The Public Utilities Board

2nd Floor
280 Smith Street
Winnipeg, Manitoba
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M A N I T O B A	)	Order No. 156/91
THE PUBLIC UTILITIES BOARD ACT	)	
	)	December 31, 1991

BEFORE: G.D. Forrest, Chairman
Catherine Milner, Member
T.Don Bulloch, Member
W.C. Pearson, Q.C., Member

APPLICATION BY CENTRA GAS MANITOBA INC. REQUESTING:

A) CONFIRMATION OF THE INTERIM REFUNDABLE RATES APPROVED IN BOARD ORDER 19/91 BASED ON 1990 HISTORIC MID-YEAR RESULTS

B) APPROVAL OF A YEAR-END RATE BASE, RATE OF RETURN AND RETAIL RATES TO BE EFFECTIVE JANUARY 1, 1992 BASED ON A 1991 HISTORICAL TEST YEAR

C) APPROVAL OF A RATE RIDER TO BE EFFECTIVE JANUARY 1, 1992 TO DISPOSE OF THE DIFFERENCES BETWEEN THE ACTUAL 1990 GROSS MARGIN AND THAT INCLUDED IN THE INTERIM REFUNDABLE RATE APPLICATION AS APPROVED IN BOARD ORDER 19/91 AND COST OF GAS CHANGES IN 1991.

D) APPROVAL OF A RATE RIDER TO BE EFFECTIVE JANUARY 1, 1992 TO RECOVER INCREASED GAS COSTS FOR 1991 TRANSPORTATION TOLLS

E) ESTABLISHMENT OF VARIOUS DEFERRAL ACCOUNTS AND OTHER RELATED MATTERS

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19.0 <u>IT IS THEREFORE ORDERED THAT</u> 86

1.0 APPEARANCES

W. C. Gardner, Q.C. R.F. Peters	Counsel for the Public Utilities Board of Manitoba (the Board)
J.D. Brett M. Rothstein, Q.C. D.G. Unruh	Counsel for Centra Gas Manitoba Inc. (The Company)
B. Meronek R. Graham	Counsel for the Consumers' Association of Canada (Manitoba) Ltd. and the Manitoba Society of Seniors (CAC/MSOS)

2.0 WITNESSES FOR THE COMPANY

G.M. Hoffman	President and General Manager
H.M. Kast	Vice-President, Finance
T.E.J. Bell	Vice-President, Marketing and Sales
J. Roberts	Director, Information Services
G.W. Neufeld	Manager, Forecast and Administration
G.B. Whitehill	Controller
B.A.J. McLean	Vice-President, Customer Accounting Services
B. Klippenstein	Manager, Gas Supply Planning
G.W. Meyer	Director, Regulatory Affairs
M.D. Smith	Arthur Andersen & Co. - Lead-Lag Study Expert Witness
Dr. R.A. Morin	Cost of Capital Expert Witness

3.0 WITNESSES FOR CAC/MSOS

Dr. L.D. Booth Dr. M.K. Berkowitz	Cost of Capital Expert Witnesses

4.0 INTERVENERS

CAC/MSOS

5.0 PRESENTERS

5.1 Winnipeg Hearing

P. Johnson	Inland Cement Company
G. Finkle	Citizen

5.2 Brandon Hearing

D. Paterson, Q.C. R. Shepherd	Keystone Mechanical Contractors Association
D. Brolund	Citizen
H. Weitman	Citizen
L. Dawson	Brandon University
J. Gorchynski	Assiniboine Community College
C. Maggiacomo	Brandon Business Improvement Association
T. Wilson	Brandon Economic Development Board
D. Weiss	Citizen
E. Backman	City Manager, Brandon
G. Peters	Brandon Chamber of Commerce

6.0 OBSERVERS

R. Flume	Manitoba Energy & Mines
G. Wilcox	Energy & Chemical Workers Union
G. Collis	Simplot Canada Limited
R. Bamburak D.W. Buhr	City of Winnipeg

7.0 COMMUNICATIONS

R.S. (Bud) Oliver	Mayor, Town of Selkirk
R.P. Menka	Manitoba Sugar Company

8.0 BACKGROUND

In Order 143/90 dated October 15, 1990 respecting the review of the regulatory process in Manitoba, the Board decided to retain the use of the historic mid-year test period. The Board did modify the regulatory process whereby rate changes from General Rate Applications (GRA) would become effective on January 1 of each year to partially eliminate regulatory rate lag and to restrict rate changes to once per year.

To accommodate this process, the Company was instructed to file its GRA by no later than August 1 of the test year. This necessitated the use of part actual and part forecast test year. This timing was to allow for the normal "90 day run-up" period to the hearing and to allow the Board adequate time to review the application so that rate changes could become effective on January 1. The Board also stated that it could make adjustments to rates at the time of its next review of the Company's application if the actual test year results were significantly different from the initial application.

Order 143/90 also approved the establishment of a deferral account to accumulate gas cost changes which might occur during 1990. This deferral account was to be balanced at a subsequent GRA.

Because Order 143/90 was issued on October 15, 1990, the Company was not expected to comply with the August 1, 1990 filing date to allow for January 1, 1991 rate changes, based on a 1990 test year. Consequently the Company filed an Interim Refundable Rate (IRR) Application on December 4, 1990. The Board issued IRR Orders 15/91 and 19/91 which approved rates to become effective March 1, 1991. The Board considered that the 1990 IRR application was to accommodate the transition to the new regulatory process. In the same order, bad debt expense for rate setting purposes was capped at $4.5 million and the Board authorized the establishment of a $2,000,000 deferral account related to the increase in bad debt expense. The Board was to review the status of this account at a subsequent GRA.

In Order 101/91, the Board approved a deferral account for incremental costs related to compliance with the recently enacted disconnection legislation.

In June 1991, the Company filed an application for an order(s) confirming as final the 1991 Interim Refundable Rates established by Order 19/91 and the inclusion of a rate rider effective January 1, 1992 to recover decreased gas margins related to 1990 gas costs. The Company filed its 1990 actual results and certain other changes from the IRR application in support of this request. The application also requested approval of new rates to be effective January 1, 1992, based on a 1991 test year partially estimated. The 1991 test year application also requested approval of certain methodology changes and establishment of new deferral accounts.

A pre-hearing conference was held at the Board's offices on July 30, 1991 to consider the procedures and issues related to this application. Subsequent to this conference, the Board issued Order 112/91 which established a timetable for an orderly exchange of information and procedures to be followed at the public hearing.

A technical conference was held at the Board's offices on August 8, 1991. This conference was attended by Board staff, Board advisors, Company officials, representatives of CAC/MSOS and various other interested parties. The major topics of discussion were changes in normalization methodology, calculation of average year degree day deficiency and results of the Lead/Lag study related to working capital allowance. These discussions were not under oath and were not entered as evidence in the hearing.

A public hearing respecting this application was held at the Viscount Gort Flag Inn, Winnipeg, Manitoba on November 4 to 9 and November 12 and 13, 1991. The hearing was reconvened at the Royal Oak Inn, Brandon, Manitoba on November 14, 1991 to hear public presentations and on November 15, 1991 to conclude the evidentiary portion of the hearing related to the cost of capital.

Closing argument was heard on November 26, 1991 at the Board office, 280 Smith Street, Winnipeg, Manitoba.

9.0 THE APPLICATION

9.1 1990 Test Year

In the support of its request for confirmation of the IRR, the Company submitted a calculation of Mid-Year Rate Base, Rate of Return, Cost of Service and Revenue Requirement based on actual 1990 Historical Test Year results, with the addition of certain known and measurable changes. Additionally the application requested approval of a rate rider in the amount of $826,842 to be effective for a 12 month period commencing January 1, 1992. This rate rider is to recover the difference between the actual 1990 gross margin and that allowed in Order 19/91. The changes in gross margin are related to WGML cost of gas components, update of 30 year normal degree day determination, update of 1990 volumes and revised dispatch rules for propane usage.

The Company's submission incorporated the following changes from its original 1990 IRR filing in calculating its actual 1990 revenue deficiency:

1. Results of a lead-lag study in calculating the working capital allowance component of Rate Base.
2. Change in normal degree day calculation using a 10 year rolling average instead of a 30 year average.
3. Change in normalization methodology.
4. Increase in return on equity from 13% to 14% and an increase in the overall rate of return from 12.50% to 12.75%.

The Company submitted that with the inclusion of the above changes and using 1990 actual results, the revenue deficiency for 1990 is $9,059,583. The interim refundable rates were based on a calculated revenue deficiency of $5,251,020. The Company did not request recovery of any further revenue deficiency other than the rate rider related to gross margin.

9.2 1991 Test Year

For rates to be effective January 1, 1992, the Company applied for a determination of a 1991 Year-End Rate Base, Rate of Return, Cost of Service and Revenue Requirement based on part actual and part estimated 1991 Test Year results, with the inclusion of known and measurable adjustments. The Company submitted that because of increases in Rate Base, Cost of Capital, Cost of Gas, Operating and Maintenance, and certain other costs, a significant revenue deficiency would result for the 1992 fiscal year without any rate increases.

The Company submitted that the changes reflected in their application from previous Rate Base/Rate of Return Applications were:

1. An increase in the allowed return on equity from 13% to 13.75% (originally requested 14%) resulting in a decrease in the overall rate of return from 12.50% to 11.81% (because of a decrease in short term borrowing rates).

2. The use of actual capital structure.

3. The use of a 1991 year-end Rate Base, including the annualization of 1991 year-end customers for both gas revenues and gas costs.

4. An increase in depreciation expense to reflect a move to calculating depreciation on year-end plant balances and the phase-in of previously approved deprecation rates.

5. The use of a new normalization methodology and new normal degree day calculations.

6. The use of a lead-lag study for determination of the cash working capital allowance requirement of Rate Base.

7. The establishment of a deferral account related to costs incurred for the Company's activities with Brokers and the Broker related costs to be reviewed at the next GRA.

8. An increase of $560,000 in operating and maintenance expenses related to incremental and on-going costs of credit and collection activities resulting from the recent disconnect legislation.

9. The addition of $1,809,800 bad debt expense and 1991 costs of $500,000 related to credit and collection activities in the previously approved Bad Debt deferral account.

10. The establishment of a deferral account related to the use of propane for peak shaving with respect to costs and volumes. This deferral account would be reviewed at the next GRA.

11. The inclusion of a rate rider in the amount of $1,734,307 for a 12 month period commencing January 1, 1992 related to TCPL toll increases effective July 1, 1991.

A request for the deferral of the difference between its final 1991 annualized and normalized gross margin and that which will be approved by the Board was withdrawn by the Company during the hearing.

The Company originally submitted that its revenue deficiency would be $6,326,847 or 2.49% over and above revenues based on annualized Interim Refundable Rates currently in place. On December 20, 1991 the Company filed with the Board further information which reduced the revenue deficiency by an additional $2,376,298 as a result of "the recent settlement agreement with WGML on the (upstream differential) pricing dispute."

10.0 <u>1990 TEST YEAR</u>

10.1 Mid-year Net Plant

The Company's evidence is that the 1990 Plant Additions and Plant Retirements were categorized as follows:

(x 1000)

Category	Additions	Retirements	Total
Customer Growth	$7,787	$142	$7,645
System Replacement	8,945	1,195	7,750
System Additions	3,123	-	3,123
System Relocations	75	-	75
Maintenance	3,999	1,494	2,505
TOTAL	$23,929	$2,831	$21,098

Following is a summary of the Company's requested 1990 Mid-year Gross Plant, Accumulated Depreciation and Mid-year Plant, compared to that allowed by the Board for the 1989 Mid-Year.

(x $1,000)

Gross Plant Category	1989 Approved	1989 Adjustments	1989 Adjusted	1990 Additions	1990 Deletions	1991 Gross Plant
Intangible	$ 214	$ 0	$ 214	$ 0	$ 0	$214
Storage	14,334	0	14,334	1,578	(3)	15,909
Transmission	23,683	(2,961)	20,722	99	(147)	20,674
Distribution	186,643	3,884	190,527	18,694	(1,352)	207,868
General	29,749	(923)	28,826	3,558	(1,329)	31,055
Sub-total	$254,623	$0	$254,623	$23,929	$(2,831)	$275,720
Construction Work in Progress	573	0	573	510	(573)	510
TOTAL	$255,196	($0)	$255,196	$24,439	($3,404)	$276,230
1990 IRR Filing			$255,196	$24,389	($1,238)	$278,340

(x $1,000)

Net Plant Category	1989 Accum. Depr.	1989 Net	1990 Accum. Depr.	1990 Net
Intangible	$ 74	$ 140	$ 82	$ 132
Storage	6,051	8,283	6,473	9,436
Transmission	3,997	16,725	4,169	16,506
Distribution	40,653	149,874	43,586	164,282
General	10,260	18,566	12,779	18,276
Sub-total	$61,035	$193,588	$67,088	$208,632
Construction Work in Progress	-	573	-	510
TOTAL	$61,035	$194,161	$67,088	$209,142
1990 IRR Filing		$194,161	$68,899	$209,441

The expenditures related to storage plant additions of $1,577,690 were for safety upgrades at the La Salle and Wilkes Avenue propane storage facilities in accordance with the recommendations of an independent safety audit consultant, CDS Research Limited.

