1992-1

YUKON UTILITIES BOARD

DECISION 1992-1

JANUARY 17, 1992

RE

YUKON ENERGY CORPORATION

YUKON UTILITIES BOARD

DECISION 1992-1

FRIDAY, THE 17TH DAY OF JANUARY, A.D. 1992

IN THE MATTER OF the "Public Utilities Act", being Chapter 143 of the Revised Statutes of Yukon, 1986, as amended;

AND IN THE MATTER OF an application by Yukon Energy Corporation to the Yukon Utilities Board for Orders approving changes in existing rates, tolls or charges for electric light, power or energy and related services supplied to its customers within Yukon.

BEFORE:

THE YUKON UTILITIES BOARD

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APPEARANCES

For Yukon Energy Corporation:	P.J. Landry
For the Yukon Electrical Company Limited:	M. D. Romanow
For City of Whitehorse:	E.J. Walter Michael Davies
For Curragh Resources Inc.:	Ian Blue Ms. Robin Adelson
For The Whitehorse Chamber of Commerce:	David Morrison
For Himself:	Peter Percival Gary McRobb
For Himself:	Doug Craig
For Independent Alliance:	Ms. B. Firth A. Nordling

WITNESSES

For Yukon Energy Corporation:	Cam Osler Michael Sweatman John Maissan Fred Berger
For the Yukon Electrical Company Limited:	Grant Lake Harvey Kerslake Rory Nugent Kathleen McShane Doug Baer John Carroll Don Willems Wayne Wright Owen Edmondson Kirk Poteet Richard Stout Hector Campbell
Curragh Resources Inc:	David Parcell

1. INTRODUCTION

Yukon Energy Corporation (**"YEC, the Company"**) filed an Application dated June 6, 1991 with the Yukon Utilities Board (**"the Board"**) for an Order or Orders of the Board fixing and approving just and reasonable rates, charges or schedules thereof, for electric light, power or energy and related services to be supplied by YEC, including terms and conditions of service.

In its Application, YEC provided its Strategic Plan for 1991 through 1995. In this Strategic Plan YEC describes its financial mandate as follows:

> "YEC's mandate is to function as a fiscally responsible and self-financing commercial entity, earning a normal commercial return on equity and charging stable and predictable long term power rates." (Tab 15, Yukon Energy Corporation Strategic Plan 1991-1995, Page 9)

The Board is cognizant of this financial mandate in its Decision with respect to the 1991 and 1992 revenue requirements.

In its Application YEC made an application for the implementation of interim refundable rates representing an overall increase in retail rates of 14.3% effective July 1, 1991 for all bills issued on or after July 1, 1991. The Board, following public notice, heard the Company's Application at a public hearing held in the City of Whitehorse on June 22, 1991. On June 25, 1991 the Board issued Interim Order 1991-1 wherein it approved an overall increase in retail rates of 13.5% as interim refundable rates effective July 1, 1991. The Board issued its reasons for its Interim Order 1991-1 in its Decision 1991-2.

The Board held pre-hearing conferences on August 8, 1991 and October 22, 1991 to establish the hearing schedule and to resolve other issues relating to the conduct of the hearing. Subsequent to the pre-hearing conferences intervenors were provided with an opportunity to make written information requests to YEC and these requests elicited written responses which were made available to all parties prior to the hearing of the Application. Written information requests by the Board together with responses thereto were also made available to all parties prior to the hearing of the main Application.

The hearing of the main Application was held in Whitehorse November 25 - 29, 1991. Subsequent to the hearing the applicant and intervenors were provided with the opportunity to submit written argument and reply argument.

During the course of the hearing members of the public who were not registered as intervenors were invited to participate in the proceedings. Dr. Doug Craig who has conducted a study on the "wind regime in the neighbourhood of Whitehorse" read into the record some brief comments on wind energy and submitted a technical report entitled "Wind Energy Potential". The Independent Alliance made an oral presentation to the Board just prior to the adjournment of the public hearing.

The Board in this Decision will determine the Company's rate base, fair return on rate base and total electric utility revenue requirement for the approved test years and will provide reasons with respect to the Board's Decision on these matters.

The Board will deal with matters respecting the rates and electric service regulations in Decision 1992-4.

2. TEST YEARS

The Board approves the forecast years 1991 and 1992 as the test years for this Application as requested by the Company.

3. RATE BASE

3.1 General

The determination of a rate base for the purpose of fixing just and reasonable rates, tolls or charges is governed by the provisions of Section 32 of The Public Utilities Act which provides as follows:

> "32.(1) The board, by order, shall determine a rate base for the property of a public utility used or required to be used to provide service to the public, and may include a rate base for property under construction, or constructed or acquired, and intended to be used in the future to provide service to the public."

Pursuant to Section 32 the Board has determined a rate base for the 1991 and 1992 test years as shown in Schedule A attached hereto.

3.2 Gross Plant-in-Service

3.2.1 Capitalization Policy

During cross-examination Company witnesses explained that it was the Company's policy to capitalize costs if an item provides benefits for more than one year, is significant in amount and/or replaces an asset that can be identified and retired.

During cross-examination Company witnesses agreed that a utility is indifferent to capitalizing versus expensing an asset provided the utility is allowed a fair return on the capital invested in the asset and is provided a return of the capital invested in the asset. A utility's main concern in establishing the accounting treatment for an asset is matching the use of the asset with expensing the cost of that asset to ensure intergenerational equity between customers.

The Board accepts the Company's capitalization policy for purposes of this Decision.

3.2.2 Change in Accounting Treatment Between Forecast and Actual

In response to an information request YEC states that:

> "The 1990 unit maintenance is lower than historical and forecast costs. During 1990

> work costing approximately $200,000 was done on one hydro unit. This work will increase the useful life of the hydro unit and was therefore capitalized." (WHSE-YEC-15)

During cross-examination Company witnesses agreed that the $200,000 maintenance expenditure was included as forecast operating and maintenance expense in the revenue requirement for 1990. Company witnesses also agreed that by capitalizing the actual expenditure the cost of the expenditure will again be included in the Company's revenue requirement over time by way of depreciation expense and the return on rate base.

The City of Whitehorse in its argument submitted that to ensure that customers do not pay twice for an expenditure, the Board should require consistent treatment between general rate applications.

The Board will reduce YEC's 1991 and 1992 gross plant-in-service by $200,000 and its depreciation expense and accumulated depreciation by an estimated amount of $4,500 for each of the years 1991 and 1992. The Board further directs that for purposes of future general rate applications, the Company should treat forecast and actual capital expenditures on a consistent basis.

3.2.3 Capital Expenditures and Net Additions to Rate Base

YEC set out its calculations of net property plant and equipment in Section 5, Schedule 3 of its Application. A summary of capital expenditures forecast for the test years

1991 and 1992 is contained in Schedule 3(c). The Company forecast capital expenditures of $10,340,000 and $19,430,000 for the years 1991 and 1992 respectively. After deducting forecast customer contributions the net capital investment by the Company is forecast to be $10,180,000 and $19,360,000 for 1991 and 1992 respectively.

In response to Board information request YEC-12 the Company set out details with respect to expenditures forecast to be transferred into rate base for each of the years 1991 and 1992 and the year end balances in construction work in progress.

In response to an undertaking during cross-examination the Company stated that a number of items had been mislabelled or misstated in Board YEC-12 and Schedule 3, details of which are described in Exhibit 8-30. The Company indicated that the impact of these changes was to reduce year-end rate base by $300,000 in 1991 and $585,000 in 1992. Accordingly, the Board has reduced YEC's midyear rate base to reflect these changes.

During cross-examination concern was expressed by intervenors with respect to the accuracy of the Company's capital forecast. In response to an undertaking to review its capital forecast the Company indicated that its most recent estimate of capital expenditures showed a decrease in its rate base of $495,000 in 1991 and an increase in its rate base of $2,250,000 in 1992 although details of the expected changes were not provided.

The Board will use the net property, plant and equipment as set out in Schedule 3, Section 5 of its Application as the starting point to determine the midyear rate base for each of the years 1991 and 1992.

3.2.4 Demand Side Management

For the reasons as outlined in Section 6 of this Decision, Demand Side Management, the Board has reduced the Company's 1992 year end rate base by $750,000.

3.2.5 Contribution in Aid of Construction - Mayo/Elsa Line

The Company expended $333,000 in 1990 on the rebuild of the Mayo/Elsa Line. During cross-examination Company witnesses explained that the capital expenditure was incurred on the basis that the United Keno Hills Mine (**"UKHM"**) would reopen. The UKHM did not reopen.

The City of Whitehorse in its argument expressed the following concern:

> "This raises the issue of who should pay for this rebuild. There was no customer contribution received on this rebuild and we believe there should have been a requirement for a customer contribution towards the cost of the rebuild. This would have protected other customers from having to carry the costs of this line in their rates for many years to come. (Page 11)
>
> ... The Board should also consider whether this facility is "used as required to be used" at this time and if it is not in service remove it from rate base and current

> rates. We also question the prudency of the decision to rebuild this line without commitment from UKHM and some form of contract for electric supply. If the decision to rebuild this line was imprudent then in our opinion the electric ratepayers in the Yukon should not be required to pay for the rebuild and it should be a cost borne by YEC until such time it is required to be in service." (Page 12)

The Company responded to the City of Whitehorse's argument as follows:

> "YEC responds that no evidence has been provided to suggest that YEC actually proceeded in an imprudent manner. As acknowledged by the City of Whitehorse, this work was expanded beyond levels previously projected in response to a restart operation at the mine as well as safety considerations due to the very poor condition of the line (Transcript, p. 759). There is no reasonable basis for excluding this expenditure from YEC's rate base, particularly in light of the recognized benefits that all ratepayers would realize if the mine was reopened." (Page 9)

The Board shares the City of Whitehorse's concerns with respect to the rebuild of the Mayo/Elsa line. Accordingly, for purposes of this Decision, the $333,000 expended on the line will be included in CWIP and deducted from rate base for each of the years 1991 and 1992. Accordingly, 1991 and 1992 depreciation expense will be reduced by $15,000. The Board will examine details of this expenditure at the upcoming capital hearing.

3.2.6 Prebuild to Mayo

In his argument Peter Percival expressed concern with respect to the inclusion of the costs for the "prebuild to Mayo" in YEC's rate base.

He submitted that subsequent to the public hearing it has been confirmed that this line is a distribution line and the cost of this line should have been recovered through the government's Rural Electrification Program.

YEC in its reply argument stated that:

> " Percival (p. 4) argues that $110,000 spent on extending the line to Henderson Corner should be excluded from YEC rate base because it is only a distribution line. YEC responds that the evidence in this hearing acknowledged this facility as part of "Distribution System Projects" (see WHSE-YEC-21, p. 2 of 18, provided September 26, 1991 which also indicated that $103,000 of the $285,000 was covered by contributions under Rural Electrification)." (Page 9)

After having reviewed the evidence the Board is not persuaded that the costs for the prebuild to Mayo should be excluded from YEC's rate base.

3.2.7 Customer Contributions

During the course of the proceedings intervenors expressed concern with respect to the Company's customer contribution policies. The Board will examine YEC's contribution policies during the upcoming capital hearing and directs the Company to provide the Board and intervenors with details of these policies at the time of that hearing.

