislative Assembly rather than to Cabinet;

- Oversight responsibility for the URRC. Lack of such responsibility resulted in QEC ignoring the URRC's recommendations the last time they were made;

- Additional time for parties to prepare their submissions including cost recovery for parties who incur out of pocket costs to prepare submissions;

While the URRC considers that all of these issues are important, all of them are substantively outside of the jurisdiction and mandate of the URRC as described in Section 1.3 above. If the GN considers that changes are required to the jurisdiction and mandate of the URRC in the future, these changes may be reflected in changes to the current legislation. In the existing time frame of this application, the URRC does not have the ability to respond to any of the requests listed in this section. The URRC notes that the original time frame for the completion of this review was December 27, 2004. The Minister Responsible for QEC granted an extension to February 2, 2005.

3.3 URRC Examination of Technical and Financial Matters

The response to technical meeting undertakings was provided in as timely a manner as possible, given other operational requirements.

All materials requested by the URRC were made available prior to the URRC's initial report being delivered, with the exception of a request that QEC respond to all materials provided by all persons appearing at the hearings in all communities. This was not completed in time.

The URRC did not set a return date for the Responses to Technical Hearing. All responses were delivered prior to the URRC's initial report being delivered.

All responses are on the public record.

4.0 Rate Base

4.1 Introduction

Represents anticipated content for the rates recommendation

4.2 Gross Plant in Service

Northwestel's comments regarding the Corporation's telecommunication's assets should be viewed in the context that the impugned investment allowed QEC to avoid purchasing telecommunications from NWTel. The disposal of those assets to Nunavut Broadband Corporation supported the creation of community broadband, which is also in competition with Northwestel.

The revisions to the rate base represent anticipated content for the rates recommendation.

4.3 Capital Additions

A comparison of the Baker Lake plant to Clyde River and Sanikiluaq plants requires appropriate adjustments for differences in the plant design, annual increases in the cost of construction since the construction of these plants, an analysis of increases in construction costs for other projects in Nunavut during this period, and analysis of the costs of delaying the project for a year.

Business plans prepared by government departments acknowledge construction costs have increased at an annual rate in excess of 10% over the last few years versus the more nominal rate used by the URRC in the rate base analysis.

QEC can provide this material in addressing this addition.

4.4 Accumulated Amortization

The Corporation very aware of the requirements of CICA Handbook Section 3110 and is working with the Office of the Auditor General to achieve appropriate Asset Retirement Obligations.

4.5 Customer Contributions

The impact of forecasting or not forecasting capital assets constructed at the request of a customer where the cost is recovered from the customer, is negligible in relation to the outcome of the General Rate Application.

The Corporation will review the accounting for contributions and contribution amortization with the Office of the Auditor General.

4.6 Working Capital

Allowing the Corporation to rely on information generated by NTPC during this first GRA permitted the GRA to be completed at a lower cost. If it is required that the Corporation will undertake separate studies specific to QEC and include them with the next GRA, this will the cost of a GRA. With the limited number of customers each proposed consultant's study needs a value-for-money decision.

4.7 Rate Base

The total rate base reflects a reduction relating to the Baker Lake plant which the Corporation will be addressing through the provision of additional information.

5.0 Return on Rate Base

5.1 Capital Structure

The URRC's acceptance of 50% of the unamortized division costs and the inclusion of the amortization of this amount in the revenue requirement increases the Corporation's equity by $4.2 million for accounting purposes.

In prior discussions on the handling of these costs the QEC Board had agreed with the OAG that should any of the division costs be recoverable through rates that the 2001 equity will be restored by the amount recoverable.

5.2 Long Term and Short Term Debt Rates

If interest rates are locked in for revenue requirement purposes, an increase in interest rates could trigger a requirement to file a GRA.

The Corporation would be interested to know the URRC's thoughts on the issue of long term debentures to pay the capital short term debt presently incurring a lower rate of interest than that available on the long term market.

5.3 Equity Return

A utility operating in the Arctic with only one source of fuel may have more business and financial risk than a utility operating in the south with a choice of generation options including diesel, coal, natural gas, hydro and nuclear, not to mention the economies of scale.

5.4 Total Return

The proposed rate of return is a useful marker, but of less consequence because of the application of the 15% arbitrary rate increase cap borrowed from the Northwest Territories Public Utilities Board.
The application of an arbitrary rate increase cap means that may of the markers provided by the URRC have more theoretical impact and are useful for future consideration.

Either the Company is expected to operate at less than the acknowledged revenue requirement or the GN is asked to make up that portion of the revenue requirement which is not within the 15 percent. The report does not identify the preferred option.

6.0 Revenue Requirement

6.1 Operations and Maintenance Expense

6.1.1 Fuel and Lubricant Expense

The reduction of the fuel and lubricants expense based on the fact that the fuel price increase only applied to the last eight months of the test year should be reconsidered because the current price forms the best estimate for all of 2005/06 to which the new rates will apply, not just eight months.

To increase plant efficiencies in general beyond the actual experienced last year plus known engine replacements, forces the Corporation into a situation where it may not be able to meet the proposed theoretical efficiency standard and therefore may not be eligible for fuel riders when fuel prices go up or not meet the standard and incur fuel costs in excess of the approved revenue requirement component without opportunity for recovery.

6.1.2 Salaries and Wages Expense

The following section may belong in a report on other matters and future direction.

> Throughout the hearings numerous parties requested to have an independent review of the overall operations of the Power Corporation. The URRC agrees with these requests and recommends that the Government of Nunavut issue a request for proposals to qualified Engineering firms or consulting firms that are knowledgeable in the operations and management of a Utility and Utility Regulation, to conduct a review of the corporation with the objective of streamlining the power corporation into a well run utility and regaining the confidence of its customers and stakeholders.
>
> The URRC recommends this review be completed in a timely manner to allow QEC to respond meaningfully to the URRC directions set out in Section 12.1 of this Report. Since the review concerns matters resulting from past decisions with respect to staffing and management the costs associated with the review should not be recoverable from the customers of the Corporation in the normal course.

It may be more effective to include issues related to decentralization, beneficiary employment and issues relating to government policy decisions in the separate report on other matters and future direction.

6.1.3 Supplies and Services Expense

The proposed reduction of supplies and services will be addressed through the provision of additional information.

The supplies and services information provided included budgets broken down by engine for overhauls, by employee for housing, by employee for training, by department, by region and by community.

6.1.4 Travel and Accommodations Expense

The reduction of travel and accommodations will be addressed through the provision of additional information.

The travel and accommodations information provided included budgets broken down by department, by region, community and individual employee. While the proposed reduction of the travel and accommodations component of the revenue requirement appears to be arbitrary, it has not affected the URRC's rate recommendation due to the application of the 15% rate increase cap.

Note 1: It may be that the fuel and lubricants expense, salaries and wages expense, supplies and service expense and travel and accommodations expense were reduced when determining the revenue requirement because the process gave no other option.

The fiscal year 2004/05 was to be the test year yet the rate recommendation was required before the year was over.

The additional information requested above would include the audited financial statements for the test year which would be available before the rate recommendation effective April 1, 2006, if any.

Note2: The time constraints impacting on the URRC also impact on the Company's ability to promptly provide the materials the URRC requests.

Many Utilities have a Regulatory or rates department (including NTPC) with dedicated employees. This is a significant expense for a small customer base, and has not been implemented at QEC In QEC, the accounting and management staff perform both functions. The URRC process was designed to be effective but simpler, shorter and less costly.

6.2 Reserves

6.2.1 Reserve for Injuries and Damages

The Reserve for Injuries and Damages has been allowed, however, what will be permitted to be charged against the reserve has been defined.

6.2.2 Rate Hearing Reserve

The Rate Hearing Reserve has been allowed to the extent of external hearing costs. If implemented, based on the requirement for studies, the next GRA will cost significantly more than the first one.

6.3 Amortization

6.3.1 Capital Asset Amortization

The Corporation has been requested to write off windmills over a longer period and to provide an amortization study to determine whether NPC diesel plants should continue to be amortized at the same rate as NTPC diesel plants.

6.3.2 Financing Cost Amortization

See 5.1 Capital Structure above, the amortization of 50% of the unamortized division costs has been allowed.

6.3.3 Amortization of Customer Contributions

The Report suggests that the Corporation is not amortizing customer contributions correctly.

The Corporation's amortization calculations are audited by the OAG. The Corporation will ask the OAG to review this report and determine whether the URRC or the OAG approved amortization calculation is appropriate.

7.0 Total Revenue Requirement

The reduction in the revenue requirement may be partially mitigated by load growth and the re-established mechanism to recover increased fuel costs related to fuel pricing.

The test for management would be to keep non fuel cost expenditure increases and load growth fuel cost increases within revenue growth. This is a practical goal if the Corporation begins with a reasonable income base.

However, the URRC has made rate recommendations that fall $4.1 million short of their own recommended revenue requirement.

8.0 Revenue Forecast

8.1 Revenue from Sale of Electricity at Existing Rates

It is difficult to find a rationale for the substituting a 5 year forecast generated in 2000 by NTPC for the actual number of customers.

The Corporation will address this issue through the provision of additional information.

8.4 Total Revenue

The total revenue forecast at existing rates has proven to be accurate. Revenue to date is slightly ahead of the forecast.

9.0 Additional Riders

9.1 Alternative Energy Rider

The Corporation will have to source funding for alternative energy initiatives elsewhere, after which, the assets will form part of the rate base and the funding will form part of the calculation of the return on rate base.

Viable projects will be identified and funding options sourced. Increasing fuel prices will increase the viability of wind and hydro.

9.2 Environmental Initiatives Rider

The following section belongs in a report on other matters and future direction.

> The URRC directs QEC to provide a detailed study of the potential liability on the part of QEC with respect to future removal and site restoration expenditures, including a risk assessment of unknown contingencies, at the time of the next GRA.

The Corporation has already done site assessments complete with estimated levels of contamination in cubic meters of soil.

The question outstanding is who will pay for remediation and when.

9.3 Beneficiary Employment Rider

Creation of this fund was denied yet the Corporation still has a legal obligation to meet land claims obligations.

Operations costs have been reviewed and reduced below the revenue requirement, leaving modest to no other options for funding. Resources external to the regulatory system are the remaining viable option, but none are currently forthcoming.

10.0 Revenue Shortfall

The URRC, identifies a $12.473 revenue shortfall (see 10.0)

The URRC recommended rates would generate $8.3 million (see 12.1).

The URRC does not identify where the unaccounted $4.1 million would come or be cut from.

11.0 Rate Stabilization Fund

If implemented, the recommendation to restore the territorial fuel stabilization fund mechanism will be tested during the next fiscal year if world oil prices do not go down.

12.0 Rate Approval

12.1 Phased In Rate Increase

The 15% “rate shock” level appears to be from a prior, unquoted decision of the NWT PUB which is referenced in a submission (see 12.1) as being “adopted by the Northwest Territories PUB” without a document reference.
The Corporation will attempt to find the unreferenced source document as it appears to be significant for the URRC approach.

The following section may belong in a report on other matters and future direction.

> The URRC has recommended approval of a 15% increase in rates effective April 1 2005. This will result in additional revenues of $8.415 million. The URRC has recommended that a review of the corporation be carried out with the objective of streamlining the power corporation into a well run utility and regaining the confidence of its customers and stakeholders. The URRC has recommended that a series of reports supporting the level of non fuel O&M expenses be filed following the review. Upon receipt of the foregoing reports the URRC will make a further recommendation to the responsible Minister confirming or varying its preliminary determinations respecting salaries and wages, supplies and services and travel and accommodation expenses as well as recommend any resulting adjustments to rates effective April 1, 2006 to recover the final amount of the shortfall for 2004/05.

All of pages 72 and 73 after the first paragraph may relate to future direction.

12.2 Move to Territorial Rates from Community Based Rates

The door has been left open for rate averaging applied to the community rate structure to avoid rate shock from capital expenditures and the recommended community rates do not reflect capital expenditures that have occurred since the last GRA (seven years), thereby departing from the community rate structure for every community that has had a capital expenditure since the last GRA.

As a result, there is no basis in the cost of service for the proposed rates.

The following might be included in a report on other matters. It indicates that a migration towards the blended rate structure may be the acceptable compromise between the community rate structure and the territorial rate structure. The URRC-proposed capital stabilization fund rate below is similar to the non operating component of a blended rate.

> The URRC considers it appropriate to move towards some form of rate averaging among communities so as to minimize the rate impact on smaller communities when their plant needs to be upgraded or replaced. However, the URRC also believes the relationship between costs incurred at the community level and the rates should not be completely obscured by any rate averaging mechanism. In other words the price signals to customers for electricity service should, among other rate design criteria, reflect the costs of producing and distributing that service. The URRC considers further study and assessment of rate averaging mechanisms is needed and therefore directs QEC to address alternative mechanisms for rate averaging or levelizing rates at the next GRA. In responding to this direction QEC should specifically address how any potential rate shock to customers as a result of this move to averaging of costs among communities will be mitigated. QEC should also have regard to community and customer input when responding to this direction. Until a new rate structure is in place, the URRC considers that a capital stabilization fund should be implemented as an interim measure and that revenues collected under this fund mechanism should be used to alleviate the highest rate communities to a level somewhat closer to the Nunavut or regional average rates and also applied to new power plants being completed in 2004/05 Accordingly, the URRC directs QEC to propose a capital stabilization fund as an interim mechanism for the purpose of mitigating the high rates for certain communities resulting from the community based rate structure. The capital stabilization fund mechanics should be worked out by QEC and forwarded to the Minister for approval within 90 days of the

release of this Report. URRC notes this fund adjustment will result in somewhat higher than average increases for customers in certain communities.

As part of the response to the direction concerning a capital stabilization fund QEC is also directed to address, taking into account the URRC's comments in this section concerning rate averaging, the approach to adjusting rates if an additional increase as discussed in Section 12.1, effective April 1, 2006, were to be recommended by the URRC and approved by the responsible Minister.

12.3 Cost of Service and Rate Design

Indicates the URRC would like to return to the PUB approach of Phase 1/Phase 2.

This approach does result in more time to study the details of a Revenue Requirement and a Rate Base. Potentially such a process design change could be provided for in the URRC rules of procedure or in a direction from the Minister. It does not require any legislative change.

13.0 Terms and Conditions of Service

Some suggestions but ultimately recommended as proposed. The Corporation will give serious consideration to the suggestion that customer security deposits be segregated from general funds and invested at a higher rate than daily interest so a higher rate can be paid to the customers on their deposits.

14.0 Quality of Service

14.1 Reliability Statistics

The Corporation anticipates tracking reliability statistics on a monthly basis.

14.2 Safety

The Corporation is on record with a safety goal of zero lost time. The Corporation will compare safety records with industry experience as requested.

14.3 Service Quality and Complaints

The Corporation anticipates implementing a complaints monitoring system.

15.0 Other Matters

15.1 Management of the Corporation

This section may belong, as titled, in a report on other matters.

15.2 Treatment District Heating Function

It remains to be determined whether residual heat capital expenditures and the related residual heat revenue which is presently incidental and nominal in relation to electrical generation revenue can economically be isolated from electricity rate regulation through the provision of separate cost of service information, given the small amounts generated.

15.3 Treatment of Future Industrial Customers

It appears this section of the GRA was interpreted as a request to move industrial revenue outside the realm of regulation.

This was not the case and the recommendation of the URRC is consistent with the approach the Corporation would have taken and will take when presented the opportunity.

Should the Corporation be asked to provide service for the Nanisivik Airport, this would be an opportunity to address this process.

15.4 Subsidy Level

There is a significant benefit from the implementation of subsidy decisions at the same time as the rate decisions.

This is a policy decision outside of the impact of the URRC recommendations.

16.0 Summary of Recommendations

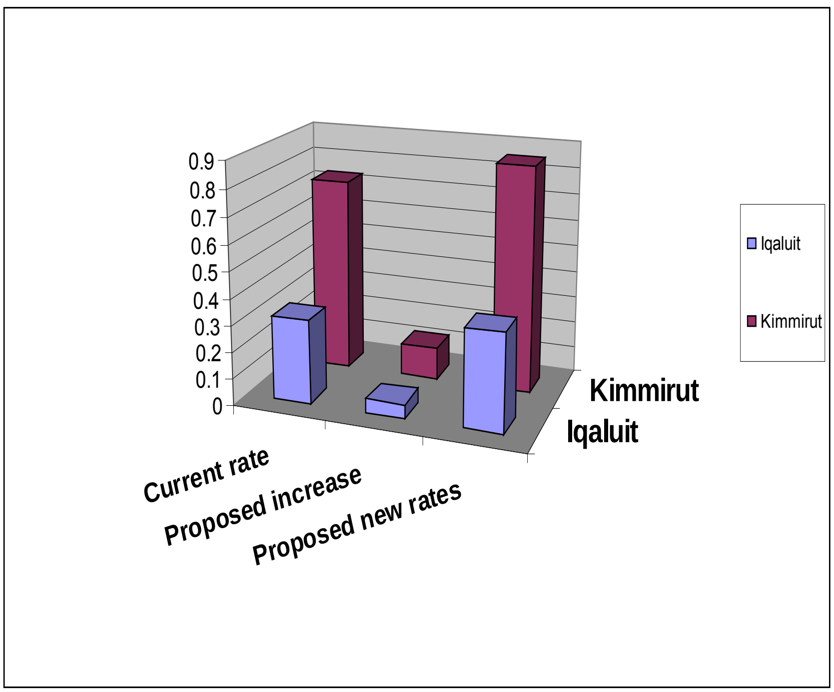
This material is repeated from the text of the report.

Recommendation 3 needs to be clarified because the schedule indicates 16.5%. The 15% appears to be approximate and relates to the overall average increase resulting from the increase in the rates for consumption including streetlights and the service charges that have not increased.

Recommendations number 4 and 5 may belong in a report on other matters and future direction.

The recommended 16.5 % increase on rates relating to consumption, see Schedule C-3, results in a widening of the cents per kWh gap between the community paying the lowest residential rate (Iqaluit) and the community paying the highest residential rate (Kimmirut).

	Current rate per kWh	URRC Proposed increase - 16.5%	URRC Proposed new rates
Iqaluit	.3158	.0522	.3680
Kimmirut	.7349	.1213	.8562
Difference	.4191	-	.4882



The revenue increase recommendation to be recovered through a rate increase is $8,415,266 divided by the kWh sales of 135,474,480 kWh equals a cents per kWh rate increase of .0621.

The Corporation would receive the same increase in revenue without increasing the cents per kWh gap between the lowest rate and the highest rate if the increase was cents per kWh rather than a percentage.

Proposed rates with .0621 cents per kWh increase

Iqaluit at	.3779
Kimmirut	.7970
Difference	.4191
Increase in gap	.0000

17.0 Summary of Directions

This entire section may belong in a report on other matters and future direction.

Some of these directions will cause the Corporation to incur more costs to be paid by the rate payer.

Where the text makes a specific direction to the Corporation, this is taken as a recommendation to the Minister consistent with the URRC and QEC legislation. Under the current legislation, the URRC makes rate recommendations to the Minister who has the authority to direct the Corporation.

Where the recommendation does not relate to rates, it may require another mechanism for direction giving, including the Ministerial/Board direction, Crown Agencies Council or other processes.

Hon Edward Picco
Minister of Energy
Government of Nunavut
Box 2410 Iqaluit, Nunavut
X0A 0H0

Dear Minister Picco:

Re: URRC Report Dated January 27, 2005
2004/05 General Rate Application by Qulliq Energy Corporation

I refer to your letter dated February 8, 2005 respecting the above Report. The URRC's comments with respect to the points raised in your letter follow.

1. Expected Contributions from GN totaling $22 million

In arriving at a fair rate of return for QEC for 2004/05, the URRC considered the corporation's capital structure and determined that a 75:25 debt equity ratio would satisfy legislative requirements as well as meet existing debt covenants. [P26] URRC took into consideration the Government funding in lieu of fuel rider of about $8 million in arriving at the 75:25 debt equity ratio. [P26] If the additional contributions now being contemplated in the amounts of $10 million and $4 million were to be also considered as equity injections by the GN in 2004/05 an entirely different capital structure from that considered appropriate by the URRC will result. For the reasons stated in the report, the URRC considers the 75:25 debt equity ratio to be appropriate for 2004/05. Accordingly, the additional contributions will not change the URRC's fair return on rate base recommendation.

2. Adjustment of Basic Monthly Fixed Charge for Residential Customers

As noted at pages 71 and 72 of the report QEC did not propose any changes to the fixed charges for residential or commercial customers nor did QEC file any evidence in this regard. In section 12.3 of the report the URRC directed QEC to provide a cost of service study to support any rate design changes at the time of the next GRA. It would be most appropriate to consider any changes to the monthly fixed charges at the time such evidence is filed and examined. A change in the fixed charges at this time may not be appropriate prior to examination of all relevant evidence.

…/2

During the community consultations there was a lack of comment for or against the monthly fixed charge of $18.00. The URRC believes this was a direct result of QEC's new billing format which shows neither monthly fixed charges nor energy charges and combines all charges together on the consumers' bill. This lack of information on the new billing system hinders the consumers' ability to understand the bill and does not facilitate the wise use of energy.

3. Separation of Report Under Immediate Rate Issues and Matters to be Addressed in the Future

The 2004/05 GRA is the first since division, by QEC. The GRA requested URRC recommendations with respect to revenue requirement as well as certain rate design matters. The community consultations dealt with all aspects of the application. URRC findings reflect a fair balancing of all of the issues raised. Accordingly, separating one or more aspects of the report is not considered to be appropriate. However, with respect to immediate rate matters items requiring the attention of QEC are referenced in sections 16 and 17.

Items 1 to 3 of section 16 deal with the implementation of a 15% increase effective April 1, 2005 for all rate classes. Since QEC did not request any change in fixed charges nor provide evidence in this regard the URRC has recommended the 15% overall revenue increase by community and rate class be recovered through increases in the energy charges for residential and commercial customers. For street lights a 15% increase is to be applied to the existing lighting rates. Since the 15% increase would recover a little more revenue than required to cover increases in fuel costs reflected in the application an across the board percentage increase as opposed to a cents per Kwh increase is recommended.

Items 4 and 5 of section 16 deal with the phased in rate increase respecting the 2004/05 test year, subject to an external review of QEC being completed and QEC providing the requested information as outlined in Section 12.1, by September 30, 2005. Following examination of the information required by September 30, 2005 the URRC will expect to determine the 2004/05 O&M expenses forecast and resulting revenue requirement on a final basis.[1] Any under recoveries due to delay in the implementation of final rates effective April 1, 2005 due to the rates phase in will, in the normal course, be recoverable by way of a rider in 2006/07.

[1] As stated in the URRC report salaries and wages, supplies and services and travel and accommodation collectively constituting the O&M expenses were determined on a preliminary basis and will be subject to adjustment following the filing of the September 30, 2005 information. All other components of revenue requirement for 2004/05 were determined on a final basis in the URRC report and these as well as forecast revenues at existing rates will not be subject to further adjustment.

Items 6 to 9 of section 16 deal with terms and conditions of service, heat rates, additional rate riders and rate stabilization fund. Each of these recommendations is also considered part of the rate recommendations.

Section 17 includes three directions that are to be addressed as part of the rate recommendations for the 2004/05 test year. First, the direction summarized from pages 72-74 of the report deals with the specific information to be filed on or before September 30, 2005 referred to earlier. Second, the direction summarized from page 79 deals with a rate mitigation proposal for certain communities with high rates, to be filed by QEC within 90 days of public release of the URRC report. Third, the direction summarized also from page 79 deals with the mechanism for adjusting rates giving effect to the final 2004/05 revenue requirement, effective April 1, 2006.

With the exception of the three rates related recommendations noted above all other directions in Section 17 concern record keeping or future filing maters. The executive summary provides an over view of the entire report.

With respect to other matters referred to in your letter, I must note that the members of the URRC did not consider it appropriate to comment on the process nor other parameters laid out in the legislation and did not do so during the proceedings. Any comments made with respect to these matters are those of parties who were part of the consultation process. However, having dealt with the first GRA the URRC will be more than willing to assist in any changes concerning process or mandate of the URRC and will endeavor to do so before March 31, 2005.

The URRC's responses to the comments on technical aspects of the report are set out in Attachment 1 to this report.

Yours truly,

ORIGINAL SIGNED BY

Raymond Mercer
Chairperson;
Utility Rates Review Council
Of Nunavut

P. O. Box 1000, Station 200, Iqaluit, NU X0A 0H0
Tel: (867) 975-6012 ● Fax: (867) 975-6090

Qulliq Energy Corporation

Comments on some Aspects of the January 27, 2005 Report of the URRC

Executive Summary

If the Report could be reorganized into two separate reports, one report would be the recommendations to the Minister on rates and the second report would be on other matters identified during the course of the URRC review and future direction.

If this approach were to proceed, then the following and similar text would belong in the second report on other matters and future direction.

> The URRC has recommended that a review of the corporation be carried out with the objective of streamlining the power corporation into a well run utility and regaining the confidence of its customers and stakeholders. The URRC has recommended that a series of reports supporting the level of non fuel O&M expenses be filed following the review. Upon receipt of the foregoing reports the URRC will make a further recommendation to the responsible Minister confirming or varying its preliminary determinations respecting salaries and wages, supplies and services and travel and accommodation expenses as well as recommend any resulting adjustments to rates effective April 1, 2006 to recover the final amount of the shortfall for 2004/05.
>
> The URRC has recommended that in place of the territorial rate structure proposed by QEC the existing community based rate structure be continued in the interest of rate stability. The URRC has provided directions to QEC to come forward with proposals for gradual movement towards some form of rate averaging among communities.
>
> The URRC has recommended that the additional riders proposed by QEC made up of the Alternative Energy Rate of $0.005 per Kwh to facilitate alternative energy initiatives in Nunavut, the Environmental initiatives rate of $0.005 per Kwh to fund the Corporation's share of future removal and site restoration costs and the Beneficiary employment rate of $0.0125 per Kwh to fund the cost of complying with the Nunavut Land Claims Agreement, be denied. Instead the URRC has provided alternative directions to the corporation for dealing with the issues raised.

URRC Response:

Please see Item 3 of the URRC letter to the Minister

1.0 Background

1.1 Regulatory History

Represents anticipated content for the rates recommendation

URRC Response:

No Response required by the URRC

1.2 Corporate Organization and Duties

Represents anticipated content for the rates recommendation

URRC Response:

No Response required by the URRC

1.3 Jurisdiction and Mandate of URRC

Represents anticipated content for the rates recommendation

URRC Response:

No Response required by the URRC

2.0 Application

2.1 Requested Approvals of QEC

Represents anticipated content for the rates recommendation
Cut and paste from the GRA

URRC Response:

No Response required by the URRC

2.2 Requirement for Application

Represents anticipated content for the rates recommendation
Cut and paste from the GRA

URRC Response:

No Response required by the URRC

3.0 Process for Hearing of the Application

3.1. Community Consultations

The following portion of the Report relates to the provision of future direction to the Corporation.

> As part of the technical meetings conducted between the URRC and QEC, QEC provided its view that it expects to consult with customers prior to the filing of its next Application. The URRC expects that prior to QEC filing its next GRA, QEC will have community consultations with its customers and directs QEC to provide, as part of its next GRA, commentary concerning the process and results of these community consultations. While the URRC recognizes that QEC has overall management responsibility to operate the utility, input from its customers is also an important element of the management of the utility.

URRC Response:

Please see Item 3 of the URRC letter to the Minister

3.2 Consultations with Business and Community Customers

The sections relating to the expansion of the URRC mandate might appear in a report on other matters and future direction; see below.

URRC notes that a number of the submissions from parties, over and above providing comments on the costs, revenues and rates structure of the proposed application, requested that the URRC be expanded in its mandate beyond that which is currently in place. These comments included:

- An expanded mandate beyond the current legislative role of the URRC in the determination of the revenue requirement, rates and terms and conditions of QEC and its affiliates including additional responsibility for Petroleum Products, the Territorial Power Support Program and the ability for the URRC to make a final determination of the rates rather than the GN or alternatively have the URRC report directly to the Legislative Assembly rather than to Cabinet;

- Oversight responsibility for the URRC. Lack of such responsibility resulted in QEC ignoring the URRC's recommendations the last time they were made;

- Additional time for parties to prepare their submissions including cost recovery for parties who incur out of pocket costs to prepare submissions;

While the URRC considers that all of these issues are important, all of them are substantively outside of the jurisdiction and mandate of the URRC as described in Section 1.3 above. If the GN considers that changes are required to the jurisdiction and mandate of the URRC in the future, these changes may be reflected in changes to the current legislation. In the existing time frame of this application, the URRC does not have the ability to respond to any of the requests listed in this section. The URRC notes that the original time frame for the completion of this review was December 27, 2004. The Minister Responsible for QEC granted an extension to February 2, 2005.

URRC Response:

Please see URRC letter to the Minister

3.3 URRC Examination of Technical and Financial Matters

The response to technical meeting undertakings was provided in as timely a manner as possible, given other operational requirements.

All materials requested by the URRC were made available prior to the URRC's initial report being delivered, with the exception of a request that QEC respond to all materials provided by all persons appearing at the hearings in all communities. This was not completed in time.

The URRC did not set a return date for the Responses to Technical Hearing. All responses were delivered prior to the URRC's initial report being delivered.

All responses are on the public record.

URRC Response:

The following table sets out the dates when information requests were issued and when they were responded to by QEC:

	URRC Issue Date	URRC Established Due Date	Due date as amended by QEC	Actual Response Date by QEC
1st round IRs	Oct 5/04	Oct 13/04	Oct 18/04	Oct 18/04
2nd round IRs	Oct 18/04	Nov 5/04	Dec 13/04	Part 1 Dec 13/04 Part II Jan 20/05
3rd round IRs	Oct 25/04	Oct 29/04		Dec 8/04
Undertakings at Technical Meeting	Dec 14, 15/04	Jan 7/05		Jan 28/05

4.0 Rate Base

4.1 Introduction

Represents anticipated content for the rates recommendation

URRC Response:

No Response required by the URRC

4.2 Gross Plant in Service

Northwestel's comments regarding the Corporation's telecommunication's assets should be viewed in the context that the impugned investment allowed QEC to avoid purchasing telecommunications from NWTel. The disposal of those assets to Nunavut Broadband Corporation supported the creation of community broadband, which is also in competition with Northwestel.

The revisions to the rate base represent anticipated content for the rates recommendation.

URRC Response:

The URRC determination in Section 4.2 is consistent with the foregoing explanation.

4.3 Capital Additions

A comparison of the Baker Lake plant to Clyde River and Sanikiluaq plants requires appropriate adjustments for differences in the plant design, annual increases in the cost of construction since the construction of these plants, an analysis of increases in construction costs for other projects in Nunavut during this period, and analysis of the costs of delaying the project for a year.

Business plans prepared by government departments acknowledge construction costs have increased at an annual rate in excess of 10% over the last few years versus the more nominal rate used by the URRC in the rate base analysis.

QEC can provide this material in addressing this addition.

***URRC Response**: See next page*

URRC Response:

URRC determinations in Section 4.3 is consistent with the limited supporting evidence presented by QEC and the URRC's Baker Lake Report. The 2004/05 capital addition for the Baker Lake plant was determined on a final basis for purposes of the 2004/05 rate base and revenue requirement.

4.4 Accumulated Amortization

The Corporation very aware of the requirements of CICA Handbook Section 3110 and is working with the Office of the Auditor General to achieve appropriate Asset Retirement Obligations.

URRC Response:

The URRC's determinations for regulatory purposes are not considered inconsistent with Section 3110 of the CICA handbook for reporting purposes.

4.5 Customer Contributions

The impact of forecasting or not forecasting capital assets constructed at the request of a customer where the cost is recovered from the customer, is negligible in relation to the outcome of the General Rate Application.

The Corporation will review the accounting for contributions and contribution amortization with the Office of the Auditor General.

URRC Response:

No Response required by the URRC

4.6 Working Capital

Allowing the Corporation to rely on information generated by NTPC during this first GRA permitted the GRA to be completed at a lower cost. If it is required that the Corporation will undertake separate studies specific to QEC and include them with the next GRA, this will the cost of a GRA. With the limited number of customers each proposed consultant's study needs a value-for-money decision.

***URRC Response**: See next page*

URRC Response:

The URRC's determinations and directions are considered to strike a fair balance based on the evidence presented

4.7 Rate Base

The total rate base reflects a reduction relating to the Baker Lake plant which the Corporation will be addressing through the provision of additional information.

URRC Response:

The 2004/05 capital addition for the Baker Lake plant was determined on a final basis for purposes of the 2004/05 rate base and revenue requirement.

5.0 Return on Rate Base

5.1 Capital Structure

The URRC's acceptance of 50% of the unamortized division costs and the inclusion of the amortization of this amount in the revenue requirement increases the Corporation's equity by $4.2 million for accounting purposes.

In prior discussions on the handling of these costs the QEC Board had agreed with the OAG that should any of the division costs be recoverable through rates that the 2001 equity will be restored by the amount recoverable.

URRC Response:

The URRC's determinations and directions are considered to strike a fair balance based on the evidence presented.

5.2 Long Term and Short Term Debt Rates

If interest rates are locked in for revenue requirement purposes, an increase in interest rates could trigger a requirement to file a GRA.

The Corporation would be interested to know the URRC's thoughts on the issue of long term debentures to pay the capital short term debt presently incurring a lower rate of interest than that available on the long term market.

URRC Response:

The URRC acknowledges the concern noted above. However, no evidence respecting date and terms of issuance of long term debt to replace the short term capital loan was presented during the proceedings. A material change in cost of borrowing could trigger a new GRA to the extent it is material in the context of the overall revenues and costs

5.3 Equity Return

A utility operating in the Arctic with only one source of fuel may have more business and financial risk than a utility operating in the south with a choice of generation options including diesel, coal, natural gas, hydro and nuclear, not to mention the economies of scale.

URRC Response:

The URRC's determinations and directions are considered to strike a fair balance based on the evidence presented

5.4 Total Return

The proposed rate of return is a useful marker, but of less consequence because of the application of the 15% arbitrary rate increase cap borrowed from the Northwest Territories Public Utilities Board.
The application of an arbitrary rate increase cap means that may of the markers provided by the URRC have more theoretical impact and are useful for future consideration.

Either the Company is expected to operate at less than the acknowledged revenue requirement or the GN is asked to make up that portion of the revenue requirement which is not within the 15 percent. The report does not identify the preferred option.

URRC Response:

The 15% does not constitute a rate cap but rather the first part of a rates phase in for 2004/05.

The January 27, 2005 URRC report determined the 2004/05 revenue requirement on a preliminary basis. The determination is preliminary because the O&M expense component was determined on a preliminary basis whereas all other components of revenue requirement were determined on a final basis. The forecast revenues at existing rates were also determined on a final basis. Before determination of the 2004/05 final revenue requirement the URRC recommended that an external review of

the corporation be carried out and certain information set out in Section 12.1 be provided to the URRC by September 30, 2005.

The URRC report contemplates a two step adjustment of rates. The first step involves a 15% across the board increase largely to cover fuel cost increases. The second step contemplates recommended rates effective April 1, 2006 that would recover the final URRC determined revenue requirement, following review of the information to be filed by September 30, 2005.

The above approach has been referred to as the rates phase in approach and is designed to achieve two objectives. First a staged increase will mitigate rate shock given that the corporation has not had an increase since 1998. Second, it provides an opportunity for the utility to support the prudent level of expenditures in O&M expenses comprised of salaries and wages, supplies and services and travel and accommodation, items with respect to which the URRC was not satisfied with the evidence presented in these proceedings. The items, namely the non O&M components of revenue requirement, that were determined on a final basis will not change as a result of the information to be filed September 30, 2005.

In addition to the foregoing the URRC has directed QEC to respond to certain other matters concerning rates. First, QEC was directed, within 90 days of public release of the URRC report, to file a proposal to mitigate the high rates for certain communities. Second, QEC was directed to provide within the same 90 day time frame a proposed mechanism for adjusting rates giving effect to the final 2004/05 revenue requirement effective April 1, 2006.

6.0 Revenue Requirement

6.1 Operations and Maintenance Expense

6.1.1 Fuel and Lubricant Expense

The reduction of the fuel and lubricants expense based on the fact that the fuel price increase only applied to the last eight months of the test year should be reconsidered because the current price forms the best estimate for all of 2005/06 to which the new rates will apply, not just eight months.

To increase plant efficiencies in general beyond the actual experienced last year plus known engine replacements, forces the Corporation into a situation where it may not be able to meet the proposed theoretical efficiency standard and therefore may not be eligible for fuel riders when fuel prices go up or not meet the standard and incur fuel costs in excess of the approved revenue requirement component without opportunity for recovery.

<u>URRC Response:</u>

The forecast fuel prices determined by the URRC reflect the company's application. Any change in rates triggered by higher than forecast fuel prices would be the subject of adjustments under the rate stabilization fund mechanism recommended by the URRC

The URRC adjustments in general reflect the actual fuel efficiencies experienced last year plus known engine replacements:

"On balance the URRC considers it appropriate to increase the 2003/04 actual fuel efficiencies for each of the communities which added new plant in 2004/05 by 2% to arrive at the URRC recommended fuel efficiencies for these communities. For Baker Lake the URRC will use the revised fuel efficiency recommended by QEC." [Page 35]

<u>6.1.2 Salaries and Wages Expense</u>

The following section may belong in a report on other matters and future direction.

> Throughout the hearings numerous parties requested to have an independent review of the overall operations of the Power Corporation. The URRC agrees with these requests and recommends that the Government of Nunavut issue a request for proposals to qualified Engineering firms or consulting firms that are knowledgeable in the operations and management of a Utility and Utility Regulation, to conduct a review of the corporation with the objective of streamlining the power corporation into a well run utility and regaining the confidence of its customers and stakeholders.
>
> The URRC recommends this review be completed in a timely manner to allow QEC to respond meaningfully to the URRC directions set out in Section 12.1 of this Report. Since the review concerns matters resulting from past decisions with respect to staffing and management the costs associated with the review should not be recoverable from the customers of the Corporation in the normal course.

It may be more effective to include issues related to decentralization, beneficiary employment and issues relating to government policy decisions in the separate report on other matters and future direction.

URRC Response:

Please see Item 3 of the URRC letter to the Minister

6.1.3 Supplies and Services Expense

The proposed reduction of supplies and services will be addressed through the provision of additional information.

The supplies and services information provided included budgets broken down by engine for overhauls, by employee for housing, by employee for training, by department, by region and by community.

URRC Response:

Information provided to the URRC is reflected in Attachments 11B, 11C and 11 D filed January 20, 2005. These attachments provide monthly 2004/05 budget figures for supplies and services-operational, supplies and services-housing, training costs and medical costs, by expense type and by community (Plant).

6.1.4 Travel and Accommodations Expense

The reduction of travel and accommodations will be addressed through the provision of additional information.

The travel and accommodations information provided included budgets broken down by department, by region, community and individual employee. While the proposed reduction of the travel and accommodations component of the revenue requirement appears to be arbitrary, it has not affected the URRC's rate recommendation due to the application of the 15% rate increase cap.

Note 1: It may be that the fuel and lubricants expense, salaries and wages expense, supplies and service expense and travel and accommodations expense were reduced when determining the revenue requirement because the process gave no other option.

The fiscal year 2004/05 was to be the test year yet the rate recommendation was required before the year was over.

The additional information requested above would include the audited financial statements for the test year which would be available before the rate recommendation effective April 1, 2006, if any.

Note2: The time constraints impacting on the URRC also impact on the Company's ability to promptly provide the materials the URRC requests.

Many Utilities have a Regulatory or rates department (including NTPC) with dedicated employees. This is a significant expense for a small customer base, and has not been implemented at QEC In QEC, the accounting and management staff perform both functions. The URRC process was designed to be effective but simpler, shorter and less costly.

URRC Response:

Regulation is a surrogate for competition for monopolies that are not subject to the price discipline of the competitive market. The onus is upon regulated utilities to demonstrate by way of credible and well supported evidence the matters requested in the application are just and reasonable.

6.2 Reserves

6.2.1 Reserve for Injuries and Damages

The Reserve for Injuries and Damages has been allowed, however, what will be permitted to be charged against the reserve has been defined.

URRC Response:

No Response required by the URRC

6.2.2 Rate Hearing Reserve

The Rate Hearing Reserve has been allowed to the extent of external hearing costs. If implemented, based on the requirement for studies, the next GRA will cost significantly more than the first one.

URRC Response:

The URRC's determinations and directions are considered to strike a fair balance based on the evidence presented

6.3 Amortization

6.3.1 Capital Asset Amortization

The Corporation has been requested to write off windmills over a longer period and to provide an amortization study to determine whether NPC diesel plants should continue to be amortized at the same rate as NTPC diesel plants.

URRC Response:

No Response required by the URRC

6.3.2 Financing Cost Amortization

See 5.1 Capital Structure above, the amortization of 50% of the unamortized division costs has been allowed.

URRC Response:

No Response required by the URRC

6.3.3 Amortization of Customer Contributions

The Report suggests that the Corporation is not amortizing customer contributions correctly.

The Corporation's amortization calculations are audited by the OAG. The Corporation will ask the OAG to review this report and determine whether the URRC or the OAG approved amortization calculation is appropriate.

URRC Response:

No Response required by the URRC

7.0 Total Revenue Requirement

The reduction in the revenue requirement may be partially mitigated by load growth and the re-established mechanism to recover increased fuel costs related to fuel pricing.

The test for management would be to keep non fuel cost expenditure increases and load growth fuel cost increases within revenue growth. This is a practical goal if the Corporation begins with a reasonable income base.

However, the URRC has made rate recommendations that fall $4.1 million short of their own recommended revenue requirement.

URRC Response:

Please see Item 3 of the URRC letter to the Minister

8.0 Revenue Forecast

8.1 Revenue from Sale of Electricity at Existing Rates

It is difficult to find a rationale for the substituting a 5 year forecast generated in 2000 by NTPC for the actual number of customers.

The Corporation will address this issue through the provision of additional information.

URRC Response:

No Response required by the URRC

8.4 Total Revenue

The total revenue forecast at existing rates has proven to be accurate. Revenue to date is slightly ahead of the forecast.

URRC Response:

No Response required by the URRC

9.0 Additional Riders

9.1 Alternative Energy Rider

The Corporation will have to source funding for alternative energy initiatives elsewhere, after which, the assets will form part of the rate base and the funding will form part of the calculation of the return on rate base.

Viable projects will be identified and funding options sourced. Increasing fuel prices will increase the viability of wind and hydro.

URRC Response:

No Response required by the URRC

9.2 Environmental Initiatives Rider

The following section belongs in a report on other matters and future direction.

> The URRC directs QEC to provide a detailed study of the potential liability on the part of QEC with respect to future removal and site restoration expenditures, including a risk assessment of unknown contingencies, at the time of the next GRA.

The Corporation has already done site assessments complete with estimated levels of contamination in cubic meters of soil.

The question outstanding is who will pay for remediation and when.

URRC Response:

No Response required by the URRC

9.3 Beneficiary Employment Rider

Creation of this fund was denied yet the Corporation still has a legal obligation to meet land claims obligations.

Operations costs have been reviewed and reduced below the revenue requirement, leaving modest to no other options for funding. Resources external to the regulatory system are the remaining viable option, but none are currently forthcoming.

URRC Response:

At Page 66 the URRC stated as follows:
"QEC must fulfill its responsibilities under the agreement in a prudent manner consistent with its business needs and priorities. The URRC considers the creation of a separate fund may not facilitate full regulatory scrutiny of how QEC fulfills its responsibilities under the agreement."

The review of the prudent level of beneficiary employment expenditures will fit appropriately into the external review referred to in Section 12.1 pages 72-73 of the Report.

10.0 Revenue Shortfall

The URRC, identifies a $12.473 revenue shortfall (see 10.0)

The URRC recommended rates would generate $8.3 million (see 12.1).

The URRC does not identify where the unaccounted $4.1 million would come or be cut from.

URRC Response:

Please see Item 3 of the URRC letter to the Minister

11.0 Rate Stabilization Fund

If implemented, the recommendation to restore the territorial fuel stabilization fund mechanism will be tested during the next fiscal year if world oil prices do not go down.

URRC Response:

No Response required by the URRC

12.0 Rate Approval

12.1 Phased In Rate Increase

The 15% “rate shock” level appears to be from a prior, unquoted decision of the NWT PUB which is referenced in a submission (see 12.1) as being “adopted by the Northwest Territories PUB” without a document reference.
The Corporation will attempt to find the unreferenced source document as it appears to be significant for the URRC approach.

The following section may belong in a report on other matters and future direction.

> The URRC has recommended approval of a 15% increase in rates effective April 1 2005. This will result in additional revenues of $8.415 million. The URRC has recommended that a review of the corporation be carried out with the objective of

> streamlining the power corporation into a well run utility and regaining the confidence of its customers and stakeholders. The URRC has recommended that a series of reports supporting the level of non fuel O&M expenses be filed following the review. Upon receipt of the foregoing reports the URRC will make a further recommendation to the responsible Minister confirming or varying its preliminary determinations respecting salaries and wages, supplies and services and travel and accommodation expenses as well as recommend any resulting adjustments to rates effective April 1, 2006 to recover the final amount of the shortfall for 2004/05.

All of pages 72 and 73 after the first paragraph may relate to future direction.

URRC Response:

Please see Item 3 of the URRC letter to the Minister

As to what level of increase constitutes rate shock is based on the evidence and the judgment of the regulator taking into account all of circumstances at the time. The percentage increase considered to constitute rate shock by the regulator in a given jurisdiction may not necessarily constitute rate shock in another considering all the circumstances of the case. In this case, considering all of the circumstances particular to the application for service to customers in Nunavut the URRC recommended a 15% increase as a first step.

12.2 Move to Territorial Rates from Community Based Rates

The door has been left open for rate averaging applied to the community rate structure to avoid rate shock from capital expenditures and the recommended community rates do not reflect capital expenditures that have occurred since the last GRA (seven years), thereby departing from the community rate structure for every community that has had a capital expenditure since the last GRA.

As a result, there is no basis in the cost of service for the proposed rates.

The following might be included in a report on other matters. It indicates that a migration towards the blended rate structure may be the acceptable compromise between the community rate structure and the territorial rate structure. The URRC-proposed capital stabilization fund rate below is similar to the non operating component of a blended rate.

> The URRC considers it appropriate to move towards some form of rate averaging among communities so as to minimize the rate impact on smaller communities when their plant

needs to be upgraded or replaced. However, the URRC also believes the relationship between costs incurred at the community level and the rates should not be completely obscured by any rate averaging mechanism. In other words the price signals to customers for electricity service should, among other rate design criteria, reflect the costs of producing and distributing that service. The URRC considers further study and assessment of rate averaging mechanisms is needed and therefore directs QEC to address alternative mechanisms for rate averaging or levelizing rates at the next GRA. In responding to this direction QEC should specifically address how any potential rate shock to customers as a result of this move to averaging of costs among communities will be mitigated. QEC should also have regard to community and customer input when responding to this direction.

Until a new rate structure is in place, the URRC considers that a capital stabilization fund should be implemented as an interim measure and that revenues collected under this fund mechanism should be used to alleviate the highest rate communities to a level somewhat closer to the Nunavut or regional average rates and also applied to new power plants being completed in 2004/05 Accordingly, the URRC directs QEC to propose a capital stabilization fund as an interim mechanism for the purpose of mitigating the high rates for certain communities resulting from the community based rate structure. The capital stabilization fund mechanics should be worked out by QEC and forwarded to the Minister for approval within 90 days of the release of this Report. URRC notes this fund adjustment will result in somewhat higher than average increases for customers in certain communities.

As part of the response to the direction concerning a capital stabilization fund QEC is also directed to address, taking into account the URRC's comments in this section concerning rate averaging, the approach to adjusting rates if an additional increase as discussed in Section 12.1, effective April 1, 2006, were to be recommended by the URRC and approved by the responsible Minister.

URRC Response:

Please see Item 3 of the URRC letter to the Minister

12.3 Cost of Service and Rate Design

Indicates the URRC would like to return to the PUB approach of Phase 1/Phase 2.

This approach does result in more time to study the details of a Revenue Requirement and a Rate Base. Potentially such a process design change could be provided for in the URRC rules of procedure or in a direction from the Minister. It does not require any legislative change.

URRC Response:

No Response required by the URRC

13.0 Terms and Conditions of Service

Some suggestions but ultimately recommended as proposed. The Corporation will give serious consideration to the suggestion that customer security deposits be segregated from general funds and invested at a higher rate than daily interest so a higher rate can be paid to the customers on their deposits.

URRC Response:

No Response required by the URRC

14.0 Quality of Service

14.1 Reliability Statistics

The Corporation anticipates tracking reliability statistics on a monthly basis.

URRC Response:

No Response required by the URRC

14.2 Safety

The Corporation is on record with a safety goal of zero lost time. The Corporation will compare safety records with industry experience as requested.

URRC Response:

No Response required by the URRC

14.3 Service Quality and Complaints

The Corporation anticipates implementing a complaints monitoring system.

URRC Response:

No Response required by the URRC

15.0 Other Matters

15.1 Management of the Corporation

This section may belong, as titled, in a report on other matters.

URRC Response:

No Response required by the URRC

15.2 Treatment District Heating Function

It remains to be determined whether residual heat capital expenditures and the related residual heat revenue which is presently incidental and nominal in relation to electrical generation revenue can economically be isolated from electricity rate regulation through the provision of separate cost of service information, given the small amounts generated.

URRC Response:

The key principle determined by the URRC is as follows:

"The URRC considers electrical customers should not cross subsidize district heating customers and district heating customers should not cross subsidize electrical service customers." [Page 89]

15.3 Treatment of Future Industrial Customers

It appears this section of the GRA was interpreted as a request to move industrial revenue outside the realm of regulation.

This was not the case and the recommendation of the URRC is consistent with the approach the Corporation would have taken and will take when presented the opportunity.

Should the Corporation be asked to provide service for the Nanisivik Airport, this would be an opportunity to address this process.

URRC Response:

No Response required by the URRC

15.4 Subsidy Level

There is a significant benefit from the implementation of subsidy decisions at the same time as the rate decisions.

This is a policy decision outside of the impact of the URRC recommendations.

URRC Response:

No Response required by the URRC

16.0 Summary of Recommendations

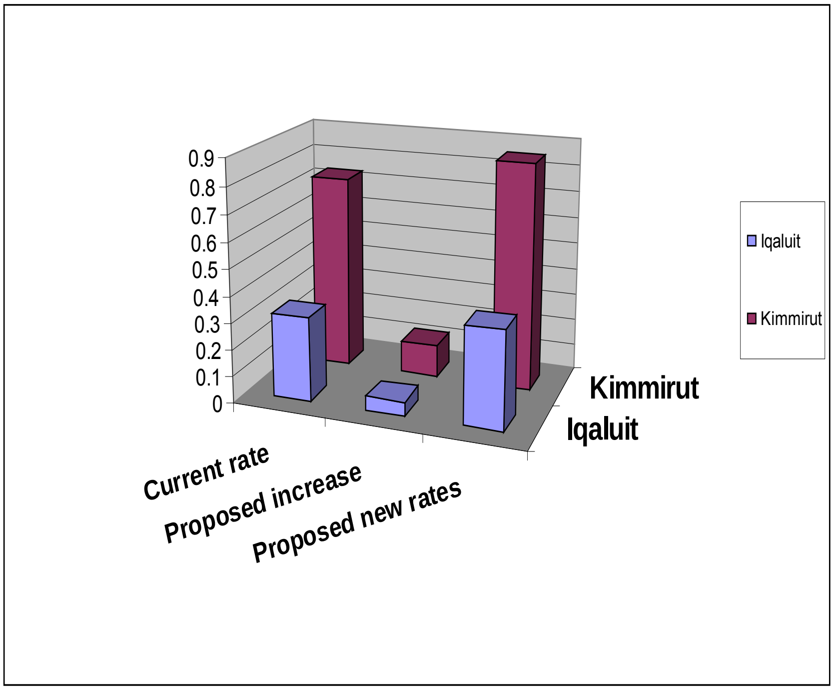
This material is repeated from the text of the report.

Recommendation 3 needs to be clarified because the schedule indicates 16.5%. The 15% appears to be approximate and relates to the overall average increase resulting from the increase in the rates for consumption including streetlights and the service charges that have not increased.

Recommendations number 4 and 5 may belong in a report on other matters and future direction.

The recommended 16.5 % increase on rates relating to consumption, see Schedule C-3, results in a widening of the cents per kWh gap between the community paying the lowest residential rate (Iqaluit) and the community paying the highest residential rate (Kimmirut).

	Current rate per kWh	URRC Proposed increase - 16.5%	URRC Proposed new rates
Iqaluit	.3158	.0522	.3680
Kimmirut	.7349	.1213	.8562
Difference	.4191	-	.4882



The revenue increase recommendation to be recovered through a rate increase is $8,415,266 divided by the kWh sales of 135,474,480 kWh equals a cents per kWh rate increase of .0621.

The Corporation would receive the same increase in revenue without increasing the cents per kWh gap between the lowest rate and the highest rate if the increase was cents per kWh rather than a percentage.

Proposed rates with .0621 cents per kWh increase

Iqaluit at	.3779
Kimmirut	.7970
Difference	.4191
Increase in gap	.0000

URRC Response: **See next page**
URRC Response:

Please see Item 3 of the URRC letter to the Minister

The 15% across the board increase largely covers fuel cost increases. The URRC has directed QEC to address the mechanism for adjusting rates giving effect to the final 2004/05 revenue requirement effective April 1, 2006.

17.0 Summary of Directions

This entire section may belong in a report on other matters and future direction.

Some of these directions will cause the Corporation to incur more costs to be paid by the rate payer.

Where the text makes a specific direction to the Corporation, this is taken as a recommendation to the Minister consistent with the URRC and QEC legislation. Under the current legislation, the URRC makes rate recommendations to the Minister who has the authority to direct the Corporation.

Where the recommendation does not relate to rates, it may require another mechanism for direction giving, including the Ministerial/Board direction, Crown Agencies Council or other processes.

URRC Response:

Please see Item 3 of the URRC letter to the Minister

All matters referred to in Section 17 of the report are considered part of the records and evidence required to support rate applications

NUNAVUT

UTILITY RATES REVIEW COUNCIL

Report to the Minister Responsible for the Qulliq Energy Corporation On:

The 2004/05 General Rate Application by the Qulliq Energy Corporation

January 27, 2005

THE UTILITY RATES REVIEW COUNCIL

MEMBERS	Ray Mercer	Chairman
	Gordon Rennie	Member
	Louie Qingnatuq	Member
	Peter VandenBrink	Temporary Member
	Adla Itorcheak	Temporary Member

SUPPORT		
	Kirk Janes	Secretary
	Raj Retnanandan	Consultant
	Barry Shymanski	Consultant
	Annie Ningeok	Minutes Secretary
	Betty Brewster	Inuktitut Interpreter
	Connie McCrae	Inuinnaqtun Interpreter

QEC WITNESSES

The following attended one or more community consultations as representatives of Qulliq Energy Corporation:

Dennis Lyall	Vice Chair
Jimmy Kilabuk	Director
Gordon Main	Director
Anne Crawford	President and Chief Executive Officer
Hazen Hawker	Chief Operating Officer
Peter Mackey	Director of Operations and IT
Lee Douglas	Senior Planning Engineer
Yasmina Pepa	Communications Officer

LIST OF ABBREVIATIONS

CWIP	Construction Work in Progress
GN	Government of Nunavut
GRA	General Rate Application
NPC	Nunavut Power Corporation
NTI	Nunavut Tunngavik Incorporated
NTPC	Northwest Territories Power Corporation
NWC	North West Company
QEC	Qulliq Energy Corporation
URRC	Utilities Rates Review Council
FTE	Full Time Equivalent Employee
F&L	Fuel & Lubricants
O&M	Operation & Maintenance
AFUDC	Allowance for Funds Used During Construction
ACL	Arctic Co-operatives Ltd.
AG	Auditor General
ETS	Energy Transfer System
NT PUB	Northwest Territories Public Utilities Board

TABLE OF CONTENTS

SCHEDULES iii

APPENDICES iv

EXECUTIVE SUMMARY i

1.0 BACKGROUND 1

1.1 Regulatory History 1

1.2 Corporate Organization and Duties 1

1.3 Jurisdiction and Mandate of URRC 2

2.0 APPLICATION 3

2.1 Requested Approvals of QEC 3

2.2 Requirement for Rate Application 7

3.0 Process for Hearing of the Application 7

3.1 Community Consultations 7

3.2 Consultations with Business and Community Customers 9

3.3 URRC Examination of Technical and Financial Matters 12

4.0 Rate Base 12

4.1 Introduction 13

4.2 Gross Plant in Service 13

4.3 Capital Additions 14

4.4 Accumulated Amortization 20

4.5 Contributions 21

4.6 Working Capital 22

4.7 Rate Base 23

5.0 Return on Rate Base 23

5.1 Capital Structure 23

5.2 Long Term and Short Term Debt Rates 27

5.3 Equity Return 27

5.4 Total Return 32

6.0 Revenue Requirement 32

6.1 Operations and Maintenance Expense (O & M) 32

6.1.1 Fuel and Lubricant expense 32

6.1.2 Salaries and Wages Expense 35

6.1.3 Supplies and Services Expense 45

6.1.4 Travel and Accommodation Expense 47

6.2 Reserves 49

6.2.1 Reserve for Injuries and Damages 49

6.2.2 Rate Hearing Reserve 511

6.3 Amortization 51

6.3.1 Capital Asset Amortization 51

6.3.2 Financing Cost Amortization 55

6.3.3 Amortization of Contributions 56

6.3.4 Net Amortization Expense 57

7.0 Total Revenue Requirement 57

8.0 Revenue Forecast 57

8.1 Revenue From Sale of Electricity at Existing Rates 57

8.2 Bad Debt Expense 59

8.3 Other Revenue 60

8.4 Total Revenue 61

9.0 Additional Riders 61

9.1 Alternative Energy Rider 62

9.2 Environmental Initiatives Rider 62

9.3 Beneficiary Employment Rider 64

10.0 Revenue Shortfall Based on Existing Rates 65

11.0 Rate Stabilization Fund 65

12.0 Rate Approval 67

12.1 Phased In Rate Increase 67

12.2 Move to Territorial Rates from Community Based Rates 71

12.3 Cost of Service and Rate Design 77

13.0 Terms and Conditions of Service 78

14.0 Quality of Service 81

14.1 Reliability Statistics 81

14.2 Safety 83

14.3 Service Quality and Complaints 84

15.0 Other Matters 85

15.1 Management of the Corporation 85

15.2 Treatment of District Heating Function 85

15.3 Treatment of Future Industrial Customers 87

15.4 Subsidy Level 89

16.0 Summary of Recommendations for Approval by Responsible Minister 89

17.0 Summary of Directions to be Addressed at or prior to the Next GRA 91

SCHEDULES

Schedule A	Rate Base
Schedule A-1	Construction Work in Progress & Additions to Rate Base Per QEC
Schedule A-2	Construction Work in Progress & Additions to Rate Base Per URRC
Schedule A-2.1	Estimate of Baker Lake Plant Addition to Rate Base Per URRC
Schedule A-3	Working Capital
Schedule A-4	Contributions
Schedule B	Return on Rate Base
Schedule B-1	Capitalization
Schedule C	Revenue Requirement
Schedule C-1	Increase Decrease in Rates
Schedule C-2	Revenue at Existing Rates
Schedule C-2.1	URRC Adjustment of Number of Customers
Schedule C-3	Revenue at URRC Approved Rates
Schedule C-4	Comparison of Revenues at Existing, QEC Proposed and URRC Approved Rates
Schedule D	Fuel Costs Per URRC
Schedule D-1	Fuel Efficiencies

APPENDICES

Appendix 1	Information on Community Consultations
Appendix 2	Shared Customer Comments from Community Consultations
Appendix 3	Elders Comments

EXECUTIVE SUMMARY

Qulliq Energy Corporation (QEC), filed a General Rate Application (GRA) dated September 14, 2004 for the test year April 1, 2004 to March 31, 2005, with the responsible Minister. Before approving the Corporation's rates, the responsible Minister is obliged to seek the advice of the Utility Rates Review Council (URRC). The Report of the URRC to the responsible Minister is contained in this document.

This is QEC's first General rate application since the division of NPC from the Northwest Territories Power Corporation (NTPC) on April 1, 2001. Prior to April 1, 2001, QEC was part of the NTPC.

The average requested increase in customer rates effective April 1, 2005 is 42.7% considering the forecast revenue shortfall of $20.632 million and the additional revenue of $3.048 million requested for recovery by way of additional rate riders. Approximately 38% (i.e. $7.8 million) of the revenue shortfall is attributable to increased fuel and lubricant costs, while the remaining shortfall is related to increased operating and maintenance expenses (O&M), amortization expense and return.

The territorial rate structure recommended by QEC constitutes a departure from the existing community based rate structure. QEC's proposal results in increases and decreases by community, ranging from a reduction of 26.9% in one community to an increase of 86.9% in another, representing a spread of about 114%, in order to achieve one territorial rate.

The URRC's preliminary determination of revenue shortfall for the 2004/05 test year is $12.473 million. The major components making up this shortfall amount are as follows:

- The rate base determined by the URRC is $94.424 million compared with a requested rate base of $113.644 million

- The return on rate base determined by the URRC is $6.645 million compared with a requested return of $9.130 million. URRC determined a capital structure consisting of 75% debt and 25% equity and a rate of return on equity of 9.6%

- The fuel and lubricants expense determined by the URRC is $26.498 million compared with a requested amount of $27.578 million. The URRC approved a rate stabilization fund effective April 1, 2005 to provide a mechanism for adjusting rates as a result of changes in fuel costs from time to time

- The preliminary URRC determination for salaries and wages, supplies and services and travel and accommodations totals $29.925 million compared with a requested $33.763 million. The URRC determined that additional information is required to finalize the preliminary determinations for non fuel O&M expenses

- The revenue at existing rates determined by the URRC is $57.127 million compared with $56.542 million forecast by QEC. The primary reason for the difference results from an adjustment for inactive customers

The URRC has recommended approval of a 15% increase in rates effective April 1 2005. This will result in additional revenues of $8.415 million. The URRC has recommended that a review of the corporation be carried out with the objective of streamlining the power corporation into a well run utility and regaining the confidence of its customers and stakeholders. The URRC has recommended that a series of reports supporting the level of non fuel O&M expenses be filed following the review. Upon receipt of the foregoing reports the URRC will make a further recommendation to the responsible Minister confirming or varying its preliminary determinations respecting salaries and wages, supplies and services and travel and accommodation expenses as well as recommend any resulting adjustments to rates effective April 1, 2006 to recover the final amount of the shortfall for 2004/05.

The URRC has recommended that in place of the territorial rate structure proposed by QEC the existing community based rate structure be continued in the interest of rate stability. The URRC has provided directions to QEC to come forward with proposals for gradual movement towards some form of rate averaging among communities.

The URRC has recommended that the additional riders proposed by QEC made up of the Alternative Energy Rate of $0.005 per Kwh to facilitate alternative energy initiatives in Nunavut, the Environmental initiatives rate of $0.005 per Kwh to fund the Corporation's share of future removal and site restoration costs and the Beneficiary employment rate of $0.0125 per Kwh to fund the cost of complying with the Nunavut Land Claims Agreement, be denied. Instead the URRC has provided alternative directions to the corporation for dealing with the issues raised.

1.0 BACKGROUND

1.1 Regulatory History

Qulliq Energy Corporation (QEC), on behalf of Nunavut Power Corporation (Corporation or NPC), filed a General Rate Application (GRA) dated September 14, 2004 that was received by the URRC on September 29, 2004 for the test period April 1, 2004 to March 31, 2005. This is QEC's first General rate application filed on behalf of NPC since the division of NPC from the Northwest Territories Power Corporation (NTPC) on April 1, 2001. Prior to April 1, 2001, QEC was part of the NTPC.

The rates currently in place in Nunavut were established as a result of a NTPC GRA filed with the Northwest Territories Public Utilities Board in 1997/98 for communities in the Eastern and Central Arctic.

1.2 Corporate Organization and Duties

NPC was originally established by the Nunavut Power Utilities Act. NPC was renamed Qulliq Energy Corporation and the Nunavut Power Utilities Act was renamed the Qulliq Energy Corporation Act as a result of legislation passed in March 2003. QEC is a Crown Corporation 100% owned by the Government of Nunavut (GN).

QEC has stated in response to Information Request URRC.QEC-9(b) that "…it is anticipated that QEC will have responsibility for both the provision of electricity and petroleum products to Nunavut communities." QEC continued on to state that there would be a subsidiary of QEC named NPC providing electricity to Nunavut, irrespective of whether the transfer of Petroleum Products proceeds as of April 1, 2005.