The Company witnesses testified that $7,787,233 of the $23,929,213 was for expenditures related to providing service to 3,001 new customers in 1990.

Transportation equipment, in the amount of $1,075,230 was for the purchase of 10 new vehicles, the replacement of 46 existing vehicles and the conversion of 18 vehicles from use of gasoline to use of natural gas. Vehicles are purchased and replaced in accordance with Company policy, which was submitted as an undertaking at the hearing. Retirement costs for vehicles replaced amounted to $797,048.

Tools and equipment expenditures totalled $727,129, of which $269,026 was required for meter testing. The balance was for construction, maintenance and operations requirements for a variety of items. Computer systems and applications hardware accounted for

$1,014,350, comprising 48 new PC's and mainframe hardware and software.

System betterment expenditures of $1,839,502 included replacement and/or additions of 52,710 feet of distribution mains, including $711,658 for removal of compression couplings. Also 3,263 services were either totally or partially replaced at a cost of $3,609,902.

Measuring and regulating equipment consisted of the following expenditures:

Upgrading Gate Stations, Border Stations, Regulator Stations	$1,685,824
New Regulator Stations	382,724
Odorizers and Equipment	155,712
Electronic Equipment	1,169,200
Miscellaneous (valves, meter stations, etc.)	121,654
	$3,515,114

The above expenditures were required for replacement of obsolete equipment to enhance safety of operations and increase system capacity.

Meter expenditures amounted to $2,032,708 and consisted of replacements, inventory, and new additions.

Other expenditures related to office furniture, land acquisition, communications equipment, heavy work equipment, and building improvements.

10.2 Working Capital Allowance

In its application, the Company revised its method of calculating the working capital allowance for cash requirements, using the results of its lead-lag study, completed in early 1991.

The following is the actual 1990 requested working capital allowance component of rate base compared to that allowed in 1989 and requested in the 1990 IRR:

Component	1989 Allowed	1990 IRR	1990 Actual
Cash Expenses	$ 6,095,423	$ 7,434,938	$15,514,577
Inventories	4,552,834	4,950,759	4,935,390
Accounts Receivable Arrears	7,477,855	11,682,534	N/A
Allowance for Doubtful Accounts	(1,865,000)	(4,383,009)	N/A
Finance Contracts	6,976,081	6,863,694	6,844,256
Customer's Security Deposit	(164,285)	(187,910)	(190,138)
TOTAL	**$23,072,908**	**$26,361,006**	**$27,104,085**

10.3 1990 Rate Base Summary

The 1990 mid-year Rate Base is as follows:

COMPONENT	1989 Allowed	1990 IRR	1990 Actual
Net Utility Plant	$179,541,666	$200,828,056	$200,840,775
Working Capital Allowance	23,072,908	26,361,006	27,104,085
Contributions in Aid of Const.	(2,725,034)	(2,796,706)	(2,810,037)
TOTAL	$199,889,540	$224,392,356	$225,134,823

10.4 Revenue Requirements

The Company refiled its 1990 test year actual results which, because of certain methodology changes, reflected a revenue deficiency of $9,059,583. The 1991 interim refundable rates are based on a revenue deficiency of $5,251,020. The Company, with the exception of the 1990 rate rider, is not seeking recovery of any additional revenues.

Following is a summary of the 1990 Revenue Requirements compared to that allowed in 1989 and the 1990 IRR.

(x $1,000)

	1989 Allowed	1990 IRR	1990 Actual
Cost of Gas	$166,801	$164,260	$156,841
Operating Expenses	38,523	44,716	43,676
Amortization	265	894	1,094
Depreciation	7,281	8,526	8,509
Municipal & Other Taxes	10,159	10,878	10,803
Income Tax	6,857	9,256	9,310
Return on Rate Base	24,986	27,937	28,705
TOTAL	$254,873	$266,466	$258,937
Other Income	(2,835)	(3,758)	(3,581)
Gas Revenues	$252,038	$262,708	$255,356
Revenue - Prior Rates	N/A	$257,457	$246,297
Revenue Deficiency		$5,251	$9,059

BOARD FINDINGS

The Board will confirm the interim refundable rates as approved in Board Order 19/91, which were based on a revenue deficiency of $5,251,020.

The increase in revenue deficiency to $9,059,583 in the refiled material is primarily related to methodology changes insofar as these relate to the lead-lag study results, weather normalization changes, movement to a 10 year rolling average and use of a 14% rate of return on equity instead of the 13% approved by the Board.

The 1990 IRR order approved a gas cost of $164,259,510 with gas revenues of $257,457,583 resulting in a gross margin of $93,198,073. The 1990 filing indicated gas costs of $156,841,034 and gas revenues of $246,296,946 for a gross margin of $89,455,912, a decrease in margin of some $3,742,000. The component parts of this margin decrease are:

Component	Margin Charge
Actual Normalization - From 8 Months Actual and 4 Months Forecast	($370,000)
US Exchange Rate	(310,000)
Updated WGML Supply Price	900,000
Updated 30 Year Normal DDD	(830,000)
Sub-Total	**($610,000)**
Update to 10 Year Normal DDD	(3,049,000)
New Normalization Methodology	(83,000)
TOTAL MARGIN CHANGE	**($3,742,000)**

Additionally, the Company requested an overall rate of return of 12.75%. Based on the interim refundable approved overall rate of return of 12.45% and difference in the return on Rate Base, this would have further decreased the revenue deficiency by some $675,000, prior to income tax.

The 1990 revenue deficiency, based on 1990 actual results and the same methodology employed in the 1990 IRR filing is approximately $4,947,000.

	(x $1,000)
Cost of Gas Operating Expenses Amortization Depreciation Municipal and Other Taxes Income Taxes Return on Rate Base	$161,230 43,676 1,094 8,509 10,803 9,006 28,030
TOTAL	$262,348
Other Income	($3,581)
Gas Revenues Required	$258,767
Gas Revenues Received	$253,820
Revenue Deficiency	$ 4,947

The revenue deficiency of $5,251,020 used to establish the Interim Refundable Rate would appear to be $304,000 in excess of the revenue deficiency shown in the above calculation. The actual amount of excess revenue, if any, will not be known until the Company's actual 1991 operating results are finalized. Because of the regulatory lag of the mid year historic rate base methodology, it is not likely that the Company will earn its allowed return in 1991. The Board will therefore confirm the 1991 interim refundable rates.

10.5 1990 Rate Rider

The Company requested a rate rider of $826,842 to be effective for a 12 month period commencing January 1, 1992 consisting of the following components:

	Margin Change
Update for Actual 1990 Normalization	($368,415)
Revised Dispatch Rules	($551,772)
Update of 30 Year Normal DDD	($830,282)
WGML Supply Price Reduction	$923,627
Decreased Margin (or increase in revenue by way of Rate Rider)	($826,842)

BOARD FINDINGS

The 1990 revenue deficiency filed by the Company based on actual results for 1990, including actual gas costs and updated weather normalization calculations, reflects a revenue deficiency less than the amount adopted by the Board for establishing the Interim Refundable Rates for 1991. Therefore, the Company has recovered the amount of $826,842 through the rates that are currently in place, and to approve a rate rider to recover this amount again in 1992 would be inappropriate. The Company's request for a rate rider to be effective January 1, 1992 related to 1990 decreased gas margins is therefore denied.

10.6 1990 Cost Allocation and Rate Design

Although the Company filed its cost of service study and resultant rates based on actual 1990 test year results, they did not propose to change the interim refundable rates for 1991. In comparing the various allocations and annualized interim refundable rates to those resulting from the actual 1991, the Board concludes that there are no significant differences in the ultimate rates and will therefore accept the cost allocation and interim rates.

11.0 1991 RATE BASE

11.1 Year End Net Plant

The Company's 1991 test year application is based on 7 months of actual results and 5 months forecast results. The Company also requested the use of year end rate base for 1991, as opposed to the use of the 1991 mid-year rate base, as has been the past practice in Manitoba.

The Company's forecasted 1991 plant additions are $16,743,925 and retirements of $4,703,317 for net additions of $12,040,608. These additions and retirements are categorized as follows:

	Additions	Retirements	Net
Customer Growth	$5,748,550	$227,873	$5,520,677
System Replacement	5,842,666	804,554	5,038,112
System Additions	1,116,862	2,780,183	(1,663,321)
System Relocations	146,611	-	146,611
Maintenance	3,889,236	890,707	2,998,529
	$16,743,925	$4,703,317	$12,040,608

The following is the Company's requested 1991 Year-End Gross Plant, Accumulated Depreciation and Year End Net Plant.

(x $1,000)

Gross Plant	1990 Approved	1991 Adjustments	1991 Additions	1991 Retirements	Total Gross
Intangible	214		0	0	214
Storage	15,909		0	(2,780)	13,129
Transmission	20,674		329	0	21,003
Distribution	207,868		13,195	(805)	220,258
General	31,055		3,221	(1,119)	33,157
Sub-Total	$275,720	(510)	$16,745	($4,704)	$287,761
CWIP	$510		$1,166	0	$1,166
TOTAL	$276,230	(510)	$17,911	($4,704)	$288,927

(x $1,000)

Net Plant	1990 Acc. Depr.	1990 Net Plant	1991 Acc. Depr.	1991 Net Plant
Intangible	$ 82	$132	$91	$123
Storage	6,473	9,436	5,201	7,928
Transmission	4,169	16,506	4,638	16,365
Distribution	43,586	164,282	48,093	172,165
General	12,779	18,276	15,734	17,423
Sub-Total	$67,088	$208,632	$73,757	$214,004
CWIP	-	$ 510	-	$ 1,119
	$67,088	$209,142	$73,757	$215,123

A further breakdown of the Company's Plant Additions and Retirements is as follows:

(x1000)

	Storage		Transmission		Distribution		General		Net
	Add'n	Ret.	Add'n	Ret.	Add'n	Ret.	Add'n	Ret.	
Customer Growth	$0	$0	$329	$0	$5,347	$0	$72	$228	$5,5217
System Replacement	0	0	0	0	5,843	805	0	0	5,038
System Additions	0	2,780	0	0	1,117	0	0	0	1,663
System Relocations	0	0	0	0	147	0	0	0	147
Maintenance	0	0	0	0	741	0	3,148	891	2,998
TOTAL	$0	$2,780	$329	$0	$13,196	$805	$3,220	$1,119	$12,041

STORAGE PLANT

In Order 133/90, dated August 28, 1990, the Board instructed the Company to submit a report on the use of the propane storage facility. The Company had a safety audit conducted in 1990 which recommended certain safety upgrades to both the La Salle and Wilkes Avenue sites. These upgrades were undertaken in 1990, as discussed in a prior section of this order. Safety upgrades to the two 5,000,000 gallon storage tanks were estimated to cost $3.4 million. The Company reviewed its entire propane peak shaving requirements and decided that these two tanks should be put out of service.

Total peak shaving volume requirements will be met by additional volumes through Coastal Gas Marketing arrangements. The retirement from gross plant of these tanks is the $2,780,183.

The Wilkes Avenue site, housing City Gate #1 and several pressure storage vessels, is still utilized for purposes of injecting a propane-air mixture into the system, using propane piped from the La Salle facility. The Company indicated that the matter of use of propane for peak shaving would be further investigated, and the potential for eliminating this facility in total still exists. Also, should it be desirable, there is the possibility of selling the La Salle portion of this facility.

TRANSMISSION AND DISTRIBUTION PLANT

The expenditures related to transmission plant of $328,611 and to distribution plant of $5,347,939 were required to provide service to 2,318 new customers coming on stream in 1991. These expenditures were for transmission and distribution mains, distribution services, meters and meter regulator installations.

The Company witnesses testified that, except for certain specialized purchases, all materials and labour contracts were tendered and awarded to the low bidder. The expenditure for customer growth is some $2,450 per customer which is consistent with past experience.

Distribution plant expenditures for system replacements included main replacements of $918,600 primarily involving replacement of compression couplings and $3,001,006 for replacement of 3,628 services ($3,001,006). An additional $700,000 was spent on the meter conversion program for temperature compensating meters. Expenditures related to installation of meters and regulators for replacement services amounted to $364,568. Upgrading of meter stations, gate stations, regulator and primary stations totalled approximately $800,000. Miscellaneous expenditures included replacement and upgrading of bypass odorizers and telemetry equipment.

The system relocation expenditure of $146,671 involved the upgrading of two regulator stations in Brandon necessitated by infringement of new development.

System additions were $1,116,862 consisting of $972,799 for new mains to enable increased system operating pressures, installations of electronic instruments, and other miscellaneous equipment.

The expenditure of $741,036 in distribution plant consisted of $73,000 for land acquisition and $668,021 for various alterations, building additions, new buildings and equipment. This work was tendered with the work being carried out by the low bidder.

The Company's witnesses testified that the replacement of compression couplings on mains and services is being carried out on a planned program basis and is not leak driven. The Company witnesses indicated that the main compression coupling replacement program has been substantially completed on the entire system while the service compression coupling program would be completed by about 1996. In 1990, the Company discovered some 8,500 service compression couplings to be in existence on the former Greater Winnipeg Gas System. Additionally, some 8,700 such couplings are estimated to exist in the rural areas. The Company estimated the 8,500 dresser replacements in the Winnipeg area would cost some $4,217,000. By extension, the total program would cost some $8,600,000.