3.3 Accumulated Depreciation

In response to a Board directive in Decision 1989-4 YEC conducted a depreciation study in 1990 to determine the appropriate service life and net salvage characteristics to be applied to the Company's plant and equipment for the purpose of determining accumulated depreciation and depreciation expense. The Company provided the results of the study in Tab 4 of its Application and an explanation of the factors influencing the selected depreciation parameters was provided in Tab 13.

YEC explained that the depreciation for pre-1988 investments was calculated using a method by which the balances in plant and equipment accounts are amortized over the estimated remaining life of the plant and equipment. The Company's post 1987 investment is depreciated on an Equal Life Group (**"ELG"**) basis. The Company explained that because minimal historical experience exists for post 1987 vintages, the Company relied on selected Yukon Electrical Company Limited (**"YECL"**) service life and net salvage characteristics to calculate depreciation expense. For some accounts the YECL service life and net salvage characteristics were based on Alberta Power Limited's (**"APL"**) depreciation parameters as determined in APL's 1986 depreciation study.

The Company requested approval by the Board to calculate its depreciation rates and depreciation reserve requirements each year based on the service life and net salvage characteristics as set out in its Application. The Company explained that the annual calculation of depreciation rates based on Board approved depreciation characteristics results in a more accurate calculation of depreciation expense than the use of Board approved depreciation rates because the former method reflects the changing mix of vintage investment resulting from aging of plant, growth additions, retirements and transfers.

The Company's witness acknowledged during cross-examination that APL had conducted a depreciation study in 1991 and in response to an undertaking YEC filed Exhibit 8-45, an update to YEC's depreciation study based on the results of APL's most recent depreciation study.

The impact of the update to the YEC depreciation study was to reduce depreciation expense by $24,000 and $22,000 in 1991 and 1992 respectively. The Company in its argument recommended that the revised depreciation expense and accumulated depreciation as set out in Exhibit 8-45 be used for purposes of determining the 1991 and 1992 revenue requirements.

Curragh Resources Inc. (**"Curragh"**) in its argument expressed the following concerns with respect to depreciation expense and negative net salvage:

> "Depreciation expense for YEC and YECL amounts to four percentage points of return to the capital invested in rate base. Given the companies' concern over the impact of rate increases in Yukon today and continuing into

> 1993 and 1994, Curragh submits that this is not the time to be increasing depreciation rates. Within the simplistic framework of straight line depreciation, this is the time to be making optimistic assumptions about the remaining life of the companies' assets and to be reducing depreciation rates. Such an approach, coupled with review and adjustment of depreciation rates every few years can establish a pattern of depreciation expense over time which will help to smooth the impact of bringing on major new capital projects.
>
> Where possible, the companies propose to rely on the equal life group (ELG) methodology of estimating appropriate depreciation rates and to incorporate in depreciation rates a provision for negative salvage. The equal life group methodology relies on historical information for similar asset types and similar vintages of assets. It is a useful but complex set of procedures for the estimation of appropriate depreciation rates. However, the ELG method relies on the assumption that the past data is a predictor of the future life of assets." (Page 23)

Curragh further submitted that:

> "The appropriate levels of negative salvage in the Companies' Application were cast in doubt at the hearing as certain of the negative salvage percentages were changed significantly in response to questioning by intervenors. Although it may be coincidental, cases where significant percentage levels of negative salvage were introduced in the main application (Ex. 1, Tab 4.4, Schedule 1) were also cases where extensions were being made to the depreciable life of the asset class." (Page 24)

The Board notes that the Company's use of the ELG methodology to determine depreciation and negative net salvage is an accepted practice for regulated utilities in Canada.

As acknowledged in Curragh's argument, the Company's practices rely on past data to predict the future life of assets. The Board notes that Curragh did not provide any evidence that would indicate that past experience is not a reasonable predictor of the future life of assets, nor did it provide any evidence to support its position that the negative net salvage rates are excessive.

The Board is not persuaded that depreciation expense should be based on "optimistic assumptions about the remaining life of the assets" given the size of YEC's proposed rate increases. The Board agrees with the Company that the purpose of depreciation is to allocate the depreciable costs of an asset as evenly as possible over the service life of that asset to ensure intergenerational equity between customers.

The Board approves the service life and net salvage characteristics as amended by the Company in Exhibit 8-45.

3.4 Working Capital Allowance

Necessary working capital is included in rate base in recognition of the need for investor supplied funds for the day to day operation of the utility in addition to the capital invested in property plant and equipment. YEC's forecast working capital allowance is $1,438,000 and $1,433,000 for 1991 and 1992 respectively. (Tab 5, Schedule 2)

YEC's working capital allowance was determined based on a Lead/Lag Study performed in 1989. The Lead/Lag study is found under Tab 14 of YEC's Application. It shows that on average the Company pays its operating expenses 21 days prior to the collection of its revenues. Thus, on average, investor supplied funds are required to finance the operating expenses for a 21 day period.

3.4.1 Impact of GST on Working Capital

During cross-examination Company witnesses indicated that Goods and Service Tax (**"GST"**) had not been considered in the determination of necessary working capital as the Company did not have sufficient experience to forecast the impact. In response to an undertaking by the Company to estimate the impact of GST on necessary working capital, the Company provided the following information:

> "On a global basis we estimate the impact of GST on working capital for YECL would be an increase of $50,000 for 1991 and $60,000 in 1992. We estimate there would not be a significant change to YEC's necessary working capital. A detailed calculation based on all transactions year to date would take approximately two weeks to complete."

The Board does not consider that sufficient evidence has been provided by the Company to evaluate the impact of GST on working capital and accordingly has not made an adjustment to YEC's working capital allowance for the impact of GST.

The Board's calculation of the 1991 and 1992 working capital allowances is shown on Schedule B.

3.5 Reserves

The Board has reduced YEC's 1991 and 1992 year end rate base by $2,000,000 for the low water reserve and $250,000 insurance reserve for the reasons outlined in Section 4.2.1 of this Decision, No Cost Capital.

3.6 Electric Utility Rate Base

After having given consideration to the relevant evidence, the Board has determined the electric utility midyear rate base for YEC for the two test years to be as follows and is shown on Schedule A attached.

1991	$100,551,000
1992	$104,124,000

4. FAIR RETURN ON RATE BASE

4.1 General

Having determined the rate base for YEC, the Board is also required pursuant to Section 32(2) of the Public Utilities Act to "fix a fair return on the rate base".

> "(2) The board, by order, shall fix a fair return on the rate base.
>
> (3) In determining a rate base the board shall give due consideration to the cost of the property when first devoted to public utility use, to prudent acquisition cost less depreciation, amortization or depletion, and to necessary working capital.
>
> (4) In fixing the fair return that the public utility is entitled to earn on the rate base, the board shall give due consideration

> to all those facts that in the opinion of the board are relevant.
>
> (5) Notwithstanding the other provisions of this section, the board may adopt any just and reasonable basis for determining a method of calculating a fair return on property that is being constructed or that has been constructed or acquired but is not yet being used to provided service to the public."

In fixing the fair return on rate base, the Board considers it appropriate to take into consideration the rate of return applicable to each component of the Company's capital structure which it considers to be financing the rate base.

Generally, the Board considers that a fair return on rate base is a return that will result in providing the customers of the utility with the lowest utility rates practicable consistent with the utility's duty to furnish safe, adequate and proper service on an on-going basis.

The return should be sufficient to enable the utility to maintain its property, plant and equipment in an effective and efficient operating condition, and at the same time enable the utility to maintain its financial integrity and thus enable it to obtain necessary capital on reasonable terms. This approach is consistent with YEC's financial mandate described in its strategic plan as follows:

> "... to function as a fiscally responsible and self-financing commercial entity, earning a normal commercial return on equity and charging stable and predictable long term power rates".

4.2 Capital Structure

Tab 5, Schedule 4 of YEC's Application sets out the Company's proposed capital structure for 1991 and 1992 as follows:

	Midyear Balance 1991 (000's)	1991	Midyear Balance 1992 (000's)	1992
Long Term Debt	$ 65,850	56.62%	$ 73,950	56.13%
Common Stock	48,210	41.45%	55,552	42.16%
No Cost Capital	2,250	1.93%	2,250	1.71%
	$116,310	100.00%	$131,752	100.00%

4.2.1 No Cost Capital

YEC's no cost capital consists of a low water reserve of $2,000,000 and a reserve for uninsured losses of $250,000.

In response to an information request the Company stated that:

> "The effect of converting the present Reserve from a "shareholder reserve" to a "customer reserve in this case amounts to a gift from shareholders to customers." (CRI-YEC-5)

During cross-examination it was established that the required return would be reduced by $28,000 and $46,000 for 1991 and 1992 respectively if the reserves were to be treated as a deduction from rate base rather than as no cost capital.

Company witnesses agreed that if the entire amount of these reserves was considered to be financing the Company's rate base, the reserves should be deducted from rate base.

However, they indicated that these reserves are not like customer contributions and the Company has no obligation to apply the reserves directly to rate base.

The City of Whitehorse in its argument made the following submission:

> "... the Board should consider the source of the funds and the reasons for the existence of no cost capital in deciding this issue. These funds have been set aside from past and current rates to be used to stabilize the revenue of the utility for any unusual events from those forecast. The low water reserve for $2 million and the reserve for injuries and damages for $250,000 are both used to protect the utility and ultimately the ratepayer from major rate fluctuations. It can be argued that YEC, out of the goodness of its heart, set aside the $2 million for the low water reserve but it has effectively said these funds belong to ratepayers and should be set aside for a rainy day rather than returned to the ratepayers. We therefore consider them to be ratepayer provided funds.
>
> Based on the above, we believe the current rate payers should gain any advantage from the existence of this no cost capital therefore the no cost capital should be specifically allocated to rate base." (Page 13)

Curragh in its argument took the following position:

> "If these funds are truly intended to be 'a gift from shareholders to customers', they represent capital belonging to YEC's customers and, hence, should be treated in a manner consistent with the treatment of customer contributions. Customer contributions can be described as a "donation" to the utility's capital requirements but they are deducted from rate base and are not included in the capital structure for the purposes of computing return." (Page 6)

The Board considers that the full amount of $2,250,000 should apply to YEC's rate base. Accordingly, for the purpose of this Decision, the Board has removed the amount of $2,250,000 from YEC's midyear capital and deducted the amount from midyear rate base.

4.2.2 Long Term Debt

Note 4(b) to YEC's financial statements for the year ended December 31, 1990 shows outstanding long term debt of $5.5 million at 11.375% with no specific terms of repayment. YEC's witness stated that the loan was payable to Yukon Development Corporation (**"YDC"**) on demand but YDC had no intention of demanding payment in the short term.

In its argument the City of Whitehorse submitted there did not appear to be any reason why YEC could not renegotiate the terms of the debt to reflect current interest rates. The City of Whitehorse recommended that the Board consider reducing the interest rate on this debt to 10.25%.

The Board urges YEC to renegotiate the interest rate on this debt to a level consistent with current interest rates.

4.2.3 Retained Earnings

During cross-examination Company witnesses agreed that the forecast amounts for the Bill Relief Program to be paid out of the Company's retained earnings in 1991 and 1992 were inadvertently not deducted from retained earnings for purposes of determining the 1991 and 1992 revenue requirements. YEC advised that expected Bill Relief Program Payments are $193,538 and $467,157 for 1991 and 1992 respectively.