The two subsidiary corporations would consist of an electrical utility subsidiary that would continue the operations of Nunavut Power and a fuel subsidiary to provide for the operation of the Petroleum Products Division of the Government of Nunavut. The transition of these operations, subject to approval from the Government of Nunavut, is scheduled for April 1, 2005.

QEC provided a list and brief biography of each of its members on the Board of Directors, in response to URRC.QEC-9(c). QEC also provided an organization chart showing its staff from the senior executive to the Supervisor levels.

1.3 Jurisdiction and Mandate of URRC

The Utility Rates Review Council Act (The Act) requires the Corporation, as the supplier of electricity in Nunavut, to obtain approval of the responsible Minister in order to change rates. Before approving the Corporation's rates, the responsible Minister is obliged to seek the advice of the Utility Rates Review Council (URRC).

Within 90 days of the receipt of a request for advice from the responsible Minister the URRC is required to report to the responsible Minister its recommendation that:

a) the imposition of the proposed rate or tariff should be allowed;
b) the imposition of the proposed rate or tariff should not be allowed; or
c) another rate or tariff specified by the Review Council should be imposed.

In making its report, the URRC is required to have regard to whether the proposed rate or tariff is fair and reasonable considering among others the cost of providing the service, including related financing costs.

In carrying out its purposes under the Act, the URRC is permitted to:

a) hold public and private meetings;

b) retain the services of experts and advisors;

c) solicit advice from the public;

d) conduct meetings and mediations with utilities and concerned parties, and assist utilities and their customers in developing a consensus on contentious issues;

e) require utilities and their employees to provide all information that is needed to carry out its purposes, and may require that information to be provided under oath, or by way of solemn declaration;

f) generally, engage in activities that assist it in providing informed advice to the responsible Minister.

The URRC conducted the proceedings in accordance with the requirements and parameters specified in the Act. This report sets out the URRC's recommendations to the Minister pursuant to the Act.

2.0 APPLICATION

2.1 Requested Approvals of QEC

At Page 4 of its Application, QEC requested the following:

- a determination of a rate base for the Corporation's property that is used or required to be used in the provision of electricity and related services to the public within Nunavut including an appropriate allowance for working capital commencing on April 1, 2004 and ending March 31, 2005 (the Test Year);

- a determination of the Corporation's Revenue Requirement for the Test Year for the provision of electricity and related services to the public in Nunavut;

- the re-institution of an effective Rate Stabilization fund to mitigate the impact of changing fuel prices on electricity rates, including, a clearly defined process to be followed to implement a fuel rider as and when required;

- the approval of a rate structure appropriate for Nunavut and its communities. Three options for the rate structure are provided in this GRA, with the recommendation that a territorial rate be implemented;

- confirmation that the rate structure and rates established as the result of this GRA will not apply to the provision of electricity, fuel and heat (energy) to industrial sites where the Corporation is contracted to provide energy

- the approval of Revised Terms and Conditions of Service (April 1, 2005);

- and such further approvals as the Corporation may request and the Utilities Rate Review Council (URRC) recommend. The Corporation provided a detailed list of all items requested in Appendix F, Table 1.1.1. Appendix F Table 1.1.1 lists the following further requests for approvals:

- Additional rate riders to create specific funds as follows:

  i) Alternative Energy Rate of $0.005 per Kwh to facilitate alternative energy initiatives in Nunavut;

  ii) Environmental initiatives rate of $0.005 per Kwh to fund the Corporation's share of future removal and site restoration costs;

iii) Beneficiary employment rate of $0.0125 per Kwh to fund the cost of complying with the Nunavut Land Claims Agreement.

- Approval of a rate formula for supply of residual heat to district heating customers

On Page 2 of its Application, QEC noted that it anticipated continuing to operate until March 31, 2005 under the rates last approved in the NTPC 1997/98 GRA. In response to URRC.QEC-45, QEC indicated that it had requested the GN to provide funding in lieu of a fuel rider for the portion of the 2004/05 deficiency that relates to fuel. This deficit is forecast at $7.974 million. QEC further stated that is it not requesting a deficiency rider for the remainder of the 2004/05 revenue deficiency.

The Corporation forecast a revenue requirement of $77,174,000 for the test period. Revenue at existing rates was forecast by QEC at $56,542,000 [Appendix F, Table 1.5.1C] for a revenue shortfall of $20,632,000 or 36.5% when compared to revenue at existing rates. [Ibid] The average requested increase in customer rates was 42.7% considering the revenue shortfall of $20,632,000 and the additional revenue of $3,048,000 requested for recovery by way of additional rate riders. Approximately 38% (i.e. $7.8 million) of the revenue shortfall is attributable to increased Fuel and Lubricant costs, while the remaining shortfall is related to increased O & M, Reserves, Amortization and Return costs. A portion of these costs are related to the additional head office costs associated with the establishment of new head offices.

The territorial rate structure recommended by QEC constitutes a departure from the existing community based rate structure. QEC's proposal results in increases and decreases, ranging from a reduction of 26.9% in one community to an increase of 86.9% in another, representing a spread of about 114%, in order to achieve one territorial rate.

2.2 Requirement for Rate Application

At Page 5 of its Application, QEC states that it has:

> "…experienced significant operating losses primarily because its revenues have not kept pace with rising operating costs. At Division, on March 31, 2001, the Corporation's share of retained earnings was $43.4 million. Since that time there has been a significant deterioration in retained earnings."

Further, at Page 6 of its Application, QEC states that:

> "The Corporation requires rate relief in order for it to continue to provide service in a safe and reliable manner and to address violations of debt covenants and legislative requirements. The Corporation's insufficient revenues have placed a severe constraint on its ability to meet its financial obligations as they come due.
>
> This inaugural GRA will provide an opportunity to all stakeholders, including customers, to assess the Corporation's actual and proposed performance, and provide valuable feedback on the proposed Revenue Requirement. The Corporation recognizes that the URRC will conduct a thorough review of this Application and will solicit public comment in order to ensure that the new rate structure will serve Nunavut into the future and that the new rates are adequate and necessary to provide safe and reliable service to customers in Nunavut."

The URRC notes that as of March 31, 2004 the retained earnings was at $24.1 million The URRC notes that as part of the information gathering process, QEC provided Appendix 8 of IR No. 2, which is a copy of an unfiled Application for the 2001/02 test years. While that Application was never tested, the URRC has referenced portions of that unfiled Application in order to test the reasonableness of the forecasts provided by QEC in its current Application. The URRC also notes that in the future, QEC should give consideration to the filing of the Applications on a more frequent basis. While filing Applications on a more frequent basis may increase the administration for all parties in the short term, the URRC sees some longer term benefit from filing more frequent Applications. These benefits include less significant changes in customer rates (i.e. reduced rate shock) and the ability for all parties, including QEC, to test the reasonableness of their forecasts given the fact that QEC is a new utility.

3.0 Process for Hearing of the Application

As part of the process for hearing the Application, the URRC requested responses to certain information requests of QEC. Further details of the information request process as well as the results of a URRC technical meeting are provided in Section 3.3 following. Further, as part of the process for hearing the Application, the URRC held a number of community consultation meetings with concerned citizens and corporations. Details of these meetings follow in Section 3.1 and 3.2.

3.1 Community Consultations

The URRC held a number of meetings with individual, business and municipal customers residing in most of the communities that are served by QEC. These meetings took place in the months of November and December 2004 in a number of communities served by QEC. At each of the meetings, the URRC introduced the panel members, explained its role in the process, the legislative mandate of the URRC and the desire to gain as much input as possible from the affected parties.

QEC was also in attendance at these meetings. QEC was allowed to explain its application and the requirement for it. Individuals, representatives of municipalities, and representatives of businesses were given an opportunity to provide written and verbal submissions to the URRC for consideration. In some cases, QEC provided oral responses to the submissions or committed to follow-up with written responses.

The URRC was disappointed at the low attendance at the hearings across the Territory considering the size of the request made by QEC. A number of comments were made by attendees that there was very limited information out in the general public and a feeling of helplessness as most felt this was a done deal. The presentations from the people that did attend the hearings were excellent. In every community Elders attended the meetings and provided very valuable insights into the effects that these increase would have, not just on themselves but the whole community.

As part of the technical meetings conducted between the URRC and QEC, QEC provided its view that it expects to consult with customers prior to the filing of its next Application. The URRC expects that prior to QEC filing its next GRA, QEC will have community consultations with its customers and directs QEC to provide, as part of its next GRA, commentary concerning the process and results of these community consultations. While the URRC recognizes that QEC has overall management responsibility to operate the utility, input from its customers is also an important element of the management of the utility.

Most, but not all parties agreed that some increase in the rates was required. However, all affected parties considered that the requested increase was significant and would be a burden on any and all communities. Many parties recognized that with the Corporation's proposal, even if their community did not receive a significant increase in its rates, other communities that supplied goods and services to their community would be required to pass at least a portion of the increased costs in that community through to the community receiving goods and services. Some customers noted that more businesses were concentrated in larger communities, particularly, Cambridge Bay, Rankin Inlet and Iqaluit, where the power rates are lower than in the smaller communities and thus saw some benefit for continuation of community based rates.

A list of the communities visited including the dates these visits were conducted are shown in Appendix 1 of this Report. Their concerns were generally in the following areas:

- Level of overall rate increase proposed;
- Proposal for territorial rates;
- Size, reasonableness and support for increases in capital and operating expenses;
- Proposed rate of return;
- Lack of confidence in the Utility Management;
- Rate shock and the ripple effect through-out the Nunavut Territory;

- Concerns for the need for the three new riders, Land Claims Compliance, Alternative Energy & Environmental Initiatives;
- Lack of movement towards alternative energy and lack of energy conservation programs;
- Various comments on the Term and Condition of Service.

The URRC has compiled the shared customer comments obtained from individual customers and municipalities, who attended the meetings, in Appendix 2 to this review. The comments provided by Elders are included as Appendix 3. The URRC has considered the comments by QEC's customers in its recommendations for this Report. While not listed in every case, in some cases the URRC has included the viewpoints of the individual customers in the relevant sections of this review.

3.2 Consultations with Business and Community Customers

In addition, to consultations with individual customers, the URRC received input from a number of Business and Community Customers. This input was generally received in the form of written submissions. In addition, a number of these customers were in attendance at the community consultation meetings and provided either their written or verbal input.

The following Business, Municipality and Community customers provided written input:

- Nunavut Tunngavik Incorporated (NTI);
- The North West Company (NWC);
- Kitikmeot Corporation – Cambridge Bay (Kitikmeot);
- Kitnuna Corporation – Cambridge Bay (Kitnuna);
- Ikaluktutiak Co-op (Ikaluktutiak Co-op);
- Katujjijiit Development Corporation (Katujjijiit);
- Iqaluit Chamber of Commerce (Iqaluit CC);
- Arctic Co-operatives Limited (ACL);

- NorthwesTel;
- Kissarvik Co-op of Rankin Inlet (Kissarvik);
- Kivalliq Chamber of Commerce (KCC);
- New North Projects Ltd.;
- Nunavut Development Corporation (NDC);
- Northern Properties;
- Qikiqtani Dry Cleaning and Laundry;
- Frobuild Construction Ltd.;
- The City of Iqaluit (Iqaluit City);
- Hamlet of Kugluktuk;
- Hamlet of Cambridge Bay;
- Joe Neigo; Mayor Baker Lake
- Nunavut Association of Municipalities (NAM);
- Ed McKenna;
- Corinne Attagutsiak;
- Frank Pearce;
- Kathy Towtongie;
- Keith Irving;
- Melinda Tatty;
- Kenn Harper.

The URRC would also like to thank all of the individuals who attended the hearings and provided their insights into the proposed power rate increases. The URRC will not provide a summary of each and every one of the submissions, but will include the comments from the parties with respect to the specific issues raised by the parties. The URRC notes that a number of the submissions from parties, over and above providing comments on the costs, revenues and rates structure of the proposed Application, requested that the URRC be expanded in its mandate beyond that which is currently in place. These comments included:

- An expanded mandate beyond the current legislative role of the URRC in the determination of the revenue requirement, rates and terms and conditions of QEC and its affiliates including additional responsibility for Petroleum Products, , the Territorial Power Support Program and the ability for the URRC to make a final determination of the rates rather than the GN or alternatively have the URRC report directly to the Legislative Assembly rather than to Cabinet;

- Oversight responsibility for the URRC. Lack of such responsibility resulted in QEC ignoring the URRC's recommendations the last time they were made;

- Additional time for parties to prepare their submissions including cost recovery for parties who incur out of pocket costs to prepare submissions;

A number of parties expressed concern about the quality of information provided in support of the GRA and about the GRA process. Some examples follow.

ACL in their final submission stated the GRA is flawed in many aspects. Contributing factors include but are not limited to: filing of incomplete and inaccurate information, a lack of consultation with affected groups, inadequate time to review and consider impacts, inappropriate methodology for allocating costs between customer groups.

Ed McKenna, a customer of QEC stated in his final submission. The public needs to have confidence that the rate proposals are justified. The public must be able to draw their own conclusions and develop an understanding of that justification from the facts. This cannot be done with the information provided by the QEC.

With respect, to process ACL expressed concern over the limited role allowed for ratepayers including difficulties in obtaining timely information, limited time allowed to consider impacts, lack of due diligence in ensuring information is correct, inadequate access to the URRC to make presentations and lack of resources to cover intervener costs. ACL stated the process did not separate deliberations related to the cost structure from deliberations dealing with allocation of costs between users.

While the URRC considers that all of these issues are important, all of them are substantively outside of the jurisdiction and mandate of the URRC as described in Section 1.3 above. If the GN considers that changes are required to the jurisdiction and mandate of the URRC in the future, these changes may be reflected in changes to the current legislation. In the existing time frame of this application, the URRC does not have the ability to respond to any of the requests listed in this section. The URRC notes that the original time frame for the completion of this review was December 27, 2004. The Minister Responsible for QEC granted an extension to February 2, 2005.

3.3 URRC Examination of Technical and Financial Matters

As part of the process for examination of the application the URRC issued three sets of information requests and followed up with a technical meeting with QEC officers in Iqaluit on December 14 and 15, 2004. In response to URRC's questions at the technical meeting QEC undertook to provide certain undertaking responses in writing. Even as this report is written a number of responses to undertakings remain unanswered.

The URRC's recommendations that follow are based on information made available by the corporation.

4.0 Rate Base

QEC's proposed revenue requirement consisted of four main components. These included Operations and Maintenance expense, Reserves, Amortization and Return on Rate Base. As part of determination of Return on Rate Base, the URRC first reviewed and determined an appropriate rate base for QEC.

4.1 Introduction

The forecast rate base of QEC consists of the Beginning of Year Gross Plant in Service, Additions to Rate Base, Retirements, Mid-Year Gross Plant in Service, Mid-Year Accumulated Depreciation, Amortization of Contributions and Working Capital.

As of March 31, 2001 QEC acquired the physical assets, liabilities and equity from NTPC for those facilities required to serve customers in QEC's new service territory. As noted in the 2002/03 Annual Report provided in response to URRC.QEC-11(a), note 2, the division was calculated in accordance with the March 29, 1999 Transition Agreement and the March 30, 2001 Transfer of Interest Agreement. Subject to finalization of the liability and equity allocations as discussed in Note 13(e), the URRC accepts the opening gross plant in service balances associated with that division of assets.

4.2 Gross Plant in Service

As part of an establishment of rate base, the URRC is required to determine the opening balance of gross plant in service as of April 1, 2004.

NorthwesTel provided a submission dated November 30, 2004 in which it highlighted four significant concerns. The second significant concern dealt specifically with "…the lack of detail with reference to capital investment…" In NorthwesTel's view, this prevented interested parties from making a full assessment of the merits of the QEC proposal. NorthwesTel provided one example of an investment, namely an. investment in a telecommunications network partnership, that NorthwesTel considered had resulted in long-term adverse financial impacts. NorthwesTel submitted that this "non-energy related" infrastructure investment was costly to QEC as it "…provides much more network capacity than is required for the communication needs of the QEC." NorthwesTel submitted that the URRC and GN should "…explore how this arrangement has detrimentally affected the financial circumstances of QEC and work to resolve the matter."

QEC's 2004/05 financial statements indicate subsequent to year end, the Corporation entered into an agreement to sell its telecommunications assets for their estimated net book value of approximately $1 million. The sale is expected to be finalized by January 31, 2005.

The URRC notes the sale when recorded will have a net impact on the mid year rate base equal to the amount of the sale proceeds. Accordingly the URRC will reflect the proceeds on disposal of $1 million in the calculation of closing accumulated depreciation.

The URRC notes the opening plant balances are consistent with the audited financial statements. From its review of additions to rate base since division on April 1, 2001 the URRC is satisfied there is no evidence of imprudence in capital additions reflected in gross plant in service. Accordingly the URRC will accept the opening plant balances for purposes of this Report.

4.3 Capital Additions

QEC forecast additions to rate base of $15,216,000 for the test period. This was revised to $15,065,000 in an attachment with revised tables in response to URRC.QEC-44. The revised capital additions, by project, are shown in Schedule A-1 attached to this Report. QEC provided descriptions of the major capital projects in its Application at Pages 23 to 26. Further detail was provided in Appendix G, Tables 2.2.1, 2.2.2C and 2.2.3C.

In response to URRC.QEC-17(d) and (h), QEC provided further updates on its proposed capital projects. While QEC indicated in response (h) that all of the proposed projects had commenced, the completion dates for some of the projects had changed from the original estimates. The revised completion dates from response (h) are as follows:

Community	Project Description	Completion	Amount ($000)
Head Office	Great Plains Software Project	March 2005	358
Iqaluit	Residual Heat Project	March 2007	247
Pangnirtung	Replace Cat 398	June 2004	718
Qikiqtarjuaq	Replace Cat 353	April 2004	332
Cambridge Bay	Distribution Upgrade	November 2005	228
Kugaaruk	Replace Detroit 8V71	October 2004	477
Rankin Inlet	Residual Heat Project	March 2006	2,356
Baker Lake	New Plant	March 2005	8,907
Baker Lake	Distribution Upgrade	March 2005	374
Arviat	Plant Expansion	March 2005	2,041
Coral Harbour	Replace Cat D398 and Cat D353	June 2005	805
Pond Inlet	Distribution Upgrade	June 2005	438

The URRC considers, based on the above, any projects with forecast completion dates beyond March 2005 should not be included in the gross plant in service for QEC for the 2004/05 test year as they cannot be considered plant that is used or required to be used during the test year. Accordingly, the URRC will include projects that are not forecast to be completed by March 31, 2004 in construction work in progress (CWIP). The URRC has not tested the costs of projects included in CWIP and expects QEC to provide evidence supporting the prudence of these expenditures at the time the projects are proposed to be added to gross plant and rate base.

The URRC has carefully examined the proposed additions to gross plant in service and rate base proposed by QEC and has the following comments.

<u>Diesel Plant</u>

QEC proposed to add the cost of the new Baker Lake power plant in the amount of $8.907 million to gross plant in service in 2004/05. In the response to URRC.QEC-17(d), QEC stated: “The Corporation is anticipating that the new plant in Baker Lake will be in operation by the end of the fiscal year. Given that there is a possibility that the construction could extend into the next fiscal year, decommissioning plans were not prepared for the old plant for 2005/06.”

The URRC notes that a business case to support the Baker Lake New Plant project costs was not provided. Further, in response to URRC.QEC-18(c)(ii), QEC states further capital expenditure information will not be forthcoming until January 2005. The $8.907 million proposed cost does not appear to include any allowance for funds used during construction or AFUDC.

URRC notes QEC has not responded to the URRC's directions in the Baker Lake Project permit approval report dated May 16, 2003. That report concluded, on the face of the information provided the Baker Lake new power plant updated project costs appear to be high and perhaps excessive. This conclusion was based on a comparison of the then forecast $8.48 million Baker Lake project cost (excluding AFUDC) with the completed costs of other projects. At this time, the URRC is not convinced QEC has demonstrated the prudence of the proposed costs for this project. Based on QEC's evidence that the plant will be in service within the test period and taking into account the lack of evidence to support the prudent cost of the project, the URRC is prepared to approve the inclusion of a portion of the cost of the Baker Lake plant in gross plant in service during the test period. The URRC has estimated the portion of the Baker Lake power plant for inclusion in gross plant in Schedule A-2.1 attached based on the cost comparisons with similar power plants constructed at Clyde River and Sanikiluaq. The Clyde River and Sanikiluaq plants were used as benchmarks since the adjusted costs per KW for these two plants were close and indicative of the preponderance of past power plant construction costs reviewed in the Baker Lake Report.

The URRC considers any costs exceeding the amount calculated using the Clyde River and Sanikiluaq plant benchmarks to be imprudent and will not include such costs in gross plant in service and rate base. Accordingly, the URRC will include $7.162 million in gross plant in service as the prudent cost of the Baker Lake plant for the 2004/05 test year. QEC is directed to exclude the disallowed amount of $1.745 million from utility plant in service, in future General Rate Applications. However, if QEC is able to provide further evidence that would demonstrate the prudent cost of the Baker Lake plant should be different from that approved herein the URRC will consider such a request at the time of the next GRA.

The URRC notes that the Arviat Plant Expansion project for $2.041 million is proposed to be completed in the last month of the test period. This project consists of adding an engine bay and a fourth generator. QEC indicated at Page 25 of its Application, that the addition of the fourth generator rated between 900 – 1000 kW will increase the capacity of the plant "…to meet the load forecast for the foreseeable future and will improve the capability of the power plant to match load and increase fuel efficiency." In response to URRC.QEC-17(b) QEC indicated its standard was to have firm capacity in all communities equal to 110% of forecast peak load with the largest engine in the plant out of service.

When questioned further on the existing capacity of the plant, QEC responded in URRC.QEC-18(e)(i) that the existing capacity at Arviat is 2300 kW which is generated by three Cat units. QEC also added that "Firm capacity at Arviat with the largest engine out of service would be 1340 kW. In response to URRC.QEC-18(e)(ii), QEC stated that the "Plant personnel recorded peak loads last winter as high as 1295 kW". The Corporation's standard is to have a firm capacity of at least 110% of the peak forecasted load while the largest generator in the plant is out of service. QEC indicated it did not meet this firm capacity during the past winter where it should have been 1425 kW. In response to URRC.QEC-18(e)(iii), QEC indicated that existing loads were forecast to be as high as 1680 kW this winter.

Given the need for service reliability, the URRC will accept the forecast cost of the Arviat generation addition to gross plant and rate base for the test period.

QEC indicated the Coral Harbor Cat D398 and Cat D353 ($805,000) replacement completion dates have been moved to June 2005. The URRC will deal with the requirement for these projects in QEC's next GRA. The URRC will include the cost of these projects in CWIP for the purposes of the 2004/05 test year.

QEC indicated the engine replacements at Pangnirtung ($718,000), Qikiqtarjuaq ($332,000) and Kugaaruk ($477,000) have been completed as of June 2004, April 2004 and October

2004 respectively. The URRC will accept inclusion of these generation additions in gross plant and in rate base for the test year.

The combined "Plant Design" project ($1,000) shown at line 17 of Appendix G, Table 2.2.2C and "New Plant Design" project ($197,000) shown at line 25 of Appendix G, Table 2.2.1 totaling $198,000 in expenditures are not explained. The URRC will include these projects in CWIP in the 2004/05 test year. URRC expects QEC to provide more detail with respect to these projects and demonstrate the need and prudence of these expenditures at the time it requests inclusion of the projects in gross plant.

<u>Distribution</u>

The URRC notes that the Cambridge Bay Distribution Upgrade project for $228,000 was originally proposed to be included in rate base. The change in the in-service date, as discussed in the response to URRC.QEC-17(d) was required because the telephone communications continue to remain on the old line. The URRC has removed this project from gross plant in service at year-end 2004/05 and included the balance in CWIP. QEC will be required to provide further detail and justification for projects held in CWIP if and when QEC desires that these projects should be included in gross plant in service and rate base in future GRAs.

The URRC notes that the Baker Lake Distribution Upgrade project for $374,000 is proposed to be completed in the last month of the test period. In the response to URRC.QEC-17(d), QEC stated the new Baker Lake power plant will operate utilizing a Wye system. QEC stated Wye is now the standard distribution system configuration used by utilities because the Wye system is more suited to distribution where there is a combination of three phase and single phase loads; it is more reliable and safer.

In view of the URRC's decision to include the Baker lake power plant in gross plant in service in 2004/05 and the above noted relationship between the new power plant and the Wye distribution system the URRC will include the cost of the Baker Lake distribution system in gross plant in service and rate base in the 2004/05 test year.

QEC indicated the Pond Inlet – Distribution Upgrade ($438,000) completion date has been moved to June 2005. The URRC will deal with the requirement for this project in QEC's next GRA. The URRC will include the cost of this project in CWIP for the purposes of the 2004/05 test year.

QEC indicated in URRC QEC 17 (d) the completion of the Taloyoak – Distribution Upgrade ($173,000) has been delayed until the next test period. There was no further explanation for the delay and whether or not the project is required in the following year. The URRC will therefore not include this project into gross plant in service and rate base. The URRC will include the forecast expenditures associated with this project in CWIP. It is expected that further justification for the cost and the need for the project will be provided in QEC's next GRA.

Energy Utilization Projects

The Iqaluit ($247,000) and Rankin Inlet ($2,356,000) Residual heat projects are not forecast to be included in gross plant in service or rate base for the 2004/05 test year. In fact, the Iqaluit project is not forecast to be included into rate base until the end of the 2006/07 test period, while the Rankin Inlet project is not forecast to be included into rate base until the end of the 2005/06 test period. As noted in the response to URRC.QEC-18(b)(ii), the business case shown in the excel attachment 7A shows a positive Net Present Value in years 6 and 8 respectively. While not disregarding the positive environmental impacts of these projects, the time periods required before the benefits become positive are significant, in the URRC's view. Further, given the apparent lack of forecasting accuracy for in-service dates as demonstrated in this Application and the further lack of detail provided on these projects including the basis for the cost estimates such as the Design Engineering costs, Project Management costs, Materials and Equipment costs, Contingencies and Administration costs, the prudence of these project costs, given the information provided, is questionable. The URRC will include the costs as shown in the Application for inclusion in the closing CWIP balance for this Application, until QEC's next GRA. The URRC expects that QEC will provide significantly more detail showing the basis of the various estimates in its next GRA.

This detail should include the basis for each of the cost estimates, other alternatives examined and the reasons for the contingency and administration amounts included in the estimates. In addition, QEC will have some experience with its "actual" expenditures in comparison to the forecasts in this Application.

General

The URRC notes that the Great Plains Software upgrade project was part of CWIP as of March 31, 2004 with no expenditures forecast for the test period. The project is expected to be completed by March 31, 2005 for inclusion in this test period. There was very little detail provided to support this project. The URRC considers that it is highly unusual that any software upgrade project that was commenced in a prior test period, with no capital expenditures forecast in the current test period would be required to provide service in the 2004/05 test year. There were no reasons provided for the delay in implementation of this project. The URRC notes the corporation uses the Great Plains Software for its accounting records. The URRC is prepared to include the cost of the software in gross plant and rate base for this test period. However, QEC is directed to address the prudence of all software costs included in plant in service at the time of the next GRA.

QEC indicated the Rankin Inlet – Boom Truck ($172,000) will not be purchased during the test period as "…the purchase was intended to be a used unit from another utility." QEC further explained that the other utility decided not to sell the unit. The URRC considers that given that the truck was not purchased, the expenditure is not required in this test period.

Schedule A-2 attached hereto shows the additions to rate base approved by the URRC and the amounts included in CWIP. Based on the foregoing findings the URRC will approve additions to rate base totaling $11.676 million for 2004/05 test year.

4.4 Accumulated Amortization

QEC proposed an accumulated amortization opening balance of $51.733 million for the 2004/05 test year. This balance does not include the future removal and site restoration amount shown separately as a liability in the Corporation's Balance sheet as of March 31, 2003.

The URRC notes the amounts for amortization expense collected by the Corporation through rates in the past included a component for future removal and site restoration. Therefore URRC considers the balance for future removal and site restoration should properly be part of the accumulated amortization balance as of the beginning of the test year for purposes of determining QEC's rate base. Accordingly the URRC will increase the opening balance for accumulated amortization by $16.3 million based on the 2003/04 financial statements closing balance for future removal and site restoration. The URRC has determined the opening balance for accumulated amortization to be $68.533 million.

As noted in Section 4.2 the URRC has adjusted the closing accumulated amortization to include the proceeds on sale of the telecommunications equipment.

4.5 Contributions

The URRC notes that QEC has not included any amount for contributions in the test period. A review of Appendix G, Table 2.4.1, updated for IR No. 2 shows historical contribution additions of $699,000, $122,000 and $493,000 for the last three years.

In response to URRC QEC 21 (a) QEC stated customer contributions were not forecast because the activity that generates customer contributions, i.e., recoverable projects, are on an as requested by the customer basis and result in an increase and corresponding decrease in the rate base. In view of this explanation the URRC will accept a zero forecast of additions to customer contributions in 2004/05 for the purposes of this Report. The URRC expects QEC to forecast and reflect in the filing all expected customer extension costs and corresponding contributions in future GRAs.

4.6 Working Capital

QEC included the following items in the working capital calculation:

Cash operating expenses component of working capital	$2.331 million
Mid year inventory	$7.108 million
Mid Year deferred charges	$0.502 million
Mid year prepaid expenses	$0.404 million

The total of the amounts for the above items was reduced by the amount of mid year customer deposits in the amount of $0.651 million to arrive at the net working capital amount of $9.694 million. QEC's calculation of working capital is shown in Table 2.3.1

QEC stated it has examined the results of the detailed lead/lag study filed by NTPC in its most recent GRA, as approved by the NT PUB, and proposes to use the results of this study for purposes of this GRA. QEC expressed the view that conducting an independent lead-lag study would only add to the costs of preparing and filing this GRA, and not add materially to the accuracy of the results. QEC stated NTPC operations, particularly related to the major operating expense items like procurement and payment for diesel, are comparable to that of QEC.

The URRC notes QEC has adopted the lead lag study results from NTPC's last GRA. QEC's view is that conducting an independent lead-lag study would not necessarily be cost effective. The URRC shares QEC's concerns over the cost of carrying out a lead lag study. However QEC is a new Corporation with its own policies and practices. The QEC's best practice policies regarding meter reading, billing, collection of revenues, payment of fuel expenses, payment of other O&M expenses such as salaries and wages may not necessarily be the same as those of NTPC. In the URRC's view it is appropriate to determine a cash expenses component of working capital based on a lead lag study reflecting QEC's best practice policies regarding management of working capital. Accordingly, QEC is directed to file a lead lag study supporting the cash expense component of working capital at the next

GRA. This study should reflect QEC's best practice policies regarding management of working capital. The URRC will accept the calculation of the cash expense component of working capital based on the NTPC lead lag study for the purpose of this Report. The URRC has adjusted the cash expenses component of working capital to reflect the cash operating expenses approved in this Report as shown in Schedule A-3 attached.

The URRC notes QEC has included an amount of $502,000 for deferred charges in working capital. However, there is no evidence of such a deferred charge amount in QEC's financial statements nor has QEC provided any explanations for inclusion of this item in working capital in 2004/05. Accordingly the URRC will exclude the $502,000 deferred charges from the working capital total.

The URRC has determined QEC's working capital total to be $9.009 million as shown in Schedule A-3 attached.

4.7 Rate Base

The URRC has determined the total rate base to be $94.424 million as shown in Schedule A attached.

5.0 Return on Rate Base

5.1 Capital Structure

QEC submitted in order to maintain the financial integrity of QEC, the Corporation intends to target over the long term, a capital structure of 60/40 debt/equity, and target over the short term, the capital structure of 75/25 debt/equity required by legislation and existing debt covenants. QEC submitted for purposes of this GRA and to assist in achieving the long term capital structure target, the capital structure for the Test Year should be deemed to be 60/40 debt/equity, i.e., equal to the long term capital structure target.

Debt Capital:

As part of the debt component of capital structure QEC included long term debt, short term debt, an amount due to Petroleum Products Division and an amount recorded as owing to NTPC resulting from division on April 1, 2001.

The long term debt consists of a 20 year 6.809% debenture debt of $61 million and a $16 million floating rate capital loan facility. Both of these amounts are categorized as long term debt in QEC's 2003/04 financial statements. QEC also included as an addition to long term debt in 2004/05 an amount of $10 million. With respect to this amount QEC stated:

> "During the Test Year, the Corporation intends to incur additional short-term floating-rate debt of $10.0 million to finance capital asset additions. The Corporation will be reviewing opportunities to convert the total short term floating rate debt to long term fixed rate debt. While short-term rates are presently lower than long-term rates, the Corporation may determine that it is prudent to avoid the risk of an increase in the cost of borrowing by converting the short-term debt to long-term debt." [Application P14, 15]

The URRC considers the corporation's capital structure to consist of permanent capital. In most cases this would include long term debt, no cost capital and equity capital. Short term debt that is used to finance rate base may be also considered permanent capital. However, the URRC does not consider any debt that is incurred for the purpose of financing operating losses or to tide over temporary cash flow difficulties to be part of permanent capital.

The URRC notes QEC's evidence that the $10 million is a short term floating rate debt. There is no definitive evidence as to the corporation's plans for converting the $10 million floating rate debt into a long term loan. Accordingly the URRC will not consider the $10 million loan addition as part of the Corporation's long term debt financing the rate base.

The URRC also does not consider the short term debt, the amount due to Petroleum Products Division and the amount recorded as owing to NTPC resulting from division to be part of the corporation's long term debt financing rate base as these items are essentially short term liabilities. This is confirmed by the treatment of these items in the corporation's financial statements.

The URRC will accept the $61 million debenture debt and the $16 million capital loan facility to be part of the Corporation's long term debt financing the rate base.

Equity Capital:

The Corporation calculated its mid year equity balance as follows for 2004/05:

	$000
Beginning of year	24628
Division cost adjustment	8453
Net loss	-13198
End of Year	19883
Mid Year	22256

The division cost adjustment shown in the above table relates to the proposed reinstatement for ratemaking purposes of certain debt refinancing costs incurred by the Corporation at the time of division effective April 1, 2001. In section 6.3.2, the URRC reduced the amount of the debt financing cost reinstatement by 50%. Accordingly the URRC will reduce the addition to equity capital for division cost adjustment by 50%. Since the division adjustment relates to a prior period the URRC will include the revised division adjustment as part of the opening equity balance for 2004/05.

The URRC notes QEC's assumption that the fuel stabilization fund will be zero at the end of 2004/05 as a result of an infusion of capital from the GN for funding in lieu of fuel rider. The URRC considers this amount to be part of the equity infusion by the shareholder and considers this amount should be included as an addition to the equity capital in 2004/05. Accordingly the URRC has calculated the corporation's mid year equity balance as follows:

	$000
Beginning of year	24628
Division cost adjustment	4227
Sub total	28855
GN Funding in lieu of fuel rider 2004/05	7974
Net loss	-13198
End of Year	23631
Mid Year	26243

The URRC notes the corporation's proposal that the equity ratio should be set at 40%. This equity ratio is significantly higher than the actual and forecast equity ratio of the corporation in 2004/05.

With respect to the 40% equity ratio proposal NWC stated:

> "It is completely contrary to proper regulation to try to reflect higher equity in rates than actually exists. This is because, by definition, if assets can be financed with less equity (meaning less costs) then higher levels of equity are clearly not required to keep the utility operating." [NWC Submission P15]

The URRC considers it is not appropriate to reward the owners with respect to any return on equity capital that has not been contributed. Therefore the URRC will not accept QEC's proposal that the deemed capital structure reflect a 60:40 debt equity ratio. Rather the URRC will establish the capital structure based on the actual and forecast equity balance for 2004/05. The URRC notes, the equity capital as adjusted by the URRC amounts to an equity ratio of about 25% as shown in schedule B attached. The URRC considers this ratio is consistent with the 75:25 debt equity ratio required by legislation and the existing debt covenants. Accordingly, the URRC will approve the debt equity ratio of 75:25 for the purposes of this report.

5.2 Long Term and Short Term Debt Rates

QEC proposed a cost rate of 6.809% for the $61 million debenture debt. This rate is the same as the corresponding coupon rate. QEC also proposed the same 6.809% cost rate for the $16 million floating rate capital loan.

The URRC considers the cost rate for the floating rate capital loan should reflect the true cost of the loan. The interest on the floating loan facility was at bank prime less 25 basis points. Subsequent to March 31, 2004 year end the interest rate increased to bank prime. The corporation paid interest on this loan at 4.5% in 2002/03 and 3.5% in 2003/04 as per the financial statements. Given this information the URRC considers 4% to be an appropriate rate in 2004/05 for the floating rate capital loan. The URRC will determine the cost rate for long term debt using the coupon rate of 6.809% for the debenture debt and 4% for the floating rate capital loan.

5.3 Equity Return

QEC requested a rate of return on equity of 11.5% for 2003/04. QEC cited a number of business risks and financial risks faced by the corporation relative to other Canadian utilities, which it indicated must be considered in setting the rate of return on equity:

QEC identified the following unique business risks facing the corporation:

- Increased business risk due to the wide geographic dispersion of the service area with limited scope for economies of scale
- Increased business risk due to high degree of dependence on the GN for a good portion of the corporation's revenues given the financial constraints facing the GN
- Increased business risk due to severe climatic conditions resulting in greater supply related risks such as outages, higher than forecast operating costs, with no immediate opportunity to access economically viable alternative power sources

- Increased business risk due to the dependence on diesel for generation results in greater potential for environmental damage
- Increased regulatory risk because the responsible minister may not follow the URRC's recommendations respecting rates

QEC indicated due to the thin equity in its capital structure the financial risk resulting from debt leveraging is higher relative to other utilities. QEC submitted for every 1% by which the debt ratio exceeds 60% the return should be increased by 20 basis points.

QEC submitted in the Corporation's view, the return on equity should be reasonably sufficient to assure confidence in the financial viability of the utility. A return on equity is considered necessary to ensure the financial integrity of a rate regulated corporation.

During the community consultations the written submissions from the larger organizations had laid out arguments concerning the rights of the corporation to earn a return on equity.

The URRC took into consideration the comments of the large organizations in its deliberations on return on equity. The following are quoted statements from the written submission for information purposes. The URRC wishes to relay the opinions of these large organizations, so that they can be taken into consideration in the GN's determination of whether it requires QEC to make a profit or not.

The NWC pointed out in its written submission to the URRC dated Nov 27, 2004, page 4, under the heading "Return on Equity":

> "$5.231 million related to a proposed 'Return on Equity', where such return is neither required nor consistent, with proper regulation at the present time (addressed in appendix A) at most, a modest interest coverage target of 1.03 to 1.08 should be targeted over time, consistent with other Crown Utilities that do not have a legislative requirement to earn a commercial-type return."

NWC goes on to say in Appendix A, captioned return on equity and reserves, lines 34 to 36 on page 15:

> "as discussed in detail above, there is no basis for NPC to earn any return on its shareholders equity. However, even if this were required by the Legislation, there is most certainly no requirement for the URRC to recommend that NPC receive a return on equity that is pure fiction."

The ACL Presentation dated Nov 30, 2004, as presented by Mr. Bill Lyall, President, stated on page 6:

> "one also has to ask the question about whether the Government of Nunavut directed QEC in preparing the GRA either in writing or verbally on what the Government wanted. If there were instructions why haven't these instructions been made public? The Auditor General noted in its recommendation to the Legislature concerning the power corporation that the corporation lacked direction from Cabinet on what is expected from them."

The presentation goes on to say on page 8 "nowhere in the Act does it state the QEC has to make money. However, the provision of affordable energy is clearly one of the corporations stated objects."

The Auditor General's report on the Nunavut Power Corporation ending March 31, 2003, item 119, first bullet paragraph states:

> "Does the Government expect the Corporation to make a profit or break even? Is it expected to pay dividends of a certain amount each year, in the same way that the Northwest Territories Power Corporation does? (The Nunavut Power Utilities Act allows for dividends to be paid from time to time)"

The presentation from NTI dated Nov 29, 2004 stated on page 18 as follows:

> "Third, we suggest that all dividend payments to the shareholder be suspended until the Power Corporation can demonstrate that it is operating efficiently and until the Government gives clear direction to the corporation as to what expectations are in respect to the payment of dividends. In the old Public Utilities Act it was a requirement that the Corporation pay dividends to its shareholder. This requirement has been removed in the present Legislation

> and it is important for the Government to provide some direction in this area, as suggested by the Auditor General."

The presentation from the Ikaluktutiak Co-op, presented during the public hearings in Cambridge Bay, states as follows:

> "Lastly, QEC is asking for an additional 9.1 million dollars from its customers to pay the shareholders (the GN) a return on the Rate Base. While this is a normal practice for Utilities in the south, given the fact that the Government has covered QEC's losses in the past and given the impact of higher rates on the economy, an argument can be made that the dividend payment should be suspended until it can be demonstrated that the Corporation is operating efficiently."

The Iqaluit Chamber of Commerce made an oral and written presentation to the URRC in Iqaluit during the community consultations process. At page 3 it noted:

> "we also note that the proposed rate of return is not based on any detailed analysis. In fact the corporation proposes the rate of return should be based on the NWT Power Corporation rate of return, plus a premium because Nunavut power generation is all diesel. The proposed rate of return is arbitrary."

The URRC's finding respecting rate of return on equity is based on the Qulliq Energy Corporation Act, S.N.W.T. 1999 & S.Nu. 2003,c.5,s.2 (QECA) which states under the definitions section "revenue requirements" means the cost of service plus return on equity. Also section 29-1 states: Subject to the direction of the Executive Council, the Corporation shall, from time to time, declare dividends.

QEC's request for return on rate base is as follows:

Return on debt	Totaling	$3,901.7
Return on Equity of 11.5%	Totaling	<u>$5,227.6</u>
	Total	$9,129.3 Thousands

The URRC agrees with QEC that the return on equity should be reasonably sufficient to assure confidence in the financial viability of the utility and preserve its financial integrity. Given that QEC's funded debt is guaranteed by the GN, the URRC considers the capital attraction criterion generally considered in setting rate of return may be given somewhat lower weighting in establishing a rate of return on equity for a Crown corporation such as QEC.

The URRC notes the 9.6% rate of return on equity set by the Alberta Energy and Utilities Board (AEUB) for 2005. The URRC also notes the 75:25 debt equity ratio established herein is lower than the debt equity ratio used by the AEUB in conjunction with the 9.6% rate of return. The URRC notes a 9.6% rate of return on a 75:25 debt equity ratio will provide a coverage ratio of about 1.5 for QEC in 2004/05. While this coverage ratio may be somewhat lower than coverage ratios considered by the EUB under the capital attraction and financial integrity standards, in the URRC's view, given the relatively lower weighting given to the capital attraction standard in this case the 1.5 coverage is adequate to satisfy the financial integrity standard for QEC taking into account its business, financial and regulatory risks as well as the requirements of existing debt covenants. Accordingly the URRC will recommend approval of a 9.6% rate of return on equity for QEC in 2004/05.

The URRC is cognizant of the short term debt reflected in the corporation's financial statements. In the URRC's view short term debt resulting from operating losses or the restructuring of the corporation should not be a burden on the rate payers of QEC. The URRC considers any concerns over the financial integrity and continued financial health of the corporation stemming from such debt should be addressed by the owners of the Corporation outside of the ratemaking process.

The URRC recommends, as per Schedule B.

Long Term Debt 6.2%	Totaling	$4,355.6
Return on Equity 9.6%	Totaling	$2,289.1
	Total	$6,644.7 Thousands

This is considered a fair return that will preserve the financial integrity of the corporation and is allowed under the Qulliq Energy Corporation Act.

The final decision whether QEC should be profit making or not rests with the GN. The above recommended figures of $6.645 million for return on rate base and equity would form part of the rate increase discussed in this Report, if accepted by the GN.

5.4 Total Return

The URRC has determined the total return on rate base to be $6.645 million as shown in Schedule B attached.

6.0 Revenue Requirement

6.1 Operations and Maintenance Expense (O & M)

QEC forecast O & M of $61,341,000. [Appendix F, Table 1.5.1C] These expenses included Fuel and Lubricants in the amount of $27,578,000, Salaries and Wages in the amount of $17,316,000, Supplies and Services expense in the amount of $12,936,000 and Travel and Accommodation expense in the amount of $3,511,000.

6.1.1 Fuel and Lubricant expense

QEC forecast fuel and lubricants expense of $27.578 million for 2004/05. According to QEC, the average per liter fuel price has increased by 41.4% since the 1997/98 GRA. [Application, P. 9] The Corporation is applying for reinstatement of the Rate Stabilization Fund so that increases or decreases in the cost of diesel fuel would be flowed through to customers in a timely manner. Further, the Corporation requested URRC approval to continue with the Rate Stabilization Fund after March 31, 2005 [Application P. 65 Section 8.3]

NWC submitted that it was not possible to conduct a detailed review of the reasonableness of QEC's generation forecast or proposed fuel price increases. NWC further submitted that the Corporation's plant efficiencies were suspect and that it seemed reasonable to consider at least comparable efficiency gains to that observed in the NTPC forecast plant efficiencies for communities. Applying similar plant efficiency ratings to QEC plant would result in a reduction in fuel costs of approximately $1.623 million. NWC submitted that to address uncertainties associated with the level of fuel prices and the generation forecast provided by the Corporation, any increase recommended at the present time should be only on an interim, refundable basis, subject to further testing within the next 12 months.

Ikaluktutiak Co-op submitted that there were two categories of costs, controllable and non-controllable. Regarding controllable costs, Ikaluktutiak Co-op viewed that increased fuel costs were partially offset by new revenues and this was not recognized by the Corporation. The impact of plant efficiency had not been appropriately addressed in the Application, particularly for a newer plant.

QEC did not provide a detailed calculation of fuel costs as part of its application or in response to information requests. However, QEC provided a schedule showing the fuel efficiencies reflected in existing rates, the fuel efficiencies budgeted for 2004/05 and the actual fuel efficiencies for 2003/04. This information, provided as a part response to an undertaking given to the URRC during the technical meeting, is reflected in Schedule D-1 attached.

The URRC notes from Schedule D-1 attached that the 2004/05 budgeted average overall fuel efficiency is higher than that reflected in existing rates. The URRC also notes the overall average fuel efficiency reflected in the 2003/04 actual results is marginally higher than the budgeted number for 2004/05. The URRC notes the Corporation added new plant in the communities of Qikiqtarjuaq, Pangnirtung and Kugaaruk in April, June and October 2004 respectively. The plant additions in Arviat and Baker Lake are expected to occur in March 2005.

Given the foregoing new plant additions, the URRC considers it appropriate to recognize any potential improvement in fuel efficiencies. The URRC notes some plant additions would only occur towards 2004/05 year end whereas other additions would occur during the year. The URRC considers the plant efficiencies resulting from 2004/05 additions will be fully in place for the fiscal year beginning April 1, 2005. The URRC notes the Corporation has not provided any evidence respecting the impact of new plant on fuel efficiencies for the new additions except for the Baker Lake addition. For the Baker Lake Addition QEC states:

> "It would be reasonable to forecast that the new Baker Lake plant efficiency will exceed that of the old Baker Lake plant. Based on the comparability of the engine line ups to the plant in Pangnirtung, the new Baker Lake plant is expected to achieve an efficiency of 3.68 rather than the efficiency of 3.37 noted for the year ended March 31, 2004." URRC QEC 36 (b)]

On balance the URRC considers it appropriate to increase the 2003/04 actual fuel efficiencies for each of the communities which added new plant in 2004/05 by 2% to arrive at the URRC recommended fuel efficiencies for these communities. For Baker Lake the URRC will use the revised fuel efficiency recommended by QEC.

The URRC's calculation of fuel costs is shown in Schedule D attached hereto. Schedule D reflects QEC's forecasts of fuel prices for 2004/05 and the URRC recommended fuel efficiencies. QEC did not provide an indication of the amount included in proposed fuel costs for lube oil drum expense and other fuel. The URRC has estimated the cost of this item at 5% of the diesel plant fuel costs for the purposes of this Report. Based on the foregoing the URRC will approve fuel and lubricant expenses of $26.498 million for the purposes of this Report.

The URRC notes from QEC's application at Appendix M Table 10.1.1 the proposed line losses to be 6.8% on sales and station service to be 4.3% of sales. In comparison to the line losses and station service percentages of 5.6% and 4.6% forecast for 2004/05 in the unfiled GRA in Table A9.2.2 of that GRA, the line loss percent appears to have increased and the station service percent appears to have decreased somewhat.

The URRC has no further information regarding the reasonableness of the proposed line loss and station service percentages in these proceedings. However, the URRC does not consider the proposed percentages to be not outside the range of reasonableness. Accordingly, the URRC will accept the proposed line loss and station service percentages for the purposes of this Report.

6.1.2 Salaries and Wages Expense

QEC forecast Salaries and Wages for the test period of $17,316,000. Salaries and Wages expenses comprise approximately 22.4% of the forecast revenue requirement. QEC explained at Page 11 of its Application that "The Corporation's employees operate and maintain twenty-six (26) diesel generation power plants in 25 communities, provide mechanical, electrical and line maintenance from three regional centers, and administer the Corporation's business activities from offices in Iqaluit and Baker Lake." Further:

> "The average hourly rate has increased since the GRA that established the existing Rates. Two collective agreements will have expired between the time the Corporation's current rates came into effect and April 1, 2005 when the Corporation's new rates are to come into effect.
>
> At March 31, 2004, the Corporation employed 139 full time employees, of which, 71 or 51.1% were Nunavut Land Claim Beneficiaries.
>
> Eighty-two percent (82.0%) or 114 of the Corporation's full time employees are members of the Nunavut Employees Union (NEU) at March 31, 2004. The collective agreement between the Corporation and the NEU presently in effect expires December 31, 2004.
>
> Eighteen percent (18.0%) or 25 of the Corporation's employees were Excluded Employees at March 31, 2004. The Corporation has adapted the Government of Nunavut Excluded Employee Handbook to replace the Northwest Territories Power Corporation Excluded Employee Handbook. This document describes the terms and conditions of employment with the Corporation for the excluded or non-union employees.
>
> Appendix F, Table 5.1.3 lists salaries and wage expenditures by region and plant for the Test Year."

At Page 52, Section 6.2.2, QEC further explained:

> "Growth, inflation and Division have increased the overall cost of operating the Corporation's utility operations in Nunavut since the last GRA. The creation of a head office in Baker Lake and an administrative office in Iqaluit has given rise to administrative costs previously incurred by NTPC in Hay River, NT. The Corporation employed 25 people in Baker Lake as of March 31, 2004. All of these employees were hired in preparation for or since Division from NTPC."

While NWC did not specifically comment about Salaries and Wages, on non-fuel O & M costs, they commented in their summary that non-fuel O & M costs are proposed "…at a level more than $11 million above any reasonable measure. Back in 1997/98, Nunavut operations ran on $18 million for operating costs. By 2001/02, NPC's first year, this was up to $25 million, the next year it was $28 million, and two years later, NPC says they need almost $34 million. All of this despite the Auditor General saying they need to control costs and operate more efficiently. This type of cost increase should not be rewarded by higher rates."

Commencing at page 37 of its report, NWC provided tables showing Non-fuel O & M by community. Table C-7 compares the increases in Non-Fuel O & M expense for 2001/02 actuals, 2002/03 (per the NPC 2002/03 financial statements) to the 2004/05 forecast increases for Salaries and Wages, Supplies and Services and Travel and Accommodation. NWC concluded at Page 35 that:

> "The non-fuel O & M costs proposed by NPC reflect an immense and continuing increase to the costs to run the utility. In particular, the costs proposed as required are massively in excess of what was required by NTPC to run the utility in 1997/98. These cost increases are well above the types of increases approved for NTPC after a full review of its operations and forecasts, and are well in excess of any reasonable measure of inflation or escalation for the years in operation. In addition, the cost increases reflect a continuing trend despite the expectation that, once established, the

> Corporation would be able to stabilize its costs, and despite continuing strong caution being expressed by the Auditor General for Canada regarding 'inadequate control over spending' and 'significant weaknesses in financial management practices.'"

Ikaluktutiak Co-op submitted that there was no justification for any new positions nor for the allocation of positions after the Division. Ikaluktutiak Co-op pointed out that there were 88 positions at time of Division when compared to the 139 today. The average salary of $125,000 per year was excessive. Given that the GN made decisions on the decentralized structure, the GN should bear some responsibility for the increased cost. The information provided in the GRA did not allow for a determination of the amount of duplication that exists between various levels of administration. An independent operational review is required to be conducted to ensure that the Corporation has "…the skilled people in place to do the job." [P 10 of submission]

Katujjijiit Development Corporation stated on the second page of their presentation that:

> "There are concerns about widespread personal and unofficial use of company vehicles by staff from management down to linemen. There are concerns about excessive bonuses paid to the same senior managers that led the corporation into its current financial crisis. There is little faith in the general competence of the staff at the QEC head offices in Baker Lake. Many question why the public should pay for such excesses and for the results of years of mismanagement. These questions need to be answered before there will be general support for the sort of well planned and reasonable rate increase that is needed to make the Corporation viable."

The City of Iqaluit commented on the first page of their submission that: "The utility has taken no steps to get its financial house in order before asking the public for yet another handout." Further the City of Iqaluit stated:

> "From the outset, this has been a deeply flawed program. Before imposing yet another financial hardship on an already over-burdened population, the Government of Nunavut, and Qulliq Energy Corporation should be doing everything within their powers to curb spending, improve efficiency and develop alternatives to costly diesel fuel imports.

> Once they have taken these steps and demonstrated their commitment to cutting costs and responsibly managing Qulliq, only then should they be permitted to ask for permission to raise their rates."

The City of Iqaluit further stated that "The GN should be hiring experienced leaders who have the ability to develop a long-term business plan that will lead to the continued viability of Qulliq Energy Corp. The public purse is not bottomless, and people's pockets are pretty much empty."

The City of Iqaluit also commented that QEC needed to be accountable and needed to answer a number of questions including: providing clear company goals in requesting the rate increase, showing a need for the money to finance year-to-year operating expenses, attempting to build a reserve fund and providing further information on whether they want to recover their deficit. In the City of Iqaluit's view, neither QEC nor the GN had provided enough information to satisfy the City.

The City of Iqaluit had concerns over the amount of deficit that QEC had and how much money would be transferred to QEC this year.

In conclusion, the City of Iqaluit stated that:

> "This funding crisis requires responsible crisis management, not short-term fixes that will only create further long-term problems. It is time for Qulliq Energy Corporation, and the Government of Nunavut, to take clear, responsible action to organize their own house, reduce costs, and rein in expenses before returning to the public and asking for unfair, and irresponsible increases that threaten to cripple economic growth and self-sufficiency in our Territory."

A number of individuals, corporations and municipalities also expressed concerns about the de-centralization effort that moved the head office to Baker Lake and increased costs.

Mr. Bill Lyall, president of ACL provided an extensive submission. His submission briefly reviewed the history of the Co-ops which included the financial situation in the early 1980s faced by the Co-ops. Costs were required to be reduced and in order to meet the challenge, the ACL took major steps to reduce costs and improve efficiency. These decisions "…helped reduce our operating costs by more than one-third. Tough decisions had to be made to provide for our survival…and they were." ACL further stated at Pages 8 - 9 of its presentation that: "It is our contention that the Power Corporation has let its costs get totally out of line. The application provides no evidence of measures being adopted to reduce costs or to enable the Corporation to become more efficient."

In summary at Page 23 of its submission, ACL stated:

> "In the interest of reducing costs to all customers we are recommending that an independent commission be established to examine all aspects of the Corporation's operation with the view of reducing the cost of service for delivering power across Nunavut. We would be prepared to provide a representative to sit on the Commission. Further, until such a review is undertaken, we are recommending that further consideration of the one-rate proposal and base rate increases be deferred."

NorthwesTel submitted at Page 4 of its submission that it had concerns that "…QEC has no incentives to ensure that it achieve productivity improvements. There exists no mechanism or safeguards to ensure the QEC is striving to be as efficient as possible. The Government of Nunavut should impose on QEC a requirement for the Corporation to achieve minimum efficiency gains on expenses offset by legitimate cost increases associated with inflation and demand growth factors."

The Iqaluit Chamber of Commerce stated at Page 3 of its presentation that there was doubt on the quality of QEC's GRA. The Iqaluit Chamber of Commerce stated: "To add further doubts, we understand that the power corporation has not responded to some interrogatories – Questions asked by the experts you retained, even though deadlines were set…timeframes that are critical if the URRC is to meet its mandated responsibilities."

Mr. Frank Pearce of Iqaluit commented at page 4 of his submission that a thorough study was required to be conducted on the entire Nunavut Power Corporation operations and plans to "…establish acceptable operating benchmarks and a viable means to monitor these benchmarks included acceptable financial reporting and administrative practices. Part of this study will be to determine the level of responsibility that lies with the government(s) and that which must be borne by the public."

A number of parties referenced the Auditor General's reports and the concerns that were raised in that report. The URRC has provided a separate section that discusses the issues raised in the Auditor General's report.

The URRC understands and empathizes with many of the frustrations of the parties as it relates to QEC's salaries and wages and other operating costs. However, QEC appears to be making efforts to turn the utility around. New management has been hired. URRC.QEC-9 provided detail about the makeup of the QEC senior management including an organization chart of employees to mid-level management. URRC.QEC-10 provided QEC's code of accounts. URRC.QEC-11 provided its audited financial statement for the year-ending March 31, 2003, with March 31, 2002 comparatives as well as the March 31, 2004 financial statements and pro-forma March 31, 2005 financial statements were provided.

URRC.QEC-12(c) provided further details on the initiatives for both revenue increases and cost reductions that QEC management has undertaken. With respect to revenues, QEC has been having continuous and ongoing discussions with GN to re-institute the fuel stabilization fund.

On the cost side, QEC stated that:"

> During fiscal 2003/04 the Corporation took several steps to control operating and capital expenditures including:
>
> - Changes in executive management;

- Changes and reductions in senior management;
- Collection and cancellation of corporate credit cards;
- Removal of payment authority and bank accounts from regional offices;
- Consolidation and reduction in expenditure and commitment authorities;
- Deferral of plant operator and assistant operator training and related travel;
- Deferral of capital expenditures; and
- Rescinding of the at risk pay policy (bonuses).

QEC also provided additional information in URRC.QEC-9(d) on some of the changes in management positions prior to April 1, 2005.

Parties presenting their views regarding overall costs of the Corporation felt that the decentralization policy of the Government of Nunavut that was imposed on the Corporation has added significantly to the costs of running the Utility. Parties submitted the Government of Nunavut should review this issue as it has significant cost implications for QEC's customers and the Government of Nunavut as a whole. Parties expressed the view that the Government of Nunavut had to decide if the Corporation was a corporation or a government department and whether they wanted reliable least cost power or if the Government of Nunavut was willing to pay for the higher costs associated with political decisions. ICOC stated in its presentation on page 4

> "In our previous submission to your Council, the Iqaluit Chamber of Commerce noted that many of the costly initiatives undertaken by the Qulliq Energy Corporation were driven by political decisions and that these costs are therefore appropriately borne by the Government shareholder. This is why we now recommend that the position of the utility's only shareholder, the Government of Nunavut – on these and other important issues – must be made clear before a new rate regime is recommended. The public consultation process to date, which has had partial input from a sample of only about twenty per cent of the corporation's customer base, is incomplete."

Through the information request process, the URRC requested information on the salaries and wages per FTE from 2001/02 to present, recent union settlements and their impact compared to the forecast, forecast vacancy rates and further details on staff being added at headquarters.

Unfortunately, much of that information was not provided on a timely basis and even the information provided was not in a form that allowed easy comparison of salaries and wages from year to year by component as requested by the URRC in its information requests.

QEC is encouraged to provide more detailed information in future filings and provide responses to information requests on a more timely basis to allow the URRC and all parties to more fully evaluate QEC's application.

URRC notes salaries and wages have increased significantly in each year since 2000/01, the last year of NTPC's Nunavut operations before division. The annual changes in the level of salaries and wages are shown below:

	Salaries & Wages $000	Bonus Paid $000	Sal & Wages Net of Bonus $000	Annual Inc/Dec $000	Annual Inc/Dec %
2000/01	11730		11730		
2001/02	13028	301	12727	997	8.5%
2002/03	14656	370	14286	1559	12.2%
2003/04	17785		17785	3499	24.5%
2004/05	17316		17316	-469	-2.6%

QEC states the $5.6 million increase since division is due primarily to executive, senior management, engineering, finance, human resource, information technology and clerical office staff hired in anticipation of, or as a result of and subsequent to division.

The URRC notes most of this $5.6 million increase occurred in 2002/03 and 2003/04. The 2003/04 QEC Management Discussion and Analysis (MD&A) indicates the increase in salaries and wages from 2002/03 to 2003/04 reflects the 3% cost of living increase prescribed in the collective agreement for union employees, a 3.5% cost of living increase for non union or excluded employees, merit increases for eligible employees resulting from positive performance appraisals, and severance payments relating to turnover in senior management positions including the former president and chief executive officer, vice-president operations, vice-president finance and director of engineering. The URRC considers the severance payments paid to senior management in 2003/04 should not be reflected in the base level of salaries and wages for 2004/05.

The 2003/04 MD&A indicates the number of beneficiary employees increased by 2 from 2002/03 to 2003/04 and number of non beneficiary employees increased by 8 during the same period. Based on prior year employee additions and associated costs, the URRC estimates the salaries and wages increase due to new employee additions to be about $1 million from 2002/03 to 2003/04.

The URRC notes from the 2003/04 MD&A, page 21, that the overall number of employees increased from 135 in 2001/02 to 146 in 2002/03 and to 156 in 2003/04.However, level of overtime included in salaries and wages is steadily increasing in spite of the staff additions as follows:

	Overtime $000
2001/02	1077
2002/03	1346
2003/04	1846
2004/05	2363

The URRC considers the overtime increases to be not justified in light of the increase in FTEs in each year from 2001/02. Further the URRC notes the forecast level of overtime for 2004/05 constitutes about 24% of regular salaries and wages. The URRC considers this level of overtime to be excessive. Accordingly, the URRC considers the overtime increases since 2001/02 should not be included in the base level of salaries and wages for 2004/05.

Given the foregoing considerations the URRC has estimated the salaries and wages level for 2004/05 as follows:

	$000
2001/02 Salaries and Wages Excluding bonus	12727
2002/03 Salaries and Wages Excluding bonus	14286
2002/03 adjusted to 2001/02 overtime level	14017
Cost of Living adjustment at 3.25%	14473
Additional staff in 2003/04	1000
Adjusted 2003/04 base Salaries &Wages	15473
2004/05 Estimated Salaries & Wages Including Cost of Living Increase at 3.25%	15975

Subject to further comments in Section 12.1 of this report on salaries and wages and any further information provided by QEC as follow-up to this report, the URRC will include, on a preliminary basis, an amount of $16.0 million ($15.975 million rounded) in revenue requirement for salaries and wages for 2004/05. As shown in the above table the URRC's estimate of salaries and wages in 2004/05 primarily reflects the adjustment of the QEC proposed amount of $17.3 million for the increase in the cost of overtime since 2001/02. The URRC notes these estimates are based on the corporation's proposed FTE levels. The URRC did not have sufficient evidence to evaluate whether or not the FTE levels proposed in the application are at a prudent level consistent with sound utility management practice.

Throughout the hearings numerous parties requested to have an independent review of the overall operations of the Power Corporation. The URRC agrees with these requests and recommends that the Government of Nunavut issue a request for proposals to qualified Engineering firms or consulting firms that are knowledgeable in the operations and management of a Utility and Utility Regulation, to conduct a review of the corporation with the objective of streamlining the power corporation into a well run utility and regaining the confidence of its customers and stakeholders.

The URRC recommends this review be completed in a timely manner to allow QEC to respond meaningfully to the URRC directions set out in Section 12.1 of this Report. Since the review concerns matters resulting from past decisions with respect to staffing and management the costs associated with the review should not be recoverable from the customers of the Corporation in the normal course.

6.1.3 Supplies and Services Expense

QEC forecast Supplies and Services expense for the test period of $12,936,000. Supplies and Services expense comprise approximately 16.8% of the forecast revenue requirement. QEC explained at Page 12 of the Application that engine overhauls was the most expensive component of Supplies and Services expense for its 88 diesel engines and 26 plants as at March 31, 2004. The timing of engine overhauls was usually based on manufacturer's recommended maintenance schedule but unscheduled overhauls were sometimes required.

The second most significant expenditure in Supplies and Services expense was housing. The Corporation submitted that adequate housing was required in order to provide safe and reliable service, adequate housing in the various communities was not always available and adequate housing had a positive effect on recruitment and retention of employees. QEC housing consisted of a combination of owned and leased units. QEC intends on increasing the number of owned units.

The remainder of the components of Supplies and Services expense relates to operating expenses in plant, electrical, mechanical and distribution maintenance as well as engineering, financial, human resources and information technology administration.