BOARD FINDINGS

The Board considers this replacement program and other related expenditures to be necessary both from a safety and operational aspect and will approve these expenditures for inclusion in net plant. Similarly, the Board considers system location and system addition expenditures to be necessary for either customer growth or to enhance system capacity. As with expenditures related to customer growth, the Company tenders for the majority of system betterment and awards contracts to the low bidder.

GENERAL PLANT

General Plant expenditures were estimated to be $3,220,200 for 1991, with $1,118,580 in retirements for a net expenditure of $2,101,700. Equipment and customer premises, primarily water heaters accounted for $72,000 in additions and $227,873 in retirements. Company witnesses stated that this program would be eliminated within the near future.

Costs for household improvements, office furniture, and communications equipment amounted to $397,700, with $59,297 in retirements.

Computer systems and software acquisitions totalled $1,332,200 with $734,456 mainframe related and $332,194 P.C. related, for various uses and departments.

Other major expenditures were $942,700 for vehicles (corresponding retirements $650,794). This expenditure was for the replacement of 21 vehicles, all in accordance with the Company's vehicle replacement policy and the conversion of 16 vehicles to natural gas fuel.

Tools and work equipment and heavy work equipment totalled $471,200 with $28,533 in retirements for various miscellaneous expenditures.

BOARD FINDINGS

Having reviewed the Company's evidence and testimony, the Board accepts the Company's expenditures related to General Plant as prudent and appropriate for inclusion in Rate Base.

The Board is cognizant of the Company's requirements for capital expenditures related to customer growth and system betterment and considers such expenditures necessary provided they are carried out in a prudent manner.

The Board cautions the Company to ensure that planned expenditures are carefully priorized and that expenditures are made when necessary as opposed to when desirable. The Board would encourage the Company to carefully review its expenditures in areas of computer systems and software and to review its vehicle replacement policies such that vehicles are replaced only when maintenance costs outweigh the replacement costs of such vehicles.

The Board also requests the Company to reconsider its policy of capitalizing all items in excess of $200. This threshold appears too low.

The Board notes that the Company filed an update to its forecast 1991 capital program which increased forecasted spending by approximately $350,000 from the original filing. The Board will not require the Company to refile its application but will review these changes when the 1991 actual figures are known and will make necessary adjustments at that time should there be significant differences.

11.2 Working Capital Allowance

The following is a comparison of the requested working capital allowance to that approved in the 1990 IRR:

Component	1990 IRR	1991 Requested	Increase (Decrease)
Cash Expenses*	$ 7,434,938	$ N/A	$ N/A
Accounts Receivable Arrears**	11,682,534	N/A	N/A
Allowance for Doubtful Accounts**	(4,383,009)	N/A	N/A
Cash Requirement	N/A	16,576,711	N/A
Sub-total	14,734,463	16,576,711	1,842,248
Inventories**	4,950,759	3,277,135	(1,673,624)
Finance Contracts**	6,863,694	5,707,924	(1,155,770)
Customers' Security Deposits**	(187,910)	(190,229)	(2,319)
Total Working Capital Allowance	$26,361,006	$25,371,541	$(989,465)

* Amount was based on 1/8 operating expenses; 1/8 municipal and business taxes, and 1/12 of income taxes.

** Amounts were based on average monthly balances.

The calculation of the 1991 working capital allowance incorporates the results of the Company's Lead-Lag study. The Company was ordered to perform this study in Order 133/90. Arthur Andersen & Co., was retained by the Company to review the results of the Lead-Lag study and present expert testimony as to its reasonableness.

The results of the Lead-Lag study were used to determine the "cash requirements" which replaced the "cash expense, accounts receivable arrears and allowance for doubtful accounts" components of the former methodology.

The Lead-Lag study is more comprehensive than the former "45 day rule" as it compares the revenue lag or the period in days from when service is rendered to when payment is received from customers, with the various expense leads or the period in days between which the Company receives goods and services and pays for these goods and services. Once the revenue lags and expense leads are determined, they are applied to the appropriate average daily revenue and expense items of the Company to determine the net cash requirement component of working capital. Schedule 10.2.0 (revised) of the application contains a listing of the various leads and lags used to calculate the cash working capital. The various leads and lags were calculated using the 12 month period ending December 31, 1990.

There has been a substantial decrease in the working capital requirements related to inventories and finance contracts which has been partially offset by a large increase in cash working capital requirements as a result of the new lead-lag methodology. This increase is mainly related to the calculation of the revenue lag.

The revenue lag of 51.9 days consists of the meter reading lag, the billing lag and the collection lag. The most significant component of the revenue lag is the collection lag of 31.3 days as it represents the number of days from the billing date to the date payment is received and deposited. This collection lag is calculated by dividing the daily accounts receivable balance by daily billings. The Company's evidence is that this is longer than the normal collection lag of 20-25 days for two reasons.

Firstly, the inability of the Company to lock-off non-paying customers has led to a steady increase in accounts receivable arrears and total accounts receivable. The following table provides a comparison of the Company's forecast of accounts receivable arrears greater than 90 days, total accounts receivable, allowance for doubtful accounts and bad debt expense as at December 31, 1991 with the same information for December 31, 1990.

Component	1990 Test Year	1991 Test Year	1991 Increase (Decrease)	% Increase (Decrease)
Arrears > 90 days	$6,665,000	$9,800,000	$3,135,000	47.0
Total Arrears	11,697,000	15,451,000	3,754,000	32.1
Allowance for Doubtful Accounts	6,059,000	6,304,000	245,000	4.0
Bad Debt Expense	6,128,000	6,309,000	181,000	3.0

Given the forecasted increases in receivables and bad debt expense, the Company indicated that the impact of lock-off had been modest as lock-off had not commenced until August 1, 1991 for commercial accounts and September 3, 1991 for residential accounts. The Company testified that any future reduction in receivables as a result of lock-off will reduce the working capital calculation.

The second reason the collection lag is longer than normal is that the gross receivable balance in the collection lag calculation has not been reduced for the allowance for doubtful accounts. It is the position of the Company that from the period 1987 to 1990 there was a cumulative underrecovery of $6.2 million of bad debt expense. The Company received a $2.0 million deferral account related to the underrecovery in the 1991 IRR which reduced the net underrecovery to $4.2 million.

Since the average allowance for doubtful accounts during 1990 was also $4.2 million, it is the position of the Company that no part of this allowance has been funded by the ratepayers. The Company believes that it would be inappropriate to reduce the revenue lag for the effect of the allowance for doubtful accounts as it has been funded by the investor, not the ratepayer.

The Company testified that if the allowance had been included in the calculation, the collection lag would have been reduced by 5.9 days which would reduce the requested working capital allowance by $4.3 million, assuming the application was approved in its entirety.

CAC/MSOS had two major concerns related to the new Lead-Lag study. The first concern is that the revenue lag should be updated next year to include the effects of lock-off. The second concern is that the lead associated with other operating expenses is understated as it was based on a judgmental sample of 115 invoices.

The Company recommended that the revenue lag be updated every year regardless of the ability to lock-off, and stated that the other operating expense lead was so insignificant that a few days imprecision would not materially affect the total working capital calculation.

BOARD FINDINGS

The Board has reviewed the new Lead-Lag methodology and finds it acceptable. However, the Board will require that the Company update the revenue lag calculation at the next GRA to consider the effects of lock-off and to provide for any portion of the allowance for doubtful accounts that has been funded by the ratepayers. The Board will also require the Company to update the expense leads for any change in contracts, payment terms or payment policies.

The Board will allow a working capital allowance of $25,184,086 as follows:

Component	Requested	Board Adjustments	Allowed
Cash Requirement	$16,576,711	($187,455)	$16,389,256
Inventories	3,277,135	0	3,277,133
Finance Contracts	5,707,924	0	5,707,924
Customer Security Deposits	(190,229)	0	(190,229)
Total Working Capital Allowance	$25,371,541	($187,455)	$25,184,086

11.3 Mid-Year vs. Year-End Rate Base

The Company applied for a 1991 year-end Rate Base. The Company stated that it ought to be afforded a reasonable opportunity to earn its allowed return. To afford the Company the best opportunity, revenues earned in a given test period should be matched against expenditures and return on investment for that same period. This would be accomplished by a move to a future test year. While the Company is not requesting a future test year, the use of a year-end Rate Base would substantially enhance the Company's opportunity to earn its allowed rate of return. For example, if in the present application a mid-year rate base were utilized, the 1992 rates would only allow the Company to earn a return on a portion of the 1991 capital expenditure.

The Company also testified that the use of the mid-year Rate Base is unfair to shareholders, and because of the Company's inability to earn adequate returns, it is subject to reduced bond ratings, resulting in higher long term borrowing rates and higher rates to customers. The change from mid-year to year-end rate base in this application would not have a significant impact on revenue requirements. In addition, because of the Company's inability to raise sufficient long term debt because of its interest covenant coverage, it has had to finance some of its capital program with short term debt. Thus, in the Company's opinion, the financial integrity of the Company is in jeopardy.

CAC/MSOS urged the Board not to change to a year-end Rate Base stating that the fact that the Company's Bond Ratings were reduced was because of its inability to lock-off. There was no need for the Board to change its position as outlined in Order 143/90.

BOARD FINDINGS

In its Order 143/90, dated October 15, 1990, related to the hearing process in Manitoba, the Board decided to retain the use of a mid-year Rate Base and instructed the Company to file its next GRA (1990) on this basis. In this order, the Board considered the Company's actual return versus allowed return, different methods of calculating returns, and the Company's bond ratings. The Board also concluded that a change in test year Rate Base methodology, concurrent with the introduction of deferral accounts and the move to rates being implemented on January 1 of any given year (as opposed to the previous date of September 1) would not have been prudent.

The Board accepts the premise that rates must be fair to both the customers and shareholders. The Board notes that the Company's bond rating has been reduced by Dominion Bond Rating Service (DBRS) since its 1990 IRR application and further notes that the Company's short term debt load could approach $60,000,000 by the end of 1992. This short term debt load clearly violates the premise that capital programs with an extended service life should be funded by long term debt.

The Board is of the opinion that it must assess both the short and long term implications of moving to a year-end Rate Base. For purposes of this application, such a movement, would in fact result in a reduced revenue requirement vis-a-vis a mid-year test period.

The Board is cognizant of the fact that the Company will be required to fund plant expenditures related to customer growth on a continuing basis and substantial system betterment for the next five years. In addition, the Company will be required to replace plant which is becoming obsolete.

The Board is of the opinion that the move to a year-end Rate Base methodology is fair and reasonable to both the consumer and the Company and will enable the Company to better maintain its financial integrity and to more appropriately fund its capital requirements.

11.4 1991 Rate Base Summary

The Board will allow the following 1991 year end Rate Base.

Year End Gross Plant	$287,521,410
Accumulated Depreciation	(73,756,410)
Contributions in Aid of Construction	(2,885,842)
Working Capital Allowance	$25,184,086
1991 Year End-Rate Base	$236,063,244

12.0 RATE OF RETURN

12.1 Overall Rate of Return

12.1.1 1990 Allowed

The currently allowed overall Rate of Return and capital structure for Centra Gas as approved in Board Order 15/91 is as follows:

	Weight Percent	Cost Rate Percent	Weighted Rate Percent
Long-term debt	39.95	11.87	4.74
Short-term debt	21.90	12.58	2.76
Preferred stock	0.14	6.48	0.01
Equity	38.01	13.00	4.94
Total	100.00		12.45

12.1.2 Capital Structure

The Company's requested overall Rate of Return and capital structure as amended November 1, 1991 is as follows:

	Capital Structure	Weight Percent	Cost Rate Percent	Weighted Rate Percent
Long-term debt	83,787,408	36.16	11.99	4.33
Short-term debt	55,718,400	24.04	8.40	2.02
Preferred stock	303,525	0.13	6.48	0.01
Equity	91,936,900	39.67	13.75	5.45
Total	$231,746,233	100.00		11.81

The embedded cost of long-term debt increased from 11.87% to 11.99% primarily due to the contractual retirement of certain of the debt issues.

The Company testified that it was unable to issue any long-term debt in 1991, and under current estimates would only be able to issue $30 million of debt in 1992 when it had planned to issue $50-$60 million. The Company indicated that up to $40 million of any long-term debt issued in 1992 would be used to retire short-term debt. The Company also testified that it was fortunate that short-term interest rates had fallen recently as the high proportion of short-term debt exposed the Company to the risk of large increases in short-term interest rates.

The primary reason for the decrease in the requested Overall Rate of Return is the reduction of short-term interest rates forecasted to be in effect on December 31, 1991. In the time between the original application in July 1991 and the amended application, the estimated December 31, 1991 short-term interest rate fell from 9.10% to 8.40%.

No new equity was issued in 1991.

BOARD FINDINGS

The Board notes that generally the increase in the proportion of short-term debt in the capital structure is a result of the Company's inability to issue long-term debt related to its trust indenture and favourable short-term interest rates that have made the use of short term debt more attractive.