For the purpose of this Decision the Board has reduced YEC's retained earnings by $193,538 and $467,157 for 1991 and 1992 respectively to reflect the impact of the Bill Relief Program.

4.3 Rate of Return on Common Equity

4.3.1 Introduction

Paragraph 2 of Order of Council, 1991/62, states that:

> "2. The Board must include in the rates of Yukon Energy Corporation provision to recover a normal commercial return on Yukon Energy Corporation's equity, less one-half of one percent (.5%)."

Two witnesses appeared on the matter of a fair rate of return. The applicant(s) presented Ms. K.C. McShane, a vice-president with the Washington based consulting firm Foster Associates. Curragh Resources Inc. presented Mr. David Parcell, a vice-president with the Virginia based firm, Technical Associates Incorporated.

YEC in its evidence stated that:

> "YEC has determined that the rate of return requested by YECL represents a fair and reasonable normal commercial rate of return, and YEC will rely on the testimony of YECL with respect to the normal commercial rate of return submitted in the GRA for 1991 and 1992. In accordance with the directive, YEC has set

> its rate of return in this Application at one half of one per cent less than the rate requested by YECL." (Page 2-24)

During cross-examination by intervenors YEC's witness, Ms. McShane, indicated that her interpretation of the term "normal commercial return" is:

> "... basically the same as what would be considered the fair return on equity for any private utility." (Tr.149)

The City of Whitehorse in its argument submitted that the phrase "normal commercial return" refers to what the return would be for businesses in Yukon.

During cross-examination Ms. McShane explained that it is not appropriate to compare YEC's return to the returns of other businesses in Yukon because capital is raised in national markets and ultimately the relative cost of equity or debt is determined in national and even international markets.

YEC in its reply argument submitted that the City of Whitehorse's interpretation of Order in Council, 1991/62, is without merit. YEC submitted that Section 2 of the Order in Council must be read in conjunction with Section 4 which states:

> "4. Except to the extent otherwise stated by this Directive or the Act, the Board must review and approve rates in accordance with normal principles applicable in Canada for similar utilities." (Tab 12, Page 2)

The Board notes that implicit in evidence submitted by both Ms. McShane and Mr. Parcell is the assumption that "normal commercial return" is equivalent to the fair return on equity for any investor owned public utility.

The Board, for the purposes of this Decision, has interpreted "normal commercial return" to mean "fair return" on equity for a investor owned public utility with similar risk characteristics.

4.3.2 Fair Rate of Return on Common Equity

In its initial Application filed June 6, 1991, YEC requested a rate of return on rate base deemed to be financed by common equity of 13.5% for each of the years 1991 and 1992. YEC's request was based on YECL's requested rate of return on equity of 14% for 1991 and 1992 less a downward adjustment of 0.5% to reflect the direction contained in Order-in-Council, 1991/62.

YECL's initial requested rate of return was based on APL's (YECL's parent) requested rate of return for the years 1991 and 1992 before the Public Utilities Board, Alberta. During the course of the proceedings YECL and YEC filed evidence specific to YECL and YEC with respect to the fair rate of return on common equity.

4.3.2.1 Evidence of Ms. McShane

Ms. McShane, YEC's witness, recommended a fair rate of return of 14.75% to 15% for YECL for each of the years 1991 and 1992. YEC amended its 1992 revenue requirement based on

Ms. McShane's Yukon specific evidence and requested a 14.25% rate of return on common equity.

Ms. McShane relied upon three tests in developing her rate of return recommendation(s): the comparable earnings test, the Discounted Cash Flow (**"DCF"**) and equity risk premium. Ms. McShane acknowledged that the results of each test vary and that the weight given to each is a matter of judgement. Ms. McShane assigned a weight of 50% to her comparable earnings results and 50% weight to her DCF and equity risk premium results taken together.

With respect to Ms. McShane's application of the comparable earnings test, the Board is basically concerned with the nature of the data on which it is based. The Board recognizes that the rate of return on common equity calculation is based on earnings values and book values which reflect the application of generally accepted accounting principles. However, the Board is concerned that the application of these principles may well result in values which, in fact, have not accurately reflected the corporation's earnings in an economic sense. The Board is led to this conclusion by, among other things, Ms. McShane's acknowledgement that a major weakness of the test may be distortion of book values in earlier years. The Board is also led to this conclusion by the significant differences, on average, between per share market prices and book values for Ms. McShane's sample companies.

Ms. McShane's analysis of price level adjusted book values supports the conclusion that substantial differences exist between the accounting values and price level adjusted values. This being the case, the Board is led to the conclusion that historical rates of return on common equity may well overstate the rate of return prospectively achievable by these companies.

Ms. McShane's position is that the values based on historical accounting data are appropriate because the fair rate of return is to be applied to utilities regulated on an original cost basis. This contention has a certain appeal; however, the Board is not convinced that the data for industrial corporations which are subject to wide variations in capital intensity and, in all likelihood, in asset vintages, will average out to provide values which fit closely enough with the economic circumstances of the two utilities that are the subject of this Decision.

While the Board remains concerned with the limitations of comparable earnings data for a determination of the appropriate level of the fair return, the Board is of the view that these data provide an indication of the <u>trend</u> in rates of return. The Board notes the reductions made by Ms. McShane in her estimates of 1991 rates of return for her industrial sample during the course of her various appearances in 1991. In addition, the Board is concerned that Ms. McShane's expectation concerning the possible extent of an economic recovery is somewhat optimistic. Accordingly, the Board is of the view that Ms. McShane's estimate of 1992 corporate profitability is overstated.

With respect to Ms. McShane's application of the DCF test, the Board notes that Ms. McShane raised her estimate of growth (although data the same) from her APL estimate because of the decline in the dividend yield component. Ms. McShane acknowledged that the decline in the dividend yield could also be attributed to a decline in the rate of return required by investors in common shares. In view of the contemporaneous decline in interest rates and no clear signs of improved corporate profitability, the Board feels that the decline in the dividend yield is more likely a manifestation of a decline in Investors' Required Rates of Return (**"IRR"**). Accordingly the Board believes that Ms. McShane's DCF estimates overstate the IRR.

In developing her estimate of the IRR based on the equity risk premium method, Ms. McShane utilized a long term Government of Canada bond rate of 9.75%. At the time of the hearing, yields on Government of Canada bonds 10 years and over to maturity were in the order of 8.98%. Notwithstanding this fact, Ms. McShane felt that her 9.75% value continued to be appropriate given her expectation that an economic recovery would soon materialize. In her view, this would rekindle investors' concerns regarding inflation and bond yields would increase accordingly. In addition, Ms. McShane stated that her 9.75% estimate was related to a longer term bond typically used a benchmark for pricing corporate bonds.

As indicated earlier, the Board is concerned that Ms McShane's expectation as to the possible extent of an economic recovery is overly optimistic. Accordingly, it is the Board's view that, given present circumstances, the current level of Government of Canada bond yields should be given considerable weight in the application of the equity risk premium test for the 1992 test year. Further, for the purposes of this test, the Board does not accept Ms. McShane's position that the relevant Government of Canada bond is a particular issue used as a benchmark for the pricing of new corporate bond issues. In the Board's view, the relevant base yield for the equity risk premium test is the average yield on all long term Government of Canada bonds available to investors. These represent the long term investment opportunities foregone by investors who choose to invest in common stocks. Moreover, their average value is available from an independent government agency.

In determining the fair rate of return from her application of the DCF and equity risk premium tests, Ms. McShane adds a flotation cost component to her estimate of the IRR. She incorporates this increment to ensure that the financial integrity of the common shareholders' investment is maintained. Ms. McShane's increment would, in her view, permit the utility's shares, if publicly traded, to trade under normal conditions at prices in the order of 120% of their book value. In addition, share prices would be expected to remain above book value whenever new shares were issued.

Ms. McShane stated that the business risk of YEC exceeded that of a high grade utility attributing the difference to higher market demand risks and a higher supply risk. In particular, she stated a utility with relative high industrial sales is viewed as being more risky than one with a balanced customer base due to the greater volatility of industrial sales over the business cycle. She considered that YEC's dependence on Curragh Resources Inc. exposes the investor to significant risk and quantified this risk as being greater than that faced by investors in a high grade utility such as APL.

Ms. McShane noted that mitigating factors relative to YEC's risk included a $40 million flexible term note payable to the Government of Canada and the fact that YEC's equity ratio is higher than most high grade utilities.

Ms. McShane acknowledged on cross-examination that her estimate of the impact of a shutdown of the Curragh mine was based on the assumption that rates to other customers to compensate for reduced revenues from the mine would not be introduced for a full year after the mine closure. She also acknowledged that rates to other customers may possibly change sooner then one year after the mine is shut down.

Ms. McShane acknowledged that no Board or Commission had allowed a common equity rate of return equal to her recommended fair rate of return. Nevertheless, none of the utilities for which she had testified had market prices below their book values.

4.3.2.2 Evidence of Mr. Parcell

Mr. David Parcell, appearing on behalf of Curragh Resources Inc., confined his analysis to the application of the comparable earnings and equity risk premium tests. It was his position that he was unable to apply the DCF test in the Canadian context due to the absence of "pure" utilities in Canada.

Mr. Parcell acknowledged that both tests require the application of judgement. For his application of the comparable earnings test, Mr. Parcell indicated that judgement must be applied in developing a procedure to adjust the results obtained for industrial companies. In undertaking his comparable earnings analysis, Mr. Parcell relied upon two pieces of information, both of which incorporate the common book equity per share derived from each corporation's financial statements. The first item is the rate of return on common equity; the second is the ratio of per share market price to per share common book equity. Mr. Parcell was asked by the Board's consultant to comment on the implications of several accounting issues, all of which have implications for the values utilized by Mr. Parcell. Notwithstanding Mr. Parcell's responses, the Board is concerned that the accounting issues which impact on the interpretation of these data were not adequately addressed, particularly given that Mr. Parcell's market-to-book adjustment process also utilizes such data.

The Board is concerned with the efficacy of Mr. Parcell's methodology for estimating equity risk premiums. The Board finds it difficult to accept values for individual years as low as those estimated by Mr. Parcell for 1989 and 1990. While the Board recognizes that Mr. Parcell relied upon the average for all years, the Board is not convinced that the individual values necessarily "average out" to a value in which sufficient confidence can be placed. Moreover, recognizing that the process is directed to establishing a fair rate of return for the 1992 test year, the Board would have expected (given Mr. Parcell's position that the premium depends on the stage reached in the business cycle) that Mr. Parcell would have established the value appropriate to the stage likely to be reached in the business cycle in 1992.

With respect to the degree of confidence to be placed in Mr. Parcell's beta value adjustments, Mr. Parcell acknowledged that he had not examined the "standard error of estimate" of the regression estimates. The Board notes that the "R-squared" values reported by Ms. McShane for her beta values (the latter utilized by Mr. Parcell in his testimony), are very low. The Board considers that these values indicate that Mr. Parcell's adjustment process - relying as it does on only one measure of risk - is built on a statistical foundation of questionable worth.

4.3.3 <u>Board's Position</u>

After giving due consideration to the evidence and argument presented in connection with the general rate application, the Board has concluded that a fair rate of return on common equity of a high grade utility with a common equity ratio of approximately 35% is 12.75% for each of the years 1991 and 1992.

The Board has also concluded that YEC's business risk does not differ materially from that of a high grade utility. The Board notes that YEC's common equity ratio is expected to be approximately 41% and 42% for the test years 1991 and 1992 respectively.