Ikaluktutiak Co-op submitted that the Supplies and Services expense had grown significantly since Division and that they were not currently justifiable. They claimed that almost 75% of the Supplies and Services budget is spent by Headquarters and Regional Administration.

The URRC requested significant information on the Supplies and Services component of revenue requirement as part of the information request process. URRC.QEC-43 indicates that the frequency of engine overhauls is increasing "…as loads increase and overhaul expenditures continue to increase as the component costs; part, freight and wages increase." The increase in housing costs for the Supplies and Services category was increasing because of "…increased numbers of employees located in Nunavut."

Notwithstanding, the above explanations, Information Request URRC.QEC-29 asked significantly more information on the breakout of the engine overhaul from housing components of the Supplies and Services category of costs, the specific basis for the forecast, actuals from prior years with explanations for deviations and further details on the historical level of unscheduled overhauls. QEC could not provide the requested information with respect to prior year actuals in the requested format nor did it provide explanations for changes in supplies and services from year to year by component.

The Supplies and Services expense for years 2001/02 to 2004/05 are as follows:

2002 $9,314,000;
2003 $10,831,000;
2004 $10,694,000;
2005 $12,936,000 (forecast for test period)

The URRC considers that QEC has not provided sufficient justification to justify the proposed level of Supplies and Services costs. There are still many components of the forecast where further information is needed including the historical breakdown of the engine overhaul costs versus housing costs, explanations for deviations, rationale for increased housing costs in light of the move to purchase or capitalize housing versus leasing (operating cost). As part of the explanation for the changes between 2002 and 2003, in its annual report, QEC explained that while the costs had risen, the use of contractors and consultants had been reduced due to increased staffing levels.

The URRC notes QEC's statement in response to URRC QEC 29 (j) that between division and July 1, 2004, the Corporation provided an annual housing allowance of $4200 per employee to all employees. Beginning on July 1, 2004**,** the Corporation began phasing out the housing allowance for any employee who was supplied housing by NPC. For these employees the housing allowance has been reduced to $2800 for the period from July 1, 2004 to June 30, 2005. QEC did not quantify the impact of the above change on the 2004/05 forecast.

In the absence of adequate support for the level of supplies and services expense forecast for 2004/05 the URRC will estimate the 2004/05 levels having regard to the actual expense in 2003/04. Subject to further comments in Section 12.1 of this report on Supplies and Services and further information provided by QEC as follow-up to this report, the URRC will allow an increase from the 2004 Supplies and Services expense, of 5% for 2004/05. Accordingly, for the purposes of this Report the URRC has determined on a preliminary basis, the supplies and services expense for 2004/05 to be $11.225 million.

6.1.4 Travel and Accommodation Expense

QEC forecast Travel and Accommodation expense for the test period of $3,511,000. Travel and Accommodation expense comprise approximately 4.5% of the forecast revenue requirement. Travel and Accommodations expenses related to capital items are capitalized and amortized. Travel and Accommodations expenses include costs associated with scheduled and emergency maintenance, medical, training and administration.

Ikaluktutiak Co-op submitted that if "…the travel budget was divided equally between all employees, each employee would have $25,000 to spend on travel and accommodation."

The URRC requested significant information on the Travel and Accommodation component of revenue requirement as part of the information request process. URRC.QEC-43 indicates that the costs for travel, including business, medical and training have increased as a result of "…increased numbers of employees, a separate Board of Directors and a decentralized office."

Notwithstanding the above explanation, Information Request URRC.QEC-30 also asked significantly more information on the breakout of the actual and forecast costs for each of the categories of scheduled maintenance, emergency maintenance, medical, training and administration. Information was also requested on the amounts of the above costs that were capitalized for each of the years from 2001/02 to 2004/05 forecast. The information requested was not provided in the format requested. QEC did not also provide detailed explanations and quantification of changes from year to year in the various categories of expenses included in travel and accommodation expense.

In response to URRC QEC 30 (b) QEC stated it pays 100% of the medical travel costs of its employees and their dependents. Medical travel cost is forecast using one trip per employee to the nearest southern destination, i.e., Edmonton, Winnipeg or Ottawa for Kitikmeot, Kivalliq and Qikiqtaaluq respectively. QEC stated interim information for the forecast year indicates the decreased level of travel expenditures disclosed in the 2003/04 audited financial statements versus 2002/03, will continue into the forecast year 2004/05.

The Travel and Accommodation expense for years 2001/02 to 2004/05 are as follows:

2002	$2,653,000;
2003	$2,896,000;
2004	$2,559,000;
2005	$3,511,000 (forecast for test period)

The URRC considers that QEC has not provided sufficient justification to justify the proposed level of Travel and Accommodation costs. There are still many components of the forecast where further information is needed including significantly more information on the breakout of the actual and forecast costs for each of the categories of scheduled maintenance, emergency maintenance, medical, training and administration. QEC explained in its annual report at Page 20 that the Corporation "…has been successful in recruiting to the extent that there is no longer a reliance on contractors and consultants to fulfill full time employee responsibilities." The URRC would expect as there are less contractors and consultants, all things being equal, the Travel and Accommodation expenses should be lower. The URRC also recognizes that with de-centralization, there is an expectation that Travel and Accommodation expenses will increase. However, de-centralization, to some extent occurred in 2004 and the Travel and Accommodation expenditures decreased. The URRC notes QEC's statement that the decreased level of travel expenditures disclosed in the 2003/04 audited financial statements versus 2002/03, will continue into the forecast year 2004/05.

Subject to further comments in Section 12.1 of this report on Travel and Accommodation expense and further information provided by QEC as follow-up to this report, the URRC will allow an increase from the 2004 Travel and Accommodation expense of 5% for 2005. As noted in Section 12.1, the URRC expects further information from QEC on the Travel and Accommodation expense including the medical travel expense forecast in light of any contributory responsibility on the part of the territorial or Federal government. The URRC has determined the travel and accommodation expense, on a preliminary basis, to be $2.7 million for the purposes of this Report.

6.2 Reserves

6.2.1 Reserve for Injuries and Damages

QEC forecast an addition to the reserve for injuries and damages for the test period of $150,000. When Division occurred, there was a balance of $300,000 in this reserve that was transferred to QEC. There was no regulatory authority to continue use of the account and thus the amount was written off for financial reporting purposes against retained earnings at March 31, 2002. For the purposes of this Application, QEC reinstated the $300,000 opening balance transferred to QEC at division.

QEC indicated the reserve for injuries and damages account will provide for payments with respect to:

- Uninsured losses
- Deductible portion of insured losses
- Insurance premium increases

The Corporation proposed that any increases from the base level of premiums forecast in this GRA will be included for recovery in the future from customers. The base level of premiums for the Test Year was forecast at $0.7 million. QEC proposed, in the future, if it chooses to increase deductibles or self insure specific assets in order to reduce insurance premiums, the reserve will be increased by an annual appropriation equal to the insurance premiums avoided. QEC stated consistent with industry practice, the reserve has been expanded to include other injuries and damages.

The URRC notes the parameters outlined by the corporation for the reserve for injuries and damages and considers them to reasonable. However, the URRC notes QEC's statement in response to URRC QEC 33 (a) that the corporation does not intend to limit the application of the reserve to sudden and accidental, high impact low probability events. The URRC considers the reserve for injuries and damages should not be used to charge expenses that are of a maintenance nature as uninsured losses. There should be rules to determine what types of expenses are charged to the reserve. The URRC considers losses resulting from sudden and accidental, high impact low probability events are the types of expenses normally allowed to be charged to the reserve as uninsured losses. The URRC directs QEC to adopt the above definition for uninsured losses for the purposes of recording uninsured losses.

The URRC's calculation of the reserve for injuries and damages balance is shown in Schedule B-1 attached. Since this reserve represents customer money the URRC will include the mid year balance of this account in capital structure for the purposes of determining the return on rate base.

6.2.2 Rate Hearing Reserve

QEC forecast an addition to the Rate Hearing reserve for the test period of $100,000. When Division occurred, there was a balance of $300,000 that was transferred to QEC. There was no regulatory authority to continue use of the account and thus the amount was written off for financial reporting purposes against retained earnings at March 31, 2002.
For the purposes of this Application, QEC reinstated the $300,000 opening balance transferred to QEC at division.

The URRC notes the corporation incurred external hearing costs to date of $163,692. [URRC QEC 34] In consideration of external hearing costs the URRC will allow an estimated $100,000 to be added to the hearing reserve and a corresponding amount to be expensed against the reserve on a forecast basis for 2004/05. The Corporation is directed to record all external hearing costs incurred with respect to these proceedings against the reserve when they become known.

The URRC's calculation of the hearing reserve balance is shown in Schedule B-1 attached. Since the hearing reserve represents customer money the URRC will include the mid year balance of this account in capital structure for the purposes of determining the return on rate base.

6.3 Amortization

6.3.1 Capital Asset Amortization

QEC forecast net Capital Asset Amortization for the test period of $6,327,490 (i.e. $6,405,414 gross amortization expense less $77,924 insurance amortization) as shown on lines 45 and 47 of Appendix I, Schedule 4.3.1 and at line 13 of Table 1.5.1 both from the response to Information Request No. 3. The composite gross amortization rate of 4.01% is based on the $6,327,490 of forecast amortization expense divided by the forecast March 31, 2004 opening gross plant in service of $157,810,977 shown in Appendix I, Schedule 4.3.1, line 60. Net Capital Asset amortization comprises approximately 7.7% (8.2% on a gross basis) of the forecast revenue requirement. The Corporation's amortization rates are based on the results of a Negotiated Settlement Agreement between NTPC and its customers in NTPC's 2001/03 GRA. [Section 4.2 of Application with detail included as part of Attachment 8A of the Unfiled 2001/02 GRA which was included in response to URRC.QEC.15(c) in Information Request No. 2] The estimate of net salvage included in the amortization rates is based on NTPC's estimate of the costs to retire their diesel plant as well as a review of net salvage percents used by other electric utilities. QEC also expressed the view [Page 42 of Application] that unless circumstances exist to warrant the undertaking of an amortization study, the costs incurred to conduct such a study would not be justified given the comparability of the NTPC assets and the most recent amortization study for that utility.

NWC submitted [pp 38 – 39 of the NWC submission] that there was no reasonable basis for NPC (QEC) to propose that it adjust its amortization rates based on the results of an amortization study of another utility. Specifically, the amortization rate of 20% (i.e. 5 years) for wind assets used by NTPC was based on minimal experience and did not take into account NPC's (QEC's) proposed plans for wind generation as a commercially viable operation, which would require wind generation assets to last more in the range of 20 years versus 5 years. NWC submitted that on that basis alone, the amortization should be reduced by $100,000. Further, NWC submitted that NPC (QEC) should consider completing its own amortization study.

The URRC is prepared to accept for the purposes of this rate application the proposed amortization rates recommended by QEC with the exception of Wind Turbine rate of 20% proposed by QEC. The URRC agrees with NWC's comments that the life of these assets would better match an economic life in the 20 year range. Applying this life to the plant balance shown in Table 4.3.1 to the Wind Turbine assets results in a reduction in amortization expense of $150,390.

The URRC notes that QEC calculated its amortization expense on the basis of the March 31, 2004 plant balance and has effectively not requested amortization expense on assets forecast to be placed in service during the test period. The URRC is prepared to allow for amortization expense on one half of the URRC recommended additions to gross plant in service times the composite amortization rate of 4.01%. This treatment is consistent with the mid-year concept used by QEC in this application. Based on the $11,676,000 of capital additions recommended for allowance in rate base as per the Rate Base schedule, the URRC has included an additional amount of one half of $11,194,000 times 4.01% as estimated amortization expense for assets forecast to be put in service, or an additional $234,000 for the test year. The URRC expects that QEC will include amortization expense assuming its forecast assets will be in service, on average, on a mid-year basis for its next GRA.

While the URRC agrees with QEC that there would be some costs involved in conducting an amortization study, the URRC considers that QEC should have an amortization study done within the next two years. While the asset lives may be somewhat similar between NTPC and QEC, appropriate amortization rates should be established for this new utility. In the URRC's view, the cost of an amortization study will be a worthwhile expenditure for QEC and its customers, particularly when there appears to be an expectation by QEC that the net salvage included in the amortization rates may not be sufficient to recover future removal and site restoration. The URRC directs that QEC conduct an amortization study prior to the end of March 31, 2006 for presentation in the next GRA. The amortization study should specifically include factors that are common to QEC's operating territory in the determination of the proposed lives and net salvage.

The URRC notes that QEC has not included an amount for amortization of differences between the theoretical and actual accumulated amortization. This is on the basis that NTPC did not ask for the same in its last application. The URRC considers that there is likely sufficient difference between the NTPC and QEC with respect to differences between the calculation of the amounts of amortization of differences between theoretical and actual accumulated amortization, to warrant a separate calculation for QEC. The URRC recommends that QEC carry out that calculation for inclusion in its next GRA annual amortization expense calculations.

The URRC notes that QEC has included $15,861,786 shown at line 58 of Table 4.3.1 for "Fully Amortized Assets". The URRC is unsure why this amount is shown. While the URRC recognizes that fully depreciated assets will not have impact on rate base, if the assets are no longer used or required to be used, then they should be retired and not included in gross plant in service. The URRC notes that QEC has applied the average service life procedure for amortization of assets. The application of this procedure to the calculation of the amortization rates means that some assets will recover more than their original cost over their life and some will recover less. In total, the asset costs of the account will be appropriately recovered over the average service life. An assumption that assets are fully depreciated cannot be verified using the average service life method, for the above reasons. The URRC recommends that for QEC's next GRA, it provide a full explanation of why the $15,861,786 is shown as "Fully Amortized Assets" and whether these assets should continue to be included in gross plant in service or should be retired.

The response to URRC.QEC-17 (d) and (e) states that for certain assets there were no retirements because the assets are fully amortized. For the same reasons noted above, the URRC considers that when assets are no longer used or required to be used, they should not be included in gross plant in service. The URRC will not adjust the opening balance gross plant in service, but expects QEC will make whatever adjustments are required, with a full explanation for its next GRA.

The response to URRC.QEC-15(g) states that "During the fiscal years ended March 31, 2002, 2003, and 2004, the only assets disposed of were diesel engines that were replaced and used vehicles that were sold as is where is. The costs of removal of diesel engines that were replaced were included in the cost of installing the new engines and there were no costs of removal relating to the used vehicles." The URRC notes that by adoption of the NTPC amortization rates which include negative net salvage for certain asset accounts, the amortization rates of QEC include a component for recovery of negative net salvage. It is not appropriate to also include estimated or actual cost of removal or negative net salvage in the capital cost of new assets. That practice could lead to a "double recovery" of asset costs, which is not appropriate. The URRC is unable to estimate the impact of this inappropriate practice and will not adjust the amortization expense or capital expenditures in this application. However, the URRC recommends that QEC complete a study for its next GRA that shows the impact that the practice of recovery of cost of removal or negative net salvage in the asset costs of replacement assets has had in prior years and make an adjustment to gross plant in service, accumulated amortization and rate base to correct for this inappropriate practice.

On the basis of the above, the URRC recommends gross amortization expense before deduction of amortization of customer contributions of $6,405,414 less $150,930 for a change in the asset lives for Wind Turbines plus $234,000 for amortization expense for additions during the test year. The URRC has determined the gross amortization expense after deducting Insurance Amortization of $77,924, to be $6,410,560. There are also corresponding changes to the Accumulated Amortization and Rate Base schedules to recognize the adjustment to amortization expense.

6.3.2 Financing Cost Amortization

QEC proposed to include in the equity component of capital structure an amount of $8.453 million reversing a portion of debt refinancing costs written off previously in the financial statements. The original amount incurred as refinancing costs amounted to $9.945 million and the $8.453 million represents the unamortized portion as of March 31, 2004. QEC proposed amortization of the $9.945 million financing costs over 20 years.

QEC indicated the financing costs were incurred as a result of early repayment of NTPC's debt. QEC indicated since the debt that was repaid early was replaced by new debt with a lower cost rate the amortization of the costs associated with early repayment in the amount of $497,000 should be included in revenue requirement.

The URRC notes the financing costs were incurred as a result of division of the corporation effective April 1, 2001. The URRC considers all costs attributable to division should be borne by the shareholder of the corporation as they are related to the ownership structure of the corporation and are not considered to be of direct benefit to the customers. The URRC also notes the replacement of the then existing higher cost debt by new debt resulted in an ongoing interest rate benefit to the customers. The URRC considers some recognition should be given to the benefit resulting from the replacement of higher cost debt by lower cost debt. On balance the URRC considers 50% of the financing costs to be of benefit to customers. The URRC considers the balance 50% to be shareholder related. Accordingly, the URRC will add $4.227 million to the equity component of capital structure and include an amount of $249,000 for amortization of financing costs.

6.3.3 Amortization of Contributions

Appendix G, Table 2.4.1, line 9 and Table 1.5.1, line 14 shows an amortization of contribution amount of $378,000 for the test period.

QEC stated in response to URRC QEC 31 (l) the amortization of contributions rate is the same as the amortization rate for assets. The URRC considers the amortization of contribution rate should be based on 0% net salvage amortization rate since contributions correspond to the asset costs only. For the purposes of this Report the URRC will accept the proposed amortization of contributions rate. However the URRC directs QEC to use the correct amortization rate for contributions at the time of the next GRA.

The URRC will accept an amortization of customer contributions amount of $378,000 for the test period.

6.3.4 Net Amortization Expense

The URRC has determined the net amortization expense to be $6.282 million made up of gross amortization in the amount of $6.411 million, less amortization of contributions in the amount of $0.378 million plus financing cost amortization in the amount of $0.249 million.

7.0 Total Revenue Requirement

The URRC has determined, on a preliminary basis, the total revenue requirement to be $69.6 million as shown in Schedule C attached.

8.0 Revenue Forecast

8.1 Revenue From Sale of Electricity at Existing Rates

QEC, in its initial application, forecast revenue from electricity sales of $56.382 million in 2004/05. In response to URRC QEC 2a) QEC revised the revenue forecast down to $55.462 million. The major reason for the difference between the initial forecast and the revised forecast is a proposed reduction for fixed charge revenue from inactive residential and commercial customers. The revised forecast shows about 24% of residential customers and about 18% of commercial customers are considered inactive by QEC. The URRC notes QEC did not provide a forecast of customers by community for 2004/05.

The URRC's analysis indicates the average consumption per customer based on QEC's 2004/05 forecast is significantly higher when compared with the average consumption per customer from the unfiled 2001/02 GRA, as shown below:

	Residential	Commercial
Per unfiled GRA		
Number of Customers	9842	2899
Sales Mwh	51590	79174
Consumption per Customer	437	2276
Per 2004/05 GRA Proposed		
Number of Customers	7859	2493
Sales Mwh	52021	81439
Consumption per Customer	552	2722

The above table and the lower average consumption per customer lends support to the view the number of customers as per QEC's revised forecast is likely understated. A comparison of the 2003/04 actual revenue per Kwh, before bad debt, with the forecast revenue per Kwh shows the following result:

	2004/05	2003/04
Sales Revenue	55462	54127
Sales Mwh	135300	129200
Revenue per Kwh	0.40992	0.41894

The above table lends further support to the view the 2004/05 revised forecast revenue may be understated due to understatement of number of customers and corresponding fixed charge revenue.

Based on the above analysis, the URRC will increase the number of residential and commercial customers such that the number of such customers in each community is not lower than the forecast for 2004/05 made at the time of the 2001/02 GRA. The URRC considers this adjustment is appropriate considering the high percentage of inactive customers not subject to the fixed charge revenue. The URRC's calculation of the adjusted number of customers by community for 2004/05 is shown in Schedule C-2.1 attached. The consumption per customer and revenue per Kwh resulting from the URRC's calculation is as follows:

	Residential	Commercial
Per URRC 2004/05 GRA		
Number of Customers	9840	2935
Sales Mwh	52021	81439
Consumption per Customer	441	2312
	04/05 URRC	03/04 Actual
Sales Revenue	56102	54127
Sales Mwh	135300	129200
Revenue per Kwh	0.41465	0.41894

The above table shows the average consumption per customer based on the URRC revised customer numbers is closer to historical levels and the average revenue per Kwh is closer to the 2003/04 actual revenue per Kwh. Accordingly, the URRC will revise its forecast of revenue at existing rates to reflect the increase in number of customers to $56.102 million.

8.2 Bad Debt Expense

QEC did not reflect bad debt expense as a separate component of revenue requirement. However, QEC appears to reflect bad debt expense as a deduction from revenues in its financial statements. Paragraphs 147 to 149 of the 2004 Auditor General of Canada's First Report to the Second Legislative Assembly of Nunavut states;

"147. At division, the Corporation had accounts receivable of $11 million. A year later, they had grown by some 233 percent to $25 million. At 31 March 2003, the Corporation had reduced its accounts receivable to just under $19 million, but this is still 175 percent higher than at division.

148. By not collecting its bills on time the Corporation has to finance its operations by borrowing. It ran out of cash in its first year, borrowed from the bank, and paid interest on its overdraft. This added up to about $1 million over the first two years.

149. The longer the Corporation's bills remain outstanding, the more difficult they are to collect. This means higher bad debts, about $857,000 in its first two years of operations. Bad debts for a well-run utility company should be small."

The URRC notes the AG's comments and considers bad debt expense for the 2004/05 test year should not be set on historical levels. Having regard to the AG's comment that bad debts for a well run utility should be small and having regard to the fact Government pays about 80% of the bills in some form or another, URRC will allow a bad debt expense of 1% on 20% of revenues. URRC estimates this amount to be about $130,000 ($64.5 million revenue*20%*1%) for the 2004/05 test year.

8.3 Other Revenue

QEC forecast other revenues of $1.080 million for the 2004/05 test period. The following table shows a comparison of the components of other revenues as forecast for 2004/05 and as recorded for 2003/04:

	2004/05 Fore Per QEC	2003/04 Act
Residual Heat	300	299
Joint Use	300	288
Miscellaneous Charges	400	570
Time and Materials	80	
	1,080	1,157

No explanations have been provided for the forecast reduction in the miscellaneous charges and time and materials categories in 2004/05 relative to the recorded figures. URRC is not aware of any reason why the forecast for 2004/05 should be lower than the recorded figures for other revenues. Accordingly the URRC will increase other revenue by $75,000 from 1.080 million to $1.155 million for purposes of this Report.

8.4 Total Revenue

The URRC has determined total revenue at existing rates to be $57.127 million made up of the following components:

	$000
Sales Revenue	56102
Bad debt Expense	-130
Other Revenue	1155
Total Revenue at Existing Rates	57127

9.0 Additional Riders

9.1 Alternative Energy Rider

QEC requested an Alternative Energy Rate of $0.005 per Kwh to fund alternative energy initiatives in Nunavut. QEC indicated the proposed rate would be applied as a separate rate over and above the rates determined by the revenue requirement proposed in its application.

The alternative energy fund would be used to examine and carry out hydro electric pre-feasibility studies, community district heating projects and wind generated electricity systems.

The URRC fully supports and endorses the corporation's attempts to reduce dependence on diesel based generation as well as promote demand side management initiatives. However, the URRC believes there should be full accountability for the money spent on such projects. Further the corporation ought to be able to demonstrate the prudence of such initiatives based on a business case analysis. These requirements are common practice among other regulated utilities. The URRC considers rather than the proposed fund, deferral account treatment of alternative energy expenditures would provide an appropriate mechanism to account for these expenditures. The URRC considers this mechanism would provide accountability for money spent and enable regulatory scrutiny. The following directions are therefore provided for the treatment of the cost of funding alternative energy studies:

- QEC should develop policies and guidelines specifying the nature of studies that will qualify as alternate energy studies, consistent with the purposes of QEC as a regulated utility providing electricity and heat services

- Prudent expenditures on alternative energy studies may be treated as part of the corporation's regulated costs for ratemaking purposes;

- AFUDC may be earned by the Corporation on the mid year balance of prudent expenditures charged to the alternative energy deferral account if the project extends beyond one year ;

- If a project that is investigated proves viable the costs should be added to the capital cost of the relevant alternative energy project;

- If a project that is investigated proves not viable the costs should be amortized over a reasonable period.

In view of the foregoing the URRC does not support QEC's request for approval of an alternative energy rate.

9.2 Environmental Initiatives Rider

QEC requested an environmental initiatives rate of $0.005 per Kwh to fund the Corporation's share of future removal and site restoration costs. QEC indicated the proposed rate would be applied as a separate rate over and above the rates determined by the revenue requirement proposed in its application.

With respect to the reason for the fund QEC stated as follows:

> "The Corporation's round of site assessments for all communities and the federal government's budget announcement including funds for environmental clean up instigated joint communications from the Corporation and NTPC to the federal government regarding future remediation costs because the Northern Canada Power Commission was the operator of the sites prior to the creation of NTPC in 1988.
>
> The extent of the federal government's participation in site restoration with NTPC and QEC is not known at this time. Based on the site assessments and costing determined by site remediation projects undertaken to date, the total cost to remediate existing QEC contaminated sites could be in excess of $50 million." [Application p 46]

The URRC notes the future removal and site restoration reserve of about $16.3 million as of March 31, 2004. Additions are made to this reserve annually at the rate of about $600,000 to $700,000. Remediation costs deducted from the reserve amount to $200,000 to $300,000 annually. The URRC also notes QEC's concern the accumulations in the reserve may not be adequate to cover future removal and site restoration expenditures. QEC states the extent of the federal government's participation in site restoration with NTPC and QEC is not known at this time.

QEC has not provided any studies that would support a higher level of liability on the part of QEC for future removal and site restoration costs that would justify an increase in the annual amount presently accumulating in the future removal and site restoration reserve. Further the Federal Government's share of these expenditures is unknown at the present time. In view of this the URRC considers the amount of funds requested to augment the amounts currently being added to the reserve to be unsupported. Therefore the URRC will not recommend the proposed environmental initiatives rate of $0.005 per Kwh.

The URRC directs QEC to provide a detailed study of the potential liability on the part of QEC with respect to future removal and site restoration expenditures, including a risk assessment of unknown contingencies, at the time of the next GRA.

9.3 Beneficiary Employment Rider

QEC requested approval of a beneficiary employment rate of $0.0125 per Kwh to fund the cost of complying with the Nunavut Land Claims Agreement. QEC indicated the proposed rate would be applied as a separate rate over and above the rates determined by the revenue requirement proposed in its application.

QEC indicated the funds generated by the beneficiary employment rate will be used to train Inuit employees as required by the Nunavut Land Claims Agreement.

Nunavut Tunngavik Incorporated (NTI), stated its mission is Inuit economic, social and cultural well being through implementation of the Nunavut Land Claims Agreement. NTI opposed QEC's beneficiary employment rate proposal. In this regard NTI stated:

> "NTI is well aware of the difficulties the Government of Nunavut has had in securing the funding from the federal government required for claims implementation, and especially with regard to Article 23. However, the issue must be settled between the two governments: it is not a cost to be borne by beneficiaries or passed on to the consumer, Inuit or non-Inuit. NTI's position on this matter has always been clear: the Government of Canada cannot "Pass the Buck" on claims obligations." [NTI Final Submission P5]

The URRC notes about 50% of the corporation's employees were beneficiaries under the Nunavut Land Claims Agreement in 2003/04. These costs are included in the salaries and wages component of revenue requirement. The URRC is concerned the creation of a separate fund for this purpose will not facilitate an integrated regulatory review of all transactions related to the Land Claims Agreement.

QEC must fulfill its responsibilities under the agreement in a prudent manner consistent with its business needs and priorities. The URRC considers the creation of a separate fund may not facilitate full regulatory scrutiny of how QEC fulfills its responsibilities under the agreement. Accordingly, the URRC can not support QEC's request for a separate beneficiary employment rate.

10.0 Revenue Shortfall Based on Existing Rates

The URRC has determined on a preliminary basis, the revenue shortfall based on existing rates to be $12.473 million as shown in Schedule C-1 attached.

11.0 Rate Stabilization Fund

QEC proposed that a rate stabilization account be reestablished for QEC to provide a mechanism to adjust rates when fuel prices change from time to time:

> "The Corporation is seeking approval to continue with the Rate Stabilization Fund account after March 31, 2005. As with the past operation of this account, QEC proposes to use a "trigger" mechanism such that a rate change will only take place when the balance in the fund account is outside of a certain threshold limit. Previously, that limit was $2 million. While this target was appropriate when NTPC provided service to all diesel communities, both in the east and the west.
>
> To recognize Division, and to reflect the fact the QEC only has 25 communities, QEC proposes that the trigger be reduced to $1 million." [Application P 66]

QEC requested implementation of the rate stabilization mechanism effective April 1, 2005. QEC indicated the expected balance in the rate stabilization account will be zeroed out at the end of March 2005 from funds provided by the GN from time to time. QEC requested that the URRC further define and recommend a process to obtain approval to implement a fuel rider after March 31, 2005.

In view of the volatility of diesel fuel prices seen in recent years and given that fuel costs constitute a significant portion of QEC's revenue requirement (about 40%), the URRC considers reestablishment of the rate stabilization account will provide an appropriate mechanism to adjust rates when fuel prices change from time to time. Accordingly, the

URRC approves the establishment of the rate stabilization fund and adjustment mechanisms related to the fund as set out in the directions that follow, effective April 1, 2005.

The URRC notes QEC's proposal that, consistent with the past, fuel riders resulting from the rate stabilization mechanism should be based on a Nunavut wide fuel rider. Considering the administrative simplicity of this proposal and noting that fuel price increases or decreases directionally impact all communities, although not exactly to the same degree, the URRC is of the view a Nunavut wide fuel rider is not unduly discriminatory in the context of the existing community based rates. Accordingly, the URRC will support a Nunavut wide fuel rider resulting from the adjustments to the rate stabilization fund.

URRC notes QEC did not refer to any carrying costs with respect to the fuel stabilization fund balance. The URRC considers QEC should be compensated and conversely, should compensate customers for the costs of carrying the rate stabilization account on its balance sheet as a current asset or liability. Given the short term nature of the balance in the rate stabilization account, the URRC considers the corporation's short term borrowing rate should be used for the purpose of calculating carrying costs.

QEC is directed to adopt the following procedures with respect to implementation of the rate stabilization fund and adjustment mechanism:

- The balance in the rate stabilization fund as of April 1, 2005 shall be zero;

- The amount charged or credited in each month to the fund will reflect the following adjustment formula for each community:

  Actual or forecast generation in Kwh/Last URRC approved efficiencies in Kwh per liter* (Actual price per liter-forecast price per liter);

- Interest shall be charged or deducted from the rate stabilization fund balance based on short term interest rates;

- If at any point in time the forecasts indicate the fund balance will exceed the threshold of plus or minus $1 million within a six month period the Corporation shall apply to the Responsible Minister for approval of a Nunavut wide fuel rider designed to recover or refund the balance in the fund over a suitable period targeting a zero balance at the end of the above mentioned six month period, when recovery or refund is complete;

- To the extent accommodated by the corporation's billing system, the Nunavut wide fuel rider shall be an across the board percent rider. This will provide for a proportionate increase or decrease in costs for all communities and rate classes.

12.0 Rate Approval

12.1 Phased In Rate Increase

A number of parties submitted the corporation should be allowed some increase effective April 1, 2005. For example NWC stated:

> "In the interim, the preliminary submission indicates that at most, based on the evidence available, Nunavut Power should be provided an effective increase of $11.234 million, or about an average 20.2% increase. However, the Council should also seriously consider whether it ought to adopt provisions similar to the Northwest Territories PUB, which ensure no customer faces increases that are beyond 15% in any year." [NWC Supplementary submission P3]

The ICOC submitted the average increase allowed the corporation should be about 17%:

> "The Iqaluit Chamber of Commerce is concerned about the viability and survival of the Nunavut Power Corporation. We recognize that something must be done to increase cash flow, since power rates have not increased for the past seven years and the corporation risks insolvency. Accordingly, we do recommend that in lieu of the proposed General Rate Application there be an interim refundable rider recommended by the URRC, which would reflect inflationary increases since the last power rate revision. We recommend that

> these increases, which we calculate to be 17 per cent, be imposed across the board in Nunavut and that there be no adjustments of any kind in the rate design. [ICOC Final Submission P7]

A number of parties expressed concern over the corporation's cost structure and the stability of rates going forward given its current financial position. For example NTI stated:

> "NTI does not want to see the current cost structure imported into the new GRA. It is not clear that the Utility has fully explored ways to increase efficiencies and cut costs. Other testimony has clearly spelled out a number of ways that the Utility can reduce its costs.
>
> Further, in view of recent changes in management, NTI feels that it will take time for the new CEO to fully understand the nature of the Corporation and to get a clear sense of where reductions can be made. For this reason, NTI is asking that URRC recommend that the GN freeze electricity rates until a comprehensive operational review is completed. The review should be led by a person or company with a particular expertise in the management of a Utility company. Further, we believe its report should be tabled in the Legislative Assembly. [NTI Final Submission P16]

ICOC submitted that many of the costly initiatives undertaken by QEC were driven by political decisions and that these costs are therefore appropriately borne by the shareholder:

> "In our previous submission to your Council, the Iqaluit Chamber of Commerce noted that many of the costly initiatives undertaken by the Qulliq Energy Corporation were driven by political decisions and that these costs are therefore appropriately borne by the Government shareholder. This is why we now recommend that the position of the utility's only shareholder, the Government of Nunavut – on these and other important issues – must be made clear before a new rate regime is recommended. The public consultation process to date, which has had partial input from a sample of only about twenty per cent of the corporation's customer base, is incomplete." [ICOC Final SubmissionP4]

Many parties expressed concern over the quality of information provided to test the application. For example the ACL stated:

> "The GRA is flawed in many aspects. Contributing factors include but are not limited to: filing of incomplete and inaccurate information, a lack of

> consultation with affected groups, inadequate time to review and consider impacts, inappropriate methodology for allocating costs between customer groups." [ACL Final Submission P13]

The URRC notes that QEC did not complete the responses to the undertakings from the Technical meeting and that information requests by the URRC as part of these proceedings were not filed on a timely basis. The URRC notes and agrees with the concerns of customers that some elements of the cost structure of the Corporation as reflected in the recorded results may not reflect a cost structure that is consistent with prudent operations. The URRC also agrees complete information has not been provided to adequately test the forecasts provided by QEC.

In reviewing rate increases the URRC must balance the corporation's financial situation as well as the rate shock impact for customers resulting from a high percentage increase in any given year. The URRC notes NWC's submission that a 15% increase is reasonable from a customer impact point of view. The URRC agrees with parties that an increase is appropriate to offset fuel cost increases since the last time rates were set in 1998 when QEC was a part of NTPC. Accordingly the URRC recommends a 15% across the board increase effective April 1, 2005. This amounts to an increase of $8.3 million and is marginally higher than the amount required to cover increased fuel costs of about $7.8 million.

The URRC has determined on a preliminary basis that the Corporation may qualify for an additional increase provided it can satisfy the URRC as to the effectiveness of the Corporation's financial management plan as well as demonstrate the prudence of certain cost elements included in the revenue requirement. However, in the interest of rate stability, the URRC considers any additional increase must be phased in over a period. Having recommended approval of a 15% increase effective April 1, 2005 any additional increase must be phased in the following year effective April 1, 2006.

With respect to the increase of 15% effective April 1, 2005 the URRC recommends approval of the residential and commercial energy rates under the Governmental and non Governmental categories set out in Schedule C-3 attached. The URRC notes QEC did not propose changes to the residential and commercial fixed monthly charges nor did it propose changes to the commercial demand charge. For the purposes of this Report the URRC recommends approval of the existing residential and commercial monthly fixed charges and the commercial demand charge. The URRC recommends approval of a 15% increase for all street lighting rates.

In Section 6.1.2 the URRC referred to the need for an external review of the corporation. The URRC considers this review and the resulting findings ought to form the basis for QEC's response to the information required for URRC consideration of the additional increase referred to above. Accordingly the URRC directs QEC to provide the following information on or before September 30, 2005 following completion of the review referred to in Section 6.1.2 of this Report:

- Detailed report on the corporation's financing plan following implementation of the 15% increase in rates recommended herein and an assessment of the corporation's financial position in 2005/06 assuming the increases determined in this report on a preliminary basis are implemented;

- Detailed report of forecast salaries and wages by function (Finance, Engineering, Operations etc) for 2004/05 and 2005/06 budgets, providing budget type justification for the prudent level of FTEs by category (Union, Excluded, Beneficiaries under the Land Claims Agreement) and the prudent levels of regular salaries and wages, overtime, casual labour, charged out labour (including capitalized labour) and fringe benefits required for the provision of electricity and residual heat services in Nunavut in an efficient and cost effective manner. In discussing fringe benefits and beneficiary employment the matter of any shared responsibility on the part of other levels of Government must be addressed. The report should identify charges to affiliates if QEC employees perform services for affiliates of the Corporation;

- A detailed report of supplies and services providing an overview of the elements comprising this expense category including planned maintenance, other maintenance and housing expense for 2004/05 and 2005/06 budgets. More specific details should be provided on the following:

a) A detailed report on planned maintenance expenditures carried out/forecast in accordance with maintenance cycles on diesel plant and distribution plant in each year from 2001/02 to 2004/05, 2005/06 budgets. The report should identify any planned maintenance deferred from one year to the next. The planned maintenance report should address how the deterioration in reliability levels discussed in section 14.1 of this report will be addressed.

b) A detailed report of housing expenditures explaining the relationship between housing expense and staffing levels and further explaining the changes in the level of this category of expense from year to year from 2001/02 to 2004/05 and 2005/06 budgets.

- A detailed report of travel and accommodations expense, explaining the changes in the components of this category of expense from year to year, from 2001/02 to 2004/05 and 2005/06 budgets. The report should address the prudent level of medical travel expense in light of any contributory responsibility on the part of the territorial or Federal Governments.

Following receipt of the foregoing reports the URRC will make a further recommendation to the responsible Minister confirming or varying its preliminary determinations respecting salaries and wages, supplies and services and travel and accommodation expenses as well as recommend approval, denial or adjustment of the additional increase effective April 1, 2006 referred to above.

12.2 Move to Territorial Rates from Community Based Rates

QEC's existing rates are community based rates. QEC requested that the community based rates be replaced by territorial rates. Under territorial rates or postage stamp rates customers within the same rate class would pay the same rates irrespective of the community they live in. QEC provided the following reasons for its proposed move to territorial rates at page 87-89 of its application:

- A territorial rate structure recognizes that Nunavut is one territory and not three competing regions or twenty-five competing communities;

- A territorial rate structure encourages investment in alternative energy projects and will ensure all Nunavummiut benefit from future alternative energy projects, regardless of where they are located in the territory;

- A territorial rate structure will ensure smaller communities are not penalized by rate spikes when their plant needs to be upgraded or replaced. When recommending the new plant in Baker Lake, the URRC requested the Corporation provide a proposal for mitigating rate shock resulting from the addition of a new power plant to the rate base. A territorial rate would not only mitigate new plant rate spikes, it would rectify on a going forward basis, previous rate spike;

- A territorial rate structure recognizes that the subsidies provided to residential customers have already created territorial rates for those customers;

- A territorial rate structure recognizes that the Corporation's base, minimum, and administrative charges are already territorial rates;

- A territorial rate structure recognizes that re-establishing the Rate Stabilization Fund will result at some time in the future, a territorial fuel rider should fuel prices continue to rise or a territorial fuel rebate, should fuel prices decline;

- A territorial rate structure will result in rates that are fair and reasonable for all Nunavummiut;

- Administration of electricity rates and the rate setting process will be significantly streamlined with the number of rate schedules reduced from twenty-five to one;

- The transition to territorial rates will result in some communities experiencing a reduction in rates, even with the proposed increase in this GRA;

- The transition to territorial rates will result in some communities experiencing an increase in rates combined with the proposed increase in this GRA. The transition for customers other than Housing Support and Territorial Support could be phased in over a reasonable period of time while remaining neutral to the approved Revenue Requirement.

Schedule C-2, column F attached hereto shows the increases and decreases for each community based on QEC proposed rates. Under QEC's proposal larger centers, among others, namely Iqaluit, Cambridge Bay and Rankin Inlet would see significant increases over and above the QEC proposed average increase of approximately 42.1% purely as a result of the proposed move to territorial rates. Certain other communities would see lower than average increases under QEC's proposed rates.

A number of parties while supporting the concept of some form of levelized rates objected to QEC's territorial rate proposal stating there has not been a rigorous assessment of the implications of the QEC proposal. For example ACL stated:

> "While the Co-op System supports the principle of levelized rates system we feel that implementation should be delayed until a rigorous assessment is undertaken and affected parties have an opportunity to provide their input into the process.
>
> Further we believe that other options should be considered as well, such as pooling costs of capital or fuel to promote greater predictability and certainty in respect of the rates in general." [ACL Final Submission P12]

NTI identified other options that must be considered in any move to levelized rates:

> "With respect to the concept of a single rate for all Nunavut, NTI recommends that this issue be deferred for further thought and study and to allow for more public input. In developing future options consideration should be given to alternate arrangements, such as:
>
> - Pooling the cost of capital and fuel to be shared for all communities while allowing community price differences to deal with differences in plant efficiency and economies of scale;
>
> - Establishing rate zones that reflect capacity to pay and overall impact such that the smaller communities;
>
> - Introducing graduated rates so that the cost goes up progressively as customers exceed recommended guidelines. This would encourage conservation and ultimately reduce costs in communities." [NTI Final Submission P17]

Certain customers submitted the proposed move to territorial rates would adversely impact the economy. For example the Iqaluit Chamber of Commerce stated:

> "The one rate structure will seriously damage Nunavut's developing economy by shifting the burden of staggering rate increases to a minority of homeowners and commercial ratepayers, firstly in Nunavut's most economically advanced communities, but then in a ripple effect to smaller communities, resulting in sharp increases to Nunavut's already very high cost of living and overloading the budget of the utility's biggest customer – the Government of Nunavut itself." [Iqaluit Chamber of Commerce Final SubmissionP6, 7]

The URRC notes QEC's reasons for moving to territorial rates which reflects an averaging or levelizing of costs concept among communities. One of the reasons provided by QEC to support the move to territorial rates is that it would ensure smaller communities are not penalized by rate spikes when their plant needs to be upgraded or replaced. However, The URRC notes from Schedule C-4 attached, QEC's proposal would result in significant rate spikes for larger communities if approved with consequent impacts on their local economies. The URRC also notes the submissions of parties that there has not been a rigorous assessment of the implications of the QEC proposal in relation to other alternatives for levelizing rates.

The URRC considers it appropriate to move towards some form of rate averaging among communities so as to minimize the rate impact on smaller communities when their plant needs to be upgraded or replaced. However, the URRC also believes the relationship between costs incurred at the community level and the rates should not be completely obscured by any rate averaging mechanism. In other words the price signals to customers for electricity service should, among other rate design criteria, reflect the costs of producing and distributing that service. The URRC considers further study and assessment of rate averaging mechanisms is needed and therefore directs QEC to address alternative mechanisms for rate averaging or levelizing rates at the next GRA. In responding to this direction QEC should specifically address how any potential rate shock to customers as a result of this move to averaging of costs among communities will be mitigated. QEC should also have regard to community and customer input when responding to this direction.

In view of the significant impact on customers in certain communities and in view of the lack of adequate examination of alternative rate averaging mechanisms in these proceedings, the URRC can not support QEC's territorial rate proposal. In place of the proposed territorial rates the URRC will recommend approval of the existing community rate structure.

With respect to the mechanism for recovery of the increase effective April 1, 2005 recommended in Section 12.1 of this Report the URRC notes there are two potential alternatives. First, to approve the increase based on community revenue requirement and second, to approve the increase on an across the board basis. As stated earlier, the URRC considers a move towards some form of rate averaging among communities so as to minimize the rate impact on smaller communities when plant additions are made is appropriate. The URRC considers an across the board increase at this time is directionally consistent with this balance between community based rates and the some form of rate averaging in the future. Further the community based cost of service provided by QEC in response to URRC QEC 44 Attachment was not tested adequately due to time limitations.

Accordingly the URRC considers an across the board recovery of the increase effective April 1, 2005 is appropriate for the purposes of this Report.

Consistent with the goal of moving towards some form of rate averaging among communities so as to minimize the rate impacts on communities when plant additions are made, the URRC considers it appropriate to mitigate the rate levels of communities that have experienced significantly higher rates relative to other communities, since the last GRA. Prior to division several communities had new power plants built and suffered huge rate spikes in their power rates. Baker Lake would be poised for a rate spike with its new power plant expected to be commissioned at the end of this test year under community based rates. While the issue of a new rate structure may take some time to create and implement, there are some communities that require some kind of help now to reduce rate shock from the new power plants built or being built. In the URRC's report to the Minister Responsible for NPC dated May 16, 2003 regarding the application by the NPC for a project permit for construction of a power plant at Baker Lake the URRC stated at page 10 under the heading At the Time of the Next General Rate Application Item "D:

> "NPC to provide a proposal for mitigating rate shock resulting from the addition of the new power plant to rate base. Amongst, the proposals NPC should address the mechanics and merits of using a capital stabilization fund by the corporation to mitigate rate shock whenever new plant, the cost of which is significant in relation to existing plant, is added to community rate base."

Until a new rate structure is in place, the URRC considers that a capital stabilization fund should be implemented as an interim measure and that revenues collected under this fund mechanism should be used to alleviate the highest rate communities to a level somewhat closer to the Nunavut or regional average rates and also applied to new power plants being completed in 2004/05 Accordingly, the URRC directs QEC to propose a capital stabilization fund as an interim mechanism for the purpose of mitigating the high rates for certain communities resulting from the community based rate structure. The capital stabilization fund mechanics should be worked out by QEC and forwarded to the Minister for approval within 90 days of the release of this Report. URRC notes this fund adjustment will result in somewhat higher than average increases for customers in certain communities.

As part of the response to the direction concerning a capital stabilization fund QEC is also directed to address, taking into account the URRC's comments in this section concerning rate averaging, the approach to adjusting rates if an additional increase as discussed in Section 12.1, effective April 1, 2006, were to be recommended by the URRC and approved by the responsible Minister.

12.3 Cost of Service and Rate Design

QEC proposed rates for different classes of customers based on its proposed territorial rate model for these proceedings. The corporation did not carry out a full cost of service study for this purpose but rather relied on elements of the cost of service study and rate design undertaken by NTPC for their most recent GRA, in particular the outcome for diesel communities

The URRC notes in view of its decision to continue the existing community based rates, the allocations of costs under a territorial model are moot for these proceedings. However, URRC considers a fully allocated cost of service study should be provided as part of the next GRA and directs QEC to do so.

The URRC recognizes a fully allocated cost of service study cannot be meaningfully examined until there is resolution on the issue of rate averaging among communities. To address this matter the URRC recommends the following sequencing of the next GRA. The response to the URRC's direction on rate averaging options should be provided as part of a separate phase I application for consideration of revenue requirement and rate averaging mechanisms. The revenue requirement and rate averaging mechanism approved by the URRC in phase I will then form the basis for cost allocations to customer classes and rate design in a phase II application. Accordingly, the URRC directs QEC to follow the above sequence of proceedings for the next GRA.

13.0 Terms and Conditions of Service

In Section 13 of the Application, QEC describes its proposed changes to the Terms and Conditions of Service, to be effective April 1, 2005. The proposed Terms and Conditions of Service were provided in Appendix L of the Application at Pages 97 – 109.

The Corporation described the proposed changes to the Terms and Conditions of Service as follows:

> "The proposed changes to the Terms and Conditions of Service are intended to ensure ease of understanding by both the Corporation's customers and the Corporation's employees. As well, the changes focus on, in a favorable and logical manner, concerns that have occurred over the preceding number of years. The revised Terms and Conditions of Service will improve the Corporation's capability to deal with the requirements of its customers and secure equality and uniformity in the Corporation's consideration of its Customers."

Further to the proposed Terms and Condition of Service changes, a number of comments on the Terms and Conditions of service were received from citizens of the communities that are served by the Corporation. These concerns included Disconnection in the winter, Notice Period for Disconnection, Availability of Bills and Service in other Languages than English, Time to Pay Bills and Ability for Customers to Read their Own Meters. QEC indicated at a number of the community meetings their willingness to work with customers on specific issues. QEC stated that it would endeavor not to disconnect customers in winter but would instead use load limiter devices. QEC stated that there are 1-800 numbers available for all customers who have questions about their bill or service. Inuktitut language service is available on all of these numbers. QEC also stated that it is considering making available a Budget Plan for customers who wanted to levelize their payments. Further, regarding payment of bills, QEC discussed the terms of its Automated Payment plan.

In Section 2.9 Customer, QEC is proposing to bind a person or organization to a contract that may or may not have been signed, providing that the customer is receiving service.

With respect to this matter QEC stated in response to URRC QEC41 (b) as follows:

> "Signing is not essential to the creation of a legal obligation to pay. Many agreements are oral, implied or contain legislatively imposed terms, yet each creates a legal responsibility to pay. It is not normal for customers to sign the full terms of service, nor to sign their acceptance of changes such as new rates, but the approval of the URRC makes these terms an effective part of any customer's contract.
>
> Where it can be demonstrated that the initial customer is absent from the unit, and the occupant received the benefit of services, then the occupant has received electricity and has a legal obligation to pay a reasonable amount for the supply they have accepted. Similar obligations occur for water rates, land taxes and other occupancy based services.
>
> It is the Corporation's experience, that customers unable or unwilling to pay their utility bill will deny responsibility where a signed customer service order was not obtained because the Corporation was not advised of the change in occupant or tenant.
>
> The Corporation is of the view that a signed customer service order should be obtained, however, when a change of responsibility has occurred without advising the utility, the utility should not be set up as a domestic relations monitor, nor should irresponsible users be permitted to drive up the costs of electricity for others who pay regularly and take responsibility."

The URRC notes there is a similar clause in NTPC's current terms and conditions of service. The URRC notes QEC's explanations as set out above and will therefore recommend approval of the proposed Section 2.9.

In Section 4.3 Service Connection and Section 6.2(c) Maintenance Adjustment for Municipal Street Lighting Service, QEC is proposing to charge customers additional costs unless the service connection or service maintenance is scheduled during regularly scheduled maintenance trips to the communities. In response to URRC.QEC-41(e), QEC stated while the annual budgets include provisions for "regularly scheduled maintenance trips to communities", the regional operations and maintenance supervisors have the authority to schedule maintenance trips based on the availability of personnel, unplanned maintenance requirements, participation in capital projects, accumulated engine hours for overhauls, etc., within the budgeted amounts.

Based on the foregoing the URRC is prepared to recommend approval of this new clause. The URRC expects QEC will communicate with customers and schedule maintenance trips so as to permit customers to better plan their construction requirements and requests for service.

In Section 4.5 Rejection of Application for Service, QEC is proposing to include a customer's lack of credit-worthiness as a basis for rejecting an application or request for service. The URRC understands that QEC does not wish to burden credit worthy customers with the added expense of potential customers who may not pay their bills. Credit checks are often required to as a pre-condition for customers taking service with a utility. The URRC is prepared to recommend approval of the revision in order to reduce the likelihood that new customers who are deemed not credit-worthy will default on payments. Clause 4.5 (d) provides customers another option to obtain service and the URRC expects that QEC will allow customers who are not credit-worthy but who provide a sufficient security deposit or letter of credit to take service.

Section 5.9 Interest and Refund of Deposits states that QEC will pay "…simple interest on the security deposit from the date the deposit is paid, at an annual rate of interest equal to the Daily Interest Savings rate in effect at the end of each month as posted by the Canadian Imperial Bank of Commerce." In response to URRC.QEC-41(g), QEC stated it is the Corporation's view that the individual customer deposits are relatively small in amount and the daily interest savings rate is more appropriate to these amounts than a commercial paper short term interest rate. QEC stated commercial paper short term investments usually have minimum dollar amounts significantly higher than the amount of individual customer deposits. QEC deposits the security deposits in the Corporation's receipts accounts and uses them as cash flow from operations.

The URRC notes QEC has proposed inclusion of customer deposits in the amount of $651,000, as a component of working capital. The URRC notes, in total this represents a substantial sum. The URRC will accept the Corporations proposed treatment of customer deposits for the purposes of this Report. However, the URRC directs QEC to address the appropriateness and feasibility of investing customer deposits in commercial paper short term investments at the time of the next GRA. At the same time QEC should address the appropriate rate of interest to be paid on customer deposits and the appropriate working capital treatment of deposits.

Schedule C provides QEC's list of fees and charges for service, security deposits, basic service charges, late payment and disconnection charges and miscellaneous fees and charges. In response to URRC.QEC-41(j), QEC stated the corporation did not apply for an increase to the Service Connection Fee. The existing Service Connection Fee was approved by the Northwest Territories PUB. The Corporation proposed to address the revenue deficiency through increases in rates related to consumption. The existing Service Connection Fee may have been cost based originally, however, it is not sufficient to cover the cost of service connection today. The URRC directs QEC to address the cost basis for service connection fees at the time of the next GRA.

The URRC recommends approval of the terms and conditions of service proposed by QEC.

14.0 Quality of Service

This section addresses issues of Reliability Statistics, Safety and Complaints.

14.1 Reliability Statistics

At Page 7 of its Application, QEC states that “The Corporation strives to continually improve its service reliability and actively promotes safety awareness amongst its employees and the general public.” QEC states further that “For the year ending March 31, 2004, reliability across the NPC system exceeded 99.83%.”

URRC.QEC-13(b) and (c) requested QEC to provide its quarterly and annual actual and forecast reliability statistics for 2001 to 2005 forecast. QEC indicated that it did not keep quarterly reliability statistics. Attached to the information response were annual reliability statistics for the periods requested.

In response to URRC.QEC-13(c) with respect to the target reliability statistics and levels for 2004/05, QEC stated:

> “The Corporation’s target reliability is 100% and it is achieved regularly on a daily basis in the majority of Nunavut’s communities.
>
> Over the longer period of a year, the Corporation’s reliability is near 100%.
>
> The Corporation recognizes that reliability depends upon the continued employment of qualified personnel, continued maintenance and monitoring of generation and distribution plant and equipment, and the sufficiency of the capacity of the generation and distribution plant and equipment.
>
> The Corporation also recognizes that expenditures in the pursuit of 100% reliability are subject to diminishing returns and the level of reliability must be balanced with fiscal realities and responsibilities, despite differing public perception, especially during an outage.”

The URRC considers that reliability statistics are very important for any utility. The reliability statistics are even more important for a utility such as QEC who operates in extreme weather conditions and where customers who lose electricity in these extreme conditions can be subject to great discomfort and hardship. As noted above, while the URRC considers that annual reliability statistics are an important consideration when reviewing service levels, quarterly statistics are even more important, especially given the climate that QEC operates in. For example, an outage in the summer for a residential customer will not have as severe an implication as an outage in the middle of winter in a blizzard. Further, it is expected that planned outages would take place during warmer weather and thus the inconvenience to customers would be minimized. Further, the URRC considers that while overall reliability for the utility is important, the reliability by region and by community is even more important.

The URRC considers that quarterly statistics, for both planned and particularly for unplanned outages, are especially important when determining the level of service that customers should expect. The URRC directs QEC to immediately commence collecting quarterly statistics, by region and by community, for both planned and unplanned outages and report those statistics collected to the point in time of the filing of their next GRA.

Overall the reliability statistics provided by QEC indicates there has been a substantial increase in unplanned outage minutes in 2003/04 relative to 2001/02 and 2002/03. QEC did not identify or quantify any specific whether related factors that might have contributed to the increase in 2003/04.

For future proceedings the URRC considers QEC's reliability record should be presented to the URRC in a form that would allow comparison of key reliability statistics with those in the industry. Accordingly, the URRC directs QEC to recommend appropriate target measures for reliability having regard to industry standards, at the next GRA.

14.2 Safety

At Page 7 of its Application, QEC states that "Safety considerations are incorporated into every aspect of the Corporation's operations." Further that "The Workers' Compensation board of Northwest Territories and Nunavut, recently recognized Nunavut Power Corporation in the large employer category for the third year in a row for the undertaking of safety activities throughout the year."

URRC.QEC-13(a), (d) and (e) provide further information on the WCB Employee Recognition Award as well as further information on the safety training programs that QEC is undertaking. Attachments are provided that show the annual safety statistics for 2001 to 2004. The URRC is encouraged that QEC has a safety program, is receiving awards of excellence on an ongoing basis and keeps detailed information on accidents and incidents. The URRC expects that QEC has meetings, at least monthly, to review the accident statistics and examine ways and methods to reduce accidents and incidents. The URRC expects that QEC will continue its record of safety.

For future proceedings the URRC considers the corporation's safety record should be presented to the URRC in a form that would allow comparison of key safety statistics with those in the industry. Accordingly, the URRC directs QEC to recommend appropriate target measures for safety having regard to industry standards, at the next GRA.

14.3 Service Quality and Complaints

QEC indicated it does not record customer complaints at present. The URRC considers it important for QEC to record and monitor customer complaints and explain how the complaints were resolved. Accordingly, QEC is directed to commence maintaining a complaints log for recording customer complaints by complaint category and explain how each complaint was resolved.

URRC considers QEC should also give consideration to monitoring performance and service quality levels as follows:

- Level of customer satisfaction based on customer surveys;
- Billing performance measures identifying percentage of bills QEC failed to render, percentage of billing inaccuracies and percentage of bills corrected;
- Call answer service levels including abandonment rate

The URRC directs QEC to institute the above service quality measures for monitoring and reporting service quality and customer satisfaction levels, as soon as possible and in any event no later than April 1, 2006. QEC is directed to report to the URRC at the time of the next GRA on the service quality and customer satisfaction measures so implemented and the date implemented. QEC is also directed to recommend appropriate targets for performance and service quality measures having regard to industry standards, at the next GRA.

15.0 Other Matters

15.1 Management of the Corporation

In a report dated May 10, 2004 addressed to the Speaker of the Legislative Assembly of Nunavut the Auditor General found a number of deficiencies with respect to QEC and made nine main recommendations with a number of other specific recommendations where deficiencies were required to be addressed.

Many of the parties to this proceeding provided comments on the Auditor General’s report and queried why QEC had not addressed the issues raised in the report.

The URRC considers the concerns respecting management of the corporation raised in the Auditor General’s report to be matters within the purview of the review of the corporation referred to in Section 6.1.2 and expects these concerns will be addressed as part of that review to the extent they have not already been addressed or resolved.

15.2 Treatment of District Heating Function

QEC indicated the corporation owns and operates district heating systems in several communities. QEC stated the district heating program was expanded between 1999 and 2001 by undertaking projects in Pangnirtung and Arviat. Kugluktuk and Taloyoak also generate heat sales revenue. QEC stated it presently supplies thermal energy in Cambridge Bay, Rankin Inlet and Sanikiluaq where the district heating systems are owned and operated by others.

QEC stated residual heat sales revenue recovers residual heat capital investments and related operating and maintenance costs by contributing towards the Revenue Requirement. QEC proposed URRC recommend approval of the following residual heat kWh rate formula:

Residual Heat kwh Rate = Cost Factor x Fuel Cost ($/l) x ETS Efficiency 1528
Heat Content of Fuel (kwh/l) x Average Annual Efficiency 1529

Individual variables proposed are set as follows:
Cost Factor = 90%
Fuel Cost = local heating fuel price
ETS Efficiency = 95%
Net Heat Content = 9.79 kwh/liter
Average Annual Efficiency = 0.70

QEC stated the fuel cost is based on the delivered price of local heating fuel. The energy transfer station (ETS) efficiency reflects actual heat exchanger design specifications. The net heat content is based on the lower heating value of P50 Arctic grade diesel fuel. The average annual efficiency is an estimate of seasonal boiler operations.

The URRC notes the corporation presently treats the costs and revenues of serving district heating customers as part of the overall costs and revenues of QEC. The URRC considers district heating is a separate service distinct from electricity service. Accordingly, in the URRC's view all costs associated with individual district heating projects should be assigned or allocated to heat customers. This view was confirmed in the URRC's Baker Lake project permit report dated May 16, 2003 where the URRC stated:

"Project approvals for waste recovery systems should be on a cost recovery basis from the heat customers, not the electrical customers." [Page 7]

The URRC considers electrical customers should not cross subsidize district heating customers and district heating customers should not cross subsidize electrical service customers. Accordingly, the URRC directs QEC to prepare a fully allocated cost study at the time of the next GRA, showing the costs applicable to district heating and those applicable to electrical service customers in those communities where district heating service is offered. The costs allocated to district heating should include all incremental facilities costs as well as shared facilities costs. QEC must demonstrate how cost recovery is being achieved for district heating.

Since the corporation's investment levels as well as other terms and conditions of service may be different for district heating service the URRC directs QEC to develop a set of terms and conditions of service for district heating service, including investment levels and file this information for consideration by the URRC and approval by the responsible Minister within 90 days of this Report.

For the purposes of this Report the URRC accepts and recommends approval of the residual heat rate formula as proposed in this application by QEC.

15.3 Treatment of Future Industrial Customers

QEC requested confirmation by the URRC that the rate structure and rates established as the result of this GRA will not apply to the provision of electricity, fuel and heat (energy) to industrial sites where the Corporation is contracted to provide energy.

With respect to this proposal NWC stated as follows:

NPC is proposing that rates to new industrial customers be separated from the rates flowing from this GRA, and that "providing there is not an increase in the Revenue Requirement to customers subject to the rate structure and rates established under this GRA" that NPC would effectively retain revenues from industrial customers at rates it sees fit to charge. This is wholly inconsistent with the principles of utility regulation. For example, in both NWT and Yukon, the rates charged to industrial customers (mines) to provide them with service are included in the rate determination of the utility's retail (residential and commercial) customers. As an example, in Yukon when the Faro mine returned to service in 1995/96, rates for commercial customer dropped by nearly 50% as a result of the mine sharing in paying for the fixed costs of the system. In contrast, at other times industrial loads can cause increases in costs and risks for the utility (such as leaving behind bad debts) that other customers may be required to bear. The proposal put forward by NPC appears to effectively seek to treat industrial customer as non- regulated profitable sales for NPC without any obvious benefits for NPC's existing ratepayers. Considerable further detail (and debate) is required before fully apprised decisions can be made as to how best protect NPC's existing customers. [NWC Submission P52]

The URRC notes there are presently no industrial sites served by QEC. However, QEC indicated there is the potential for new industrial customers to come on-stream in the future and considered any revenue variability and other cost risks associated with serving these large customers should not adversely impact QEC's other customers and rates.

The URRC considers it would be appropriate for QEC to enter into contractual terms with specific large industrial customers for service designed to achieve a reasonable balancing of risk between the customer and QEC's other customers. The URRC also considers, consistent with the practice in other jurisdictions, the revenues and costs resulting from industrial contracts should be included in the corporation's revenue requirement and revenues, and must be subject to review at the time of QEC's subsequent GRAs. The URRC considers any contractual rates established with large industrial customers should reflect the principles of cost causation including an allocation of shared costs. QEC is directed to reflect the foregoing principles in any future filings and in contractual arrangements with large industrial customers.

15.4 Subsidy Level

For the purpose of it is generally understood that the Government of Nunavut's Territorial Power subsidy program is not a part of the rate setting process. However, during the community consultations the issue of the subsidy program was raised in practically every community that was visited. The items listed below are matters that the Government of Nunavut and QEC may take into consideration for information purposes.

1. The customers receiving the subsidy program that reduces their rate to the Yellowknife Hydro Rate for the first 700 Kwh of consumption and then full rate for any consumption above 700 Kwh indicated the 700 Kwh limit is now inadequate. The program needs to be reviewed since the style of living has changed in Nunavut since this program was first introduced. The general consensus was that the 700 Kwh limit should be increased. Some customers suggested 1000 Kwh.

2. Private homeowners and businesses raised the issue of lack of price signals to public housing tenants under an unlimited $0.06 per Kwh rate. It was suggested that there be some kind of a consumption ceiling and possibly sliding price scale to ensure that there is some incentive to conserve.

3. Most or all communities voiced their concern regarding the status of the subsidy program. All customers support the subsidy program and wanted some assurance that it will remain and suggested that the Government's intent for the program should be disclosed up front as part of the GRA.

16.0 Summary of Recommendations for Approval by Responsible Minister

The following recommendations are made with respect to rates:

1. URRC recommends approval of the residential and commercial energy rates under the Governmental and non Governmental categories set out in Schedule C-3 attached, effective April 1, 2005.

2. For the purposes of this Report the URRC recommends approval of the existing residential and commercial monthly fixed charges and the commercial demand charge.

3. The URRC recommends approval of a 15% across the board increase for all street lighting rates effective April 1, 2005.

4. The URRC recommends that the Government of Nunavut issue a request for proposals to qualified Engineering firms or consulting firms that are knowledgeable in the operations and management of a Utility and Utility Regulation, to conduct a review of the corporation with the objective of streamlining the power corporation into a well run utility and regaining the confidence of its customers and stakeholders. The URRC recommends this review be completed in a timely manner to allow QEC to respond meaningfully to the URRC directions set out in Section 12.1 of this Report.

