IN THE MATTER OF THE Utilities
Commission Act, S.B.C. 1980
c. 60, as amended

- and -

IN THE MATTER OF an application by
Centra Gas British Columbia Inc. to amend
its Schedule of Rates

DIRECT TESTIMONY OF COMPANY WITNESSES

March 02, 1992

Centra Gas

CENTRA GAS BRITISH COLUMBIA INC.

DIRECT TESTIMONY OF COMPANY WITNESSES

INDEX

CENTRA GAS BRITISH COLUMBIA INC.

DIRECT TESTIMONY OF COMPANY WITNESSES

RICHARD R. BURKE

CENTRA GAS BRITISH COLUMBIA INC.

TESTIMONY OF
RICHARD R. BURKE

Q. Mr. Burke, would you please state your present position with Centra Gas British Columbia Inc.?

A. I am Vice President, Finance.

Q. Would you describe your qualifications and business experience?

A. I am a Chartered Accountant. I have worked in the natural gas distribution business for eleven years. I have been a Vice-President with ICG/Centra since June 1983 and held positions in the Finance and Regulatory functions in Winnipeg and Toronto.

Q. Have you previously testified before any regulatory bodies?

A. I have testified before the Ontario Energy Board and the Minnesota Public Utilities Commission.

Q. What is the purpose of your testimony at this hearing?

A. I appear as a general policy witness for the Company and will join Mr. A.M. Haines on the opening panel to respond to questions relating to gas volumes, revenues and proposed rate changes. I will also appear on the financial panel to address any questions relating to the Company's capital structure and required Rate of Return.

Q. Please provide a brief history and overview of the application.

A. On October 31, 1991 the Company applied for a decrease in the cost of gas from our supplier and to pass through certain "uncontrollable" costs increases effective November 1, 1991. Approval of the full application would have resulted in an average net increase to residential and commercial customers of 3% of retail rates.

By order G-112-91 the Commission approved rate decreases due to a decreased cost of gas of $0.078/GJ for residential/commercial customers and $0.133/GJ for industrial customers effective November 1, 1991 and refused the pass through of cost increases ordering the filing of the present application.

On December 16, 1991 the Company filed a detailed application entitled <u>"Material in Support of a General Rate Increase"</u> the "Application".

On January 8, 1992 the Commission in Order #G-8-92 approved interim increases effective February 1, 1992.

The total Application now consists of the following documents:

1) Material in Support of a General Rate Increase dated December 16, 1991.
2) Common Service Allocation Study.
3) Plant Additions Study.
4) Direct Testimony of Witnesses.

Q. In what order does the Company propose to present its evidence?

A. Subject to the convenience of the Commission we anticipate calling the following four panels:

Panel 1	Rate Changes, Sales Volumes and Normalization
	- R.R. Burke and A.M. Haines
Panel 2	Rate Base and Cost of Service

	-	D.J. Maxwell and D.G. Olsen
Panel 3	Gas Supply	
	-	D.I. Andrews
Panel 4	Rate of Return and Capital Structure	
	-	R.R. Burke and A.M. Haines

Q. When did Centra last file a general rate application requesting an increase?

A. Our last general application was filed in 1984 with a decision rendered in 1985. Since the Commission's 1985 Decision, while we have applied for and received both pass through increases and decreases, we have not applied for a general increase. The net effect of not applying is that rates, even with the February 1, 1992 interim rates are only 8% higher than 1985 rates. While this has been beneficial for our customers, the shareholders return has slipped significantly in the last two years necessitating this application.

Q. Besides Rate Relief are you seeking any special Commission Orders?

A. Yes. In it's 1985 Decision the Commission excluded the cost of a new office building and certain Customer Information System costs from rate base pending a further order.

In 1985 we constructed the office building at a total cost of $275,876 including land. While this amount was less than the amount estimated during the hearing it was still in excess of the amount approved by the Commission for inclusion in Rate Base in Order #G-61-85. The shareholders have been carrying the cost of the difference since 1985 and it is now time to bring these costs into Rate Base. The Rate payers have benefited from the completion of this building in 1985 because it has improved the efficiency of the Fort St. John operation for the past six years and will be included in approved Rate Base at the 1985 cost not 1992 costs. When customer growth and inflation are taken into account we believe these expenditures are more than reasonable and seek formal approval to include these in the rate base.

Customer Service System (CSS) expenses were also questioned in the last hearing with the Commission disallowing $33,000 of these items from Rate Base, leaving it open to the Company to reapply if the system proved itself. We now are in a better position to indicate this is a worthwhile system and are seeking approval to bring the full amount of capitalized CSS expenditures into rate base.

Q. Please explain the reasons for not including Port Alice in this application, in light of the Commission Decision made in 1985.

A. In 1985 the Company only had two divisions, Fort St. John and Port Alice and accordingly for a number of reasons we partially merged the Cost of Service. Today we have four service areas and this is no longer appropriate.

Q. Please discuss the Companies Proposed Capital Structure and Return.

A. The company proposes the following Capital Structure:

	Percent	Cost
Short Term Debt	4.59%	8.08%
Long Term Debt	18.48%	13.89%
Deemed Long Term Debt	40.55%	9.34%
Preferred Shares	.67%	6.48%
Equity	35.71%	14.25%

Short Term Debt

The short term debt has been calculated as being the amount required to fund 75% of the working capital requirement. A rate of prime less one-half percent has been used.

Long Term Debt

The long term debt component is the balance of outstanding long term debt.

Deemed Long Term Debt

This is the amount of debt that Centra has not yet placed in the long term market but will do so in the near future. We have assumed for the purpose of the Application that the debt is placed at the cost of Long Term Canada bonds.

We hope that prior to the May 25, 1992 hearing we will have placed this debt and be in a position to provide the Commission with actual costs.

Preferred Shares

The amount and cost of preferred shares remains unchanged.

Common Equity

The common equity component of the capital structure remains unchanged from the level approved in the last decision of 35.71%.

Q. How was the common equity return rate of 14.25% derived?

A. The return of 14.25% represented my best estimate of a fair return based on my understanding of returns which are allowed to other utilities and our comparative risk at the time of filing. Since that original decision a formal review of my assessment was done by Kathleen McShane, an expert on rate of return, and this review is attached as Schedule "A" to my evidence. Ms. McShane's evidence confirms my opinion.

In order to save costs it is the Company's intention that I speak to Ms. McShane's detailed review of the companies return.

Q. Does this complete your testimony?

A. Yes.

CENTRA GAS (BRITISH COLUMBIA), INC.
(Fort St. John District)

Opinion

of

KATHLEEN C. McSHANE

FOSTER ASSOCIATES, INC.
Washington, D.C. 20005

February 26, 1992

PREFACE

My name is Kathleen C. McShane. I am a Senior Consultant and Vice President of Foster Associates, Inc., an economic consulting firm located in Washington, D.C. A summary of my qualifications appears as Appendix A to this document.

Centra Gas (B.C.) has requested an Opinion on the reasonableness of their application for a return of 14.25% on the common equity portion of their Fort St. John rate base investments subject to the jurisdiction of the British Columbia Utilities Commission.

The Opinion is based on an evaluation of the business and financial risks of the Fort St. John gas distribution operations, the outlook for interest rates, the results of tests I typically rely upon for estimating the fair return, and which have recently been presented to the B.C.U.C., as well as a comparison of the request with recent regulatory decisions in Canada.

CONCLUSIONS

Based on my analysis, it is my opinion that the requested return on equity of 14.25% for Centra B.C.'s Fort St. John operations is reasonable. This opinion reflects my conclusions that (1) the fair return for the lowest risk Canadian utilities, based on the comparable earnings, discounted cash flow and risk premium tests, is in the range of 13.5-13.75%; (2) the business and financial risks of the Fort St. John operations are higher than those of the typical Canadian utility resulting in a required risk premium above the lowest risk utilities of approximately 1.0 percentage point; and (3) the level of allowed returns for low risk utilities, at a projected long Canada rate of 9.25-9.5% is likely to be in the 13.0-13.5% range.

BUSINESS, FINANCIAL AND INVESTMENT RISKS

The principal business risks faced by a gas distributor are market/demand risks, supply risks and physical risks.

The market/demand risks are a function of the economic characteristics of the service area, including the size, diversity of the economic base, the volatility of demand by industrial customers, and the outlook for long-term economic growth.

The Fort St. John operations serve approximately 7,000 customers in northeastern British Columbia, located in the heart of a key oil and gas production area.

Approximately 2.3 PJs of gas are delivered off the Fort St. John system to the following customer classes:

Customer Class	Volumes (PJs)
Residential	0.9
Small Commercial	0.9
Industrial	0.5

Eight industrial customers account for approximately 22% of the system load. These customers are in the forest products and oil and gas production industries, and rely on natural gas for fuel and processing purposes. Both industries are highly cyclical and are subject to periodic slowdowns and shutdowns.

The dependence of the Fort St. John area on the fortunes of two cyclical resource-based industries directly impacts on volumes sold to residential and small commercial customers. A lack of diversity in the local economy gives rise to a more transient population. Downturns in the forest and paper products and oil and gas industries expose the Fort St. John operations to greater risk of declines in residential and commercial volumes than distributors operating in areas with greater economic diversity and a less cyclical industrial base.

A further demand risk which the Fort St. John operations face as a result of their location is by-pass, since oil and gas producers may elect to use their own production for compressor fuel. As the decision of one of the company's largest customers to use its own gas indicates, the economics of by-pass are a realistic concern to the Fort St. John system.

The supply risks, in contrast to the market/demand risks, are low. The proximity of gas reserves affords Fort St. John customers access to low cost gas. On the other hand, physical risks are relatively high due to harsh climatic conditions. In particular, the risks associated with metering and forecasting maintenance costs due to the impact of the cold on the physical plant are higher than for a distribution system in a more temperate climate.

On balance, the business risks of the Fort St. John operations, when compared to the Eastern and Alberta distributors, as well as to B.C. Gas, are above average, in large part due to its small size, remote location and exposure (in all customer classes) to the cyclical nature of two resource-based industries.

With respect to <u>financial risks</u>, Centra (B.C.)'s Fort St. John operations can be evaluated in terms of capital structure ratios and interest coverage ratios. The company projects the following capital structure for 1992:

Capital Component	Proportion
Short Term Debt	4.6
Long Term Debt	18.5
Deemed Long Term Debt	40.5
Common Equity	35.7
Preferred Equity	0.7
TOTAL	100.0

Fort St. John's total debt ratio is 63.6%. By comparison, the median debt ratio approved for regulatory purposes for major Canadian utilities is 53.0%. For gas distributors, it is 59.3%. The common equity ratio, at 35.7%, is close to the 36.7% median for all utilities and slightly above the gas distributor median of 35.2% (Schedule 1). Comparing the capital structure ratio of Fort St. John to the standards established by the Canadian Bond Rating Service (CBRS) for utility bond debt ratings, the 63.6% projected debt ratio lies in the B++ range (over 60%).

An interest coverage ratio for Fort St. John has been calculated using, an interest rate on short term debt of 8.0%, the embedded cost rate for long term debt of 13.87%, the embedded cost for preferred stock of 6.48%, a projected rate for deemed long term debt of 1.0 percent above long Canadas of 10.375%, and an income tax rate of 42.84%. The resulting interest coverage ratio is 2.36 times. This is slightly below the 2.47 times achieved by gas and electric utilities in 1990, when returns for the comparison firms averaged 13.9%, and 2.8 times achieved on average from 1983-1990 (Schedule 2). The coverage ratios achieved by other utilities reflect gradual deterioration in recent years, a trend which has been viewed with some concern by CBRS. The projected 2.36 times for Fort St. John compares to a CBRS standard of 2.5 times for a B++ rated utility and 3.0 times for an A rated utility.

On balance, with its relatively high debt ratio and a projected coverage ratio of 2.36 times, Fort St. John's financial risk are somewhat above average.

The total inherent business and financial risks, or investment risks, of the Fort St. John operations would place it in a risk class, from a common equity perspective, at approximately the same level as that of the smaller Canadian utilities, such as Pacific Northern Gas, Maritime Electric and Island Telephone, which operate in relatively cyclical and economically undiversified service areas. These utilities are rated B++(high) by CBRS or BBB(high) by DBRS. Because these three utilities have common equity which is publicly traded, their cost of capital can be directly estimated and compared to that of higher grade utilities.

Using the discounted cash flow model, I compared the cost of equity capital over the period 1983-1990 of a sample of 5 high grade utilities (rated, on average, A+(low)), a sample of 12 non-diversified utilities (rated, on average, A) and a sample of the three B++ utilities listed above.

The formula relied upon is as follows:

$$\text{Price/Earnings} = \frac{\text{Discounted Payout Ratio (D/E)}}{\text{Cost of Attracting Capital (k)} - \text{Expected Growth (g)}}$$

$$\text{or} \quad k = \frac{D/E}{P/E} + g$$

In this formula, growth was estimated as the product of actual return on equity x earnings retention ratio, often referred to as "sustainable growth".

The following results were obtained:

	1983-1990		
	5 High Grade Utilities 1/	12 Non-Diversified Utilities 2/	B++ Rated Utilities 3/
Average CBRS Rating	A+ (low)	A	B++(high)
P/E Ratios	9.5	9.1	8.1
Payout Ratio	59.4%	59.2%	54.8%
Return on Equity	14.3	14.4	14.5
Retention Rate (1-P/O)	40.6	40.8	45.2
Growth Rate (g)	5.8	5.9	6.6
Implicit Cost of Attracting Capital (k)	12.1	12.4	13.3

1/ B.C. Telephone; Canadian Utilities; Fortis; Maritime Telegraph & Telephone; and TransAlta Utilities.

2/ B.C. Gas; B.C. Telephone; Canadian Utilities; Consumes Gas; Fortis; Island Telephone; Maritime Electric; Maritime Telegraph & Telephone; Newtel Enterprises; Pacific Northern Gas; Quebec Telephone and TransAlta Utilities.