The Board notes that although short-term rates are currently favourable, the high proportion of short-term debt could expose the Company to substantial financial risk in the future. Financial theory dictates that long-term assets should be funded by long-term debt. However the Board is of the belief that the Company has prudently financed its operations given its financial circumstances and as such will approve the requested capital structure.

12.2 Expert Witnesses - Conclusions

12.2.1 Dr. Morin - The Company's Witness

The Company witness employed the "Comparable Earnings", "Discounted Cash Flow" ("DCF") and "Risk Premium" methods to estimate a fair rate of return on the common equity of the Company. A sample of 27 low-risk industrial companies was used to determine the comparable earnings results. He performed his DCF analysis on 4 samples including a Canadian Energy sample, a Canadian telephone sample, a sample of low-risk industrial companies and a U.S. Gas Distribution sample. His risk premium analysis included a Canadian telephone sample, a U.S. Gas Distribution sample and the Capital asset pricing Model ("CAPM") and the Empirical Capital Asset pricing Model ("ECAPM").

The original estimate of 14.00% was revised (November 1, 1991) to 13.75% as a result of reductions in DCF results, reductions in the yield on long-term Canada bonds of about 50 basis points and reductions in the Comparable Earnings because of lower earnings in 1990.

A summary of the results of his analyses both original and amended as well as the overall estimate is presented in the following table:

Samples	Updated Estimate (percent)	Original Estimate (percent)
DCF Samples		
Canadian Energy	13.76	14.02
U.S. Gas Distributors	13.31	13.52
Canadian Telephone	12.18	13.35
Canadian low-risk industrials	13.55	13.85
Comparable Earnings Samples	12.89	12.76
Risk Premium Samples		
Canadian Telephone	13.87	14.62
U.S. Gas Distributors	14.37	15.12
CAPM	13.65	14.15
ECAPM	14.37	14.87
Average	13.55	14.05
Recommendation	13.75	14.00

12.2.2 Dr. Booth & Dr. Berkowitz - CAC/MSOS Witnesses

CAC/MSOS provided DCF evidence using its Components of Growth and Inflation Adjusted Growth estimates on a sample of Canadian Telephone Companies. They presented two risk premium methods including CAPM and the risk premium over preferred stock yields. They recommended a rate of return on equity of 11.75% for Centra Gas.

The following table presents a summary of the above estimates as well as the overall estimate:

DCF Samples	**%**
Components of Growth (telephone)	11.19
Inflation Adjusted Growth (telephone)	11.22
Risk Premium Samples	
CAPM	11.19
Preferred Stock	11.55
Average	11.29
Recommendation	11.75

12.2.3 Fair Rate of Return

During the hearing the Company presented what it saw as the three standards or notions relating to a fair rate of return. These three standards include maintaining financial integrity, attracting capital, and competing with alternate investments of a similar risk.

CAC/MSOS agreed with these three standards of fair rate of return but added that in its judgement only those methods that measure the investors' opportunity cost of funds such as the Risk Premium and the DCF method are relevant. The Company argued that the Comparable Earnings method is also relevant as the concept of fairness should include the actual rates of return earned by companies of comparable risk.

CAC/MSOS added that fairness also involves the ratepayer and that the Board must determine a rate of return that while providing a fair rate of return to the investor also results in a fair and reasonable rate to consumers.

When questioned by Board counsel, both of the experts admitted that the reason for the differences in the recommended rate of return was mainly due to professional judgement. In fact CAC/MSOS admitted that in most cases the interveners' experts were lower and the Company's experts higher than the final rate of return allowed.

BOARD FINDINGS

The Board is of the opinion that it must consider all the evidence before it, including the rate of return on equity estimates of both the Company's and CAC/MSOS witnesses in making its final determination of the allowed rate of return on equity.

Based on the evidence before it the Board will make specific adjustments to the estimates for the areas where the Board has made a determination and will weigh the results based on its opinion related to the remaining areas of disagreement between the experts.

The Board expects that the following sections that deal with these specific issues will reduce the amount of time spent on rate of return evidence at future hearings.

12.3 Comparable Earnings Method

In the Comparable Earnings Method ("CE") the Company developed a group of 27 low-risk industrial companies which it considered to be of comparable risk to the Company. This sample was developed by applying various filter and screening criteria to a sample of 397 companies. The Company then determined the 10 year mean return on equity for those 27 industrials for the period 1980 to 1989 as 12.96% and used this as an estimate of the return on equity. At the hearing the Company adjusted this 10 year period to include 1990 results which changed the estimate to 12.89%.

While the Company admitted that the CE is not ideal from an economic point of view, it believes that it is a notion of fairness and that, in fact, investors do look at historic return on equity performance when determining their expectations.

CAC/MSOS had three main criticisms of the CE method. The first objection is that CE only measures historic accounting returns and not the opportunity cost of investors' funds. Second, CAC/MSOS objects to the 1980 to 1989 time period which it argued is not a full business cycle and includes the unprecedented high inflationary period of 1980-1982 which biases the results upward. Third, CAC/MSOS believes that the risk filter and screening process that the Company used selects high performance firms that have earned excess returns because of market power.

BOARD FINDINGS

Once again the Board notes the criticisms related to the CE method, and has given little weight to the method in determining the fair rate of return on equity.

The Board expects that the rate of return experts will spend considerably less time debating the merits of this method at future hearings.

12.4 Significant Issues

12.4.1 Flotation Costs

All of the Company's DCF and Risk Premium samples include an allowance for flotation costs which according to information supplied to the Board varies from 20 to 56 basis points. It is the position of the Company that such an allowance is necessary to account for the sum of costs of flotation (printing, legal and accounting), market pressure and underwriting fees associated with new equity issues.

The Company's position was that flotation costs are legitimate business costs like any other business cost and as such investors expect to earn a fair rate of return not only on the amount invested, but also on the costs associated with that investment. The Company also testified that this flotation adjustment would be required each and every year otherwise the investor would only earn a rate of return on the investment net of flotation costs and not the full investment. The Company further testified that the adjustment compensates investors for all of the past issues of equity as well as the current issues and cited the last Westcoast equity injection of $9.5 million in 1990 as an example when flotation costs would have been incurred.

The Company determined the adjustment to be in the order of 7% based on U.S. studies that show flotation costs to be 5%, and a survey of direct flotation costs of Canadian stock issues in the 1980's indicating flotation costs were on average 6.46%. Adding market pressure brought the allowance to 7%. Under cross examination by CAC/MSOS the Company testified that a more appropriate after tax adjustment would be 5%.

CAC/MSOS agreed that all legitimate business costs including flotation costs should be collected from consumers. CAC/MSOS testified that the issue was not if legitimate flotation costs of Westcoast should be passed on but rather the amount that is passed on, how it is calculated and on what part of equity does it apply.

CAC/MSOS recommended that in the future Westcoast pass on reasonable flotation costs that apply to the Company and that these costs be held in an amortization account and amortized over a reasonable period of time in which the equity is used.

BOARD FINDINGS

The Board notes the position of CAC/MSOS that regardless of the type of cost incurred by the company, if that cost is paid for by the consumer it should be justified like any other cost. The Board does not believe that the company has presented sufficient evidence of past flotation costs and market pressure to warrant an arbitrary adjustment to the entire equity of the Company.

With respect to the future, the Board notes the Company's comments that the whole adjustment is irrelevant if flotation costs are included in revenue requirements as an expense. The Board also notes the Company's comment that it would be fairly easy to impute a reasonable portion of Westcoast's flotation costs to the Company.

The Board will deny the flotation cost adjustment as a specific element of rate of return and as such will focus on the Company's estimates excluding flotation costs. However, the Board may in the future consider the inclusion of specific and reasonable flotation costs as an item of revenue requirement if such costs are incurred on the Company's behalf by Westcoast.

12.4.2 Quarterly Dividend Adjustment

In the DCF evidence the Company included a quarterly dividend adjustment, the effect of which was to increase the DCF estimates by 30-40 basis points. The Company testified that this adjustment was necessary to take into consideration the quarterly timing of dividend payments and the reinvestment of these dividends.

The Company further testified that the use of the annual rather than the quarterly DCF model would violate the standard of capital attraction as investors could earn a higher rate of return on comparable risk investments.

CAC/MSOS agreed that the quarterly dividend model was theoretically correct but that the problem comes in the application of this quarterly model to an annual average equity rate base.

CAC/MSOS also argued that investors would take the annual rate of return regulatory practice into account and bid down the stock price thus increasing their rate of return to the desired level.

BOARD FINDINGS

Based on the evidence presented at the hearing and the fact that the Company does, in fact, pay dividends on a quarterly basis, the Board is of the opinion that the use of the quarterly dividend adjustment in conjunction with an historic year-end Rate Base is appropriate.

The Board will thus consider the quarterly dividend adjustment in determining the rate of return on equity.

12.4.3 U.S. Data

The Company used a sample of 28 U.S. Natural Gas Distribution companies ("LDC's") for both the DCF Method and the Risk Premium Method. This sample resulted in return on equity estimates of 13.31% and 14.37% percent respectively (including flotation costs).

The Company testified that it looked at U.S. LDC's because of the lack of publicly traded gas companies in Canada that have a stock price, a beta and a dividend policy. The Company was of the opinion that it was necessary to present evidence related to Gas utilities to determine the Company's fair rate of return and that in the U.S. there is a very large sample of homogeneous gas LDC's.

The Company admitted that there was a difference in tax treatment of equity versus debt from Canada to the U.S. but was of the opinion that these tax differences had been narrowing in the last number of years, and that tax treatment was secondary to risk in determining return on equity. Based on the above the Company was of the opinion that the U.S. data was relevant as the U.S. and Canadian capital markets are integrated.

CAC/MSOS felt that U.S. data was irrelevant because of the different monetary and fiscal policies of the Canadian and U.S. governments and the different tax treatment of dividends in Canada including the dividend tax credit, $100,000 capital gains exemption, and tax free intercorporate dividends. CAC/MSOS also pointed out that in Canada there was a 10% restriction on foreign investments. CAC/MSOS believes that all of these differences means that there is no relationship between U.S. and Canadian equity yields and that it is not relevant to add a U.S. risk premium to a Canadian interest rate.

BOARD FINDINGS

The Board notes the Company's concerns over the lack of reliable Canadian Gas LDC data and agrees that the Gas LDC data is relevant to estimate a fair return on equity.

The Board believes, however, that there are tax differences and differences in government policies between Canada and the U.S., such that the equity yields of the two countries are not directly comparable and as a result have placed little weight on the U.S. estimates.

12.5 DCF Approach

12.5.1 Energy Sample

The Company used a sample of five Canadian Energy Utilities in its DCF analysis that estimated the fair return on equity to be 13.76% (including flotation costs). This estimate is an average of the results using dividend growth and earnings growth. The Company considered the risk of Centra to be slightly higher than that of the Energy sample.

CAC/MSOS was of the opinion that in the past Energy Companies had been perceived as being riskier than telephone utilities, but at present the risk of both of these samples would be similar. CAC/MSOS testified that using ten year historical growth estimates would bias the rate of return estimate upwards because at present the risk of energy utilities is perceived as being lower than it was in the past.

CAC/MSOS and Board counsel also questioned the Company as to why they would retain the DCF energy sample estimate when they concluded that the Risk Premium Energy sample results were unreasonably high. The Company responded that the DCF Energy results were included for consistency and because it felt it was important to submit some evidence related to Gas LDC's, no matter how small the sample may be.

12.5.2 Telephone Sample

The Company also used a sample of five Canadian Telephone companies in its DCF analysis and the estimate of this sample is 12.18% (including flotation costs). The Company used both the earnings per share growth (EPS) and dividends per share growth (DPS) but retained the higher DPS estimate because of the downward bias of unfavourable earnings of these telephone companies related to unregulated operations, particularly Bruncor which the Company eliminated from the sample. The Company also retained the higher DPS estimate as it perceived telephone companies to be less risky than Centra.

12.5.3 Low Risk Industrials

The Company started out with the same sample of low-risk Industrials that it used for its Comparable Earnings method. The results for this sample varied substantially from company to company and the Company concluded that the results would likely be unreliable in view of the heterogeneity of the sample. The Company then modified the stringent risk filter and this resulted in a sample of 51 companies surviving instead of the original 16 companies.

When questioned on the reliability of the resulting sample results the Company stated that this sample was slightly more risky than the original sample. The Company also testified that this sample was used because of a lack of publicly traded undiversified utilities in Canada, and that the only other alternative would be to put more emphasis on Risk Premium methods.

CAC/MSOS counsel also pointed out the criteria that the companies were screened against indicates that this low-risk industrial sample was of a higher risk than utilities in general.

12.5.4 Growth Rate

There was substantial disagreement between CAC/MSOS and the Company with respect to growth rates.

CAC/MSOS disagreed with the Company's use of historic ten year (1980-1989) growth rates because it does not believe that these growth rates represent current investor expectations. CAC/MSOS testified that changes in dividend payout ratios, systematic changes in earned returns of Telephone companies downward since the high inflationary period in the early 1980's, and systematic changes in the rate of inflation over time would mean that investors would not expect historic growth rates to continue into the future.