5. The URRC has determined on a preliminary basis that the corporation may qualify for an additional increase effective April 1, 2006 provided it can satisfy the URRC as to the effectiveness of the corporation's financial management plan as well as demonstrate the prudence of certain cost elements included in the revenue requirement. Following receipt and examination of the reports requested for filing on or before September 30, 2005, the URRC will make a further recommendation to the responsible Minister confirming or varying its preliminary determinations respecting salaries and wages, supplies and services and travel and accommodation expenses as well as recommend

approval, denial or adjustment of the additional increase effective April 1, 2006 referred to in Section 12.1.

6. The URRC recommends approval of the revised terms and conditions of service filed by QEC as part of its application for electricity service. The URRC recommends approval of its direction that QEC develop a separate set of terms and conditions of service for district heating service, including investment levels and file this information for consideration by the URRC and approval by the responsible Minister within 90 days of this Report.

7. The URRC recommends approval of the residual heat rate formula proposed by QEC in this application

8. The URRC recommends denial of the alternative energy rate, the environmental initiatives rate and the beneficiary employment rate proposals of QEC

9. The URRC recommends approval of the rate stabilization fund in accordance with the parameters specified in Section 11 of this Report

17.0 Summary of Directions to be Addressed at or prior to the Next GRA

The following is a summary of directions the URRC recommends be approved by the responsible Minister for compliance by the corporation at the time or prior to the next GRA.

Page 8

The URRC expects that prior to QEC filing its next GRA, QEC will have community consultations with its customers and directs QEC to provide, as part of its next GRA, commentary concerning the process and results of these community consultations.

Page 16

QEC is directed to exclude the disallowed amount of $1.745 million from utility plant in service, in future General Rate Applications.

Page 20

However, QEC is directed to address the prudence of all software costs included in plant in service at the time of the next GRA.

Page 23

Accordingly, QEC is directed to file a lead lag study supporting the cash expense component of working capital at the next GRA. This study should reflect QEC's best practice policies regarding management of working capital.

Page 52

The URRC directs QEC to adopt the above definition for uninsured losses for the purposes of recording uninsured losses.

Page 52

The Corporation is directed to record all external hearing costs incurred with respect to these proceedings against the reserve when they become known.

Page 55

The URRC directs that QEC conduct an amortization study prior to the end of March 31, 2006 for presentation in the next GRA. The amortization study should specifically include factors that are common to QEC's operating territory in the determination of the proposed lives and net salvage.

Page 58

However the URRC directs QEC to use the correct amortization rate for contributions at the time of the next GRA.

Page 63-64

The following directions are therefore provided for the treatment of the cost of funding alternative energy studies:

- QEC should develop policies and guidelines specifying the nature of studies that will qualify as alternate energy studies, consistent with the purposes of QEC as a regulated utility providing electricity and heat services

- Prudent expenditures on alternative energy projects may be treated as part of the corporation's regulated costs for ratemaking purposes;

- AFUDC may be earned by the Corporation on the mid year balance of prudent expenditures charged to the alternative energy deferral account if the project extends beyond one year ;

- If a project that is investigated proves viable the costs should be added to the capital cost of the relevant alternative energy project;
- If a project that is investigated proves not viable the costs should be amortized over a reasonable period.

Page 65

The URRC directs QEC to provide a detailed study of the potential liability on the part of QEC with respect to future removal and site restoration expenditures, including a risk assessment of unknown contingencies, at the time of the next GRA.

Page 68-69

QEC is directed to adopt the following procedures with respect to implementation of the rate stabilization fund and adjustment mechanism:

- The balance in the rate stabilization fund as of April 1, 2005 shall be zero;

- The amount charged or credited in each month to the fund will reflect the following adjustment formula for each community:

    Actual or forecast generation in Kwh/Last URRC approved efficiencies in Kwh per liter* (Actual price per liter-forecast price per liter);

- Interest shall be charged or deducted from the rate stabilization fund balance based on short term interest rates;

- If at any point in time the forecasts indicate the fund balance will exceed the threshold of plus or minus $1 million within a six month period the Corporation shall apply to the Responsible Minister for approval of a Nunavut wide fuel rider designed to recover or refund the balance in the fund over a suitable period targeting a zero balance at the end of the above mentioned six month period, when recovery or refund is complete;

- To the extent accommodated by the corporation's billing system, the Nunavut wide fuel rider shall be an across the board percent rider. This will provide for a proportionate increase or decrease in costs for all communities and rate classes.

<u>Page 72-74</u>

Accordingly the URRC directs QEC to provide the following information on or before September 30, 2005 following completion of the review referred to in Section 6.1.2 of this Report:

- Detailed report on the corporation's financing plan following implementation of the 15% increase in rates recommended herein and an assessment of the corporation's financial position in 2005/06 assuming the increases determined in this report on a preliminary basis are implemented;

- Detailed report of forecast salaries and wages by function (Finance, Engineering, Operations etc) for 2004/05 and 2005/06 budgets, providing budget type justification for the prudent level of FTEs by category (Union, Excluded, Beneficiaries under the Land Claims Agreement) and the prudent levels of regular salaries and wages, overtime, casual labour, charged out labour (including capitalized labour) and fringe benefits required for the provision of electricity and residual heat services in Nunavut in an efficient and cost effective manner. In discussing fringe benefits and beneficiary employment the matter of any shared responsibility on the part of other levels of Government must be addressed. The report should identify charges to affiliates if QEC employees perform services for affiliates of the corporation;

- A detailed report of supplies and services providing an overview of the elements comprising this expense category including planned maintenance, other maintenance and housing expense for 2004/05 and 2005/06 budgets. More specific details should be provided on the following:

  a) A detailed report on planned maintenance expenditures carried out/forecast in accordance with maintenance cycles on diesel plant and distribution plant in each year from 2001/02 to 2004/05, 2005/06 budgets. The report should identify any planned maintenance deferred from one year to the next. The planned maintenance report should address how the deterioration in reliability levels discussed in section 14.1 of this report will be addressed.

  b) A detailed report of housing expenditures explaining the relationship between housing expense and staffing levels and further explaining the changes in the level of this category of expense from year to year from 2001/02 to 2004/05 and 2005/06 budgets.

- A detailed report of travel and accommodations expense, explaining the changes in the components of this category of expense from year to year, from 2001/02 to 2004/05 and 2005/06 budgets. The report should address the prudent level of medical travel expense in light of any contributory responsibility on the part of the territorial or Federal Governments.

Page 77

The URRC considers further study and assessment of rate averaging mechanisms is needed and therefore directs QEC to address alternative mechanisms for rate averaging or levelizing rates at the next GRA. In responding to this direction QEC should specifically address how any potential rate shock to customers as a result of this move to averaging of costs among communities will be mitigated. QEC should also have regard to community and customer input when responding to this direction.

Page 79

Accordingly, the URRC directs QEC to propose a capital stabilization fund as an interim mechanism for the purpose of mitigating the high rates for certain communities resulting from the community based rate structure. The fund mechanics should be worked out by QEC and forwarded to the Minister for approval within 90 days of the release of this Report. URRC notes this fund adjustment will result in somewhat higher than average increases for customers in certain communities.

Page 79

As part of the response to the direction concerning a capital stabilization fund QEC is also directed to address, taking into account the URRC's comments in this section concerning rate averaging, the approach to adjusting rates if an additional increase as discussed in Section 12.1, effective April 1, 2006, were to be recommended by the URRC and approved by the responsible Minister.

Page 79

However, URRC considers a fully allocated cost of service study should be provided as part of the next GRA and directs QEC to do so.

Page 79

The URRC recognizes a fully allocated cost of service study cannot be meaningfully examined until there is resolution on the issue of rate averaging among communities. To address this matter the URRC recommends the following sequencing of the next GRA. The response to the URRC's direction on rate averaging options should be provided as part of a separate phase I application for consideration of revenue requirement and rate averaging mechanisms. The revenue requirement and rate averaging mechanism approved by the URRC in phase I will then form the basis for cost allocations to customer classes and rate design in a phase II application. Accordingly, the URRC directs QEC to follow the above sequence of proceedings for the next GRA.

Page 83

However, the URRC directs QEC to address the appropriateness and feasibility of investing customer deposits in commercial paper short term investments at the time of the next GRA. At the same time QEC should address the appropriate rate of interest to be paid on customer deposits and the appropriate working capital treatment of deposits.

Page 83

The URRC directs QEC to address the cost basis for service connection fees at the time of the next GRA.

Page 85

The URRC directs QEC to immediately commence collecting quarterly statistics, by region and by community, for both planned and unplanned outages and report those statistics collected to the point in time of the filing of their next GRA.

Page 85

Accordingly, the URRC directs QEC to recommend appropriate target measures for reliability having regard to industry standards, at the next GRA.

Page 86

Accordingly, QEC is directed to commence maintaining a complaints log for recording customer complaints by complaint category and explain how each complaint was resolved.

Page 87

The URRC directs QEC to institute the above service quality measures for monitoring and reporting service quality and customer satisfaction levels, as soon as possible and in any event no later than April 1, 2006.

Page 87

QEC is directed to report to the URRC at the time of the next GRA on the service quality and customer satisfaction measures so implemented and the date implemented.

Page 87

QEC is also directed to recommend appropriate targets for performance and service quality measures having regard to industry standards, at the next GRA.

Page 89

Accordingly, the URRC directs QEC to prepare a fully allocated cost study at the time of the next GRA, showing the costs applicable to district heating and those applicable to electrical service customers in those communities where district heating service is offered.

Page 91

The URRC also considers, consistent with the practice in other jurisdictions, the revenues and costs resulting from industrial contracts should be included in the corporation’s revenue requirement and revenues, and must be subject to review at the time of QEC’s subsequent GRAs. The URRC considers any contractual rates established with large industrial customers should reflect the principles of cost causation including an allocation of shared costs. QEC is directed to reflect the foregoing principles in any future filings and in contractual arrangements with large industrial customers.

ON BEHALF OF THE

UTILITY RATES REVIEW COUNCIL

DATED January 27, 2005
Ray Mercer
Chairman

Schedule A
Qulliq Energy Corporation 2004/05 GRA
Rate Base
$000

	Reference	2004/ 05 Per NPC	2004/ 05 Per URRC
Gross Plant in Service			
Beginning of year		157811	157811
Additions	A-1, A-2	15065	11676
Retirements			
Disposals			
End of Year		172876	169487
Mid Year		165343	163649
Accumulated Amortization			
Beginning of year	Note 1	51733	68033
Amortizations		6328	6411
Retirements			
Disposals			1000
End of Year		58061	75444
Mid Year		54897	71739
Mid Year Net Plant		110446	91911
Mid Year Contributions		-6496	-6496
Working Capital		9694	9009
Rate Base		113644	94424

Notes:

1. Opening accumulated amortization has been increased by $16.3 milion to reflect future removal & site restoration amounts collected from customers in the past.

Schedule A-1

Qulliq Energy Corporation 2004/05 GRA

Construction Work In Progress & Additions to Rate Base Per QEC

$000

	Beginning	Additions	AFUDC	Transfer To Rate Base	Closing
Diesel Plant:					
Baker Lake Plant	4997	3910		8907	0
Arviat Plant expansion	6	2036		2041	0
Pangnirtung Engine Replace (Cat 398)	609	109		718	0
Qikiqtarjuaq Engine Replace (Cat 353)	332			332	0
Plant design project	1	197		0	198
Plant Expansion design-Igloolik		46		0	46
Coral Harbour Engine Rep (Cat 398, D353)		805		805	0
Kugaaruk Eng. Replace (Det Diesel 8V71)		477		477	0
	5943	7580	0	13279	244
Distribution:					
Gjoa Haven distribution project	1			1	0
Kugaaruk	20			20	0
Rankin Inlet distribution plant	3			3	0
Baker Lake distribution plant	9	365		374	0
Chesterfield Inlet distribution	1			1	0
Iqaluit distribution	1			1	0
Pond Inlet distribution	0	438		438	0
Igloolik distribution	5			5	0
Kimmirut distribution	11			11	0
Taloyoak Pole replacement		173		173	0
Cambridge Bay Rebuild Feeder to Airport		228		228	0
	52	1204	0	1255	0
Energy Utilization					
Rankin Inlet Residual heat	113	2243		0	2356
Iqaluit Residual heat	247			0	247
	359	2243	0	0	2602
General					
Great plains software	358			358	0
Boom Truck		172		172	0
	358	172	0	530	0
Total	6713	11198	0	15065	2846

Schedule A-2

Qulliq Energy Corporation 2004/05 GRA					
Construction Work In Progress & Additions to Rate Base Per URRC					
$000					
	Beginning	**Additions**	**Disallowed**	**Transfer To Rate Base**	**Closing**
Diesel Plant:					
Baker Lake Plant	4997	3910	1745	7162	0
Arviat Plant expansion	6	2036		2041	0
Pangnirtung Engine Replace (Cat 398)	609	109		718	0
Qikiqtarjuaq Engine Replace (Cat 353)	332			332	0
Plant design project	1	197		0	198
Plant Expansion design-Igloolik		46		0	46
Coral Harbour Engine Rep (Cat 398, D353)		805			805
Kugaaruk Eng. Replace (Det Diesel 8V71)		477		477	0
	5943	7580	1745	10729	1049
Distribution:					
Gjoa Haven distribution project	1			1	0
Kugaaruk	20			20	0
Rankin Inlet distribution plant	3			3	0
Baker Lake distribution plant	9	365		374	0
Chesterfield Inlet distribution	1			1	0
Iqaluit distribution	1			1	0
Pond Inlet distribution	0	438			438
Igloolik distribution	5			5	0
Kimmirut distribution	11			11	0
Taloyoak Pole replacement		173		173	0
Cambridge Bay Rebuild Feeder to Airport		228			228
	52	1204	0	589	666
Energy Utilization					
Rankin Inlet Residual heat	113	2243		0	2356
Iqaluit Residual heat	247			0	247
	359	2243	0	0	2602
General					
Great plains software	358			358	0
Boom Truck		172			172
	358	172	0	358	172
Total	6713	11198	1745	11676	4490

Schedule A-2.1

Qulliq Energy Corporation 2004/05 GRA
Estimate of Baker Lake Plant Addition to Rate Base Per URRC

<u>Comparison of Recent Construction Costs of Generating Stations</u>

(From URRC's Baker Lake Plant Project Permit Report Dated May 16, 2003)

			Repulse Bay	**Clyde River**	**Sanikiluaq**	**Baker Lake**
1	Year Constructed		1999-2001	1999-2001	2000-2001	2002-2005
2	Total Cost ($) [Table C-1]		2401980	3324859	3144628	8480542
3	**New Gensets**		499900	393957	399256	1100000
4	**Non standard items:**					
5	Bulk storage tanks					200000
6	Relocate CAT 3512					200000
7	Transformer					50000
8	Heat Recovery joint costs[Response11 (b)]					587000
9	Switchgear		191000	362465	202955	420000
10		Sub total	191000	362465	202955	1457000
10	**Adjusted Cost [L2-3-10]**		1711080	2568437	2542417	5923542
11	Ultimate capacity of plant (KW) [Resp 5 (a) P 7 of 17]		4500	4500	4500	6000
12	Cost Per KW [L10/L11]		380.24	570.76	564.98	987.26

<u>Estimation of Prudent Costs of Baker Lake Plant based on the Sanikiluaq plant</u>

13	Inflation adjustment @ 3.2% per annum for 4 years lag between projects	1.134276	1.1342761
14	Inflation adjusted cost/ KW	647.40	640.85
15	Adjusted Baker Lake cost for common items	3884422	3845070.5
16	Add: Non standard items	1457000	1457000
17	Add: Gensets	1100000	1100000
18	Total Adjusted Baker Lake Costs	6441422	6402071
19	Estimated AFUDC at a cost rate of 7% 2002-2005	742988	738449
20	Baker Lake Cost allowed	7184410	7140519
21	Average Estimated Cost of Baker Lake Plant		7162465

AFUDC Calculation assuming equal expenditures in each year

Year 1 (2001/02)		
Opening balance	0	0
Addition	1610356	1600518
AFUDC	56362	56018
Closing balance	1666718	1656536
Year 2 (2002/03)		
Opening balance	1666718	1656536
Addition	1610356	1600518
AFUDC	173033	171976
Closing balance	3450106	3429029
Year 3 (2003/04)		
Opening balance	3450106	3429029
Addition	1610356	1600518
AFUDC	297870	296050
Closing balance	5358332	5325597
Year 4 (2004/05)		
Opening balance	5358332	5325597
Addition	1610356	1600518
AFUDC (Half Year AFUDC)	215723	214405
Closing balance	7184410	7140519
Total AFUDC	742988	738449

Schedule A-3

Qulliq Energy Corporation 2004/05 GRA
Working Capital
000

	Reference	2004/ 05 Per QEC	Per URRC
Cash working capital	Notes 1 & 2	2331	2144
Mid Year Deposits		-651	-651
Mid Year Inventory		7108	7108
Mid Year Deferred charges		502	0
Mid Year Prepaid expenses		404	404
Working Capital		9694	9005

Note 1
Cash Working Capital Per QEC

	Amount	Net Lag	Working Capital
Fuel and Lubricants	27578	13.87	1048
Salaries & Wages	17316	13.87	658
Supplies & Services	12936	13.87	492
Travel & Accomodations	3511	13.87	133
			2331

Note 2
Cash Working Capital Per URRC

	Amount	Net Lag	Working Capital
Fuel and Lubricants	26498	13.87	1007
Salaries & Wages	16000	13.87	608
Supplies & Services	11225	13.87	427
Travel & Accomodations	2700	13.87	103
			2144

Schedule A-4			
Qulliq Energy Corporation 2004/05 GRA			
Contributions			
$000			
		2004/ 05	
	Reference	Per NPC	Per URRC
Gross Contributions			
Beginning of year		10703	10703
Additions		0	0
Retirements			
Disposals			
End of Year		10703	10703
Mid Year		10703	10703
Accumulated Amortization of Contributions			
Beginning of year		4018	4018
Amortizations		378	378
Retirements			
Disposals			
End of Year		4396	4396
Mid Year		4207	4207
Mid Year Net Contributions		6496	6496

Schedule B							
Qulliq Energy Corporation 2004/05 GRA							
Return on Rate Base							
$000							
		Per NPC					
	Reference	Mid Yr Capital	Deemed Capital	Ratio	Rate Base	Cost Rates	Return
Short term debt		15	15	0.01%	10	4.0%	0.4
PPD		9914	9914	6.10%	6928	4.0%	277.1
Long term debt		82000	82000	50.42%	57303	6.8%	3901.7
Mid year NTPC		5646	5646	3.47%	3945	4.0%	157.8
Equity		22256	65050	40.00%	45458	11.5%	5227.6
Total	Note 1	119831	162625	100.0%	113644		9129.8

		Per URRC					
	Reference	Mid Yr Capital	Deemed Capital	Ratio	Rate Base	Cost Rates	Return
Long term debt	Note 2	77000	77000	74.10%	69965	6.2%	4355.6
No Cost Capital		675	675	0.65%	613	0.0%	0.0
Equity		26243	26243	25.25%	23845	9.6%	2289.1
Total		103918	103918	100.0%	94424	7.0%	6644.7

Note 1

Return on mid year NTPC and PPD not included in total return

Note 2

Cost of Long Term debt Per URRC

April 1 2004 balance:			
Debenture debt	61000	6.809%	4153.5
Floating rate capital loan	16000	4.000%	640.0
	77000	6.225%	4793.5
March 31, 2005 balance			
Debenture debt	61000	6.809%	4153.5
Floating rate capital loan	16000	4.000%	640.0
	77000	6.225%	4793.5
Mid Year Debt Rate	77000	6.225%	4793.5

Schedule B-1

Qulliq Energy Corporation 2004/05 GRA

Capitalization

$000

	2004/ 05	
	Per QEC	**Per URRC**
Short Term Debt		
Beginning of year	30	
Additional borrowing	11970	
Repayment	-12000	
End of year	0	
Mid Year	15	0
Mid year PPD	9914	0
Long Term debt		
6.809% Debenture debt	61000	61000
Floating rate capital loan facility	16000	16000
Total beginning of year	77000	77000
Additional borrowing	10000	0
End of Year	87000	77000
Mid Year	82000	77000
Mid Year NTPC	5646	
Equity		
Beginning of year	24628	24628
Division cost adjustment	8453	4227
Sub total		28855
GN Funding in lieu of fuel rider 2004/05		7974
Net loss	-13198	-13198
End of Year	19883	23631
Mid Year	22256	26243
No Cost Capital		
Hearing Reserve:		
Beginning of year		300
Addition		100
Estimated Expense		-100
Closing balance		300
Mid Year Balance		300
Reservefor Injuries & Damages:		
Beginning of year		300
Addition		150
Estimated Expense		0
Closing balance		450
Mid Year Balance		375
	119831	103918

Revenue Requirement			
$000			
	Reference	2004/ 05	
		Per NPC	Per URRC
Operations and Maintenance			
Fuel & lubricants		23897	
Fuel & lubricants Aug 1 adjustment		3681	
Total Fuel & Lubricants		27578	26498
Salaries & wages		17316	16000
Supplies & services		12936	11225
Travel & accomodations		3511	2700
Total O&M expense		61341	56423
Reserves			
Reserve for injuries & damages		150	150
Rate hearing reserve		100	100
Total reserves		250	250
Amortization			
Capital asset amortization		6328	6411
Amortization of contributions		-378	-378
Financing cost amortization		497	249
Total amortizations		6447	6282
Return on rate base		9136	6645
Total revenue requirement		77174	69600

Schedule C-1			
Qulliq Energy Corporation 2004/05 GRA			
Increase Decrease in Rates			
$000			
		2004/ 05	
	Reference	**Per NPC**	**Per URRC**
Total revenue requirement		77174	69600
Revenue at Existing rates			
Sales revenue	Sch C-2	55462	56102
Bad debt Expense			-130
Other Revenue	Note 1	1080	1155
Total Revenue at Existing Rates		56542	57127
Shortfall		20632	12473
Additional Riders:			
Sales Mwh		135474	135474
Alternative Energy Rider ($0.005/Kwh)		677	
Environmental Initiatives Rider (($.005/Kwh)		677	
Beneficiary Employment Rate ($0.0125/Kwh)		1693	
Additional Riders total		3048	0
Total Shortfall Based on Existing Rates		23680	12473
Shortfall as Percent of Existing Rates		42.7%	22.2%
Rate Increase Efective April 1, 2005			
Sales Revenue at existing Rates			56102
Increase effective April 1, 2005			8415
Sales Revenue at URRC Approved Rates			64517
Percent increase effective April 1, 2005			15.0%
Phased in Rate Increase (Preliminary)			
Total 2004/05 shortfall			12473
Increase effective April 1, 2005			8415
Phased in increase Effective April 1, 2006			4058
Percent increase effective April 1, 2006			6.3%

Note 1 Other revenue increased by $75,000 consistent with prior year actuals

Schedule C-2
Qulliq Energy Corporation 2004/05 GRA
Revenue at Existing Rates
$000

		Residential			Commercial			Rates				Energy Charge Revenue		Fixture Rev	Fixed Charge Revenue		Demand Rev	Total
		Sales	Customers		Sales	Customers		Residential		Commercial		Residential	Commercial	Str Lights	Resid.	Comm.	Comm.	Revenue
			Non Govt	Govt		Non Govt	Govt	Non Govt	Govt	Non Govt	Govt							
501	Cambridge Bay	2,639,137	587	45	4784152	75	100	41.63	41.63	35.27	35.27	1,098,596	1,687,337	47,401	136,512	84000	71703	3125549
502	Gjoa Haven	1,459,976	284	29	1608500	27	52	50.15	51.95	47.94	47.94	734,655	771,105	43,524	67,608	37920	23261	1678073
503	Taloyoak	1,098,753	216	18	1379654	19	46	55.82	60.98	54.83	54.83	617,787	756,450	32,305	50,544	31200	17260	1505546
504	Kugaaruk	798,089	148	9	1067259	20	28	65.89	65.89	58.00	58.00	525,874	619,028	18,498	33,912	23040	19409	1239761
505	Kugluktuk	2,114,436	424	26	2506550	42	82	52.61	56.03	48.72	48.72	1,116,570	1,221,218	49,183	97,200	59520	43242	2586933
		8,110,391	*1,659*	*127*	*11346114*	*183*	*308*					*4,093,481*	*5,055,138*	*190,911*	*385,776*	*235,680*	*174,875*	*10,135,861*
601	Rankin Inlet	4,887,926	890	73	7292398	143	97	32.82	32.82	28.25	31.82	1,604,303	2,165,239	47,906	208,008	115200	137139	4277795
602	Baker Lake	2,698,410	546	31	3677485	65	124	37.96	37.96	35.29	35.29	1,024,416	1,297,825	49,844	124,632	90720	55725	2643162
603	Arviat	2,570,686	506	22	4428988	46	91	43.59	43.59	40.34	40.34	1,120,594	1,786,587	33,447	114,048	65760	51003	3171439
604	Coral Harbour	1,099,963	210	7	1425469	18	55	53.47	53.47	48.67	48.67	588,150	693,786	36,048	46,872	35040	25636	1425532
605	Chesterfield Inlet	576,221	130	10	830962	13	30	55.30	55.30	51.24	51.24	318,654	425,782	19,337	30,240	20640	13098	827751
606	Whale Cove	538,315	105	9	736214	8	35	62.03	104.13	81.45	90.44	351,355	652,969	38,776	24,624	20640	11640	1100003
607	Repulse Bay	922,811	141	11	1140106	4	31	47.36	47.36	41.14	41.14	437,043	469,073	22,198	32,832	16800	18325	996271
		13294332	*2528*	*163*	*19531622*	*297*	*463*					*5,444,514*	*7,491,260*	*247,556*	*581,256*	*364,800*	*312,566*	*14,441,952*
701	Iqaluit	14,603,303	2164	418	30976328	413	260	31.58	31.58	25.47	26.34	4,612,155	7,994,149	141,640	557,712	323040	659418	14288113
702	Pangnirtung	2,656,797	426	50	2914262	57	94	35.06	37.85	30.55	34.12	939,142	954,798	45,443	102,816	72480	53520	2168200
703	Cape Dorset	2,046,850	343	37	2486555	37	102	36.88	38.96	34.26	38.96	758,999	937,799	39,630	82,080	66720	47904	1933132
704	Resolute Bay	619,401	77	5	2318842	45	58	57.73	58.87	54.84	54.84	358,016	1,271,653	56,612	17,712	49440	44614	1798047
705	Pond Inlet	1,992,266	295	37	2168138	36	102	50.67	55.34	46.17	46.17	1,019,963	1,001,035	73,701	71,712	66240	45534	2278184
706	Igloolik	2,317,713	392	32	2124829	36	89	33.46	33.46	30.36	30.36	775,500	645,123	41,898	91,584	60000	35931	1650036
707	Hall Beach	902,027	154	7	1328310	23	30	49.89	51.99	47.91	47.91	450,836	636,402	29,660	34,776	25440	17226	1194340
708	Qikiqtarjuaq	815,483	174	18	1097170	25	38	42.82	49.69	40.36	49.69	354,288	504,562	21,970	41,472	30240	5324	957856
709	Kimmirut	665,063	121	7	884567	11	29	73.49	73.49	64.12	64.12	488,756	567,185	27,421	27,648	19200	15458	1145668
710	Arctic Bay	1,236,593	185	13	1020465	12	33	49.15	49.15	43.49	43.49	607,765	443,812	24,138	42,768	21600	16396	1156479
711	Clyde River	1,334,383	176	15	1311085	18	37	42.99	43.29	37.55	37.55	573,937	492,352	21,744	41,256	26400	14640	1170329
712	Grise Fiord	263,891	51	7	611034	7	30	51.83	63.75	60.65	60.65	140,792	370,592	16,366	12,528	17760	8038	566076
713	Sanikiluaq	1,162,710	152	7	1319721	19	43	45.57	45.57	43.51	43.51	529,847	574,210	27,318	34,344	29760	22018	1217497
		30616481	*4709*	*654*	*50561305*	*739*	*945*					*11,609,997*	*16,393,672*	*567,541*	*1,158,408*	*808,320*	*986,021*	*31,523,959*
		52,021,204	*8,897*	*943*	*81,439,041*	*1,220*	*1,715*					*21,147,992*	*28,940,070*	*1,006,008*	*2,125,440*	*1,408,800*	*1,473,462*	*56,101,772*
	Energy Charge Adjustment Ratio														90.87%		90.94%	

Schedule C-2.1

Qulliq Energy Corporation 2004/05 GRA

URRC Adjustment of Number of Customers

		Per URRC 2004/05 GRA						Per Unfiled GRA		Difference		Adjusted Customers		Adjustment Percent	
		Residential			Commercial			Residential	Commercial	Residential	Commercial	Residential	Commercial	Residential	Commercial
		Non Govt	Govt	Total	Non Govt	Govt	Total								
501	CAMBRIDGE BAY	393	30	423	75	100	175	632	173	209	-2	632	175	1.494	1.000
502	GJOA HAVEN	223	23	246	23	45	68	313	79	67	11	313	79	1.272	1.162
503	TALOYOAK	176	15	191	19	46	65	234	58	43	-7	234	65	1.225	1.000
504	KUGAARUK	119	7	126	18	25	43	157	48	31	5	157	48	1.246	1.116
505	KUGLUKTUK	348	21	369	37	72	109	450	124	81	15	450	124	1.220	1.138
		1259	*96*	*1355*	*172*	*288*	*460*	*1786*	*482*	*431*	*22*	*1786*	*491*		
601	RANKIN INLET	625	51	676	124	84	208	963	240	287	32	963	240	1.425	1.154
602	BAKER LAKE	428	24	452	49	93	142	577	189	125	47	577	189	1.277	1.331
603	ARVIAT	431	19	450	36	72	108	528	137	78	29	528	137	1.173	1.269
604	CORAL HARBOUR	183	6	189	18	55	73	217	63	28	-10	217	73	1.148	1.000
605	CHESTERFIELD INLET	89	7	96	13	30	43	140	43	44	0	140	43	1.458	1.000
606	WHALE COVE	72	6	78	7	29	36	114	43	36	7	114	43	1.462	1.194
607	REPULSE BAY	125	10	135	4	31	35	152	35	17	0	152	35	1.126	1.000
		1953	*123*	*2076*	*251*	*394*	*645*	*2691*	*750*	*615*	*105*	*2691*	*760*		
701	IQALUIT	1703	329	2,032	336	211	547	2582	673	550	126	2582	673	1.271	1.230
702	PANGNIRTUNG	359	42	401	38	62	100	476	151	75	51	476	151	1.187	1.510
703	CAPE DORSET	294	32	326	27	75	102	380	139	54	37	380	139	1.166	1.363
704	RESOLUTE BAY	76	5	81	45	57	102	82	103	1	1	82	103	1.012	1.010
705	POND INLET	283	36	319	26	74	100	332	138	13	38	332	138	1.041	1.380
706	IGLOOLIK	298	24	322	29	71	100	424	125	102	25	424	125	1.317	1.250
707	HALL BEACH	129	6	135	23	30	53	161	45	26	-8	161	53	1.193	1.000

708	QIKIQTARJUAQ	129	13	142	25	38	63	192	56	50	-7	192	63	1.352	1.000
709	KIMMIRUT	106	6	112	11	29	40	128	37	16	-3	128	40	1.143	1.000
710	ARCTIC BAY	160	11	171	11	32	43	198	45	27	2	198	45	1.158	1.047
711	CLYDE RIVER	171	15	186	16	32	48	191	55	5	7	191	55	1.027	1.146
712	GRISE FIORD	41	6	47	6	28	34	58	37	11	3	58	37	1.234	1.088
713	SANIKILUAQ	147	7	154	17	39	56	159	62	5	6	159	62	1.032	1.107
		3896	532	4428	610	778	1388	5363	1666	935	278	5363	1684		
		7108	***751***	***7859***	***1033***	***1460***	***2493***	***9840***	***2898***	***1981***	***405***	***9840***	***2935***		

Schedule C-3
Qulliq Energy Corporation 2004/05 GRA
Revenue at URRC Recommended Rates
$000

		Residential			Commercial			Rates			
		Sales	Customers		Sales	Customers		Residential		Commercial	
			Non Govt	Govt		Non Govt	Govt	Non Govt	Govt	Non Govt	Govt
	Average Percent increase							16.51%	16.51%	16.49%	16.49%
501	Cambridge Bay	2,639,137	587	45	4784152	75	100	48.50	48.50	41.09	41.09
502	Gjoa Haven	1,459,976	284	29	1608500	27	52	58.43	60.53	55.85	55.85
503	Taloyoak	1,098,753	216	18	1379654	19	46	65.04	71.05	63.87	63.87
504	Kugaaruk	798,089	148	9	1067259	20	28	76.77	76.77	67.57	67.57
505	Kugluktuk	2,114,436	424	26	2506550	42	82	61.30	65.28	56.76	56.76
		8,110,391	1,659	127	11346114	183	308				
601	Rankin Inlet	4,887,926	890	73	7292398	143	97	38.24	38.24	32.91	37.07
602	Baker Lake	2,698,410	546	31	3677485	65	124	44.23	44.23	41.11	41.11
603	Arviat	2,570,686	506	22	4428988	46	91	50.79	50.79	46.99	46.99
604	Coral Harbour	1,099,963	210	7	1425469	18	55	62.30	62.30	56.70	56.70
605	Chesterfield Inlet	576,221	130	10	830962	13	30	64.43	64.43	59.69	59.69
606	Whale Cove	538,315	105	9	736214	8	35	72.27	121.32	94.89	105.36
607	Repulse Bay	922,811	141	11	1140106	4	31	55.18	55.18	47.93	47.93

		13,294,332	2528	163	19531622	297	463				
701	Iqaluit	14,603,303	2164	418	30976328	413	260	36.80	36.80	29.67	30.68
702	Pangnirtung	2,656,797	426	50	2914262	57	94	40.84	44.10	35.59	39.75
703	Cape Dorset	2,046,850	343	37	2486555	37	102	42.96	45.39	39.91	45.39
704	Resolute Bay	619,401	77	5	2318842	45	58	67.26	68.59	63.89	63.89
705	Pond Inlet	1,992,266	295	37	2168138	36	102	59.03	64.48	53.79	53.79
706	Igloolik	2,317,713	392	32	2124829	36	89	38.98	38.98	35.37	35.37
707	Hall Beach	902,027	154	7	1328310	23	30	58.12	60.57	55.81	55.81
708	Qikiqtarjuaq	815,483	174	18	1097170	25	38	49.88	57.89	47.02	57.89
709	Kimmirut	665,063	121	7	884567	11	29	85.62	85.63	74.70	74.70
710	Arctic Bay	1,236,593	185	13	1020465	12	33	57.26	57.26	50.66	50.66
711	Clyde River	1,334,383	176	15	1311085	18	37	50.08	50.44	43.75	43.75
712	Grise Fiord	263,891	51	7	611034	7	30	60.39	74.27	70.65	70.65
713	Sanikiluaq	1,162,710	152	7	1319721	19	43	53.09	53.09	50.69	50.69
		30,616,481	4709	654	50561305	739	945				
		52,021,204	8,897	943	81,439,041	1,220	1,715				

Schedule C-3
Qulliq Energy Corporation 2004/05 GRA
Revenue at URRC Recommended Rates
$000 (cont.)

		Energy Charge Revenue		Fixture Rev	Fixed Charge Revenue		Demand Rev	Total
		Residential	Commercial	Str Lights	Residential	Commercial	Commercial	Revenue
				15.0%				
501	Cambridge Bay	1,279,947	1,965,645	54,511	136,512	84000	71703	3592318
502	Gjoa Haven	855,928	898,290	50,053	67,608	37920	23261	1933060
503	Taloyoak	719,768	881,219	37,151	50,544	31200	17260	1737142
504	Kugaaruk	612,683	721,130	21,273	33,912	23040	19409	1431446
505	Kugluktuk	1,300,888	1,422,644	56,560	97,200	59520	43242	2980055
		4,769,214	5,888,928	219,548	385,776	235,680	174,875	11,674,021
601	Rankin Inlet	1,869,134	2,522,372	55,092	208,008	115200	137139	4906944
602	Baker Lake	1,193,521	1,511,887	57,321	124,632	90720	55725	3033807
603	Arviat	1,305,576	2,081,265	38,464	114,048	65760	51003	3656116
604	Coral Harbour	685,239	808,218	41,455	46,872	35040	25636	1642460
605	Chesterfield Inlet	371,256	496,010	22,238	30,240	20640	13098	953482
606	Whale Cove	409,355	760,669	44,592	24,624	20640	11640	1271519
607	Repulse Bay	509,188	546,442	25,528	32,832	16800	18325	1149114
		6,343,269	8,726,862	284,689	581,256	364,800	312,566	16,613,443
701	Iqaluit	5,373,509	9,312,697	162,886	557,712	323040	659418	16389261
702	Pangnirtung	1,094,172	1,112,282	52,259	102,816	72480	53520	2487530
703	Cape Dorset	884,291	1,092,478	45,575	82,080	66720	47904	2219048
704	Resolute Bay	417,116	1,481,399	65,104	17,712	49440	44614	2075384
705	Pond Inlet	1,188,334	1,166,144	84,756	71,712	66240	45534	2622720
706	Igloolik	903,515	751,529	48,183	91,584	60000	35931	1890743

707	Hall Beach	525,258	741,370	34,109	34,776	25440	17226	1378179
708	Qikiqtarjuaq	412,772	587,784	25,266	41,472	30240	5324	1102858
709	Kimmirut	569,438	660,735	31,534	27,648	19200	15458	1324013
710	Arctic Bay	708,093	517,014	27,759	42,768	21600	16396	1333629
711	Clyde River	668,680	573,560	25,006	41,256	26400	14640	1349542
712	Grise Fiord	164,033	431,717	18,821	12,528	17760	8038	652897
713	Sanikiluaq	617,311	668,920	31,416	34,344	29760	22018	1403770
		13,526,523	19,097,630	652,672	1,158,408	808,320	986,021	36,229,574
		24,639,006	33,713,420	1,156,909	2,125,440	1,408,800	1,473,462	64,517,038

Schedule C-4

Qulliq Energy Corporation 2004/05 GRA

Comparison of Revenues at Existing (as Adjusted), QEC Proposed and URRC Recommended Rates

$000

Kitikmeot		Sales in Kwh	Revenue Existing Rates As Adjused by URRC	Revenue QEC Proposed Base Rates	QEC Proposed Additional Rider Revenue	Total Revenue at QEC Proposed Rates	QEC Requested Change	URRC Recommended Revenue	URRC Recommended Increase
		A	B	C	D	E	F	G	H
501	CAMBRIDGE BAY	7529393	3,126	4,258	169	4,428	41.7%	3,592	14.9%
502	GJOA HAVEN	3140140	1,678	1,809	71	1,879	12.0%	1,933	15.2%
503	TALOYOAK	2535622	1,506	1,450	57	1,507	0.1%	1,737	15.4%
504	KUGAARUK	1895744	1,240	1,085	43	1,128	-9.0%	1,431	15.5%
505	KUGLUKTUK	4693477	2,587	2,709	106	2,814	8.8%	2,980	15.2%
		19,794,376	10,136	11,311	445	11,756	16.0%	11,674	15.2%
Kivalliq									
601	RANKIN INLET	12287736	4,278	6,957	276	7,233	69.1%	4,907	14.7%
602	BAKER LAKE	6522415	2,643	3,704	147	3,851	45.7%	3,034	14.8%
603	ARVIAT	7068878	3,171	3,961	159	4,120	29.9%	3,656	15.3%
604	CORAL HARBOUR	2574716	1,426	1,486	58	1,544	8.3%	1,642	15.2%
605	CHESTERFIELD INLET	1431280	828	830	32	862	4.2%	953	15.2%
606	WHALE COVE	1314164	1,100	775	30	804	- 26.9%	1,272	15.6%
607	REPULSE BAY	2081709	996	1,187	47	1,234	23.9%	1,149	15.3%
		33,280,898	14,442	18,901	749	19,650	36.1%	16,613	15.0%
Qikiqtaaluq									
701	IQALUIT	45958639	14,288	25,665	1,034	26,699	86.9%	16,389	14.7%
702	PANGNIRTUNG	5677427	2,168	3,242	128	3,370	55.4%	2,488	14.7%
703	CAPE DORSET	4627773	1,933	2,647	104	2,751	42.3%	2,219	14.8%
704	RESOLUTE BAY	2980279	1,798	1,706	67	1,773	-1.4%	2,075	15.4%
705	POND INLET	4279852	2,278	2,478	96	2,574	13.0%	2,623	15.1%
706	IGLOOLIK	4541098	1,650	2,605	102	2,707	64.0%	1,891	14.6%
707	HALL BEACH	2280762	1,194	1,290	51	1,341	12.3%	1,378	15.4%
708	QIKIQTARJUAQ	1941609	958	1,115	44	1,159	20.9%	1,103	15.1%
709	KIMMIRUT	1582126	1,146	914	36	949	- 17.1%	1,324	15.6%
710	ARCTIC BAY	2288559	1,156	1,314	51	1,366	18.1%	1,334	15.3%
711	CLYDE RIVER	2669852	1,170	1,516	60	1,576	34.7%	1,350	15.3%
712	GRISE FIORD	893885	566	516	20	536	-5.3%	653	15.3%
713	SANIKILUAQ	2531606	1,217	1,436	57	1,493	22.6%	1,404	15.3%
		82,253,467	31,524	46,445	1,851	48,295	53.2%	36230	14.9%
		135,328,741	56,102	76,656	3,045	79,701	42.1%	64,517	15.0%

Residual Heat	300	300	300
Joint Use	300	300	300
Miscellaneous Charges	400	400	475
Time and Materials	80	80	80
	1,080	1,080	1,155
	57,182	77,736	65,672

Schedule D
Qulliq Energy Corporation 2004/05 GRA
Fuel Costs Per URRC
$000

		Price 4 Months to July 31	Fuel Efficiencies	Generation 4 Months to July 31	Fuel Liters to July 31	Fuel Cost to July 31	Price 8 Months to Mar 31	Generation 8 Months to Mar 31	Fuel Liters to Mar 31	Fuel Cost to Mar 31	Fuel Cost 2004/05
501	CAMBRIDGE BAY	0.8088	3.690	2394	649	525	0.8865	5701	1545	1370	1894
502	GJOA HAVEN	0.766	3.670	1058	288	221	0.8724	2520	687	599	820
503	TALOYOAK	0.9111	3.630	796	219	200	0.9247	1895	522	483	683
504	KUGAARUK	0.8151	3.611	618	171	140	0.925	1472	408	377	517
505	KUGLUKTUK	0.7615	3.660	1523	416	317	0.8865	3626	991	878	1195
				6389	1744	1402		15214	4152	3707	5108
Kivalliq											
601	RANKIN INLET	0.5174	3.740	4030	1078	558	0.574	9599	2567	1473	2031
602	BAKER LAKE	0.6503	3.680	2186	594	386	0.7486	5207	1415	1059	1446
603	ARVIAT	0.531	3.713	2272	612	325	0.572	5411	1457	834	1159
604	CORAL HARBOUR	0.6393	3.460	850	246	157	0.7369	2024	585	431	588
605	CHESTERFIELD INLET	0.5377	3.150	482	153	82	0.5785	1148	364	211	293
606	WHALE COVE	0.6249	3.400	448	132	82	0.7215	1066	314	226	309
607	REPULSE BAY	0.6587	3.600	675	188	124	0.7576	1607	446	338	462
				10943	3001	1714		26062	7148	4572	6286
Qikiqtaaluq											
701	IQALUIT	0.4698	3.800	15022	3953	1857	0.573	35779	9416	5395	7252
702	PANGNIRTUNG	0.4874	3.754	1846	492	240	0.5743	4396	1171	673	912
703	CAPE DORSET	0.4746	3.630	1518	418	198	0.5606	3616	996	558	757
704	RESOLUTE BAY	0.5609	3.660	1158	316	177	0.653	2758	754	492	670
705	POND INLET	0.495	3.430	1429	417	206	0.5825	3404	992	578	784
706	IGLOOLIK	0.5167	3.480	1436	413	213	0.6057	3420	983	595	808
707	HALL BEACH	0.5041	3.490	744	213	107	0.5922	1773	508	301	408
708	QIKIQTARJUAQ	0.4746	3.203	662	207	98	0.5606	1577	492	276	374
709	KIMMIRUT	0.4747	3.630	532	147	70	0.5608	1269	350	196	266

710	ARCTIC BAY	0.4992	3.500	746	213	106	0.587	1778	508	298	405
711	CLYDE RIVER	0.4696	3.380	903	267	125	0.5553	2150	636	353	479
712	GRISE FIORD	0.6184	3.460	303	88	54	0.6766	722	209	141	195
713	SANIKILUAQ	0.612	3.700	823	222	136	0.7457	1959	529	395	531
				27122	7366	3590		64601	17544	10252	13841
				44454	12111	6705		105877	28844	18531	25236
	Lube oil & Drum expense, Other fuel (5% of Fuel)										1262
	Total Fuel Expense										26498
	Average efficiency		3.67								

Schedule D-1
Qulliq Energy Corporation 2004/05 GRA
Fuel Efficiencies
$000

Plant No.	Plant	Approved Efficiency Existing Rates	Budgeted Efficiency 2004-2005	Actual Efficiency Y/E 2004	URRC Recommended	Generation 2004/05 Mwh	Liters at Efficiencies in Existing Rates	Liters at at Budgeted Efficiencies	Liters at Actual 04/05 Efficiencies	Liters at Actual 04/05 Efficiencies
501	Cambridge Bay	3.431	3.720	3.690	3.690	8095	2359	2176	2194	2194
502	Gjoa Haven	3.230	3.520	3.670	3.670	3578	1108	1016	975	975
503	Taloyoak	3.190	3.580	3.630	3.630	2691	844	752	741	741
504	Kugaaruk	3.395	3.510	3.540	3.611	2090	616	595	590	579
505	Kugluktuk	3.496	3.720	3.660	3.660	5149	1473	1384	1407	1407
601	Rankin Inlet	3.637	3.660	3.740	3.740	13629	3747	3724	3644	3644
602	Baker Lake	3.399	3.400	3.370	3.680	7393	2175	2174	2194	2009
603	Arviat	3.356	3.580	3.640	3.713	7683	2289	2146	2111	2069
604	Coral Harbour	3.398	3.400	3.460	3.460	2874	846	845	831	831
605	Chesterfield Inlet	3.180	3.280	3.150	3.150	1630	513	497	517	517
606	Whale Cove	3.363	3.450	3.400	3.400	1514	450	439	445	445
607	Repulse Bay	3.332	3.670	3.600	3.600	2282	685	622	634	634
701	Iqaluit	3.645	3.760	3.800	3.800	50801	13937	13511	13369	13369
702	Pangnirtung	3.297	3.660	3.680	3.754	6242	1893	1705	1696	1663
703	Cape Dorset	3.519	3.450	3.630	3.630	5134	1459	1488	1414	1414
704	Resolute Bay	3.314	3.650	3.660	3.660	3916	1182	1073	1070	1070
705	Pond Inlet	3.608	3.460	3.430	3.430	4833	1340	1397	1409	1409
706	Igloolik	3.425	3.470	3.480	3.480	4856	1418	1399	1395	1395
707	Hall Beach	3.491	3.710	3.490	3.490	2517	721	678	721	721
708	Qikitarjuaq	3.051	3.450	3.140	3.203	2239	734	649	713	699
709	Kimmirut	3.330	3.570	3.630	3.630	1801	541	504	496	496
710	Arctic Bay	3.089	3.320	3.500	3.500	2524	817	760	721	721
711	Clyde River	3.324	3.550	3.380	3.380	3053	918	860	903	903
712	Grise Fiord	3.335	3.460	3.460	3.460	1025	307	296	296	296
713	Sanikiluaq	3.449	3.630	3.700	3.700	2782	807	766	752	752
						150,331	43,178	41,459	41,240	40,955
Average Efficiency rate							3.48	3.63	3.65	3.67

Appendix 1

Information on Community Consultations

Iqaluit	**Nov 5/04**	**Arctic Winter Games Arena**
2:00 pm	@ 70 people	
7:00 pm	@ 50 people	
Igloolik	**Nov 8/04**	**Community Hall**
2:00 pm	@ 40 people	
7:00 pm	@ 30 people	
Arctic Bay (Ikpiarjuk)	**Nov 9/04**	**School Gym**
2:00 pm	@ 10 people	
7:00 pm	@ 25 people	
Grise Foird (Ausuittuq)	**Nov 10/04**	**Community Hall**
4:00 pm	@ 30 people	
Pond Inlet (Mittimatilik)	**Nov 12/04**	**Community Hall**
10:00 am	0 people	
2:00 pm	@ 25 people	
Kugluktuk	**Nov 15/04**	**Elementary School Gym**
2:00 pm	0 people	
7:00 pm	@ 5 people	
Cambridge Bay (Ikaluktutiak)	**Nov 16/04**	**Community Hall**
2:00 pm	@ 7 people	
7:00 pm	@ 20 people	
Cambridge Bay (Ikaluktutiak)	**Nov 17/04**	**Community Hall**
2:00 pm	@ 10 people	

Gjoa Haven (Uqsuqtuuq)	**Nov 18/04**	**Community Hall**
2:00 pm	0 people	
7:00 pm	@ 15 people	
Baker Lake (Qamani'tuaq)	**Nov 19/04**	**Community Hall**
2:00 pm	0 people	
7:00 pm	@ 20 people	
Rankin Inlet (Kangiqliniq)	**Nov 22/04**	**Community Hall**
2:00 pm	@ 12 people	
7:00 pm	@ 13 people	
Arviat	**Nov 23/04**	**Community Hall**
2:00 pm	@ 1 people	
7:00 pm	@ 7 people	
Coral Harbour (Salliq)	**Nov 24/04**	**Community Hall**
2:00 pm	@ 7 people	
7:00 pm	@ 18 people	
Iqaluit	**Nov 29/04**	**Cadet Hall**
2:00 pm	@ 7 people	
7:00 pm	@ 20 people	
Iqaluit	**Nov 30/04**	**Anglican Parrish Hall**
2:00 pm	@ 25 people	
7:00 pm	@ 30 people	

Appendix 2

Shared Comments in Community Consultation

The following are shared comments taken from the minutes of the Community Consultations across Nunavut.

- rate increase is scary
- housing and rent is expensive
- power bills are expensive
- its hard to keep up with bills
- one rate will not work
- do not approve of this rate increase
- our pay cheques/salary has never been increased, if you increase, do it slowly
- GN employees wages to go up too?
- what your proposing is scary, it's hurting us
- can't you cut costs or save
- have you thought about recycling heat, it would be cheaper, it is done in Iqaluit
- Elders Pension, we are not working, everything is going up, food, transportation and we are not eating properly due to expensive food and now power bills are going up, we will have no more money to buy food
- we need more subsidy
- why is there only 2 day cut off period?
- should move Baker Lake office to Iqaluit
- how are we going to survive?, with the rate increase

- NWT was taking care of us better, ever since we changed to Nunavut, it's a lot worse
- why such a short notice for the hearings?
- I'm having hard time making ends meet, how are we going to live?
- how come the rates are going up, is it because of mismanagement?
- we don't like one rate, smaller communities will be happy, but our community uses more electricity than any other communities in Nunavut except Resolute Bay, there is constant darkness in our community (3 months)-Grise Fiord, we are all different, we should not be thought of same, same rate?
- rate increase will affect everything, prices will go up, food, small businesses, even if subsidized
- mismanagement, the executives are at fault, why should we have to pay for they're mistakes
- worried about the rate increase, 48 hours notice should be longer, short time when we get the bills for people who cannot pay, even if it's small amount
- our wages has never increased since 1967-1970, GN gets wage increases, is all of us getting wage increases with this increase rate?
- everything has gone up except our wages
- if you want to raise prices, how are we going to pay for stuff, when wages has never increased?
- please add inuktitut translation to our bills
- how do you deal with cutoffs?
- does businesses pay more than public, is it using more power/ electricity?
- have you thought of wind power, they would be cheaper?
- it's getting impossible to pay for anything due to high cost of everything.
- how come in each community rates are different? I thought this proposal was for same rate issue or one rate as you say?

- how come the received payments are not on the bills?

- oil?? Nunavut buys bulk fuel, don't use that as an excuse to raise fuel or power.

- Elders; power rates are hard to pay with our pensions, its going to get harder, with this proposal rate increase, I am overwhelmed and ready to give up

- How come rates are going up, rates are not fixed?

- Powers get cut off, if it goes up more powers will be cut off, people don't work has a hard time paying their electricity

- its getting harder, we pay the highest in everything

- GN should move us to a cheaper place because it's getting impossible to pay for anything due to high cost of goods and services

- shame on management, they should be the ones paying, if they had operated properly this wouldn't have happen and now its effecting everyone, Nunavut is paying for this mismanagement

- there is no increase in social assistance, there is no increase in employment insurance (EI)- have to fight the government to be able to get EI, there is no increase in minimum wages, look how long it took to get minimum wage that's close to $10 per hour, I heard the Government department on the radio, saying at $10 per hour, no body can live on $10 an hour.

- elders were told, they will not pay much, but everything is still going up

- if I speak will it make a difference, small businesses has support but for homeowners have a hard time, fuel, sewage, everything is going up, it's not only that, no fuel, power cut offs it's scary, especially in winter

- Different rates some high, some low, Nunavut should be equal, its not, if people are equal, they would be a lot happier

- $77 million, for how many years?

- Give us more time to be prepared

- same format/questions as Baffin District

- why should we have to suffer because of mismanagement?
- don't let the residents of Nunavut pay for mismanagement of funds by the power corporation
- can barely make ends meet, it will be impossible if is approved, need to eat, can barely feed the kids, everything is expensive
- it will be a ripple effect; grocery prices will go up, rent increase, businesses will go under, municipal service will go up
- for people who can't pay their power bill, and gets cut off than gets evicted. Power rates, your asking too much too fast. Homelessness, when you get cut off. Increase it in a smaller rate and slowly
- don't raise our rates, look for other ways to cut off. What about 2007, I want you to understand, government can also take away subsidies. Rates increase, look for other ways
- even if we say no to this rate increase, will it make a difference? Fuel prices are already high.
- this rate increase is not right, costs are hard to keep up, will be more difficult. Every year we have to be prepared, we may have to close down recreation, power, fuel, water is

Appendix 3

Elders Comments

The URRC was impressed with the quality of presentations made by the Elders in most all of the public meetings during the community consultations process. The URRC had assured the Elders that their time was not wasted in appearing before the council and were also assured that their comments would form part of this report. The following issues may not necessarily be part of the Utilities GRA. However, in the end results of a rate change, it impacts on the Elders.

1. One issue that came up time after time was statements from the Elders that at the time the Government moved the people to settlement life from their nomadic way of life they were promised that in replacement for leaving their cultural life style & independence the Government would provide them with food shelter and clothing at no cost.

2. The Government, business and municipal employees have an escalating clause for the cost of living increases or some form of settlement allowance. The pension cheque amount is standard all over, however, the cost of living expense is much higher in the north and in smaller communities. With the increase in power and fuel the purchasing power of their cheques are getting to be very small. The Elders would like to see an escalating clause added to their old age pension cheques to help them keep up with the higher cost of living.

3. The Elders were also concerned that if the cost of living continues to increase and their income does not, then life will become even harder to cope with since their relatives that are struggling now will give up and move back with them.

BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF

FORTISBC INC.

RESIDENTIAL INCLINING BLOCK RATE

DECISION

January 13, 2012

BEFORE:

D. Morton, Panel Chair/Commissioner
L.A. O'Hara, Commissioner
M.R. Harle, Commissioner

TABLE OF CONTENTS

Page No.

1.0	**EXECUTIVE SUMMARY**		**1**
2.0	**INTRODUCTION**		**3**
	2.1	**Application**	**3**
	2.2	**Legislative and Regulatory Context**	**4**
		2.2.1 Legislative Framework	4
		2.2.2 The 2009 RDA Decision	6
	2.3	**Orders Sought**	**7**
	2.4	**Regulatory Process**	**8**
3.0	**OVERVIEW OF FORTISBC PROPOSAL**		**10**
	3.1	**Framework for Proposed RIB Rate Structure**	**10**
	3.2	**RIB Rate Scenarios Proposed**	**11**
	3.3	**Evaluation Criteria**	**13**
	3.4	**Pricing Principles for 2012 to 2015**	**14**
	3.5	**Option 8: FortisBC's Preferred Option**	**16**
	3.6	**RIB rates and TOU rates**	**17**
4.0	**KEY ISSUES AND COMMISSION DETERMINATIONS**		**19**
	4.1	**Residential Inclining Block Rate and its Structure**	**19**
		4.1.1 FortisBC Submission	19
		4.1.2 Intervener Submissions	20
		4.1.3 FortisBC Reply	20
		4.1.4 Commission Determination	21
	4.2	**Customer Charge**	**23**
		4.2.1 FortisBC Submission	24
		4.2.2 Intervener Submissions	25
		4.2.3 Commission Determination	26
	4.3	**Threshold**	**27**
		4.3.1 FortisBC Submission	27
		4.3.2 Intervener Submissions	28
		4.3.3 Commission Determination	29

TABLE OF CONTENTS

Page No.

4.4	**Customer Impact Criterion**		**30**
	4.4.1	FortisBC Submission	31
	4.4.2	Intervener Submissions	31
	4.4.3	FortisBC Reply	32
	4.4.4	Commission Determination	33
4.5	**Block 1 and Block 2 Rates**		**34**
	4.5.1	FortisBC Submission	35
	4.5.2	Intervener Submissions	35
	4.5.3	FortisBC Reply	36
	4.5.4	Commission Determination	36
4.6	**FortisBC's Long-Run Marginal Cost**		**37**
	4.6.1	FortisBC Submission	38
	4.6.2	Intervener Submissions	39
	4.6.3	Commission Determination	40
4.7	**Pricing Principles**		**41**
	4.7.1	Fortis BC Submission	43
	4.7.2	Intervener Submissions	43
	4.7.3	Commission Determination	43
4.8	**Anticipated Conservation**		**44**
	4.8.1	FortisBC Submission	44
	4.8.2	Intervener Submissions	46
	4.8.3	Commission Determination	48
4.9	**Voluntary TOU rates and Mandatory RIB Rates**		**50**
	4.9.1	FortisBC Submission	50
	4.9.2	Intervener Submissions	51
	4.9.3	Commission Determination	52
4.10	**Indirect Customers**		**52**
	4.10.1	FortisBC Submission	53
	4.10.2	Intervener Submissions	54
	4.10.3	Commission Determination	54

TABLE OF CONTENTS

Page No.

5.0 SUMMARY OF COMMISSION PANEL DETERMINATIONS **56**

COMMISSION ORDER G-3-12

APPENDICES

APPENDIX A Regulatory Process
APPENDIX B List of Exhibits

1.0 EXECUTIVE SUMMARY

This Decision relates to an application filed by FortisBC Inc. (FortisBC, the Company) to introduce Residential Inclining Block (RIB) rates in its service territory. The filing is in response to an earlier British Columbia Utilities Commission (Commission) directive in Order G-156-10 following FortisBC's 2009 Rate Design and Cost of Service Analysis (2009 RDA) proceeding. A RIB rate is intended to promote conservation by employing a tiered rate structure in which consumption that occurs above a certain threshold level is billed at a higher rate. The higher tier rate is designed to incent customers to reduce their consumption.

The proceeding was conducted as a written hearing. There were 15 Registered Interveners, of which five filed submissions: the BC Sustainable Energy Association (BCSEA), Mr. Andy Shadrack, Nelson Hydro, British Columbia Old Age Pensioners' Organization *et al.* (BCOAPO), and Strata Corporation KAS2464 (Strata KAS2464). The Applicant originally filed 18 different RIB rate options, all with the same basic structure of a Customer Charge, a threshold, and two block rates. During the hearing, a considerable number of additional options were explored. The Applicant submits that Option 8, with the following components:

- A Customer Charge of $29.65 per billing period;
- A bi-monthly threshold of 1,600 kWh;
- A Block 1 rate of 8.453 cents per kWh; and
- A Block 2 rate of 12.408 cents per kWh.

is the most effective approach. The Option 8 charges shown above assume an implementation date of January 1, 2012. This option is approved as requested. The Panel also approves FortisBC's proposed Pricing Principle 1, which governs how the RIB prices will be calculated in subsequent years. FortisBC is directed to apply Pricing Principle 1 to future rate increases for the years 2012 to 2015. Specifically:

a. The Customer Charge is exempt from general rate increases, other than rate rebalancing increases;

b. The Block 1 rate is subject to general and rebalancing rate increases; and

c. The Block 2 rate is increased by an amount sufficient to recover the remaining required revenue (i.e., the residual rate).

In its determination, the Panel considers several factors, including bill impacts, conservation, Bonbright Principles, and FortisBC's proposed pricing principles for the years 2012 to 2015 that will guide FortisBC in applying rate increases going forward. We discuss how these considerations affect the Customer Charge, the threshold, and the Block 1 and Block 2 rates. The Panel also considers the relationship between the Block 2 rate and FortisBC's long-run marginal cost of energy.

FortisBC is directed to implement the residential RIB rate as soon as is reasonably practicable, and by no later than July 31, 2012. It is also directed to establish a control group and such monitoring as is required to enable it to provide a RIB Rate Evaluation Report (Report) on conservation impacts of the RIB rate. FortisBC is also directed to include in the Report an update of the Conservation Potential Review; an in-depth analysis of its long-run marginal cost including the cost to distribute and transport the energy; the potential effect of a two-tier wholesale rate; and an analysis of the interaction of RIB and Time-of-Use (TOU) rates, should TOU rates be implemented during the reporting period. The reporting period is to run from the implementation date to December 31, 2013 and the Report is to be submitted to the Commission by no later than April 30, 2014.

2.0 INTRODUCTION

This Decision relates to an application filed by FortisBC to introduce Residential Inclining Block rates in its service territory (the Application). The Application is in response to an earlier Commission directive in Order G-156-10 following FortisBC's 2009 Rate Design and Cost of Service Analysis proceeding. A RIB rate is intended to promote conservation by employing a tiered rate structure in which consumption that occurs above a certain threshold level is billed at a higher rate. The higher second tier, or "block" rate, is designed to incent customers to reduce their consumption.

There were 15 Registered Interveners in the proceeding including a number of individual residential customers, associations, and corporations.

The introduction of RIB rates in the FortisBC service area is befitting an era where the provincial legislation encourages conservation and British Columbia Hydro and Power Authority (BC Hydro) has had a residential inclining block rate structure in place since October 2008.

2.1 Application

On March 31, 2011, FortisBC filed an Application for Residential Inclining Block rates pursuant to Directive 10[1] of Commission Order G-156-10 which was issued following FortisBC's 2009 RDA proceeding. Directive 10 directs FortisBC "... to develop a plan for introducing residential inclining block rates that also incorporate a lower Basic Charge in the immediate future and to file an RIB rate application with the Commission no later than March 31, 2011."

---

[1] Directive 10 in fact refers to the number in the Summary of Directives in the FortisBC 2009 RDA Decision. That Directive is Directive 5 in Order G-156-10. FortisBC refers to Directive 5 in Footnote 7 on p. 14 of the Application and again at p. 1 of its Final Submissions.

Accordingly, FortisBC applies under sections 58 – 61 of the *Utilities Commission Act* (*UCA*) for Commission approval of a new, two-tier, inclining block rate for its residential customers who are currently served under Rate Schedule RS 01. The RIB rate is intended to be the default, mandatory rate for all residential customers who are not taking service under FortisBC's TOU option, Rate Schedule 2A. This structure, if approved, will result in new rates upon implementation. The Application also seeks approval of a Pricing Principle on a go-forward basis, which will determine how each of the three rate elements (i.e., the Customer Charge, the Block 1 rate and the Block 2 rate) will be increased to meet the general revenue requirement adjustments required each year. (Exhibit B-1, p. 1)

2.2 Legislative and Regulatory Context

2.2.1 <u>Legislative Framework</u>

Utilities Commission Act

Section 59 of the *UCA,* in part, requires the Commission to set rates for a public utility that enable the utility to earn a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property. Further, a public utility must not make, demand or receive a rate that is unjust, unreasonable, unduly discriminatory or unduly preferential or contravenes the *UCA*, the regulations, orders of the Commission or any other law. Section 60, in part, provides that in setting a rate, the Commission may use any mechanism, formula or other method of setting the rate that it considers advisable and may order that the rate derived from such mechanism or formula or other method is to remain in effect for a specified period.