3/ Maritime Electric; Island Telephone and Pacific Northern Gas.

The difference between A+(low) rated (on average) utilities -- the lowest risk utilities -- and B++ rated utilities is 1.2 percentage points. The difference between A rated (on average) utilities and B++ utilities is 90 basis points. These calculations suggest that an equity return 1.2 percentage points over that of the lowest risk utilities and of 0.9 percentage points above average risk utilities is not unreasonable for Fort St. John.

As a check on these spreads, I looked at the recent debt cost spreads among the different utility ratings. Traded long-term debt securities for B++ rated utilities PNG and Island Telephone have recently yielded approximately 60 basis points above those of the sample of 5 high grade utilities, and 44 basis points above those of the sample of 12 non-diversified utilities. In light of these spreads, and given the relatively greater risk to which equity investors are exposed than bond investors, the calculated cost of equity spreads are not unreasonable estimates of the required equity risk premium increments required by investors in low, average and higher risk utilities. Based on debt spreads, a fair equity return for Fort St. John would be no less than 60 basis points above that of an A+(low) rated utility; a return of 1.2 percentage points higher is indicated by the cost of equity capital estimates. Viewed as a range, these estimated produce a midpoint of 90 basis points.

OUTLOOK FOR INTEREST RATES

The 14.25% return requested by Fort St. John should be evaluated in light of the outlook for long-term Canada yields. A comparison of the two permits an assessment of the risk premium implied in Fort St. John's return request.

During 1991 long Canadas fell approximately 150 basis points, from approximately 10.25% to a low of about 8.65% (Schedule 3). Despite historically low rates of inflation and no clear sign of a renewed economic upswing, long Canada rates have risen in recent weeks to about 9%.

Some further upward pressure on rates is anticipated, based on the following:

(1) Yields on long U.S. Treasuries have risen from a low of 7.4% in early January to about 7.9% in mid-February. Increased corporate demands for funds, in conjunction with the heavy federal government demand will put

some strain on the capital markets. I expect a further increase to 8.0-8.25% as the year progresses.

(2) Higher real interest rates available in international bond markets, which put pressure on both U.S. and Canadian rates, reflecting the two countries' need for foreign funds to finance their deficits.

(3) The continued overvaluation of the Canadian dollar in relation to its long-term purchasing power, requiring a relatively high spread with U.S. rates in order to attract funds.

(4) Political uncertainty within Canada, which will tend to keep the spread with U.S. rates relatively high.

Based on these considerations, for 1992-1993, I anticipate an average yield on long Canadas of 9.25-9.50%, reflecting a spread with U.S. rates of 125-150 basis points.

Based on my outlook for interest rates, Fort St. John is requesting a premium above long Canadas of 4.75-5.0 percentage points. Assuming that this return incorporates a margin for financing flexibility adequate to achieve a market/book ratio of 115%, a 14.25% return translates into a "bare-bones" market cost of equity (using the discounted cash flow model) of 13.0%, or a risk premium, over long Canadas, of 3.625%. This premium lies at the lower end of the range of reasonable risk premiums.

TESTS FOR ESTIMATING THE FAIR RETURN ON EQUITY

Three tests are typically relied upon to estimate the fair return on equity: comparable earnings, discounted cash flow and equity risk premium. The conceptual and technical aspects of these tests, as I apply them, have been reviewed by this Commission in a recent proceeding. The following is a brief synopsis of the results and the implications for the fair return for Centra (B.C.)'s Fort St. John operations.

1. The comparable earnings test was applied to a sample of industrials over a nine-year business cycle ending in 1991. The sample is identical to that relied upon in the recent Pacific Northern Gas case. For the entire cycle, the earnings of these low risk industrials averaged 13.6% An analysis of the relative risks of the industrials and utilities, using the discounted cash flow approach referred to in my earlier discussion of Fort St. John's investment risks, indicates that the industrials are of approximately similar risk to average risk utilities (A rated) and of lower risk than a higher risk utility like Fort St. John. An adjustment to the return of 75 basis points to reflect the greater risk of BBB rated utilities compared to A-rated utilities raises the return requirement to 14.5%.

2. The discounted cash flow test applied to the same sample of industrials indicates recent dividend yields of 2.2% (adjusted for growth of 10.0%) (Schedules 5 and 6). The risk adjustment is identical to that utilized with the comparable earnings test raising the return requirement to 13.0%.

   An adjustment for financing flexibility adequate to achieve a market/book ratio of 115% raises the "bare-bones" cost to a return on book equity of 14.2%.

3. The risk premium test results presented below are limited to a single test based on the differential between discounted cash flow estimates of the cost of capital of two samples of utilities, rated respectively, on average, A+(low) and A. The study indicates that the average risk premium over the period

1983-1991 was 2.8% (Schedules 7 and 8). Over this period long Canada rates averaged 10.6% and inflation expectations averaged 4.8%. Statistical analysis shows that the risk premium varies inversely with inflation expectations and interest rates. At an expected long Canada yield of 9.25-9.50% and longer term inflationary expectations of 3.0%, the required premium would be approximately 3.5%. The higher risks of Fort St. John relative to the samples of utilities raises the required premium to approximately 4.25%, for a "bare-bones" cost of 13.6%. An adjustment for a market/book ratio of 115% raises the "bare-bones" cost to a return on book equity of 14.9%.

Comparing Fort St. John's request to the results of these three tests indicates that it lies at the bottom of the range indicated by the three tests.

COMPARISON WITH ALLOWED RETURNS

While recognizing that there is circularity involved in the process of comparing allowed returns to a requested return, it provides a perspective on Fort St. John's return request. In the last twelve months, as shown on Schedule 1, fifteen decisions on rate of return have been issued for major Canadian utilities. The returns ranged from 12.85% to 14.0%; the average and median were 13.5% (Schedule 1). On average, these utilities had an A bond rating. Long Canadas averaged 9.8% during 1991, implying a risk premium ranging from 3.1-4.2% and averaging 3.7%. Giving recognition to Fort St. John's greater business and financial risks, and recognizing that required equity returns do not move in lock step with bond yields, a 14.25% return request is compatible with risk premiums allowed by other regulatory boards for lower risk utilities. To illustrate, the Regie du Quebec allowed a return of 14.0% for 1992 for Gaz Metro, an A rated utility. At a 10% bond yield, a four percent risk premium is implied. At my projected 9.375% long Canada bond yield for 1992, a compatible risk premium for Gaz Metro would be 4.25%, for a return of 13.6,25%. A spread of 75 basis points between an A rated utility like Gaz Metro and Fort St. John places the return for the latter at 14.375%.

CONCLUSIONS

On the basis of my analysis of Fort St. John's business and financial risks, my outlook for interest rates, and the results of the comparable earnings, discounted cash flow and equity risk premium tests, as well as giving recognition to recent regulatory decisions, it is my opinion that the 14.25% return request of Centra (B.C.) for its Fort St. John operations is reasonable.

Kathleen C. McShane
February 24, 1992

Appendix A

Qualifications

of

Kathleen C. McShane

I am a Vice President and senior consultant of Foster Associates, Inc., where I have been employed since 1981. I hold an M.B.A. degree in Finance from the University of Florida, and M.A. and B.A. degrees from the University of Rhode Island. I am also a Chartered Financial Analyst.

I worked for the University of Florida and its Public Utility Research Center before joining Foster Associates, functioning as a research and teaching assistant. I taught both undergraduate and graduate classes in financial management and assisted in the preparation of a financial management textbook.

At Foster Associates, I have worked in the areas of financial analysis, energy economics and cost allocation. I have participated in the preparation of more than 75 rate of return testimony and exhibits, which have been filed as evidence in Federal and Provincial jurisdictions in Canada and the U.S. I have also conducted studies on U.S. gas markets for Canadian gas, U.S. pipeline profitability, Canadian telephone company financial policy, U.S. gas distributor market performance, and U.S. and Canadian gas pipeline regulation and energy policy.

I have testified before the Alberta Public Utilities Board on behalf of Alberta Power, Canadian Western and Northwestern Utilities; the British Columbia Utilities Commission on behalf of Pacific Northern Gas; the Canadian Radio and Television Commission on behalf of Bell Canada; the National Energy Board on behalf of TransCanada PipeLines, Westcoast Transmission and Trans Quebec & Maritimes Pipeline; the Public Utility Board of the Northwest Territories on behalf of Northwest Territories Power Corporation; the Ontario Energy Board on behalf of Consumers Gas, ICG (Ontario), Tecumseh Gas, and Union Gas; La Regie du Gaz de Quebec on behalf of Gaz Metropolitain; The Yukon Utilities Board on behalf of Yukon Electrical Company Limited and Yukon Energy Corporation on rate of return and before the National Energy Board on behalf of Gaz Metropolitain and the Government of Quebec on pipeline cost allocation. In the U.S., I have testified before the Arizona Corporation Commission and the El Paso Public Utility Board on behalf of Southern Union Gas.

Publications and Papers

- Marketing Canadian Natural Gas in the U.S., (co-authored with Dr. William G. Foster), published by the IAEE in Proceedings: Fifth Annual North American Meeting, 1983.

- Canadian Gas Imports: Impact of Competitive Pricing on Demand, (co-authored with Dr. William G. Foster), presented to A.G.A.'s Gas Price Elasticity Seminar, March 1986.

- Market-Oriented Sales Rates and Transportation Services of U.S. Natural Gas Distribution Companies, (co-authored with Dr. William G. Foster), Papers and Proceedings of the Eighth Annual North American Conference, May 1987.

CENTRA GAS (BRITISH COLUMBIA), INC.
(Fort St. John District)

Statistical Materials

to accompany

Opinion

of

KATHLEEN C. McSHANE

FOSTER ASSOCIATES, INC.
Washington, D.C. 20005

February 26, 1992

EQUITY RETURN AWARDS AND CAPITAL STRUCTURES ADOPTED BY REGULATORY BOARDS FOR CANADIAN UTILITIES

	Decision Date (1)	Order/ File Number (2)	Debt (3)		Preferred Stock (4)	Deferred Taxes (5)	Common Stock Equity (6)	Equity Return (7)	
Gas Distributors									
Canadian Western Natural Gas a/	7/90	C-90026	41.48		22.23		36.29	13.25	%
Centra Gas Manitoba, Inc.	12/91	156/91	60.20	b/	0.13		39.67	12.60-13.10	
Centra Gas Ontario, Inc.	5/91	EBRO 467	61.42	b/	2.58		36.00	13.75	
Consumers Gas	2/92	EBRO 473	59.30	b/	5.70		35.00	13.125	
Gaz Metropolitain	11/91	D-91-41	54.06		7.51		38.43	14.00	
Inland Natural Gas	8/87	G-52-87	57.16	b/	10.27		32.57	13.25-13.75	
Northwestern Utilities a/	11/91	E-91044	40.20		25.50		34.30	13.75	
Pacific Northern Gas	4/91	G-36-91	52.59	b/	4.09	12.59	30.72	13.75-14.25	
Union Gas	4/91	EBRO 470	60.63	b/	10.37		29.00	13.50	
Gas Pipelines									
Alberta Natural Gas	12/86	AO-23-TG180	65.00				35.00	13.25	
Foothills Pipe Lines (Yukon) Ltd.	12/86	AO-9-TG-4-82	75.00				25.00	14.25	
Nova Corporation of Alberta	6/91	Board of Dir.	63.98		2.99	1.03	32.00	13.75	
TransCanada PipeLines	7/91	RH-1-91	59.10		10.90		30.00	13.50	
Trans Quebec & Maritimes Pipeline	2/91	RH-2-90	75.00				25.00	13.75	
Westcoast Energy	1/91	RH-1-90	61.50		3.50		35.00	13.75	
Electrics									
Alberta Power a/	12/91	E-91095	45.67		23.02		31.31	13.50	c/
Fortis	12/91	PU 6[1991]	48.18		6.40		45.42	13.00-13.50	
Maritime Electric	7/91	E-91-7	43.82		14.77		41.41	13.25-13.75	
TransAlta Utilities a/	12/91	E91093	41.79		21.14		37.08	13.25	
West Kootenay Power	12/90	G-109-90	39.76	b/	7.75	6.09	46.41	13.25-13.75	
Telephone Companies									
Bell Canada	3/88	CRTC 88-4	42.40		5.80		51.80	12.25-13.25	
B.C. Telephone	12/88	CRTC 88-21	43.62		8.41		47.97	13.00-14.00	
Island Telephone	12/90	CRTC 90-28	52.00		7.00		41.00	13.25-14.25	
Maritime Telegraph & Telephone	12/90	CRTC 90-30	52.00		7.00		41.00	13.00-14.00	
New Brunswick Telephone	8/89	PUB-	45.00		2.40		52.60	13.50	
Newfoundland Telephone	7/90	CRTC 90-15	56.00		3.00		41.00	13.25-14.25	
Quebec-Telephone d/	12/91	RT-91-010-B	46.52		2.98		50.50	12.50-13.80	
Teleglobe Canada	12/91	CRTC 91-21	40.00				60.00	12.75-14.75	

a/ Excludes no-cost capital; if that were included, the ratios would be:

	Debt	No-Cost Capital		Preferred Stock	Deferred Taxes	Common Equity
Alberta Power	42.15%	7.70%	e/	21.25%		28.90%
Canadian Western Natural Gas	41.40	0.19		22.19		36.22
Northwestern Utilities	40.10	0.20		25.50		34.20
TransAlta Utilities	38.77	7.22	e/	19.61		34.40

b/ Includes short-term debt of 24.04% for Centra Gas Manitoba, 9.62% for Centra Gas Ontario, 5.69% for Consumers Gas, 11.24% for Inland Natural Gas, 17.99% for Pacific Northern Gas, 3.83% for Union Gas, 1.12% for West Kootenay.

c/ Determined by the Board for 1991.

d/ Capital structure ratios for year end 1990.

e/ Includes contributions in aid of construction: Alberta Power, 7.39%; TransAlta Utilities, 5.37%.

