# ANNUAL REPORT

# 2002

**THE PUBLIC UTILITIES BOARD**

The Honourable Gregory F. Selinger
Minister of Finance
103 Legislative Building
Winnipeg, Manitoba
R3C 0V8

Dear Mr. Selinger:

Pursuant to the provisions of Section 109(1) of The Public Utilities Board Act, I am pleased to submit to you, the Forty-Third Annual Report of the Board, pertaining to the year 2002 ending on the Thirty-first day of December .

I wish to acknowledge Board Staff, Advisors and my fellow Members for their ongoing dedication to the activities of the Board.

Sincerely,

G. D. Forrest
Chairman

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# RESPONSIBILITIES

The Public Utilities Board (the Board) is an independent quasi-judicial body operating under the authority of the Manitoba Legislature. While The Public Utilities Board Act was passed in 1959 the Board has regulated services under other legislation since 1912.

The Board is responsible for the regulation of public utilities as defined under *The Public Utilities Board Act*; namely: Centra Gas Manitoba Inc., Stittco Utilities Man Ltd., Gladstone, Austin Natural Gas Co-op Ltd., Swan Valley Gas Corporation, all energy providers and most water and sewer utilities in the Province.

The Board also regulates the premiums charged by Manitoba Public Insurance for compulsory auto insurance and related premiums charged on drivers' licences and the rates charged by Manitoba Hydro for the sale of power, all pursuant to *The Crown Corporations and Public Review and Accountability Act*. Other enactments which assign regulatory or adjudicative responsibilities to the Board are:

The Greater Winnipeg Gas Distribution Act
The Gas Allocation Act
The Prearranged Funeral Services Act
The Cemeteries Act
The City of Winnipeg Act (passenger carrier agreements)
The Manitoba Water Services Board Act (Appeals)
The Highways Protection Act (Appeals)

The Board is also responsible for the administration of The Gas Pipe Line Act which requires the Board to authorize construction and operation of all gas pipe lines in Manitoba.

# MEMBERS OF THE BOARD

As of December 31, 2002 the members of the Board were:

G. D. Forrest, Chairman
R. A. Mayer, Q.C., Vice-Chairman
D. Côté
M. Girouard
E. Jorgensen
Dr. K. Avery Kinew
S. Proven
Mario J. Santos

# SUMMARY OF BOARD ACTIVITIES

## BOARD MEETINGS AND HEARINGS

| | |
|---|---|
| Board Meetings | 27 |
| Public Hearing Days | 38 |
| Appeal Hearings | |
| Disconnection of Service | 0 |
| The Highways Protection Act | 3 |
| Municipal Gas | 36 |
| Pre-Hearing Conference Days | 3 |

## ORDERS ISSUED

During the year ending December 31, 2002, 222 Orders were issued, as follows:

**Regulated Industry Orders:**

| | |
|---|---|
| Water and Sewer Utilities | 75 |
| Manitoba Hydro | 75 |
| Natural Gas and Propane Utilities | 24 |
| Service Disconnection & Reconnection | 0 |
| Manitoba Public Insurance Corporation | 8 |
| The City of Winnipeg (Transportation) | 0 |
| Highways Protection Act | 2 |
| The Cemeteries Act | 4 |
| Municipal Gas Appeals | 34 |

Note: Copies of the decisions of The Public Utilities Board of Manitoba are available from the Board's office upon request.

# NATURAL GAS DISTRIBUTION

## CENTRA GAS MANITOBA INC.

**CENTRA GAS MANITOBA INC. APPLICATION FOR AN INTERIM EX-PARTE ORDER OF THE BOARD AUTHORIZING AND APPROVING AMENDMENTS TO THE TERMS AND CONDITIONS OF SERVICE - Order No. 14/02 - January 30, 2002**

In order to implement the Western Transportation Service ("WTS") and the associated Agency Billing and Collection Service ("ABC"), the Board approved amendments to the Terms and Conditions of Service ("Terms and Conditions") of Centra Gas Manitoba Inc. ("Centra") in Order 49/00, dated March 30, 2000. The Board approved further amendments to Centra's Terms and Conditions related to the payment due date and the late payment rate, in Order 154/00, dated December 5, 2000.