Clean Energy Act

The *Clean Energy Act* (*CEA*) received Royal Assent on June 3, 2010. The *CEA* advances 16 specific energy objectives to help achieve British Columbia's energy vision including new measures to promote electricity efficiency and conservation. One of these efficiency and conservation objectives is to take demand-side measures and to conserve energy.

The *CEA* defines **"demand-side measure"** to mean a rate, measure, action or program undertaken

(a) to conserve energy or promote energy efficiency,

(b) to reduce the energy demand a public utility must serve, or

(c) to shift the use of energy to periods of lower demand.

(*CEA*, Section 2)

The BC Energy Plan (2007): A Vision for Clean Energy Leadership

Prior to the introduction of the *CEA*, the provincial government's emphasis on the promotion of energy efficiency was articulated in both the 2002 and 2007 Energy Plans. The 2007 Energy Plan includes, among other things, the following two Policy Actions relating to energy conservation and efficiency:

> **Policy Action #2:** Ensure a coordinated approach to conservation and efficiency is actively pursued in British Columbia.
>
> **Policy Action #4:** Explore with B.C. utilities new rate structures that encourage energy efficiency and conservation.

The 2007 Energy Plan also lists the following future energy efficiency and conservation initiatives in more detail:

- Continuing to remove barriers that prevent customers from reducing their consumption;
- Building upon efforts to educate customers about the choices they can make today with respect to the amount of electricity they consume;

- Exploring new rate structures to identify opportunities to use rates as a mechanism to motivate customers either to use less electricity or use less at specific times (emphasis added);

- Employing new rate structures to help customers implement new energy efficient products and technologies and provide them with useful information about their electricity consumption to allow them to make informed choices (emphasis added); and

- Advancing ongoing efforts to develop energy-efficient products and practices through regulations, codes and standards.

(The BC Energy Plan (2007), p. 5)

FortisBC states it believes that its RIB rate proposal is "one component within a comprehensive demand reduction strategy that helps the Commission and the Province fulfill conservation goals." (Exhibit B-1, p. 8)

2.2.2 The 2009 RDA Decision

In the 2009 RDA Decision, the Commission rejected FortisBC's position that no conservation rates should be introduced before FortisBC implemented its Advanced Metering Infrastructure (AMI) and by Directive 10 directed FortisBC to introduce RIB rates. The Commission articulated its reasons as follows:

- The timeline for the AMI implementation is subject to a number of factors with a potential outcome that introduction of wide spread time-of-use (TOU) rates could be five years away, which is contrary to the intent of the government policy;

- Hourly customer consumption data (available only after the introduction of the AMI) is not necessary to the design of a RIB rate structure. BC Hydro introduced RIB rates in October 2008 – long before its planned Smart Meter installation;

- The Commission Panel disagrees with the FortisBC position that a customer choosing to use less electricity during the peak periods will not use more electricity during the off-peak period to compensate; and

- The Panel is not persuaded by the FortisBC argument that customers would be confused over introduction of two kinds of conservation rates over a short period of time.

By way of summary, the Commission was "especially concerned that backing away from the RIB rate structure in the FortisBC service area today, in anticipation of TOU rates being implemented in five years time, would represent a foregone opportunity for energy efficiency and conservation." (2009 RDA Decision, pp. 56-57)

2.3 Orders Sought

Pursuant to sections 58-61 of the *UCA*, FortisBC is seeking Commission approval to implement a RIB rate structure that reflects two steps, or blocks, and incorporates the following design features:

- A threshold level of bi-monthly consumption, above which the Block 2 rate will apply, set at 1,600 kWh;
- A Customer Charge of $28.93 per two-month billing period, exempt from revenue requirement rate increases, with only rebalancing adjustments applied in future years (Customer Charge and Basic Charge are used interchangeably in this Decision);
- A Block 1 rate and a Block 2 rate determined using the customer impact criterion that 95 percent of customers are subject to annual billing increases no greater than 10 percent as a result of the RIB rate structure;
- The Block 1 rate adjusted by an amount equal to the sum of the general revenue requirement increase and rebalancing adjustments; and
- The Block 2 rate adjusted by an amount sufficient to recover the balance of the general revenue requirement and any rebalancing adjustments after the Customer Charge and Block 1 rate are calculated (the residual rate).

(Exhibit B-1, Appendix B)

FortisBC proposes to implement the RIB rate between six and nine months after receiving the Commission's Decision on the Application. It states that introducing a RIB rate is a significant change that must be preceded and accompanied by thorough information and a customer education component, the development of which cannot commence until direction is provided. (Exhibit B-1, p. 2)

A January 1, 2012 implementation date, using the methodology described in the Application to determine the rate, would produce a RIB rate with the following components:

- A Customer Charge of $29.65 per billing period;
- A Block 1 rate of 8.453 cents per kWh; and
- A Block 2 rate of 12.408 cents per kWh.

These rates are further addressed in Section 4.5. It should be noted, however, that due to some concerns regarding the evidence submitted and related procedural delays, as addressed in Section 2.4, the most likely implementation will now take place in the second half of 2012. This could result in additional adjustments to the rates shown above.

2.4 Regulatory Process

FortisBC proposed a written hearing process, which included only one round of Information Requests (IR), and concluded on June 15, 2011 with the filing of its Reply Submission. Based on this regulatory timetable FortisBC anticipated the RIB rate structure would become effective January 1, 2012. (Exhibit B-1, p. 3)

However, a number of events occurred that resulted in a longer written hearing process. Some of these occurrences were the following:

- Additional rounds of IRs;
- Discussions between Commission staff and FortisBC regarding technical issues that arose while reviewing the responses to IR1;
- Establishment of a Procedural Conference for August 3, 2011 where the Commission Panel sought submissions on seven issues, including sufficiency of the evidentiary record, pricing principles, and conservation impact; (Exhibit A-15) and

- Based on the submissions received on August 3, 2011, the Panel determined that in many instances the record was inadequate to support FortisBC's submissions. Accordingly, the Commission Panel directed FortisBC to file additional evidence addressing, among other issues, revenue stability, calculation of 2012 RIB rates, long-run marginal costs, elasticity and conservation measures, and Basic Charge. (Exhibit A-17)

A more detailed description of the regulatory process is provided in Appendix A.

3.0 OVERVIEW OF FORTISBC PROPOSAL

3.1 Framework for Proposed RIB Rate Structure

FortisBC states the Bonbright Principles continue to provide a framework against which all rate design activities and options can be compared. These principles, as paraphrased by FortisBC, are shown below:

Principle 1	Recovery of the revenue requirement;
Principle 2	Fair apportionment of costs among customers (appropriated cost recovery should be reflected in rates);
Principle 3	Price signals that encourage efficient use and discourage inefficient use (consideration of social issues including environmental and energy policy);
Principle 4	Customer understanding and acceptance;
Principle 5	Practical and cost-effective to implement (sustainable and meet long-term objectives);
Principle 6	Rate stability (customer rate impact should be managed);
Principle 7	Revenue stability; and
Principle 8	Avoidance of undue discrimination (interclass equity must be enhanced and maintained).

(James C. Bonbright, Principles of Public Utility Rates, Columbia University Press, 1961)

As a conservation rate, a RIB rate's main purpose is to induce conservation. It is generally acknowledged that the RIB rate design is conducive to savings in energy and its impact on savings in demand is only coincidental to customers' response to the RIB rate design (Exhibit B-5, BCUC 1.9.3; BCUC 1.17.6). The other conservation rate currently in use at FortisBC is its Time-of-Use rate. The purpose of the time-based rate is to conserve capacity (Exhibit B-12, BCUC 2.4.1). FortisBC submits that customers who choose to take service under the TOU billing would not be compelled to move to the RIB rate (FortisBC Final Submissions, p. 1).

Under the Bonbright Principles against which all RIB rate options are evaluated, the RIB rate option that is most preferred would be one that induces the most conservation and also balances the competing Bonbright objectives.

In this Application, FortisBC analyzes 18 rate scenarios and further evaluates the scenarios for a preferred option by making choices that include meeting the following relevant objectives:

- Customer bill impact (Bonbright Principles 4 and 6, customer understanding and acceptance, and rate stability);
- Efficient Price Signal (Bonbright Principle 3, price signals that encourage efficiency use and discourage inefficient use); and
- Promotion of Conservation (Policy Action #44 from the 2007 Energy Plan).

3.2 RIB Rate Scenarios Proposed

FortisBC states that in an effort to design a rate that (i) FortisBC customers will understand, (ii) maintains provincial consistency, (iii) meets the defined objectives, and (iv) complies with the Commission directive, it has restricted the options to RIB rate structures that vary the following four components:

1. Customer Charge: The customer charge is the fixed portion of the bill that does not vary with usage. Typically, the customer charge is used to recover the costs incurred by the utility of providing services such as billing and meter reading to customers. The Commission has specifically directed FortisBC to submit an inclining block rate option that includes a lower customer charge. (Order G-156-10, Directive 5);
2. Threshold: A threshold in an inclining block rate is the kWh consumption level at which the price for each subsequently consumed kWh will increase;
3. Block 1 rate: The rate, expressed in cents per kWh, at which each kWh of consumption up to the threshold is billed; and

4. Block 2 rate: The rate, expressed in cents per kWh, at which each kWh of consumption above the threshold is billed.

The Application includes 18 RIB rate scenarios (Options 1-18) for comparison.

FortisBC states that the Customer Charge under the Rate Schedule (RS) 01 was forecast to be $28.93 per two-month billing period effective May 1, 2011. This number became the starting point for the RIB rate design work. FortisBC points out that at its current level the Customer Charge collects "just under 44 per cent of the amount required by strict adherence to cost causation principles." FortisBC further states that, as the Commission has determined the proposed RIB rate will include a reduction in the Customer Charge, the level at which it will be ultimately set becomes somewhat arbitrary. To gauge the impact of a lower Customer Charge on the other rate components, FortisBC selected a bi-monthly Customer Charge of $21.50 to model for analysis.

For the threshold level, FortisBC has modeled the following three bi-monthly thresholds based on customer billing data from 2009 and 2010:

- Mean Consumption: 2,100 kWh
- Median Consumption: 1,600 kWh
- 85 percent of Median: 1,350 kWh

For each combination of the two customer charges ($28.93 and $21.50) and the above three threshold levels, FortisBC then specified three permissible customer impact levels:

1. 90% of customers will see a RIB related increase of less than or equal to 10%;
2. 95% of customers will see a RIB related increase of less than or equal to 10%; and
3. 100% of customers will see a RIB related increase of less than or equal to 10%.

(Exhibit B-1, p. 17)

The customer impact criterion is expressed in terms of the percentage of residential customers who will experience an annual rate impact due solely to the implementation of the RIB option of less than 10 percent. FortisBC notes that the 10 percent figure is generally seen as the threshold of "rate shock", though it is not an official position of the Commission.

These permutations become the 18 RIB rate scenarios included in the Application for further analysis. (Exhibit B-1, pp. 14-17)

3.3 Evaluation Criteria

For each of the 18 RIB rate scenarios, FortisBC determined the following RIB rate evaluation criteria.

Table 1: RIB Rate Evaluation Criteria

Evaluation factor	Description
Annual Breakeven kWh	The level of annual consumption required to have annual billing under the RIB rate option equal annual billing under the current flat rate option.
Percentage of Customers That Benefit	The percentage of customers whose annual bill for electricity is lower under the RIB Rate option than under the existing flat rate.
Maximum Bill Impact	The highest single percentage increase experienced by a customer in any month when the RIB rate option is compared to the flat rate.
Percentage of Customers with Bill Increases > 20%	The percentage of customers who will experience an annual increase in their bills greater than 20% when billing under the RIB rate option is compared to billing under the existing flat rate.
Number of Customers With Consumption in Block 2 At Least Once	The number of customers who will have consumption in a billing period in the second block at least once in a year.
Percentage of Load Billed in Block 2	Of the total residential load (in kWh), the percentage that is consumed in the second block.
Conservation Impact	The conservation impact of a RIB rate option is the estimated reduction in both consumption and demand that is attributable to the implementation of the given RIB rate option.

Source: Exhibit B-1, p. 20, Table 7-1

To reduce the 18 rate scenarios to a smaller set of scenarios for further analysis, FortisBC relied on the following three RIB rate objectives:

> Customer Bill Impacts: Customer bill impacts, while unavoidable, should not be unreasonable. FortisBC states that the evaluation of customer bill impacts should be informed by concurrently examining the criteria "Maximum Bill Impact" and "Percentage of Customers with Bill Increases > 20%" (Exhibit B-5, BCUC 1.8.1);
>
> Efficient Price Signals: The differential between Block 1 and Block 2 rates must be sufficient to provide a meaningful signal to incent conservation behaviour (the first screening criterion); and
>
> Promotion of Conservation: The total residential load that would be billed in the second block, as a percentage of the entire load, became the second screening criterion.

FortisBC states that by applying the above two screening criteria, it reduced the 18 RIB rate scenarios down to four scenarios (Options 2, 8, 11 and 17) which would be analysed by applying different Pricing Principles over the 2012-2015 time period.

3.4 Pricing Principles for 2012 to 2015

FortisBC states that it must design a RIB rate that will recover its annual revenue requirements for the residential customer class, which becomes a constraint by making it impossible to vary each RIB rate component independently. At a minimum, one of the four variables will be dependent on the levels chosen for the other three. FortisBC designed its 18 RIB rate scenarios to cover its 2011 revenue requirements to begin with. Subsequently, FortisBC had to develop pricing principles regarding how to apply future general revenue requirement related rate increases to each of the three rate components in future years.

FortisBC further states it has based the analysis on the residential rates expected to be in effect as of May 1, 2011. This includes the impact of the 2.5 percent rebalancing increase as approved by Commission Order G-196-10, but does not include any forecast interim flow-through rate adjustments related to the BC Hydro 2012-2014 Revenue Requirements Application. (Exhibit B-1,

p. 15)

The Company takes the position that it is complying with Commission Order G-156-10 to introduce a lower Customer Charge by exempting the existing Customer Charge from future general rate adjustments other than those related to rebalancing through 2015. FortisBC's rationale is that this Pricing Principle effectively reduces the Customer Charge relative to other billing determinants over time. (Exhibit B-1, p. 16)

To further test the remaining four scenarios, FortisBC designed four Pricing Principles to apply the following anticipated residential rate increases to the three rate components.

Table 2: Forecast Residential Rate Increase

Rate Component	2012	2013	2014	2015
	(%)			
Revenue Requirement Increase	6.4	4.2	3.4	6.5
Rebalancing	2.5	2.3	-	-
Total Increase	8.9	6.5	3.4	6.5

Source: Exhibit B-1, p. 25, Table 8-2

Two of the four scenarios (Options 2 and 8) are designed on the above stated premise that the Customer Charge is exempt from rate increase, except for rate balancing adjustments. In these cases, FortisBC explored the following alternatives:

Pricing Principle 1

- The general and rebalancing rate increases are applied to the Block 1 rate; and
- The Block 2 rate is increased by an amount sufficient to recover the remaining required revenue; i.e. the residual rate.

Pricing Principle 2

- The Block 1 rate is frozen; and

- The Block 2 rate is increased by an amount sufficient to recover the required revenue; i.e., the residual rate.

For the remaining two scenarios (Options 11 and 17) the following alternatives were explored:

Pricing Principle 3

- General and rebalancing rate increases applied equally across the Customer Charge and Block 1 rate components; and
- The Block 2 rate is increased by an amount sufficient to recover the remaining required revenue; i.e. the residual rate.

Pricing Principle 4

- Block 1 rate is frozen;
- General and rebalancing increases applied to the Customer Charge; and
- Block 2 rate increase by an amount sufficient to recover the remaining required revenue; i.e. the residual rate.

(Exhibit B-1, p. 25)

3.5 Option 8: FortisBC's Preferred Option

Upon further review, FortisBC eliminated half of the above permutations from consideration due to the high and increasing ratio between the Block 1 and Block 2 rates. FortisBC submits that a second block rate that is too high will be unduly punitive to higher consumption customers, such as those with electric heat. Any scenario in which the annual rate increases are only applied to the Block 2 rate results in such a high ratio.

FortisBC further states that the ratio between Block 1 and Block 2, which is an indication of the conservation incentive provided by the rate, should also remain fairly constant and not decrease over time to the point where this incentive is no longer effective.

As the final outcome of its selection process, FortisBC recommends Option 8 as its preferred option and proposes the following Pricing Principle (Pricing Principle 1):

- A Customer Charge frozen at the existing level, with only rebalancing adjustments applied in future years;
- A Block 1 rate adjusted by an amount equal to the sum of the general revenue requirement increase and rebalancing adjustments; and
- A Block 2 rate adjusted by an amount to recover the balance of the general revenue requirement and any rebalancing adjustments.

The resultant RIB rate structure, based on May 1, 2011 rate levels, is comprised of:

- A bi-monthly Customer Charge of $28.93;
- A Block 1 rate of 7.828 cents per kWh;
- A Block 2 rate of 11.272 cents per kWh, reflecting a 44 percent differential between the two blocks; and
- A bi-monthly threshold of 1,600 kWh.

(Exhibit B-1, p. 27)

3.6 RIB rates and TOU rates

FortisBC refers to its public consultation with respect to customers' preferences for various residential rate options, which was conducted in late 2009. As part of that consultation, FortisBC included a number of RIB rate options in addition to the existing flat rate option.

By way of summary, FortisBC states that the consensus reached during the public consultation, as well as its preference, was for maintaining the status quo pending the AMI implementation. The RIB rate option was seen by customers as a viable option, although it had lower support than waiting for AMI. Based on the above, FortisBC believes that customer acceptance will be largely based on credible evidence on conservation impacts and careful management of bill impacts. (Exhibit B-1, pp. 12-13)

Based on the Commission directives in Order G-156-10 and BC Hydro's submission in a recent application (RIB Re-Pricing Application) that after its implementation of Smart Meters and Infrastructure Program, BC Hydro would not propose a mandatory TOU rate, FortisBC's current position is to offer a suite of time-based rates to complement its mandatory RIB rate. (Exhibit B-5, BCUC 1.6.4; BCUC 1.4.3.3)

This topic will be addressed in further detail in Section 4.9.

4.0 KEY ISSUES AND COMMISSION DETERMINATIONS

4.1 Residential Inclining Block Rate and its Structure

4.1.1 FortisBC Submission

The RIB rate option proposed by FortisBC has the same four basic components as that implemented by BC Hydro: a Customer Charge, a single threshold, and two block rates. In its Final Submission, FortisBC submits that: "A RIB rate composed of those four components offers provincial consistency, and alternative structures were therefore not included as an option in the original Application."

In addition, FortisBC also provides a non-exhaustive list of examples of other potential RIB rate structures, including:

- RIB rates featuring multiple thresholds and rate blocks;
- RIB rates that include a time component such as hourly or seasonal blocks;
- RIB rates that contain a demographic parameter such as income or heating fuel choice;
- RIB rates that feature a geographic parameter; and
- RIB rates that feature an individual customer consumption baseline.

However, it "believes that consistency with the four component rate structure adopted by BC Hydro is a desirable component of its RIB rate and that the Commission should not consider any rate variant that does not comply." (FortisBC Final Submission, p. 2)

4.1.2 Intervener Submissions

Strata KAS2464 believes the RIB rate proposal mutes market forces and blunts the imagination and innovation of the future. It submits that overall the negative possibilities outweigh the positive benefits. However, it acknowledges that if the Commission continues to believe that conservation can be efficiently promoted via a residential inclining block rate, the FortisBC proposal with its various shortcomings is the preferred option. (Strata KAS2464 Final Submission, p. 3)

The BCOAPO expresses concern about the specific rate proposed and submits that introducing a rate where both blocks will vary from the Long-Run Marginal Cost (LRMC) more than the current flat rate within the short term is counterproductive because it does not promote the efficient use of electricity while causing material customer impacts. Further, it "…sees no value in a rate design for a rate design's sake and submits that the objective is not and should not be simply to reduce use for its own sake, but to do so when and if it makes sense." In summary, the BCOAPO maintains that "…it may be a difficult pill for parties to swallow… to find that the correct action is no action at all, but that is, in BCOAPO's submission, the case here." (BCOAPO Final Submission, p. 6)

BCSEA agrees with FortisBC's proposed RIB rate structure, containing a Customer Charge, a threshold and two block rates. (BCSEA Final Submission, p. 1) No other Interveners commented on this issue.

4.1.3 FortisBC Reply

In Reply, FortisBC notes that "…the BCOAPO does not offer any opinion on what different conclusion or recommendation in terms of an appropriate rate would result from an alternate approach." (FortisBC Reply Submission, p. 11)

4.1.4 Commission Determination

As previously described in this Decision, this Application was brought forward by FortisBC in response to a directive by the Commission. This directive is supportive of the objectives of the *CEA* for British Columbia to take demand side measures, to conserve energy, and to achieve electricity self sufficiency. These objectives can benefit from the use of conservation rates, such as the RIB, for electricity. The issue before the Panel is how best to structure a conservation rate to decrease demand and induce conservation in an efficient manner – a manner that optimizes the utilization of resources.

In a competitive market, rising prices affect consumers' behaviour by sending a price signal to induce consumers to reduce consumption. Thus, rising prices discourage the uneconomic use of scarce resources. In a perfectly competitive market, the price of any increment of a resource will be driven to the full economic cost of that increment, and will therefore be an "economic efficient" price which achieves optimal resource utilization.

In the absence of market pricing, as is the case in the regulated sector, the challenge for utilities and regulators is to establish an economic efficient price, or rate, that encourages energy conservation while ensuring that the utility's revenue requirement is met. While an arbitrary increase in a rate may well encourage less consumption, it may not be an economically efficient reduction in consumption. In any event, given revenue requirement constraints, a flat rate cannot simply be increased. An inclining block structure, which charges a lower rate for amounts consumed below a threshold and a higher rate above that threshold, can potentially be structured to be both economically efficient and meet the utility's revenue requirements. However, a RIB rate structure that is incorrectly priced can have disadvantages and unintended consequences, the principal among them being that customers overuse underpriced resources and underuse overpriced resources. The choices made are suboptimal and the consequence is lower productivity and/or lower conservation. A rate structure based on sound rate-making principles can ensure that what consumers pay will reflect the true economic value of the energy they buy, and that energy resources find their best possible uses.

Bonbright Principle 3 embodies this notion and accordingly, the Panel gives this principle added weight in its consideration. The Panel is of the opinion that the RIB rate structure proposed by FortisBC - a relatively simple inclining pricing structure - incents conservation. However, other Bonbright Principles which provide, for example, for fairness, and stability must also be considered. In this regard, the Panel notes that FortisBC has considered such issues as bill impacts, ease of understanding and rate stability in the design of its proposed RIB rate Option 8. These considerations will be discussed further in subsequent sections of this Decision.

An important characteristic of a RIB rate structure is that it allows the utility to introduce price signals that reflect the increased marginal cost of electricity. Setting the Block 2 rate equal to the LRMC and allowing the Block 1 rate to be set residually ensures that any consumption, in excess of the threshold, is billed at the LRMC. The Panel considers this to be a key element of a RIB rate that can be used to induce conservation and be economically efficient. The Panel notes that while the BCOAPO does not appear to object to the notion of a RIB rate, it does not agree with the RIB rates as proposed because the Block 2 rate is not significantly below the LRMC and could potentially exceed it in the near future**.** The Panel does not agree with this assessment for the reasons given in Section 4.6.3, where we discuss the relationship between FortisBC's LRMC and the approved RIB rate option in more detail.

The Panel also does not agree with the negative possibilities of the RIB rate proposal as articulated by Strata KAS2464. There has been no evidence provided that would support its position that RIB rates mute market forces and stifle innovation.

The Panel is satisfied that the introduction of a RIB rate, in addition to being an effective tool in promoting conservation; is simple for the utility and users to understand; does not unduly discriminate against certain segments of residential ratepayers, as we will discuss in Section 4.2.3; and promotes revenue stability as we will discuss in Section 4.2.3. **Accordingly, the Panel finds that a RIB rate structure is in the public interest and directs FortisBC to implement this rate structure, subject to the parameters described below.**

With regard to the four-component RIB structure proposed by FortisBC, the Panel is supportive of its goal to maintain provincial consistency. The single threshold with two blocks is simpler to implement and understand - for both the utility and its customers – when compared to structures with multiple thresholds. Of the other potential RIB rate structures cited, each introduces a challenge or complexity not present in the proposed structure. For example, there may be privacy issues associated with approaches that require the utility to obtain demographic information from its customers; individual customer baselines may be perceived as unfair and also present difficulties from an implementation and operations perspectives; multiple thresholds may be confusing for some or many customers. These issues have been explored in considerable detail in previous BC Hydro RIB rate hearings and the Panel is satisfied with the Applicant's choice in this regard. **The Commission Panel directs that the FortisBC's RIB rate consist of four components: a Customer Charge, a threshold, and two block rates.**

Although no submissions were received on the specific implementation date, the Panel notes that in the Application and the proposed regulatory schedule included therein, FortisBC estimated an implementation date of April 1, 2012. Given schedule delays, we acknowledge that this date may no longer be feasible. However, we do encourage FortisBC not to delay the implementation process any further. **Accordingly, FortisBC is to implement the RIB rate as soon as is reasonably practicable and by no later than July 31, 2012. FortisBC is to file a revised Tariff Sheet for Rate Schedule 01 no later than 30 days prior to the date the RIB rate becomes effective.**

4.2 Customer Charge

Directive 5 of Order G-156-10 ordered FortisBC "... to develop a plan for introducing residential inclining block rates that also incorporate a lower Basic Charge in the immediate future...". As described earlier, FortisBC's proposed Option 8 would exempt the Customer Charge from rate adjustments other than those related to rebalancing through 2015. FortisBC submits that this rate design effectively reduces the Customer Charge over time relative to other billing determinants. (Exhibit B-1, p. 1) FortisBC further notes that, upon implementing the RIB rate in 2012, the

Customer Charge will also decrease in absolute terms as compared to the Customer Charge that would be in effect in 2012 if the RIB rate were not put in place. Indeed, in 2012, the Customer Charge would increase to $29.65 per billing period with a RIB rate or, by contrast, it would increase to $31.25 if the flat rate structure was maintained, assuming that the 2012 rate increase requested by FortisBC in its 2012-2013 Revenue Requirements Application is approved. (FortisBC Final Submission, p. 4)

Other levels of Customer Charge have been explored as part of this proceeding. They are $0.00, $7.50, $10.00, $15.00 and $21.50.

In FortisBC's RIB rate proposal, the Customer Charge is also a determinant of the Block 1 and Block 2 rates. This is because the rates are determined by first selecting a Customer Charge, a threshold, and an allowable customer bill impact, and then finding the unique combination of Block 1 and Block 2 rates that collects the required revenue.

4.2.1 FortisBC Submission

FortisBC submits that the Customer Charge should not be lowered other than as achieved by applying FortisBC's proposed Pricing Principle as described above for three reasons:

- The current level of the Customer Charge is already below the COSA-derived amount;
- Fixed costs, to the extent possible, should be recovered through fixed charges; and
- Revenue stability for the utility should be considered.

(FortisBC Final Submission, p. 4)

Further to the last point above, FortisBC maintains that "the collection of fixed costs through fixed charges, as well as the established need for revenue stability needs to be considered. Decreasing the customer charge and increasing the energy charges adds sales revenue volatility. FortisBC believes that its proposal provides an appropriate balance between the needs of the Company and the concerns customers may have with the level of the customer charge." (BCUC 1.1.12.4)

Beyond these reasons, FortisBC demonstrates that lowering the Customer Charge below $28.93 would result in smaller block differentials and lower conservation impacts, all else being equal. (FortisBC Final Submission, pp. 4-5)

4.2.2 Intervener Submissions

BCSEA agrees with FortisBC that the evidence supports the above conclusion and adds that, for any given bill impact constraint, increasing the Block 1/Block 2 rate differential has a larger impact on conservation than does increasing the energy charges by decreasing the Customer Charge. BCSEA places a priority on maximizing conservation within various constraints and, accordingly, supports approval of FortisBC's proposal regarding the Customer Charge. (BCSEA Final Submission, p. 4)

BCOAPO acknowledges that FortisBC's most recent Cost of Service Analysis (COSA) based on its 2009 RDA indicated that the true cost of service per account was almost twice the current Customer Charge. Therefore, BCOAPO submits that there is no reason to either change FortisBC's Customer Charge if the Commission approves a RIB rate or reduce the Customer Charge in any future rate designs. (BCOAPO Final Submission, p. 6)

Mr. Shadrack states that his household "... would be quite happy if that basic charge was reduced over a similar five-year period to avoid rate shock" and "believes that the goal should be to reduce the Customer Charge to $9.78." The methodology suggested by Mr. Shadrack differs from the approach taken by FortisBC in its Application and would see absolute decreases applied to the Customer Charge in each of the five years. However, Mr. Shadrack also comments that if the Commission does not lower the Customer Charge, then it must direct FortisBC to address how it would ensure that those who reduce their electrical consumption, under an inclining block rate, are not going to end up being financially penalized. He also submits that when setting the Customer Charge, the difference between FortisBC's Customer Charge and that of BC Hydro should be considered. He maintains that "….this anomaly must be addressed in a timely manner." (Shadrack

Final Submission, p. 2)

Despite not commenting specifically on the Customer Charge or any other elements of the proposed RIB rate, Strata KAS2464 submits that the FortisBC proposal, with its various shortcomings, is the preferred option should the Commission continue to believe that conservation can be efficiently promoted via a RIB rate. (Strata KAS2464 Final Submission, p. 3)

Finally, Nelson Hydro, which describes itself as an interested but not directly affected party, believes that holding the Customer Charge fixed and applying increases only to the energy charges appears to be a good way to make the transition from cost-based to conservation-based rates. (Nelson Hydro Final Submission, p. 2)

4.2.3 Commission Determination

The Panel does not agree with the submission of Mr. Shadrack that the difference between BC Hydro's and FortisBC's Customer Charges must be addressed, or, indeed, that it even constitutes an anomaly. The cost structures of the two utilities are different, which alone could lead to a difference in the Customer Charge. In any event, how BC Hydro determines its Customer Charge is not within the scope of this hearing. Further there has been no evidence provided in this hearing to show that FortisBC's Customer Charge is anomalous. The Panel notes that in this Application, FortisBC demonstrated that its bi-monthly Customer Charge was well within the range of the residential customer charges of other major utilities in Canada (ATCO Limited Electric, ENMAX Power Company, EPCOR Utilities Inc., Toronto Hydro, Hydro Ottawa, NS Power, NF Power, NB Power (Urban). (Exhibit B-11, p. 28) For those utilities, FortisBC shows that the adjusted 2-month Customer Charge averages $31.28. The Panel also notes that in the FortisBC 2009 RDA, FortisBC submitted a comparison of the Customer Charges for Saskpower, NB Power, NF Power, Manitoba Hydro, Hydro Quebec, NS Power and BC Hydro. This comparison shows FortisBC's proposed Customer Charge lying below the average monthly Customer Charge of $15.34 for those utilities.

The Panel acknowledges the need for revenue stability and notes FortisBC's comments that decreasing the Customer Charge could increase revenue volatility, a claim which no Intervener has refuted.

For these reasons, the Commission Panel is persuaded by FortisBC's submission regarding the Customer Charge and **approves its proposal to set the Customer Charge at $28.93 based on May 1, 2011 rates and exempt it from general rate increases, other than rate rebalancing increases for the years 2012 to 2015.**

4.3 Threshold

A threshold in an inclining block rate is the kWh consumption level above which the price for each subsequently consumed kWh is billed at the Block 2 rate. As noted earlier, the threshold is also one of the key determinants of the Block 1 and Block 2 rates in FortisBC's proposed RIB rate design. Based on 2009 and 2010 customer billing data, FortisBC has modeled three threshold levels, corresponding roughly to the residential mean consumption (2,100 kWh), the residential median consumption (1,600 kWh) and a kWh value set at approximately 85 percent of the median consumption (1,350 kWh). (Exhibit B-1, p. 17)

A threshold set at 1,500 kWh has also been examined through the written hearing process.

4.3.1 FortisBC Submission

FortisBC has selected a threshold of 1,600 kWh per billing period for Option 8, its preferred RIB rate option, which corresponds to the median consumption for residential customers. This threshold would result in approximately 37 percent of the load being billed at the Block 2 rate. (Exhibit B-1, p. 18)

FortisBC acknowledges that the Commission, in Order G-124-08, approved BC Hydro's RIB rate threshold at 1,350 kWh, a reduction from BC Hydro's proposed 1,600 kWh threshold, in order to expose more customers to the Block 2 rate and in consideration of a letter from the Minister of Energy, Mines and Petroleum Resources citing the threshold at 10 percent below the average usage. However, FortisBC notes that in its case, all other RIB rate determinants remaining unchanged, a similar determination would effectively prompt the approval of Option 2 rather than Option 8. (FortisBC Final Submission, p. 3) This would result in lower Block 1 and Block 2 rates with no anticipated increase in conservation. (Exhibit B-11, Appendix B) Furthermore, FortisBC notes that in the BC Hydro case, a threshold of 1,600 kWh results in approximately 62 percent of customers being billed at the Block 2 rate at least once while a threshold of 1,200 kWh would see that number rise to 74 percent. By contrast, a FortisBC threshold set at 1,600 kWh would result in 72.8 percent of customers being billed at the Block 2 rate at least once. Therefore, FortisBC essentially shows that the difference in characteristics between the two utilities means that approximately the same proportion of customers would be billed at the Block 2 rate despite the different thresholds. (FortisBC Reply Submission, p. 6)

FortisBC also states that setting the threshold near the median level provides a rationale that is both easy to understand and communicate to customers and sees no compelling reason to vary the threshold from its proposed 1,600 kWh value. (FortisBC Final Submission, p. 3)

4.3.2 Intervener Submissions

No Intervener took issue in written submissions with the threshold proposed by FortisBC.

In BCSEA's view, three main alternatives have emerged for the RIB rate threshold that can each be relatively easily communicated:

- 1,600 kWh per billing period, preferred by FortisBC, is roughly the residential median consumption;

- 1,500 kWh per billing period is roughly 90 percent of the residential median consumption (Exhibit B-13, BCSEA 2.15.1) and is the basis of the BC Hydro's RIB threshold; and

- 1,350 kWh per billing period is BC Hydro's actual RIB threshold.

(BCSEA Final Submission, p. 4)

BCSEA acknowledges that while a lower threshold exposes more customers to the Block 2 rate, it yields a conservation estimate that is either the same as or, in some designs, slightly lower than with a higher threshold. Therefore, BCSEA tends to agree with FortisBC that there is no compelling reason to vary the threshold from the proposed 1,600 kWh value, although it would also find acceptable thresholds of either 1,500 kWh or 1,350 kWh per billing period. (BCSEA Final Submission, p. 5)

The BCOAPO makes no submission regarding the threshold level. As part of his proposed alternative RIB rate design, Mr. Shadrack supports setting the threshold initially at 1,600 kWh per billing period and lowering it by 15 percent to 1,350 kWh over five years. Strata KAS2464 does not mention the threshold specifically, but indicates its support for FortisBC's preferred option should the Commission approve a RIB rate. (Strata KAS2464 Final Submission, p. 3) Likewise, Nelson Hydro supports the RIB rate option proposed by FortisBC without commenting expressly on the threshold level. (Nelson Hydro Final Submission, p. 3)

4.3.3 Commission Determination

Once the Customer Charge has been established, the remaining elements of the RIB rate can now be set. The threshold value is the amount of monthly consumption above which a customer is billed at the higher rate. Because of the constraint that the amount of revenue recovered by the RIB rate cannot exceed the amount of the approved revenue requirement for the residential customer class, the Block 1 rate will necessarily be less than the current flat rate while the Block 2 rate will be above it. Thus, if customers were billed only at the Block 1 rate, whatever it may be, they will pay less for their electricity under the RIB rate than they do currently under the flat rate.

The Panel is of the opinion that it is desirable to ensure that as many customers as possible incur the Block 2 rate at some point during any given year.

A key determinant, then, in setting the threshold value is the percentage of customers that will be billed in the higher rate at least once in any given year. Generally speaking, the lower the threshold, the more customers are exposed to the higher Block 2 rate. The higher the threshold, the fewer customers will be exposed to the Block 2 rate.

As previously discussed, BC Hydro's initial RIB rate application proposed 1,600 kWh, which was subsequently reduced to 1,350 kWh, in large part because this threshold represents 10 percent below the average usage and would result in increased billing at the Block 2 rate. FortisBC's proposed threshold of 1,600 kWh, although substantially higher than the threshold adopted by BC Hydro, results in roughly the same proportion of customers being billed at the Block 2 rate. **The Panel approves the threshold of 1,600 kWh proposed by FortisBC**. While making this determination, the Panel also notes the observation of BCSEA that while a lower threshold generally exposes more customers to the Block 2 rate, in these particular circumstances, the conservation savings may not actually be higher with a lower threshold. In its Final Submission, it compares Option 2, with a threshold of 1,350 kWh with Option 8 (with a 1,600 kWh threshold). Both options have identical conservation savings.

4.4 Customer Impact Criterion

The customer impact criterion is the last of three key determinants used by FortisBC to determine the Block 1 and Block 2 rates, along with the Customer Charge and the threshold. The customer impact criterion is expressed in terms of the percentage of residential customers who will experience an annual rate impact due solely to the implementation of the RIB rate of less than 10 percent. FortisBC has modeled three levels of allowable customer bill impact, which can be summarized as 90 percent, 95 percent, or 100 percent of customers will see a RIB-related increase of less than or equal to 10 percent. (Exhibit B-1, p. 17)

4.4.1 FortisBC Submission

FortisBC proposes a RIB rate option that incorporates the 95 percent customer impact criterion. FortisBC is concerned about the potential impact of a RIB rate on its customers and therefore seeks a balance between its needs and those of its customers while also considering the goal of conservation. FortisBC acknowledges that allowing a greater percentage of its customers to experience more than 10 percent annual bill impact results in greater anticipated conservation. However, it does so by lowering the Block 1 rate further to create a larger block differential. This potentially results in greater gains to some customers with no accompanying behavioural changes while exposing a larger number of customers to high bill increases. FortisBC also believes that an unduly punitive rate that may disproportionately affect a sub-group of customers, such as those with electric heat, should be avoided. FortisBC submits that the relatively modest increases in conservation results do not justify the move from the 95 percent to the 90 percent customer impact criterion. (FortisBC Final Submission, pp. 6-7)

4.4.2 Intervener Submissions

No Intervener took issue with FortisBC's position with respect to the need to consider consumer impact. In particular, BCSEA noted that Customer Rate Impact (Bonbright Principle 6) and Efficiency Inducing Price Signals (Bonbright Principle 3) were given "additional weight" in the Commission's Decision in the recent BC Hydro RIB Rate Re-Pricing Decision (page 14-28 of Appendix A to Order G-45-11) and as such acknowledges that these two considerations properly form a primary part of the evaluation of FortisBC's proposed RIB.

However, BCSEA strongly supports approval of a RIB rate design based on the 90 percent customer impact criterion, as the RIB rate options based on this bill impact constraint consistently induces more conservation than those based on the 95 percent customer impact criterion, all else being equal. BCSEA submits that the most important choice in designing a RIB rate that induces the most conservation while meeting the other valid constraints and objectives is the adoption of the 90 percent bill impact constraint. BCSEA compares the conservation results anticipated under

FortisBC's preferred option (Option 8) with those under Option 7, which differ only with respect to the customer impact criterion. BCSEA disagrees with FortisBC's characterization that the conservation differential between those two options is "relatively modest" and shows graphically that Option 7 achieves substantially more conservation than Option 8. BCSEA further disagrees with the premises that customers with electric heat are a sub-group that would be disproportionately impacted by Option 7, as those customers are distributed across the spectrum of low to high consumption. In fact, BCSEA shows how Options 7 and Option 8 result in exactly the same impact in terms of the percentage of customers with electric heat who see a bill decrease (59 percent) or a bill increase (41 percent). To conclude, BCSEA submits that the Commission should prefer RIB rate designs based on the 90 percent customer impact criterion because those designs induce substantially more conservation without causing unacceptable bill impacts. (BCSEA Final Submission, pp. 1-3)

BCOAPO does not specifically comment on the appropriate level of customer bill impact in its written submission. Nonetheless, BCOAPO acknowledges that customer bill impact should form a primary part of the evaluation of FortisBC's proposed RIB. (BCOAPO Final Submission, p. 2)

Mr. Shadrack also does not comment specifically on the appropriate level of customer bill impact in his written submission.

Strata KAS2464 does not mention the customer impact criterion specifically, but indicates its support for FortisBC's preferred option should the Commission approve a RIB rate. (Strata KAS2464 Final Submission, p. 3) Likewise, Nelson Hydro supports the RIB rate option proposed by FortisBC without commenting expressly on the various individual rate components. (Nelson Hydro Final Submission, p. 3)

4.4.3 FortisBC Reply

In Reply, FortisBC notes that in his written submission, Mr. Shadrack did not explicitly express support for one of the customer impact criteria over another. The Company submits, however, that given Mr. Shadrack's alternative RIB rate proposal, with both a Customer Charge and a Block 1 rate predetermined, the use of the customer impact criterion in the manner in which FortisBC proposes is precluded and ultimately, the customer bill impact is ignored in the determination of the rate.

FortisBC stresses that the customer impact criterion, as an integral input into the determination of the rate itself, is more than just a yardstick for gauging the changes to bills as a result of the RIB rate. Furthermore, the selection of one customer impact level over another while holding the Customer Charge and threshold constant constitutes a trade-off between conservation and customer impact. FortisBC asks: Is the greater conservation potential worth the associated increase in negative customer impact? Its view is that customer impact directly influences the general acceptance of the rate – a key consideration when implementing a new rate. In conclusion, FortisBC submits that while the BCSEA acknowledges that it "... puts a priority on maximizing the amount of conservation", FortisBC seeks a balance that considers as fundamentally important the impact on customers. (FortisBC Reply, pp. 2-3)

4.4.4 Commission Determination

The Panel agrees that customer impact is an important criterion and will thus consider customer impact in its further determination of the appropriate RIB rate components.

FortisBC is proposing a RIB rate option with a customer impact of 95 percent (Option 8). The Panel accepts BCSEA's submission that a level of customer impact greater than this can, all else being equal, encourage greater conservation, and its proposal to adopt a 90 percent customer impact level (Option 7). Although FortisBC characterizes the conservation differential between Option 7 and Option 8 as being "relatively modest," BCSEA submits that the conservation savings associated with Option 7 are approximately half as much compared to those of Option 8. (Final Submission, BCSEA, p. 2) However, the Panel notes that consideration must be given, when weighing conservation benefits against bill impacts, to the factual basis of these two elements. There is an acknowledged uncertainty surrounding elasticity estimates and the resulting conservation forecasts. (FortisBC Final Submission, pp. 10-11) This is in contrast to the considerably better understanding of bill impacts and the fact that bill impacts may affect customers with large families and not just profligate consumers of electricity. Given this, the Panel is inclined to give somewhat more weight to the bill impacts than the conservation impacts.

In addition, this increase in conservation comes at a cost, which is disproportionately borne by a small sub-group of ratepayers. For example, in its Reply Submission, FortisBC estimates that the percentage of customers with bill increases above 20 percent rises from 0.2 percent to 2.7 percent when the customer impact changes from 95 percent to 90 percent. Additionally, the maximum bill impact rises from 22.6 percent to 36.2 percent and the Block 1 rate falls further below the current flat rate.

The Panel questions whether it is just and fair to disproportionately burden these ratepayers while, in essence, reducing rates for a greater number of customers. BCSEA argues that Option 7 is not "punitive", nor does it agree "with the premise that customers with electric heat are a sub-group that would be disproportionately impacted by Option 7." (BCSEA Final Submission, pp. 1-3) BCSEA further submits that a RIB rate is not inherently unjust, unreasonable, unduly discriminatory or unduly preferential. The Panel agrees, but is of the opinion that a RIB rate should be calibrated to ensure that the intended benefits are not out of proportion to their costs and that these costs should be borne by as broad a base of ratepayers as possible. **Thus the Panel agrees with FortisBC's proposed 95 percent bill impact criteria.**

4.5 Block 1 and Block 2 Rates

The Block 1 and Block 2 rates are determined as a function of the Customer Charge, threshold and customer impact criterion, meaning that for each combination of these three determinants, there is only one combination of Block 1 and Block 2 rates that would collect the required revenue. (Exhibit B-1, p. 17)

4.5.1 FortisBC Submission

Given FortisBC's position regarding the Customer Charge, threshold and customer impact criterion, as described in Sections 4.2 to 4.4 above, FortisBC's proposal for a RIB rate remains its original preferred option (Option 8). A January 1, 2012 implementation, using the methodology described in the Application to determine the rate, would produce a RIB rate with the following components:

- A Customer Charge of $29.65 per billing period;
- A Block 1 rate of 8.453 cents per kWh; and
- A Block 2 rate of 12.408 cents per kWh.

(FortisBC Final Submission, p. 7)

This determination is described at length in Exhibit B-11, in response to the Commission's request for clarification on how 2012 rates are to be calculated, as well as in Exhibit B-13 in response to BCOAPO IR2 Q4a. (FortisBC Final Submission, pp. 7-8) The above RIB rate stands in contrast to the current flat rate, which if continued in 2012, would yield a Customer Charge of $31.25 and an Energy Charge of 9.816 cents per kWh. FortisBC notes that the actual RIB rate will vary from the above description as it depends upon the month of implementation and the amount of actual residential consumption that occurs up to the implementation date while under the flat rate. (FortisBC Final Submission, p. 7)

4.5.2 Intervener Submissions

BCSEA did not comment specifically on the attributes of Block 1/Block 2 rates in FortisBC's proposed Option 8 or in any other RIB rate options. However, FortisBC's proposed RIB rate components as described in Section 4.5.1 cannot be supported by BCSEA given its support for the 90 percent customer bill impact, as opposed to the 95 percent customer bill impact supported by FortisBC.

BCOAPO submits that “there really is no need for FortisBC to implement a RIB rate in order to send the proper price signals to customers” and that “the correct action is no action at all.” (BCOAPO Final Submission, p. 6) As a result, BCOAPO did not comment on the specific levels of the Block 1 and Block 2 rates.

Strata KAS2464 and Nelson Hydro express their overall support for the RIB rate as proposed by FortisBC without commenting specifically on the levels of the Block 1 and Block 2 rates.

4.5.3 FortisBC Reply

In Reply, FortisBC stresses that if levels for the Customer Charge, threshold and customer impact criterion are selected and deemed to be the most appropriate on an individual basis but then generate a Block 1 and Block 2 rate combination that is ineffective or unpalatable, then one may conclude that a RIB rate may not provide the best solution. Furthermore, manipulating the rate themselves would compromise the other rate determinants. (FortisBC Reply, p. 7)

4.5.4 Commission Determination

The Panel recognizes that once the three key determinants - the Customer Charge, threshold and customer impact criterion - have been selected, there is only one combination of Block 1 and Block 2 rates that can satisfy the revenue requirement constraint. **Given the Commission Panel’s approval of FortisBC’s proposal for each of the determinants, it follows that the Panel also agrees with its proposal for the Block 1 and Block 2 rates. The Panel also acknowledges that the Block 1 and Block 2 rates will differ somewhat from the values of 8.453 and 12.408 cents per kWh respectively as they are dependent upon the specific 2012 implementation date.**

4.6 FortisBC's Long-Run Marginal Cost

The issue of determining FortisBC's true LRMC arose as the Commission probed the potential relationship between the utility's LRMC and the level of the Block 2 rate and, in particular, the appropriateness of capping the Block 2 rate at the LRMC.

FortisBC defines LRMC as the cost to acquire additional energy where existing resources are insufficient to meet load requirements. In the near to medium term, FortisBC expects to meet incremental requirements through increased market purchases. (Exhibit B-8, Commission Panel IR 7.1) This is why, in a first instance, FortisBC calculated its LRMC based on the forecast of the market price of energy as opposed to construction of new resources. In the additional evidence filed at the Commission Panel's request, FortisBC acknowledged that a LRMC from new resources could be developed from a forecast of the cost of potential new resources. FortisBC submits that a reasonable proxy for the cost of new resources in the long-term is the BC New Resources Market Energy Curve presented in its 2012 Long-Term Resource Plan. (Exhibit B-11, pp. 16-17) The following table summarizes FortisBC's various marginal cost and LRMC values presented throughout this Application.

Table 3: FortisBC's Marginal Cost and Long-Run Marginal Cost of Energy

Definition	**Value**	**Reference**
Marginal Cost: short-term avoided costs over the 2012 to 2015 period, based primarily on avoided 3808 Energy Purchases with minor amount of market purchases and surplus sales)	\$38.04 per MWh	Exhibit B-8, Commission Panel IR 7.1 Exhibit B-8, Commission Panel IR 7.2
Long-Run Marginal Cost: cost to acquire additional power through market purchases where existing resources are insufficient to meet load requirements	\$84.94 per MWh	Exhibit B-8, Commission Panel IR 7.1 Exhibit B-8, Commission Panel IR 7.2

Long-Run Marginal Cost: cost to acquire additional power from new resources	$111.96 per MWh (30-year levelized value starting in 2011 using a nominal discount rate of 8 percent) $125.80 per MWh (including 11 percent losses)	Exhibit B-11, p. 17

Source: Exhibit B-11, p. 17

In the second round of Information Requests, FortisBC was asked to confirm that the LRMC set at $125.80 per MWh did not include the cost of delivery and to calculate its LRMC segmented by: 1) the energy cost (including line losses); 2) transmission delivery cost; and 3) distribution delivery cost. (Exhibit B-12, BCUC 2.9.3; BCUC 2.9.6) In response, FortisBC affirms that the plant-gate levelized value of $111.96 per MWh is the estimated required contractual price to procure energy from a newly constructed BC generation resource and the $125.80 per MWh includes line losses of 11 percent. FortisBC also confirms that the LRMC of $125.80 per MWh does not include other delivery costs, since it assumes that any incremental transmission costs would be paid directly by the project proponent or would be reflected in an adjustment to the plant-gate price paid to the project. FortisBC does not, however, indicate by how much the plant-gate price would need to be adjusted to reflect those delivery costs. (Exhibit B-12, BCUC 2.9; BCUC 2.9.6)

4.6.1 FortisBC Submission

FortisBC acknowledges that fundamentally the move to marginal cost based pricing is undertaken to set prices that lead to the most efficient use of resources and that, purely in terms of economic theory, it may not be desirable to price any electricity above the marginal cost. (Exhibit B-11, pp. 15-16) However, FortisBC submits that, given the utility's current cost structure and existing rates, pricing the Block 2 rate at LRMC fails the test of workability. Indeed, the LRMC of $125.80 per MWh is only slightly above the Block 2 rate of $0.12408 per kWh if the RIB rate as proposed by FortisBC becomes effective in 2012. An increase in the Block 2 rate of only 1.4 percent would push it beyond the LRMC. FortisBC further argues that, in order to have the LRMC cap the Block 2 rate and given the mandate to lower the Customer Charge, subsequent rate increases would impact only the Block 1 rate, which would then rapidly lead to a convergence of the Block 1 and Block 2 rates and effectively nullify the conservation impact. In addition, FortisBC submits that residential customers are far more likely to look at the Block 1/Block 2 rate differential when making consumption-related decisions than they are to relate the Block 2 rate to any measure of LRMC. As a result, they argue conservation would be driven more by customer consideration of the rate differential than of whether the Block 2 rate is above or below the LRMC value. (FortisBC Final Submission, pp. 8-9)

In conclusion, FortisBC recommends that no cap be introduced on the Block 2 rate at this time. (FortisBC Final Submission, p. 9)

4.6.2 Intervener Submissions

BCSEA agrees that the Block 2 rate should not be capped going forward as annual revenue requirement increases would more or less quickly cause the Block 2 rate to reach the cap and the Block 1/Block 2 rate differential to begin to disappear and states that the priority should be on inducing conservation. Should the Commission choose to cap the Block 2 at the LRMC, BCSEA submits that the reference point for the Block 2 rate should be FortisBC's marginal cost of new generation and not a blended figure that includes market supply. (BCSEA Final Submission, p. 5)

BCOAPO acknowledges FortisBC's view that capping its Block 2 rate at its LRMC would result in a rapid convergence of the two block rates with dwindling conservation impacts resulting. BCOAPO further notes in its written submission:

> "... the inherent flaw in FortisBC's reasoning is that they have interpreted the purpose of this exercise as being the introduction of RIB rates and the reduction of electricity use. Instead, BCOAPO submits that RIB rates are not and should not be the overall objective, but rather a means to an end. The means is the rate structure and the end is to encourage efficient electricity use via rates that send the proper price signals to encourage customers to make the appropriate consumption decisions and this can only be achieved using a RIB rate structure when the LRMC is significantly higher than the existing rate."

This leads the BCOAPO to conclude that FortisBC is a different utility than BC Hydro with significantly different circumstances regarding rates and avoided costs. Consequently, the two utilities are not directly comparable and BCOAPO argues there is really no need for FortisBC to implement a RIB rate in order to send the proper price signals to customers, as they are coming soon, whether the utility has a RIB or not. (BCOAPO Final Submission, pp. 5-6)

Mr. Shadrack, Nelson Hydro and Strata KAS2464 do not address FortisBC's LRMC or the issue of capping the Block 2 rate in their respective Final Submissions.

4.6.3 Commission Determination

In the 2007 BC Hydro Rate Design Application Decision, the Commission acknowledged the pivotal role of conservation rates and found that conservation is the only practical way to avoid dilution of the Heritage benefit with the ever increasing reliance on high marginal cost of incremental supply (BC Hydro 2007 RDA Decision, p. 57, Order G-130-07). In the 2008 BC Hydro Residential Inclining Block (RIB) Decision, the Commission determined that the long-run cost of new supply is the appropriate referent for the Step-2 energy rate (BC Hydro 2008 RIB Decision, p. 107, Order G-124-08). The Panel finds that no new evidence has been provided in this proceeding to cause it to depart from those conclusions. **Accordingly, the Commission Panel determines that the long-run marginal cost of new supply continues to be the appropriate referent for the Block-2 energy rate.**

Should, then, the Block 2 rate be capped at the long-run marginal cost of new supply? The Panel accepts FortisBC's submission that pricing electricity above FortisBC's long-run marginal cost is not economically efficient. However, the Panel is not prepared to direct that the Block 2 rate be capped at the LRMC as proposed by FortisBC in this hearing. Table 3 above shows three different marginal costs:

1. Short-term avoided costs based on avoided Rate Schedule 3808 Energy Purchases;
2. LRMC to acquire additional power through market purchases; and

3. LRMC to acquire additional power from new resources.

While the Panel considers the most appropriate referent to be the cost of acquiring energy through new resources, we note that all of the above marginal costs represent only the cost of acquiring the energy. Thus, there is ambiguity between the LMRC as defined by FortisBC and the true long-run marginal cost of new supply to the customer. The Block 2 rate is a delivered rate, while the LRMC is a cost of acquisition – it only relates to the cost of procuring energy but does not include the LRMC of transporting that energy to customers through transmission and distribution networks. FortisBC estimates the LRMC at $125.80 per MWh, or 12.58 cents per kWh, which includes line losses of 11 percent, but does not include other delivery costs. FortisBC has provided no further information about the cost to deliver this additional energy acquired from market purchases or new resources. Accordingly, the Panel finds that there is insufficient evidence to support the position of the BCOAPO that there is "…no need for FortisBC to implement a RIB rate in order to send the proper price signals to customers."

FortisBC's proposed Block 2 rate is 12.408 cents per kWh, assuming a 2012 implementation date, which is below its estimated LRMC cost of 12.58 cents per kWh, which includes line losses but excludes other delivery costs. Thus, the Panel is satisfied that this Block 2 rate is below the actual delivered LRMC. Because of the uncertainty of the actual LRMC, the Panel does not agree that the Block 2 rate be capped at this time. **However, FortisBC is directed to provide an update of the full long-run marginal cost of acquiring energy from new resources, including the cost to transport and distribute that energy to the customer as part of the reporting to be submitted in 2014.**

4.7 Pricing Principles

Throughout this written hearing process, the term "Pricing Principle" referred to the manner in which future rate increases are applied to the Customer Charge, Block 1 rate and Block 2 rate. FortisBC's proposed Pricing Principle (Pricing Principle 1), which allows the Customer Charge to decrease over time in relation to the other RIB rate components, is as follows:

Customer Charge: exempt from revenue requirement rate increases but subject to rebalancing adjustments;

Block 1: adjusted by an amount equal to the sum of the general revenue requirement increase and any rebalancing adjustments; and

Block 2: adjusted by an amount sufficient to recover the balance of the general revenue requirement and any rebalancing adjustments.

(Exhibit B-1, p. 15)

In its Application, FortisBC also examined three alternative Pricing Principles which, together with Pricing Principle 1, are summarized in the following table.

Table 4: FortisBC's Pricing Principles Summary

Pricing Principles Summary			
	Treatment of Customer Charge	**Treatment of Block 1 Rate**	**Treatment of Block 2 Rate**
Pricing Principle 1	• Exempt from ARR* and BC Hydro flow-through Increase • Rebalancing applied	• Subject to all increases	• Calculated residually to ensure Revenue requirement is collected
Pricing Principle 2	• Exempt from ARR* and BC Hydro flow-through Increase • Rebalancing applied	• Frozen	• Calculated residually to ensure Revenue requirement is collected
Pricing Principle 3	• Subject to all increases	• Subject to all increases	• Calculated residually to ensure Revenue requirement is collected
Pricing Principle 4	• Subject to all increases	• Frozen	• Calculated residually to ensure Revenue requirement is collected
*ARR = Annual Revenue Requirement			

(FortisBC Final Submission, p. 10)

4.7.1 FortisBC Submission

FortisBC believes that its proposed Pricing Principle provides the most workable combination because Pricing Principles 3 and 4 do not result in a lowering of the Customer Charge and therefore do not comply with Commission Order G-156-10 and Pricing Principle 2 causes the Block 2 rate to escalate too quickly resulting in a block differential that is too large and unduly penalizes some customers. Thus, FortisBC submits that the Commission should approve Pricing Principle 1. (FortisBC Final Submission, p. 10)

4.7.2 Intervener Submissions

BCSEA supports FortisBC's proposed Pricing Principle 1, which it considers a middle-of-the-road approach compared to the alternatives because the Block 1 rate does not increase so quickly as to eliminate the Block 1/Block 2 rate differential and the Block 2 rate does not increase excessively. (BCSEA Final Submission, p. 5)

In its written submission, Nelson Hydro also supports FortisBC's proposed Pricing Principle. (Nelson Hydro Final Submission, p. 2) BCOAPO and Strata KAS2464 do not comment specifically on this topic. Mr. Shadrack, who proposes an entirely different RIB rate scenario in his written submission, does not comment specifically on FortisBC's proposed Pricing Principle 1.

4.7.3 Commission Determination

We have previously determined that the Customer Charge will be frozen (except for rate rebalancing increases). Pricing Principles 3 and 4 are not consistent with this approach and are not considered further. The difference between Pricing Principles 1 and 2 is that the Block 1 rate is frozen in Pricing Principle 2 and subject to all rate increases in Pricing Principle 1. Freezing the Block 1 rate will cause the differential between the two rates to increase over time. The Panel accepts FortisBC's submission that this will quickly result in a block differential that is too large and will unduly penalize some customers. **Accordingly, the Panel directs FortisBC to apply Pricing Principle 1 to any future price increases until 2015.**

4.8 Anticipated Conservation

4.8.1 <u>FortisBC Submission</u>

FortisBC "is supportive of the Government's Energy Plan goal of having conservation offset 50 per cent of cumulative load growth by 2020." To this end it has proposed rate structures that encourage energy efficiency and conservation. It believes that "RIB rates can encourage customers to conserve by increasing electricity rates as consumption rises." In all the scenarios it has proposed, the price of energy consumed in the upper block is greater than the current flat rate energy price and represents a real rate increase over current charges for the consumption above the threshold. (Exhibit B-1, p. 4)

The proposals are the first step down the path to FortisBC's commitment to implementing time based conservation and efficiency rates. "FortisBC believes that the proposal for a RIB rate contained in this application is one component of a comprehensive demand reduction strategy that helps the Commission and the Province fulfill conservation goals." (Exhibit B-1, p. 8) In the Application, FortisBC defines the conservation impact of the RIB rate as "the estimated reduction in both consumption and demand that is attributable to the implementation of the given RIB rate option." (Exhibit B-1, p. 20) FortisBC later clarifies that no capacity savings were assumed for the RIB program and the only change is to FortisBC's energy requirements. (Exhibit B-5, BCUC 1.9.3, BCUC 1.17.6)

FortisBC adopts the assumption that a 1 percent change in price in the Block 1 rate will result in -0.05 to -0.20 percentage change in energy consumption and that a 1 percent change in price in the Block 2 rate will result in -0.10 to -0.30 percentage change in consumption. Based on these assumptions, the proposed two-block RIB rate, if approved, would result in estimated conservation savings in the range 1.9 percent to 5.5 percent. (Exhibit B-1, Table 7-2, p. 22)

FortisBC acknowledges the uncertainty inherent in assessing conservation impacts of the RIB rate structures but takes the position that this should not be viewed as a barrier to proceeding to choose the preferred option. FortisBC believes that based on the conservation analysis, the implementation of a RIB rate will lead to conservation behaviour on the part of those customers. (FortisBC Final Submission, p. 10)

It is clear that a RIB rate is not FortisBC's preferred approach to encouraging conservation. "The Application was filed upon the Direction provided in BCUC Order G-156-10. Of its own volition, FortisBC would not have arrived at the conclusion that a RIB rate is preferred as a method of mitigating increasing demand…The Company takes no position on the likelihood or degree to which conservation results will materialize while the RIB rate is in place and further cannot forecast annual conservation impacts with any degree of confidence." (Exhibit B-5, BCUC 1.18.1, p. 60)

Part of the uncertainty on the conservation results that can be attributed to a RIB rate is the unknown relationship between the existing DSM programs and a conservation RIB rate that would cover 99 percent of its residential customers. FortisBC believes that introducing a RIB rate may reduce DSM expenditures but DSM targets will not be affected by RIB rates. It submits that: "factors make it difficult to predict the impact of RIB on DSM programs as a whole. FortisBC expects a positive impact on DSM measures that result in significant energy savings…" (Exhibit B-5, BCUC 1.23.1), and that: "RIB and other conservation rates are not considered 'part' of PowerSense DSM…Although the goal of conservation rates is similar to PowerSense programs, the expertise required to design and implement them is different. For this reason, conservation rates have not been considered part of the PowerSense program." (Exhibit B-13, BCOAPO 2.2c) FortisBC has not indicated whether or not its DSM targets would be reviewed as a result of the implementation of a new rate structure that would cover almost all of its residential customers. Nor has it indicated whether it would initiate a new or an updated Conservation Potential Review (CPR) to assess the potential of DSM savings and therefore, new DSM targets, following implementation of the RIB rate.

With regard to conservation savings and energy efficiency from RIB rate, FortisBC is of the opinion that: "Savings would occur due to a change to a RIB rate starting with the time the rate is implemented. It may take several years for those full savings to occur due to the fact that a portion of the savings result from behavioural changes, which would be immediate, and another portion results from a change in electric-consuming devices, which occurs over time. FortisBC does not have an estimate of the savings in each year as a result of the RIB rate." (Exhibit B-6, Okanagan Environmental Industry Alliance (OEIA) 1.11.1.2)

Another source of uncertainty on conservation results is FortisBC's assumption on elasticity. FortisBC submits: "Given the uncertainty surrounding elasticity estimates and the resulting conservation forecasts, FortisBC believes a prudent and conservative approach to evaluating the efficacy of the RIB rate is to implement its preferred option, submit to the Commission its plan for monitoring and evaluating the RIB rate over the period ending December 31, 2013, and then address any program modifications that may be indicated by the resulting report." (FortisBC Final Submission, pp. 10-11) Therefore, "FortisBC … requests the Commission approve a RIB rate that includes: …The development of a plan to evaluate the conservation impact of the RIB with a reporting requirement for the period covering the date of implementation to December 31, 2013." (FortisBC Final Submission, p. 13)

4.8.2 Intervener Submissions

BCSEA supports the approval of a FortisBC RIB rate as a means to achieve conservation. However, BCSEA strongly prefers Option 7 where '90% see <10% bill impact', rather than Option 8 proposed by FortisBC where '95% see <10% bill impact', as "RIB rate designs based on the '90% see <10%'s constraint consistently induce more conservation than those based on the '95% see <10%'s constraint." (BCSEA Final Submission, pp. 1-3)

BCSEA also supports a requirement that FortisBC use a control group to enhance its evaluation of the impact of the proposed RIB rate. It submits that "…FortisBC's ability to quantify the analysis in the RIB rate application was limited by the lack of data on the elasticity of demand of FortisBC's own customers. Using a control group in parallel with the introduction of the RIB rate is an opportunity for FortisBC to develop elasticity data for its own customers." In BCSEA's view, this opportunity should not be missed. It submits that such data would be very useful both for evaluating the RIB rate and for FortisBC's consideration of time-of-use rate designs after its Advanced Metering initiative has been implemented. (BCSEA Final Submission, p. 6)

Nelson Hydro supports "the implementation of the RIB rate as proposed by FortisBC as a means to encourage conservation. Nelson Hydro's interest in this is to monitor the outcome of this rate design to determine answers to:

- What energy consumption reductions are achieved,
- Do the consumption reductions persist or are they temporary,
- How does the rate design impact electric heat customers,
- What operating cost reductions result to the utility?"