Source: Board Decisions.

2088A1

TIMES INTEREST CHARGES
EARNED BEFORE INCOME TAXES
FOR SELECTED GAS AND ELECTRIC UTILITIES

Year	B.C. Gas a/	Canadian Utilities Ltd.	Consumers Gas	FORTIS, Inc.	Gaz Metro	Maritime Electric	Pacific Northern Gas, Ltd.	TransAlta Utilities	Union Gas	West Kootenay Power
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1980	3.41	3.17	2.35	3.46	1.59	3.20	3.74	3.77	1.87	1.39
1981	2.71	3.14	1.96	3.27	1.67	2.70	3.31	3.28	2.03	1.43
1982	3.09	3.80	2.45	3.79	2.28	2.50	1.88	3.09	2.01	1.91
1983	2.67	4.57	2.40	3.72	2.24	3.00	2.05	3.46	2.59	2.96
1984	2.03	4.75	2.89	3.39	2.92	3.20	2.10	4.13	2.64	2.70
1985	2.36	4.35 b/	2.90	3.25	2.30	3.30	2.26	4.34	2.50	2.47
1986	1.72	4.48	2.68	3.13	2.13	3.60	2.03	3.97	2.55	2.42
1987	1.65	3.85	2.36	2.78	2.05	3.80	1.92	4.56	2.51	2.41
1988	1.64	3.43	2.49	2.80	2.18	3.60	1.93	3.93	2.16	2.40
1989	1.51	3.26	2.33	2.51	2.45	3.20	1.91	3.06	2.00	3.03
1990	1.54	2.91	2.03	2.62	2.62	3.20	1.99	2.93	1.80	3.01

a/ Reflects fiscal year ending June 30 through 1982 and December 31 thereafter.
b/ Restated from 4.54.

Note: Times interest charges earned represent the ratio of gross income (including AFUDC) before the deduction of income taxes to total interest charges.

Source: Annual Reports to Stockholders; Moody's Investors Service, Inc.

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TREND IN OUTSTANDING BOND YIELDS AND INTEREST RATES
(Percent Per Annum)

	Government of Canada			U.S. Government		ScotiaMcleod Long Term Bond Index		Canadian Bond Rating Service Utilities		
Year	Canadian Prime Rate a/	3-Month Treasury Bills a/	Long-term Bonds a/ b/	3-Month Treasury Bills c/	Long-term Bonds d/	AA Corporates	A Corporates	A+	B++	Exchange Rates (Canadian dollars in U.S. funds)
1966	6.00%	4.99%	5.69%	4.88%	4.77%					$0.93
1967	5.92	4.64	5.94	4.32	5.01					0.93
1968	6.92	6.26	6.75	5.34	5.45					0.93
1969	7.96	7.19	7.58	6.68	6.33					0.93
1970	8.17	5.99	7.91	6.46	6.86					0.96
1971	6.48	3.56	6.95	4.35	6.12					0.99
1972	6.00	3.56	7.23	4.07	6.01					1.01
1973	7.65	5.47	7.56	7.04	7.12					1.00
1974	10.75	7.82	8.90	7.87	8.05					1.02
1975	9.40	7.39	9.04	5.82	8.19			10.72%	11.05%	0.98
1976	10.08	8.87	9.18	5.00	7.86			10.57	10.78	1.01
1977	8.50	7.33	8.70	5.26	7.67	9.68%	9.92%	9.86	10.16	0.94
1978	9.69	8.68	9.28	7.22	8.48	10.01	10.14	10.14	10.35	0.88
1979	12.92	11.68	10.21	9.86	9.29	10.81	10.97	10.96	11.14	0.85
1980	14.27	12.80	12.48	11.62	11.30	13.17	13.36	13.23	13.43	0.86
1981	19.29	17.72	15.22	14.08	13.44	16.09	16.31	16.04	16.41	0.83
1982	15.79	13.62	14.26	10.72	12.76	15.70	16.00	15.50	16.13	0.81
1983	11.16	9.32	11.79	8.62	11.18	12.68	12.86	12.45	12.79	0.81
1984	12.10	11.06	12.75	9.57	12.39	13.49	13.62	13.20	13.55	0.77
1985	10.58	9.43	11.04	7.49	10.79	11.67	11.89	11.48	11.84	0.73
1986	10.56	8.97	9.52	5.97	7.80	10.17	10.34	10.34	10.72	0.72
1987	9.55	8.15	9.95	5.83	8.58	10.66	10.77	10.86	11.26	0.76
1988	10.83	9.48	10.24	6.68	8.96	10.80	11.00	10.93	11.46	0.82
1989	13.33	12.04	9.92	8.12	8.45	10.67	10.91	10.69	11.32	0.85
1990	14.06	12.80	10.85	7.51	8.61	11.76	11.95	11.80	12.37	0.86
1991	9.94	8.71	9.76	5.42	8.14	10.52	10.76	10.52	11.10	0.87
1990 1Q	14.00	12.92	10.53	7.76	8.44	11.53	11.69	11.59	12.16	0.85
2Q	14.75	13.60	11.04	7.77	8.65	11.94	12.08	12.02	12.59	0.86
3Q	14.25	12.77	11.05	7.49	8.80	11.82	12.06	11.88	12.51	0.87
4Q	13.25	11.95	10.79	7.02	8.55	11.73	11.98	11.71	12.24	0.86
1991 Jan	12.25	10.48	10.22	6.30	8.27	11.14	11.35	11.14	11.64	0.86
Feb	11.25	9.72	9.89	5.95	8.03	10.75	11.08	10.70	11.24	0.87
Mar	11.25	9.67	9.88	5.91	8.29	10.66	10.98	10.72	11.18	0.86
Apr	10.75	9.24	9.91	5.65	8.21	10.64	10.93	10.73	11.31	0.87
May	9.75	8.81	9.91	5.51	8.27	10.74	10.91	10.78	11.32	0.87
Jun	9.75	8.65	10.36	5.60	8.47	11.07	11.27	11.14	11.67	0.88
Jul	9.75	8.66	10.17	5.58	8.45	10.86	11.06	10.91	11.52	0.87
Aug	9.75	8.53	9.97	5.39	8.14	10.66	10.85	10.73	11.29	0.88
Sep	9.50	8.34	9.59	5.25	7.95	10.21	10.40	10.10	10.84	0.88
Oct	8.75	7.79	9.12	5.03	7.93	9.93	10.12	9.84	10.58	0.89
Nov	8.50	7.41	9.18	4.60	7.92	9.92	10.15	9.79	10.52	0.88
Dec	8.00	7.21	8.96	4.21	7.70	9.68	9.97	9.65	10.12	0.87
1992 Jan	7.50	7.08	8.97	3.84	7.58	9.81	9.96	9.79	10.33	0.85

a/ Monthly data reflect rate in effect at end of month.
b/ I0 years or more.
c/ Rates on new issues.
d/ 20-year constant maturities for 1974-1978; 30-year maturities after 1978. Series represents yields on the more actively traded issues adjusted to constant maturities by the U.S. Treasury based on daily closing bids.

Source: Bank of Canada Statistical Summary (September I97I) and Bank of Canada Review; Financial Post; McLeod, Young, Weir; Monthly Bond Yield Averages; Federal Reserve Board; Federal Reserve Bulletin (various issues), Annual Statistical Digest; Moody's Public Utility Manual and Bond Survey (various issues).

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RATES OF RETURN ON AVERAGE COMMON STOCK EQUITY IN RELATION TO MARKET-TO-BOOK RATIOS FOR 28 TSE 300 STABLE INDUSTRIALS

Year	Returns on Average Equity (1)	Market-to-Book Ratios (2)
1976	14.8%	89%
1977	15.8	84
1978	15.7	99
1979	19.3	106
1980	16.9	104
1981	15.3	111
1982	11.5	102
Average		
1976-82	15.6	99
1983	13.7	127
1984	14.9	143
1985	14.6	163
1986	14.7	192
1987	15.4	209
1988	15.3	191
1989	14.7	197
1990	10.6	174
1991 a/	8.8	NA
Average		
1983-90	14.2	174
1983-91	13.6	NA

a/ Developed from IBES Consensus EPS Estimates

Source: FRI Information Services, Ltd.; Institutional Brokers Estimate System; Moody's Investors Service, Inc.; Toronto Stock Exchange Review.

RATES OF GROWTH IN PER SHARE EARNINGS, DIVIDENDS AND AVERAGE BOOK VALUE FOR SELECTED CANADIAN INDUSTRIALS

For Periods Ending In Indicated Year:	28 Industrial Companies (5 Year Least Squares)	28 Industrial Companies (10 Year Least Squares)
	(1)	(2)
	Growth in Earnings Per Share	
1983	8.0	--
1984	5.1	--
1985	12.6	--
1986	12.7	12.8
1987	13.2	12.2
1988	11.6	10.7
1989	12.3	10.9
1990	8.0	10.5
	Growth in Dividends Per Share	
1983	12.6	--
1984	6.4	--
1985	6.7	--
1986	8.5	10.8
1987	11.2	11.5
1988	11.3	10.7
1989	11.7	8.7
1990	11.8	10.8
1991	7.3	10.3
	Growth in Average Book Value Per Share	
1983	10.6	--
1984	9.6	--
1985	8.9	--
1986	11.0	--
1987	12.2	11.1
1988	11.9	9.6
1989	10.9	9.8
1990	11.6	11.3

Source: Annual Reports to Stockholder; Moody's Investors Service, Inc.; Toronto Stock Exchange Review.

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DIVIDEND PAYOUT RATIOS AND YIELDS FOR SELECTED CANADIAN INDUSTRIALS

Year		28 Industrial Companies: Dividend Payout Ratios (1)	28 Industrial Companies: Dividend Yields (2)
1976		34.6%	3.8%
1977		24.3	4.4
1978		23.1	4.4
1979		26.0	4.2
1980		28.7	3.3
1981		26.4	4.2
1982		31.7	4.5
1983		24.0	3.0
1984		23.4	2.8
1985		30.6	2.6
1986		34.1	2.2
1987		30.9	2.5
1988		27.7	2.6
1989		28.8	2.3
1990		36.6	2.8
1990	1Q		2.5
	2Q		2.8
	3Q		3.0
	4Q		3.0
1991	1Q		2.4
	2Q		2.2
	3Q		2.1
	4Q		2.0

Source: FRI Information Services, Ltd.; Globe and Mail; Toronto Stock Exchange Review; Standard & Poor's Stock Guide.

2088A6

EQUITY RISK PREMIUM FOR HIGH GRADE UTILITY INDEX DETERMINED BY REFERENCE TO DCF COST OF CAPITAL

	DCF Costs of Capital				Long-term Government	Risk Premium				
						Col	Col	Col	Col	
ear	a/	b/	c/	d/	Bond Yields	(1)-(5)	(2)-(5)	(3)-(5)	(4)-(5)	Average
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
976	14.9	15.2	14.4	15.1	9.2	5.8	6.0	5.2	5.9	5.7
977	15.0	15.1	14.1	15.4	8.7	6.3	6.4	5.4	6.7	6.2
978	15.4	15.4	14.4	15.9	9.3	6.1	6.1	5.1	6.6	6.0
979	15.5	15.3	14.8	16.1	10.2	5.3	5.1	4.6	5.9	5.2
980	14.9	14.4	14.2	15.5	12.5	2.4	1.9	1.7	3.0	2.3
981	16.2	15.8	15.9	16.5	15.2	1.0	0.5	0.7	1.3	0.9
982	17.7	17.4	17.6	17.9	14.3	3.4	3.1	3.4	3.6	3.4
983	15.7	15.2	15.4	16.1	11.8	3.9	3.4	3.6	4.3	3.8
984	15.8	15.2	15.2	16.3	12.8	3.0	2.4	2.5	3.5	2.9
985	14.6	14.0	13.9	15.3	11.0	3.6	2.9	2.9	4.3	3.4
986	13.8	13.1	13.1	14.5	9.5	4.3	3.6	3.6	5.0	4.1
987	13.2	12.4	12.7	13.9	10.0	3.3	2.5	2.8	3.9	3.1
988	13.0	12.2	12.9	13.5	10.2	2.8	2.0	2.6	3.2	2.7
989	12.0	11.1	12.3	12.3	9.9	2.1	1.2	2.4	2.3	2.0
990	12.2	11.4	12.6	12.4	10.9	1.3	0.5	1.8	1.5	1.3
991	11.6	11.0	11.9	11.7	9.8	1.8	1.3	2.1	1.9	1.8
VERAGE										
976-1991	14.5	14.0	14.1	14.9	10.9	3.5	3.0	3.1	3.9	3.4
976-1982	15.7	15.5	15.1	16.1	11.3	4.3	4.2	3.7	4.7	4.2
983-1991	13.5	12.8	13.3	14.0	10.6	2.9	2.2	2.7	3.3	2.8

Growth reflects 25% weight given to each 5 and 10 year growth in dividends and 50% weight to growth in retained earnings.
Growth reflects one-third weight given to 5 year growth in dividends and two-thirds weight to growth in retained earnings.
Growth reflects one-third weight given to 10 year growth in dividends and two-thirds weight to growth in retained earnings.
Growth reflects one-third weight given to each 5 and 10 year growth in dividends and to growth in retained earnings.

ource: Schedule 7, page 2 of 2; Bank of Canada Review.