The Company's position is that historical growth rates are used by investors to determine future growth expectations and that ten years is long enough to avoid undue distortion or short-term fluctuations in the data.

To correct for the problems that they see in the Company's growth estimates, CAC/MSOS used the Components of Growth and Inflation

Adjusted Growth Estimates. The Components of Growth method estimates growth by multiplying the rate of return times the retention rate of earnings which is 1 minus the dividend payout rate. The Company believes that this method is conceptually wrong for regulated utilities as one has to specify the rate of return to determine growth which is then used to estimate the rate of return. The Company considers this method to be circular and believes that empirical literature considers this the worst possible proxy for growth. Company counsel also criticized CAC/MSOS for using substantial subjectivity in estimating various ranges of retention rates and return on equity for the Telephone sample.

The Inflation Adjusted Growth estimate tries to separate growth into two parts; real growth, and inflationary growth. Using this method CAC/MSOS estimated that real earnings and dividends growth for the Telephone sample has been approximately zero and that as a result growth will be equal to expected inflationary growth which CAC/MSOS estimated as 4.1-5.0%.

The Company criticized this method as it does not believe that Telephone stocks are perfect inflation hedges or that utility stocks track the consumer price index (CPI). The Company also stated that this is a method that in its experience only CAC/MSOS witnesses used.

BOARD FINDINGS

The Board believes that the DCF method is a valid approach in estimating the fair rate of return on equity. However, the Board notes the substantial disagreement between the expert witnesses with respect to growth rates and the problems inherent in estimating such growth rates.

The Board notes that the Company's DCF telephone sample is biased downwards because of recent losses in unregulated industries, and that there were problems with the sample selection of the low-risk industrials. The Board also notes that the Company's DCF energy sample is based on a relatively small number of companies and as such the reliability of the data is questionable.

Therefore, the Board has placed more weight on the Risk Premium evidence than the DCF evidence.

12.6 Risk Premium Approach

12.6.1 Geometric vs Arithmetic Mean

The Company used arithmetic means in estimating its risk premium evidence. In the Company's opinion to determine the return over the next period or to determine a single period return the arithmetic mean is the most accurate estimate. If one is interested in the actual performance of the investment over a period of time then the geometric mean is the most appropriate. The Company testified that when you compound the arithmetic mean in every sub period then you obtain the geometric mean. The Company contended that to determine the cost of equity at a specific point in time for the next year the arithmetic mean is the most appropriate measure of return on equity. The Company believed that the geometric mean is just a performance measure over a long period of time.

CAC/MSOS provided estimates based on the arithmetic mean, geometric mean, and the ordinary least squares regression method ("OLS") but relied primarily on the OLS method to determine the risk premium. CAC/MSOS believed that since an investment in a utility stock is a long-term investment that the method that is the best estimate over a period of time (geometric) should be used.

The Company and CAC/MSOS both agreed that using the arithmetic mean would produce a higher result than the geometric mean but neither expert provided an estimate of the impact on the estimate of using one or the other method.

BOARD FINDINGS

The Board is of the opinion that it is more appropriate to use the arithmetic mean rather than the geometric mean when determining risk premiums and return on equity for the next period.

12.6.2 Preferred Stock Risk Premium

CAC/MSOS also presented evidence of the risk premium over preferred shares that resulted in a return on equity estimate of 11.55%. This risk premium was determined by calculating the difference between equity returns of the Telephone sample and a preferred stock index from Foster Associates. This risk premium of 2.17% was then added to a sample of current preferred stock yields from the October 5-6, 1991 Financial Post and a further 50 basis point adjustment was also added for future increases in long-term bond yields to produce the 11.55% estimate. It was the position of CAC/MSOS that preferred share data was relevant because of the similar tax treatment to common equity but admitted that preferred shares are not as liquid as bonds and the estimates are more likely to be inaccurate. CAC/MSOS also stated that the preference share market was much more important in Canada than the U.S. for tax reasons.

The Company testified that preference shares were highly specialized, illiquid, thinly traded heterogenous issues that were unreliable to use as a sample because of the difficulty of calculating the yields. The Company also stated that there was no publicly published index for preferred shares and CAC/MSOS had to rely on an in-house index whose construction was not well known.

BOARD FINDINGS

The Board is interested in this method of calculating risk premiums especially given the lack of data associated with other methods. However the Board is of the opinion that there may be some inaccuracies in the underlying data and as a result has given more weight to CAC/MSOS's more traditional CAPM estimate.

12.7 CAPM & ECAPM

12.7.1 Risk Free Rate of Return

In its updated evidence the Company used an estimate of long-term Canada Bond yields of 9.5% as its risk free rate. CAC/MSOS used a long-term Canada Bond yield of 10.0% as its risk free rate.

12.7.2 Market Risk Premium

In its CAPM and ECAPM estimate the Company used a market risk premium of 6.0-7.5%. The 6.0-7.5% range was determined using three risk premium studies; namely the Canadian Hatch & White study of 5.93% (1950-1987), the Boyle-Panzer-Sharp (1924-1983) of 8.0%, and the U.S. Ibbotson-Sinquefield study (1920-1989) of 7.1%.

CAC/MSOS concluded that the market risk premium was 2.2-3.0%. This conclusion was based on an analysis of the excess of the Scotia

McLeod total return index (equity) over the Scotia McLeod long bond index and Canada Treasury bill yields. This analysis used the arithmetic mean, geometric mean and ordinary least squares regression and covered the period 1956 to 1990. CAC/MSOS used that time period, as prior to 1956 there was no consistent data with respect to the TSE 300. For 1956-1990 the indicated risk premium over long bonds was 2.42% to 3.24% to which CAC/MSOS added 34 basis points as the Scotia McLeod bond index had historically been that much higher than Canadian long-term bonds. The resulting 2.76% to 3.58% range was lowered to 2.2% to 3.0% as CAC/MSOS's analysis had shown that the risk premium had decreased in the 1973-1990 period due to interest rate uncertainty.

One of the main disagreements with respect to the calculation of the Risk Premium was the appropriate period of time to use. The Company was of the belief that risk premium should be calculated over the longest time period possible as over long periods of time actual returns and investor expectations will converge. The Company further stated that in the last 18 years (1973-1990) investors' expectations have not been met as high interest rates have increased bond returns higher than expected. The Company cited as an example the negative risk premiums of the 1981-1983 period. The Company felt that events must be averaged out over time and that it cannot be assumed that the events of the last 18 years will be repeated.

CAC/MSOS stated that determining the relevant period of time was a balancing act between the need to have large amounts of data and changes in the economy that may make some of that data irrelevant. CAC/MSOS does not believe that you can look back at the last 60-70 years of data and say that events such as wars, and wage and price controls will be experienced in the future. CAC/MSOS disagreed with the use of the 1950-1956 period as it was the beginning of modern financial market history in Canada when the Bank of Canada got involved in the money market and established a treasury bill market. CAC/MSOS believed that these factors increase the excess return on equity over bonds and as a result this period is not representative of current expectations.

CAC/MSOS also believed that due to the interest rate uncertainty after 1973, the riskiness of bonds increased relative to that of equities and as a result the risk premium has decreased. As a result CAC/MSOS reduced its market risk premium to give weight to the post 1973 results.

CAC/MSOS also commented that if the three risk premium studies that the Company used which end in 1981 (Boyle-Panzer-Sharp), 1987(Hatch & White) and 1989 (Ibbotson-Sinquefield) were updated to the present, the Company's Risk Premium results would be lower. The Company agreed with that proposition but indicated that the magnitude of the adjustment would be small. CAC/MSOS testified that the Boyle-Panzer-Sharp study which ended in 1981 was hopelessly outdated and the Company replied by testifying that the 8.0% risk premium of this study was not incorporated into its final range.

The Company felt that the Hatch & White study which corresponds to the low-end of its risk premium range was much more comprehensive than the Scotia McLeod study as it covers more stocks. CAC/MSOS felt that Scotia McLeod was the most respected source of capital market data in Canada.

CAC/MSOS was of the opinion that the Ibbotson-Sinquefield study which the Company used to determine the top of the risk premium range was irrelevant as it was a U.S. study and the fact that its results were higher than the Canadian Hatch and White study proved its irrelevance. The Company thought that the study was relevant as it was the most comprehensive research ever performed on capital markets.

12.7.3 Beta

The Company calculated its beta from its sample of comparable risk utility companies by adjusting the average utility beta of .35 to .57 for empirical evidence that suggests that beta's revert to the overall market beta of 1.0. The Company testified that this adjustment corrects for negative measurement errors when estimating low beta's and thin trading of Canadian stocks.

CAC/MSOS determined its beta estimate of .45 by averaging the 35 year Canadian utility beta of .45 with the current estimate of beta of .35 to get the low end of the beta range and by using its instrumental variable model to estimate the high end of the range at .499. CAC/MSOS then averaged the high and the low to arrive at the .45 estimate. The low end of the beta range was developed because of CAC/MSOS's belief that beta's tend to regress towards the utility mean of .45 as investors are currently looking at utilities as having very similar risks.

12.7.4 ECAPM

The Company also presented evidence using the ECAPM method which essentially smooths the CAPM evidence so that the risk-return relationship is not as great. This method is based on empirical evidence that suggests that the CAPM method underpredicts the actual rate of return for companies with betas lower than 1.0 (the Company) and overpredicts for companies with betas greater than 1.0.

CAC/MSOS did not use the ECAPM method and it testified that the problem with the CAPM method only existed if treasury bills were used in the calculation. When long-term bonds are used CAC/MSOS does not believe the ECAPM method is valid.

BOARD FINDINGS

The Board notes that both the Company and CAC/MSOS agreed that estimates of long-term Canada bond yields of 9.5% to 10.0% are reasonable.

The Board believes that given the current estimates of the Company's long-term bond rate CAC/MSOS's risk premium range of 2.2 to 3.0% is lower than a reasonable risk premium based on the risk that the Company faces. However the Board is also of the view that the Company's risk premium range of 6.0 - 7.5% is higher than a reasonable risk premium because of the use of potentially outdated data and U.S. data which may not be totally relevant to Canada. The Board also believes that a reasonable beta for the Company is between the .45 and .57 estimates of the two experts. As a result of the above factors the Board has placed approximately equal weight on the Company's and CAC/MSOS's CAPM estimates. The Board has placed marginally lower weight on the Company's ECAPM estimate than its CAPM estimate.

The Board also notes that the Company presented risk premium evidence based on a Canadian telephone sample and a Canadian Energy sample that the Company dismissed as unreliable. The Board has placed no weight on the Energy sample and some weight on the Canadian Telephone sample.

12.8 Other Issues

12.8.1 Premium for Control

CAC/MSOS testified that there may be value of control in owning 100 percent of the shares of the Company because of the ability to control the underlying cash flow of the Company without minority shareholder involvement. CAC/MSOS testified that evidence of this is the fact that premiums are paid for control which suggests that the rate of return would be above the required rate of return. CAC/MSOS however did not recommend lowering the rate of return for that reason.

The Company was of the opinion that the identity of the investor was not important and it would be unfair to have different rates of return for different investors. The Company also testified that this is no real benefit to corporate diversification as the individual investor can diversify as well.

BOARD FINDINGS

The Board is interested in this concept but has not received sufficient evidence to determine a method of quantifying the value of control with respect to the rate of return.

12.8.2 Interest Coverages

The Company testified that the 11.75% rate of return recommendation of CAC/MSOS would violate the capital attraction standard of fair rate of return. The Company testified that, under this scenario, this interest coverage would be at or below the two times coverage necessary to issue long-term debt and that there would be the possibility of further downgrading of the Company's bond rating. These two factors would also impair the financial integrity of the Company, thus violating another standard of fair rate of return.

The Company further stated that the Board must consider interest coverage in its decision on the fair rate of return.

CAC/MSOS testified that it was also concerned about the interest coverage and financial integrity and flexibility of the Company and these concerns led to its 46 basis point increase in their recommended rate of return from the 11.29% average to the 11.75% final recommendation. CAC/MSOS however did not think that the problem was urgent as the Company was still projecting the required two times coverage for 1991 and 1992. CAC/MSOS went on further, to state that if interest rates decline further, allowed rates of return on equity will also decline and the Gas industry as a whole may face the problem of having interest coverage less than two times. CAC/MSOS pointed out that the Board had to balance the cost of higher debt costs because of further downgrading with the costs of increasing the rate of return on equity to meet coverage restrictions.

CAC/MSOS also pointed out that while the DBRS had downgraded Centra the CBRS had reaffirmed its rating.

BOARD OF FINDINGS

The Board has made no specific adjustments for interest coverage considerations, but has considered interest coverage issues as a qualitative factor in its final determination of the fair rate of return.

12.9 Conclusion

The Board is of the opinion that, aside from financial models, it must consider changes in economic indicators and risk to determine a fair rate of return. The Board notes the following comments with respect to these areas.

The Company and CAC/MSOS both agreed that long-term Canada bond yields had dropped since the last GRA in 1990 and that this would tend to decrease the required return on equity. The Company also added that the reduction would not be proportionate to the decrease in long-term bond rates because as interest rates fall, risk premiums tend to increase.