Accordingly, the Board has determined that a fair rate of return, on the portion of YEC's rate based deemed to be financed by common equity, is 12.75% for each of the tests years 1991 and 1992. After applying the provisions of Section 2 of Order-in-Council, 1991/62 the Board has determined a fair rate of return on the portion of YEC's rate base deemed to be financed by common equity to be 12.25% for each of the test years 1991 and 1992.

5. ELECTRIC UTILITY REVENUE REQUIREMENT

5.1 Fuel Expense

5.1.1 Fuel Price

YEC forecast an average cost per litre of fuel of 29.1 cents and 31.0 cents for 1991 and 1992 respectively. During cross-examination Company witnesses indicated that the 1991 and 1992 fuel prices were forecast to increase by 5% and 6% respectively. These increases were based on the forecast inflation rate plus 1%.

During cross-examination the Company witnesses stated the following with respect to the forecast cost of fuel for 1991:

> "Due to the very high prices resulting from the Gulf War in the later part of 1990 and the effects that are still being felt in the early part of 1991 in the first couple of months, since April this year, the price, the variance has been relatively small. We have had a slightly positive variance, a favourable variance.
>
> For the Yukon, in January a price variance accrued of $230,000, in February it was $98,000, and now we are running favourable at approximately $10,000 a month. So it's reasonably close for the remainder of '91 after the prices stabilized." (Tr.783)

In response to a question by the Board's consultant, Company witnesses indicated the following with respect to the forecast increase in fuel costs for 1992:

> "Q. Given current economic circumstances, how can you be satisfied that the fuel prices will increase in 1992?
>
> A. MR. LAKE: We don't know that they will increase in 1992. We made this estimate in the fall of 1990 and revisited it in

> the early spring of 1991. It was our assessment that the fuel price forecast that we had started with in the original preparation of this application would be just as valid as any other forecast we could come up with at that time."(Tr.868)

Company witnesses also acknowledged that if actual fuel costs exceed those included in basic electric rates, the difference can be recovered by the Company through Rider F of the Company's tariff.

The witness also stated that if the forecast prices turned out to be too high the Company and, hence, the shareholders would have the use of customer supplied funds until they were returned by application of Rider F.

Curragh in its argument submitted:

> "Moreover, having insulated the shareholder from forecast risk through the introduction of Rider F, the forecasts put forth in the GRA should not be allowed to provide an indirect cash flow benefit to the shareholder." (Page 20)

Based on the evidence the Board is satisfied that the forecast fuel price for 1991 is reasonable. However, the Board considers that the Company has not provided sufficient evidence to support a 6% increase for fuel prices in 1992. The Board is also concerned that if the 1992 forecast fuel cost per litre is too high the Company would have the use of customer supplied funds until they were returned by the application of Rider F.

The Board has used 1991 fuel prices for purposes of determining the Company's 1992 revenue requirement.

For purposes of determining the forecast average fuel cost in 1992 the Board has used the methodology set forth by the Company in Exhibit 8-40.

For purposes of determining the 1992 revenue requirement the Board has assumed an average cost of fuel per litre of 29.26 cents per litre. This average price reflects the fuel forecast to be consumed in each location in 1992. The use of the 1991 price results in a decrease in the 1992 revenue requirement of approximately $290,000.

5.1.2 Reasonableness of Fuel Costs

Curragh in its argument expressed concern about the reasonableness of the fuel costs incurred by the Company. Curragh's concern was based on the fact that the price paid for fuel by Curragh at the Faro Mine is less than the price paid by YEC for fuel used at Faro. During cross-examination Company witnesses indicated that:

> "It has been their experience over the years that it has always been preferable, namely cheapest to all the customers, to pick one supplier out of those bids supplying the whole package." (Tr.863)

Company witnesses also stated the Company is not purchasing diesel from White Pass at Faro because:

> "... in looking at the total consumption for the YEC communities, the fuel prices from Petro-Canada were lower than the fuel price or fuel costs which would result from awarding the contract to White Pass." (Tr.811)

Curragh submitted in its argument that the Company should be required to submit relevant cost information to demonstrate that its fuel costs have been prudently incurred. Curragh further submitted that in the interim a downward adjustment of 10% to diesel fuel prices should be made in determining the 1991 and 1992 revenue requirement.

The Board recognizes that fuel costs are a significant part of the Company's revenue requirement and is concerned that the Company may not be achieving the lowest possible fuel cost. The Board directs the Company to re-examine its tendering process and to provide evidence at the time of its next general rate application which demonstrates that the Company is achieving the lowest possible fuel costs for all electrical customers in Yukon. YEC should provide details of the tendering procedures used, suppliers approached and the saving (cost) comparisons between purchasing fuel for all locations from one supplier and utilizing different suppliers for different locations.

5.2 Operating and Maintenance Expense

5.2.1 Rate of Inflation Forecast

In response to an information request the Company indicated it had assumed 4% and 5% inflation factors to forecast operating and maintenance expenses for 1991 and 1992 respectively.

During cross-examination the Company's witness, Ms. McShane, indicated that the general consensus was a 3.5% forecast rate of inflation for 1992.

In response to an undertaking the Company provided an analysis of the impact of a 3% inflation rate on the Company's 1992 forecast expenses. The Company provided four different calculations which showed the impact of inflation varying from $18,500 to $177,000.

In reviewing the calculations the Board concludes that there are three issues to be addressed with respect to the impact of the 1992 inflation rate on the Company's revenue requirement. The issues to be addressed are:

(1) Should the 1992 operating and maintenance expenses be restated to reflect the actual inflation rate from October 1990 to October 1991?

(2) Should fuel expense be restated to reflect a lower forecast inflation rate? This issue was dealt with in Section 5.1.1.

(3) What is the appropriate inflation rate to be used for the 1992 forecast?

The 1992 forecast was originally prepared on the basis of a 4% inflation rate in 1991 and a 5% inflation rate in 1992. Subsequently, the Company noted that the actual inflation rate from October 1990 to October 1991 was 5.5%.

Witnesses for both YECL and YEC made the following statement:

> "Looking first at Yukon Electrical operating expenses, the items included here include labour, materials, services and supplies, parent allocations, insurance and property tax, and they exclude fuel and purchase power. For the filing, we had estimated costs to be in the range of $4.1 million for those categories, and we're now estimating those costs to be approximately 4.4 million.
>
> For YEC, the costs included here include labour, materials, supplies and services, YEC corporate costs, insurance and property tax, again excluding fuel. The initial estimate had been $7.6 million, and we are still projecting at this time $7.6 million." (Tr.761)

YECL did not provide any specific details with respect to its revised forecast of $4.4 million for operating expenses. However, in Exhibit 8-32 the Companies provided a combined detailed analysis of the changes in their 1991 costs. YEC did not propose that these changes be included in its 1991 revenue requirement.

The Board notes that the combined operating expenses of the two Companies were originally forecast to be $11,700,000 and are now forecast to be $12,000,000. However, the $12,000,000 includes $280,000 for expenses not originally forecast (Curragh Contract Negotiations of $200,000 and Company Direct Hearing Costs of $80,000).

The Board is not persuaded that it is appropriate to adjust the 1991 forecast to reflect an inflation factor of 5.5% prior to adjusting the 1992 forecast.

The Board has concluded that a 3.5% inflation rate is appropriate based on the evidence provided by Ms. McShane.

The Board, for purposes of determining the 1992 revenue requirement has used a 3.5% inflation factor to forecast YEC's other operating costs and corporate costs. The impact of the reduced inflation rate for 1992 is a reduction in the Company's revenue requirement of approximately $58,000 as shown on Schedule E.

5.2.2 Labour Costs

5.2.2.1 Allocation of Labour Costs

During cross-examination details of YEC personnel and the allocation of personnel costs between YDC and YEC were provided in Exhibit 8-43. Company witnesses indicated that they were not sure how the allocation factors for personnel costs were arrived at and that staff were not required to provide time sheets.

The Board is concerned that there could be a misallocation of labour costs between YDC and YEC. The Board directs that time sheets and similar records be produced to justify allocations in the future.

5.2.2.2 Labour Productivity

The Board notes that there has been a continuous increase in labour costs since 1988 and further increases are forecast for the 1991 and 1992 test years. The Board is concerned that the Company's increased labour cost may be excessive in relation to the services provided by the Company.

Accordingly, the Board directs YEC to provide, at the time of its next general rate application, appropriate measures of labour productivity on an historical and forecast basis.

5.3 Depreciation Expense

For the reasons outlined in Sections 3.3 and 3.2.2 of this Decision, the Board has reduced depreciation expense by $43,500 and $41,500 for each of the years 1991 and 1992 respectively.

5.4 Maintenance

5.4.1 Hydro Maintenance

The City of Whitehorse in its argument submitted that the 1991 and 1992 forecast hydro maintenance should be reduced on the basis that YEC has historically forecast significantly higher expenditures for hydro maintenance than it has actually incurred.

In response to an information request the Company provided a comparison of forecast and actual hydro maintenance expense for 1989 and 1990 and provided explanations for the 1991 and 1992 forecasts.

A summary of the response is as follows:

	Actual	Forecast
1989	257	483
1990	160	344
1991	n/a	385
1992	n/a	555

With respect to 1990 the Board notes that $200,000 of the forecast expense was capitalized when incurred. The Board has addressed this issue in Section 3.2.2 of this Decision and has deducted the $200,000 from YEC's rate base.

Due to the adjustment the Board concludes the 1990 forecast was not materially different from actual.

In 1991 YEC forecast $385,000 for hydro maintenance, approximately $40,000 more than forecast for 1990. In response to questioning on how the 1991 O&M forecast expenditures compared to actual, a Company witness stated:

> "For YEC, the costs included here include labour, materials, supplies and services, YEC corporate costs, insurance and property tax, again excluding fuel. The initial estimate had been $7.6 million, and we are still projecting at this time $7.6 million." (Tr.761)

With respect to the 1992 forecast hydro maintenance expense, the Company has forecast $555,000, $170,000 greater than forecast for 1991. Explanations for the increase in 1992 hydro maintenance expense over the 1991 expense include:

a) A major overhaul on hydro unit #1 at Aishihik estimated to cost $130,000.

b) $40,000 for painting the Whitehorse and Aishihik hydro plants and $12,000 for maintenance work on the Aishihik service elevator.

The Board recognizes the City of Whitehorse's concern with respect to overforecasting of hydro maintenance.

However, the Board is not persuaded that a significant overforecast in one year (1989) establishes a trend. The Board notes that the Company is forecasting a significant increase in hydro maintenance expense in 1992 and will continue to monitor forecast and actual hydro maintenance in future general rate applications.

5.4.2 <u>Diesel Maintenance</u>

The City of Whitehorse in its argument expressed the following concern with respect to the 1991 and 1992 diesel maintenance expense forecast:

> "YEC is forecasting higher maintenance costs in 1991 and 1992 due to increased number of diesel units and increased diesel generation. It is difficult for us to determine the exact needs for the level of expenditures being forecast and we do note the cyclical nature of the planned overhauls. While these forecasts appear high to us, we are not in a position to argue they are not required at this time. We hope the new more efficient units being purchased will maybe reflect in less maintenance in the future. We also trust that YEC and YECL have reviewed the major overhauls planned and do not expect to capitalize any of the costs associated with these overhauls." (Page 27)

A comparison of actual diesel maintenance expense to forecast is as follows:

	<u>Actual</u>	<u>Forecast</u>
1988	266	n/a
1989	371	418
1990	274	455
1991	n/a	561
1992	n/a	455

The Board notes that YEC included $78,000 and $80,000 for contingencies in the 1989 and 1990 forecast. In response to an information request YEC indicated that the 1991 and 1992 forecasts do not include an amount for contingencies.