88A7_1

EQUITY RISK PREMIUM FOR HIGH GRADE UTILITY INDEX DETERMINED BY REFERENCE TO DCF COST OF CAPITAL

	Growth in Dividends a/		Growth in Retained	Weighted Growth Rates				Dividend
Year	Five-Year	Ten-Year	Earnings	b/	c/	d/	e/	Yield
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1976	8.9	6.5	6.9	7.3	7.6	6.7	7.4	7.4
1977	10.2	7.5	6.4	7.6	7.7	6.8	8.0	7.1
1978	11.3	8.6	7.0	8.5	8.4	7.5	9.0	6.6
1979	11.0	9.5	7.2	8.8	8.5	8.0	9.3	6.5
1980	10.5	9.8	6.6	8.4	7.9	7.7	9.0	6.3
1981	9.2	9.7	7.5	8.5	8.1	8.2	8.8	7.4
1982	9.1	9.8	8.4	8.9	8.6	8.9	9.1	8.4
1983	9.5	10.1	7.3	8.6	8.0	8.3	9.0	6.8
1984	9.8	10.0	6.8	8.3	7.8	7.8	8.8	7.1
1985	10.0	9.8	6.0	7.9	7.3	7.3	8.6	6.4
1986	9.4	9.4	5.3	7.3	6.7	6.7	8.0	6.3
1987	8.1	9.0	4.7	6.6	5.8	6.1	7.3	6.4
1988	6.6	8.5	5.0	6.3	5.5	6.1	6.7	6.5
1989	4.4	8.1	4.6	5.4	4.6	5.8	5.7	6.4
1990	3.9	7.5	4.6	5.2	4.4	5.6	5.3	6.8
1991	4.0	6.4	4.5	4.8	4.3	5.1	5.0	6.6

a/ Reflects least squares rates of growth ending in indicated years.
b/ Growth reflects 25% weight given to each 5 and 10 year growth in dividends and 50% weight to growth in retained earnings.
c/ Growth reflects one-third weight given to 5 year growth in dividends and two-thirds weight to growth in retained earnings.
d/ Growth reflects one-third weight given to 10 year growth in dividends and two-thirds weight to growth in retained earnings.
e/ Growth reflects one-third weight given to each 5 and 10 year growth in dividends and to growth in retained earnings.

Note: Growth rates and dividend yields are the midpoint of the average and median values for the sample.

Source: Annual Reports to Stockholders; Moody's Public Utility Manual; Toronto Stock Exchange Review.

EQUITY RISK PREMIUM FOR EXPANDED UTILITY INDEX DETERMINED BY REFERENCE TO DCF COST OF CAPITAL

	DCF Costs of Capital				Long-term Government	Risk Premium				
						Col	Col	Col	Col	
r	a/	b/	c/	d/	Bond Yields	(1)-(5)	(2)-(5)	(3)-(5)	(4)-(5)	Average
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
6	15.8	15.9	15.5	16.0	9.2	6.6	6.7	6.3	6.8	6.6
7	15.1	15.0	14.5	15.4	8.7	6.4	6.3	5.8	6.7	6.3
8	15.0	15.0	14.5	15.3	9.3	5.7	5.7	5.2	6.0	5.7
9	14.7	14.4	14.3	15.0	10.2	4.5	4.1	4.1	4.8	4.4
0	15.1	14.6	14.6	15.7	12.5	2.6	2.2	2.1	3.2	2.5
1	16.6	16.1	16.1	17.1	15.2	1.4	0.8	0.9	1.9	1.2
2	18.3	18.0	18.0	18.6	14.3	4.0	3.7	3.7	4.3	3.9
3	16.4	16.0	16.1	16.7	11.8	4.6	4.2	4.3	5.0	4.5
4	16.3	16.0	15.5	16.8	12.8	3.5	3.2	2.8	4.0	3.4
[illegible]	15.1	14.7	14.4	15.6	11.0	4.0	3.6	3.3	4.6	3.9
6	13.3	12.8	12.8	13.8	9.5	3.8	3.2	3.3	4.3	3.6
7	12.4	11.7	12.2	12.8	10.0	2.4	1.8	2.3	2.9	2.3
8	12.6	12.1	12.9	12.8	10.2	2.4	1.9	2.6	2.5	2.4
9	12.1	11.5	12.6	12.2	9.9	2.2	1.6	2.7	2.3	2.2
0	11.9	11.4	12.4	11.9	10.9	1.1	0.6	1.5	1.1	1.1
1	11.5	11.2	11.8	11.4	9.8	1.7	1.5	2.1	1.7	1.7
:RAGE										
6-1991	14.5	14.1	14.3	14.8	10.9	3.6	3.2	3.3	3.9	3.5
6-1982	15.8	15.6	15.3	16.1	11.3	4.5	4.2	4.0	4.8	4.4
3-1991	13.5	13.1	13.4	13.8	10.6	2.9	2.4	2.8	3.1	2.8

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owth reflects one-third weight given to each 5 and 10 year growth in dividends and to growth in retained earnings.

rce: Schedule 8, page 2 of 2; Bank of Canada Review.

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EQUITY RISK PREMIUM FOR EXPANDED UTILITY INDEX DETERMINED BY REFERENCE TO DCF COST OF CAPITAL

Year	Growth in Dividends a/ Five-Year (1)	Growth in Dividends a/ Ten-Year (2)	Growth in Retained Earnings (3)	Weighted Growth Rates b/ (4)	Weighted Growth Rates c/ (5)	Weighted Growth Rates d/ (6)	Weighted Growth Rates e/ (7)	Dividend Yield (8)
1976	8.5	7.3	7.2	7.6	7.6	7.2	7.7	8.0
1977	9.1	7.6	6.4	7.4	7.3	6.8	7.7	7.4
1978	9.4	7.9	7.2	7.9	7.9	7.4	8.2	6.8
1979	8.9	8.7	6.8	7.8	7.5	7.4	8.1	6.6
1980	9.6	9.3	6.4	7.9	7.5	7.4	8.4	6.9
1981	9.1	9.2	6.2	7.7	7.2	7.2	8.2	8.6
1982	9.3	9.3	7.6	8.4	8.2	8.1	8.7	9.4
1983	9.3	9.5	7.4	8.4	8.0	8.1	8.7	7.7
1984	10.7	9.5	7.1	8.6	8.3	7.9	9.1	7.4
1985	10.1	9.1	6.4	8.0	7.6	7.3	8.5	6.8
1986	8.3	8.4	5.3	6.8	6.3	6.3	7.3	6.3
1987	6.4	7.9	4.7	5.9	5.2	5.8	6.3	6.3
1988	5.1	7.3	5.5	5.9	5.4	6.1	6.0	6.6
1989	4.2	7.3	5.4	5.5	5.0	6.0	5.6	6.4
1990	3.7	6.5	5.0	5.0	4.5	5.5	5.0	6.7
1991	3.8	5.5	4.9	4.8	4.6	5.1	4.8	6.5

a/ Reflects least squares rates of growth ending in indicated years.
b/ Growth reflects 25% weight given to each 5 and 10 year growth in dividends and 50% weight to growth in retained earnings.
c/ Growth reflects one-third weight given to 5 year growth in dividends and two-thirds weight to growth in retained earnings.
d/ Growth reflects one-third weight given to 10 year growth in dividends and two-thirds weight to growth in retained earnings.
e/ Growth reflects one-third weight given to each 5 and 10 year growth in dividends and to growth in retained earnings.

Note: Growth rates and dividend yields are the midpoint of the average and median values for the sample.

Source: Annual Reports to Stockholders; Moody's Public Utility Manual; Toronto Stock Exchange Review.

CENTRA GAS BRITISH COLUMBIA INC.

DIRECT TESTIMONY OF COMPANY WITNESSES

ANTHONY M. HAINES

CENTRA GAS BRITISH COLUMBIA INC.

TESTIMONY OF ANTHONY M. HAINES

Q. Mr. Haines, would you please state your present position with Centra Gas British Columbia Inc.?

A. I am Manager of Strategic Planning and Regulatory Affairs of Centra Gas British Columbia Inc. My responsibilities include all aspects of the regulation of the utility working very closely with the BCUC and MEMPR. I am also responsible for the Financial Planning activities of the company, these include preparation of the long-term strategic plan, annual budget and monthly outlooks.

Q. What are your qualifications and business experience?

A. I graduated from the University of Lethbridge in 1984 from the Bachelor of Commerce program with an accounting major. I have completed my fourth year of the Certified Managerial Accounting Program. I have worked for 10 years in the oil and gas business and specifically 3 years for Centra Gas British Columbia Inc.

Q. Have you previously testified before any regulatory bodies?

A. No.

Q. What is the purpose of your testimony at this hearing?

A. I am here to testify to the calculation of volumes and revenue which includes the determination of appropriate weather normalization methodology. I will also provide information and explanation with regard to the preparation of the common services allocation study prepared by the Utility Consulting Group of Ernst & Young. Finally, I will be testifying to the application of the revenue deficiency to individual rate classes (rate design).

Q. Please provide details on the proposed method of weather normalization.

A. Our analysis of the weather in Fort St. John indicated a significant warming trend. We prepared our analysis using 5 of the most commonly accepted methods. In comparing the 30 year average currently approved to the average of the last 5 years we see a 10% increase in the normal annual temperature in the area. This change is significant in that our average use per customer has been based on the 30 year average. Therefore the company is experiencing increasing revenue shortfall as a result of the warming trend. Although the company feels that the five year average method is the best indicator of the forecast for future consumption, five years may not be a large enough sample to accept at this time. Therefore I feel the more appropriate method is the 5/25 weight average used in this application. This results in a 5% increase in the normal annual temperature forecast. Which is about half of the current trend experienced.

Q. Please provide specific details on the gas volume requirements of Centra Gas' customers.

A. The forecast of weather normalized consumption per customer for the 1992 Forecast was determined as follows:

1) <u>Residential</u>

This customer class exhibits a declining weather normalized consumption pattern which appears to indicate a conservation trend is in effect. The 1992 forecast of 155 GJ per customer reflects a further 1% reduction for conservation from 157 GJ per customer received in 1991.

2) Small Commercial

No change to the weather normalized use is evident for this rate class. The forecast 1992 consumption per customer was estimated at 752 GJ.

3) Special Rate Customers/Industrial Customers

The historic weather normalized consumption pattern for customers in this category indicates no consistent trends, therefore to arrive at a reasonable forecast volume for 1992, the average of the weather normalized volumes for the years 1989 through 1991 was selected. Direct confirmation of forecast volumes was confirmed by our local sales representative in February 1992.

4) Take or Pay

On April 16, 1991 Scurry Rainbow Oil Limited elected not to renew their contract for natural gas supply. Scurry Rainbow, an industrial customer located in Fort St. John held a ten year (265,000 GJ) take or pay contract for natural gas supply which expired on April 16, 1991. Centra Gas was unable to renegotiate a new contract competitive with Scurry's estimated cost of solution gas.

5) Gas Revenue

1992 Forecast revenues have been calculated using existing rates as at January 1, 1992 and customer forecast growth for the year.

6) Transportation Revenue

Volumes are based on current outlook and the rates reflect existing rates.

Q. Please describe your current rate design and how the proposed rate change was determined.

A. The Revenue deficiency has been allocated to rate classes on a cost of service (excluding cost of gas) basis. This method was considered appropriate because had the allocation been made on actual rates charged, transportation customers would have received unequitable allocation.

Q. Do you have any updates to make to the Application?

A. In Appendix A to my testimony we have provided an updated projection for 1992 revenue requirement. It is our intention to file revised Schedules to the Application incorporating actual 1991 results shortly.

Q. What are the principle changes?

A. There are 2 major changes:

1. Rate Base

   The rate base has been reduced by 785,704 due to an error in calculating plant additions in 1987.

2. Share Services

   Shared Services have been reduced from 495,400 in the original application, a proxy amount used based on the 1985 Decision, to 384,600.

7) Other Utility Income

Late payment charges, NGV tank rentals and Gas Plant rent have been projected based on the 1991 experience to date.

Q. Please describe the Common Services Cost Allocation Study that was prepared.

A. Order G-8-92 the BCUC directed Centra Gas to have a common services allocation study prepared. Centra Gas contracted this study to the utility consulting group of Ernst & Young. The decision to use Ernst & Young was based on two factors. Firstly Ernst & Young utility group has the expertise to complete a study of this nature and secondly with Ernst & Young as the company's external auditors it was felt that the experience of the audit group would help in the basic understanding of the companies organization.

The parameters of the study was to:

1. Identify common services provided within the company.
2. Establish the costs associated with providing services.
3. Determine appropriate method for allocation of costs by way of direct interviewing and overall view of the companies activities.
4. Ensure the resulting allocations are fair and appropriate to all service areas.

The study has been completed and we feel the resulting allocations are appropriate for the services provided. Fort St. John's cost has been reduced substantially from the last hearing.