The Company and CAC/MSOS both agreed that corporate profits had dropped since the last GRA and this would tend to reduce the rate of return. The witnesses also agreed that there had been a marginal drop in the risk premium which would tend to reduce the return on equity. The witnesses were both generally of a view that stock prices had dropped reducing the dividend yield and fair rate of return.

The Company stated that various factors such as increased short-term business risks due to the recession, increased forecasting risk, financial risks related to converting short-term debt to long-term debt and weather risks because of the high concentration of residential consumers result in increased risk to the Company which should result in an increase to the required rate of return.

CAC/MSOS commented that equity holders are able to diversify the portfolio and as a result, weather risk is less of a problem.

The Board believes it is important to use samples of Gas LDC's to determine a fair rate of return for the Company. CAC/MSOS only used Telephone samples in its evidence but made a small adjustment for the possibility that the Company was riskier than that sample. The Board believes that Gas LDC's are riskier than Telephone companies despite CAC/MSOS's evidence that they have been perceived as having similar risk in the last few years. The Board is also concerned that the recent losses of telephone companies with respect to unregulated industries may bias the return estimate downward.

The Board is also of the opinion that a larger number of samples smooths out the estimation error attached to a particular sample.

The Board has also considered the interest coverage and capital attraction implications of its decision by balancing the needs of consumers against the need to attract capital to maintain a safe and reliable plant.

The Company advocated the approval of a range of fair rate of return to provide an incentive for the company to achieve efficiencies to earn the top end of the range and to accommodate potential interest rate volatility in 1992 as well as recognizing that the determination of fair rate of return is not an exact science. The consumer would benefit as the reduced costs would flow through to the rates in the following year.

Based on the Board's weighing of the various methods presented to it, the Board's assessment of economic indicators and risk and the standards of fair rate of return the Board believes that the range of the fair rate of return of the Company is 12.60% to 13.10%.

The Board will therefore approve the midpoint of this range of 12.85% to be used for the purpose of setting rates.

This results in an overall rate of return of 11.46%, based on the approved capital structure, calculated as follows:

	Weight Percent	Cost Rate Percent	Weighted Rate Percent
Long-term debt	36.16	11.99	4.33
Short-term debt	24.04	8.40	2.02
Preferred stock	0.13	6.48	0.01
Equity	39.67	12.85	5.10
TOTAL	100.00		11.46

13.0 REVENUE REQUIREMENT

13.1 Gas Costs and Gas Sales

13.1.1 Normalization

In this application, the Company requested two changes related to the normalization of gas volumes:

1) A change in the normalization methodology based on a least squares regression model.

2) A change from the current use of a 30 year average, to determine normal degree days, updated every 10 years, to a 10 year rolling average.

The previous normalization methodology determined a base load (non-temperature sensitive) equal to the lowest month's consumption. The balance of the monthly loads were adjusted by monthly weather adjustment factors related to the ratio of normal monthly degree days to actual monthly degree days.

The least squares regression model is a more statistically based approach and estimates customer consumption by variation in degree days and seasons. The Company listed numerous advantages of this model in that it is quantifiable, employs a measure of temperature and seasonal effects for each rate class, and is a more accurate forecasting method than others. The Company witnesses stated that the change in normalization methodology would increase 1991 annual revenue requirements by $83,098.

With respect to the requested change in determining normal degree days, the Company's witnesses submitted that the objective is for rates to be fair and reasonable to both the consumer and the Company. Weather normalization adjustments should result in no gain or loss to either party over a period of time.

The Company contended that with respect to recent weather trends, the use of the 30 year block average results in actual weather being warmer than estimated and does not reasonably forecast next year's weather. The Company's position is that the use of the 10 year rolling average will result in better forecasts of weather and a better balance between colder and warmer years over a shorter period of time than does the use of the 30 year average.

The Company further contended that within the last decade, the 30 year average consistently overstated normalized volumes thereby resulting in a revenue shortfall. The Company stated that this is unfair and negatively affects the Company's financial integrity to the ultimate detriment of its customers.

The Company investigated numerous other degree day determination methods and concluded that, in terms of least square normal error, the 10 year rolling average was the most appropriate.

The Company requested Dr. Ball, Professor of Climatology at the University of Winnipeg, to review the Company's conclusions.

Company witnesses testified that Dr. Ball did not disagree with the Company's conclusions.

CAC/MSOS urged the Board not to change the method of determining normal degree days for the following reasons:

1) There is insufficient evidence to justify a change in the manner of defining normal year, particularly a change of the magnitude suggested by the Company.

2) The differences between the various averaging methods as measured by Least Squared Normal Error Analysis are not statistically significant and can be attributed to random chance.

3) Over the past 30 years, the 30 year average definition of normal weather has been fair to both the Company's shareholders and its customers.

4) Over the past 40 years, the 30 year average has provided a better balance of actual degree days in excess of the average and actual degree days below the average on a cumulative basis than has the 10 year average.

5) A change to a 10 year average at this particular point in time would produce an element of unfairness to the Company's customers.

6) Dr. Ball's report described the use of a 10 year average as "acceptable". Dr. Ball does not clearly indicate that a 10 year average is better than all other averaging methods. It appears that Dr. Ball's support for the use of a 10 year

average is due to the recent variability in weather which he says will reduce in the mid 1990's.

7) A move to a 10 year average would contribute to rate instability as it would be too responsive to short term changes in weather patterns.

CAC/MSOS suggested that should the Board determine there is a need to have a normal year definition more responsive to changes, the Board should adopt a 30 year rolling average. CAC/MSOS suggested that the reason for the Company's request was more related to the current financial circumstances and that the Company was requesting a degree day determination which would be more responsive to short term weather variations.

BOARD FINDINGS

As previously stated, the Board accepts the premise that rates should be fair to both the customer and the Company. The Board considers that the central question in respect of this issue is the time period over which any normal degree day determination method will, on balance, be fair to both parties.

With respect to the arguments of CAC/MSOS, the Board cannot accept that there is insufficient evidence on record. Statistical weather data has been submitted going back to 1911 and the Company has submitted its summary of the analysis of 10 different degree day determination methods. The Board cannot accept that the LSNE analysis of these methods is insignificant, nor that the adoption of a 10 year rolling average will lead to unacceptable rate instability, given all the other elements of the Company revenue requirements. An analysis of the data indicates that while the change to a 10 year rolling average at this time may be perceived as being unfair to the customer, retaining the 30 year average at this time would be clearly unfair to the Company.

The Board is of the opinion that, regardless of methods used, the effect on the Company and the customer will be relatively cost neutral over time. The Board accepts that the difference between actual and normal degree days and the variability of weather from year to year are better forecasted by use of the 10 year rolling average. The Board also recognizes that the 10 year rolling average will better reflect most recent weather trends and also considers that it is appropriate that both customers and shareholders be "balanced" over a shorter rather than longer period to preserve intergenerational equity to a greater degree. The Board will therefore accept the Company's proposal to use a 10 year rolling average in determining its normal degree days.

13.1.2 Costs and Revenues

In its original application, the Company stated that the normalization and annualization impact on 1991 gas purchases was to increase costs by $3,165,893. This reflects the fact that 1991 is anticipated to be warmer than normal, using the 10 year rolling average to determine normal degree days. Similarly, the normalization adjustment for revenue generated from gas sales increases revenues by $7,046,585.

The Company initially filed evidence, on a normalized and annualized basis, that the cost of gas has increased by $1,526,200 over 1990. The various components of the overall increase were as follows:

Cost of Gas - 1990		$156,841,034
Additional Costs - CGM & Union Brymore Peaking	$340,000	
Reduction in WGML Supply Price	($5,051,400)	
Increased Volumes - Load Growth	1,500,000	
Annualization of 1991 Year-End Customers	640,000	
Change in TCPL Tolls Effective July 1, 1991	3,272,100	
Increases in Unaccounted for Gas	825,500	
		$ 1,526,200
Cost of Gas - 1991		$158,366,593

The increase in the peaking gas supply is attributable to the increase in monthly demand charges and backhaul changes.

The WGML price contained in this application is based on the 100% load factor weighted average price paid by Ontario distributors, calculated at $1.9866/GJ. This unit price includes the disputed upstream differential component. The Company's calculations indicated that the disputed amount will be approximately $3,410,000 as of December 31, 1991 and some $7,150,000 (not including interest) as of December 31, 1992, should the dispute remain unresolved.

In a letter to Board Counsel dated December 20, 1991, the Company advised that it had negotiated a settlement with WGML in connection with the upstream differential pricing dispute. As a result of this settlement, the revenue deficiency is reduced by $2,376,298.

The other cost increases result from increased TCPL tolls as approved by the National Energy Board, which represents a flow-through cost to Manitoba consumers.

The Company's unaccounted for gas has increased from 1.33% in 1990 to 1.86% in 1991, resulting in a $825,500 increase in costs.

The Company witness indicated that gas cost calculations respecting its Coastal Gas Marketing arrangements for peaking supply used a Canada to USA exchange rate of $1.1905. The current situation is such that the actual exchange rate for 1991 is estimated to be closer to $1.14. This would result in decreased costs of some $400,000.

BOARD FINDINGS

The Board will accept the gas cost and gas sales revenues as submitted by the Company. The Board will expect the Company to continue its deferral account related to gas costs as previously ordered by the Board. This deferral account is to track specifically:

1) Changes in Canada to USA exchange rates.
2) Changes in TCPL tolls.
3) Any changes in WGML pricing, if necessary.

The Board will accept the decreased gas costs resulting from the settlement of the upstream differential dispute for this application. However, the Board will require that the Company satisfy the Board that the terms of this settlement were prudent at the next GRA.

Increases or decreases arising from the above changes will be incorporated into January 1, 1993 rates by way of a rate rider.

As previously stated, the Board will not necessarily consider any increase in gross margin in isolation, but rather will consider all elements of expenses and revenues when 1991 results are finalized.

The Board is concerned at the substantial increase in unaccounted for gas from 1.33% to 1.86% of purchases. The Board will expect the Company to fully investigate this matter and to present the Board with its findings as soon as such a report is available, but in any case, by no later than its next GRA.

13.2 Operating Expenses

The Company applied for 1991 operating expenses of $46,722,678, an increase of 7.0% over the 1990 actual expenses of $43,675,572. The details of these 1991 operating expenses compared to 1990 expenses based on responsibility centres are shown below.

The Public Utilities Board

RESPONSIBILITY CENTRE	1990 ACTUAL	1991 REQUESTED	$ CHANGE	% CHANGE
Operations	$20,643,300	$21,367,400	$724,100	3.5
Finance	12,367,000	13,130,900	763,900	6.2
Marketing & Sales	2,114,600	2,574,100	459,500	21.7
Planning	414,500	428,000	13,500	3.3
Regulatory Affairs & Info. Services	4,340,800	4,813,400	472,600	10.9
Human Resources	5,383,200	6,422,500	1,039,300	19.3
Executive	2,805,300	3,086,900	281,600	10.0
	$48,068,700	$51,823,200	$3,754,500	7.8
Adjustments:				
Expenses Capitalized	(3,765,900)	(4,568,900)	(803,000)	21.3
Inter-Corp. Recoveries	(791,500)	(819,500)	(28,000)	3.5
Direct Capital	(1,106,500)	(1,041,200)	65,300	-5.9
Bad Debt Adjustment	(1,671,014)	(1,809,800)	(138,786)	8.3
Transportation Depreciation	836,500	945,300	108,800	13.0
	(6,498,414)	(7,294,100)	(795,686)	12.2
Sub-Total	41,570,286	44,529,100	2,958,814	7.1
Normalization & Annualization:				
Payroll and Associated Benefits	574,348	513,800	(60,548)	-10.5
UIC Increases	-	161,529	161,529	NA
Health and Education Tax	44,446	5,987	(38,459)	-86.5
Employee Savings Plan	149,011	-	(149,011)	-100.0
Pension Plan Adjustment	151,717	-	(151,717)	-100.0
	919,522	681,316	(238,206)	-25.9
Known & Measurable Adjustments:				
Payroll & Associated Benefits	1,136,712	1,078,051	(58,661)	-5.2
Health & Education Tax	22,666	21,311	(1,355)	-6.0
Postage Increase	26,356	-	(26,356)	-100.0
Name Change Costs	-	(147,100)	(147,100)	NA
Credit Collection Costs	-	560,000	560,000	NA
	1,185,734	1,512,262	326,528	27.5
TOTAL OPERATING EXPENSES	$43,675,542	$46,722,678	$3,047,136	7.0

The Company requested that a known and measurable adjustment of $560,000 related to lock-off and credit collection be included in 1992 rates. The Company estimated that the costs of lock-off and credit collection in 1991 would be $500,000. This amount has been added to the Bad Debt deferral account. It is the opinion of the Company that these collection efforts will be ongoing and somewhat increased in 1992 and, as a result, this amount should be included in 1992 rates. This $560,000 increase represents a 1.28% overall increase in operating expenses over the 1990 actual total costs.

The Company estimated that the 1991 bad debt expense would be $6,309,000 or a $138,786 increase over the 1990 actual bad debt expense of $6,171,014. The bad debt expense allowed in rates for both years has been "capped" at the $4.5 million cap as approved in Order 15/91. Accordingly, a further $1,809,000 is added to the deferral account for 1991.