The Board shares the City of Whitehorse's concern with respect to the forecast diesel maintenance expense. However, the Board concludes that the evidence provided during the proceeding does not support a reduction in the allowed diesel maintenance expense. The Board will continue to monitor the forecast and actual diesel maintenance expense in future general rate applications.

6. DEMAND SIDE MANAGEMENT

Paragraph 5, Order in Council, 1991/62 states:

> "5.(1) The Board shall encourage Yukon Energy Corporation and The Yukon Electrical Company Limited to promote economy and efficiency in the generation, transmission and use of electricity.
>
> (2) The Board shall allow Yukon Energy Corporation and The Yukon Electrical Company Limited to recover, through rates, the expenditures reasonably incurred by them for the purposes set out in subsection (1)."

In its Application the Company included $50,000 in operating expenses for 1991 for Demand Side Management (**"DSM"**) programs and $250,000 in Construction Work in Progress (**"CWIP"**). The 1992 forecast included $50,000 for operating expenses for DSM programs and $500,000 of capital expenditures for DSM programs. The amount of $750,000 was forecast to be transferred from CWIP to rate base at the end of 1992.

Company witnesses indicated during cross-examination that the DSM program is in its infancy and that the programs which were initially chosen by the Company were based upon programs which had been successful in other jurisdictions. The Company commissioned a study by Power Smart Inc. on the potential of DSM in Yukon. This study is now complete and the Company is in the process of evaluating it.

In response to an information request the Company indicated that it was in the process of obtaining evaluation reports from other companies who had implemented similar DSM programs and would provide the Board with these evaluations when received. The Board notes that on December 13, 1991, subsequent to the public hearing, the Company filed several reports on DSM programs that had been implemented in other jurisdictions.

Company witnesses indicated that the 1991 DSM expenditures included expenditures for a water saver program, a power cord saver program, planning and public awareness programs.

With respect to the power saver cord program the Board notes that Exhibit 8-49 indicates that Manitoba Hydro had abandoned promoting the power saver cords in 1987-88 on the basis that with the -7 Celsius thermostat setting the cords were on nearly all of the time during Winnipeg's winter weather conditions. ICG, a power company in the Northwest Territories, concluded that the power saver cords would not succeed in Yellowknife. Company witnesses indicated that the Company is encouraging use of timers in conjunction with the power saver cords. Company witnesses acknowledged that a timer used by itself may be effective if the user is prepared to adjust the timer for temperature differences.

In response to questions about the 1992 forecast DSM expenditures, Company witnesses indicated that they plan to deal with the expenditures in detail at the capital hearing and that the Company had not finalized a detailed plan for 1992.

With respect to the accounting for DSM programs, Company witnesses indicated that accounting policies had not yet been finalized and a thorough review at year end would be required.

The City of Whitehorse in its argument recognized the potential for DSM. However, it also recognized that it was not clear at the time of the hearing as to what programs were covered by the proposed 1992 DSM expenditures and what impact the Companies' DSM programs would have on the sales of energy.

The City of Whitehorse on this basis recommended that the Board place the DSM expenditures in CWIP at the end of 1992 to enable the details of the DSM programs to be pursued during the upcoming capital hearing.

The Board supports the concept of DSM. However, the Board is concerned about the reasonableness of the forecast costs included in the 1991 and 1992 general rate application. The Board notes that the Company implemented several DSM programs in 1991 prior to the finalization of the Company's DSM study. In addition, the Board notes the Company relied primarily on programs that had been implemented in other jurisdictions. When asked for evaluations from other jurisdictions on the DSM programs implemented by YEC, the Company could not provide any studies or evaluations until subsequent to the public hearing.

The Board also notes that the Company has not provided any evidence contrary to the experience in Winnipeg and Yellowknife with respect to the power saver cord. With respect to the 1992 forecast expenditures on DSM, the Company has provided no evidence with respect to the purpose of forecast expenditures. The Board also notes that the Company has not finalized its accounting policies with respect to DSM programs.

The evidence indicates that YEC included in its 1991 and 1992 forecast operating and maintenance expenses costs relating to a utility engineer and a manager of policy and communications. The Board understands that these two positions are predominantly related to DSM activities. The Board considers it appropriate to deal with the cost relating to these two positions in its deliberations relative to YEC's DSM activities. The Board has estimated the annual cost of these two positions to be $100,000 per year and will deal with this cost as part of the Company's DSM expenditures.

The Board considers that at this time it would be inappropriate to include any costs relating to DSM expenditures in YEC's 1991 and 1992 revenue requirement. The Board directs the Company to provide detailed support for its 1991 DSM programs and its planned 1992 DSM programs in the upcoming capital hearing.

In particular the Board directs the Company to provide detailed program evaluations and cost benefit studies together with a detailed description of the results of similar programs carried out in other jurisdictions.

The Board directs that all DSM expenditures for 1991 and 1992 be placed in CWIP. Accordingly, the Board has reduced the operating expenses by $150,000 for each of the test years 1991 and 1992. The year end 1992 rate base has also been reduced by $750,000.

7. LOW WATER RESERVE

At December 31, 1990 there was a balance of $2 million in the Company's low water reserve. As explained in Decision 1989-4, the $2 million reserve was established out of retained earnings to protect against increased costs to produce electricity by diesel generation at times of low water conditions and shutdowns of hydro facilities.

In the current application YEC has proposed the following with respect to the low water reserve:

> "I. Appropriations would be made from YEC income to the extent that YEC diesel generation costs in any year are below forecast levels due to above average hydraulic generation capability, and such appropriations would be added to the above contingency reserve (subject to the condition that the reserve not exceed a specified maximum level as set out below).
>
> II. Withdrawals from the above contingency reserve would be added to YEC income to the extent that YEC diesel generation costs exceed forecast levels due to below average hydraulic generation capability." (YEC's Application, Page 2-25)

YEC is also proposing:

> "... that the maximum contingency reserve amount for the above purposes reflect a reasonable estimate of YEC losses which could result from replacing hydraulic generation with diesel generation in low water years." (YEC's Application, Page 2-26)

In response to an information request the Company indicated that it was proposing a maximum contingency reserve of $4 million.

The response also states that:

> "Variations to the reserve will not normally be factored into General Rate Applications as the GRA is based upon average water flows for prospective test years.
>
> The reserve will be affected only when hydraulic generation varies from these amounts due to fluctuations in water flow. This will be done on a retrospective basis after the actual results for the operating year have been taken into consideration. The debit or credit to the reserve will be utilized in the calculation of net income for the year. For

> example, if hydraulic generation exceeds the forecast due to higher than expected water flows, then the savings in diesel will be credited to the reserve. If hydraulic generation is less than the forecast due to lower than expected water flows, then the additional costs incurred making up the shortfall with diesel will be debited to the reserve and credited to expense."
> (WHSE-YEC-10)

Company witnesses further explained how the low water financial reserve will work to stabilize rates in Yukon.

> "I think that's the important thing to focus on from the customers' point of view, is that it [the low water financial reserve] takes any excess earnings which result from a factor such as rainfall, and makes sure that the customers eventually get it.
>
> As I stated before, in the case of a low water year, we would be inclined, I think [in the absence of such a reserve], to come back to the Board for higher rates in a year because the potential impact is quite large."
> (Tr.591)

On the basis of the evidence adduced during the hearing, it is the Board's understanding that the low water reserve will be implemented by the Company in the following manner:

(1) The Company will determine the level of the lake at the time the forecast is prepared.

(2) The Company will forecast average water inflows during the year.

(3) Based on steps (1) and (2) the Company will forecast the amount of hydro generation and thus the required amount of diesel generation.

(4) At the end of the year the Company will determine if the forecast diesel generation differed from actual experience due to water flows and if so the reserve will be increased or decreased accordingly.

Based on the above procedures it is the Board's understanding that no direct charge will be included in the forecast revenue requirement for the low water reserve. Rather, if the Company over earns in a year because the actual diesel generation is less than the forecast diesel generation due to higher than forecast water flows, the reserve would be increased to the extent of the difference between forecast and actual diesel generation up to a maximum of $4 million. Similarly, if the Company under earns in a year because actual diesel generation exceeds forecast diesel generation due to lower than forecast water flows, the reserve would be decreased.

In its October 1991 update YEC stated:

> "The proposed GRA adjustments do not include any additions in 1992 to YEC's low water financial reserve, thereby facilitating the minimum 1992 rate increase; as a result, the 1993 overall retail rate increase will be increased by approximately six percentage points above the level otherwise required if 1992 rates had reflected the maximum potential 1992 increase ($2.0 million) in YEC's financial reserve." (October 1991 Adjustments, Page 4)

The Board's understanding of this statement is that rates would be impacted in the following manner:

(1) The 1992 revenue requirement as initially filed was based on average hydro and diesel generation.

(2) The 1992 amended revenue requirement was based on above average hydro generation and below average diesel generation resulting in lower rates than would have prevailed if average hydro and diesel generation had been used.

(3) If, in 1993, water flows are such that hydro generation is average resulting in average diesel generation, an increase in rates above 1992 levels will be required.

In YEC's argument it requested that the Board approve the following with respect to the low water reserve:

"(a) Whether this reserve should be established in the manner proposed by YEC, including the various ground rules set out by YEC in the evidence?

(b) If the Board approves the reserve, is the proposed $4.0 million approved as the maximum amount applicable at this time for the reserve?

(c) If the Board approves the above proposals, is the proposed adjustment to YEC's initial Application (the October 21, 1991 update) accepted with respect to Aishihik generation for the test year 1992, i.e., the increase in forecast Aishihik generation from 107 to 150 GWh for that test year based solely on higher-than-expected water availability which occurred after filing of the initial Application in June 1991?" (Page 51) initial Application in June 1991?" (Page 51)

The Board is concerned that the use of the "level of the lake at the time the (hydro) forecast is prepared" as proposed in the October 1991 update rather than using a hydro generation forecast based upon long term average hydro generation may lead to rate instability.

For the purpose of this Decision the Board accepts the updated hydro generation forecast for 1992. At the time of the next general rate application the Board expects the Company to present evidence relating to the advantages and disadvantages of using current water levels as compared to long term average hydro generation. Also for the purpose of this Decision the Board will accept the procedure for the low water reserve as described at Pages 2-25 and 2-26 of the Company's Application and the $4 million maximum. However, the Board anticipates that all matters relating to the low water reserve will need to be re-examined at the next general rate application.

8. RIDER F - FUEL ADJUSTMENT RIDER

YEC'S evidence indicated that at the end of 1990 fuel costs exceeding those included in rates (unfavourable variance) of $544,190 had not been collected from its customers. The unfavourable variance was included as a deferred charge on YEC's 1990 balance sheet.

Company witnesses indicated that the unfavourable variance in the fuel adjustment account at the end of October 1991 was $783,000. Company witnesses also indicated that YEC proposed to collect $544,190 of the variance over a six month period commencing in 1993.