Q. What impact do these have on the Revenue Deficiency?

A. They reduce the projected revenue deficiency from 829,580 to 526,281.

Q. Does this conclude your testimony?

A. Yes.

Appendix A

IN THE MATTER OF THE Utilities
Commission Act, S.B.C. 1980
c. 60, as amended

- and -

IN THE MATTER OF an application by
Centra Gas British Columbia Inc. to amend
its Schedule of Rates

REVISIONS TO APPLICATION
Dated December 16, 1991

March 02, 1992

Centra Gas

CENTRA GAS BRITISH COLUMBIA INC. **March 2, 1992**
FORT ST. JOHN DISTRICT

REVISIONS TO APPLICATION
DATED DECEMBER 16, 1991

INDEX

REVENUE DEFICIENCY - 1992 FORECAST (Revised)
Based on Proposed Rate of Return

Line	Particulars	Amount	Ref.
1	Rate Base ($)	11,089,442	4.2.1R
2	Earned Return @ Present Rates ($)	843,804	9.2.1R
3	Rate of Return on Rate Base (%)	7.61	
4	Proposed Rate of Return on Rate Base (%)	11.92	14.2.1R
5	Proposed Earned Return ($)	1,321,863	14.2.1R
6	Revenue Deficiency After Tax ($)	478,059	
7	Income Taxes on Revenue Deficiency ($)	48,222	3.4.1R
8	REVENUE DEFICIENCY BEFORE TAX ($)	526,281	3.2.1R

TOTAL REVENUE REQUIREMENT - 1992 FORECAST (Revised)
Based on Proposed Rate of Return

Line	Particulars	Amount	Ref.
1	Cost of Gas	4,029,130	11.2.1R
2	Total Operating Expenses	1,699,800	12.2.1R
3	Depreciation	616,076	5.4.4R
4	Amortization: C.I.A.C.	(91,673)	6.2.1R
5	Deferrals	107,258	8.2.1R
6	Municipal Taxes	281,292	12.6.1R
7	Income Taxes @ Proposed Rates	78,368	3.4.1R
8	Proposed Earned Return on Rate Base	1,321,863	14.2.1R
9	TOTAL REVENUE REQUIREMENT	8,042,114	
	Reconciliation of Revenue Requirement:		
10	Gas Sales Revenue @ REDUCED Rates	7,251,636	10.5.1R
11	Transportation Revenue @ REDUCED Rates	162,497	10.7.1
12	Other Utility Revenue	101,700	10.9.1
13	Total Revenue @ REDUCED Rates	7,515,833	
14	Revenue Deficiency	526,281	
15	TOTAL REVENUE REQUIREMENT	8,042,114	

COME TAXES @ Proposed Rates - 1992 FORECAST (Revised)

ie	Particulars		Amount	Ref.
1	Proposed Earned Return after Tax		1,321,863	14.2.1R
2	Deduct: Interest on Debt		751,079	14.2.1R
3	Accounting Income after Income Taxes		570,784	
4	Add: Depreciation (net of contrib. amort.)		524,403	9.2.1R
5	Amortization Rate Application Costs		60,000	
6	Total Additions		584,403	
7	Deduct: Capital Cost Allowance		781,727	13.4.1R
8	Overheads		182,700	
9	Cumulative Eligible Capital		6,420	
10	1991 Rate Application Costs		120,000	
11	Total Deductions		1,090,847	
12	Taxable Income after Tax		64,340	
13	1-current income tax rate		0.5716	
14	Taxable Income		112,561	
	<u>Income Tax Calculation:</u>	<u>Rate</u>		
15	Federal Tax	38.00%	42,773	
16	Less: Tax Abatement	10.00%	11,256	
17	Net Federal Tax	28.00%	31,517	
18	Federal Surcharge on Net Federal Tax	3.00%	946	
19	Provincial Tax	14.00%	15,759	
20	Inc Tax Calculated	42.84%	48,222	
21	LCT on Year End Rate Base	0.20%	30,145	
22	INCOME TAX PAYABLE		78,368	

RATE BASE - 1992 FORECAST (Revised)

Line	Particulars	Amount	Ref.
	Gross Plant in Service:		
1	Balance at beginning of Year	18,081,356	5.2.3R
2	Balance at end of Year	18,974,056	5.2.3R
3	Mid-Year Balance	18,527,706	
	Accumulated Depreciation:		
4	Balance at beginning of Year	4,133,393	5.4.4R
5	Balance at end of Year	4,664,402	5.4.4R
6	Mid-Year Balance	4,398,898	
7	Net Mid-Year Plant in Service - District	14,128,808	
8	Allocated Net Mid-Year Plant - Regional	317,331	(1)
9	Less: Net Mid-Year Contributions	3,923,514	6.2.1
10	Deferred Income Taxes	196,400	
11	Working Capital	763,217	7.2.1R
12	**MID-YEAR RATE BASE**	11,089,442	

(1) "Common Services Allocation Study" Page IV-1

OSS PLANT CONTINUITY SCHEDULE - District (Revised)
ember 31,1990 to December 31,1992

:	Code	Particulars	Plant Balance Dec 31/90	1991 Actual Net Additions	Plant Balance Dec 31/91	1992 Forecast Net Additions	Plant Balance Dec 31/92
		Intangible Plant:					
1	401	Franchise & consents	610	0	610	0	610
2	402	Other Intangible Plant	462	0	462	0	462
3		Total Intangible Plant	1,072	0	1,072	0	1,072
		Manufactured Gas Plant:					
4	433	Manufacturing Gas	0	0	0	0	0
5	434	Gas Holders	0	0	0	0	0
6		Tot.Manufactured Gas Plant	0	0	0	0	0
		Local Storage Plant:					
7	442	Structures & Improvements	0	0	0	0	0
8	443	Gas Holders Storage	0	0	0	0	0
9		Total Local Storage Plant	0	0	0	0	0

CENTRA GAS BRITISH COLUMBIA INC.
FORT ST. JOHN DISTRICT

OSS PLANT CONTINUITY SCHEDULE - District (Revised)
ember 31,1990 to December 31,1992

e	Code	Particulars	Plant Balance Dec 31/90	1991 Actual Net Additions	Plant Balance Dec 31/91	1992 Forecast Net Additions	Plant Balance Dec 31/92
		Transmission Plant:					
10	460	Land	6,299	0	6,299	0	6,299
11	461	Land rights	19,186	6,999	26,185	0	26,185
12	463	Meas & Reg Structures	11,202	3,520	14,722	0	14,722
13	465	Mains	1,949,710	20,770	1,970,480	0	1,970,480
14	467	Meas & Reg Equipment	331,036	38,525	369,561	193,200	562,761
15	461	Land rights-Special Industrials	22,394	4,396	26,790	0	26,790
16	465	Mains-Special Industrials	507,719	0	507,719	0	507,719
17		Total Transmission Plant	2,847,546	74,210	2,921,756	193,200	3,114,956
		Distribution Plant:					
18	470	Land	3,928	0	3,928	0	3,928
19	471	Land Rights	79,780	22,518	102,298	5,000	107,298
20	472	Structures & Improvements	58,225	0	58,225	97,500	155,725
21	473	Services	3,358,443	169,313	3,527,756	127,200	3,654,956
22	474	Meter & Reg Installation	756,493	18,446	774,939	18,200	793,139
23	475	Mains	6,768,706	160,589	6,929,295	132,200	7,061,495
24	476	Compressor Equipment	325	0	325	0	325
25	477	Meas & Reg Equipment	586,277	5,109	591,386	100,800	692,186
26	478	Meters	613,402	15,113	628,515	24,200	652,715
27	470	Land-Special Industrials	1,027	0	1,027	0	1,027
28	471	Land Rights-Special Industrials	6,435	0	6,435	0	6,435
29	473	Services-Special Industrials	604	0	604	0	604
30	474	Met & Reg Inst-Special Industrials	43,133	0	43,133	0	43,133
31	475	Mains-Special Industrials	606,478	0	606,478	0	606,478
32	477	Meas & Reg Equ-Special Industrials	45,776	0	45,776	0	45,776
33	478	Meters-Special Industrials	104	0	104	0	104
34		Total Distribution Plant	12,929,136	391,088	13,320,224	505,100	13,825,324

:OSS PLANT CONTINUITY SCHEDULE - District (Revised)
cember 31,1990 to December 31,1992

e	Code	Particulars	Plant Balance Dec 31/90	1991 Actual Net Additions	Plant Balance Dec 31/91	1992 Forecast Net Additions	Plant Balance Dec 31/92
		General Plant:					
35	480	Land	32,089	0	32,089	60,000	92,089
36	482	Structures & Improvements	332,478	3,505	335,983	12,000	347,983
37	483	Office Furn & Equipment	44,245	435	44,680	10,700	55,380
38	48330	Computer Equipment	426,373	49,967	476,340	0	476,340
39	484	Transportation Equipment	160,209	62,240	222,449	44,800	267,249
40	485	Heavy Work Equipment	47,859	0	47,859	0	47,859
41	486	Tools & Work Equipment	82,133	5,836	87,969	22,600	110,569
42	487	Equip on Customer Premises	235,387	23,889	259,276	6,800	266,076
43	488	Communication Equipment	42,374	6,178	48,552	37,500	86,052
44	487	Equ on Cust Prem-Compressor	283,107	0	283,107	0	283,107
45		Total General Plant	1,686,254	152,050	1,838,304	194,400	2,032,704
46		TOTAL GROSS PLANT	17,464,008	617,348	18,081,356	892,700	18,974,056

Retirements are included in Net Additions:

1991:	General Plant	Computer Equipment	$21,562
1992:	Transmission Plant	Meas. & Reg. Equipment	$10,000
	General Plant	Transportation Equipment	$30,000
		Tools & Work Equipment	$2,000

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE - District (Revised)
December 31,1991 to December 31,1992

Line	Code	Particulars	Rate %	Accumulated Depreciation Balance Dec 31/91	1992 Forecast Depreciation Expense	1992 Retirements	Accumulated Depreciation Balance Dec 31/92
		Intangible Plant:					
1	501	Franchise & consents	1%	203	6	0	209
2	502	Other Intangible Plant	1%	153	5	0	158
3		Total Intangible Plant		356	11	0	367
		Manufactured Gas Plant:					
7	533	Manufacturing Gas	3%	0	0	0	0
8	534	Gas Holders	3%	0	0	0	0
11		Tot.Manufactured Gas Plant		0	0	0	0
		Local Storage Plant:					
13	542	Structures & Improvements	0%	0	0	0	0
14	543	Gas Holders Storage	2%	0	0	0	0
16		Total Local Storage Plant		0	0	0	0
		Transmission Plant:					
17	560	Land	0%	0	0	0	0
18	561	Land rights	1%	7,248	2,545	0	9,793
19	563	Meas & Reg Structures	3%	2,997	442	0	3,439
20	565	Mains	2%	562,794	90,182	0	652,976
21	567	Meas & Reg Equipment	3%	72,932	11,087	10,000	74,019
22		Total Transmission Plant		645,971	104,256	10,000	740,227

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE - District (Revised)

December 31,1991 to December 31,1992

Line	Code	Particulars	Rate %	Accumulated Depreciation Balance Dec 31/91	1992 Forecast Depreciation Expense	1992 Retirements	Accumulated Depreciation Balance Dec 31/92
		Distribution Plant:					
23	570	Land	0%	964	0	0	964
24	571	Land Rights	1%/10%	9,747	1,041	0	10,788
25	572	Structures & Improvements	3%	20,104	1,747	0	21,851
26	573	Services	2%/10%	470,736	70,616	0	541,352
27	574	Meter & Reg Installation	3%/10%	242,849	23,811	0	266,660
28	575	Mains	2%/10%	1,507,674	153,981	0	1,661,655
30	577	Meas & Reg Equipment	3%/10%	160,714	22,324	0	183,038
31	578	Meters	3%/10%	192,038	18,865	0	210,903
32		Total Distribution Plant		2,604,826	292,385	0	2,897,211
		General Plant:					
33	580	Land	0%	0	0		0
34	582	Structures & Improvements	3%	75,647	10,079		85,726
35	583	Office Furn & Equipment	5%	20,333	2,234		22,567
36	58310/20	Systems-CSS/MIS	14%	243,779	68,117		311,896
37	58330	Computer Equipment	17%	144,922	47,877		192,799
38	584	Transportation Equipment	15%	77,452	33,367	37,500	73,319
39	585	Heavy Work Equipment	5%	19,005	2,393		21,398
40	586	Tools & Work Equipment	5%	36,942	4,398	2,000	39,340
41	587	Equip on Customer Premises	5%/13%	245,249	12,964		258,213
42	588	Communication Equipment	5%	18,911	2,428		21,339
43		Total General Plant		882,240	183,857	39,500	1,026,597
44		TOTAL ACCUM. DEP'N		4,133,393	580,509	49,500	4,664,402
45		Allocated Depreciation - Common Services			35,567		
46		TOTAL DEPRECIATION EXPENSE			616,076		

WORKING CAPITAL SUMMARY - 1992 FORECAST (Revised)

Line	Particulars	Amount	Ref.
1	Cash Working Capital Requirements	413,330	7.4.1R
2	Operating & Maintenance Inventory	249,000	
	Deferred Balances, Mid-Year:		
3	Regulatory Expense	30,000	8.2.1R
4	Scurry Rainbow Deficiency	70,887	8.2.1R
5	Cost of Gas Refund	0	
6	Total Deferred Balances	100,887	
7	TOTAL WORKING CAPITAL REQUIREMENTS	763,217	

SH WORKING CAPITAL REQUIREMENTS - 1992 FORECAST (Revised)

IE	Particulars	Revenue Lag Days	Expense Lag(Lead) Days	Net Lag Days	Amount Paid or Accrued 1992 Forecast
	Amount Paid/Accrued:				
1	Cost of Gas	57.5	43.9	13.6	4,029,130
	Operating and Maintenance:				
2	Payroll	57.5	8.9	48.6	626,554
3	Other(including Employee Benefits)	57.5	30.7	26.8	1,073,246
4	Property Tax	57.5	(30.5)	88.0	281,292
5	Provincial Tax	57.5	36.8	20.7	254,234
6	Income tax	57.5	15.2	42.3	78,368
7	G.S.T.			6.7	526,108
	Cash Amount Required:				
8	Cost of Gas				150,126
	Operating Expenses:				
9	Payroll				83,426
0	Other				78,803
1	Property Tax				67,818
2	Provincial Tax				14,418
3	Income Tax				9,082
4	G.S.T.				9,657
5	TOTAL CASH WORKING CAPITAL REQUIREMENTS				413,330

SUMMARY OF DEFERRED BALANCES - 1992 FORECAST (Revised)

Line	Particulars	Regulatory Expense	Scurry Rainbow	Cost of Gas	Amortization Expense
1	1992 Opening Balance	0	94,516	0	
2	Additions	120,000	0	0	
3	1992 Amortization	60,000	47,258	0	107,258
4	1992 Closing Balance	60,000	47,258	0	
5	1993 Amortization	60,000	47,258	0	107,258
6	1993 Closing Balance	0	0	0	
7	1992 Mid-Year Balance	30,000	70,887	0	