Company witnesses testified that marketing and sales expenses had increased $459,500 or 21.7% over the 1990 actual. Of the $459,000, there is an increase of $223,100 related to salary increases ($126,800) and three additional staff ($96,300). The remainder of the increase was related to the introduction of three new marketing programs and a more concerted effort with respect to general advertising. This increase represents a 1.05% increase in overall operating expenses.

Company witnesses testified that the average overall increase for salaries and wages was 4.0%. Exclusive of salary increases for marketing and sales, this salary increase is approximately $869,000. In 1991, the Company added 17 new employees primarily in the area of accounting and information services which would account for an increase of approximately $750,000 in payroll costs. The Company provided information that the increase in operating expenses (exclusive of marketing and sales) was approximately $670,000 or 3.4%. The above increases were partially offset by an increase in capitalized expenses of $803,000.

BOARD FINDINGS

The Board notes that there appears to be a trend toward higher than average increases in the area of marketing and sales. The Board is concerned about the apparent benefits of this increased marketing activity in view of the present market penetration and the competitive advantage of natural gas over fuel oil and electricity.

The Board notes the request for the inclusion of increased credit and collection costs in 1992 rates given the Company's increased activities in these areas. The Board will approve this request for 1992 and will monitor the Company's collection activities in subsequent rate applications.

The Board notes that the overall increase in operating expenses exclusive of the increased credit and collection costs and marketing cost is $2,027,636 or 4.64%.

The Board, as discussed under the Utility Plant Section of this Order, considers expenditures, both operating and capital, to be necessary for system betterment and customer growth. The Board, however, cautions the Company to fully optimize its operating costs in other areas such as marketing, information systems and accounting, given the current economic conditions in Manitoba.

The Board notes that the operational audit will be completed in the spring of 1992. The Board remains concerned about increasing costs in many areas, particularly in light of the serious economic downturn, and expects that the report on the operational audit will adequately address some of these concerns. The Board intends to review this area in more detail in subsequent general rate applications.

Notwithstanding the foregoing, given the current economic conditions, the Board urges the Company to make every effort to restrain spending in all areas of general operations excluding system betterment.

13.3 Amortization

The Company has requested $1,303,302 related to amortization expense for 1991. Included in this amount are amortization expenses related to Daly storage field investigation ($70,000) which will be fully amortized in 1995. Amortization expense of $853,000 for previous rate hearings will be fully amortized in 1991. The expenses related to 1991 hearings will commence in 1992 and could approximate the previous hearing expenses. Other amortization expenses ($47,200) are related to prior cost allocation studies and safety appraisals.

The Company has applied for the inclusion of $1,559,135 in an amortization account which includes $993,575 of the net book value of the Wilkes Avenue storage tanks, $260,000 decommissioning cost and $305,500 related to interest on the unamortized balance at the Company's short term borrowing rate. This account would be amortized over a five year period at $311,827 per year.

BOARD FINDINGS

The amortization expense has increased substantially from the 1989 total of $264,960. This is primarily due to the increased number of hearings concerning interim rate filings, GRA's, regulatory process hearings, gas purchase hearings, various studies conducted by the Company and the decommissioning of the Wilkes Avenue storage tanks. The Board considers the other amortization expenses and amortization periods to be reasonable and will allow these in the Company's revenue requirements.

13.4 Depreciation Expense

Following is a comparison of the Company's requested 1991 depreciation expenses compared with the allowed 1989 and 1990 expenses.

	1989	1990	1991
Depreciation Expense	$7,280,754	$8,508,964	$10,253,848

In this application, the Company used the year end plant balance for most plant categories to calculate the 1991 depreciation expense. In prior applications, opening year plant balances were used for this calculation. Additionally, the 1991 depreciation rates were increased from those used the previous year. The increase in rates is the second of a three phase rate increase as ordered by the Board in Order 133/90. The last phase-in of increased depreciation rates will occur on January 1, 1993 for the 1992 test year.

The Company testified that using 1991 opening plant balances in calculating the depreciation expense to be recovered by 1992 rates is another significant component of regulatory lag. The impact of depreciation expense related to 1991 plant additions, with tax effect, is an addition to revenue requirement of about $1 Million.

BOARD FINDINGS

The Board accepts the new 1991 depreciation rates as being the second of a three phase increase to achieve the depreciation rates approved by the Board in Order 133/90. The Board will allow the use of year end plant balance for calculating the depreciation expense.

13.5 Municipal and Other Taxes

The Company's application included municipal, corporate and business taxes of $11,261,400. Included in this amount is $494,000 for forecasted 1992 mill rate and plant additions, or a 5% increase over 1991 municipal taxes. The total taxes of $11,261,400 is an increase of $458,773 (4.2%) over the 1990 actual.

BOARD FINDINGS

The Board considers the 4.2% forecasted increase in the municipal and other taxes to be reasonable and will approve the $11,261,400, as requested.

13.6 Income Taxes

The Company's application requested an income tax component of revenue requirements of $10,178,465 as follows:

Income Tax - Existing Sales Rate	$ 8,400,718
Income Tax - Revenue Deficiency	$ 1,777,747
Income Tax - Proposed Sales Rate	$10,178,465

BOARD FINDINGS

As a result of the Board's reduction in the overall rate of return and certain other adjustments herein contained, the income taxes have been reduced, as summarized below:

Income Tax - Existing Sales Rate	$8,400,718
Income Tax - Revenue Deficiency	$1,083,634
Income Tax - Allowed Rates	$9,484,352

13.7 Return on Rate Base

The Company's application requested a return on Rate Base of $27,901,208, based on an overall rate of return of 11.81% and a year-end historic Rate Base of $236,250,699. As discussed in section 12.0 of this Order, the Board will allow an overall rate of return of 11.46% and a year end rate base of $236,063,244. This will result in an allowed return on Rate Base of $27,052,848.

13.8 Other Income

The Company's application for 1991 included $4,127,236 of other income, an increase of $546,504 over actual 1990 other income of $3,580,732. The increase was primarily related to late payment charges of $323,566, and revenue from finance contracts of $105,957. Additionally, the 1990 other income included a known and measurable adjustment of ($37,800) to reflect the Board ordered change in billing due date from 12 to 21 days. These increases were offset by less rental income of $98,569, and decreased propane handling charge revenues and other miscellaneous amounts.

The Board will accept Other Income in the amount of $4,127,236, as filed.

13.9 Summary of Revenue Requirement

The Board will approve a revenue requirement from gas sales of $257,965,265 as summarized below.

Component	1991 Requested	Board Adjustments	1991 Allowed
Cost of Gas: Normalized & Annualized	$156,014,073	-	$156,014,073
Operating Expenses	46,722,678	-	46,722,678
Amortization	1,303,302	-	1,303,302
Depreciation	10,253,848	-	10,253,848
Municipal & Other Taxes	11,261,400	-	11,261,400
Income Taxes	10,178,465	($694,111)	9,484,352
Return on Rate Base	27,901,208	($848,360)	27,052,848
Total Revenue Requirement	**$263,634,974**	($1,542,473)	$262,092,501
Other Income	4,127,236	-	4,127,236
Revenue Requirement - Gas Sales	**$259,507,738**	($1,542,473)	257,965,265
Revenue from Existing Rates	$255,557,189	-	$255,557,189
Revenue Deficiency	**$3,950,549**	($1,542,473)	$2,408,076

14.0 1991 RATE RIDERS

In its amended application, the Company requested a rate rider of $2,028,697, to be effective January 1, 1992 for a twelve month period. This amount is related to increased TCPL tolls and increased upstream differential charges which were approved by the National Energy Board (NEB) on July 1, 1991. In the Company's 1991 original gas cost calculations, the impact of the upstream differential had been included as of November 1, 1991, in conjunction with WGML's calculation of the Ontario distributors 100% load factor average weighted cost of gas. The request is, therefore, to defer the upstream differential increase for a 4 month period of 1991. The Company's information, dated December 20, 1991 respecting the upstream differential dispute settlement reduced this rate rider to $1,734,307.

Additionally, the Company's 1991 gas cost calculations were based on NEB approved January 1, 1991 tolls. Consequently, the request is to recover the six month increase respecting this toll in a rate rider to become effective January 1, 1992 for a 12 month period.

BOARD FINDINGS

The Board will allow the requested rate rider related to 1991 gas cost changes to be effective January 1, 1992.

15.0 DEFERRAL ACCOUNTS

The Company has requested that the Board allow the establishment of two deferral accounts, one related to costs associated with broker activity and the other related to the use of propane for peak shaving purposes.

15.1 Broker Activity Deferral Account

Board Order 119/91, dated September 3, 1991 allowed brokers of natural gas to enter the Manitoba market with the view of arranging for alternate, cheaper, short term gas supplies for Manitoba consumers. In that Order, the Board stated that it would expect Centra to identify any associated incremental costs, other than costs related to backstopping, in future rate applications.

The Company's witnesses stated that these costs were not yet quantifiable, but would include matters such as notice publication, printing, staff overtime and additional staff requirements.

BOARD FINDINGS

The Board accepts that the Company will experience some unknown incremental costs, especially during the initial stages as Brokers enter the Manitoba market. While the Board will allow the establishment of this account, it cautions the Company to be prudent in expending funds and will expect any such expenditures to be fully justified at the next GRA.

As to the allocation of these costs, it is the Board's view that the customers creating these costs and benefitting from the lower priced short term gas should pay for the associated incremental costs and not the customers remaining on system supply. This matter will be reviewed at the next GRA.

15.2 Propane Deferral Account

The Company also requested approval of a deferral account respecting the use of propane for peak shaving. This account would track two specific elements:

1. Cost difference between the 1991 actual and normal propane volumes multiplied by the difference between unit costs of propane and overall system cost of gas.
2. Cost difference between revenues for use of propane compared to use of natural gas for the same load, to recognize the difference in heating value of the two fuels.

In the 1991 gas supply calculations, the Company has included a normalized propane volume of about 950 10^3m^3 for peak shaving. The Company's arrangement with Coastal Gas Marketing (CGM) for natural gas peaking supply contains both maximum daily deliveries and maximum annual capacities. In order to insure adequate natural gas peaking supply in the event of an extremely cold period, in the latter part of the heating season, the Company must balance the use of propane with the CGM supply on a daily basis. Because of variances in weather on a daily basis and the limit of propane-air injection capability, the Company is unable to accurately project annual propane uses until well into the heating season, namely in March of the following year.

The Company's position is that in a year warmer than normal, if no propane were required, the customer would benefit by the amount of the cost of 950 10^3m^3 of propane. Company witnesses testified that in a very cold year, 14,600 10^3m^3 of propane could be used. The difference in costs would be a swing of a maximum saving of about $50,000 to the consumer compared to a maximum cost of some $1,000,000 to the Company. Under the existing method, the rates would only assure that the $50,000 is then passed on to the consumer or to the Company. This is unlike natural gas in that the consumer and the company have an equal probability of being cost neutral over a period of time.

The second aspect of the Company's request is to allow it to recover the cost differential between the cost of propane ($3.38/GJ) and the average cost of system gas ($2.681/GJ). Additionally, because a unit of propane/air mixture has a heating value of approximately 51.1 GJ/10^3m^3 compared to natural gas at 37.4 GJ/10^3m^3 and gas sales are measured on a volumetric basis, a measured volumetric unit of propane/air will result in the customer receiving more heating value than if this same volumetric unit consisted of natural gas (meter loss). The Company's proposal would see the total propane volume adjusted for both meter loss and difference in unit costs.

BOARD FINDINGS

The Board accepts the Company's rationale for the propane use deferral account for this application. The Board will expect a detailed explanation of the Company's 1991/92 actual peaking supply use and will further expect the Company to provide details which will clearly indicate that the Company's use of propane in conjunction with its CGM natural gas peaking supply is the optimum for both normal and maximum years at the next GRA.

The Board will also expect the Company to consider the use of propane when it arranges for future peaking supplies, be it in conjunction with long term storage or other arrangements.

15.3 Bad Debt Deferral Account

The Company has requested that the $1,809,800 of 1991 bad debt expense in excess of the $4.5 million cap be placed in the bad debt deferral account. The Company has also requested that $216,300 of interest related to the 1990 expense deferral and $500,000 of 1991 expenses relating to lock-off and credit collection activities be included in the deferral account. The Company received approval to defer the incremental costs related to lock-off in Order 101/91.

The Company projects that the balance of the bad debt deferral account will be $4,526,100 as at December 31, 1991 as follows:

1990 Deferral	$2,000,000
Interest on 1990 Deferral	216,300
1991 Deferral	1,809,800
1991 Incremental Collection Costs	500,000
TOTAL	**$4,526,100**

While the Company did not request that any amount of this deferral account be included in 1992 rates, witnesses for the Company testified that any increase in the balance above the $4.5 million projected would be of concern to the Company.