The Board notes that the fuel adjustment rider reads as follows:

> "The change in this Rider will change in accordance with changes in the Companies' fuel cost calculated on a unit basis by reference to kW.h sales. Such changes to the change in this Rider shall be implemented <u>coincident</u> with changes in the Companies' costs of fuel or at such time as is practical." (emphasis added)

The Board considers that any changes in the Company's fuel cost should be dealt with in a timely manner. The Board is concerned that with the upcoming capital hearing and the uncertainty of future water levels rate payers may well be facing significant increases in rates in 1993 and it is inappropriate to exacerbate the increase with collection of Rider F which relates to fuel costs in 1990 and 1991.

The Board is of the view that YEC's decision to defer the collection of higher fuel costs due to the Gulf War is inconsistent with its financial mandate to function as a fiscally responsible and self-financing commercial entity earning a normal commercial return on equity and charging stable and predictable long term power rates.

The Board directs YEC to calculate and file a rider designed to recover the unfavourable variance balance as at December 31, 1991 over a twelve month period commencing with billings on and after February 1, 1992. The Board also directs the Company to file on a monthly basis commencing in January 1992 a calculation of the fuel price variance and to establish procedures to collect (refund) any fuel variance on a timely basis.

9. AISHIHIK LAKE WATER MANAGEMENT

Peter Percival and Gary McRobb in their argument submitted that developing energy supply on the Whitehorse-Aishihik-Faro grid as economically as possible should be a top priority for YEC. These intervenors submitted that one option that should be considered is the use of top storage on Aishihik Lake.

The Board considers hydrological management of YEC's reservoirs to be integral to developing economical sources of energy. The Board intends to examine the potential for top storage at Aishihik Lake and Marsh Lake at the upcoming capital hearing. The Board directs the Company to fully examine all aspects of its management of hydro resources and to be prepared to provide evidence supporting its policies and on the use of top storage or other procedures which may reduce the cost of electrical energy at the time of the capital hearing.

10. REGULATORY PROCESS

YEC in its argument made the following submission:

> "YEC is concerned about the costs incurred during the application process. The cost of this exercise must ultimately be borne by the customers and therefore the Board should critically analyze the process which has taken place since the applications were filed with a view to ensuring that costs can be minimized in future hearings." (Page 41)

The Board notes that the Whitehorse Chamber of Commerce also expressed concern with respect to the cost and complexity of the regulatory process.

The Board shares these concerns with respect to the cost and complexity of the regulatory process. The Board will provide an opportunity for parties to address this issue at the time of the upcoming cost of service review. All parties wishing to make representations to the Board on this subject are invited to do so at the time of the cost of service review.

11. TOTAL REVENUE REQUIREMENT

The Board directs YEC to prepare a revised calculation of total utility revenue requirement for the test years 1991 and 1992 in accordance with this Decision and Decisions 1992-2 and 1992-4.

ORDER

NOW THEREFORE IT IS ORDERED THAT:

Yukon Energy Corporation shall prepare and file with the Board within thirty (30) days a revised calculation of total utility revenue requirement for the test years 1991 and 1992 in accordance with this Decision and Decisions 1992-2 and 1992-4.

DATED AT WHITEHORSE, YUKON this 17th day of January 1992.

YUKON UTILITIES BOARD

CHAIRMAN

FOLLOWING ARE

SCHEDULES "A", "B", "C", "D" AND "E"

(Consisting of 9 Pages)

ATTACHED TO AND FORMING PART OF

YUKON UTILITIES BOARD

DECISIONS 1992-1

DATED JANUARY 17, 1992

YUKON UTILITIES BOARD

CHAIRMAN

YUKON ENERGY CORPORATION

1991

RATE BASE

($ 000)

	AS FILED		AS ALLOWED	
	Previous Year	Current Year	Previous Year	Current Year
Plant				
Cost	107,073	116,662	106,873	116,462
Deduct:				
Accumulated Depreciation	8,202	11,022	8,202	10,979
Construction-in-progress	623	1,402	956	2,035 *
Low water & ins reserves				2,250
	98,248	104,238	97,715	101,199
Mid-year net plant		101,243		99,457
Working capital		1,437		1,429
		102,680		100,886
Deduct:				
Contributions	265	405	265	405
Mid-year contributions		335		335
Net rate base		102,345		100,551

* Excludes adjustment for DSM operating expenses

YUKON ENERGY CORPORATION

1992

RATE BASE

($ 000)

	AS FILED		AS ALLOWED	
	Previous Year	Current Year	Previous Year	Current Year
Plant				
Cost	116,662	135,504	116,462	135,304
Deduct:				
Accumulated Depreciation	11,022	14,212	10,979	14,127
Construction-in-progress	1,402	12,486	2,035	13,821 *
Low water & ins reserves			2,250	2,250
	104,238	108,806	101,199	105,106
Mid-year net plant		106,522		103,152
Working capital		1,432		1,404
		107,954		104,556
Deduct:				
Contributions	405	459	405	459
Mid-year contributions		432		432
Net rate base		107,522		104,124

* Excludes adjustment for DSM operating expenses

YUKON ENERGY CORPORATION

1991

WORKING CAPITAL ALLOWANCE

($ 000)

	AS FILED	AS ALLOWED
Operating & maintenance expenses	13,336	13,186
Taxes - other than income	142	142
Cash operating expenses	13,478	13,328
21/365 thereof	775	767
Inventory (three year average)	662	662
Working capital	1,438	1,429

YUKON ENERGY CORPORATION

1992

WORKING CAPITAL ALLOWANCE

($ 000)

	AS FILED	AS ALLOWED
Operating & maintenance expenses	13,258	12,760
Taxes - other than income	150	150
Cash operating expenses	13,408	12,910
21/365 thereof	771	743
Inventory (three year average)	661	661
Working capital	1,432	1,404

YUKON ENERGY CORPORATION

1991

CAPITAL STRUCTURE AND COST OF CAPITAL

($ 000)

AS FILED

	MID YEAR BALANCE	CAPITAL RATIOS	MID-YEAR RATE BASE	COST RATE	RETURN
		%		%	
Long term debt	65,850	56.616	57,944	8.450	4,896
Common shares	48,210	41.450	42,422	13.500	5,727
No cost capital	2,250	1.934	1,980		
	116,310	100.000	102,345	10.380	10,623

AS ALLOWED

	MID YEAR BALANCE	CAPITAL RATIOS	MID-YEAR RATE BASE	COST RATE	RETURN
		%		%	
Long term debt	65,850	57.782	58,100	8.450	4,909
Common shares	48,113	42.218	42,451	12.250	5,200
No cost capital					
	113,963	100.000	100,551	10.054	10,110

YUKON ENERGY CORPORATION

1992

CAPITAL STRUCTURE AND COST OF CAPITAL

($ 000)

AS FILED

	MID YEAR BALANCE	CAPITAL RATIOS	MID-YEAR RATE BASE	COST RATE	RETURN
		%		%	
Long term debt	73,950	56.128	60,350	8.830	5,329
Common shares	55,552	42.164	45,336	14.250	6,460
No cost capital	2,250	1.708	1,836		
	131,752	100.000	107,522	10.964	11,789

AS ALLOWED

	MID YEAR BALANCE	CAPITAL RATIOS	MID-YEAR RATE BASE	COST RATE	RETURN
		%		%	
Long term debt	73,950	57.292	59,655	8.830	5,268
Common shares	55,125	42.708	44,469	12.250	5,447
No cost capital					
	129,075	100.000	104,124	10.291	10,715

YUKON ENERGY CORPORATION

1991

OPERATING AND MAINTENANCE EXPENSES

($ 000)

	AS FILED	AS ALLOWED
Operating and maintenance expenses		
Production	3,803	3,803
Transmission & distribution	754	754
General	157	157
Public information	63	63
Commercial	282	282
Administration	509	509
Fuel	5,834	5,834
Purchased power	9	9
Insurance	440	440
YEC corporate expenses	1,485	1,485
DSM adjustment		(150)
Total operating & maintenance expenses	13,336	13,186
Taxes - other than income	142	142
Depreciation	3,067	3,024
Total utility expenses	16,545	16,352

YUKON ENERGY CORPORATION

1992

OPERATING AND MAINTENANCE EXPENSES

($ 000)

	AS FILED	AS ALLOWED
Operating and maintenance expenses		
Production	4,126	4,126
Transmission & distribution	801	801
General	178	178
Public information	63	63
Commercial	310	310
Administration	596	596
Fuel	5,123	4,833
Purchased power	9	9
Insurance	508	508
YEC corporate expenses	1,544	1,544
Inflation adjustment		(58)
DSM adjustment		(150)
	-------	-------
Total operating & maintenance expenses	13,258	12,760
Taxes - other than income	150	150
Depreciation	3,397	3,356
	-------	-------
Total utility expenses	16,805	16,266
	=======	=======

YUKON ENERGY LIMITED

1992

CALCULATION OF IMPACT OF INFLATION ON OPERATING EXPENSES

	AS FILED 1992 EXPENSES	AS ALLOWED 1992 EXPENSES
Total other	2,506	2,470
YEC Corporate Costs	1,544	1,522
	-------	-------
	4,050	3,992
	=======	=======
	5%	3.5%

YUKON ENERGY CORPORATION

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THE YUKON ELECTRICAL COMPANY LIMITED

ELECTRIC SERVICE REGULATIONS

1. INTERPRETATION

1.1 Definitions

Unless the context requires otherwise, the following words and phrases, whenever used in these Regulations, the Electric Service Tariff or an application, contract or agreement for service, shall have the meanings set out below.

"billing demand" - the demand upon which billing to a customer is based.

"Board" - the Yukon Utilities Board.

"company" - The Yukon Electrical Company Limited or Yukon Energy Corporation.

"connected load" - the sum of the capacities or ratings of the electric energy consuming apparatus connected to a supplying system.

"construction contribution" - the difference between the cost of extending the company's facilities to serve a customer and the maximum company investment specified in Schedule B.

"customer" - means a person, firm, corporation, association or organization who or which as applied for and has been accepted for the provision of Service by the Utility.

"demand" - the rate at which electric energy is delivered by the company (expressed in kilowatts, kilovoltamperes or other suitable unit) at a given instant or averaged over any designated period of time.

"energy" - electric energy (expressed in kilowatt hours).

"extraordinary circumstances" - circumstances not reasonably within the control of the company, including acts of God, strikes, lockouts or other industrial disturbances, acts of the public enemy, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, high water, washouts, inclement weather, orders or acts of civil or military authorities, civil disturbances, explosions, breakdown or accident to equipment, and any other cause, whether of the kind herein enumerated or otherwise.

"facilities" - a physical plant (including, without limitation, generating plants, transmission and distribution lines, transformers, meters, equipment and machinery).

"family dwelling" - a residential dwelling unit which is not a multiple dwelling (see definition of "multiple dwelling").

"in-service date" - the date on which the customer specifies service is to be available or the date the service is actually available, whichever is later.

"interconnected system" - those portions of the company's facilities which are connected to the Whitehorse/Aishihik power grid.

"isolated system" - those portions of the company's facilities which do not form part of the interconnected system.

"load" - the demand and energy delivered to or required at any point of delivery.

"load factor" - the ratio of the average demand (in kilowatts) supplied during a designated period to the peak or maximum load (in kilowatts) occurring in the period. To express load factor as a percentage:

(a) multiply the energy used in the period by 100;

(b) multiply the maximum demand by the number of hours in the period; and

(c) divide (a) by (b).