(Nelson Hydro Final Submission, p. 3)

"BCOAPO suggests … the promotion of conservation through pricing is only appropriate where it encourages energy efficiency initiatives that cost less than new supply and if the pricing is sending signals that actually lead to cost-effective decisions." (BCOAPO Final Submission, p. 3) BCOAPO believes that "A change in focus with a greater emphasis on "cost-effectiveness" would align the objectives of FortisBC's conservation rates with its DSM programs…" (BCOAPO Final Submission, p. 3)

BCOAPO submits that there is a serious disconnect between the screening measures adopted by FortisBC in this rate design and the Bonbright Principles. (BCOAPO Final Submission, p. 4) It states that FortisBC has fundamentally erred in its screening measures by deciding that an efficient price signal is that which encourages some portion of customers to reduce consumption. This leads to FortisBC's claim that the primary goal of the RIB is to promote conservation with no consideration as to how the resulting Block rates …compare to the Utility's avoided costs (BCOAPO Final

Submission, pp. 4-5).

BCOAPO argues that “To introduce a RIB rate where both Blocks will vary from the LRMC more than the current flat rate within the short term is counterproductive because it does not promote the efficient use of electricity while causing material customer impacts…It may be a difficult pill for parties to swallow… to find that the correct action is no action at all, but that is, in BCOAPO’s submission, the case here.” (BCOAPO Final Submission, p. 6)

Strata KAS2464 believes the RIB rate proposal will result in only marginal conservation benefits. (Strata KAS2464 Final Submission, p. 3) It supports a requirement that FortisBC use a control group to evaluate the impact of the proposed RIB rate and disagrees with FortisBC submission that it is premature. Throughout the RIB application FortisBC did not demonstrate it understood the demands of its own customers.” (Strata KAS2464 Final Submission, pp. 1-2)

Mr. Shadrack does not specifically address the linkage of the RIB rates to conservation. However, he does make several observations related to the introduction of the RIB rate, including:

- “the Commission needs to set an inclining block rate with clear hard targets and a mechanism to get there.” (Shadrack Final Submission, p. 1)
- “any inclining block rate design…should allow the customer to recoup the cost of investing in energy efficient devices in a timely manner.” (Shadrack Final Submission, p. 2)
- “the introduction of an inclining block rate, in and of itself, must be accompanied by clearly focused DSM programs that compliment [sic] the inclining block rate” (Shadrack Final Submission, p. 3)

4.8.3 Commission Determination

Balancing energy conservation with the Bonbright Principles is an appropriate evaluative approach by FortisBC to select the RIB rate option. While we acknowledge the submission made by BCSEA regarding Option 7’s inducement of greater conservation than the proposed Option 8, we are not persuaded that this, in itself, is sufficient to over-ride the balance of the various Bonbright Principles achieved in Option 8. In particular we have previously discussed the issues to be considered in the trade-off between bill impact and conservation**.** The Commission Panel acknowledges FortisBC's position that the conservation impact between the various options may be small enough to not have much impact on the final determination of the rate option selected. However we feel that further analysis of conservation impacts is required because of the uncertainties articulated by FortisBC.

The Panel fully supports FortisBC's intention to develop a plan to monitor and estimate the conservation impacts that can be attributed to RIB implementation. **Accordingly, the Commission Panel directs FortisBC to meet a reporting requirement covering the period from the date of implementation to December 31, 2013**. This report (the 'RIB Rate Evaluation Report') should provide FortisBC, the Commission and the Interveners the opportunity to evaluate the effectiveness of the RIB rate program, particularly with respect to its impact on conservation. In addition to including an update of the Conservation Potential Review and a report on the potential effects of interaction between RIB rates and DSM targets, the RIB Rate Evaluation Report should also address the questions raised by Nelson Hydro at page 3 of its Final Submission:

- What energy consumption reductions are achieved,
- Do the consumption reductions persist or are they temporary,
- How does the rate design impact electric heat customers, and
- What operating cost reductions result to the utility?

The RIB Rate Evaluation Report is to be submitted to the Commission by no later than April 30, 2014.

We also concur with both BCSEA and Strata KAS2464 that it is not too early to make use of a control group to enhance the evaluation of the impact of the RIB rate. **Accordingly, the Panel directs FortisBC to establish a control group in conjunction with the introduction of the RIB rate**

to develop elasticity data for its own customers. The results of this elasticity study are also to be included in the RIB Rate Evaluation Report. In this regard we note that in its Final Submission, FortisBC indicated that it works together with municipal utilities in offering demand side programs and incentives. It may be helpful if FortisBC could provide comparisons of consumption of its direct and indirect customers throughout the reporting period.

While the Commission Panel acknowledges BCOAPO's position on the desirability of understanding the linkage of conservation rates to the long-run marginal cost of electricity, we do not concur with its view that it is counterproductive to introduce a RIB rate because it does not promote the efficient use of electricity. The conservation associated with the RIB rate is, in itself, a legitimate reason for its introduction, taking account of all Bonbright Principles of pricing, not just the principle associated with efficient price signals.

4.9 Voluntary TOU rates and Mandatory RIB Rates

4.9.1 FortisBC Submission

As noted in Section 4.8.1, it is clear that a RIB rate is not FortisBC's preferred approach to encouraging conservation. Submissions of FortisBC from the Application and the IR process include:

- "The consensus reached during the public consultation, and the preference of FortisBC, was for maintaining the status quo pending the AMI implementation (Exhibit B-1, p. 13)
- "FortisBC does not believe that the implementation of a RIB rate eases the introduction of time based rates. The Company further believes that the interim nature of the RIB rate, being effective between the current flat rate and the implementation of any time-based rates will create difficulties for the transition. FortisBC is concerned that customer confusion may result from the implementation of the two types rate types in fairly quick succession." (Exhibit B-5, BCUC 1.4.3)
- "FortisBC believes that time based rates provide conservation benefits which are at a minimum as good as a RIB rate while simultaneously providing customers with more of an opportunity to conserve, thus reducing their total cost of electricity." (Exhibit B-5,

> BCUC 1.6.3,) "FortisBC believes that the primary goal of time-based rates is to conserve capacity, but that energy conservation also occurs." (Exhibit B-12, BCUC 2.4.1)

FortisBC submits that time-based conservation rates offer the best alternatives to flat rates for FortisBC and its customers. It is currently FortisBC's intention to introduce some suite of time-based rates to complement the RIB rates, likely on a voluntary participation basis, if a RIB rate is mandated by the Commission. (Exhibit B-5, BCUC 1.6.4) However, despite this reservation, FortisBC states that the implementation of the RIB rate is a stand-alone program and that the eventual move to time-based rates does not feature as a consideration in any of the work done to date." (Exhibit B-6, OEIA 1.5.1)

The RIB rate Application has not changed FortisBC's intention regarding the implementation of Advanced Metering Infrastructure and time based rates although those rates are now expected to be optional rather than mandatory (Exhibit B-6, OEIA 1.8.4.1). FortisBC states that "in due course" it will consider a rate structure that combines time-based and RIB principles, but believes that such a rate structure is overly complex to customers (Exhibit B-13, BCSEA 2.31.1) At this juncture, FortisBC has not yet completed any detailed analysis on the effects of wide-scale time based rates that could be implemented after an Advanced Metering Infrastructure was implemented, and therefore it cannot state conclusively as to whether TOU rates can achieve better conservation than RIB rate. (Exhibit B-8, BCUC IR 1.5.2, p. 20)

4.9.2 Intervener Submissions

Mr. Russell Work is opposed to the proposal to implement the RIB rate, as he believes that "it will have minimal impact on energy conservation." (Exhibit B-6, Work IR 1, p. 1) He argues for promoting TOU metering but provided no evidence on the benefits of doing so. No other Intervener addressed the relative merits of a voluntary TOU rate and mandatory RIB rates or provided any submission on combining RIB and TOU rates.

4.9.3 Commission Determination

FortisBC refers to the "interim nature" of the RIB rate, being effective between the current flat rate and the implementation of any time based rates. The Commission Panel cautions FortisBC against concluding that the RIB rate is only temporary in nature, particularly in view of not yet having made application for its AMI initiative, nor for any TOU rates associated with it. The RIB rate could well be an integral part of a longer-term conservation initiative and should be designed with that in mind, including the approaches used to measure and manage its ongoing efficacy.

In its submission, FortisBC proposes that: "Customers who choose to take service under FortisBC's existing conservation rate, Time-of-Use billing, would not be compelled to move to the RIB rate." The Panel acknowledges the difficulties of applying the RIB rate to these customers and accordingly **directs that customers currently receiving service under Time-of-Use billing will not be charged at the RIB rate until and unless these customers elect to move from TOU billing to RIB rate billing. However, the Panel directs FortisBC to apply the RIB rate on a mandatory basis to all residential customers not currently receiving service under TOU billing.**

If FortisBC moves forward with its Advanced Metering Initiative as it currently plans to do, it will need to develop a strategy to integrate the RIB rate regime with its TOU rate regime. If this is accomplished during the reporting requirement period, there will be an opportunity to include the effect of combined TOU and RIB rates on conservation in the RIB Evaluation Report. **The Panel directs FortisBC to consider effective ways to report this information and include the results in the RIB Rate Evaluation Report.**

4.10 Indirect Customers

On October 27, 2011, the Commission Panel requested that the parties address in their Final Submissions the following questions:

1. Should the Panel consider the implications of conservation rate setting for indirect customers of FortisBC in this proceeding?
2. Should the Panel consider the implications of conservation rate setting for these indirect customers in future FortisBC rate design proceedings?

(Exhibit A-22)

4.10.1 FortisBC Submission

FortisBC submits that whether or not the Commission "should" have these considerations is a matter of provincial policy "best left to the Commission and government to determine." FortisBC further submits that if the questions are rephrased to inquire as to whether the Commission "can" directly influence rates of indirect customers in the current regulatory environment, then FortisBC's answer is "no" to the two questions. FortisBC states that electric utilities who are direct customers of FortisBC, as a Wholesale customer class, set their own rates for their customers, and are not regulated by the Commission. FortisBC also submits: "The Commission may consider the implications of conservation rate setting for FortisBC direct customers, including those rates for wholesale municipal electric utilities; however the Commission cannot consider the implications of conservation rate setting for FortisBC indirect customers." (FortisBC Final Submission, p. 12)

FortisBC further submits that: "Municipal electric utilities who are direct customers of FortisBC (Wholesale customer class) set their own rates for their customers, and are not regulated by the Commission in doing so other than if operating outside municipal boundaries. The definition of 'public utility' in the *Utilities Commission Act* excludes 'a municipality or regional district in respect of services provided by the municipality or regional district within its own boundaries'."

FortisBC also acknowledges that these five municipal utilities' residential customers, though indirect, do, in aggregate, comprise a significant portion of FortisBC's load. These indirect residential customers will not be subject to a conservation rate.

FortisBC submitted the 'Residential End Use Survey' which "took into account responses from indirect customers of FortisBC because the purpose of the Survey was in part to assist FortisBC in forecasting future electrical demand and in designing demand side management programs." (FortisBC Final Submission, p. 12)

4.10.2 Intervener Submissions

BCSEA also submits that the Panel should not consider the implications of conservation rate setting for indirect customers in this proceeding. BCSEA further notes that it has insufficient information to comment on the consideration of implications on indirect customers of future rate design applications by FortisBC. (BCSEA Final Submission, p. 6)

Nelson Hydro responded to the first of the above questions with the comment: "No…. we note that broadening the scope to include customers of other utilities could require a substantive repeat of the process." In response to the second question, it submitted: "No. In BC there are eight distinct electrical utilities and the proceedings for one should not spill over into the others. Some of these utilities do not require BCUC approval for their rate setting." (Nelson Hydro Final Submission, p. 1)

4.10.3 Commission Determination

The Panel agrees with the submissions of the parties, but notes that five of FortisBC's wholesale customers: the Cities of Kelowna, Grand Forks, Nelson, Penticton and Summerland all have a significant component of residential ratepayers. In this regard, the Panel also notes that FortisBC and municipal utilities work together in offering demand side programs and incentives and this cooperative approach to DSM is mutually beneficial.

Accordingly, we question why FortisBC should not work together with these municipal utilities to assist them to implement a RIB rate for their own residential customers as part of a demand side management program. As FortisBC gains experience with its own RIB rate, and if it can demonstrate customer acceptance and conservation savings, it will be in a better position to assist its wholesale customers with their own RIB rates, should they choose to go that route.

FortisBC could also consider a two-tier conservation rate for its Wholesale customers. In this regard, the Panel refers to a recent Commission Decision concerning the resolution of a complaint filed by Zellstoff Celgar Limited Partnership regarding the failure of FortisBC to complete a general service agreement and FortisBC's application of RS 31 demand charges. (Celgar Complaint Decision, Order G-188-11) In that Decision, FortisBC was directed to submit an application to the Commission by May 31, 2012 for a two-tier stepped transmission rate to reflect conservation objectives. FortisBC was further directed to consult with all classes of its customers to determine guidelines for the level of non-Power Purchase Agreement embedded cost of power to which eligible self-generation customers should be entitled.

The Panel is of the opinion that ideally, all of FortisBC's customers, including Wholesale customers, should be charged a rate that reflects conservation objectives. Accordingly, after introduction of inclining block rates for its residential customers, FortisBC should consider the implementation of two-tier rates for its wholesale customers. **In particular, the Panel directs FortisBC, as part of its RIB Rate Evaluation Report, to provide an analysis of the potential effect of a two-tier wholesale rate on the consumption of its wholesale customers.**

5.0 SUMMARY OF COMMISSION PANEL DETERMINATIONS

In this decision, the Panel has provided a number of directives. These are summarized below:

1. **FortisBC is directed to implement a RIB rate, which consisting of four components: a Customer Charge, a threshold, and two block rates, set at the following values, based on May 1, 2011 rates:**

    - **A Customer Charge of $28.93 per billing period;**
    - **A threshold set at 1,600 kWh per billing period;**
    - **A Block 1 rate of 7.828 cents per kWh; and**
    - **A Block 2 rate of 11.272 cents per kWh.**

2. **FortisBC is to implement this RIB rate as soon as is reasonably practicable and by no later than July 31, 2012. FortisBC is to file a revised Tariff Sheet for Rate Schedule 01, no later than 30 days prior to the date the RIB rate becomes effective.**

3. **FortisBC is directed to apply Pricing Principle 1 to future rate increases for the years 2012 to 2015. Specifically:**

    a. **The Customer Charge is exempt from general rate increases, other than rate rebalancing increases;**

    b. **The Block 1 rate is subject to general and rebalancing rate increases; and**

    c. **The Block 2 rate is increased by an amount sufficient to recover the remaining required revenue (i.e., the residual rate).**

4. **FortisBC is directed to apply the RIB rate on a mandatory basis to all residential customers with the exception of those taking service at a Time of Use rate at the time this Decision is issued.**

5. **FortisBC is directed to file a RIB Rate Evaluation Report (Report), covering the period from the date of implementation to December 31, 2013. The Report should provide the utility, the Commission and the interveners the opportunity to evaluate the effectiveness of the RIB rate program, in particular with respect to its impact on conservation. The RIB Rate Evaluation Report is to include, but not be limited to, the following:**

    a. **The energy consumption reductions achieved;**
    b. **Whether the consumption reductions persist or are temporary;**
    c. **How the rate design impacts electric heat customers; and**
    d. **The resulting operating cost reductions to the utility.**

    The Report should also include an in-depth analysis of the full long-run marginal cost to acquire energy from new resources, including the long-run marginal cost to transport and distribute that energy to the customer, and how that cost compares to the Block 2 rate; the combined effect of integrating TOU and RIB rates on the conservation achieved by the RIB, should that information be available; an update of the Conservation Potential Review and report on the potential effects of interaction between RIB rates and DSM targets; comparison of energy usage of indirect customers with the energy usage of direct customers; and an analysis of the potential effect of a two-tier wholesale rate on the consumption of its wholesale customers. The Report is to be filed with the Commission by no later than April 30, 2014.

6. **FortisBC is directed to establish a control group in conjunction with the introduction of the RIB rate to develop elasticity data for its own customers. The results of this elasticity study are to be included in the RIB Rate Evaluation Report.**

DATED at the City of Vancouver, in the Province of British Columbia, this 13th day of January 2012.

D. MORTON
PANEL CHAIR

L.A. O'HARA
COMMISSIONER

M.R. HARLE
COMMISSIONER

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by FortisBC Inc.
for Approval of a Residential Inclining Block Rate

BEFORE: D. Morton, Panel Chair/Commissioner January 13, 2012
L.A. O'Hara, Commissioner
M.R. Harle, Commissioner

O R D E R

WHEREAS:

A. On March 31, 2011, FortisBC Inc. (FortisBC) filed an application for approval of a Residential Inclining Block (RIB) Rate (Application) to the British Columbia Utilities Commission (Commission) pursuant to sections 58 to 61 of the *Utilities Commission Act*;

B. The Application proposes to implement a default mandatory RIB rate for FortisBC's residential customers. The RIB rate is composed of a Customer Charge and two rate blocks separated by a threshold level of consumption of 1,600 kWh per two-month billing period;

C. The Application examines 18 options. The option proposed by FortisBC has the Block 1 and Block 2 rates set at levels such that 95 percent of customers will experience annual bill impacts of less than 10 percent;

D. FortisBC proposes to exempt the Customer Charge from future rate increases, other than those related to rebalancing through 2015, effectively reducing the Customer Charge relative to the other billing determinants. FortisBC also proposes to apply future general revenue requirement rate increases as follows:

1) Block 1 rate would be increased by an amount equal to the sum of the general revenue requirement increase and any rebalancing adjustments; and

2) Block 2 rate would be calculated residually to recover the balance of the general revenue requirement and any rebalancing adjustments;

E. FortisBC proposed that the Application be reviewed through a written hearing process, including only one round of Information Requests (IRs) and concluding on June 15, 2011 by way of its Reply Submission. Based on this Regulatory Timetable, FortisBC anticipated the RIB rate structure to become effective January 1, 2012;

F. The Application was reviewed through a written hearing process. The Regulatory Timetable was revised a number of times and ultimately included:

- One round of IRs from Commission staff and Interveners;
- One round of IRs from the Commission Panel;
- A Procedural Conference held in Vancouver on August 3, 2011 to consider, among other matters, whether FortisBC had filed sufficient evidence to enable the evaluation of the Application, and whether the Application should proceed with an oral or written hearing;
- The filing by FortisBC of additional evidence on August 24, 2011 to clarify, among other issues, how 2012 RIB rates are to be calculated, the value of the long-run marginal cost, elasticity and conservation measures, and the customer charge calculated on a cost of service basis;
- An additional round of IRs from Commission staff and Interveners; and
- The filing of evidence by Interveners;

G. The Commission has reviewed the Application and the material submitted through the written hearing process.

NOW THEREFORE the Commission, for the reasons set out in Decision issued concurrently with this Order, determines as follows:

1. FortisBC is directed to implement a RIB rate consisting of four components: a Customer Charge, a threshold and two block rates, set at the following values, based on May 1, 2011 rates:

    a. A Customer Charge of $28.93 per billing period;
    b. A threshold set at 1,600 kWh per billing period;
    c. A Block 1 Rate of 7.828 cents per kWh; and
    d. A Block 2 Rate of 11.272 cents per kWh.

2. FortisBC is to implement this RIB rate as soon as is reasonably practicable, and by no later than July 31, 2012. FortisBC is to file a revised Tariff Sheet for Rate Schedule 01, no later than 30 days prior to the date the RIB rate becomes effective.

3. FortisBC is directed to apply Pricing Principle 1 to future rate increases for the years 2012 to 2015. Specifically:

    a. The Customer Charge is exempt from general rate increases, other than rate rebalancing increases;
    b. The Block 1 rate is subject to general and rebalancing rate increases; and
    c. The Block 2 rate is increased by an amount sufficient to recover the remaining required revenue (*i.e.*, the residual rate).

4. FortisBC is directed to apply the RIB rate on a mandatory basis to all residential customers with the exception of those taking service at a Time-of-Use (TOU) rate at the time this Decision is issued.

5. FortisBC is directed to provide a RIB Rate Evaluation Report (Report) covering the period from the date of implementation to December 31, 2013. This Report should provide the utility, the Commission and Interveners the opportunity to evaluate the effectiveness of the RIB program, in particular with respect to its impact on conservation. The Report is to include, but not be limited to, the following:

    a. The energy consumption reductions achieved;
    b. Whether the consumption reductions persist or are temporary;
    c. How the rate design impacts electric heat customers; and
    d. The resulting operating cost reductions to the utility.

    The Report should also include an in-depth analysis of the full long-run marginal cost of acquiring energy from new resources, including the long-run marginal cost to transport and distribute that energy to the customer, and how that cost compares to the Block 2 rate; the combined effect of integrating TOU and RIB rates on the conservation achieved by the RIB, should that information be available; an update of the Conservation Potential Review and report on the potential effects of interaction between RIB rates and Demand Side Management targets; comparison of energy usage of indirect customers with the energy usage of direct customers; and an analysis of the potential effect of a two-tier wholesale rate on the consumption of its wholesale customers. This Report should be submitted to the Commission no later than April 30, 2014.

6. FortisBC is directed to establish a control group in conjunction with the introduction of the RIB rate to develop elasticity data for its own customers. The results of this elasticity study are to be included in the RIB Rate Evaluation Report.

DATED at the City of Vancouver, in the Province of British Columbia, this 13th day of January 2012.

BY ORDER

D. Morton
Panel Chair/Commissioner

THE REGULATORY PROCESS

FortisBC filed the RIB rate application on March 31, 2011. By Order G-68-11the Commission established an Initial Regulatory Timetable for the review process. (Exhibit A-2)

Due to the limited interest expressed by parties for the Procedural Conference scheduled for May 10, 2011, the Commission Panel decided to cancel that proceeding and requested written submissions on the procedural matters. (Exhibit A-3)

On May 20, 2011, after reviewing the written submissions by parties the Commission Panel established a written hearing process and issued a revised Regulatory Timetable by Order G-94-11 which included two rounds of Information Requests (IRs). (Exhibit A-7)

In response to some technical issues raised by Commission Staff during the review process FortisBC indicated that it had identified a discrepancy in some of the information presented in the RIB application. Accordingly, the Commission Panel suspended the Regulatory Timetable pending FortisBC's proposed update. (Exhibit A-10, Exhibit A-11)

In response to the June 27, 2011 filing of FortisBC's Errata No. 3 (Exhibit B-1-2), the Commission Panel issued its own IR to FortisBC on July 8, 2011. (Exhibit A-12)

In reference to FortisBC's responses to the Panel IR, Mr. Shadrack's IR, and to the issues of simplification and a convenient comparison of RIB rate options raised by BCSEA, the Commission Panel convened a Procedural Conference for August 3, 2011 in Vancouver. (Exhibit A-15) Specifically, the Panel was seeking submissions from the participants on whether there was sufficient evidence on the record to introduce a RIB rate and whether the hearing of the Application by way of a written hearing process remains preferable to an oral hearing process. (Exhibit A-15)

Following the Procedural Conference the Panel, by Order G-142-11, directed FortisBC to file additional evidence as described in the Reasons for Decision on or before August 24, 2011. FortisBC was also directed to ensure that all evidence that is filed is accurate. (Appendix A-17)

By Letter L-84-11 the Commission Panel confirmed that the hearing will continue to proceed as a written hearing and established a revised Regulatory Timetable leading to the completion of the evidentiary record by November 21, 2011. (Exhibit A-20)

The only Intervener filing Intervener Evidence was Mr. Shadrack.

On October 27, 2011, the Commission Panel requested submissions regarding conservation rates for indirect customers of FortisBC. ((Exhibit A-22)

Final Submissions were filed by FortisBC and Interveners on November 4, 2011 and November 14, 2011 respectively, with a reply Submission of FortisBC filed on November 21, 2011.

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

FortisBC Inc.
Residential Inclining Block Rate Application

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter dated April 6, 2011 – Appointment of Panel
A-2	Letter dated April 12, 2011 and Order G-68-11 - Establishing an initial Regulatory Timetable and Procedural Conference
A-3	Letter dated May 5, 2011 - Cancellation of Procedural Conference
A-4	Letter dated May 9, 2011 – Commission Staff response to Exhibit C10-2
A-5	Letter dated May 11, 2011 – Commission Information Request No. 1
A-6	Letter dated May 12, 2011 – Amended Initial Regulatory Timetable
A-7	Letter dated May 20 – Revised Regulatory Timetable and Reasons for Decision
A-8	Letter dated May 20 – Response to WR regarding Exhibit C15-2
A-9	Letter dated May 30 – Correction to the Regulatory Timetable
A-10	Letter dated June 21, 2011 – Possible amendment to the current Regulatory Timetable
A-11	Letter dated June 24, 2011 - Suspension of Regulatory Timetable
A-12	Letter L-55-11 dated July 8, 2011 – Commission Panel Information Requests
A-13	Letter dated July 12, 2011 – Clarification regarding Suspension of Regulatory Timetable
A-14	Letter dated July 13, 2011 – Clarification regarding Interveners Information Request No. 2
A-15	Letter Dated July 25, 2011 – Procedural Conference

Exhibit No.	Description
A-16	Letter Dated July 25, 2011 – Order of Appearances for Procedural Conference on August 3, 2011
A-17	Letter Dated August 10, 2011 and Order G-142-11 – Revised Regulatory Timetable
A-18	Letter Dated August 15, 2011 –Clarification – Order G-142-11
A-19	Letter Dated September 8, 2011 –Commission Information Request No. 2
A-20	Letter Dated October 14, 2011 – Commission Letter L-84-11 Revised Regulatory Timetable
A-21	Letter Dated October 20, 2011 –Commission Information Request No. 1 to Intervener Mr. Andy Shadrack
A-22	Letter Dated October 27, 2011 – Commission Request for Comments from Applicant and Interveners in Final Submissions
A-23	Letter Dated November 21, 2011 – Response on Late Final Submission
A2-1	Letter Dated May 11, 2011 – Commission Staff filing British Columbia Hydro and Power Authority – 2008 Residential Inclining Block Rate – Appendix C, Utility Survey Results
A2-2	Letter Dated May 11, 2011 – Commission Staff filing Regulation of the Minister of Ministry of Energy, Mines and Petroleum Resources – Ministerial Order No. M 271 dated November 6, 2008 – Demand-Side Measures
A2-3	Letter Dated October 19, 2011 – Email exchange between BCUC Staff and FortisBC Inc. (Michael Leyland) confirming FortisBC's residential rates from January 2005 to October 2011
APPLICANT DOCUMENTS FORTISBC INC.	
B-1	**FORTISBC INC. (FBC)** Letter dated March 31, 2011- Filing Residential Inclining Block Rate Application
B-1-1	Letter dated June 7, 2011 – FBC Submitting Errata No. 1 to the Application
B-1-2	Letter dated June 27, 2011 – FBC Submitting Errata No. 3 to the Application including responses to BCUC IR 1 and responses to BCOAPO IR1

Exhibit No.	Description
B-2	Letter dated April 6, 2011- FBC Submitting comments on NH (C2-1) letter regarding proposed regulatory agenda
B-3	Letter dated May 9, 2011 – FBC Submitting comments on proposed process
B-4	Letter dated May 13, 2011 – FBC Reply submissions on Proposed Process
B-5	Letter dated June 7, 2011 – FBC Submitting Responses to BCUC Information Requests No. 1
B-5-1	Letter dated June 17, 2011 – FBC Submitting Erratum No. 2 to its Responses to Commission Information Requests No. 1
B-6	Letter dated June 7, 2011 – FBC Submitting Responses to Interveners Information Requests No. 1
B-7	Letter dated July 14, 2011 – FBC Submitting Response to BCUC Letter L-55-11
B-8	Letter dated July 22, 2011 – FBC Responses to BCUC IRs on Errata 3
B-9	Letter dated July 29, 2011 – FBC Submitting Errata to IR No.1 from BCUC and TR
B-10	Letter dated August 2, 2011 - FBC Submitting responses to Exhibit A-15
B-10-1	Letter dated August 4, 2011 - FBC Submitting corrected spreadsheet
B-11	Letter dated August 24, 2011 - FBC Submitting Additional Evidence
B-12	Letter dated September 29, 2011 – FBC Responses to BCUC IR No. 2
B-13	Letter dated September 29, 2011 – FBC Responses to Intervener IRs No. 2

INTERVENER DOCUMENTS

C1-1	**TARNOFF, RICHARD (TR)** Online Registration dated April 4, 2011– Request for Intervener Status by Richard Tarnoff
C1-2	Letter dated May 14, 2011 Via Email – TR Submitting Information Request No. 1
C1-3	Letter dated July 31, 2011 – TR Submitting comments regarding Basic Charge
C1-4	Letter Dated September 8, 2011 Via Email – TR Submitting IR No. 2

Exhibit No.	**Description**
C2-1	**NELSON HYDRO (NH)** Letter dated April 5, 2011- Submitting comments regarding proposed regulatory agenda
C2-2	Letter dated May 11, 2011 – NH Submitting comments on procedural matters
C2-3	Letter dated May 16, 2011 – NH Submitting Information Request No. 1
C2-4	Letter Dated September 8, 2011 Via Email – NH Submitting IR No. 2
C3-1	**OKANAGAN ENVIRONMENTAL INDUSTRY ALLIANCE (OEIA)** Online Registration dated April 14, 2011 - Request for Intervener Status by Ludo Bertsch
C3-2	Letter dated May 10, 2011 – OEIA Submitting comments on procedural matters
C3-3	Letter dated May 16, 2011 – OEIA Submitting Information Request No. 1
C4-1	**BRITISH COLUMBIA HYDRO AND POWER AUTHORITY (BCH)** Online Registration dated April 14, 2011 - Request for Intervener Status by Joanna Sofield
C5-1	**BRITISH COLUMBIA OLD AGE PENSIONERS ORGANIZATION ET AL (BCOAPO)** Email Registration dated April 15, 2011 – Request for Intervener Status by Jim Quail
C5-2	Letter dated May 10, 2011 – BCOAPO Submitting comments on proposed process
C5-3	Letter dated May 13, 2011 – BCOAPO Submitting Information Request No. 1
C5-4	Letter dated June 28, 2011 – BCOAPO Submitting Information Request No. 2
C5-5	Letter dated August 3, 2011 - BCOAPO Submitting notice of Counsel change
C5-6	Letter Dated September 8, 2011 Via Email – BCOAPO Submitting IR No. 2
C6-1	**CITY OF KELOWNA** Email Registration dated April 19, 2011 – Request for Intervener Status by Cindy McNeely
C7-1	**GABANA, NORMAN (GN)** Email Registration dated April 21, 2011 – Request for Intervener Status
C7-2	Letter dated May 9, 2011 – GN Submitting comments on proposed process
C7-3	Letter dated May 15, 2011 Via Email – GN Submitting Information Request No. 1
C8-1	**RAJAPAKSHE, RASIKA** Email Registration dated April 25, 2011 – Request for Intervener Status

Exhibit No.	Description
C9-1	**SHADRACK, ANDY (SA)** Email Registration dated April 26, 2011 – Request for Intervener Status
C9-2	Letter dated May 9, 2011 – SA Submitting comments on proposed process
C9-3	Letter dated May 11, 2011 Via Email – SA Submitting comments on Oral Hearing
C9-4	Letter dated May 12, 2011 Via Email – SA Submitting Information Request No. 1
C9-5	Letter dated May 16, 2011 Via Email – SA Submitting Additional Information Request No. 1
C9-6	Letter dated June 12, 2011 Via Email – SA Request for extension
C9-7	Letter dated June 16, 2011 Via Email – SA Submitting comments regarding IR No. 1 responses
C9-8	Letter dated June 21, 2011 Via Email – SA Submitting response to Exhibit A-10
C9-9	Email dated July 8, 2011 – SA Submitting Late Information Request No. 2
C9-10	Email dated July 16, 2011 – SA Comment regarding FBC Information Request No. 1 Responses
C9-11	Letter dated July 28, 2011 Via Email – SA Submitting comments
C9-12	Letter Dated September 8, 2011 – SA Submitting Information Request No. 2
C9-13	Letter Dated October 13, 2011 Via Email – SA Submitting Evidence
C9-14	Letter Dated October 13, 2011 Via Email – SA Submitting Response to Commission Information Request No. 1
C10-1	**STRATA CORPORATION KSA2464 (SCK)** Email Registration dated April 26, 2011 – Request for Intervener Status by Henry Stanski and John Loewen
C10-2	Letter dated May 5, 2011 Via Email – SCK Submitting comments on Application
C10-3	Letter dated May 9, 2011 Via Email – SCK Response to Exhibit A-3
C10-4	Letter dated May 15, 2011 Via Email – SCK Submitting further comments on Application
C10-5	Letter dated May 23, 2011 - SCK Additional Comments and Questions #2

Exhibit No.	Description
C10-6	Letter dated July 11, 2011 – SCK Comments and Information Request No. 2
C10-7	Letter dated July 31, 2011 – SCK submissions regarding A-15
C11-1	**B.C. SUSTAINABLE ENERGY ASSOCIATION (BCSEA)** Web Registration dated April 28, 2011 – Request for Intervener Status by William J. Andrews
C11-2	Letter dated May 10, 2011 – BCSEA Submitting comments on procedure
C11-3	Letter dated May 16, 2011 – BCSEA Submitting Information Request No. 1
C11-4	Letter dated July 12, 2011 – BCSEA Submitting Information Request No. 2
C11-5	Letter Dated September 8, 2011 Via Email – BCSEA Submitting IR No. 2
C12-1	**SLACK, BURYL** Facsimile Registration dated April 30, 2011 – Request for Intervener Status
C13-1	**IRRIGATION RATEPAYERS GROUP (IRG)** Dated May 4, 2011 - Request for Intervener Status by Fred Weisberg
C14-1	**KOOTENAY TAX PAYERS ASSOCIATION (KTPA)** Dated May 4, 2011 - Request for Intervener Status by Josh Smienk
C14-2	Letter dated May 4, 2011 – KTPA Submitting request to register for the procedural conference
C15-1	**WORK , RUSSELL (WR)** Letter Dated May 4, 2011 Via Email and Online Registration - Request for Late Intervener Status by Russell Work
C15-2	Letter submitted May 19, 2011 – WR Submitting Information Request No. 1

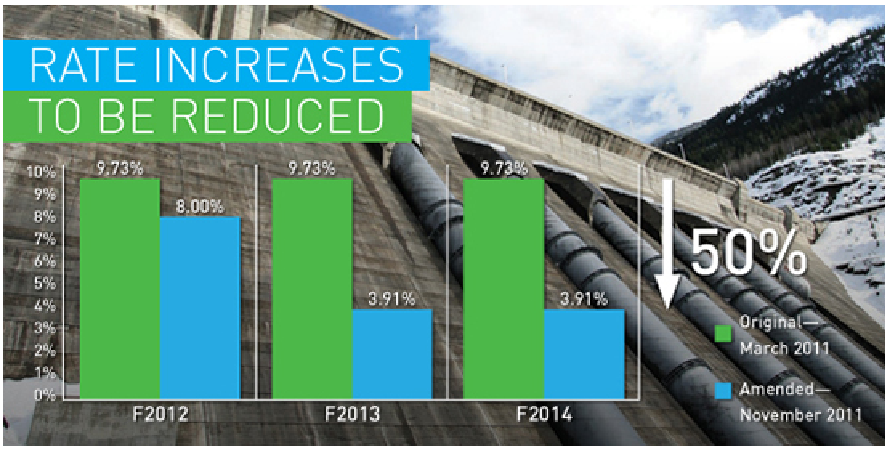
LETTERS OF COMMENT

E-1	Mersereau, Brent - Letter of Comment dated April 25, 2011 Via Email
E-2	Marty, Maurice - Letter of Comment dated July 31, 2011

NEWS

Nov 24, 2011

Amended revenue requirements application: A message to customers



Costs cut to reduce rate increases needed to power B.C., now and in the future

Message from Charles Reid
Executive Vice-President, Finance and Chief Financial Officer

In keeping with our commitment to keep our customers informed about BC Hydro's investments in the electricity system, our cost-cutting measures and the impact of both on your bill, I want to give you an update on our amended revenue requirements application, filed today with the British Columbia Utilities Commission.

In short, we are applying for a rate increase to all customer classes (residential, commercial and industrial) that is half of what we originally filed in March 2011.

50 per cent reduction in the 3-year rate increase

Following a government review of BC Hydro, we accelerated our ongoing efforts to reduce costs, and worked with the Province to identify additional cost savings. In addition, we have experienced more favorable economic conditions than originally anticipated.

As a result, we reduced the proposed rate increase by half. Our rate application today confirms what we previously announced in August: that the proposed rate increase for F2012-14 would be:

- 8 per cent for the current fiscal year that ends March 31, 2012 (already in place);
- 3.9 per cent for each of the following two fiscal years.

This means that beginning in April of next year, our average residential customer will see an increase of about $3 per month on their bills for each of the next two years.

We know that even a modest rate increase can impact your budget, which is why we're doing everything we can to become a more efficient and cost-effective company. We're following through on the government review's recommendations to find cost savings wherever we can, including reducing the size of our staff and starting or completing some capital projects later than planned.

Keeping the lights on and investing in B.C.'s future

See also

- Amended Revenue Requirements Application F2012-2014
- Fact sheet: Keeping BC Hydro Rates Low [PDF, 186 KB]
- Fact sheet: Government Review of BC Hydro [PDF, 139 KB]
- Fact sheet: Managing Regulatory Accounts to protect customers [PDF, 285, KB]
- About the Revenue Requirements Application (Slideshow) [PDF, 1.6 MB]

Every day, you count on us to deliver safe, reliable electricity. The system that generates and delivers that power is aging. Our generating facilities and transmission and distribution systems were built in the 1960s, 70s and 80s and paid for by generations of British Columbians who came before us.

Now, we need to make critical investments to maintain and expand our system to meet new demand as our population grows.

Among many critical upgrades, BC Hydro is planning to:

- Install two additional generating units at the Mica generating station;
- Replace five turbines at the generating facility at the W.A.C. Bennett dam
- Build a 340-kilometre transmission line in northwest of B.C. and a 255-kilometre line from the Interior to the Lower Mainland
- Build a new substation and underground transmission line in Vancouver
  increase the generating capacity of the Fort Nelson generating station

The amended rate increases we filed for today strike the right balance between keeping rates affordable for our customers, and upgrading the system to ensure we can continue to deliver power to you safely and reliably. This is especially top of mind as we enter storm season and the colder months of winter.

Our homes, businesses and industries are dependent on electricity, and it's typically only when the power goes out due to a storm or equipment failure that we truly appreciate its value.

Low rates can be even lower with conservation

Even with these proposed rate increases, you will continue to benefit from electricity rates that are among the lowest in North America [JPEG, 125 KB].

We encourage you to take a look at our Power Smart programs and incentives to see how you can partially or even fully offset rate increases by simply using less electricity. Smart meters will also make it easier for you to monitor and manage your energy use to conserve electricity and save money.

We're here for you

I want to assure you that everything we do is done with you, our customer, top of mind.

We are proud to be a Crown Corporation for the benefit and service of British Columbians. Whether it's keeping rates low, restoring your power quickly and safely, investing on your behalf in facilities for the future, we know you are counting on us.

We take seriously our role in your daily life and in operating the clean, affordable electricity system that is the backbone of B.C.'s economy.

All of us at BC Hydro are committed to working hard to keep the lights on for you and your family, and we will work equally hard to manage costs to continue to keep your rates affordable, both now and in the future. .

Sincerely,

Charles Reid
Executive Vice-President, Finance and Chief Financial Officer

Ministry of Energy and Mines, Economy Sector, Government Operations Sector, Cariboo Chilcotin Coast Region, Kootenay Rockies Region, Northern B.C. Region, Provincewide, Thompson / Okanagan Region, Vancouver Coast & Mountains Region, Vancouver Island / Coast Region

10 Year Plan Means Predictable Rates as BC Hydro Invests in System

/2013/11/10-year-plan-means-predictable-rates-as-bc-hydro-invests-in-system.html

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View on YouTube (http://www.youtube.com/watch?v=QFCx2S9yJE8)

Tuesday, November 26, 2013 9:25 AM

VICTORIA - Bill Bennett, Minister of Energy and Mines and Minister Responsible for Core Review today announced a 10 year plan that will keep electricity rates as low as possible while BC Hydro makes investments in aging assets and new infrastructure to support British Columbia's growing population and economy.

Over the past several months, government and BC Hydro have worked together to reduce pressure on rates. This effort builds on the 2011 review that identified over $391 million in savings. New measures in the 10 year plan will reduce the amount of money that government takes from the utility, free up additional cash to support investments in infrastructure and lower BC Hydro's operating costs.

Decades ago, BC Hydro built the backbone of our electricity system. Today, major components of that system need to be repaired or replaced. Meanwhile, British Columbia's population and economy are growing and new technologies have increased household power use. Today, government released BC Hydro's approved Integrated Resource Plan which sets out cost effective investments in infrastructure, conservation and clean energy to meet an expected 40 per cent increase in demand over the next 20 years.

To keep rates predictable while funding investments in aging and new infrastructure:

- Government will set rate increases for the initial two years of the 10 year plan at nine per cent and six per cent;
- The BC Utilities Commission (BCUC) will set increases for the following three years within caps of four per cent, 3.5 per cent and three per cent; and
- In the final five years of the plan, rates will be set by the BCUC and actions by government and BC Hydro will ensure increases remain low and predictable.

To help industrial customers and customers on low incomes reduce their bills by using less electricity, BC Hydro will invest $1.6 billion in Power Smart programs under the 10 year plan. In addition, a rate design review process will be launched to examine ways to provide industrial customers with more options to reduce their electricity costs, as recommended by the Industrial Electricity Policy Review Task Force.

In response to another recommendation from the task force, government will initiate a review of the BCUC, through the Core Review process, with the goal of increasing the commission's effectiveness and efficiency so that BC Hydro rates can be set by the commission starting in the third year of the plan.

Currently, 80 per cent of the balance in BC Hydro's regulatory accounts is being paid down under amortization schedules approved by the BCUC. Under the 10 year plan, the remaining balance will start being paid down. In addition, to keep rate increases as gradual as possible, a new account will be created to spread costs that occur in the earlier years of the plan, over a longer period. This account will be paid down to zero within the term of the plan.

(http://www.flickr.com/photos/bcgovphotos/11071741983/)

Quotes:

Bill Bennett, Minister of Energy and Mines and Minister Responsible for Core Review -

"This is a balanced and responsible plan that keeps rates as low as possible while funding infrastructure investments to support our growing economy and population. Since 2011, government and BC Hydro have worked hard to reduce pressure on rates and we will continue to work together over the course of this plan to keep our electricity system affordable, reliable and sustainable."

Charles Reid, CEO, BC Hydro -

"BC Hydro has worked hard to keep costs down for our customers and we will continue to work with government to find savings wherever possible as we make the investments required to keep our system reliable and meet growing demand."

Learn More:

The following backgrounders and information can be found at: http://www.newsroom.gov.bc.ca/2013/11/10-year-plan.html (http://www.newsroom.gov.bc.ca/2013/11/10-year-plan.html)

Backgrounders:

BC Hydro Rates (http://www.newsroom.gov.bc.ca/downloads/Backgrounder_BC_Hydro_Rates.pdf)

BC Hydro Capital Plan (http://www.newsroom.gov.bc.ca/downloads/Backgrounder_BC_Hydro_Capital_Plan.pdf)

Integrated Resource Plan (http://www.newsroom.gov.bc.ca/downloads/Backgrounder_Integrated_Resource_Plan.pdf)

Taking Pressure off Rates (http://www.newsroom.gov.bc.ca/downloads/Backgrounder_Taking_Pressure_off_Rates.pdf)

Industrial Electricity Policy Review Report (http://www.newsroom.gov.bc.ca/downloads/Backgrounder_Industrial_Electricity_Policy_Review_Report.pdf)

Reports:

BC Hydro's Resource Plan Executive Summary (http://www.newsroom.gov.bc.ca/downloads/BC_Hydro_Integrated_Resource_Plan.pdf)

The Industrial Electricity Policy Review Task Force Report (http://www.newsroom.gov.bc.ca/downloads/Industrial_Electricity_Policy_Review_Task_Force_Final_Report.pdf)

Presentation:

10 Year Plan for BC Hydro (http://www.newsroom.gov.bc.ca/downloads/Presentation.pdf)

Contact:

Jake Jacobs
Media Relations
Ministry of Energy and Mines and Responsible for Core Review

250 952-0628

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THE PUBLIC UTILITIES BOARD

OF THE

NORTHWEST TERRITORIES

DECISION 11-2012 **May 1, 2012**

IN THE MATTER OF the Public Utilities Act, being Chapter 110 of the Revised Statutes of the Northwest Territories, 1988(Supp.), as amended.

AND IN THE MATTER OF an application by the Northwest Territories Power Corporation for changes in the existing rates, tolls and charges for electrical energy and related services provided by the Northwest Territories Power Corporation to their customers within the Northwest Territories.

TABLE OF CONTENTS

1. APPLICATION 1
2. INTERIM RATES 8
   2.1 Argument 8
   2.2 Reply Argument 10
   2.3 Board Analysis and Decision 12
   2.4 Proposed GNWT-NTPC Funding Agreement 14
3. SECTION 51(2)(b) APPLICATION 19
4. BOARD ORDER 22

1. APPLICATION

Interim Rate Application filed on March 23, 2012

By letter dated March 23, 2012, the Northwest Territories Power Corporation (“**NTPC**”, “**Corporation**”) filed its General Rate Application (“**GRA**”) to determine the revenue requirements and rates for the fiscal years 2012/13 and 2013/14 (“**Test Years**”).

In conjunction with its GRA and as per Section 44 of the *Public Utilities Act*, NTPC also filed an Interim Rate Application (“**IRA**”) dated March 23, 2012 in which it requested approval of interim rates to increase all energy charges for all customer classes, in all communities, except Norman Wells, by 7% and for interim rates to increase all energy charges for all customer classes in Norman Wells by 15%. NTPC also requested that all interim rates be effective April 1, 2012. NTPC stated that to be consistent with the 2012/14 GRA, NTPC was not seeking to adjust customer charges or demand charges.

In previous interim rate applications, NTPC has proposed interim rate riders to collect approximately 80% of the Corporation’s shortfall that would result from fully implementing the proposed revenue requirement in the GRA, subject to a maximum overall rate increase of 15%. In the current GRA, NTPC proposed to transition to rates that fully recover the Corporation’s revenue requirement over a four-year period.

For the 2012/13 test year, NTPC is requesting approval of final rates that are 7% higher than current rates for all communities and rate classes except Norman Wells, where 15% energy rate increases are proposed to assist with the transition of Norman Wells into the Thermal zone as per Provision (9)(a) of the February 10, 2011 Rate Policy Guidelines.

Despite the additional revenue from interim rates, NTPC still expects to incur a substantial shortfall in the 2012/13 test year. As a result, NTPC and its shareholder, the Government of the Northwest Territories ("**GNWT**"), have implemented financial funding measures. These funding measures will mitigate the rate impact for customers during this transition. NTPC states that it can continue providing safe and reliable service, while maintaining its financial viability for 2012/13. NTPC has provided Table 1 which summarizes the Corporation's 2012/13 shortfall and GNWT support.

Table 1: Summary of GNWT Support - 2012/13

	2012/13 Test Year
2012/13 Revenue Requirement (Proposed)	102,506
Revenue @ Existing Rates	82,571
Non-electrical Revenue	734
2012/13 Shortfall	**19,201**
Revenue from Interim Rates	5,571
GNWT Financial Support	**13,630**

As noted in the GRA, in the event a final 2012/13 revenue requirement is approved at a level below that is proposed, NTPC is still seeking a final rate increase of 7% on energy rates for all customer classes in 2012/13. A lower approved 2012/13 revenue requirement would simply reduce the level of GNWT financial support required for 2012/13.

NTPC stated that the proposed interim rates for 2012/13 increase energy rates by approximately 7% and are far lower than what NTPC has applied from previous interim rate applications. The current proposal collects only 29% of the Corporation's 2012/13 shortfall.

NTPC provided reasons for proposing these specific interim rates as follows:

1. Delay in implementing these adjustments will materially increase NTPC's revenue shortfall for 2012/13. That shortfall needs to be recovered from customers.
2. This approach is consistent with the principals of past interim rate approvals in that the proposed rate impact does not exceed 15% for any customer class.
3. This approach assists with a measured transition to the necessary higher level of rates.
4. It complies with GNWT Rate Policy Guidelines and specifically addresses Provision (9)(a) of the February 10, 2011 Rate Policy Guidelines which requires that Norman Wells be integrated into the Thermal zone as part of the GRA, for all classes
5. The proposed interim rates ensure the Corporation is able to continue to provide safe and reliable service and maintain NTPC's financial viability for 2012/13.

NTPC stated that in addition to the funding for the 2012/13 shortfall and to further mitigate this rate impact for customers, the GNWT has also agreed to pay the current balance in the Territorial Wide Fuel Stabilization Fund at March 31, 2012. Although not yet final, this amount is estimated to be approximately $4.3 million. This payment eliminates any upward rate pressures that might be caused by higher fuel prices from previous periods. Diesel price escalation from April 1, 2012 onwards will continue to be addressed by the Territorial Wide Fuel Stabilization Fund.

By email, dated March 23, 2012, the Board stated that NTPC would need approval of any interim rates by April 6, 2012. Due to the time available to the Board to review and decide upon the IRA, the Board provided a copy of the IRA to a previous distribution list of NTPC. The Board stated that any party, who wish to comment upon the interim application, had until March 29, 2012.

Amendment to the Interim Rate Application

By letter, dated March 28, 2012, the Corporation stated that it wished to amend its IRA to reduce the requested increase for all customer classes in Norman Wells from 15% to 7%, effective April 1, 2012. This amendment will bring Norman Wells' proposed increases in line with the increases in energy charges sought for all customers in all other communities.

In the March 23, 2012 amendment of the proposed Norman Wells interim rates, Schedule 2 showed a reduction of the revenue from interim rates to $5,313,000, which is a $258,000 decrease from the above table, as a result of the decreased interim rates in Norman Wells.

Information Requests ("IR") from the Board

On March 30, 2012, the Board issued IR No. 1 to NTPC seeking details of the GNWT's financial support in 2012/13. The NTPC confirmed that the financial support to be provided by the GNWT is not fixed but rather is a variable amount that will be equal to the shortfall between the final approved overall 2012/13 revenue requirement and the revenue raised by the NTPC with 7% interim rate increases.

NTPC also confirmed in its response that the revenue raised by the interim rate increases were to be tracked separately and reconciled with the final approved 2012/13 revenue requirement with any over-collection being refunded to customers and any shortfall to be recovered from ratepayers.

On April 3, 2012, the Board issued IR No. 2 to NTPC seeking details of the proposed reduction in Norman Wells' interim rates from 15% to 7% and the implications for NTPC's proposed revenue requirement and the amount of the GNWT's financial support.

NTPC responded that it is investigating options for the collection of the $258,000 and the preferred approach will be submitted to the Board during the review of the GRA.

Comments by Interveners

The Board received comments on the IRA from the NWT Association of Communities ("**NWTAC**"), the City of Yellowknife and Town of Hay River ("**Hydro Communities**"), the Town of Norman Wells, the Town of Inuvik and the Town of Fort Smith.

Fort Smith is opposed to the proposed rate increase. It raised issues with the use of surplus power from Taltson as well as concerns about aging local infrastructure. Fort Smith recommends proper long range planning and adequate consultation with communities and other stakeholders as the first step to moving forward.

In its first letter dated March 28, 2012, the NWTAC raised numerous issues. Many of the issues raised were procedural in nature and were responded to by the Board with a March 28th letter. Other issues raised by the NWTAC such as the overall impact of the combined GRA increases and the efficiency of the NTPC were not responded to by the Board as they are matters that will be examined during the review of the GRA. The NWTAC recommends that there be no interim rates set at this time.

Norman Wells expressed its concern about the impact of the increase on the residents and businesses of the community. It recommended that the request for interim rates be denied with no rate increases until after the review of the GRA.

Inuvik expressed its concern that the interim increases would make it difficult for residents to afford to remain in the community. This would have an effect on the community and region in its ability to attract and retain workers. Inuvik requested that the rate increases not be approved until proper analysis and discussion can take place.

Yellowknife and Hay River expressed concern that there was inadequate time between the filing of the IRA and the comment date to properly review the application. They recommend that such application should be filed earlier with more time for review.

Yellowknife and Hay River noted that NTPC has applied for interim rates that are equal to the proposed GRA increases and state:

> *"…Thus, unless the Board approves the full 2012-2013 rate increases applied for by NTPC, NTPC will be over collection from customers through interim rates."*

Yellowknife and Hay River also expressed concern that the 7% increases are being applied across the board without reference to the disparity amongst the revenue to cost ratios between the zones.

Yellowknife and Hay River recommended that a further period of review be scheduled for the interim rate application but that if the Board decided to go ahead and make a decision without further process then it should issue the following 2 directions to NTPC:

(a) all revenues collected by way of the interim rates will be tracked by community/zone to allow full reconciliation and true-up to the final approved revenue requirement, rate base and annual rate increases approved by the Board;

(b) NTPC shall file all future applications, including interim rate applications, sufficiently in advance of the requested approval date to allow the Board to establish a process schedule to allow the Board and interveners to adequately assess the application.

Additional Review Period

By letter dated April 5, 2012, the Board stated that given the magnitude of the proposed interim rate increases and the lateness of the filing of the interim application, the Board had decided to accept the recommendation of the Hydro Communities and schedule an additional review period.

The Board, Hydro Communities and the Town of Inuvik, Village of Fort Simpson and Hamlet of Fort Providence (“**Thermal Generation Communities**” “**TGC**”) submitted IRs on April 13, 2012. NTPC responded to the IRs on April 17, 2012. NTPC, the HC and the TGC submitted Argument on April 20, 2012 and Reply Argument on April 24, 2012.

2. INTERIM RATES

In the additional review process established by the Board, the HC, the TGC and NTPC each submitted argument and reply argument to the Board to sum up their respective positions and to respond to the positions of the other parties.

2.1 Argument

NTPC argues that the requested 7% interim rates are just and reasonable as the increases will eliminate the need for a future shortfall rider while still maintaining the financial integrity of NTPC and the ability of NTPC to provide safe and reliable service.

NTPC also argues that the 7% increase represents the collection of $5.313 million, which is only 29% of the total projected 2012/13 revenue shortfall of $19.201 million. Typically NTPC would be requesting recovery of 80% of the total shortfall ($15.360 million) but is not doing so in this case because of the provision of government funding. NTPC argues that in light of the significantly lower than normal rate of recovery of the revenue shortfall, the 7% interim rates meet the test for just and reasonable rates.

On the matter of the government funding, NTPC states that if the Board were to approve rate increases of less than 7% then the additional shortfall will have to be recovered from the customers through a future rate rider. NTPC states:

> *"The GNWT contribution of $13.630 million is a maximum contribution that may be reduced if NTPC's revenue requirement is ultimately reduced through the GRA."*

NTPC argues that delaying the collection of that portion of the total shortfall that is targeted for the ratepayers through interim rates would mean that a shortfall rider would add to the rate impacts over the following 3 years on top of increases to the base rates.

NTPC concludes that the proposed interim rates are just and reasonable and requests Board approval.

In its argument, the HC state that it appears NTPC has already provided a commitment to the GNWT that any reductions in its revenue requirement will reduce the GNWT subsidy and not customer rates. The HC state that it would be premature to decide at this time that any reductions in revenue requirement are solely attributable to the GNWT subsidy. The HC argument goes on as follows:

> *"…As such, YK/HR submit that other alternatives in the allocation of reductions to revenue requirement are equally valid for interim rates. Applying NTPC's 80% factor from prior interim rate decisions to the shortfall in revenue requirement of $19.201 million results in an interim shortfall of $15.361 million. As noted above, the proposed GNWT subsidy of $13.630 million is a maximum, there is no contract regarding the subsidy, and timing of the subsidy has not been established. As such, for interim rates, the entire subsidy of $13.630 million should be retained and all reductions to interim rates arising from reductions to revenue requirement should be attributed to customers. This results in an interim rate increase of $1.731 million or 2.1%.*
>
> *In summary, YK/HR submit that the Board should establish interim rates based on a maximum of 80% of the requested revenue shortfall ($15.361 million)."*

The TGC argue that the funding from the GNWT, which comprises 71% of the total shortfall, adequately satisfies the historical 60-64% recovery of shortfalls through interim rates and so no additional funding of NTPC through interim rates on the customers should be necessary.

The TGC also argue that based upon historical reductions in the shortfalls of about 20% in previous GRAs, NTPC would over-collect its shortfall by $3.8 million with the proposed 7% interim rates.

Based upon these arguments, the TGC recommends that the need for interim rates, if any, should only be assessed upon the conclusion of the oral proceeding.

2.2 Reply Argument

NTPC argues that the TGC recommendation to delay the implementation of interim rates until after the oral proceeding would defeat the very purpose of interim rates. NTPC states:

> *"…In that situation instead of spreading the 7% rate impact over basically the entire year as is now proposed, the shortfall would be condensed over five months and would have to be more than double the size. Alternatively, a longer shortfall rider would be required to make up the shortfall at a time when customers are likely to already be facing base rate increases in the 2013/2014 test year. At the end of the day, the shortfall approved by the Board must be recovered from the customers. Delaying implementing interim rates only delays and heightens the rate impact on customers."*

On the matter of the GNWT-NTPC funding agreement, NTPC states the following:

> *"The TGC suggests that the GNWT funding should be sufficient for the purposes of interim rates for NTPC [para. 15]. YK/HR suggests that all reductions in interim rates arising from reductions to the revenue requirement should be attributed to customers [para. 12]. In effect, both TGC and YK/HR seem to be suggesting that the PUB should impose additional conditions or parameters on the GNWT funding commitment. This is simply not possible. The dollar value of the commitment made by*

> *the GNWT was calculated based upon the difference between the applied for revenue requirement ($19.2 million), as compared to revenues arising from the 7% rate increase proposed in the GRA ($5.6 million). Obviously, the GNWT can frame its commitment any way it wishes. Accordingly, the GNWT has decided to provide funding up to a maximum amount, with that commitment based on a customer contribution of a 7% rate increase, which it is fully entitled to do. The GNWT also provides the funding commitment on a sliding scale that will be reduced in the event of a reduction of the revenue requirement, which again it is fully entitled to do. TGC somewhat imprecisely argues that the GNWT funding will be forthcoming even if the Board were to reject the IR application [para. 16]. As NTPC has previously confirmed, the government funding is predicated on a shortfall with rate increases of 7%. The maximum GNWT funding will not be increased (however, it may be decreased if the revenue requirement is decreased such that the $13.6 million is not fully required to protect ratepayers to the 7% level). Similarly, there is no basis to suggest that the PUB can extend the GNWT commitment, to provide the transition support, to also funding shortfalls arising from failure to implement rates at the 7% rate impact level [as suggested by TGC at para. 19].”*

In its reply argument, the HC stated the following:

> *“YK/HR are also concerned by NTPC's statements that there has been considerable consultation and due diligence between the GNWT and NTPC and that NTPC "was able to engage with the GNWT in a process" with no apparent participation by the Board or customers. YK/HR are uncertain whether the proposed GNWT funding "may be reduced" or in fact must be reduced if the Board ultimately orders a reduction in revenue requirement in NTPC's General Rate Application. If the funding must be reduced by any reductions in revenue requirement ordered by the Board, and customer rates must increase by 7%, then the only discretion available to the Board is whether NTPC should be able to recover the full 7% increase effective May 1,2012 as an interim rate or whether a reduced interim rate increase should be approved with the remaining shortfall to be collected at later date through a rate rider. Given NTPC’s use of the word "may" as discussed above, there is still some ambiguity as to whether the GNWT financing must be reduced if the Board ultimately determines that a reduction in revenue requirement is appropriate in NTPC's General Rate Application. On this basis, and given that such ambiguity will likely not be resolved until NTPC’s General Rate Application is dealt with, YK/HR maintain their recommendation that interim rates should be set at a*

> *maximum of 80% of final rates. This would result in an increase to all customers' rates of approximately 2.1%.*
>
> *If there is no discretion available to the Board, and by agreement between NTPC and the GNWT any reduction in interim rates must serve to reduce the GNWT subsidy, NTPC should have clearly indicated that in its application, thus making it clear that a 7% increase is a fait accomplit and neither customers nor the Board have any power to change it, at least with respect to the 2012/2013 test year."*

In its reply argument, the TGC reaffirms its position that the collection of 71% of the shortfall through GNWT funding and 29% of the shortfall through 7% interim rates is likely to produce an excess of revenue for NTPC and a resulting refund to the ratepayers.

The TGC also states that NTPC provided no additional reasoning in its argument as to why the $13.63 million in GNWT funding will not be adequate, without interim rate increases, to run its operations in a safe and reliable manner nor demonstrated that the absence of interim rate revenue would impair NTPC's financial integrity.

2.3 Board Analysis and Decision

NTPC proposes that rate increases to reflect the proposed test year revenue requirements be phased in with increases in energy rates of 7% in each of 2012/13, 2013/14 and 2014/15 and the balance in 2015/16. Under this proposal the forecast revenue shortfalls during the phase-in period are to be funded by the GNWT.

NTPC is forecasting a total shortfall for the 2012/13 test year of $19.2 million and has provided explanations as to the issues and items that in its view are responsible for the amount of the shortfall. Despite the significance of the shortfall, NTPC is proposing to collect only about $5.3 million through the interim rates, as per the amended Application.

In its argument and reply argument, the HC did not identify any contentious items which should be excluded from the 2012/13 revenue requirement pending full examination in the GRA. The TGC did suggest a number of items in Para. 20 of its Argument that it felt could be excluded from the revenue requirement for the purpose of setting interim rates; however in the Board's view, this list was not supported by adequate analysis. Having regard to the size of the revenue deficiency and the level of interim increase requested, the Board is not persuaded that it should adopt the approach of excluding specific items from the revenue requirement, for the purpose of setting the interim rates in this proceeding.

The Board notes that even if it were to use a 20% shortfall reduction, consistent with the outcome of some of the past GRAs, the proposed shortfall of $19.2 million would only be reduced to $15.4 million, which is still $10.1 million higher than the $5.3 million that is being proposed for collection through the interim rates. Given that difference and given the uncertainties around the GNWT-NTPC funding mechanism discussed further in Section 2.4, it is the Board's view that the level of the requested interim increase is not unreasonable in view of the particular circumstances of this Application.

The $5.3 million that NTPC is proposing to collect with the interim rates represents about 28% of the total forecast shortfall of $19.2 million for test year 2012/13. As the Board historically has approved interim rates which collect in the range of 60% to 80% of the total shortfall, the 28% recovery proposed by NTPC is well within the parameters used by the Board in making its determination of what is just and reasonable for interim rate revenue shortfall recoveries.

Collecting the 28% of the shortfall with interim rates would result in an overall increase in energy rates for the ratepayers of 7%. In the Board's view, the 7% increase is not unreasonable from a rate impact point of view considering the magnitude of the revenue shortfall, and it is well within the 15% maximum for a single-event rate increase that the Board has sometimes used in the past as a guideline indicative of rate shock.

Given all of the above, it is the Board's view that the 7% interim increase in energy rates proposed by NTPC is just and reasonable and will be approved by the Board.

2.4 Proposed GNWT-NTPC Funding Agreement

Status of the Proposed Agreement

The reason that NTPC has proposed to use interim rates to recover only $5.3 million of the $19.2 million 2012/13 shortfall is a proposed funding agreement that NTPC has discussed with the Government of the Northwest Territories. That agreement provides that the GNWT will fund the difference, up to a maximum of $13.63 million, between 1) the revenue collected from ratepayers with the 7% energy rate increases and 2) the total approved revenue requirement. NTPC described the nature and status of the proposed funding agreement in YK NTPC 1 b) and c) as follows:

> "*There is no written agreement between NTPC and the GNWT with respect to GNWT's funding measures for customers. These funding measures are based on discussions and presentations at the request of Government from NTPC with an objective to help transition customers from 2007/08 rates to 2013/14 proposed rates over the next 4 years. The GNWT's funding contribution is still subject to budget approval (expected in May 2012 as part of the overall territorial budget). The commitment from*

> *GNWT (although not yet formally approved in the budget) is to finance the residual between the full rates proposed in the GRA, and the full revenue shortfall ultimately determined by the Board, not to exceed $13.6 million for 2012/13….*"

The Board notes that if there are reductions to the revenue requirement as a result of the Board's review of the GRA, then the proposed NTPC-GNWT agreement establishes that these savings will flow, not to the ratepayers through lower rates, but instead, to the GNWT through lower government funding of NTPC's revenue shortfall in 2012/13.