BOARD FINDINGS

The Board notes the significant increases in arrears that is projected by the Company and the resulting bad debt expense of $6,309,000 which is $138,000 higher than the actual 1990 bad debt expense of $6,171,000. The Board also notes that lock-off had only a marginal effect on bad debt expense in 1991. The Board is concerned that accounts receivable arrears and bad debt expense could continue to grow if the lock-off policy does not have a substantial effect. Under this scenario, the deferral account could have a balance in excess of $6 million by December 31, 1992. A significant rate increase would then be required to dispose of the account at that time.

The Board is concerned about the increasing balance in this deferral account, and will expect the Company to submit a proposal for the orderly disposition of this account at the next GRA. The Board will consider the disposition of the bad debt deferral account at that time.

16.0 COST ALLOCATION

The Company filed a cost of service study to allocate the revenue requirements to each customer class. The Company's witnesses stated that the 1991 study was consistent with that used in the 1990 IRR application except for two changes:

1. Functional classification of the cash working capital allowance based on the results of the lead/lag study.

2. Translation of the new responsibility centre accounts into the former CGA functional accounts for allocation purposes.

Additionally, the Company provided a report dealing with weighting factors used to allocate customer related costs to customer classes. This study showed that a weighting factor of 100 would be appropriate for the special contract and interruptible customers.

In all other matters, the cost allocation study was consistent with that previously utilized and approved by the Board.

The following is a summary of the percentages, the 1991 functionally allocated costs to the various customer classes with comparisons to 1990 IRR and 1990 application.

Customer Class	1990 IRR	ACTUAL 1990	1991
Small General Service	60.92	61.19	61.40
Large General Service	30.62	31.07	30.94
Special Contracts	0.23	0.24	0.24
Interruptible	8.23	7.50	7.39
TOTAL	100.00	100.00	100.00

BOARD FINDINGS

The Board has reviewed the matter of customer weighting factors and is satisfied that the evidence would support an increase from the current factor of 20 to some larger number, 40 being recommended by the Company. However, in view of the relatively higher rates proposed for the interruptible class, the Board will not change the factor at this time, but will review the Company recommended weighting factor of 40 at the next GRA.

Therefore, the Board will accept the functional classification factors and customer class allocation factors as submitted by the Company.

The Board will order the Company to refile its cost of service study to reflect Board adjustments to revenue requirements as articulated in various other sections of this Order.

17.0 RATE DESIGN

The Company's original application requested two changes in rate structure from that currently in effect:

1. Continuation of the increase in the fixed monthly charge for Brandon consumers to equal that of other Manitoba consumers.
2. Institution of an alternative rate design for the SGS customer class. The alternative rate would see an elimination of the fixed monthly charge with an offsetting increase in the unit commodity charge.

The Company submitted that, in keeping with its philosophy of equal rates for equal services, the move to equalize the fixed monthly charge for Brandon was appropriate. This would result in the Brandon fixed monthly charge increasing from $9.00 to $10.00, the fixed monthly charge for other consumers.

The Company submitted that a fixed charge was appropriate to recover the fixed operating costs, and that the Company planned to increased the fixed charge over a period of time to recover more of its fixed costs. The Company's perception is that the nature of the fixed charge is misunderstood by the customers and, therefore, the Company has offered the alternative SGS rate.

In determining the revenues required to be generated, the Company has utilized the following revenue to cost ratios (R/C ratios) for 1991, compared to those used for the 1990 IRR.

	R/C Ratios		
Customer Class	1990 IRR	1990	1991
Small General Service	0.978	0.977	0.977
Large General Service	1.035	1.035	1.032
Special Contracts	1.014	1.015	1.014
Interruptibles	1.020	1.025	1.033
TOTAL	100.00	100.00	100.00

The Company's originally requested 1992 rates would result in the following annualized customer class revenue increases, over the existing class revenues based on 1991 interim refundable rates.

	Increases Over 1991 IRR	
Customer Class	$	%
SGS	4,563,173	2.99
LGS	1,361,132	1.66
Special Contracts	0	0
Interruptibles	723,431	3.69
TOTAL	$6,647,736	2.49%

Company witnesses stated that, in accordance with its special contract with Simplot Canada Ltd., rates will not increase as the R/C ratio for Simplot (including imputed gas costs) has not moved outside the range of 99.50% to 1.015. Under the Contract terms, therefore Simplot's rates must remain unchanged.

In calculating its Transportation service (T-service) rate, the Company has deducted, from the appropriate class sales rates, the Company's average cost of gas for that class. In this application the Company has adjusted T-service rates to recognize "unaccounted for gas" so that T-Service customers will also be required to pay for this gas.

The Company has adjusted Interruptible T-Service to eliminate the remaining differential between the actual required rate and the temporary Interruptible T-Service rate deemed in Order 133/90, dated August 28, 1990.

The Company's original application indicated the following ranges of rate increase impacts within customer classes, depending on annual consumption:

	Percentage Increases	
Customer Class	Overall	Range
SGS - Brandon	4.6%	3.9 - 4.9
- Other	2.9	2.8 - 3.3
LGS Sales	1.76	1.3 - 1.8
Firm T-Service	11.85	4.0 - 12.4
Interruptible	0.3	0.3 - 0.3
Interruptible T-Service	35.78	19.8 - 36.2

The Company submitted that T-Service rate increases are not valid for comparison with rate increases of other classes because other classes include cost of gas as a denominator on the cost side while T-Service rates do not. The Company submitted that if an assumption were made that T-Service customers could purchase their gas at 90% of system gas costs, the increases, for their total energy bills would range from 1.8% to 2.5% for the Firm T-Service and from 3.2% to 4.5% for the Interruptible T-Service.

BOARD FINDINGS

As previously mentioned, the Board will require the Company to refile its cost of service study to reflect adjustments to revenue requirements. The Board estimates that the downward adjustment to the revenue requirement, reflecting both Board adjustments and the December 20, 1991 information will result in an overall increase of 1.01% compared to the 2.49% originally requested by the Company on an annualized basis. Annualized percentage increases for each customer class and the range of increases within each class will also be reduced. The Board will review the rate impacts upon receipt of the refiled documents and will determine final rates based on such a review.

The Board considers that the move to equalize Brandon's SGS rate with that of other consumers in Manitoba to be appropriate, at this time. In reviewing the history of this matter the Board has found that, prior to the amalgamation of the three Manitoba utilities into the present Company, the SGS (or residential) consumers in Brandon were being subsidized to a large degree by Simplot Canada Ltd. Additionally, upon purchase of ICG Utilities of Greater Winnipeg Gas, the Rate Bases of both Companies were rolled into a single rate base. This also resulted in rate increases to Brandon being less than they otherwise would have been since 1988.

The Board has considered the presentations made by the people at the Brandon portion of the hearing. While most people present objected to the size of increase requested, others suggested that one more increase in the fixed monthly charge would tend to discourage business and commercial development in Brandon. Other presenters recognized that Brandon has had an advantage in the rate structure and wished to maintain that advantage.

The Board wishes to point out that the change in the fixed monthly charge is only applicable to the SGS Class which consists of predominantly residential and small commercial consumers. The Board considers the concept of having equal rates when receiving an identical service to be acceptable. The Board will therefore approve the equalization of the fixed monthly charge for the SGS class in Brandon.

The Board believes it proper that some portion of the Company's fixed operating costs be recovered by way of a fixed monthly charge. The Company's evidence is that in 1991 it attached 2,318 new customers at an incremental capital cost of $5,397,939. This, on average, represents a cost of some $2,450 per customer. With minor exceptions this is the cost of the customer's portion of the distribution main, service line and meter and regulator installation. Given the average service life of mains, services and meters, the Board is of the opinion that the present fixed monthly charge of $10 or $120 per year does not even cover the capital cost. Meter reading, billings and ongoing maintenance costs are additional fixed costs which clearly are not presently being recovered in the fixed monthly charge. Fixed costs are necessary, regardless of actual natural gas consumption. The Board will therefore not allow the Company to institute its proposed alternate SGS Rate. The Board, in conjunction with a review of the Company's expansion criteria, will re-examine the matter of an appropriate amount for a fixed monthly charge and will consider both capital and operating costs in some detail in its deliberations.

With respect to the T-Service rates, the Board agrees that in order to properly compare annual energy increases the cost of gas must be considered an integral part of the total annual impact. The Board notes that using the Company's assumed cost of gas, the average increases in the Firm T-Service annual energy bill would be almost identical to the overall system average, while the Interruptible T-Service annual bill would be some 1 to 2% over the system average. Conversely, deducting the gas costs from the SGS class and comparing non gas cost increases would result in an average increase of 7.7%, and with a range of some 7% to 8.6%.

The Board, in Order 133/90, recognized past errors in under allocating costs to the Interruptible Class but, in the interests of avoiding extreme rate shock of the order of 250%, instituted a phase-in mechanism for the gradual movement towards proper rates for this class. This application will see the elimination of the final rate differential. The Board will therefore accept, in principle, the Company's rate design for this class, recognizing that Board adjustments to the Company's application will tend to decrease these rates somewhat.

In response to a Board Information request the Company submitted the following data respecting the changes in the typical residential consumer's (using 3,711 m^3) annual heating bill since the start of natural gas deregulation, in 1985, for consumers in the former Greater Winnipeg Gas franchise area.

DATE	ANNUAL BILL
October 31, 1985	$678
November 1, 1987	610
January 1, 1988	614
November 1, 1989	658
September 1, 1990	708
March 1, 1991	730
January 1, 1992 (originally requested)	754

Percent increase over October 31/85 = 11.2%

18.0 BURNER TIP SERVICE

In response to instructions in Board Order 133/90, the Company submitted a detailed report on its experience with its offering of a uniform burner tip service to the rural areas of the Province. The Company position remains that all customers within the Province should receive the same service for the same rate. It is the Company's opinion that they can offer this service at a lower cost than can the private sector. They have greater flexibility to respond to calls of a priority nature by virtue of their larger service staff.

The Keystone Mechanical Contractors Association (KMCA), formerly the Rural Manitoba Mechanical Contractors, continued to object to the offering of this service by the Company. They asked that the Board Order the Company not to provide this service in the rural areas and further suggested that the private sector might be better able to provide this service in all areas of the Province.

In response to a question by KMCA, the Company testified that the total cost of this service for 1991 in the rural areas was approximately $50,000, while in the former Greater Winnipeg Area it was some $767,000. KMCA maintained that this amount of $50,000 would be significant to the rural contractors.

An additional point which KMCA continued to pursue is that the "window of opportunity" for the rural contractors was being eliminated in that since they were not responding to requests for burner tip service, they were not in a position to receive potential spin-off work.

BOARD FINDINGS

While the Board can appreciate the concerns of KMCA, it is of the opinion that the Company is in a better position to offer this service. The Board notes that one of the potential problems, put forward by the presenter at previous hearings was that the offering of Burner Tip Service was merely a ploy for the Company to ultimately get into the business of major repair and appliance sales and servicing. KMCA remained silent on this issue and the evidence is that this has not occurred.

The Board notes that the Company has specifically requested that Arthur Andersen, a consultant currently conducting an operation audit for the company, contact KMCA when they are assessing the merits of the burner tip service offered by the Company. Upon receipt of this report, the Board will ultimately deal with this issue.

19.0 IT IS THEREFORE ORDERED THAT

1) The Interim Refundable Rates, effective January 1, 1991 as approved in Order 19/91 BE AND ARE HEREBY CONFIRMED.

2) The request for a rate rider to be effective January 1, 1992 in the amount of $826,842 related to 1990 gas costs BE AND IS HEREBY DENIED.

3) The request for a Year-End Rate Base BE AND IS HEREBY APPROVED.

4) The allowed 1991 Year-End Rate Base be $236,063,244.

5) For 1992 rate setting purposes, the allowed return on equity be 12.85 percent and the overall rate of return be 11.46 percent.

6) The total annualized and normalized revenue requirement based on year-end data from gas sales be $257,965,265.

7) The request for a rate rider to be effective January 1, 1992 in the amount of $1,734,307 related to 1991 gas cost changes BE AND IS HEREBY APPROVED.

8) The Company present a proposal at the next general rate application to deal with the Bad Debt deferral account.

9) The calculation of depreciation based on year-end balances of plant for all plant categories other than computers, heavy work equipment and transportation equipment BE AND IS HEREBY APPROVED.

10) The use of the least square regression model for normalization calculations BE AND IS HEREBY APPROVED.

11) The use of the 10 year rolling average to determine normal degree days BE AND IS HEREBY APPROVED.

12) The request for establishment of two deferral accounts, one related to broker activity and the other related to actual propane volumes and costs BE AND IS HEREBY APPROVED.

13) The request to increase the Small General Service fixed monthly charge for Brandon customers to $10.00 per month BE AND IS HEREBY APPROVED.

14) The request to institute an alternative rate design eliminating the fixed monthly charge for the Small General Service class BE AND IS HEREBY DENIED.

15) The Company file with the Board for approval a revised schedule of rates including a revised cost allocation study, which reflect the adjustments as set out above, and maintain to the greatest degree possible the revenue to cost ratios as set out in the Company's application.

THE PUBLIC UTILITIES BOARD

"G.D. FORREST"

Chairman

"D. DEGRAFF"

Acting Secretary

Certified a true copy of Order No. 156/91 issued by The Public Utilities Board

Acting Secretary