UTILITY INCOME - 1992 FORECAST (Revised)
Based on Rates reduced by the Cost of Gas Decrease Effective November 1, 1991

Line	Particulars	Amount	Ref.
1	Sales Volume	2,309,835	10.3.2R
2	Natural Gas Revenue	7,251,636	10.5.2R
3	Cost of Gas	4,029,130	11.2.1R
4	Gross Margin	3,222,506	
5	Transportation Revenue	162,497	10.7.1
6	Other Utility Revenue	101,700	10.9.1
7	Net Utility Revenue	3,486,703	
	Expenses:		
8	Operating	687,500	12.3.1
9	Maintenance	205,800	12.4.1
10	General	421,900	12.5.1
11	Shared Costs	384,600	12.2.1R
12	Depreciation	616,076	5.4.4R
13	Amortization of Deferrals	107,258	8.2.1R
14	Amortization of Contributions	(91,673)	6.2.1
15	Municipal Taxes	281,292	12.6.1R
16	Total Expenses	2,612,753	
17	Utility Income Before Income Taxes	873,950	
18	Income Tax	30,145	13.2.1R
19	NET UTILITY INCOME @ Reduced Rates	843,805	

SALES VOLUME - 1992 FORECAST (Revised)
Based on Normalized Consumption

Line	Particulars	January	February	March	April	May	June	July	August	September	October	November	December	Total
	Residental Volume:													
1	No. of Customers	5,973	5,973	5,973	5,973	5,973	5,979	5,994	6,007	6,020	6,035	6,044	6,053	6,000
2	Use Per Customer	26.38	19.72	19.03	10.32	5.53	5.35	2.95	2.72	7.77	10.44	19.70	25.06	154.97
3	Total Residential (GJ)	157,568	117,788	113,666	61,641	33,031	31,988	17,682	16,339	46,775	63,005	119,067	151,688	930,238
	Commercial Volume:													
4	No. of Customers	989	991	993	993	993	995	996	996	996	996	996	996	994
5	Use Per Customer	119.39	120.36	81.79	44.30	23.25	17.86	16.99	23.72	22.75	69.11	93.64	119.25	752.41
6	Total Commercial (GJ)	118,077	119,277	81,217	43,990	23,087	17,771	16,922	23,625	22,659	68,834	93,265	118,773	747,497
	Special Customer Volume:													
7	DG Smith	0	0	0	0	600	1,700	2,500	600	400	1,100	0	0	6,900
8	FSJ High School	1,700	1,400	1,200	800	600	300	100	100	300	600	1,000	1,100	9,200
9	Pioneer Square	700	600	500	400	300	200	100	100	200	300	500	800	4,700
10	Czar Resources	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Woods Petroleum	5,900	2,000	5,000	2,400	3,300	2,400	2,100	500	1,700	2,700	3,700	4,700	36,400
12	Central Treating	(now Industrial)												0
13	Wainoco	5,200	4,900	4,300	3,900	5,200	4,100	3,800	500	4,500	3,800	3,800	6,000	50,000
14	Pioneer Inn	1,300	1,200	1,100	800	700	600	500	500	600	900	1,200	1,300	10,700
15	FSJ Co-op	1,300	1,200	1,100	700	500	300	200	200	200	600	900	1,300	8,500
16	McKenzie Developments	1,800	1,600	1,400	900	600	400	400	300	500	1,000	1,600	2,000	12,500
17	FSJ Hospital	3,600	3,100	2,700	1,800	1,300	800	600	700	1,100	1,700	2,800	3,300	23,500
18	Scurry Rainbow Battery	400	300	300	600	0	0	0	0	100	200	300	400	2,600
19	Total Special Customers (GJ)	21,900	16,300	17,600	12,300	13,100	10,800	10,300	3,500	9,600	12,900	15,800	20,900	165,000

SALES VOLUME - 1992 FORECAST (Revised)
Based on Normalized Consumption

Line	Particulars	January	February	March	April	May	June	July	August	September	October	November	December	Total
	Industrial Volume:													
20	Conoco	4,300	2,100	1,800	2,400	2,100	1,900	2,200	800	2,300	2,000	2,200	2,400	26,500
21	Wainoco	2,800	1,700	2,700	2,700	800	200	0	0	100	1,600	2,500	6,800	21,900
22	Union Pacific	1,000	3,200	3,800	2,100	3,400	2,700	3,000	100	1,900	2,000	2,300	2,300	27,800
23	Tundra Turbos	2,800	2,300	2,600	2,100	3,000	2,000	2,100	1,900	2,200	2,400	2,300	2,500	28,200
24	Central Treating	3,700	3,100	3,000	1,200	1,000	900	900	900	1,300	1,400	1,600	3,000	22,000
25	Westcoast Petroleum	3,200	2,900	2,900	2,900	2,800	4,200	6,000	6,000	6,700	2,700	4,000	3,900	48,200
26	CanFor	19,300	14,600	15,200	13,400	11,700	12,700	11,800	10,300	11,000	12,200	14,600	15,800	162,600
27	PeaceWoods Main/Backup	16,200	16,300	14,300	10,300	8,400	8,600	8,000	7,800	7,800	10,200	11,000	11,000	129,900
28	Total Industrial (GJ)	53,300	46,200	46,300	37,100	33,200	33,200	34,000	27,800	33,300	34,500	40,500	47,700	467,100
29	TOTAL SALES VOLUME (GJ)	350,845	299,565	258,783	155,031	102,418	93,759	78,904	71,264	112,334	179,239	268,632	339,061	2,309,835

FORT ST. JOHN DISTRICT

SALES REVENUE - 1992 FORECAST (Revised)
Based on Normalized Consumption

Line	Particulars	January	February	March	April	May	June	July	August	September	October	November	December	Total
	Residential													
1	Fixed Monthly Charge	18,636	18,636	18,636	18,636	18,636	18,654	18,701	18,742	18,782	18,829	18,857	18,885	224,630
2	Commodity	517,296	386,698	373,165	202,367	108,441	105,017	58,050	53,641	153,562	206,845	390,897	497,992	3,053,971
3	Total Residential	$535,932	$405,334	$391,801	$221,003	$127,077	$123,671	$76,751	$72,383	$172,344	$225,674	$409,754	$516,877	$3,278,601
	Small Commercial													
4	Fixed Monthly Charge	3,086	3,092	3,098	3,098	3,098	3,104	3,108	3,108	3,108	3,108	3,108	3,108	37,224
5	Commodity	387,647	391,586	266,635	144,419	75,795	58,342	55,555	77,561	74,389	225,982	306,189	389,932	2,454,032
6	Total Commercial	$390,733	$394,678	$269,733	$147,517	$78,893	$61,446	$58,663	$80,669	$77,497	$229,090	$309,297	$393,040	$2,491,256
	Large Commercial													
7	Fixed Monthly Charge	304	304	304	304	304	304	304	304	304	304	304	304	3,648
8	DG Smith	0	0	0	0	1,970	5,581	8,208	1,970	1,313	3,611	0	0	22,653
9	FSJ High School	5,581	4,596	3,940	2,626	1,970	985	328	328	985	1,970	3,283	3,611	30,203
10	Pioneer Square	2,298	1,970	1,642	1,313	985	657	328	328	657	985	1,642	2,626	15,431
11	Czar Resources	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Woods Petroleum	19,370	6,566	16,415	7,879	10,834	7,879	6,894	1,642	5,581	8,864	12,147	15,430	119,501
13	Central Treating	(now Industrial)												0
14	Wainoco	17,072	16,087	14,117	12,804	17,072	13,460	12,475	1,642	14,774	12,475	12,475	19,698	164,151
15	Pioneer Inn	4,048	3,737	3,425	2,491	2,180	1,868	1,557	1,557	1,868	2,803	3,737	4,048	33,319
16	FSJ Co-op	4,048	3,737	3,425	2,180	1,557	934	623	623	623	1,868	2,803	4,048	26,469
17	McKenzie Developments	5,605	4,982	4,360	2,803	1,868	1,246	1,246	934	1,557	3,114	4,982	6,228	38,925
18	FSJ Hospital	$10,969	$9,446	$8,227	$5,485	$3,961	$2,438	$1,828	$2,133	$3,352	$5,180	$8,532	$10,055	71,606
19	Scurry Rainbow Battery	1,219	914	914	1,828	0	0	0	0	305	609	914	1,219	7,922
20	Total Large Commercial	$70,514	$52,339	$56,769	$39,713	$42,701	$35,352	$33,791	$11,461	$31,319	$41,783	$50,819	$67,267	$533,828

SALES REVENUE - 1992 FORECAST
Based on Normalized Consumption

Line	Particulars	January	February	March	April	May	June	July	August	September	October	November	December	Total
	Industrial													
21	Fixed Monthly Charge	6,441	6,441	6,441	6,441	6,441	6,441	6,441	6,441	6,441	6,441	6,441	6,441	77,292
22	Conoco	11,042	5,393	4,622	6,163	5,393	4,879	5,650	2,054	5,906	5,136	5,650	6,163	68,051
22	Wainoco	7,003	4,252	6,753	6,753	2,001	500	0	0	250	4,002	6,253	17,007	54,774
23	Union Pacific	2,501	8,003	9,504	5,252	8,503	6,753	7,503	250	4,752	5,002	5,752	5,752	69,527
24	Tundra Turbos	7,003	5,752	6,503	5,252	7,503	5,002	5,252	4,752	5,502	6,002	5,752	6,253	70,528
25	Central Treating	9,254	7,753	7,503	3,001	2,501	2,251	2,251	2,251	3,251	3,501	4,002	7,503	55,022
26	Westcoast Petroleum	6,803	6,165	6,165	6,165	5,953	8,929	12,756	12,756	14,244	5,740	8,504	8,291	102,471
27	CanFor	29,471	22,294	23,210	20,462	17,866	19,393	18,019	15,728	16,797	18,629	22,294	24,127	248,290
28	Peacewoods	25,191	25,347	22,237	16,017	13,062	13,373	12,440	12,129	12,129	15,861	17,105	17,105	201,996
29	Total Industrial	$104,709	$91,400	$92,938	$75,506	$69,223	$67,521	$70,312	$56,361	$69,272	$70,314	$81,753	$98,642	$947,951
30	TOTAL SALES REVENUE	$1,101,888	$943,751	$811,241	$483,739	$317,894	$287,990	$239,517	$220,874	$350,432	$566,861	$851,623	$1,075,826	$7,251,636

COST OF SALES - 1992 FORECAST (Revised)
Based on Normalized Consumption

Line	Particulars	January	February	March	April	May	June	July	August	September	October	November	December	Total
	Sales Volume:													
1	Sales Volume General	297,545	253,365	212,483	117,931	69,218	60,559	44,904	43,464	79,034	144,739	228,132	291,361	1,842,735
2	Sales Volume Industrial	53,300	46,200	46,300	37,100	33,200	33,200	34,000	27,800	33,300	34,500	40,500	47,700	467,100
3	Total Sales Volume (GJ)	350,845	299,565	258,783	155,031	102,418	93,759	78,904	71,264	112,334	179,239	268,632	339,061	2,309,835
	Gas Purchases (1.70% line loss):													
4	Purchases General	302,603	257,672	216,095	119,936	70,395	61,589	45,667	44,203	80,378	147,200	232,010	296,314	1,874,061
5	Purchases Industrial	54,206	46,985	47,087	37,731	33,764	33,764	34,578	28,273	33,866	35,087	41,189	48,511	475,041
6	Total Purchases (GJ)	356,809	304,657	263,182	157,667	104,159	95,353	80,245	72,476	114,244	182,287	273,199	344,825	2,349,102
	Cost of Sales:													
7	General	541,659	461,233	386,810	214,685	126,007	110,244	81,744	79,123	143,877	263,488	415,298	530,402	3,354,570
8	Industrial	76,973	66,719	66,864	53,578	47,945	47,945	49,101	40,148	48,090	49,824	58,488	68,886	674,561
9	TOTAL COST OF SALES	$618,632	$527,952	$453,674	$268,263	$173,952	$158,189	$130,845	$119,271	$191,967	$313,312	$473,786	$599,288	$4,029,131

OPERATING, MAINTENANCE AND GENERAL EXPENSE SUMMARY (Revised)

Line	Particulars	1991 Actual (1)	1992 Forecast	
	Direct Expenses:			
1	Operating		687,500	
2	Maintenance		205,800	
3	General		421,900	
4	Total Direct Expenses		1,315,200	
5	Shared Expenses		384,600	(2)
6	TOTAL O&M EXPENSES		1,699,800	
7	Cost per Customer		242	
8	AVERAGE CUSTOMERS		7,012	

(1) To be produced at a later date.
(2) "Common Services Allocation Study" Page IV-2, Exhibit IV-1

INCOME TAXES @ Existing Rates - 1992 FORECAST (Revised)

Line	Particulars		Amount	Ref.
1	Utility Income Before Income Taxes		873,950	9.2.1R
2	Deduct: Interest on Debt		751,079	14.2.1R
3	Accounting Income before Income Taxes		122,871	
4	Add: Depreciation (net of contrib. amort.)		524,403	9.2.1R
5	Amortization Rate Application Costs		60,000	
6	Total Additions		584,403	
7	Deduct: Capital Cost Allowance		781,727	13.4.1R
8	Admin O/H Capitalized		182,700	
9	Cumulative Eligible Capital		6,420	
10	1991 Rate Application Costs		120,000	
11	Total Deductions		1,090,847	
12	Taxable Income (Loss)		(383,573)	
	Income Tax Calculation:	Rate		
13	Federal Tax	38.00%	0	
14	Less: Tax Abatement	10.00%	0	
15	Net Federal Tax	28.00%	0	
16	Federal Surcharge	3.00%	0	
17	Provincial Tax	14.00%	0	
18	Inc Tax Calculated	42.84%	0	
19	LCT on End Year Rate Base	0.20%	30,145	
20	INCOME TAX PAYABLE		30,145	