As NTPC was unable during the review of the interim rate application to place this proposed agreement before the Board in writing, there remains uncertainty regarding the exact nature of this proposed agreement, including the amount to be provided to NTPC, and that uncertainty is a cause of concern to the Board. For instance, the Board understands that this funding agreement is subject to, and contingent upon, the review and approval of the NWT Legislative Assembly during its upcoming budget deliberations.

The Board would have significant concerns if the proposed agreement were not concluded on a timely basis. An unfunded 2012/13 revenue deficiency of $13.9 million, out of a total revenue requirement of $102.5 million, would raise major concerns regarding the financial health and integrity of the utility. Similarly, if it were NTPC's intention to collect that unfunded shortfall from the ratepayers, the Board would be concerned about allowing a large shortfall to accumulate that would eventually have to be recovered on top of higher base rates.

The Board agrees with the HC that NTPC's use of the word "may" when discussing the agreement in its argument created some ambiguity that needs to be clarified. A further issue is the additional $258,000 shortfall that was created when NTPC reduced its proposed interim rate increase in Norman Wells from 15% to 7%, seemingly without any agreement that the GNWT would cover the lost revenue.

Given these issues and concerns, the Board directs NTPC to submit, by May 31st, either a final written copy of the funding agreement with the GNWT, or a letter confirming the agreement has been finalized and setting out the specific details of the funding arrangement. If necessary, based upon the contents of the funding agreement, NTPC is also to file by May 31st an application to adjust the interim rates for July 1st. In the absence of a final agreement, NTPC is directed to file an application by May 31st to adjust the interim rates for July 1st.

Concerns with the Proposed Agreement

The HC raised a concern that the proposed agreement would impact the Board's discretion to determine just and reasonable rates to be charged to the ratepayers.

While there is some ambiguity regarding the details of the proposed agreement, as the Board understands it, this agreement does not intrude upon the Board's authority and discretion to determine the test year revenue requirements as well as just and reasonable rates for NTPC.

If the proposed funding agreement allows the actual rates to be below what would be just and reasonable rates based upon the overall revenue requirement, then that is to the benefit of the ratepayers, as long as NTPC is kept financially whole and no shortfall is being accumulated for later recovery.

What does concern the Board about this proposed agreement is the mechanism by which Board-ordered reductions in the revenue requirement will be matched by reductions in the GNWT's funding. Under the proposed mechanism, any reductions to revenue requirement resulting from the Board's GRA review process will reduce the revenue to be collected from the ratepayers only after the reductions exceed $13.63 million. At that point, the benefit of the revenue reductions would transfer from the GNWT to the ratepayers and translate into lower rates.

The purpose of the hearing process is to test the proposed revenue requirement and, typically, any reductions resulting from this testing would flow to customer rates. A major component of interveners' submissions is to find ways to reduce the revenue requirement and so reduce the rates to be charged. While there are certainly longer-term benefits to the interveners by keeping the revenue requirement lower, immediate revenue reduction, and immediately lower rates, is a major focus of the interveners. As it is unlikely in the Board's view that this process will be able to find savings of greater than $13.63 million, this suggests that the interveners' short-term incentive to find reductions might be reduced.

In the Board's view this could result in the GRA process being less effective, which in turn could result in a higher final approved revenue requirement than might otherwise be, had there been greater incentive to find reductions or cost savings. This could potentially leave the GNWT with a higher level of government funding to NTPC than might have been if this GRA review had the potential of immediate financial benefits for the interveners.

It is the Board's view that the proposed GNWT-NTPC agreement would be improved if it were instead based upon either:

1) a fixed amount of GNWT funding that is not dependent upon the approved revenue requirement, or;

2) a philosophy of sharing the risks and rewards of the GRA review between the GNWT and the interveners.

3. SECTION 51(2)(b) APPLICATION

The IRA was filed with the Board on March 23, 2012 with a requested effective date of April 1st. Even with the extra time to April 6th to have the rates changed prior to April billing, this was clearly not enough time for the Board to run an effective review process with the full participation of the interveners.

In a letter, dated December 31, 2007, the Board had already addressed the issue of late filing of GRAs and the implementation of interim rates. The Board issued the following direction to NTPC on this matter:

> *"For future GRAs, the Board's expectation is that the NTPC will file its Phase 1 GRA with sufficient time to permit the approval of interim rates for the first day of the test year.*
>
> *If significant reasons exist that prevent the NTPC from filing in time to have interim rates in place for the start of the test year, then the Board accepts that Section 51(2)(b) could be used. However, a significant burden will be upon the NTPC to convince the Board that it would be just and reasonable for the Board to exercise its discretion and allow reconciliations in the period between the start of the test year and the start of the interim rates.*"

By not filing the current application until March 23rd, NTPC had clearly not met the standard expected by the Board and prevented the Board from running an effective review process with the full participation of the interveners.

In the Board's April 5th letter, which outlined the additional review period, the Board stated the following:

> *"If NTPC desires the collection of the revenue shortfall that is created between April 1st to May 1st due to the delay in the implementation of interim rates, then the Board expects to receive a Section 51(2)(b) request*

> *from NTPC, along with supporting reasons that meet the standard set by the Board in its December 31, 2007 letter.*
>
> *The Board directs NTPC that if a Section 51(2)(b) request is going to be filed, then it is to be filed by April 13th. The interveners will be allowed to respond to this request in their argument."*

NTPC, by letter dated April 13, 2012, requested Section 51(2)(b) approval of the Board to recover the shortfall (estimated at $500,000) that results from the delay in implementing the requested interim rates from April 1st to May 1st for the following reasons:

1. The delay in NTPC's filing to March 23, 2012 was directly related to the consultation and due diligence process required to secure the GNWT funding that make possible the four-year transition support for Customers.
2. As a result of this GNWT funding commitment, the requested interim rates are substantially lower than NTPC would have requested had the GRA been filed without a financial commitment from the GNWT.
3. Absent the GNWT funding on behalf of Customers, NTPC would also require a stabilization fund rider, in addition to interim rate increases.
4. Securing the GNWT funding results in a material benefit to Customers over the next three years.
5. The additional shortfall incurred from the delay is material to the Corporation's financial position and NTPC has no ability to recover these amounts from other sources.

NTPC reiterated these same points in its argument.

Neither the HC nor the TGC expressed any opposition to the Section 51 request in their arguments and so there was no need for any reply argument from NTPC.

The Board accepts the NTPC argument that delaying the submission of the GRA and the IRA produced benefits for the ratepayers through the negotiation of government funding to reduce rate impacts.

NTPC's Section 51 request to collect the revenue shortfall created by the delay in implementing the interim rates from April 1st to May 1st is approved. NTPC is directed to include any revenue shortfall resulting from delay in implementation of interim rates in its reconciliation of final rates for 2012/13.

Although the Board has approved the Section 51 request, the Board wants to reiterate its concern about late filing of GRAs and IRAs. Unnecessarily creating revenue shortfalls through late applications is not acceptable to the Board. Although the Board has approved the Section 51 request in this case, the Board expects NTPC to be better prepared to manage its relationship with its shareholder so that future GRAs and IRAs can be filed in a timely manner. For greater certainty, the Board directs NTPC that GRAs and IRAs are to be filed at least 6 weeks prior to the first day of the first test year.

4. BOARD ORDER

NOW THEREFORE, IT IS ORDERED THAT:

1. The energy rates set out in Schedule 1 of the amended interim rate Application dated March 28, 2012, under the proposed interim rates column, are hereby approved for implementation, effective May 1, 2012, on an interim refundable basis. All revenues collected by the interim rates are to be tracked by zone and rate class to allow reconciliation and true-up in accordance with the final GRA decision.

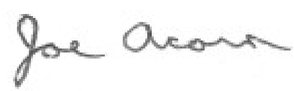
2. The Board directs NTPC to include any revenue shortfall resulting from delay in implementation of interim rates in its reconciliation of final rates for 2012/13.

3. The Board directs NTPC to submit, by May 31st, either a final written copy of the funding agreement with the GNWT, or a letter confirming the agreement has been finalized setting out the specific details of the funding arrangement. If necessary, based upon the contents of the funding agreement, NTPC is also to file by May 31st an application to adjust the interim rates for July 1st. In the absence of a final agreement, NTPC is directed to file an application by May 31st to adjust the interim rates for July 1st.

4. The Board directs NTPC that GRAs and IRAs are to be filed at least 6 weeks prior to the first day of the first test year.

5. Nothing in this Decision and order shall bind, affect or prejudice the Board in its consideration of any other matter or question relating to the Northwest Territories Power Corporation.

ON BEHALF OF THE
PUBLIC UTILITIES BOARD
OF THE NORTHWEST TERRITORIES



Joe Acorn
Chairman

Dated May 1, 2012

Industrial Electricity Policy Review Task Force Final Report

Tim Newton
Peter Ostergaard
Chris Trumpy

October 31, 2013

Table of Contents

Executive Summary 3

1. Strategic Context 8

2. Rationale and Mandate for Review 12

3. Industrial Electricity Policy Objectives 13

4. Effective Utility Regulation 14

5. Task Force Assessment of Policy and Legislative Framework 18

6. Task Force Assessment of Issues in Terms of Reference 22

7. Additional Issues for Government Consideration 34

Appendices 37

Executive Summary

Introduction

Electricity drives our provincial economy. Its production, delivery, use, and conservation is in itself a source of economic activity, social well being, and provincial revenues. Its development and use may contribute to a clean environment and greenhouse gas emission reduction. Policies and programs that attempt to reconcile tradeoffs among these goals may need to change as circumstances and priorities evolve.

Because electricity is important to the economy, it's important to government. Successive governments have released five separate energy plans since 1980, responding to the issues of the day and their economic development and environmental priorities, and each of these has impacted subsequent energy policy.

Our focus in conducting this review was on industrial electricity policy. We were asked to review the existing policy framework to determine how it supports government's broad policy objectives of economic development, GHG reduction and conservation. In doing so, we met with and received input from representatives of utilities, industry, other customer groups, independent power producers, the British Columbia Utilities Commission (the Commission), First Nations, and others.

We are making a series of recommendations to provide policy clarity, ratemaking process improvements, and rate options for industrial customers. Our recommendations, if accepted, will take several years to fully implement and require some major adjustments. However, we have identified a few key changes that government could implement today.

Process

Following the Terms of Reference issued in January 2013, the task force had over 30 meetings with 18 groups and received 35 submissions.

The task force provided a backgrounder and nine issues papers for comment initially, and received three rounds of comments on this material. When the task force's mandate was extended in mid 2013, it provided another round of four issues papers for comment by stakeholders. In October 2013 it released its interim report, without recommendations, to stakeholders for comment. Some suggested revisions, and task force recommendations, are included in the final report to the Minister of Energy and Mines.

Expectations for Industrial Electricity Policy

Our view is that government has three broad objectives with respect to Industrial Energy Policy:

- Economic development

- Environment (GHG reductions)
- Effective regulation

Low cost, reliable electricity supports economic development. Rates should be kept as low as possible, given legal and policy requirements. A transparent process is important in setting electricity prices, allowing all options to be considered and helping to build acceptance of any rate adjustments that are required.

Government should pursue the least cost opportunities to achieve the GHG reductions it has enshrined in legislation. The current rules-based approach to the electricity generation sector may not be the best.

Over the years government has refined and expanded its list of priorities to the point where it is difficult for BC Hydro and the Commission to function effectively. BC Hydro ratepayers are expected to pay for government's broader public policy priorities, transferring responsibility from taxpayers.

Recommendations

Our report includes 17 recommendations, covering policy changes, process changes, rate design, and other issues raised by stakeholders that merit consideration.

Our first category of changes is in policy. The current set of policies is confusing and we are recommending elimination of a number of policy priorities which we do not think serve a useful purpose. We also recommend some replacement policies which in our mind will provide clarity. The most important of these are the establishment of a carbon price to use when considering alternative generating sources and the elimination of the legislated objectives specifying a floor on renewable generation and conservation.

The second category of recommendations are changes in process. Government use of directives to drive public policy has increased dramatically over the years, decreasing public scrutiny and creating controversy around BC Hydro's procurement and capital investments. We are recommending some changes in the traditional regulatory compact which, if accepted, would affect the way government acts.

The third set of recommendations is around rate design and rate options. Although stakeholders cautioned the task force against getting into detailed rate design, we identified a number of elements of and potential options for industrial rates that should be looked at in a transparent hearing type process.

The major ones are Tariff Supplement 6 that sets out new industrial customer contribution policies, time of use and interruptible rates, and retail access. Existing policies do not offer the industrial sector some of the options to reduce their costs that are available in other jurisdictions. Any rate redesign should be done through a public process as these are complex issues.

Several additional issues surfaced during our discussions with stakeholders. For example, while stakeholders generally support a return to Commission regulation of BC Hydro, many express reservations about the Commission's capacity to deliver clear, timely decisions. There is also a lot of confusion about the size and impact of BC Hydro's regulatory account balances.

Legislation needs to change to fully implement a number of our recommendations. However, in our view this does not mean that they cannot be adopted or that existing processes could not be amended. The requirement that the BC Hydro Integrated Resource Plan (IRP) be approved by Cabinet is in legislation. Cabinet could agree that it will only consider future IRPs with a recommendation from the Commission. Similarly, a public review could begin on establishing a long-term carbon price.

However, we want to highlight two recommendations that government can implement quickly.

First, we recommend that government adopt four principles in any decision-making process involving BC Hydro's public policy role. These are:

- Clearly Articulated Policy
- Appropriate Risk Allocation
- Market Based Solutions
- Public Scrutiny of Costs and Benefits

These are articulated in Table 1 below, and in Section 4.3.

Second, we recommend a review be undertaken to evaluate the Commission's resource needs, review processes, and performance. Its purpose would be to ensure that the Commission can deliver on its responsibilities under the regulatory compact in a timely way.

Other high priorities for action in the near term include the development of a revised retail access program at BC Hydro. BC Hydro should also look at potential arrangements for industrial power consumers to take advantage of their flexibility, such as industrial time of use or interruptible rates, where these rates could benefit both those customers and BC Hydro. If BC Hydro's surplus management plan proposes to put additional costs on ratepayers, it should be brought forward in a Commission-led process.

Table 1: Task Force Recommendations

Policy Recommendations:	
Recommendation:	**Timing**
Government should assess any directions or exemptions against the expanded regulatory compact recommended in Section 4.3.	Immediate
Acquire all possible conservation up to the cost of new supply. There is no need for the BC Hydro-specific 66 per cent conservation objective in the *Clean Energy Act*.	Short term

A long-term carbon price should be used in evaluating all electricity supply proposals and the price should be determined by Government after a public process. This would eliminate the need for the objective to generate at least 93 per cent of the electricity in British Columbia from clean or renewable resources.	Consultations beginning in 2014, implementation before next IRP
Government should provide clarity on the role carbon offsets will play in meeting Government's greenhouse gas reduction goals.	Before 2016
As BC Hydro's surplus diminishes, Government should consider whether a requirement for self-sufficiency is consistent with a long-run approach to least cost electricity prices.	Before 2020
Process Recommendations:	
Recommendation:	**Timing**
Government should adopt four additional principles beyond the "regulatory compact" –which allows a utility to earn a fair return on its investment in exchange for providing safe, reliable service at rates based on costs – in any decision-making process involving electricity policy. Our expanded compact includes the following principles: • *Clearly Articulated Policy:* Government should determine the provincial public interest and set clear, understandable policy objectives, and apply them consistently to all utilities; • *Allocating Risk:* Utility owners (including the Province) make decisions based on an evaluation of risks, and the costs and benefits associated with these risks should be allocated to the party taking the risk; • *Market Based Solutions:* Market based solutions are generally preferable to those imposed by Government, provided externalities are priced and predictable, because they send appropriate price signals to drive decision-making and behaviour; and • *Public Scrutiny of Costs and Benefits:* Ratepayers should be provided with an opportunity for public review, either by the Commission or government, of any policy-driven initiatives that could significantly increase costs before these are implemented.	Immediate
BC Hydro should ultimately bring its surplus management plan forward in a Commission-led process if the management plan proposes to put additional costs on ratepayers or transfer costs between ratepayers.	When management plan developed
BC Hydro's future Integrated Resource Plans should be reviewed and accepted by the Commission after a public process. As the owner of BC Hydro, Government may wish to review the Integrated Resource Plan before it is submitted to the Commission.	Before next IRP
Rate Design Recommendations:	
Recommendation:	**Timing**
Continue using postage stamp rates.	N/A
BC Hydro should develop a revised retail access program.	Over the next year

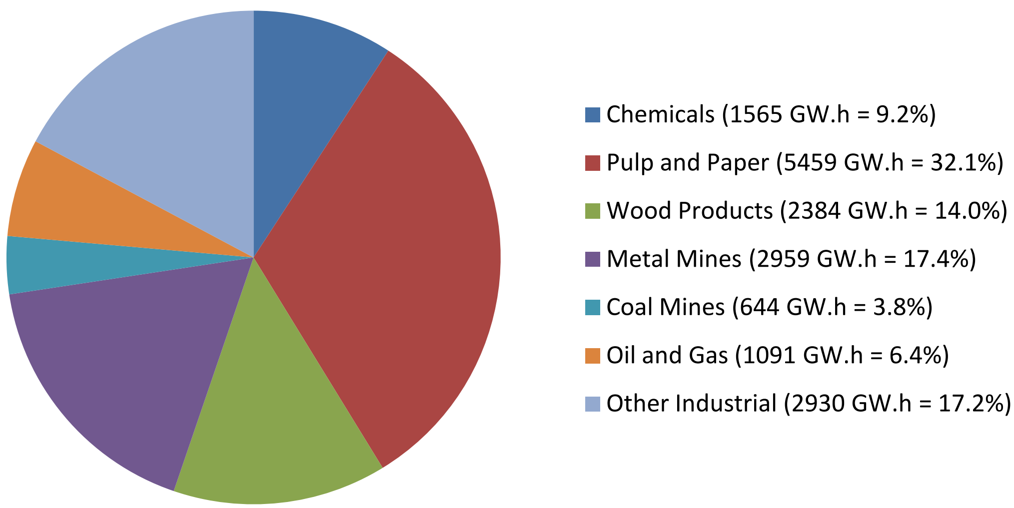
BC Hydro should work with its industrial customers and the Commission to develop options that take advantage of industrial power consumption flexibility, such as time of use rates and interruptible rates.	Over the next year
The industrial tariff supplement that sets out the terms and conditions of connections, Tariff Supplement 6, is over 20 years old and should be reviewed in a Commission public process.	Before next IRP
End use rates which have no impact on ratepayers could be considered but those which impact ratepayers and are directed by Government should be paid for by taxpayers and not ratepayers.	Before next IRP
Government need not act on the Commission's 2009 Transmission Service Rate report until BC Hydro's surplus has diminished and the effect of the other recommendations in this report can be seen.	Before 2020
Other Recommendations:	
Recommendation:	**Timing**
An independent review of the Commission should be undertaken to evaluate resource needs, review processes, and performance.	Immediate
BC Hydro should host a workshop on its regulatory accounts to improve understanding of the balances and the provisions in place for dealing with them.	Over the next year
BC Hydro should benchmark and publicly report on its transmission interconnection turnaround times for both new generation and new load.	Before next IRP

1. Strategic Context

British Columbia Hydro and Power Authority's (BC Hydro) 2013/14 Load Forecast estimates industrial customers will purchase approximately 17,032 gigawatt-hours (GW.h) of electricity. This accounts for about 32 per cent of BC Hydro's domestic sales. Transmission Service customers (i.e., customers that take service at 60 kilovolts (kV) or higher) such as chemical producers, pulp and paper mills and mines comprise over 75 per cent of the total industrial sales volume. Large General Service (LGS) customers (i.e., customers that take service at 60 kV or lower) such as sawmills, wood manufacturers and natural gas producers consume the remainder.

Figure one includes a breakdown of BC Hydro's industrial customers based on 2013/14 projected industrial demand.

Fig. 1: 2013/14 Industrial Power Sales Forecast in Annual Gigawatt Hours (GW.h)



Industrial customers are typically price-takers in competitive global commodity markets with limited ability to pass increased costs to customers. Proximity to natural resources, access to capital and market competitiveness have driven, and will continue to drive, investment decisions. Particularly for energy intensive industries, electricity costs heavily influence decisions to invest, expand, contract, or close. Industrial electricity demand declined sharply in 2008/2009 and current industrial use is 2% below 2007 levels. A summary of BC Hydro's industrial customers is included in Appendix 1.

The Province created BC Hydro in 1962 to provide reliable, low cost electricity to residential, commercial and industrial customers in British Columbia. Access to competitively-priced electricity has been a part of provincial economic development policy since that time. However, there are several drivers that place upward pressure on electricity rates: capital reinvestment in BC Hydro's assets; BC Hydro's projected energy supply surplus; depressed export market conditions; recovery of growing regulatory account balances; and achieving legislated greenhouse gas (GHG) reduction targets. An additional driver that has been placing upward pressure on rates is a changeable and increasingly complex policy and regulatory environment.

1.1 Capital Reinvestment in BC Hydro's Assets

Some of BC Hydro's infrastructure is nearing the end of its economic life. While reinvestment has been deferred to keep rates low, BC Hydro cannot delay any further and must invest capital to safely refurbish and expand its system to meet demand as well as North American reliability standards. Excluding Site C, BC Hydro plans to spend approximately $2 billion per year for the next 10 years on sustaining and growth capital projects. A $2 billion capital program translates into roughly a 5 per cent annual rate increase to pay for amortization, borrowing costs and return on equity. This level of increase does not include any other cost pressures faced by BC Hydro.

1.2 Projected BC Hydro Energy Surplus

A policy of the 2007 Energy Plan was to ensure British Columbia would be electricity self sufficient by 2016, and BC Hydro would acquire additional "insurance power". The fact that BC Hydro had been a net importer in some prior years was the result of BC Hydro making the prudent choice --consistent with approved system planning and reliability criteria--to import electricity at a lower price than the cost of generating it from intraprovincial resources. Government issued a regulation directing BC Hydro to be self-sufficient under historically low, or critical, water conditions. It also directed BC Hydro to acquire 3,000 GW.h of insurance power by 2026.

The 2010 *Clean Energy Act* (*CEA*) advanced the insurance power acquisition deadline to 2020. The updated Electricity Self Sufficiency Regulation also confirmed the critical water planning requirements. BC Hydro continued to acquire resources to meet the legislated requirement. In February 2012, the legislation and regulation were amended: the 3,000 GW.h insurance requirement was eliminated and the planning criteria changed from critical water levels to average water levels, a 4,100 GW.h reduction. The planning requirements, in conjunction with aggressive demand side management (DSM) targets and slow load growth, create an energy surplus expected to last to 2021. This is based on a load forecast that does not include any significant demand for electricity from the liquefied natural gas sector.

1.3 Weak Export Markets

To optimize its system, BC Hydro buys and sells electricity in markets outside of British Columbia such as the Mid-Columbia Electricity Market (Mid-C). System optimization enables BC Hydro to buy and sell electricity when market conditions are most advantageous. Money made from trading reduces electricity rates in British Columbia. As shown in the table below, Mid-C prices are depressed due to low natural gas prices, an oversupply of subsidized United States wind energy, and the slow economic recovery, particularly in California. BC Hydro's draft Integrated Resource Plan (IRP) forecasts export market prices of between $25 and $40 per MW.h over the twenty year planning period. Depressed market conditions combined with the relatively high cost of power in BC Hydro's recent calls means BC Hydro will likely receive low export revenues for surplus power.

Table 2: Summary of Mid-C Annual Average Prices
(Firm on Peak, US Dollars per Megawatt Hour (MW.h))

FY 2009/10	FY 2010/11	FY 2011/12	FY 2012/13	Total Change
$37.13/MW.h	$31.08/MW.h	$27.96/MW.h	$23.63/MW.h	-36%

1.4 Regulatory Accounts

BC Hydro has 27 regulatory accounts. One purpose of regulatory accounting is to align the costs and benefits of utility expenditures over time. This supports intergenerational equity by matching costs to ratepayers who directly benefit from the expenditure without unduly large rate increases for current ratepayers. Another purpose of regulatory accounts is to smooth out the rate impact of volatile revenue or cost items.

Total account balances are $4.67 billion as of June 30, 2013, up from the April 1st, 2013 balance of $4.43 billion due primarily to the Powerex settlement agreement with California parties. The account balances are forecast to grow slightly before settling back to current levels and ultimately declining. In April 2012 the British Columbia Utilities Commission (Commission) directed BC Hydro to increase the 2.5% rate rider to 5.0% to accelerate recoveries for three regulatory accounts.

Given the magnitude of the regulatory accounts, a rate rider is expected to be in place for a number of years so that BC Hydro can collect sufficient future revenue to pay down the regulatory accounts. Ministry of Energy and Mines staff advise that recovery mechanisms built into current rates have been established to recover about 80 per cent of the outstanding regulatory account balances.

1.5 Legislated Greenhouse Gas Targets

The Province passed the *Greenhouse Gas Reduction Targets Act* in 2007. The statute directs a six per cent GHG emission reduction below 2007 levels by 2012, an 18 per cent reduction by 2016, a 33 per cent reduction by 2020 and an 80 per cent reduction by 2050. These targets are repeated in the *CEA*.

British Columbia's electricity generation sector accounted for two per cent of provincial GHG emissions in 2010. This is a relatively small GHG emissions footprint compared to the stationary combustion sources (including heating) of 26% and transportation's 38%. Meeting the 2050 targets would require British Columbia to virtually decarbonise its economy. Electrification of the industrial and transportation sectors would be part of the suite of actions necessary to meet this objective. Once the current surplus is exhausted, electrification would likely accelerate the procurement of zero-carbon electricity (hydro, wind, solar, biomass, natural gas with offsets, etc.) as well as triggering a large transmission and distribution build out.

1.6 Policy and Legislative Environment

The *Utilities Commission Act* (*UCA*) operates to ensure that utilities provide safe, reliable energy services at the lowest reasonable cost while enabling shareholders the opportunity to earn a fair return on invested capital.

The 2007 Energy Plan signalled Government's desire to value environmental objectives, such as GHG reductions, in Commission decision-making. The *UCA* was amended in 2008 to accomplish this. Section 2 of the *CEA* introduced 16 Provincial Energy Objectives to guide Commission decisions, covering issues such as rate competitiveness, economic development, GHG reductions, and clean or renewable electricity requirements. Competing *CEA* objectives have introduced complexity to the regulatory regime.

The *CEA* also exempted several projects, programs and contracts that the Government deemed to be in the provincial public interest from Commission oversight. These have contributed to BC Hydro's revenue requirements and rates.

2. Rationale and Mandate for Industrial Electricity Policy Review

Concerns about rising electricity costs, the suitability of BC Hydro's industrial tariff, outstanding Commission recommendations about the Transmission Service Rate (TSR), and policy and scope matters arising from the Dawson Creek/Chetwynd Area Transmission Reinforcement Project review, pointed to the need for some sort of systematic evaluation. The then Minister of Energy, Mines and Natural Gas launched the Industrial Electricity Policy Review (Review) in January 2013. The Terms of Reference (ToR) require the task force to review the current industrial electricity policy and legislative framework, and advise Government on changes that may be required to achieve provincial policy objectives.

We are to identify how transmission voltage rates contribute to the Province's conservation, environmental policy and economic development objectives. We have also been directed to assess the tradeoffs that may be necessary between the three objectives as well as provide principles to guide the Province's use of its directive powers related to BC Hydro and the Commission in order to pursue provincial policy objectives.

The ToR further requested us to consider the following specific items:

- Allocation of embedded cost resources between new and existing customers;
- Whether postage stamp rates remain appropriate for industrial customers;
- Whether end use rates would be appropriate for industrial customers;
- Whether retail access would be appropriate for industrial customers;
- What action(s) the Province should take in relation to the Commission's 2009 TSR report;
- A comparison of effective industrial electricity costs in relevant jurisdictions; and
- Any other issues related to current or future transmission voltage rates the task force determines relevant to its recommendations.

In June 2013, the Review ToR were supplemented to include:

- A review and evaluation of industrial time of use pricing;
- A review of utility interconnection policies and timelines;
- Approaches to interconnecting large loads in hydroelectric based jurisdictions; and
- A review and evaluation of retail access policies.

The ToR and the June supplement are included as Appendix 2 and the task force process and consultation summaries are included in Appendix 3.

3. Industrial Electricity Policy Objectives

Government has three broad policy objectives for industrial electricity policy: environmental; economic development; and effective regulation.

We defined the "environmental objective" as Government's GHG reduction targets and their implications for industrial customers. Government has legislated targets for GHG emissions which require substantial decreases over time. We recognize that environmental policy extends beyond climate policy and that electricity-related non-GHG environmental issues deserve full consideration, but felt that Government has other regulatory and consultation processes, particularly the Ministry of Environment's regulations and the Environmental Assessment Office, to address these issues.

We defined "economic development" as the creation of new and/or maintenance of existing economic activity. Low priced, reliable power supports this objective.

We defined "effective regulation" as a regime with understandable policy direction and clear role definition, as well as fair, transparent, inclusive and timely decision-making based on sound evidence. Section 4 explains in detail what we mean by effective regulation.

The Terms of Reference requested us to review the extent to which industrial rates may be used to contribute to provincial electricity conservation objectives. The task force did so and concluded that conservation is not a discrete policy issue, but a tool to implement the other policy objectives depending on how it is used. For example, conservation programs that cost less than adding new supply-side resources keep rates lower and avoid adding potentially GHG-producing new generation.

4. <u>Effective Utility Regulation</u>

In considering changes to the industrial electricity policy and regulatory framework, it is useful to understand the main components of the existing framework—namely the role of the regulator and the role of the government—and the tensions arising from the differing roles. In addition to the standard regulatory compact, additional principles to help define effective utility regulation in circumstances where a government shareholder wishes to use its utility to advance an active public policy agenda are identified.

4.1 The Role of Utility Commissions

A significant energy policy decision of the 1980 Energy Plan was to place BC Hydro under full British Columbia Utilities Commission (Commission) regulation. The *Utilities Commission Act*, and similar provincial and state legislation, delegates powers to energy regulatory tribunals, following the "regulatory compact". In exchange for an exclusive right to serve a defined area:

- A regulated utility must provide safe, reliable, non-discriminatory service to its ratepayers at rates that are based on costs; and
- The regulator must allow the regulated utility an opportunity to earn a fair return on its invested capital.

Tribunals make decisions based on evidence, and abide by standards of procedural fairness. Significant decisions are based on open hearings with interveners offering testimony. A tribunal's role in providing openness and transparency in its reviews of utility applications also helps remove perceptions of political interference from controversial decisions.

Commissions set rates which allow utilities to recover costs of providing service and earn a reasonable return on its investment. These costs must be necessary and/or prudently incurred to provide utility services, without compromising safety, reliability, environmental stewardship and First Nations obligations. Integrated resource plans are intended to guide the selection of the lowest cost resources that would yield the best overall outcome for ratepayers.

Commissions are also charged with ensuring that significant capital additions and energy supply contracts are in the "public interest". The definition of "public interest" in the context of utility regulation is narrower than in a public policy context. Unless directed otherwise, energy utility regulators tend to interpret their jurisdiction as extending to include social and environmental considerations only if these considerations are likely to impose financial costs or benefits in the future.

4.2 The Role of Government

Provincial governments have overall responsibility for electricity and energy policy. As with most provinces and territories, British Columbia periodically prepares Energy Plans that reflect governments' vision for the future of its energy sector and its contribution to provincial prosperity. Provincial Energy Plans from 1980, 1990, 1994, 2002, and 2007 contain common themes of energy security, economic development, environmental sustainability, clean energy, and energy efficiency. These plans were prepared with varying degrees of input from the public, stakeholders, and advisory groups.

Governments implement many of the components of energy plans through their energy utility tribunals, through "hard wired" legislation and regulations, and through softer policy statements. All of these can be appropriate tools for introducing public interest criteria that extend beyond the traditional least-cost mandate of regulators.

In British Columbia, the Government has the ability to displace BC Hydro's and the Commission's discretion on matters through directives, directions, exemptions, and regulations under several sections of at least four Acts. Government's use of its regulatory powers has increased over time. There have been 87 BC Hydro-related regulatory directives since 1980. Almost one third of them were issued since 2010, as the *Clean Energy Act* created a number of enabling powers that were exercised by regulation. Many have had the effect of imposing costs onto BC Hydro ratepayers. A breakdown of the number and type of regulatory directions is in Appendix 4.

Government also has the ability to introduce statutes when the existing regulatory powers are deemed inadequate. Some examples include rate freezes and exemptions of BC Hydro projects, programs and contracts from Commission review and approval. Government also can direct BC Hydro activities through non-legislative ways such as the annual Government Letter of Expectations.

Subjects covered by regulatory directions have also changed over time. Directives can provide helpful articulation of government policy on BC Hydro's capital structure or guidance on environmental matters. Some important policy matters (e.g. industrial stepped rates) were made through government directive, after a report and recommendations by the Commission. The trend in recent years has been to remove or change the Commission's authority over BC Hydro rates, contracts, and projects.

The number and range of government policy instruments has impacted the effective regulation of BC Hydro in three ways:

- There can be considerable confusion over their interpretation. The policy decision to phase out Burrard Thermal is the subject of five separate enactments; another example was the prolonged debate over the scope of the Dawson Creek/Chetwynd Area Transmission Reinforcement Project proceeding.
- The use of directives and legislation to determine energy resource and technology choices means decisions may not be supported with the information that would normally accompany an evidence-based process. This creates a risk that a growing portion of BC Hydro's revenue requirements is no longer based on least cost planning.
- As BC Hydro's shareholder, the government has the ability to insulate itself from risks that shareholders of an investor owned utility would bear, and also transfer costs from the taxpayer to the ratepayer. For example, a 2009 Order (OIC 205) directed the Commission to establish a regulatory account to recover the costs of the Government-imposed Tsawwassen home purchase program arising from the Vancouver Island Transmission Reinforcement Project.

4.3 Additions to the Regulatory Compact

BC Hydro impacts British Columbia's economy, environment, and government revenues. As noted above, this has led to a complex regulatory environment.

BC Hydro, other utilities, and stakeholders have raised concerns about the Commission's capacity to deliver clear, timely decisions. Some utilities have sought Government's use of its authority to displace Commission jurisdiction to achieve timeliness and certainty. Most stakeholders, including utilities, seek a strengthened, better resourced Commission. We discuss Commission capacity matters in Section 7.3.

We have identified four principles that will augment the regulatory compact and lead to more effective utility regulation.

Recommendation: Government should adopt four additional principles beyond the "regulatory compact" –which allows a utility to earn a fair return on its investment in exchange for providing safe, reliable service at rates based on costs – in any decision-making process involving electricity policy. Our expanded compact includes the following principles:

- *Clearly Articulated Policy:* Government should determine the provincial public interest and set clear, understandable policy objectives, and apply them consistently to all utilities;
- *Allocating Risk:* Utility owners (including the Province) make decisions based on an evaluation of risks, and the costs and benefits associated with these risks should be allocated to the party taking the risk;
- *Market Based Solutions:* Market based solutions are generally preferable to those imposed by Government, provided externalities are priced and predictable, because they send appropriate price signals to drive decision-making and behaviour; and
- *Public Scrutiny of Costs and Benefits:* Ratepayers should be provided with an opportunity for public review, either by the Commission or government, of any policy-driven initiatives that could significantly increase costs before these are implemented.

5. Task Force Assessment of Policy and Legislative Framework

Historically, the *Hydro and Power Authority Act* and the *Utilities Commission Act* set out the electricity policy and legislative framework. This was later supplemented by the *BC Hydro Public Power Legacy and Heritage Contract Act*, the 2007 Energy Plan, and the *Clean Energy Act (CEA)*. These collectively constitute the current policy and legislative framework for the purposes of this Review.

We have used the principles in Section 4.3 to assess the industrial electricity policy and legislative framework. We selected what we thought were the key requirements of the electricity policy and legislative framework and summarize them below.

Our assessment of the complete list of commitments can be found in Appendix 5.

5.1 BC Hydro to be Self-Sufficient by 2016

Government's policy statement related to self sufficiency is clear in both the Energy Plan and *CEA*. However, policy implementation has changed with the revised definition of self sufficiency and the removal of the requirement for BC Hydro to acquire insurance power (low market prices and limited premiums for clean and renewable generation have limited the value of surplus power and the likely cost of an electricity deficit in low-water years). Self sufficiency policy and legislation applies to BC Hydro and not to other utilities. It is unclear whether there is an appropriate allocation of risk between the shareholder and ratepayers because the policy does not appear settled. It is also likely that the policy will have the effect of increasing costs to ratepayers by acquiring power that may be sold in the export market at a loss in high water years.

Recommendation: As BC Hydro's surplus diminishes, Government should consider whether a requirement for self-sufficiency is consistent with a long-run approach to least cost electricity prices.

5.2 Government Review and Approval of BC Hydro's Integrated Resource Plan

Government's policy statement concerning BC Hydro's Integrated Resource Plan (IRP) is clear. However, BC Hydro is the only utility required to submit its IRP to Government for review and approval rather than the Commission. The process for BC Hydro does not meet our test for risk allocation because the *CEA* directs BC Hydro to base its IRP on the Provincial Energy Objectives which limit BC Hydro's planning options. Neither government nor Commission review of the IRP would be market-based. BC Hydro has made great efforts to engage stakeholders in the IRP development process. However, the engagement process is not a proxy for a Commission review.

Recommendation: BC Hydro's future Integrated Resource Plans should be reviewed and accepted by the Commission after a public process. As the owner of BC Hydro, Government may wish to review the Integrated Resource Plan before it is submitted to the Commission.

5.3 93% Clean and Renewable Standard for Total Provincial Electricity Generation

Government's policy intent for the 93% clean objective is to maintain British Columbia's low-carbon electricity generation sector in order to support British Columbia's legislated GHG reduction targets. It applies generally to British Columbia's electricity generation sector rather than specifically to BC Hydro. This objective allocates risk to the ratepayer rather than government. The policy was implemented with minimal public scrutiny of costs and does not consider alternatives.

Recommendation: A long-term carbon price should be used in evaluating all electricity supply proposals and the price should be determined by Government after a public process. This would eliminate the need for the objective to generate at least 93 per cent of the electricity in British Columbia from clean or renewable resources.

5.4 Meet 66 Percent of BC Hydro's Incremental Load Growth through Conservation

Government's policy intent for the 66 per cent objective is to reduce future electricity procurement costs through Demand Side Measures (DSM). It applies only to BC Hydro and no other utility. It is unclear whether risks are assigned appropriately, or if the policy is market-based. The definition of cost-effective DSM is set by regulation. Risks and benefits may be assigned appropriately if the Government's definition remains below the marginal cost of incremental electricity supply. Strong energy conservation price signals and continued utility investment in DSM programs may make the 66% objective unnecessary.

Recommendation: Acquire all possible conservation up to the cost of new supply. There is no need for the BC Hydro-specific 66 per cent conservation objective in the *Clean Energy Act*.

5.5 Pursue All Cost-Effective Demand Side Management Investments

Government's policy statement is clear. It applies to all utilities, including BC Hydro. Risks would be assigned appropriately provided the correct market signals are put in place. It is unclear whether the Government's definition of "cost-effective DSM" is market-based. However, BC Hydro has put forward three conservation rates and received approval for DSM expenditures from the Commission, so it meets the public scrutiny requirement.

5.6 Encourage Utilities to Design Rates that Encourage Efficiency and Conservation

Government's policy objective is clear, risk is allocated appropriately to ratepayers, conservation rates are a market-based mechanism and utility rates are typically reviewed and approved through a Commission process.

5.7 Net-Zero and Zero GHG Emission Requirements for Thermal Generation (Natural Gas and Coal)

Three policies of the 2007 Energy Plan require that all thermal electricity generation must have net-zero or zero GHGs. This would need to be achieved through offsets, or in the case of coal-fired generation, carbon capture and sequestration. However, it appears the requirements will be applied unevenly across fuel uses. For instance, the net-zero requirements do not apply to natural gas-fired direct drive technology, or gas space and water heating. It is not clear why GHG emissions from fossil fuel combustion should be offset, at ratepayer expense, for electricity generation if emissions are not offset when fossil fuels are used for other purposes. The 2016 offset requirement is legislated in the *Environmental Management Act*, but there is no regulation to implement it. This policy uncertainty potentially removes a low-cost resource option from consideration by BC Hydro and other potential gas-fired generation because of the unsettled GHG liability.

The policy does not allocate risk effectively because it applies to only part of the economy. Offsets are a market mechanism to support GHG reductions, but the mechanism's utility is limited as qualifying offsets have not been defined and it is unclear what long term costs will be. Costs associated with this policy were not subject to public scrutiny.

Recommendation: Government should provide clarity on the role carbon offsets will play in meeting Government's greenhouse gas reduction goals.

5.8 Project, Program and Contract Exemptions from Commission Oversight

Government's intent is clear because it uses its legislative authority to establish that a project, program and/or contract is in the provincial public interest. Examples from the *CEA* include: the Northwest Transmission Line (NTL), Mica 5 and 6, Revelstoke 6, Site C Dam and the Electricity Purchase Agreements (EPAs) from the Clean Power and Bioenergy Calls. However, there are distinctions among these projects.

The NTL and clean energy EPAs apply only to BC Hydro, transfer risk from the shareholder to ratepayers to achieve Government objectives, and were not subject to Commission review of costs. The power calls were market-based to the extent there was a competitive bidding process, but the policy decision to limit the calls to clean and renewable power limited the bidding pool. Similarly, there was a competitive bidding process to award the NTL construction contract, but Government legislated many aspects of the project, so it is unclear whether it can be considered market-based.

It is unclear whether the risk allocation of NTL, Mica, Revelstoke, and Site C is appropriate because there was no Commission assessment of potential alternatives or scrutiny of costs. However, it is possible that these projects are in fact the best projects for BC Hydro to pursue to meet its future energy and capacity requirements.

Recommendation: Government should assess any directions or exemptions against the expanded regulatory compact recommended in Section 4.3.

6. Task Force Assessment of Issues in Terms of Reference

6.1 Contribution of Transmission Voltage Rates to Provincial Conservation Objectives

Analysis

Conservation programs support provincial environmental objectives by avoiding the need to add new electricity sources, and economic development objectives as long as program costs are lower than the cost of adding new supply.

The vast majority of transmission service customers operate under the Transmission Service Rate (TSR), a stepped rate that sends a price signal to conserve. Large General Service (LGS) customers are also subject to a conservation rate. Recent changes to the TSR under Tariff Supplement 74 (TS 74) provide customers with certainty about the application of Customer Baseline Load (CBL) adjustment and reset provisions to ensure the CBL is "right-sized". These changes should improve the effectiveness of the TSR over the long-term. BC Hydro uses economic tests and follow-up audits to verify that industrial Demand Side Measures (DSM) investments are cost-effective.

Conclusion

Overall, BC Hydro's industrial customers have responded to the conservation price signals in the TSR and LGS Rate. Industrial customers still have strong interest in BC Hydro's industrial PowerSmart programs and they want to see these programs continue and diversify. This suggests there are still cost-effective conservation opportunities in the industrial sector available, regardless of the 66 per cent conservation objective.

6.2 Contribution of Transmission Voltage Rates to Provincial Environmental Policy

Analysis

British Columbia's electricity generation sector has low GHG emissions, unlike many other jurisdictions in North America which rely on coal or natural gas. As noted, electricity generation in British Columbia accounted for two per cent of GHG emissions in 2010. Transmission voltage rates do not contribute to meeting provincial GHG objectives, but rates are affected by acquisition strategies driven by the GHG reduction targets. Other electricity policies covered below have a more direct impact. Since the 2050 goal is for an 80% reduction in the 2007 level of GHG emissions, any transmission rate policy which supports these goals would have to ensure that carbon impacts of any new electricity supply are fully factored in.

Conclusion

It is unclear whether additional transmission and distribution investments to support electrification, higher volume acquisition of zero-GHG generation resources, or more aggressive conservation actions would be among the lowest-cost initiatives to implement provincial environmental policies.

6.3 Contribution of Transmission Voltage Rates to Provincial Economic Development Objectives

Analysis

Low, stable and predictable rates combined with reliable service support economic development. Average Transmission Service rates rose by over 40 per cent between 2006 and 2012 (see Appendix 6). Future increases will place pressure on electricity-intensive industrial customers. BC Hydro's F2012 Fully Allocated Cost of Service study shows both Transmission and LGS >150 kW customers pay slightly more than their costs of service, with revenue/cost ratios of 104% and 106% respectively. (These compare to revenue/cost ratios of 90% for residential customers and 126% for small commercial customers). At this time the residential class of customers does not pay for its costs of service and if future Commission rate design decisions transition rate classes toward 100% revenue to cost ratios, there could be a contribution to economic development from some commercial and industrial class customers.

Industrial customers appear to have a degree of operational flexibility to reduce peak demand. This may provide value to both customers and BC Hydro under the proper circumstances.

Conclusion

Future rate increases may lead some industrial customers to invest in efficiency, but may prove difficult for others to absorb. In those cases, rate increases may lead to decisions to close or reduce production in British Columbia, or move production out of the province.

6.4 Trade-offs Required When Reconciling Provincial Policy Objectives

Analysis

Because electricity generation infrastructure can remain in service for 20-40 years or more, it is not clear what the optimal trade-off between achieving Government's GHG reduction target and economic development goals is without a long-term price for carbon. The carbon tax is not a proxy for a long-term price for carbon consistent with Government's legislated GHG targets. BC Hydro forecasts costs to rise under almost any scenario, but they would likely rise faster if Government aggressively pursues GHG emission reductions relative to pursuing rate mitigation.

The current policy and legislative framework does not explicitly recognize the current and future costs it imposes on BC Hydro ratepayers. Clean energy requirements within the *Clean Energy Act (CEA)* limit BC Hydro's ability to acquire low cost resources but the *CEA* simultaneously directs BC Hydro to be a low cost utility and support provincial economic development objectives.

Conclusion

A known long-term carbon price and clear offset policy that can be used to compare different long-term electricity resource options would support Government climate policy goals.

6.5 Principles to Guide Government's Use of its Legislative Authority Related to BC Hydro and the Commission

Analysis

When Government uses its legislative authority to achieve provincial public policy objectives, this imposes costs on ratepayers and can limit due diligence. Some provincial energy policy objectives were presented in legislative form rather than in Government policy documents such as an updated Energy Plan. Enshrining these objectives in legislation may ease implementation of Government's policies, but limits Government's flexibility to adapt its electricity policy to reflect changing economic, energy market and fiscal circumstances.

Conclusion

Government's role to determine the provincial public interest should be separated from its role as shareholder of BC Hydro. Principles could provide government with guidance on what costs should be allocated to ratepayers, and those that should be allocated to government as shareholder. Public scrutiny of BC Hydro's expenditures by the British Columbia Utilities Commission (Commission) will increase public acceptability of the results. Adoption of our recommended expanded regulatory compact will provide Government with guidance on considering its use of legislative authority to supersede the Commission.

6.6 Allocation of Embedded Cost Resources Between New and Existing Customers

Analysis

The Heritage Contract states that BC Hydro ratepayers are to share the benefit of BC Hydro's embedded cost resources. This is accomplished through cost-of-service rates so that customers with similar characteristics (ratepayer classes) pay the same price for electricity. This premise holds true for new customers under 150 megavolt amperes (MV.A), but not for those over this threshold. Under Tariff Supplement 6 (TS 6), approved by the Commission in 1991, customers requesting service at 150 MV.A or higher are required to pay the full incremental cost of any generation procurement they trigger.

It appears the purpose of this limit was to prevent very large loads from diluting BC Hydro's embedded cost resources and driving up rates for existing ratepayers, however we were unable to find definitive proof because of the tariff's age. The 150 MV.A threshold presents a cost barrier not found in other jurisdictions, and sends a signal that new large electric loads are not supported in British Columbia.

New customers are also required to pay for system upgrades to BC Hydro's bulk electric system if their load triggers the need to do so. However, some of these costs are absorbed by all ratepayers (i.e., rolled in to rates) if the new customer generates sufficient revenue to BC Hydro in its first seven years of operation.

Conclusion

The underlying principles and operational aspects of TS 6 could be reviewed in a forum where all interested stakeholders may participate and provide input. We received several different approaches to a contribution policy that require technical review to determine their feasibility.

We could not find a firm rationale for the implementation of the 150 MV.A threshold in TS 6. The only similar threshold we've been able to find is a 50 MW threshold for Hydro Quebec. Hydro Quebec is only required to serve up to this threshold but can choose to serve beyond this. The tariff would not necessarily treat customers above or below the threshold differently. It also appears that nothing similar exists in other jurisdictions based on the cross-jurisdictional analysis provided by BC Hydro. However, we also understand the ultimate goal of the threshold is to protect existing ratepayers from unreasonable electricity cost increases.

Recommendation: The industrial tariff supplement that sets out the terms and conditions of connections, Tariff Supplement 6, is over 20 years old and should be reviewed in a Commission public process.

6.7 Whether Postage Stamp Rates Remain Appropriate for Industrial Customers

Analysis

Postage stamp rates are the standard approach to utility rate setting in North America. Stakeholders unanimously supported the continuance of postage stamp rates. However, this support depends on a contribution policy that balances the interests of new and existing customers.

Conclusion

There is little support to move away from postage stamp rates for customers taking service at transmission voltage rates.

Recommendation: Continue using postage stamp rates.

6.8 Whether End Use Rates Would be Appropriate for Industrial Customers

Analysis

There are two types of end use rates: those that follow established rate-making principles and process, and those that do not. The former are subject to Commission approval, such as "Irrigation Rates" and "Street Light Rates". Stakeholders considered that these produced benefits to BC Hydro through using electricity during periods of surplus in the case of irrigation and by saving the costs of metering when the actual use could be easily determined from the actual use pattern in the case of street lighting. Since all customers benefitted, or were kept whole, these rates should be treated as other cost based rates.

If rates are set to meet government objectives, where the rates are not based on established rate making principles, and the costs of the rates are not covered by projected revenue, then stakeholders believed the shortfall in revenue should not be covered by other rate classes.

Conclusion

End use rates may make sense under specific circumstances. End use rates should not be subsidized by ratepayers. Stakeholders have indicated that they do not support end-use rates unless those rates are cost-based.

Recommendation: End use rates which have no impact on ratepayers could be considered but those which impact ratepayers and are directed by Government should be paid for by taxpayers and not ratepayers.

6.9 Whether Retail Access Would be Appropriate for Industrial Customers

Analysis

Retail access would enable industrial customers to buy some or all of their electricity from third party providers and delivered over BC Hydro's transmission system at regulated rates.
BC Hydro's Retail Access Program (RAP) was operational from 2006 to 2011. It was intended to enable Tier 2 electricity to be purchased from domestic IPPs, from TSR customers with surplus self- generation, or from power marketers sourcing electricity in the US or Alberta. The Program was comprised of a Program Agreement (TS 71) and Energy Imbalance Schedule

(RS 1890), billing and CBL treatment under RS 1823, and the CBL Determination Guidelines (TS 74). Program customers would retain their existing Contract Demand and Electricity Supply Agreements with BC Hydro.

No customers participated in the Program for reasons relating to BC Hydro's traditional role as least cost supplier, and the risks and costs to obtain third party electricity. Intertie access is another limiting factor. However, as BC Hydro's rates increase and the gap between Mid-C prices and the Tier 2 rate widens, the economic incentive is growing for industrial customers to seek alternatives.

The Province's 2011/12 Shareholder Letter of Expectations asked BC Hydro to enhance open access tariffs to facilitate direct purchases of electricity by large users. However, BC Hydro was concerned that the Program needed to be modified to address several shortcomings, and sought Government and Commission approval to suspend it. The Commission approved the suspension in early 2012, but directed BC Hydro to file a status report and then bring forward a proposal on a RAP by late March 2014.

The ability to access market priced electricity when prices are low may improve industrial competitiveness, but it also may expose remaining ratepayers to risks. Perhaps the most common "no harm" provisions are exit fees and re-entry rules. Exit fees are imposed by utilities on departing customers if the departure creates, or risks creating, stranded assets. Exit fees are usually calculated as the anticipated revenue from the departing customer less the market value of the "freed-up" electricity. Re-entry rules also build off a utility's obligation to serve: a retail access tariff may require a minimum commitment period by departing customers, or responsibility for any costs directly associated with their return.

A consultant surveyed retail access programs in seventeen utilities across North America for BC Hydro: details on or links to retail access program eligibility, exit fees, and commitment periods are included as an Appendix to BC Hydro's March 28, 2013 submission to the task force. Of the seventeen jurisdictions surveyed, only British Columbia and Newfoundland have no active market access program, although Quebec's would only be triggered by a Hydro Quebec proposal, and no such proposal has ever been made. Eligibility restrictions seem more prevalent in major Canadian utilities than in the US utilities surveyed, and are only completely absent in Alberta and Ontario, which are characterized by competing generation companies bidding into power pools.

An industrial customer retail access program has three main potential benefits:

- It would provide a lower cost and customized pricing and delivery for a segment of a customer's supply, providing a hedge against competitors who have access to lower cost power
- A reduced reliance on BC Hydro for existing and future loads reduces its supply obligations, potentially lowering future rate increases
- Competition would encourage BC Hydro to become more efficient

Conversely, three main potential drawbacks to retail access are:

- It may be difficult to design a program that both delivers material value to participating customers and maintains a “no harm” principle
- Competing uses for the transmission system may limit BC Hydro’s ability to optimize its generation and transmission system, particularly in times of surplus
- Retail access may be inconsistent with the Province’s self-sufficiency and GHG reduction objectives by enabling the costs of these policies to be avoided

Stakeholders identified three potential approaches to retail access: from British Columbia generators other than BC Hydro; market access to both British Columbia and mid-Columbia generation; and market price indexing. Limiting access to intra-provincial generation would not provide the savings associated with currently low Mid C prices.

In addition to possible risk allocation (e.g. exit and re-entry rules) to ensure non-participating ratepayers are not adversely affected, any new retail access program would need to resolve the following issues and deficiencies of the former program:

- Agreement term (e.g. 1, 3, or 5 years?)
- Firm energy and firm transmission (customer’s obligation to deliver?)
- Designated point of delivery (e.g. border or elsewhere?)
- Coordination with Network Integrated Transmission Service Agreement (is title transferred?)
- Carbon liability
- Energy accounting and billing (e.g. does demand charge cover point to point transmission charges?)
- BC Hydro’s obligation, if any, to provide electricity when a retail access customer’s supply or transmission is unexpectedly curtailed.

Conclusion

Retail access is a sound policy concept, in keeping with Government’s objectives to support industries. There is sufficient interest among stakeholders to develop a revised program, perhaps implemented as a pilot with defined limits to its duration and volume. A pilot program would also test rules crafted to avoid stranded costs and possible impacts on other ratepayers, as well as research and identify other conditions that would need to apply to a more permanent program.

Recommendation: BC Hydro should develop a revised retail access program.

6.10 Whether Government Should Take Action on the Commission's 2009 Transmission Service Rate Report

Analysis

The 2009 Commission TSR Report contained eight recommendations. Rate design issues related to revenue neutrality and bill neutrality were key to these recommendations. Bill neutrality was pursued when the TSR was designed because it was determined that industrial customers should not pay more than what they paid at the time. Revenue neutrality was pursued to ensure other rate classes did not bear the costs of TSR implementation. While revenue neutrality and bill neutrality continue to make sense, they limit how much the current rate design can be altered to accommodate changing circumstances.

The inherent trade-offs in the rate design, in conjunction with greatly reduced electricity purchases due to the economic downturn, led to overly generous initial CBL calculations. BC Hydro and industrial customers appear to have addressed the issues related to CBL rules and the persistence of DSM investments through TS 74. Stakeholders agree that the rate design is not perfect, but it does send a conservation price signal that prompts customers to respond.

The Commission's recommendations included a caveat that no changes should be made to the TSR until either BC Hydro adopts Time of Use (ToU) rates or the economy stabilizes. It further recommended that any potential future changes should be considered in consultation with transmission service customers. These principles also remain sound given BC Hydro currently projects an energy surplus. BC Hydro does not appear to have a conservation problem in the near term, so there is little incentive to make drastic changes to a regime that appears to be working.

Conclusion

The Commission's recommendations on bill neutrality and revenue neutrality are valid when BC Hydro returns to load/resource balance. However, there does not appear to be a pressing need to address these rate design issues at this time.

Recent changes to CBL calculations and the persistence of DSM expenditures will strengthen the conservation price signal in the TSR. However, this will need to be verified in the future to ensure the changes have achieved their goals.

Recommendation: Government need not act on the Commission's 2009 Transmission Service Rate report until BC Hydro's surplus has diminished and the effect of the other recommendations in this report can be seen.

6.11 Comparison of Effective Industrial Electricity Costs in Relevant Jurisdictions

Analysis

Appendix 6 contains data which compares BC Hydro's industrial rates to jurisdictions across North America. 'Apples to apples' comparisons are difficult; for example, the 5% rate rider is not included, nor are numerous rate adjustments in other jurisdictions. The data suggests that rates in British Columbia remain low relative to other jurisdictions although they have risen faster in recent years. In 2006 British Columbia had the second lowest rates of 22 jurisdictions and in 2012 British Columbia was fourth lowest. Over this period BC Hydro's average industrial rates increased by over 40 per cent which is amongst the highest rates of increase over that period.

Conclusion

British Columbia's comparative advantage in industrial rates has diminished in recent years.

6.12 Whether Time of Use and Interruptible Rates Would be Appropriate for Industrial Customers

Analysis

While both ToU and interruptible rates can reduce the need for peaking capability the difference is that ToU relies on a less certain and slow price response, while utility directed interruptible rates can be implemented quickly and with greater certainty.

Industrial customers welcomed the idea of ToU and interruptible rates as an option to offset increases in rates, but cautioned that there were many factors that needed to be considered. The lack of use of BC Hydro ToU rate Schedule 1825 appears to be a result of the complexity of the rate in trying to address these factors. The need for customers to invest to be able to participate in ToU is an entrance barrier that needs to be overcome, requiring significant potential benefits and certainty over the time frame needed to recover the investment.

Stakeholders who were not industrial customers recognised that in some respects ToU is similar to energy conservation in that customers who adopt ToU reduce BC Hydro's cost of acquiring new peaking resources, reducing costs to all customers, and reducing the impact on the environment.

Some industrial stakeholders said they were not at all sure that the difference in either BC Hydro's costs or the short-run spread in market prices in neighbouring jurisdictions would allow sufficient difference in ToU rates between low cost periods and high cost periods to be attractive enough to potential customers.

Industrial customers who might be interested in interruptible rates could face initial costs to invest in equipment to make interruptions possible and would likely face additional costs whenever they were interrupted. The number of interruptions a customer might face in a given time as well as the duration of each interruption would likely be factors increasing interruption costs. The reduction in rates or payments in return for interruptions will have to compensate the customer for these costs if there is to be any acceptance of the interruptible rate by industrial customers.

BC Hydro's ability to interrupt customer loads can meet increased reserve requirements, possibly reducing BC Hydro's costs. For an interruptible rate to be feasible, the savings to BC Hydro must exceed the incentives required to attract a potential customer.

Conclusion

ToU and interruptible load rates may provide cost relief to some industrial customers and reduce BC Hydro costs. There are many variations of these rates in other jurisdictions. Careful program design will help avoid unintended consequences, so there should be detailed consultations and possibly use of pilot programs.

Recommendation: BC Hydro should work with its industrial customers and the Commission to develop options that take advantage of industrial power consumption flexibility, such as time of use rates and interruptible rates.

6.13 Utility Interconnection Timelines

Analysis

Delays in transmission availability are cited as an obstacle to industrial development in British Columbia. BC Hydro's transmission interconnection process is perceived as slow, cumbersome, unresponsive and expensive by customers. The risk of missing in-service dates could drive new industries to self-supply rather than take grid service.

Interconnection processes in British Columbia, like those in most jurisdictions, are governed by tariffs. While BC Hydro is subject to timelines on its open access transmission tariff, it is not on its tariff to connect large industrial customers. Fixing timelines for potential new industrial electricity customers could remove a source of investment uncertainty from projects.

Information on connection timelines in other jurisdictions has been limited. Alberta's Electricity System Operator estimates a typical timeline of 24-36 months, but timelines can vary with project complexity, the number of projects active, stakeholder impacts, etc. Bonneville Power Administration staff indicate that utilities in the Pacific Northwest do not have fixed interconnection timelines for industrial interconnections. Even with better information on other jurisdictions, the topography and amount of radial transmission in British Columbia may complicate transmission development in ways that make it difficult to directly compare timelines in British Columbia to other jurisdictions.

Fixed interconnection timelines would likely require that utilities devote more resources to the interconnection process or that they take on additional risks associated with delivery or less comprehensive analysis when multiple connection requests happen at once. Regulatory and consultation process requirements may mean any timeline is no longer under the utility's control. If the utility staffs up to deal with a rush of interconnection requests, it becomes difficult for the regulator to assess whether costs are appropriately allocated after the requests slow down. There is a risk of upward pressure on rates. If utilities do not devote additional resources to meet timelines, they must accept the risk that either they will not meet the timeline (and incur any penalty for failing to meet it), or reliability or cost overrun risks due to lack of study.

Public-private partnerships for the planning and development of transmission might offer utilities an opportunity to reduce their exposure to project cost risks as long as there are safeguards to ensure standards are met. Natural gas generation sited nearer to load may, in some cases, be another way to limit costs and risks associated with interconnection by limiting the need for transmission reinforcement.

Conclusion

Limiting interconnection timelines would be useful to new industrial customers, but would involve costs to ratepayers and/or potential risks to utilities. It is not clear that current practices optimally weigh this trade-off. Careful consideration must be made of the appropriate targets and processes and the potential costs and benefits of any change.

Recommendation: BC Hydro should benchmark and publicly report on its transmission interconnection turnaround times for both new generation and new load.

6.14 Government Approaches to Attracting and Retaining Industrial Load

Analysis

Government has the ability to intervene by modifying interconnection policy or by setting rates to attract or retain industrial customers. British Columbia has done so in the past, notably with the Power for Jobs program in the 1990s. Ontario has a program to provide price relief for up to 5,000 GW.h per year to new or expanding loads to recover load lost through the 2008 economic downturn.

In its early days, the Bonneville Power Administration served several industrial customers directly, but has not issued new contracts of this type. The Government of Quebec has legislative authorities to set electricity rates for certain customers and to grant load allocations at certain rates. It has apparently negotiated deals with large industrial customers in the past, offering lower electricity rates for things like employment guarantees, and may continue to do so.

Newfoundland and Labrador's Electrical Power Control Act (EPCA) specifies that rates should promote the development of industrial activity in Labrador, and specific industrial customers have lower rates assigned to them, offset by specific charges. However, the Public Utilities Board and not the government administers the EPCA and the charges. It's not clear what role government had in setting these.

The Government of Manitoba works with potential new large electricity customers who are considering locating in the province, but not on rate or interconnection issues. These are the responsibility of the Manitoba Public Utilities Board and Manitoba Hydro. If a new customer has a concern with Manitoba Hydro's execution of its policies or timelines, they can raise the issue through government.

One risk of using special electricity rates to encourage specific kinds of load arises from the fact that rate allocation is typically zero-sum: the revenue shortfall from one group of customers must be made up somewhere else. One option is to fund targeted rate cuts through a reduction in the dividend, but otherwise the revenue would have to come from other customers. Cross-subsidization of a favoured customer group by another can impact the disfavoured group's competitiveness. For example, a rate intended to attract new industrial load could shift costs to an existing customer and cause that customer to go out of business, taking its associated jobs, investment, tax revenue, and load with it.

Tax policy may be an alternative to using interconnection cost or electricity rates as a means to attract load. Few jurisdictions in North America apply state or provincial sales taxes to industrial electricity consumption; Manitoba has lower provincial sales tax rates on some trade-exposed industries, like mining and manufacturing. This approach would avoid cross-subsidization, and the costs of meeting government priorities would remain with the taxpayer. Government would assess whether the socio-economic benefits of the project justified foregoing tax revenues.

Conclusion

Different jurisdictions each face their own unique geographic, market, and political pressures and have different approaches to policy as a result.

7. <u>Additional Issues for Government Consideration</u>

There were three issues that arose during the consultation process that fell under the "other considerations" provisions of the Review mandate: BC Hydro's regulatory account balances, its energy surplus, and British Columbia Utilities Commission (Commission) capacity. We include them here to ensure the full range of stakeholder views are considered by Government.