"multiple dwelling" - a residential building containing more than one residential dwelling unit.

"point of delivery" - the point at which the company's service conductors are connected to the wires or apparatus of a customer.

"power factor" - the ratio of the highest metered kilowatt demand in a billing period to the highest metered kilovoltampere demand in that same billing period.

"service" - the delivery of energy by the company at the demand required by a customer.

2. INTRODUCTION

2.1 Board Approval

These regulations have been approved by the Board.

The company may amend these regulations by filing a notice of amendment with the Board. Included in the notice to the Board shall be notification of which customer groups are affected by the amendment and an explanation of how affected customers will be notified of the amendments. The amendment will take effect 120 days after such notice is filed unless the Board orders otherwise.

2.2 Electric Service Tariff

These regulations are the Electric Service Regulations referred to in the company's Electric Service Tariff and form part of the Electric Service Tariff.

2.3 Effective Date

These regulations come into force on May 1, 1991, and replace the company's previous Electric Service Regulations. Whenever the Board approves an amendment to these Regulations, revisions will be issued, with the effective date of the amendments indicated on the top of each affected page.

3. GENERAL PROVISIONS

3.1 Regulations Prevail

These regulations apply to the company and to every customer.

No agreement can provide for the waiver or alteration of any part of these regulations unless such agreement is first filed with and approved by the Board.

3.2 Ownership of Facilities

The company remains the owner of all facilities it provides to serve the customer, unless a contract between the company and customer specifically provides otherwise.

Payment made by customers for costs incurred by the company in installing facilities does not entitle customers to ownership of any such facilities, unless a contract between the company and the customer specifically provides otherwise.

3.3 Use of Energy

Unless otherwise provided in a contract with the company, a customer shall not sell energy provided by the company unless the company has first given written consent.

3.4 Customer Extensions

A customer shall not extend service facilities beyond property owned or occupied by him.

3.5 Customer Generation

A customer must sign an agreement with the company if he wishes to use service.

a) in parallel operation with; or

b) as supplementary, auxiliary or stand-by service to any other source of electric energy.

3.6 Frequency and Voltage Levels

The company will make every reasonable effort to supply energy at 60-Hertz alternating current. The voltage levels and variations will comply with the Canadian Standards Association standards and as specified in Schedule A.

Some voltage levels set out in Schedule A may not be available at all locations served by the company.

4. APPLICATION FOR AND CONDITIONS OF SERVICE

4.1 General Requirements

To enable the company to provide the requested service, applicants for service shall supply information regarding their load and preferred supply conditions.

An applicant may be required to sign an application or a contract for service and may be required to provide credit information or references.

4.2 Conditions of Service

Before connecting any service, the company will inform the customer if there are any special conditions that must be satisfied.

4.3 Connection Fee

Whenever a connection is made, the customer will pay a non-refundable connection fee of either:

(a) $15 if the connection is made during the company's regular business hours; or

(b) an amount not to exceed the company's actual costs if the connection is made at any other time,

which will be included in the customer's first billing.

4.4 Application of Rate Schedules

Whether or not a Customer has signed an application or contract for Service, the Regulations and the rate schedule applicable to the Service supplied by the Company shall apply. In addition to payments for electric service, the customer is required to pay the company the amount of any tax or assessment levied by any tax authority on electric service delivered to the customers.

4.5 Extensions to Electric Heat Customers

On isolated systems, service for electric space heating purposes may be supplied to customers only with the prior written permission of the Company.

4.6 Multiple Dwellings

Each individual unit within a multiple dwelling will be served as a separate point of delivery, unless the company agrees otherwise.

The company and a customer may agree that one bill will be issued covering all individual units in a multiple dwelling.

Where the company and a customer have agreed that service to a multiple dwelling shall be delivered through a single point of delivery, the applicable general service (non-residential) rate schedule will apply to the service.

Where a customer was, on March 31, 1989, receiving one bill in respect of more than one unit, the customer may continue to be billed on that basis until such time as the customer's load changes or the service conductors and meters serving that customer are relocated.

4.7 Totalized Metering

Normally, the company will issue a separate bill for each point of delivery.

When service is provided through multiple points of delivery to a customer's plant site consisting of centralized processing facilities or product transportation facilities located on lands leased or owned by the customer, where such multiple points of delivery are located within a radius of half a mile of each other, the customer and company may agree that the demand and energy at each point of delivery be totalized and only one bill issued for each billing period.

The customer shall pay the incremental metering cost associated with totalized metering.

4.8 Consolidated Billing

The company will issue a separate bill for each point of delivery. However, the customer and company may agree that the company will issue one bill totalling charges for service delivered at more than one point of delivery.

4.9 Security Deposit

The company may require any customer who is unable to establish a satisfactory credit rating, or who has been disconnected or those where a current-limiting device has been installed, to provide a security deposit which shall not exceed the company's estimate of the customer's total bills for any three-month period.

The company will pay simple interest on the security deposit from the date the deposit is paid, at a rate of interest equal to the rate fixed for the most recent rate of the Yukon Landlord and Tenant Act and such interest will be credited to the customer's account on the first billing following December 31 of each year.

The company may refund a security deposit when the customer has established a satisfactory payment history over a 12-month period or when the customer's service is terminated. Any interest owing at the time a security deposit is refunded will be included in the refund or credited to the customer's account.

4.10 Use of Security Deposit

If a customer fails to pay any amount billed, the company may apply all or any portion of that customer's security deposit to the unpaid amount.

When the company has to take this step, the customer may be required to pay a security deposit up to the maximum amount allowed in regulation 4.9.

4.11 Delay in Taking Service - Subdivision

When a customer requests service to a subdivision, then in addition to any other charges payable by the customer, the customer shall make a payment, not to exceed the maximum company investment specified in Schedule B, for each point of delivery within the subdivision where service will not be taken within 12 months of the in-service date.

When service is taken at a point of delivery within five years of the in-service date, the company will refund the payment applicable to that point of delivery. Otherwise, such payment will be forfeited to the company.

4.12 Delay in Taking Service - Other than Subdivision

Except in the case of a customer who requests service to a subdivision under regulation 4.10, if service is not taken within 30 days of the in-service date, the company may begin billing the customer for the minimum amount specified in the appropriate rate schedule or as specified in the contract between the company and the customer, whichever is greater.

4.13 Extension of Service

If the company's estimated costs of extending facilities at the request of a customer are less than the maximum company investment specified in Schedule B for the type of service provided, the customer will not be required to make any contribution.

In all other cases, an agreement for payment of extension charges must be made between the customer and the company before any work on the extension is commenced.

4.14 Underground Subdivision Extensions

Underground subdivision extensions shall be undertaken subject to the conditions set out in Schedule C.

4.15 Conversion from Overhead to Underground Service

When a customer requests that existing company facilities be converted from overhead to underground, the customer will be charged for all costs incurred by the company in connection with the conversion, including the following:

(a) the estimated cost of removing the existing facilities, less the estimated salvage value, plus

(b) the estimated cost for the installation of the new underground facilities, less any applicable increase in company investment as specified in Schedule B.

4.16 Temporary Service

Where the company reasonably believes that a requested service will be temporary, it may require the customer requesting the service to pay the company's total estimated cost of installation and removal of the service, plus the cost of unsalvageable material.

The company may require that such payment be made before the temporary service is installed.

4.17 Mobile Homes

Service shall normally be provided to mobile homes through separate points of delivery, based on the applicable residential rate schedule.

Service provided to common use areas (e.g., laundry facilities) in a mobile home park shall be separately metered and billed at the applicable general service rate.

In mobile home parks or trailer courts where the company reasonably believes homes are temporary, the company may elect to provide service only through the point of delivery billed to the mobile home park or trailer court.

4.18 Relocation of Company Facilities

The company may require a customer to pay all reasonable costs incurred by the company in relocating any company facility at the customer's request.

If requested by the company, the customer shall pay the estimated cost of the relocation in advance.

Where the cost of the relocation is estimated to be more than $2,000, the customer shall pay the actual cost of the relocation and upon establishing such actual cost, a refund or supplementary billing will be issued to the customer.

4.19 Reconnection or Restoration of Service

This section applies when the company is asked to reconnect or restore service to a customer whose service was previously restricted by a current-limiting device or discontinued (whether at the request of the customer or not).

This section does not apply when a customer's service was disconnected for safety reasons. (See regulation 11.2)

Before reconnecting or restoring service, the customer shall pay:

(a) any amount owing to the company;

(b) a collection charge of $30 if the reconnection is made during the company's normal business hours, or, in any other case, an amount not exceeding the company's actual cost of reconnection;

(c) the security deposit, if any, required under regulation 4.8.

4.20 Construction Contribution Refunds

When a customer provides a construction contribution to obtain service, the company will refund a portion of the service charges if another customer shares a part of the service to which the construction contribution relates.

5. RIGHTS OF WAY AND ACCESS TO FACILITIES

5.1 Easements

The customer shall grant, or cause to be granted, to the company, without cost to the company, such easements or rights-of-way over, upon or under the property owned or controlled by the customer as the company reasonably requires to provide service to such customer.

5.2 Right of Entry

The company's employees or agents shall have the right to enter a customer's property at all reasonable times for the purpose of installing, maintaining, monitoring and removing the company's facilities and for any other purpose incidental to the provision of service.

The customer shall provide the company with reasonable access to company facilities located on the customer's property.

5.3 Vegetation Management

The customer shall permit the company to manage vegetation on the property owned or controlled by the customer to maintain proper clearances and reduce the risk of contact with the company's facilities.

The company shall endeavor to notify a customer before such work is performed.

5.4 Interference with Company's Facilities

Customers shall not place any structures that would interfere with the proper and safe operation of the company's facilities or which would adversely affect compliance with any applicable legislation.

5.5 Customer Brushing

Customers requesting service that requires new electrical facilities/powerlines, shall be responsible for brushing to Company specification along with providing an unobstructed access to each structure.

6. METERS

6.1 Installation

The company shall provide, install and seal all meters necessary for measuring the energy supplied to a customer, unless otherwise specifically provided in a contract with the customer.

Each customer shall provide and install a CSA-approved meter receptacle or other CSA-approved facilities suitable for the installation of the company's meter or metering equipment.

6.2 Location

Meter locations shall be approved by the company based on type of service and convenience of access to the meter. Where a meter is installed on a customer-owned pole, the pole shall be provided and maintained by the customer as required by the Canadian Electric Code and any other applicable legislation.

6.3 Meter Tests and Adjustments

The company may inspect and test a meter at any reasonable time.

At the request of a customer, and upon payment of a $25 fee, the company shall arrange for a meter to be tested by an official designated for that purpose by Consumer and Corporate Affairs Canada or such other federal government agency as may, from time to time, be designated for the purpose.

If a test determines that the meter is not accurate within the limits set by government standards, the customer's bill will be adjusted accordingly. Where it is impossible to determine when the error commenced, it shall be deemed to have commenced three months before the test or on the date of the meter installation, whichever occurred later.

In the event that an adjustment is required, the $25 shall be refunded.

6.4 Energy or Demand Diversion

If under any circumstances, a person prevents a meter from accurately recording the total demand or energy supplied, the company may disconnect the service, or take other appropriate actions.