'AL COST ALLOWANCE - 1992 FORECAST (Revised)

Particulars	Class	Rate	UCC Balance 12/31/91	1992 Forecast Additions	1992 Retirement	50% Of Net Additions	UCC Balance For 1992 CCA Calculation	1992 Forecast CCA
Utility Plant-Pre/88	2	6%	4,919,821	0	0	0	4,919,821	295,189
Utility Plant-Post/87	1	4%	4,113,253	537,600	10,000	263,800	4,377,053	175,082
Buildings-Pre/88	3	5%	160,869	0	0	0	160,869	8,043
Buildings-Post/87	1	4%	142,144	109,500	0	54,750	196,894	7,876
Funiture & Fixtures	8	20%	436,529	10,700	0	5,350	441,879	88,376
Comm. Equip.-post/76	8	20%	16,559	37,500	0	18,750	35,309	7,062
Comm. Equip.-pre/77	9	25%	109	0	0	0	109	27
Vehicles/Computer Equip	10	30%	585,025	106,900	39,500	33,700	618,725	185,618
Buildings	6	10%	28,554	0	0	0	28,554	2,855
Computer Software	12	100%	0	0	0	0	0	0
Leasehold Improvement	13	20%	57,840	0	0	0	57,840	11,568
Franchises	14	5%	632	0	0	0	632	31
TOTAL CCA			10,461,335	802,200	49,500	376,350	10,837,685	781,727

'PITAL STRUCTURE AND COST OF CAPITAL - PROPOSED FOR 1992 (Revised)

ne	Particulars	Capitalization Amount	Capitalization Percent	Average Embedded Cost	Cost Component	Proposed Earned Return	Total Annual Cost of Debt
		$	%	%	%	$	$
1	Short Term Debt	572,413	5.16	8.08	0.42	46,576	46,251
2	Long Term Debt	2,194,574	19.79	13.89	2.75	304,960	304,826
3	Deemed Long Term Debt	4,282,672	38.62	9.34	3.61	400,329	400,002
4	Preferred Shares	79,743	0.72	6.48	0.05	5,545	
	Common Equity	3,960,040	35.71	14.25	5.09	564,453	
6	MID YEAR RATE BASE	11,089,442	100.00		11.92	1,321,863	751,079

MUNICIPAL TAXES (Revised)

Line	Particulars	1992 Forecast
1	Property Tax	206,938
2	1% Of Revenue	74,354
3	TOTAL MUNICIPAL TAXES	281,292

DETERMINATION OF UNIT RATE INCREASE AND PROPOSED RATES

LIN	PARTICULARS	REF./CALC.	SGS	LGS-1	LGS-2	SIS-1	SIS-2	SIS-4	SIS-5	SIS-7	SIS-8	SIS-9	TOTAL
	Determination of Unit Rate Increase:												
1	Annual Sales & Trans Volumes (GJ)		1,784,935	31,700	26,100	26,500	99,900	48,200	48,300	162,600	129,900	100,900	2,459,035
2	Cost of Service at Existing Rates	Line 1xLine 9	2,664,908	41,971	32,808	30,422	107,992	33,885	34,631	16,910	17,147	13,420	2,994,093
3	Revenue Deficiency ($)	3.2.1R	468,410	7,379	5,768	5,348	18,985	5,957	6,088	2,973	3,014	2,359	526,281
4	Revenue Deficiency (%)	Line3/Line 2	17.58	17.58	17.58	17.58	17.58	17.58	17.58	17.58	17.58	17.58	17.58
5	Proposed Cost of Service	Line 2+Line 3	3,133,318	49,350	38,576	35,770	126,977	39,842	40,719	19,883	20,161	15,779	3,520,374
6	Cost of Service Increase	Line 3/Line 1	0.262	0.233	0.221	0.202	0.190	0.124	0.126	0.018	0.023	0.023	
	Proposed Rates ($/GJ):												
7	Existing Rates Before Interim	Jan.01/92	3.283	3.114	3.047	2.568	2.501	2.123	2.137	1.524	1.552	1.553	
8	Existing Cost of Gas	Feb.01/92	1.790	1.790	1.790	1.420	1.420	1.420	1.420	1.420	1.420	1.420	
9	Existing Cost of Service	Line 7-Line 8	1.493	1.324	1.257	1.148	1.081	0.703	0.717	0.104	0.132	0.133	
10	Cost of Service Increase	Line 6	0.262	0.233	0.221	0.202	0.190	0.124	0.126	0.018	0.023	0.023	
11	Proposed Cost of Service	Line 9+Line 10	1.755	1.557	1.478	1.350	1.271	0.827	0.843	0.122	0.155	0.156	
12	Proposed Rates		3.545	3.347	3.268	2.770	2.691	2.247	2.263	1.542	1.575	1.576	
13	Interim Rates	Feb.01/92	3.698	3.482	3.396	2.887	2.801	2.322	2.34	1.557	1.593	1.594	
14	Decrease over Interim Rates		-4.1%	-3.9%	-3.8%	-4.1%	-3.9%	-3.2%	-3.3%	-1.0%	-1.1%	-1.1%	

FORT ST. JOHN DISTRICT

CONTINUITY SCHEDULE OF FORT ST. JOHN DISTRICT RATES (Revised)

	Aug 01/85	Dec 01/85	Jan 01/86	Nov 01/86	Dec 01/88 Jan 01/89	May 01/89 Jul 01/89	Nov 01/89	Nov 01/90	Jan 01/92	Interim Feb 01/92	1992 Proposed Rates
SGS											
Fixed	3.00	3.00	3.12	3.12	n/c	3.12	3.12	n/c	3.12	3.12	3.12
Commodity	3.466	3.195	3.316	3.000	n/c	3.169	3.361	n/c	3.283	3.698	3.545
LGS-1											
Fixed	25.00	25.00	25.95	25.95	n/c	25.95	25.95	n/c	25.95	25.95	25.95
Commodity	3.289	3.032	3.147	2.831	n/c	3.000	3.192	n/c	3.114	3.482	3.347
LGS-2											
Fixed	100.00	100.00	103.80	103.80	n/c	103.80	103.80	n/c	103.80	103.80	103.80
Commodity	3.219	2.967	3.080	2.764	n/c	2.933	3.125	n/c	3.047	3.396	3.268
SIS-1											
Fixed				25.95	n/c	n/c	25.95	25.95	25.95	25.95	25.95
Commodity				2.573	n/c	n/c	2.547	2.701	2.568	2.887	2.770
SIS-2											
Fixed				103.80	n/c	n/c	103.80	103.80	103.80	103.80	103.80
Commodity				2.506	n/c	n/c	2.480	2.634	2.501	2.801	2.691
SIS-3 (BalFor, CanFor)											
Fixed	200.00	200.00	207.60	207.60							
Commodity	3.206	2.955	3.067	2.493							
SIS-4 (Westcoast)											
Commodity+COG	2.645	2.594	2.694	2.132	n/c	n/c	2.106	2.256	2.126	2.322	2.247
SIS-5 (PetroCan)											
Commodity+COG	2.660	2.608	2.708	2.146	n/c	n/c	2.120	2.270	2.140	2.340	2.263
SIS-6 (Scurry Rainbow)											
Commodity+COG	3.274	3.018	3.133	2.559	n/c	n/c	2.533	2.687			
SIS-7 (CanFor)											
Fixed					3000.00	n/c	n/c	3000.00	3000.00	3000.00	3000.00
Commodity+COG					1.507	n/c	n/c	1.657	1.527	1.557	1.542
SIS-8 (BalFor)											
Fixed					3000.00	n/c	n/c	3000.00	3000.00	3000.00	3000.00
Commodity+COG					1.535	n/c	n/c	1.685	1.555	1.593	1.575
SIS-9 (Stoddart Compressor)											
Fixed						9500.00	n/c	9500.00	9500.00	9500.00	9500.00
Commodity+COG						1.536	n/c	1.686	1.556	1.594	1.576

NOTE: n/c = no change

CENTRA GAS BRITISH COLUMBIA INC.
FORT ST. JOHN DISTRICT

REASON FOR CHANGE

- Aug.01.85 final decision on GRA, also incorporates a cost of gas increase not included in GRA
  - B.O.'s #G-42-85, #G-45-85, #G-61-86 and #G-68-85
- Dec.01/85 conversion from imperial to metric measurement; no change to customers total bill
  - B.O. #G-92-85
- Jan.01/86 interim increase of 3.8%, final decision granted interim rates as permanent, August 1986
  - B.O.'s #G-101-85 and #G-29-86
- Nov.01/86 introduction of a two-tier gas supply based on load factor (SGS/LGS and SIS) which decreased cost of gas PLUS WEI/NEB hearing cost recovery
  - B.O. #G-65-86
- Dec.01/88 Jan.01/89 new contracts with CanFor and Balfour resulting in lost margin deferral accounts established to capture loss
  - B.O.'s #G-103-88 and #G-110-88
- May 01/89 permanent increase in rates as result of lost margin re: Balfour and CanFor
  - B.O. #G-19-89
- Jul.01/89 new customer - WEI Stoddart Compressor
- Nov.01.89 increased cost of gas for SGS/LGS customers PLUS removal of WEI/NEB hearing cost recovery
  - B.O. #G-59-89
- Nov.01/90 increased cost of gas for general SIS customers; does not affect those with negotiated rates
  - B.O. #G-85-90
- Jan.01/92 decreased cost of gas for all customers
  - B.O. #G-112-91
- Feb.01/92 interim rate increase re: GRA filed December 16, 1991
  - B.O. #G-8-92

CENTRA GAS BRITISH COLUMBIA INC.

DIRECT TESTIMONY OF COMPANY WITNESSES

DONALD G. OLSEN

CENTRA GAS BRITISH COLUMBIA INC.

TESTIMONY OF DONALD G. OLSEN

Q. Mr. Olsen, would you please indicate your present position with Centra Gas British Columbia Inc.?

A. I am Manager of Operations of Centra Gas British Columbia Inc.

Q. What is your educational, professional and business background?

A. I graduated from Starbuck Consolidated School in 1947 with a Grade XII and First Year University standing. In 1952 I took the position of Instrument Man with Winnipeg and Central Gas and subsequently worked for Greater Winnipeg Gas as Construction Foreman, Maintenance Foreman, and Superintendent of Construction and Maintenance with Greater Winnipeg Gas.

In 1978 I moved to Nanaimo to manage Vancouver Island Gas Co. In 1980 I assumed responsibility for Port Alice and Fort St. John as Manager of Operations.

I remained responsible for the operations in Fort St. John from 1980 to November, 1991, when the responsibility for that District was shifted to Mr. Dennis Maxwell.

Q. Have you previously testified before any regulatory bodies?

A. I have appeared before this Commission on several occasions in Nanaimo, Port Alice, Whistler and here in Fort St. John, to provide testimony on the operations of this Gas Utility.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide information on the historical cost of service and plant additions for the years 1985 to 1991.

Q. Please describe the significant changes to operating and maintenance costs since 1985?

A. Operating and maintenance costs in Fort St. John have risen steadily since 1985 due to inflation, increases in the number of customers and the increased travel and associated costs due to expansion of service to rural areas.

Q. How many additional employees have you hired since the last rate case?

A. In 1985 we had 12 employees. The number dropped to 11 in 1987 and then increased to 13.5 by 1991.

Both of the employees added in 1991, a part time meter reader and an office clerk, were already working for the Company on a service contract that provided for occasional services. As a result of a decision by the Labour Relations Board in 1991 the company was required to hire these individuals directly as employees and discontinue their service contracts. A portion of their salary and wage cost has been offset by reductions in contract costs.

Q. What impacts have the additional employees and salary increases had on the total Operating and Maintenance costs.

A. Approximately 66% of the increase shown from 1985 to 1991 can be attributed directly to salaries, wages and benefits paid to employees in Fort St. John.

All of the employees in Fort St. John except 3 are represented by the General Truck Drivers and Helpers Union Local 31. Increases granted to this union have generally followed that of Unions in the Fort St. John area.

We have periodically carried out reviews of salaries and are satisfied that the compensation we pay is set out at a level that is fair to our employees and to our customers.

Q. Please describe the major additions to plant in service for the years 1985 to 1991.

A. Six items account for 50% of the total plant additions between 1985 and 1991.

1) <u>**Transmission Upgrade - 1985**</u> $439,051

As a result of a stripping plant being built at Taylor, reducing the heating value of gas supplied to Fort St. John by approximately 12%, it was found necessary to upgrade and recertify the two four inch transmission lines servicing Fort St. John from the McMahon Plant in Taylor. This upgrade was approved by the Commission in its 1985 Decision.

The two existing lines were certified to M.O.P. of 600 psig and Engineering studies specified the lines be upgraded to M.O.P. of 900 psig. This work involved taking each line out of service, excavating at all known fittings (ie. valves, repair clamps, farm taps, tees and stopper fittings) either eliminate or bring up to code requirements and then retest for certification.

As the source gas for Fort St. John was supplied through a feed line in the McMahon Plant, it was determined, for security of supply and ease of operation, to acquire a tap source immediately down stream of the McMahon Plant, giving Centra Gas access not only to the stream from the compressor station but also, in the event of a failure at the plant, access to supply from the "Alberta Sweet Gas" line originating from the Boundary Lake Plant. Accompanied with the relocation of the "source" gas, we also built a receipt station and new odorant facilities.

This new tap involved building approximately 1.8 kilometres of 6" transmission line from the compressor station to a new Town Border Station located just north of Taylor.