7.1 BC Hydro Regulatory Account Balances

Almost every stakeholder referred to BC Hydro's large regulatory account balances. Industrial customers generally expressed concerns about how much additional cost they would bear to pay down the accounts over time. We benefitted from meeting with BC Hydro staff to improve our understanding of the accounts.

Recommendation: BC Hydro should host a workshop on its regulatory accounts to improve understanding of the balances and the provisions in place for dealing with them.

7.2 BC Hydro Energy Surplus

BC Hydro projects an energy surplus until 2021 given current supply and demand forecasts. Weak export markets and slow near-term load growth limit BC Hydro's options to reduce the surplus. The BC Hydro IRP includes measures to moderate current spending on demand side measures and to delay or cancel some independent power producer contracts where development has stalled. BC Hydro recently cancelled ten electricity purchase agreements, and delayed a further nine.

Recommendation: BC Hydro should ultimately bring its surplus management plan forward in a Commission-led process if the management plan proposes to put additional costs on ratepayers or transfer costs between ratepayers.

7.3 British Columbia Utilities Commission Capacity

While stakeholders generally support a return to Commission regulation of BC Hydro rates and projects, many express reservations about the Commission's capacity to deliver clear, timely decisions. Similar concerns are cited as reasons for the growth in government's use of its regulatory powers to displace Commission jurisdiction.

In the past decade, the number of Commission staff has increased by about 70 percent (from 22 in 2003/04 to 38 in 2012/13) and its expenditures by about 84 per cent (from $4.3 million to $7.9 million). The *Clean Energy Act (CEA)* has introduced complexity, the number of regulated utilities has grown with the addition of district energy systems, and the Commission's duties have expanded to include such topics as First Nations consultation adequacy, mandatory reliability standards, and natural gas customer choice. Nonetheless, some stakeholders consider the upward trend in staffing and expenditures outpaces the increases in the Commission's responsibilities.

Recent Commission initiatives to enhance regulatory efficiency include a Streamlined Review Process, a proposed Scaled Regulatory Framework and Guide for thermal systems, and a management committee to address compliance and reporting directives. In addition to staffing levels and expenditures, the Commission includes several performance indicators in its Annual Reports. Additional indicators that could be tracked are cycle times—the time between receipt of an application and the issuance of a decision—for applications requiring oral hearings, written hearings, and negotiated settlements. (Cycle times for these applications were graphed in detail in earlier Annual Reports.) This information would help support or refute concerns expressed by many stakeholders over what they perceive as increasingly prolonged cycle times. For quasi-judicial agencies like the Commission, expediency in processing applications can bring an increased risk of legal challenges.

Like other utility regulatory tribunals competing with higher-paying utilities for skilled staff, the Commission faces recruitment issues. Of the 38 Commission staff in June 2013, only four have been with the Commission for more than ten years, and 22 of the 38 have been with the Commission for less than four years. Some stakeholders raised concerns about the balance between the number of full time (1) and part time (10) Commissioners. Part time Commissioners are paid by the day, yet in 2012/13 three received remuneration comparable to that of a full time Commissioner. Most other energy utility tribunals have a more balanced complement of full vs. part time commissioners.

While periodic adversarial public hearings can provide useful detailed information in determining revenue requirements, they can encourage utilities to "gold plate" their applications, and regulators and interveners to stray from their proper role of utility oversight towards utility management. Negotiated settlement processes and multi-year performance based regulation usually result in lower costs, more timely decisions, and better outcomes for ratepayers than frequent hearings. Incentive regulation rewards utilities for finding cost savings without affecting safety and reliability. Fortis BC Energy Inc. is seeking approval for a five year performance-based rate plan through a negotiated settlement; this proceeding should enable current Commissioners and staff to become comfortable with these approaches.

The Commission was given authority to require long term resource plans in 2003, in the expectation that these plans would lead to efficiencies in or exemptions for subsequent project, conservation expenditure, and revenue requirement reviews. Under the *CEA*, the 2013 BC Hydro Integrated Resouce Plan (IRP) has been submitted to the Energy Minister and was open for public comment. While the fate of the IRP is yet to be determined, it is bound to prompt requests for changes to those sections of the *CEA* that increase costs to customers, and a renewed role for the Commission.

To capture efficiencies going forward, detailed information on BC Hydro's revenue requirements could be submitted, tested, and adjudicated in a one, or perhaps two, year revenue requirements application. This detailed information base would then set the stage for a multi-year performance based rate application, aided by a new or amended IRP that focuses on least cost planning and cost reduction. A more efficient regulatory regime should emerge, enabling BC Hydro to emphasize productivity improvements, instill a productivity improvement culture, and minimize costs to customers, while ensuring continued safety and reliability. Separate proceedings to review Tariff Supplement 6, retail access, and possible refinements to industrial time of use rates, interruptible rates, and the transmission service rate would proceed commensurate with BC Hydro, Commission, and customer priorities and resources.

Recommendation: An independent review of the Commission should be undertaken to evaluate resource needs, review processes, and performance.

Appendices

Appendix 1: Overview of BC Hydro's Industrial Customers

BC Hydro's 2013/14 Load Forecast estimates industrial customers will purchase approximately 17,032 GW.h of electricity. This accounts for approximately 32 per cent of BC Hydro's total domestic sales. Transmission Service customers (i.e., customers that take service at 60 kV or higher) such as chemical producers, pulp and paper mills and mines comprise approximately 77 per cent of the total industrial sales volume. Large General Service (LGS) customers (i.e., customers that take service at 60 kV or lower) such as sawmills, wood manufacturers and gas producers consume the remainder.

BC Hydro breaks down its transmission voltage customers in to four sectors: Forestry; Mining; Oils and Gas, and Other. Forestry is further broken down further in to three subsectors: Chemicals; Pulp and Paper; and Wood Products. Mining is further broken down in to two subsectors: metals and coal. BC Hydro aggregates its LGS distribution customers in to one group regardless of industry sector.

Forestry

Chemicals Subsector

The chemicals sector consists of companies that produce bleaching agents for the pulp and paper industry, and cleaning agents for the oil and gas industry and for water purification. BC Hydro projects the industry will constitute 9.2 per cent of total industrial sales in 2013. The key industry drivers are the domestic and global pulp and paper industry as well as oil and gas activity. Electricity comprises approximately 55 per cent of the industry's production costs on average.

Pulp and Paper Subsector

The pulp and paper sector consists of companies that produce newsprint, coated and uncoated paper, unbleached kraft pulp, bleached chemical pulp, thermo-mechanical pulp and marked bleached thermo-mechanical pulp. The industry is concentrated primarily in the southwest and central interior. BC Hydro projects the industry will constitute 32.1 per cent of total industrial sales in 2013. The key industry drivers are pulp and paper market prices, the US economy and the global economy. This sector uses biomass to self-generate some of their power requirements, the amount of which varies between different operations. Electricity comprises approximately 12 per cent of the industry's production cost, although there can be large variances between mills based on the age and efficiency of the equipment, the technology used, and the product produced.

Wood Products

The wood products sector consists of companies that produce dimensional and structural lumber, oriented strandboard, medium density fibreboard, plywood, fuel pellets and other specialty products. There are over 100 mills located in every region of the province. BC Hydro projects the industry will constitute 14.0 per cent of total industrial sales in 2013. The key industry drivers are domestic housing starts/repairs, US housing starts/repairs, Chinese demand and access to saw logs due to the impact of the mountain pine beetle. Electricity comprises approximately 2 per cent of the industry's production costs on average.

Mining

Metals Subsector

The metal mining sector includes copper, gold, silver, molybdenum, lead and zinc extraction and processing. BC Hydro projects the industry to constitute 17.4 per cent of total industrial sales in 2013. The key industry drivers are prices for copper, gold, and molybdenum, Government policies that support resource development, tax regimes, supporting infrastructure, and access to capital. Electricity comprises approximately 12 per cent of the industry's production costs on average.

Coal Subsector

The coal subsector consists primarily of metallurgical coal exports with a small volume of thermal coal. Most of the production comes from open pit mines located in the southeast, although northeast coal production is expected to expand. BC Hydro projects the industry will constitute 3.8 per cent of total industrial sales in 2013. The key industry drivers are global demand for steel, social license to operate (particularly related to First Nations), mining construction costs and infrastructure constraints. Electricity comprises approximately 8 per cent of the industry's production costs on average.

Oil and Gas

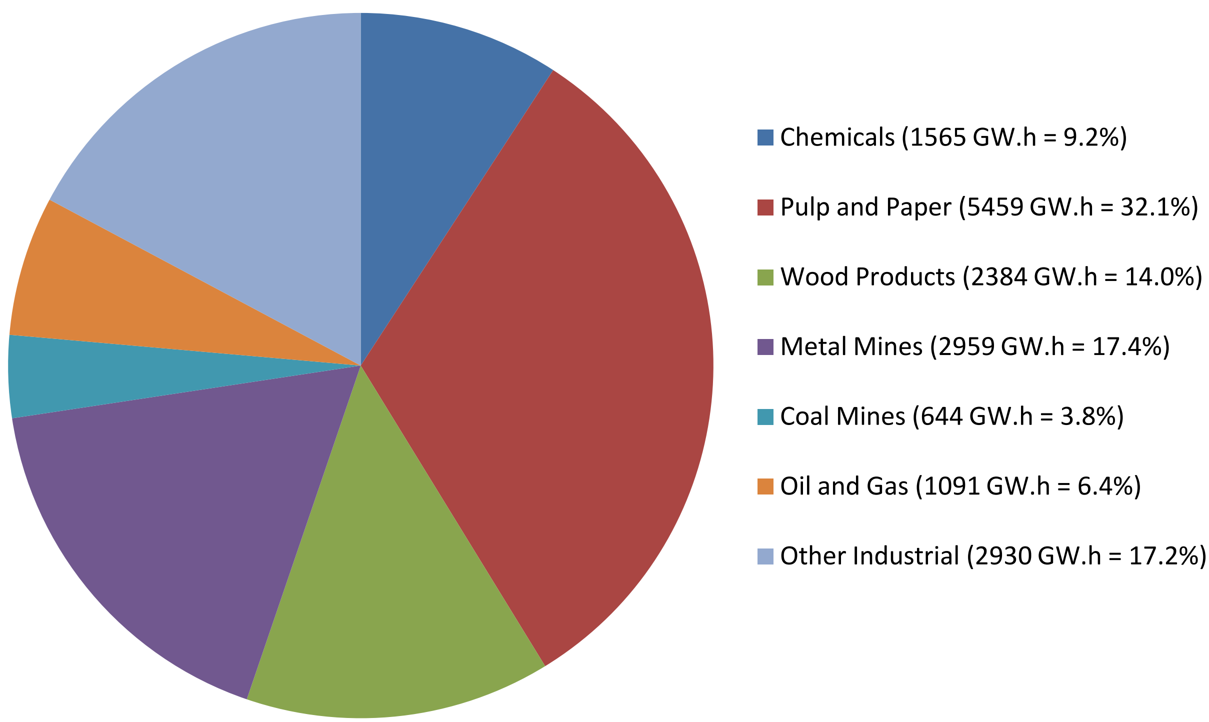
The oil and gas industry includes oil pipelines, oil refineries, gas pipelines and gas processing plants.

BC Hydro projects that the industry will constitute 6.4 per cent of total industrial sales in 2013. Key industry drivers are North American natural gas prices, development of the liquefied natural gas industry, technological development, government regulation, social license and global competition. Electricity comprises approximately 15 per cent of the industry's production costs on average.

Other Industrial Customers

BC Hydro has other industrial customers that do not fit in to one of the above subsectors, such as cement companies and automotive parts manufacturers. BC Hydro forecasts this group of industrial customers will comprise 17.2 per cent of total industrial sales in 2013. Key industry drivers are global and provincial economic growth, North American construction activity and increased regulatory oversight that may affect competitiveness.

Fig. 1: 2013/14 Industrial Power Sales Forecast in Annual Gigawatt Hours (GW.h)



Appendix 2.1: Terms of Reference for the Industrial Electricity Policy Review

1. Background

The British Columbia Hydro and Power Authority (BC Hydro) offers electricity service to approximately 120 transmission voltage customers under the Industrial Tariff and the Transmission Service Rate (TSR). Transmission voltage means that the customer interconnects to BC Hydro's grid at 69 kilovolts or greater through its own onsite substation. There are also a small number of large distribution customers who would also be considered "industrial" despite not interconnecting at transmission voltage.

The British Columbia Utilities Commission (Commission) approved the Industrial Tariff in 1991. It was implemented at a time when BC Hydro's electricity supply was getting tighter and new industrial load, or expansion of existing load, was not occurring. Economic conditions have evolved considerably since that time.

Following the 2002 Energy Plan, BC Hydro implemented the TSR, a two-tiered rate structure to promote energy efficiency and retail access. The Commission reviewed the program and submitted a report entitled, "British Columbia Utilities Commission Report to Government on BC Hydro's Transmission Service Rate Program" (Commission Report) on December 31, 2009.

The Commission acknowledged the TSR sent marginal price signals, but determined its contribution to conservation was inconclusive due to the large reduction in demand as a result of the 2008 economic downturn. It also noted that no industrial customer had pursued retail access up to the point when it released its report. The Commission recommended some changes to the design of the rate, but advised Government not take immediate action until the economy recovered.

Commission and intervener questions in the Dawson Creek/Chetwynd Area Transmission (DCAT) project as well as standalone policy issues (i.e., retail access, customer-owned generation, etc.) have reinforced the need for a review of Government's approach to industrial electricity policy. Accordingly, on April 3, 2012, Government committed to undertaking a public process to consider policy issues pertaining to BC Hydro's industrial customers.

2. Creation of Industrial Electricity Policy Review and Task Force

The Minister of Energy, Mines and Natural Gas (Minister) hereby authorizes an Industrial Electricity Policy Review (Review) for BC Hydro's transmission voltage Customers as set out in these Terms of Reference.

Further, the Minister appoints a task force consisting of three members to implement the Review:

- Mr. Chris Trumpy, Task Force Chair;
- Mr. Peter Ostergaard, Task Force Member; and
- Mr. Tim Newton, Task Force Member

3. Purpose

The purpose of the Review is to examine the current industrial electricity policy and regulatory framework, identify policy issues affecting transmission service customers, consult with affected stakeholders, conduct an integrated analysis, and make recommendations to the Minister on potential changes to the current policy and regulatory framework.

4. Task Force Mandate

The task force is directed to make recommendations on the following:

A. the extent to which the transmission voltage rates may be used to contribute to provincial electricity conservation objectives, and the changes, if any, that would be appropriate to those rates or the current regulatory framework to achieve those objectives;

B. the extent to which the transmission voltage rates may be used to contribute to provincial economic development objectives, and the changes, if any, that would be appropriate to those rates or the current statutory and/or regulatory framework to achieve those objectives;

C. the extent to which the transmission voltage rates may be used to contribute to provincial environmental policy objectives, and the changes, if any, that would be appropriate to those rates or the current regulatory framework to achieve those objectives;

D. the implications of pursuing each objective in relation to the other two; and

E. Principles to guide the Province concerning the use of its directive powers related to the Commission and/or BC Hydro in order to pursue provincial policy objectives.

The task force is to consider the following while developing its recommendations:

1. the appropriate allocation of BC Hydro's incremental and embedded costs, including generation and transmission costs, when new customers request service or existing customers request increased service;

2. whether and postage stamp rates remain appropriate for customers taking service at transmission voltage rates;

3. whether end-use rates are appropriate for customers taking service at transmission voltage rates;

4. whether retail access rates would be appropriate for customers taking service at transmission voltage rates;

5. whether it would be appropriate to act on any of the recommendations contained in Commission Report on the TSR;

6. how current transmission voltage rates compare with rates for similar types of service in other jurisdictions in Canada and the Western Electricity Coordination Council area; and

7. any other considerations related to current or future operation of transmission voltage rates the task force determines necessary in making its recommendations.

Task Force Operations and Procedure

The Review will focus on high-level industrial electricity policy issues in order to provide recommendations on overall policy framework to Government by July 31, 2013.

The task force shall seek input from stakeholders with a current or future interest in BC Hydro's transmission voltage rates. While the task force has discretion over how it chooses to engage stakeholders, a consultation record must be made public for all Review participants at the completion of each phase, unless a stakeholder explicitly requests its input to be kept confidential.

The Task Force will have access to technical expertise from the Ministry of Energy, Mines and Natural Gas, BC Hydro and the Commission as required. The Task Force also has the discretion to create any consultative bodies and/or retain independent technical advice it deems necessary to ensure it receives the information it requires to meet the objectives set out in these Terms of Reference, subject to its available budget.

The Ministry of Energy, Mines and Natural Gas will distribute a summary of the Province's industrial electricity policy to provide foundational information on the matters set out in Section 4 A-D of these Terms of Reference no later than February 8, 2013.

Reporting

The Task force shall make the following documents to the public:

1. Consultation Summary covering meetings between January and April 2013, subject to permission of participants;

2. Written submissions from stakeholders, subject to permission from document creator(s);

3. Interim Report; and

4. Final Report

Secretariat Support

The Ministry of Energy, Mines and Natural Gas will provide secretariat support to the task force.

Appendix 2.2: Text of Minister Bill Bennett's Letter Expanding the Task Force's Mandate

June 19, 2013

Mr. Chris Trumpy
Chair
Industrial Electricity Policy Review Task Force
2083 Neil Street
Victoria, BC V8R 3E1

Dear Mr. Trumpy:

On January 13, 2013, Honourable Rich Coleman, the previous Minister of Energy, Mines and Natural Gas, issued a Terms of Reference (ToR) for the Industrial Electricity Policy Review (Review). The ToR appointed a task force consisting of you, Mr. Peter Ostergaard and Mr. Tim Newton. I understand the task force is currently working on its Interim Report. As the recently appointed Minister of Energy and Mines, I would like to thank you for your work to date as well as add to the Review ToR.

I am aware of the content included in the task force's draft Consultation Summary. There appear to be several issues that emerged from the task force's consultation process that were either not explicitly noted in the ToR or require further analysis. These include, but are not limited to:

- The feasibility of "Time of Use" pricing to provide capacity benefits to BC Hydro and financial benefits to industrial customers with flexible operations;
- Industrial customer concerns related to the time and costs associated with BC Hydro interconnecting new industrial loads;
- Mixed views on the appropriateness of a threshold above which new industrial customers would pay the marginal cost of energy supply versus spreading costs across BC Hydro's entire rate base; and
- The feasibility of different retail access models (i.e., enabling industrial customers to meet some or all of their electricity needs from a supplier other than BC Hydro).

.../2

I believe it would be beneficial for the task force to explore each of these issues in further detail and include the task force's conclusions in its Interim Report. Accordingly, I am supplementing the Review ToR as follows:

1. The task force is to review current models of industrial "Time of Use" pricing from relevant jurisdictions and comment on their effectiveness and applicability to British Columbia (BC). This review is to stay strictly within the bounds of industrial customers only;

2. The task force is to review utility interconnection policies and timelines from relevant jurisdictions, and determine how they compare to BC Hydro's current approach and performance;

3. The task force is to consult with low-cost, hydroelectric-based jurisdictions to better understand their approaches to interconnecting large loads as well as to identify what, if any, role Government plays in the process; and

4. The task force is to review how retail access policy is applied in relevant jurisdictions, and comment on their effectiveness and applicability to British Columbia.

I note that July 31, 2013 is the current end date for the Review. I do not think it is reasonable to expect the task force to take on these additional tasks given the short notice involved. Consequently, I will extend the Review end date to October 31, 2013. I trust this will give the task force sufficient time to finish off its original tasks as well as address the new ones.

Please contact Mr. Les MacLaren, Assistant Deputy Minister, Electricity and Alternative Energy Division, if you have any further questions. Mr. MacLaren can be reached at 250-952-0204 or les.maclaren@gov.bc.ca.

Thank you, again, for taking on this important work.

Sincerely,

Bill Bennett

Bill Bennett
Minister

Appendix 3: Task Force Process and Consultation Summaries

The Terms of Reference (ToR) directed the task force to, "seek input from stakeholders with a current or future interest in BC Hydro's transmission voltage rates." The ToR also directed the task force to produce a Consultation Summary of stakeholder meetings and their submissions.

The task force met with any stakeholder that expressed interest. It further directed its secretariat to pursue specific stakeholders to ensure balanced input. The task force elected to consult with stakeholders through informal face-to-face meetings.

Early stakeholder input suggested it would be useful for the task force to elaborate on its mandate. Accordingly, the task force published a series of issue papers to stimulate dialogue with stakeholders. The task force provided stakeholders an opportunity to submit written comments on the issue papers and a second round of comments to respond to the submissions of other stakeholders.

The task force issued a Draft Consultation Summary of verbal and written comments from stakeholders, excluding BC Hydro. It subsequently prepared a Summary of BC Hydro comments. Both consultation summaries and a list of stakeholders are included below. Following consultation with stakeholders on the additional ToR given on June 19, the task force prepared an addendum to the Draft Consultation Summary to summarise additional verbal and written comments received.

The task force provided stakeholders the opportunity to comment on the Interim Report prior to finalizing the Report. The Minister will have the discretion on the release of the recommendations to the public.

The task force expresses its sincere thanks to all those who participated in this Review for their cooperation and contributions.

Appendix 3.1: Industrial Electricity Policy Review Task Force Initial Terms of Reference Consultation Summary

Introduction

The Terms of the Reference (ToR) for the Review directs the task force to consult with interested stakeholders and make public a consultation record and a Consultation Summary (Summary). The purpose of the Summary is to capture and synthesize verbal and written stakeholder input into the Review. This document revises and updates a draft summary sent to stakeholders in early May 2013. A separate Summary describes BC Hydro's views on the main issues. An addendum describes further stakeholder comments following the addition of four assignments issues on June 19.

In January 2013, the Ministry of Energy, Mines and Natural Gas advised interveners from the Dawson Creek/Chetwynd Area Transmission Reinforcement Certificate of Public Convenience and Necessity proceeding that the Ministry of Energy, Mines and Natural Gas would appoint a task force to undertake the Review. Interested stakeholders were invited to meet with the task force and/or provide written submissions for consideration.

The task force held 27 meetings with 17 different stakeholders between January 17 and May 31, 2013. It also received 24 submissions providing general comments on industrial electricity policy and specific comments on a series of papers issued for discussion purposes. A complete list of stakeholders who met with and/or submitted materials to the task force is included in Appendix 3.3

The task force published a series of issue papers based on its ToR to spur discussion and debate with and amongst stakeholders. The Summary includes sections addressing all of the issue papers as well as an additional section that addresses other related issues brought up by one or more stakeholders. Readers are encouraged to review specific written submissions to identify specific stakeholder views. They can be found at http://www.empr.gov.bc.ca/EPD/Pages/IndustrialElectricityPolicyReview.aspx. They have also been distributed via email to those who requested them.

The views in this document are intended to capture the written and verbal comments, opinions and positions from stakeholders as they were presented. They do not represent the task force's position or Government policy.

Economic Development

Most stakeholders expressed concerned about the rising cost of electricity supply and indicated that access to safe, reliable electricity supply at the lowest reasonable cost supports economic development. Industrial stakeholders acknowledged that development should minimize environmental impacts as much as possible, but that the current policy and legislative framework does not strike the appropriate balance between environment and economic development objectives. One stakeholder noted that only one of the 16 provincial energy objectives listed in the *Clean Energy Act (CEA)* relates to economic development. Another emphasized that minimizing environmental impact should be considered along with cost.

Industrial customers indicated that most electricity-intensive industries in British Columbia are trade-exposed price-takers that cannot pass increased electricity costs through to their respective customers. This means that increased electricity costs must be offset through operational efficiencies that are getting more difficult to find or reduced returns that may lead to decisions to invest outside British Columbia. Large rate increases over a relatively short period of time may make some industrial customers operations uneconomic. Industrial customers indicated this would cause a ripple effect through the economy (particularly in the forest sector).

Stakeholders did not feel that British Columbia continues to be a low-cost electricity jurisdiction. Industrial customers indicated that BC Hydro's industrial rates in some industry sectors are no longer competitive. They also made the point that BC Hydro's relatively low, cross subsidized residential rates are irrelevant when considering the competitiveness of industrial rates in British Columbia. Many stakeholders indicate that BC Hydro's low cost electricity advantage has been, and will continue to be, eroded due to BC Hydro's capital spending plans and the eventual recovery of the deferral accounts. Industrial customers felt that any provincial energy policy needs to recognize the inherent link between the level of electricity consumption and economic activity.

There was general agreement that taxpayers, rather than ratepayers, should bear the costs of achieving Government economic development objectives.

Industrial stakeholders from different sectors stated that shifting industrial demand from peak periods has a value to BC Hydro. Voluntary curtailment or setting up economic incentives for industrial customers to shift their usage could help address BC Hydro's projected capacity constraint at potentially lower cost than constructing new projects. Industrial customers provided various options for consideration.

Some industrial stakeholders expressed concerns at how long it takes BC Hydro to move through the transmission interconnection process from initial system studies to the project entering service. This has a material impact on what energy supply option an industrial customer would choose (if the customer has an option). One stakeholder suggested exploring public-private partnerships to undertake transmission projects.

Contribution Policy (Generation)

Most stakeholder input concerning this issue related to the 150 MV.A threshold that has the potential to trigger a contribution for the full marginal cost of generation. The majority of stakeholders, particularly industrial customers, argued that the 150 MV.A threshold is arbitrary and open to "gaming" (for example, a new load requesting service at 149 MV.A and expanding later). Industrial customers argued that the 150 MV.A threshold was unnecessarily punitive for most larger projects and could serve as a deterrent to investment.

All stakeholders recognized the underlying rationale for the 150 MV.A threshold was to prevent large electricity users from diluting BC Hydro's heritage generation resources, thereby driving up rates for other customers. However, the majority of stakeholders indicated that new customers should receive some benefit from BC Hydro's embedded cost resources and that the 150 MV.A threshold should be removed or changed. A minority of stakeholders felt the transmission extension aspects of the tariff were sufficient provided the 150 MV.A threshold was addressed. However, these actions were contingent on implementing an updated contribution policy that appropriately balances benefits and risks to existing and new customers. There were different views how this could be achieved.

Some stakeholders indicated that BC Hydro could bring forward an updated tariff to the British Columbia Utilities Commission (Commission) for review and approval. Others argued that Government should undertake a comprehensive cost/benefit analysis and set a series of economic tests when large industrial customers seek service from BC Hydro to determine if a project is in the provincial public interest, even if it caused higher rates for BC Hydro customers generally. Stakeholders presented options, but there was no agreement on the best approach.

A minority of stakeholders indicated the current generation contribution policy is appropriate. One stakeholder indicated the industrial service should not be offered below embedded cost, which is currently a feature of the Tier 1 of the Transmission Service Rate (TSR). This stakeholder also indicated that the 150 MV.A should be lowered.

Environmental Policy

There was general agreement that British Columbia-based corporations, including BC Hydro, should comply with the provincial environmental regulatory regime (e.g., environmental assessment, particulate emissions, GHG mitigation, etc.). However, there were differences of opinion beyond this basic concept.

Industrial customers indicated that BC Hydro should operate like any other utility. Accordingly, BC Hydro should not be subject to legislative obligations that do not apply to other British Columbia-based utilities or industries. Industrial customers argue that BC Hydro should not be used to achieve environmental or social policy objectives because doing so transfers costs from taxpayers to ratepayers. Government should use other legislative or fiscal tools at its disposal to achieve these objectives.

Most non-industrial stakeholders support British Columbia's legislated GHG reduction targets and the policies put in place to help achieve them. Some indicate Government should maintain BC Hydro's commitment to 93% generation standard and that "clean and renewable" should exclude all natural gas-fired generation. They also indicate BC Hydro should not rely on fossil-fuel generation to serve its customers now and in the future. Most industrial stakeholders are driven by electricity cost and felt that the 93% clean generation standard inhibits BC Hydro from acquiring lowest cost resources.

Discussions related to carbon pricing also demonstrated differences of opinion between stakeholders. Some industrial stakeholders indicated the carbon tax places British Columbia-based companies at a disadvantage to their competitors. Most stakeholders acknowledge there will be a price on carbon going forward. However, there was no agreement on what the short or long-term price of carbon should be.

This discrepancy has a material impact on what BC Hydro would consider "low cost" when it next procures energy to meet its needs. Industrial and some non-industrial stakeholders indicate that combined-cycle gas turbines are the least cost option for flexible energy and capacity, while many non-industrial stakeholders indicate renewable Independent Power Projects (IPPs) are cost-competitive when the lifecycle price of carbon is taken into account.

Both industrial and non-industrial stakeholders indicated that Government's environmental policies/objectives related to energy (i.e., treatment of GHG emissions) are unclear, and in some cases, conflict with one another. There was agreement that environmental policy should be clear, consistent and predictable so the private sector can make informed investment decisions. Stakeholders noted three examples where inconsistencies exist

1. Current government policy and legislation would require gas-fired generation to pay both the carbon tax and offset GHG emissions;
2. Current legislation permits new gas-fired generation for liquefied natural gas export facilities, but not for domestic consumption;
3. The lack of carbon tax on imported electricity understates its true cost giving it a competitive advantage over domestic clean energy generation

Regulatory Approach

Stakeholders generally agreed that Governments have historically used their legislative powers to achieve provincial policy goals through BC Hydro. Industrial stakeholders indicated that this has led to increased costs to ratepayers without sufficient due diligence. Most stakeholders argue BC Hydro should be subject to stronger regulatory oversight by the Commission. Stakeholders understand that there may be times where Government exercises its legislative powers to pursue the greater public interest, but indicate this should be a relatively rare event so that Commission authority is not pre-empted. One noted that directives should be transparent, based on public information, and consistent with BC Hydro's mandate to provide reliable power at low cost.

There was also general agreement that Government should set clear, easily understood policies and let the regulator regulate. Stakeholders understood the intent of the provincial energy objectives in the *CEA* was to ensure provincial policy objectives were considered in Commission decision-making. However, some stakeholders believe it has actually confused the decision-making process because Government did not provide guidance on the relative importance of each objective. This has increased the scope of some Commission proceedings which led to longer decision-making processes with less definitive outcomes.

Some stakeholders expressed concern about the capacity of the Commission to take on new or expanded roles. One stakeholder also questioned the use of negotiated settlements when setting rates, because there is a tendency for BC Hydro and its ratepayers to minimize short-term rate increases by deferring impacts to the future. There was also a suggestion that the Commission could undertake additional fact-finding and provide independent, non-binding advice to ensure Government can make informed decisions.

Retail Access

The majority of stakeholders said that it would be beneficial to have some form of retail access in British Columbia. Further, some indicated it would be worthwhile to explore retail access on a pilot basis. Stakeholders understood that any version of retail access needs to have rules in place (e.g. exit fees, commitment periods) to protect those ratepayers who cannot take advantage of the program to ensure they did not absorb additional costs due to industrial customers exiting and re-entering the BC Hydro system.

Some stakeholders opposed the concept of retail access due to risks to BC Hydro ratepayers. One stakeholder also noted that BC Hydro should capture market differences for the benefit of all ratepayers rather than letting members of one rate class capture this value.

Stakeholder input identified three potential approaches to retail access:

1. Retail access from British Columbia based generation other than BC Hydro's;
2. Retail access within British Columbia and market access to Mid-Columbia; or,
3. Market price indexing

The first model envisions a retail market within British Columbia where industrial customers have the ability to acquire energy and/or capacity from new or existing IPPs. The second model encompasses the first and also provides market access outside of British Columbia. The third model would see BC Hydro index a portion of an industrial customer's energy purchases to the Mid-C market which would eliminate the need to secure transmission.

Some stakeholders indicated the first model would provide industrial customers with competitively priced energy supply now and in the future should BC Hydro rates increase. It also would have the benefit of providing a potential market for domestic clean and renewable IPPs. Industrial customers' primary interest is accessing the lowest cost supply. Some stakeholders also indicated that a limited pilot program using BC Hydro's suspended Retail Access Program (RAP) would be a low risk means to determine whether the program can function, or requires revisions.

Transmission Service Rate and Conservation

Industrial and some non-industrial stakeholders believe the TSR is working as it should. The price signal appears to have worked since most industrial customers on the rate have reduced consumption to just above 90% of their customer baseline loads (CBLs). Further, recent changes limiting the length of time customers can benefit from a demand side measures investment should maintain the tier two price signal to conserve.

Other non-industrial stakeholders indicate the rate is flawed and has achieved most of what it can achieve due to the way the rate is designed. There is a perception that customers "game" the rate to ensure the vast majority of their energy consumption comes from Tier 1. Further, they indicate that it is difficult to quantify how much conservation actually occurs. The design of the rate (specifically revenue and bill neutrality) makes it difficult to change short of completely re-designing the rate.

There were also a small number of stakeholders concerned that the current operation of the rate would not suit their specific business type.

There was general recognition that conservation is preferable to adding new supply up to the avoided cost of incremental generation. There is a view that more cost-effective conservation can occur with industrial customers provided the incentives are structured correctly. Accordingly, industrial customers generally expressed strong support for the Industrial Power Smart program.

Some stakeholders questioned whether the 66% conservation target is realistic or effective given it is tied to load growth.

Contribution Policy (Transmission)

There was general agreement that it is appropriate to seek a contribution to pay for system upgrades triggered by a new industrial customer connecting to the BC Hydro transmission system. Rather, discussion revolved around how much of the system upgrade costs should be borne by existing ratepayers (recognizing benefits to the provincial economy and additional revenues to BC Hydro) versus the new customer (recognizing the customer receives access to embedded cost resources and triggers additional costs to existing ratepayers).

Stakeholders presented several potential options to address issues with the current transmission contribution policy. Most adopted similar methodologies as those proposed for generation contribution policy. One stakeholder indicated that there really should be no distinction between generation and transmission contribution policy because they are effectively one, integrated connection cost. The stakeholder argued that a clear policy that showed up-front costs would enable proponents to make economic decisions on energy supply.

A minority of stakeholders argued new customers should pay the full incremental cost of system upgrades when they connect to the BC Hydro system.

End Use Rates

There was general agreement that end use rates were not appropriate for industrial electricity policy, but a minority of stakeholders indicated they remain a policy option at Government's disposal. One stakeholder indicated Government should consider possible trade agreement implications should it consider using end use rates for economic development purposes.

Postage Stamp Rates

There was agreement amongst stakeholders that BC Hydro should continue to use postage stamp rates for industrial customers.

Other Comments

Definition of Environmental Policy for Purposes of the Review

One stakeholder indicated that emphasizing GHG emission reductions at the expense of other environmental and sustainability matters is too narrow and does not address the broader environmental impacts of generation and transmission development. This stakeholder suggested the task force adopt a broader view during its determinations if it plans to make recommendations that would impact environmental policy decision-making.

BC Hydro Costs

Several stakeholders mentioned the Government's 2011 financial and administrative review of BC Hydro. These stakeholders questioned the extent to which the review's 56 recommendations have been implemented. They also expressed concern with the amount of BC Hydro revenue that flows to governments through the dividend, water rentals, taxes, and grants in lieu of taxes, because they must ultimately be collected through rates.

BC Hydro Regulatory Accounts

The majority of stakeholders believe that BC Hydro is not making appropriate use of regulatory accounts. Customers are concerned at the rate impacts associated with retiring the regulatory account balances and how quickly that will occur.

Application of Provincial Sales Tax to Industrial Electricity Consumption

Industrial stakeholders indicated that the re-introduction of the Provincial Sales Tax on industrial electricity consumption will hurt their competitiveness given most jurisdictions do not charge a similar tax. This is effectively a 7 per cent bill increase paid to the Province.

Projected BC Hydro Surplus

Most stakeholders were aware of BC Hydro's projected near-term energy surplus from BC Hydro's updated Load/Resource Balance (LRB). Many stakeholders agreed that this represented a potential cost to ratepayers given weak export markets and that BC Hydro should take prudent action to reduce its energy surplus as quickly as possible. However, some stakeholders argued that it is too early to determine whether the near-term surplus is a risk in the absence of an updated BC Hydro IRP given the uncertainties related to the electrification of industrial load, particularly liquefied natural gas (LNG).

LNG Power Supply

Industrial and many non-industrial stakeholders have a particular interest in energy supply options for the emerging LNG industry. Industrial customers are concerned what impact(s) interconnecting such large loads would have on rates. Some non-industrial customers are interested in potential commercial opportunities related to LNG development. One stakeholder indicated the environmental assessments of projects with large new electricity loads should include a review of the environmental effects of new generation and transmission required to service them.

Flexibility of Natural Gas Generation

Some stakeholders indicated that natural gas-fired generation should be part of the province's future energy strategy given its ability to locate near load and the flexibility it provides to the overall system. This would provide options to deploy the "right" energy supply technology at the "right" time to optimize provincial energy (electricity and natural gas) use as a whole.

Cost of Future Electricity Procurement

There was no agreement on how best to mitigate cost increases associated with future electricity procurement. Industrial stakeholders focused on cost-effectiveness indicated that gas-fired generation is the best option. Some non-industrial stakeholders indicated that clean and renewable electricity is cost-competitive despite public perceptions. Some suggest it is difficult to accurately compare resource options because they depend on future natural gas prices, future carbon prices, technological advancements and the time frame used to undertake the analysis.

Appendix 3.2: IEPR Task Force BC Hydro Consultation Summary

Introduction

The task force issued a Draft Consultation Summary (Summary) on May 1, 2013. The task force elected not to include BC Hydro's input in the Summary given its unique position relative to other stakeholders and the comprehensiveness of its submissions. The task force subsequently determined that it would be prudent to issue a separate summary for BC Hydro to ensure transparency and the accuracy.

Economic Development, Environmental Policy and Regulatory Approach

BC Hydro applied conservation, environmental and economic development perspectives on a topic-by-topic basis. It also provided an overview of its current regulatory environment under the authority of the Commission. BC Hydro did not provide general comments on its contribution to achieving provincial economic or environmental policy objectives, nor did it comment on the impacts (if any) of the interaction between the provisions of the *Utilities Commission Act (UCA)* and the *CEA*.

Contribution Policy (Generation and Transmission)

BC Hydro indicated there were three issues to consider when reviewing current contribution policy: 1) allocation of costs between new and existing customers; 2) methodology to determine what a new customer contributes; and 3) the payment/security mechanism. Its comments focused on number one because it deemed numbers two and three to be technical matters best left to a future Commission process.

BC Hydro indicated that the basis for treating "large" loads differently, as set out in Tariff Supplement 6 (TS 6), was endorsed by the Heritage Contract framework, and is therefore beyond the task force's mandate and should not be up for debate. BC Hydro acknowledged that the 'absolute' 150 MV.A threshold may not be appropriate, but that some kind of threshold should be in place. BC Hydro suggested the legislative framework regarding TS 6 be altered sufficiently such that the Commission can 1) establish a new threshold or framework to delineate smaller customers from very large one; and 2) make changes to the tariff respecting the allocation of costs between new and existing ratepayers. BC Hydro further suggested it would be constructive for the task force to advise Government on what principles should guide the review.

Retail Access

BC Hydro indicated that it is possible that a properly designed retail access program may contribute to the Province's economic and conservation goals, but may not support GHG reduction goals depending on how emissions from non-utility electricity are addressed.

BC Hydro indicated that a revised RAP must be based on sound and clearly articulated policy principles, as well as adopt a “no harm” approach to other ratepayers. BC Hydro’s view was that the additional costs to participating customers associated with maintaining a “no harm” approach will diminish the incentive for industrial customers to pursue retail access.

Regardless of any recommendations the task force might make regarding retail access in the future, BC Hydro urged the task force to recommend that Government cancel the current RAP without replacement. In regard to any potential future retail access program, the task force should recommend an evidentiary process with the broader participation of all affected customer classes to consider the development of a brand new program, informed by one or more Provincial policy objectives.

Transmission Service Rate and Conservation

BC Hydro indicated that the TSR is generally functioning as intended. BC Hydro suggested that the perceived ineffectiveness of the rate (most customers at ~90 per cent of CBL) is a function of overly generous initial CBLs, successful demand side measures investment and the economic downturn reducing Tier 2 purchases.

BC Hydro indicated that the main rate design features (revenue neutrality, bill neutrality, economic signal from 90/10 split, etc.) are tightly linked and would be difficult to change in isolation from each other. Altering any one increases the risk of over or under recovery as well as cost-shifting to the other two rate classes. BC Hydro is confident that the recent changes introduced through Tariff Supplement 74 will maintain the integrity of the TSR over the long term. Accordingly, BC Hydro does not favour altering the TSR at this point, but recognizes the underlying rate design issues related to revenue and bill neutrality will need to be addressed at some point. BC Hydro suggests that a Commission proceeding is the most appropriate venue to hold this debate when the time comes.

In the meantime, BC Hydro suggests that the task force should recommend to the Government, if necessary, the Commission be instructed to undertake a narrow and focused review of the TSR to accomplish specific objectives that the Government may select based on the task force’s advice.

End Use Rates

BC Hydro indicated there are two types of end use rates: those that subscribe to *UCA* and established rate-making principles; and, those that do not. The former are justifiable provided they receive Commission approval (such as E-Plus in the 1980s). The latter are the purview of the Province and should be transparently implemented by statute or regulation.

Postage Stamp Rates

BC Hydro supports postage stamp rates and sees no compelling reason to change them.

BC Hydro indicated that Government has not formally articulated its support for postage stamp rates in policy or legislation. It indicated that such a formal expression may help clarify future regulatory decision-making.

Other Comments

Task Force Mandate

BC Hydro reiterated that the task force is being asked to consider what changes to transmission voltage rates, or the regulatory framework within which these rates are established, could be made to advance the public policy objectives of conservation, economic development and environmental policy, and to the extent that one policy is pre-eminent, what are the implications/trade-offs vs. other objectives.

BC Hydro believes the Review is not the appropriate forum to consider detailed rate-design issues that would be more properly addressed through Commission-led processes.

BC Hydro Load/Resource Balance and Projected Surplus

BC Hydro will complete its updated LRB for the IRP to due to Government in early August 2013. BC Hydro indicates that while it is reasonable to assume there will be an energy surplus in the near term, there is still a great deal of uncertainty associated with its projections. This limits what conclusions the task force can draw.

BC Hydro believes that the task force should only make recommendations to government that emphasize the relationship between conservation, economic development, and current environmental policy in respect of the issues it is exploring. Those recommendations should emphasize how government might wish to think about the relationships under various load/resource balances.

Linkages between Economic Conditions, High-Level Government Policy and Electricity Rates

BC Hydro indicates it would be useful for the task force to link BC Hydro's LRB, customer price responsiveness, industrial market conditions and general economic conditions in the context of industrial electricity rates. This analysis, in conjunction with the IRP, could inform Government of what high-level policy options are available as well as how they could be structured to provide the Commission with sufficient guidance to implement them.

Appendix 3.3: IEPR Task Force Addendum to Consultation Summary

Introduction

Following the assignment of four additional topics for the task force to examine, the task force issued additional papers on each topic and invited additional input from stakeholders. The task force met again with four stakeholder groups and had a teleconference with one new stakeholder. Four stakeholders plus BC Hydro provided written comments to the task force.

Time of Use and Interruptible Rates

Stakeholder provided considerable information on how ToU rates were applied in other jurisdictions and even some detailed examples of how they might be applied to BC Hydro. There is considerable support for introducing such rates, and encouragement that BC Hydro's interruptible rate be continued. In contrast there has been no use of BC Hydro's Schedule 1825 ToU rate, primarily because it is complex and there is uncertainty about the potential savings. The task force was cautioned not to become involved in the design of such rates but to allow a more participatory process, preferably under the oversight of the Commission.

Utility Interconnection Policies

Most stakeholders were opposed to a set threshold at 150 MV.A, and preferred either a revenue test for all new customers or offering a sliding scale of blended and marginal costs, with a higher proportion of marginal costs going to larger loads. Some stakeholders argued that the interconnection timelines for industrial customers were a significant impediment to development, and that BC Hydro should provide interconnection for industrial customers on the same fixed timelines as under the Open Access Transmission Tariff. Others cautioned that this would create risks to BC Hydro's ratepayer or shareholder, and that it would be difficult to ensure that existing ratepayers did not bear some of the costs. Stakeholders provided proposals for more private involvement in transmission to manage costs and risks, as well as more use of gas generation near load to reduce the need for transmission studies and development.

Retail Access Policy Applied in Relevant Jurisdictions

There is strong consensus among stakeholders for the return of a retail access program for a portion of an industrial customer's load. However, BC Hydro remains cautious: in its view, the currently-suspended RAP is inappropriate even as a pilot, and the overriding objective of any program should be to avoid harming non-participating customers. One stakeholder proposes a narrower "limited wholesale access" program that would restrict contract supply sources to British Columbia-based generation other than BC Hydro's. Another cautioned that Powerex should not be involved and that the carbon tax should not be avoided. Reasons in support of a program focus on an opportunity for industries both to reduce their electricity costs, and the costs that growing industrial loads impose on BC Hydro. All stakeholders urge a measured approach to avoid creating stranded costs to the detriment of non-participating customers, such as an initial pilot program, limiting the total program volume, and a minimum commitment period.

Role of Government in Adding Very Large Loads

Stakeholders almost uniformly said that there should not be cross-subsidization between rate classes or individual customers. Several argued that, where government saw significant economic benefits arising from a project, government had the option to use tax policy or to subsidize rates from shareholder revenue. Government could also manage the cost of adding large new loads by broadening resource eligibility to include existing gas capacity, new gas generation, or Canadian Entitlement power.

Appendix 3.4: Meetings and Submissions

Organization	Representatives and Contributors
Association of Major Power Consumers	Brian Wallace Richard Stout Tom Christensen
BC Business Council	Denise Dalmer Tom Syer Various Members
BC Hydro	Maureen Black Janet Fraser Jeff Christian Justin Miedema Randy Reimann David Ince David Keir Suhk Salh Wafi Kassam Fred James Tom Bechard (Powerex) Dave Hargreaves Gail McBride Sam Jones Warren Bell
BC Sustainable Energy Association/Sierra Club of BC	Thomas Hackney Bill Andrews
BC Utilities Commission	Len Kelsey Alison Thorson Jackie Ashley Doug Chong Claudia McMahon Mark Thomas
Canadian Association of Petroleum Producers	Al Dunlop Geoff Morrison Bryan Donnelly Bill Grant John Landry
Catalyst Paper	Carlo Dal Monte Bob Lindstrom
Climate Action Secretariat	Tim Lesiuk
Commercial Energy Consumers Association	David Craig

Organization	Representatives and Contributors
Clean Energy BC	Paul Kariya Loch McJannett David Austin Steve Davis James Weimer Mike Wise
ERCO Worldwide	Michael Filippelli
Fortis BC	Doug Stout Dave Perttula Gerald Chan Ron Zeilstra
Individual	Randal Hadland
Mining Association of BC	Alec Morrison David Ewing
Morgan Stanley	Deborah Hart Murray Margolis
Pacific Northwest LNG	Tessa Gill Wilf Barke
Teck Resources	Terry Brace
Treaty 8 First Nations	Rick Hendriks Philip Raphals Jeff Richert
West Fraser	Peter Rippon Veikko Paivinen Rod Albers Keith Carter

Appendix 4:   Number of Electricity-Related Regulatory Actions 1980-2013

Type	1980-84	1985-89	1990-94	1995-99	2000-04	2005-09	2010-March 2013
Utilities Commission Act Directions	2	3	3	2	4	4	6
Clean Energy Act Regulations	-	-	-	-	-	-	11
BC Hydro Public Power Legacy and Heritage Contract Act Directives	-	-	-	-	3	7	4
Utilities Commission Act Ministers' Regulations	2	8	5	0	2	3	5
Transmission Corporation Act Directives	-	-	-	-	2	1	-
Hydro and Power Authority Act Directives	0	1	2	4	3	0	0
TOTAL	4	12	10	6	14	15	26

Of the 87 directives issued over 33 years, 53 (or 60%) have been issued in the ten years since 2003. Twenty six of the 87 (or 30%) have been issued since 2010, a rate of almost eight per year, compared to less than two per year in the 1980-2002 period.

Notes to this Table:

- Many of the Utilities Commission Act Ministers' Regulations in the 1985-94 period were S. 22 and S.88 exemptions from the Utilities Commission Act for sales of surplus power or heat. The Commission itself issued several similar orders, either under a delegating Order from the Minister (M51, 1989) or with prior Cabinet Approval; these Commission-approved exemptions are not included in this Table.
- From 1993 to 2003, rates were capped and then frozen by the BC Hydro and Power Authority Rate Freeze and Profit Sharing Act; this may help explain the less frequent use of directives in that period.
- The *Clean Energy Act* is structured differently than previous statutes. It includes a number of enabling powers that are implemented by Cabinet or Ministerial Regulations.

Appendix 5: Assessment of Current Policy and Legislative Commitments

Key

✓ = Policy/legislative commitment meets task force principle.
✗ = Policy/legislative commitment does not meet task force principle.
? = Cannot determine whether policy/legislative commitment meets task force principle
NA = Specific task force principle does not apply

Policy or Legislative Commitment	Clearly Articulated Public Policy		Allocation of Risk	Market-Based Solutions	Public Scrutiny of Costs
	Public Interest Test	Universal Application			
BC Hydro to be self-sufficient by 2016	?	✗	?	✗	✗
BC Hydro submits Integrated Resource Plan, consistent with provincial energy objectives, to Government for approval	✓	✗	✗	✗	?
93% clean and renewable standard for total provincial electricity generation	✓	✓	✗	✗	✗
Encourage fuel switching from higher carbon to lower carbon sources	✓	✓	✗	?	?
Acquire 66% of BC Hydro's incremental resource needs from conservation by 2020	✓	✗	?	?	?
Pursue all cost-effective demand side management	✓	✓	✓	?	✓

Policy or Legislative Commitment	Clearly Articulated Public Policy		Allocation of Risk	Market-Based Solutions	Public Scrutiny of Costs
	Public Interest Test	Universal Application			
Encourage utilities to design rates that encourage efficiency, conservation and the development of clean and renewable energy	✓	✓	✓	✓	✓
All new generation to be net zero GHG emissions	?	✓	✗	?	✗
Existing thermal generation to be net zero GHG emissions by 2016	?	✓	✗	?	✗
Coal thermal plants to have zero GHG emissions	?	✓	✗	?	✗
BC Hydro cannot plan to rely on energy or capacity from Burrard Thermal Generating Station other than for emergencies	✓	✗	✗	✗	✗
BC Hydro to encourage economic development and creation and retention of jobs	✓	✗	?	?	?
Foster development of First Nations and rural communities through development of clean and renewable resources	✓	✗	✗	✗	✗
BC Hydro customers continue to benefit from Heritage Contract	✓	N/A	✓	✓	✓
Commission continues to regulate BC Hydro with respect to domestic rates	✓	N/A	✓	✓	✓

Policy or Legislative Commitment	Clearly Articulated Public Policy		Allocation of Risk	Market-Based Solutions	Public Scrutiny of Costs
	Public Interest Test	Universal Application			
Northwest Transmission Line exempt from Commission review.	✓	✘	✘	?	✘
Mica 5 and 6 exempt from Commission review	✓	N/A	?	✘	✘
Revelstoke 6 exempt from Commission review	✓	N/A	?	✘	✘
Site C Dam exempt from Commission review	✓	N/A	?	✘	✘
Electricity Purchase Agreements from Bioenergy Phase 2, Integrated Power Offer and Clean Power Call exempt from Commission review.	✓	✘	✘	?	✘
Commission must not exercise any power of the Utilities Commission Act that would prevent BC Hydro from moving forward with exempt projects or contracts	✓	✘	✘	✘	✘
Commission must accept a rate proposed to achieve self-sufficiency or pursue exempt projects in s.7 of *Clean Energy Act*	✓	✘	✘	✘	✘
Commission must accept a rate proposed by a public utility to pursue a prescribed undertaking in s.18 of *Clean Energy Act*	✓	✘	✘	✘	✘

Policy or Legislative Commitment	**Clearly Articulated Public Policy**		**Allocation of Risk**	**Market-Based Solutions**	**Public Scrutiny of Costs**
	Public Interest Test	**Universal Application**			
Commission cannot exercise powers under Utilities Commission Act that would directly or indirectly prevent the public utility from pursuing the prescribed undertaking in s.18 of *Clean Energy Act*	✓	✘	✘	✘	?
Establish Standing Offer Program	✓	✘	✘	✘	✘

Appendix 6: Cross Jurisdictional Industrial Rates ($ per megawatt-hour)

Location	2006	2007	2008	2009	2010	2011	2012	Rate Change in Local Currency (Note 3)
Montreal	42.60	43.50	44.70	45.30	45.50	45.30	45.10	+6%
Calgary	NA	NA	NA	93.80	50.30	68.00	82.80	NA
Charlottetown	63.80	74.20	87.50	107.20	95.80	83.60	83.60	+31%
Edmonton	63.10	68.80	96.90	56.90	69.80	84.90.	69.70	+10%
Halifax	67.50	70.40	70.40	77.00	76.10	80.70	90.00	+33%
Moncton	54.50	58.80	64.70	66.60	66.60	68.60	68.60	+26%
Ottawa	77.40	81.30	86.60	81.50	86.40	95.10	105.80	+37%
Regina	49.00	51.10	51.10	51.10	60.90	62.40	56.70	+16%
St. John's	52.30	39.80	39.80	39.80	39.80	39.80	39.80	-24%
Toronto	79.90	77.40	84.60	82.90	94.00	96.40	104.60	+32%
Vancouver	35.30	36.50	39.40	40.30	44.00	43.40	49.90	+41%
Winnipeg	31.20	31.90	31.90	34.50	35.50	36.20	36.90	+18%
Boston	133.00	155.10	147.60	184.80	119.80	111.40	101.30	-10%
Chicago	55.70	70.00	89.40	63.00	51.50	61.60	53.30	+13%
Detroit	72.30	71.00	66.50	78.70	67.60	64.60	76.90	+26%
Houston	65.50	70.20	74.50	43.80	39.00	66.20	55.50	0
Miami	91.80	85.70	75.10	99.50	63.00	62.20	60.90	-22%
Nashville	65.70	63.10	64.60	84.20	62.80	68.40	69.60	+25%
New York	136.70	177.60	151.60	152.60	122.90	126.30	115.50	0
Portland, OR	43.60	46.20	43.10	58.60	50.70	55.10	59.40	+61%
San Francisco	96.60	90.20	83.30	120.10	97.80	89.90	88.40	+8%
Seattle	61.60	51.60	45.80	56.40	52.30	52.50	56.00	+7%
Exchange Rate (USD to CAD)	0.8533	0.8650	0.9737	0.7910	0.9926	1.0385	1.0084	
BCH Rate Rank	**2nd Lowest**	**2nd Lowest**	**2nd Lowest**	**3rd Lowest**	**4th Lowest**	**3rd Lowest**	**4th Lowest**	**2nd Highest**

Note 1: Hydro Quebec data for a 50 megawatt load with an 80 per cent load factor.
Note 2: Data presented in Canadian Dollars based on Bank of Canada noon exchange rate of for April 1 of stated year.
Note 3: Rate change presented in USD for US jurisdictions to demonstrate relative competitiveness impacts.

Appendix 7: Industrial Electricity Policy Review Task Force Recommendations:

Section	Recommendation:
4.3	Government should adopt four additional principles beyond the "regulatory compact" –which allows a utility to earn a fair return on its investment in exchange for providing safe, reliable service at rates based on costs – in any decision-making process involving electricity policy. Our expanded compact includes the following principles: • *Clearly Articulated Policy:* Government should determine the provincial public interest and set clear, understandable policy objectives, and apply them consistently to all utilities; • *Allocating Risk:* Utility owners (including the Province) make decisions based on an evaluation of risks, and the costs and benefits associated with these risks should be allocated to the party taking the risk; • *Market Based Solutions:* Market based solutions are generally preferable to those imposed by Government, provided externalities are priced and predictable, because they send appropriate price signals to drive decision-making and behaviour; and • *Public Scrutiny of Costs and Benefits:* Ratepayers should be provided with an opportunity for public review, either by the Commission or government, of any policy-driven initiatives that could significantly increase costs before these are implemented.
5.1	As BC Hydro's surplus diminishes, Government should consider whether a requirement for self-sufficiency is consistent with a long-run approach to least cost electricity prices.
5.2	BC Hydro's future Integrated Resource Plans should be reviewed and accepted by the Commission after a public process. As the owner of BC Hydro, Government may wish to review the Integrated Resource Plan before it is submitted to the Commission.
5.3	A long-term carbon price should be used in evaluating all electricity supply proposals and the price should be determined by Government after a public process. This would eliminate the need for the objective to generate at least 93 per cent of the electricity in British Columbia from clean or renewable resources.
5.4	Acquire all possible conservation up to the cost of new supply. There is no need for the BC Hydro-specific 66 per cent conservation objective in the *Clean Energy Act*.
5.7	Government should provide clarity on the role carbon offsets will play in meeting Government's greenhouse gas reduction goals.
5.8	Government should assess any directions or exemptions against the expanded regulatory compact recommended in Section 4.3.

6.6	The industrial tariff supplement that sets out the terms and conditions of connections, Tariff Supplement 6, is over 20 years old and should be reviewed in a Commission public process.
6.7	Continue using postage stamp rates.
6.8	End use rates which have no impact on ratepayers could be considered but those which impact ratepayers and are directed by Government should be paid for by taxpayers and not ratepayers.
6.9	BC Hydro should develop a revised retail access program.
6.10	Government need not act on the Commission's 2009 Transmission Service Rate report until BC Hydro's surplus has diminished and the effect of the other recommendations in this report can be seen.
6.12	BC Hydro should work with its industrial customers and the Commission to develop options that take advantage of industrial power consumption flexibility, such as time of use rates and interruptible rates.
6.13	BC Hydro should benchmark and publicly report on its transmission interconnection turnaround times for both new generation and new load.
7.1	BC Hydro should host a workshop on its regulatory accounts to improve understanding of the balances and the provisions in place for dealing with them.
7.2	BC Hydro should ultimately bring its surplus management plan forward in a Commission-led process if the management plan proposes to put additional costs on ratepayers or transfer costs between ratepayers.
7.3	An independent review of the Commission should be undertaken to evaluate resource needs, review processes, and performance.

NEWS RELEASE

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Ministry of Energy and Mines
and Responsible for Core Review

BCUC Review to get commission back to setting BC Hydro rates

VICTORIA – Government is acting on two of its 10 Year Plan commitments for BC Hydro by beginning an independent review of the British Columbia Utilities Commission (BCUC) and launching a public rate design review, announced Bill Bennett, Minister of Energy and Mines and Minister Responsible for Core Review. The reviews are part of government's plan to keep electricity rates as low as possible while BC Hydro makes investments to maintain our electricity system and meet growing demand.

Government has been clear that it wants the BCUC to resume its role setting BC Hydro rates. The review of the BCUC responds to concerns, raised by customer groups and utilities, about the commission's ability to deliver clear and timely decisions. In recent years, the number of information requests and the cost of funding interveners in commission proceedings has increased dramatically, resulting in additional costs and delays. The review will be led by an independent task force and will make recommendations on how to improve the commission's effectiveness and efficiency so it can start setting BC Hydro rates by the third year of the 10 Year Plan.

The rate design review will help identify opportunities to provide large industrial customers with more flexible rate options to manage their costs and stay competitive. It will also evaluate current industrial, commercial and residential rate structures to ensure they support key objectives including energy conservation and fairness.

The BCUC review task force will begin consultations this month and will report back to government by Nov. 17, 2014. The consultation process will include meetings with First Nations, utilities and interveners as well as current and former BCUC staff. Members of the public will also be able to make written submissions to the task force. Rate design consultations will begin in May and will include a web site where customers can submit feedback and suggestions. Those consultations will inform the rate design application that BC Hydro will submit to the BCUC in the summer of 2015.

April 2014 marks the first month of government's 10 Year Plan for BC Hydro. Today, government released a progress update on key commitments including investments to maintain and upgrade BC Hydro's system as well as measures to pay down regulatory accounts, limit BC Hydo's operating costs and reduce the amount of money that government takes from the utility.

Quotes:

Bill Bennett, Minister of Energy and Mines and Minister Responsible for Core Review –

"We know that the BCUC has a very important role to play in overseeing British Columbia's utilities and we have always been clear that we want to get them back to reviewing and setting BC Hydro rates. This review will make sure they have the tools and processes in place to start setting BC Hydro rates by the third year of the 10 Year Plan."

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Learn More:

BCUC Review consultation: www2.gov.bc.ca/govtogetherbc/consultations/bc_utilities_commission.page

BCUC Review: www.empr.gov.bc.ca/EPD/Electricity/BCUC_Review/Pages/default.aspx

Two Backgrounders follow:

BCUC Review - Task Force Member Biographies
10 Year Plan Progress Update – April 2014

Media Contact:

Jake Jacobs
Media Relations
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250 952-0628

BRITISH COLUMBIA

BACKGROUNDER

For Immediate Release
2014MEM0013-000539
April 28, 2014

Ministry of Energy and Mines
and Responsible for Core Review

Independent Review of the British Columbia Utilities Commission
Task Force Member Biographies

Bill Bennett, Minister of Energy and Mines and Minister Responsible for Core Review has appointed a task force to conduct the independent review of the British Columbia Utilities Commission (BCUC). The members of the task force have extensive experience in electricity policy and utility operations.

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foremost experts on utility regulation in B.C. and represented the Ministry of Energy and Mines as the technical liaison for BC Hydro's current Integrated Resource Plan. He also served as a task force member for the recent Industrial Electricity Policy Review.

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The plan included measures to reduce the amount of money that government takes from the utility, free up additional cash to support investments in infrastructure, pay down regulatory accounts and lower BC Hydro's operating costs.

10 Year Plan commitments and progress

1. **Set rate increases for the initial two years of the 10 Year Plan at 9% and 6%. Set rate increase caps of 4%, 3.5%, and 3% for the following three years.**
On March 5, 2014, government issued Directions 6 and 7 to the BC Utilities Commission (BCUC) setting rate increases and rate increase caps as outlined in the 10 Year Plan.

2. **Fund investments in aging assets and new infrastructure.**
BC Hydro's capital plan is on budget and totals approximately $1.7 billion per year for the next 10 years. Projects that have recently started construction include the $748 million Ruskin Dam Safety and Powerhouse upgrade, the $272 million GM Shrum Turbine replacement and the $1.093 billion John Hart Generating Station replacement. Recently completed projects include the Revelstoke turbine, Stave Falls spillway gates, Columbia Valley Transmission Line and Seymour Arm capacitor station, which came in under budget by more than $150 million combined.

3. **Limit BC Hydro's operating costs.**
As a result of the 2011 government review, BC Hydro reduced its operating costs by $391 million over three years, cut executive compensation by 20% and eliminated 900 non-operational roles. Operating costs are limited to increases of less than the rate of inflation over the next two years.

4. **Pay down regulatory accounts.**
Prior to the 10 Year Plan, BC Hydro was paying down 19 of 27 regulatory accounts. As of April 1, 2014, 25 of 27 regulatory accounts are being paid down. By March 2016, nine of those accounts will be paid off.

5. **Reduce the amount of money that government takes from the utility.**
BC Hydro's net income and dividend – which represent the amount of revenue they send to government each year – have been calculated using the same formula since 1992. On March 5, 2014, government issued Direction 7 and an amendment to Heritage Special Directive HC1. Direction 7 changes how BC Hydro's net income is calculated starting in fiscal 2018 and will reduce BC Hydro's contributions to government by $2 billion over 10 years. The amendment to Heritage Special Directive HC1 changes how BC Hydro's dividend payment to government is calculated starting in fiscal 2018 and will allow BC Hydro to keep $3 billion more in cash for infrastructure investments over 10 years.

6. **Invest $1.6 billion in Power Smart Programs.**
BC Hydro's Power Smart budget over the next three years totals $445 million. This includes funding for the Energy Conservation Assistance Program which provides fridge and insulation upgrades to low-income customers as well as funding for programs to help large industrial customers invest in more efficient equipment.

7. **Launch a rate design review process.**
A public rate design review process will start this May.

8. **Initiate a review of the BCUC.**
An independent task force has been appointed to conduct a review of the BCUC so that the BCUC can start setting BC Hydro rates by the third year of the 10 Year Plan.

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Ministry of Energy and Mines, Economy Sector, Families Sector, Government Operations Sector, Cariboo Chilcotin Coast Region, Kootenay Rockies Region, Northern B.C. Region, Provincewide, Thompson / Okanagan Region, Vancouver Coast & Mountains Region, Vancouver Island / Coast Region

BCUC Review to get commission back to setting BC Hydro rates

/2014/04/bcuc-review-to-get-commission-back-to-setting-bc-hydro-rates.html

Monday, April 28, 2014 8:20 AM

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