The company may then estimate the demand and amount of energy supplied but not registered at the point of delivery. The customer shall pay the cost of the estimated demand and energy consumption plus all costs related to the investigation and resolution of the diversion.

7 METER READING AND BILLING

7.1 Reading and Estimates

Customers' bills will be based on meter readings made by the company from time to time or on estimates for those billing periods when the meter is not read.

Whenever a bill is based on an estimate, an adjustment to reflect actual usage will be made after the meter is next read.

7.2 Proration of Initial and Final Billings

The amount of any initial and final charges, other than energy, may be prorated, based upon the ratio of the number of days that service was provided to a customer in the billing period to the total number of days in the billing period.

The company may elect not to charge a customer for the billing period if, during that period, demand was five kilowatts or less, service was provided for five days or less and energy consumption was five kilowatt hours or less.

For all new accounts, the company may add the charges for service provided during the initial period to the bill for the following billing period.

7.3 Payment of Accounts

Payment of a bill for service is due and payable on the date indicated on the bill.

Failure to receive a bill does not release a customer from the obligation to pay the amount owing for any service provided by the company.

7.4 Late Payment Charge

The company may add a service charge equal to 1.0% per month (effectively 12.68% per annum) on any overdue amount.

7.5 Dishonored Cheques

The company may add a service charge of $10 to a customer's bill in respect of any cheque returned by the customer's bank for any reason.

7.6 Outstanding Charges

The Company may add to the customer's bill any outstanding charges owing to the Company (e.g. construction contribution, account receivable charges, etc.).

8 SERVICE CHANGES

8.1 Notice by Customer

A customer shall give to the company reasonable prior written notice of any change in service requirements, including any change in load to enable the company to determine whether or not it can supply such revised service without changes to its facilities.

8.2 Responsibility for Damage

The customer shall be responsible for all damage caused to the company's facilities as the result of the customer changing service requirements without the company's permission.

8.3 Changes to Company facilities

If the company must modify its facilities to accommodate a customer load or service change, the customer shall pay for all costs in connection with such modification including the following costs:

(a) the estimated cost of removing the existing facilities, less the estimated salvage value, less

(b) any applicable increased company investment.

9. COMPANY RESPONSIBILITY AND LIABILITY

9.1 Continuous Supply

The company shall make all reasonable efforts to maintain a continuous supply of energy to its customers, but the company cannot guarantee an uninterrupted supply of energy.

9.2 Planned Outages

The company reserves the right to interrupt, discontinue or reduce the supply of energy to any customer to allow for repairs and improvements to its facilities.

The company shall endeavor to give prior notice to customers who will have service interrupted and will endeavor to ensure that such interruptions are as short and infrequent as circumstances permit.

9.3 Company Liability

The company shall not be liable for any loss, damage, expense, charge, cost or liability of any kind (excepting only direct physical loss, injury or damage to a customer or a customer's property, resulting from the negligent acts or omissions of the company, its employees or agents) arising out of or in any way connected with any failure, defect, fluctuation, reduction or interruption in the provision of service by the company to its customers. For the purpose of the foregoing and without otherwise restricting the generality thereof, "direct physical loss, injury or damage" shall not include loss of profits, loss of earnings, or any other similar damage or loss whatsoever, arising out of or in any way connected with the failure, defect, fluctuation, reduction or interruption in the provision of service to a customer.

9.4 Extraordinary Circumstances

Should the company be unable, because of extraordinary circumstances, to provide a continuous supply of energy to a customer, the company's responsibilities, so far as they are affected by the extraordinary circumstances, shall be suspended during the duration of such circumstances. Where practical, the company shall give notice to the affected customers of such extraordinary circumstances.

10. CUSTOMER RESPONSIBILITY AND LIABILITY

10.1 Provide Permit

The customer shall provide permits, licences and authorizations prior to commencement of service or any change of service requirements at any point of delivery.

10.2 Customer Responsibility

The customer shall be responsible for the installation and condition of all facilities on the customer's side of the point of delivery, except metering or other equipment owned by the company.

The customer shall indemnify and save harmless the company from and against any claim or demand for injury to persons or damage to property arising out of or in any way connected with the use of the service so long as such injury or damage is not caused by the negligent acts or omissions or willful misconduct of the company, its employees and agents.

The customer shall be responsible for any damage to company facilities located on the customer's premises where the damage is caused by the negligent acts or omissions or willful misconduct of the customer or anyone permitted by the customer to be on the premises.

10.3 Protective Devices

The customer shall be responsible for determining whether he needs any devices to protect his equipment from damage that may result from the provision of service by the company. The customer shall provide and install any such devices.

10.4 Service Calls

The company may require a customer to pay the actual costs of a customer-requested service call if the source of the problem is the customer's own facilities.

11. TERMINATION OF SERVICE

11.1 Customer-requested Termination

Except where otherwise provided in a written agreement between the company and a customer, a customer may, at any time, give the company reasonable notice (in writing) that he wishes to terminate his service. Upon receipt of such notice, the company shall read the customer's meter within a reasonable time, and, shall use its best efforts to read the customer's meter at the time requested by the customer. A customer shall pay for all service provided to the time of such reading.

A customer is responsible for all service provided until notice of termination is given and the meter is read.

11.2 Company Termination for Safety Reasons

The company may, without notice, terminate a customer's service where, in the company's opinion:

(a) the customer has permitted the wiring of his facilities to become hazardous; or

(b) the wiring of the customer's facilities fails to comply with applicable law; or

(c) the use of the service may cause damage to the company's facilities or interfere with or disturb service to any other customer.

The company will reconnect the service when the safety problem is resolved and when the customer has provided, or paid the company's costs of providing, such devices or equipment as may be necessary to resolve such safety problem and to prevent such damage, interference or disturbance.

11.3 Company Termination Other Than For Safety

The company, or anyone acting under its authority, may, upon giving at least 48 hours' notice to the customer, terminate the customer's service or install a current-limiting device to restrict the service to such customer if the customer:

(a) violates any provision of these regulations or of the company's tariff;

(b) tampers with any service conductors, meters, seals or any other facilities of the company;

(c) neglects or refuses to pay the charges for service due to the company within 30 days of the date the bill for such service was rendered;

(d) violates the provision of any contract or rate schedule applicable to the service;

(e) changes service requirements without the permission of the company; or

(f) makes fraudulent use of the service being provided.

11.4 Removal of Facilities

Upon termination of service, the company shall be entitled to remove any of its facilities located upon the property of the customer and to enter upon the customer's property for that purpose.

SCHEDULE A

STANDARD SUPPLY SPECIFICATIONS

The Company's standard supply specifications, which are in accordance with Canadian Standards Association standard CAN-C235-83, are as follows:

(a) **Residential:**

240/120 V	- single phase, three wire - secondary conductors are supplied by the company - overhead or, in designated areas, underground conductors

(b) **General Service:**

240/120 V	- single phase, three wire - overhead secondary conductors are supplied by the company - underground secondary conductors are supplied by the customer
208 Y/120 V	- three phase, four wire - overhead secondary conductors are supplied by the company - underground secondary conductors are supplied by the customer
480 Y/277 V	- three phase, four wire - overhead secondary conductors are supplied by the company for loads 15 kVA to 300 kVA - overhead secondary conductors are supplied by the customer for loads 300 kVA to 1500 kVA
600 Y/347 V	- three phase, four wire - underground secondary conductors are supplied by the customer for loads 150 kVA to 2500 kVA; and
4160 Y/2400 Y	- three phase, four wire, 2,000 kVA to 10,000 kVA - overhead secondary conductors are supplied by the customer

SCHEDULE B

MAXIMUM COMPANY INVESTMENT

1. (a) "Cost" means the estimated cost of materials, labour, equipment, expenses, and any other direct costs incurred by the Utility in extending Service to a Point of Delivery.

   (b) "Annual Cost" means the estimated cost of generating and transmitting electric energy to the Customer, operating and maintaining the facilities constructed to serve the Customer and the fixed charges, including return, income tax and depreciation, on the cost of facilities constructed to serve the Customers.

2. Subject to the provisions of paragraph 3 of this Schedule B, the maximum cost which the company will incur to extend service to a point of delivery (herein referred to as the "Maximum Company Investment") shall be determined as follows:

   (a) Residential Service:

   $1,000 per single family dwelling; and
   $500 per Multiple Dwelling

   (b) General Service:

   $200 per kilowatt of estimated billing demand, which shall not be less than five kilowatts, provided that if the estimated life is less than 25 years, then the maximum company investment shall be determined in the manner described in paragraph 3;

   c) Municipal Street Lighting:

   $770 per light.

   (d) Private Lighting:

3. The maximum company investment for an extension of service not specified in paragraph 2, and the maximum company investment in any extension of service, whether or not specified in paragraph 2, the Load characteristics of which are expected to vary materially from the average for that type of service, shall be determined on the basis of a detailed analysis of the **Annual Cost** of such extension and the revenue expected to be derived therefrom. If the **Annual Cost** of serving a customer is higher than the revenue expected to be received from such service, then the maximum company investment shall be the **Cost** of the extension less the present value of the annual amounts over the expected life of the service by which the **Annual Cost** is expected to exceed the revenue.

SCHEDULE C

CONDITIONS OF UNDERGROUND SERVICE

The company shall extend service by underground conductor lines upon and subject to the following terms and conditions ("developer" means the person or party who has requested the underground service):

(a) No service is then available in the area to be served by such extension, and not less than 25 single family dwellings (or such lesser number as may be agreed to by the company) will be connected to such extension (the "underground service area"), each of which is situated upon a parcel of land upon which other single family dwellings in the underground service area are situated;

(b) All permanent service in the underground service area shall be provided exclusively through underground conductor lines;

(c) The developer shall provide, without cost to the company, such rights-of-way, easements, utility corridors and transformer locations as the company may require for the installation, operation and maintenance of such extension, which the developer shall keep free and clear of any buildings, structures, fences, pavement, trees or any other obstructions which may hinder the company in installing, maintaining or removing its facilities;

(d) The company shall not be obligated to install such extension until it is reasonably satisfied that the extension will not thereafter be damaged or interfered with, and, in any event, any costs incurred by the company in relation to the relocation, reinstallation or as a result of damage to such extension shall be paid by the developer;

(e) Service, for purposes other than residential use and street lighting, may be provided from such extension only with the consent of the company;

(f) In relation to the underground service, the developer shall cause to be provided a meter socket and service conductor protection from sixty centimeters below grade level to the line side of the meter socket and will ensure that installation of a service having a 200 ampere capacity;

(g) The developer shall provide to the company a certified copy of the registered plan of subdivision and final construction plans showing the location and evaluation of sidewalks, curbs and gutters, and underground utilities together with such evidence as the company may reasonably require to the effect that all rules and regulations applicable to the development have been or will be compiled with by the developer.

(h) Survey stakes indicating grades and property lines shall be installed and maintained by the developer;

(i) The surface of the ground for a distance of not less than one point five (1.5) meters on each side of the alignments for the underground conductor lines shall be graded by the developer to within eight (8) centimeters of a final grade;

(j) Unless otherwise agreed to by the company, the developer shall provide a survey for the location of transformers, street light bases and cable routing, as required; and

(k) Sidewalks, curbs and gutters may be constructed by the developer but not other permanent improvements shall be made until approved by the company.

In addition, the service shall be subject to such other conditions as may be specified by the company from time to time.