2) **Town Border Stations - Taylor and Fort St. John** $164,934

With the increase in delivery pressure from 600 psig to 900 psig, Town Border Stations at both Taylor and Fort St. John were required to reduce pressures to facilitate existing distribution systems in both areas. These stations consisted of bypass and crossover valving as well as first and second cut regulators and monitor systems to meet the Town demands.

3) **1986 PGEP Program** $2,073,989

In the Spring of 1986, upon receiving a PGEP grant from the Province of British Columbia, the Company undertook to install gas mains to service the North Pine, Cecil Lake and Taylor Ski Hill areas.

The North Pine project involved installing 16.1 kilometres of 2" aluminum transmission line and a total of 87.83 kilometres of 3/4" through 2" gas main and three regulator stations, to provide service for 114 farms and residences. Additionally, these mains provided access to supply two compressor stations with an annual load of 53,000 GJ's.

This system tied into the Montney service area but, because of the increased demands, required an upgrading of the Scurry Rainbow line from the Fort St. John Town Border Station to the east side of St. John's Creek.

The Cecil Lake System involved installing 12.5 kilometres of 1 1/4" aluminum transmission line from a new purchase station located on the Westcoast Boundary Lake line, three regulator stations and 148.1 kilometres of 3/4" to 2" P.E. gas main, to provide service to 148 farms and residences. Additionally, these mains provide access to six compressor stations with an annual load of 56,000 GJ's.

4) **1990 PGEP Program** $1,123,676

In 1990 the Company made application to the Government for PGEP funds to construct mains in the Rose Prairie area and for "infills" in the rural systems. The Rose Prairie System consisted of installing approximately 80 kilometres of 3/4" to 3" PE gas mains to provide service to 84 farms and residential homes. The infills consisted of 10 individual extensions consisting of 15.7 kilometres of 3/4" to 2" PE gas main and provided gas service to 66 farms and residences.

5) **PVC Replacement** $130,282

In 1989 the Company embarked on a 2 year System Betterment Program of replacing Schedule 100 PVC mains in the airport area. These mains, installed in early 1970, had become brittle, causing line breaks and fitting leaks. Further, the class of pipe would not allow for an increase in line pressure to 80 psig as in all other rural distributions. This program was completed in the airport area in 1990 allowing for a complete upgrading of all facilities in the area and standardization of operation.

In 1991 replacement of a second area of PVC piping in the Charlie Lake area began in order to coordinate work with the local government's rural sewer program. This work is planned to coincide with the sanitation program.

6) **Major Loads** $740,750

Over the period 1985 to 1991, Centra Gas undertook to provide service to several major oil companies and treatment plants throughout our franchise areas, making use of our expanded transmission and distribution facilities. These have included Woods Petroleum, Wainoco, and Westcoast Transmission, as well as numerous small batteries and dehydrators.

Q. Does this complete your testimony?

A. Yes.

CENTRA GAS BRITISH COLUMBIA INC.

DIRECT TESTIMONY OF COMPANY WITNESSES

DENNIS J.F. MAXWELL

CENTRA GAS BRITISH COLUMBIA INC.

TESTIMONY OF
DENNIS J.F. MAXWELL

Q. Mr. Maxwell, would you please state your present position with Centra Gas British Columbia Inc.?

A. I am Director Operations with Centra Gas British Columbia Inc., and am based in Victoria. I have direct administrative and operational responsibilities for communities comprising The Greater Victoria Regional District as well as Fort St. John. I am also responsible for overall Operations Policy and Procedures for the Province. I have held this position since 1991. Previously I was Project Manager for the Vancouver Island Natural Gas Distribution Project responsible for all design and construction activities providing service to 28 communities on Vancouver Island and the Sunshine Coast.

Q. What is your educational, professional and business background?

A. My experience in the industry includes service with Pacific Northern Gas Ltd., the former Gas Division of B.C. Hydro, now B.C. Gas, and BP Oil and Gas Ltd. I am a registered Professional Engineer in the province of British Columbia and graduated from the University of Alberta in 1969 in Chemical Engineering (Petroleum Pattern). I am a member of the Canadian Gas Association and serve on the Distribution Committee. I am also a member of The Pacific Coast Gas Association.

Q. Have you previously testified before any regulatory bodies?

A. I have not formally testified before the British Columbia Utilities Commission but have participated in a working capacity with the B.C.U.C. hearing held in the spring of 1991 regarding Franchise Agreements related to the Vancouver Island Natural Gas Distribution Project.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide information and explanations regarding the cost of service and rate base additions for the 1992 test year and in the future.

Q. How were the 1992 test year operating, maintenance and administration expenses forecast for this application?

A. The major components for the development of the 1992 forecast were past history, existing customer base, present facility design and operation, community growth and development plans and Centra Gas experience in the district.

Q. Please describe the major operating and maintenance components planned for 1992?

A. The principle changes in O & M in the 1992 budget are due to inflation and an increase in local staffing. The employees to be added are:

1) <u>**Measurement Technician - 1**</u>

In the past, a Measurement Technician from ICG Alberta (Leduc) or ICG BC (Nanaimo) has visited Fort St. John to carry out specific checks and calibrations as dictated by Consumer and Corporate Affairs Canada or as required by various maintenance and/or operating functions. The volume of work for measurement and regulation activities has grown to a level that justifies a full time qualified Measurement Technician. There are over 30 stations in the area of varying capacities. Most of these stations are aging and require increasing operating and maintenance attention. The transition from mechanical to electronic instrumentation over the last decade necessitates the input of the skills provided by a technician to the measurement and regulation equipment throughout the district.

Since the Company is hiring an employee and discontinuing the services provided from Leduc or Nanaimo there should be a minimal increase in costs as a result of this position. Bringing this work to Fort St. John is a direct benefit to the Company and to the community.

2) **District Clerk - 1**

One additional clerk is required. The changes in customer accounting practices, the introduction of additional computing terminals associated with these practices plus the increase in volume of customers who wish to personally pay bills at the Fort St. John office has necessitated the addition of one new clerk.

3) **Meter Reader - 0.5**

Meter reading is carried out on a monthly basis. Various PGEP projects have added greatly to the distances that have to be travelled to read meters. Coupled with holidays, occasional bad weather and specific meter read requests for people changing residences, the growth from 1.5 meter readers in 1991 to 2.0 meter readers in 1992 is justified.

Q. What rate of inflation have you assumed:

A. We have assumed an inflation rate of 4% for the purpose of projecting increases other than wages and salaries. Wage increases for union personnel were set by the signing of the agreement with the Teamsters in December 1991 and amount to slightly more than 2% increase over 1991 rates.

Q. How was the utility rate base determined for the purpose of this application?

A. A revised utility rate base in the amount of $11.1 million was determined using the actual net asset balance at December 31, 1991 and the projected net balance at December 31, 1992.

An allocation of net mid-year plant for capital assets used in the Nanaimo regional office and the Victoria head offices has been included. This is to ensure that assets purchased for the joint administration of the Fort St. John district and the balance of Centra Gas' operation are properly allocated. Details of this allocation can be found in the Common Services Allocation Study.

The mid-year unamortized balance of contributions and grants has been deducted from net mid-year plant. The Provincial Power and Gas Extension Program (PGEP) contributed the majority of these grants while the remainder came from new customers added to the system.

The working capital component of the utility rate base includes components for cash working capital, inventory and deferred balances. The deferred balance cover regulatory expenses and contribution margin losses resulting from Scurry Rainbow Oil Limited electing not to renew their contract.

Q. Please describe the major additions to gas plant in service planned for 1992.

A. Since filing the Application in December the planned additions for 1992 have been reviewed and the total budgeted amounts revised from $1,091,000 to $942,000. The major additions to plant in service are:

1) <u>**Charlie Lake PVC Replacement**</u> $86,100

We have an ongoing program to replace PVC due to problems described in Mr. Olsen's testimony. The replacement program for PVC will reflect only work that may arise as a result of leak and/or damage problems and the sewer upgrade program and accordingly is considered to be essential.

System betterment plans for future growth and security of supply to Charlie Lake and surrounding areas will dictate the extent of PVC replacement in future years.

2) **<u>Station Upgrade and Modifications</u>** $402,600

a) **<u>Town Border & Station 1A</u>**

The existing Town Border Station has passive monitor regulators, no pressure relief, no liquid separation, no filter and no line heater. For safety and security of supply it is necessary that the station be upgraded as this station supplies the majority of gas to the community.

The existing Station 1A has no line heater and a large pressure reduction. Frost heaving is severe consequently piping and equipment misalignment are oncoming problems. Coupled with work at the Town Border Station, the pressure reduction at Station 1A will be halved with minor station modifications.

b) **<u>Taylor Purchase Station</u>**

A new instrument will be purchased to affix to the purchase meter to provide a signal to the odourization equipment to ensure effective odourant levels are introduced to the main supply to Taylor and Fort St. John. This modification is necessary now to ensure effective odourant levels exist in the supply gas. The existing station will be fenced and made secure. Minor site improvements are included.

c) **Station Alarms**

Elementary alarm systems are present at only one site. It will have to be upgraded to adapt to the proposed new Communications Center planned for Victoria.

It is proposed that station alarms be extended to include a total of six to eight sites. These alarms will feed into the overall provincial communications/emergency network based in Victoria.

d) **Baldonnel**

Odourization is an important safety issue for the public and the company, consequently $10,000 has been placed in the 1992 budget to provide effective odourization for this area.

e) **Petro Canada Station**

Two nearby farm taps (Alcan & Ross) will be consolidated into the Petro Canada Station thus eliminating operation and maintenance costs associated with these two farm taps.

Installation of a Metrotech instrument on the meter will allow remote reading of the daily volumes and permit a review of daily allocations without visiting the site.

A considerable savings in operation expenses will be achieved by this expenditure by eliminating daily visits by a Meter Reader.

3) **Vehicles** $82,250

The aging of trucks in the district has necessitated the replacement of 3 vehicles. Each will exceed 130,000 km in 1992. Company policy and operating experience dictates replacement of vehicles as soon as practical after 100,000 km has been exceeded. The addition of a Measurement Technician necessitates a specific new vehicle for this function. A total of four new vehicles with associated canopies, tool boxes and railings amounts to an expenditure of $82,250.

Q. Does this complete your testimony?

A. Yes.

CENTRA GAS BRITISH COLUMBIA INC.

DIRECT TESTIMONY OF COMPANY WITNESSES

DOUG I. ANDREWS

CENTRA GAS BRITISH COLUMBIA INC.

TESTIMONY OF
DOUGLAS I. ANDREWS

Q. What is your name, the name of your company, your present position with that company and the nature of the relationship of your company with Centra Gas British Columbia Inc. ("Centra Gas")?

A. My name is Douglas Andrews. My company's name is Canadian Hydrocarbons Marketing Inc. ("CHMI"). I am Vice-President of Marketing with CHMI. CHMI provides natural gas supply and management services to Centra Gas for the Fort St. John franchise area. CHMI has provided this service since November, 1986.

Q. What is your educational, professional and business background?

A. I received a Bachelor of Science degree from the University of Saskatchewan in 1968 and a Masters of Business Administration degree from the University of Alberta in 1976. I am a Professional Engineer in Alberta. I was employed by an electric power distribution company in Alberta for eight years, a natural gas pipeline consulting firm in Alberta for five years, then a partner with a management consulting firm for two years and in 1982 became Manager of Gas Supply for the ICG Utilities Alberta and British Columbia companies. Subsequently, in 1986, I joined the ICG affiliate company now known as Canadian Hydrocarbons Marketing Inc. In April, 1990, the ICG utility companies, including CHMI, were purchased by Westcoast Energy Inc. I have held my current position with CHMI since 1987.

Q. Have you previously testified before any regulatory bodies?

A. Yes, I have appeared as a witness before the Alberta Energy Resources Conservation Board, the Northwest Territories Public Utilities Board and the Alberta Public Utilities Board.

Q. What is the purpose of your testimony?

A. I will be appearing as a witness for Centra Gas to respond to questions relating to gas supply to the Fort St. John franchise area.

Q. Please describe the current gas supply arrangements for Fort St. John and any pertinent issues relating to gas supply.

A. Centra Gas's Fort St. John franchise area gas supply currently consists of two contracts with Conoco Canada Limited (by 1991 assignment from Remington Energy Ltd. dated November 1, 1986 and Westcoast Energy Inc. offline sales agreement dated June 1, 1954) between predecessors of both companies.

The Conoco contract was one of the first direct purchase arrangements for core market supply in British Columbia, It is estimated that over the first five years of the term of this contract, that Centra has achieved gas cost savings averaging over $600,000 per year.

The Conoco contract provides a Maximum Daily Volume of 340 10^3M^3/day at the Sikanni plant outlet which provides 12,767 GJ at Fort St. John. This gas is delivered through back to back contracts between Conoco/CHMI and CHMI/Centra Gas and utilizes CHMI equivalent Westcoast Transportation Service - Northern. This procedure also permits Centra Gas access from time to time to CHMI's larger gas pool on Westcoast for purposes of Conoco backstop to the Conoco contract and daily requirements in excess of 12,767 GJ/day.

The Westcoast offline sales agreement is for an indefinite term and for all volumes required by Centra Gas at Fort St. John. This contract, along with other Westcoast offline sales contracts, is currently before the National Energy Board (December 17, 1991) to convert from sales to service by November 1, 1992 provided Centra Gas can put other satisfactory gas supply arrangements in place.

At this juncture, CHMI is negotiating with Conoco to extend the contract term complete with an additional gas reserves. It is also intended that an additional suppler will be integrated into the portfolio, either by November 1, 1992 or November 1, 1993. As well, although Centra Gas is prepared to covert the Westcoast contract from sales to service, this would not be pursued if there is any perceived loss of security of supply or ability to meet the peak day requirements.

Q. Does this complete your testimony?

A. Yes.