On October 26, 2001, Centra applied to the Board for an interim ex-parte order authorizing and approving proposed amendments to Centra's existing Terms and Conditions of Service, to become effective November 1, 2001. Centra submitted that the following proposed amendments were necessary to clarify and refine clauses related to the WTS and ABC service offerings to reflect actual experience and to incorporate other amendments previously ordered by the Board:

1. Extending the processing period for WTS enrollments from 30 to 45 days.
2. Making Invoice and Remittance guidelines consistent for WTS and ABC Service.
3. Changing the valuation of gas loans that are carried over as part of the annual financial reconciliation under WTS for brokers with and without ABC contractual arrangements.
4. Changing the credit requirements that brokers must meet to participate in WTS.
5. Changing all references to "invoice" with "statement" for WTS and ABC Service.
6. Amending articles to reflect the change from mandatory to optional ABC Service for Small General Service and Large General Service customers, effective May 1, 2001.
7. Amending articles to reflect the removal of the Buy/Sell Interruptible Delivery Option, effective November 1, 2001, as previously ordered by the Board.
8. Amending articles to reflect the discontinuance of Buy/Sell Service effective November 1, 2001, subject to the "grandfathering" provisions in Order 78/01.
9. General "clean up" to ensure consistency in wording, numbering and to clarify certain articles of the Terms and Conditions.

The Board was not convinced that there was a need to extend the processing period for WTS enrolment from 30 to 45 days. The Board approved the other amendments to the Terms and Conditions of Service, as requested by Centra.

**AN APPLICATION BY CENTRA GAS MANITOBA INC. FOR AN INTERIM ORDER APPROVING PRIMARY GAS SALES RATES TO BE EFFECTIVE FOR ALL GAS CONSUMED ON AND AFTER FEBRUARY 1, 2002 - Order No. 15/02 – January 30, 2002**

On December 12, 2001, Centra applied to the Board for approval of interim sales rates to be effective February 1, 2002 and to remain in effect until a further Order of the Board.

Centra also requested the Board to approve a rate rider to dispose of the estimated January 31, 2002 Primary Gas PGVA over the next 12 months normalized volumes.

Pursuant to Board requirements, Centra filed an update to its original Application with the Board on January 22, 2002.

The dramatic increase in Centra's Primary Gas costs during 2000 was due to a demand and supply imbalance, unusually high demand as a result of a strong North American economy, and colder than normal weather in November and December. This resulted in a gas price in excess of $13.00 per Gj in January 2001. Following this peak, the price decreased abruptly because of the early end to the 2000/01-winter season. Prices continued to decline during the spring and early summer of 2001, and the trend has continued through the fall. The reason for this trend is the market's expectation of an economic slowdown resulting in less demand, greater available supply, current high levels of storage gas inventory, and a switch to alternate fuels in response to the past winter's unprecedented high natural gas prices. Gas prices stabilized in the last months of 2001 and in early 2002.

Centra placed price hedges to bring price protection to 50% of the eligible TCE/Mirant contract volumes for November 2001 to October 2002.

On November 14, 2001, Centra placed further derivatives for an additional 40% of the purchases under the TCE/Mirant Contract for December 2001 to October 2002 volumes.

In addition to the Primary Gas Base Rate change related to the cost of Western Canadian gas, Centra requested approval of the imposition of a rate rider to refund the Primary Gas PGVA balance at January 31, 2002 estimated to be $10,259,161 owing to Centra's customers.

Pursuant to Board requirements, Centra filed an updated forward price strip with the Board on January 22, 2002. The price strip for the period from February 1, 2002 to January 31, 2003, based on closing prices at January 17, 2002 adjusted to incorporate hedging impacts was $3.182/Gj compared to the $4.255/Gj contained in the December 12, 2001 application. Centra also updated its Nova Tolls and AECO/Empress differentials to reflect revised actual and forecast unit prices. Additionally, Centra revised the gas costs from those reported in the initial application as a result of hedging transactions placed since May 25, 2001. For the May 25 and October 4, 2001 transactions, the overall costs were decreased to reflect the revised estimated Buy/Sell volumes. These reductions totalled $1,191,228.

The other significant change was related to the costless collars placed by Centra on November 14, 2001 for February to October 2002 volumes. Total estimated impacts were $12,629,065 compared to $9,436,977 contained in the original application. In terms of unit costs the impacts of all hedging transaction revisions increased from $0.191 per Gj to $0. 256 per Gj.

Using the 100% inclusion rate, and fuel, overhead and storage gas costs resulted in a Primary Gas cost embedded in the base sales rate of $0.1558 per cubic metre, compared to the original request of $0.1702 per cubic metre.

The proposed February 1, 2002 billed Primary Gas Rate requested by Centra was $0.1477 per cubic metre, compared to the originally requested billed rate of $0.1620 per cubic metre.

Based on the revised strip and other changes, the following table details the decreases to the annual natural gas bills of different customer classes.

**ANNUALIZED AS BILLED RANGE OF CUSTOMER IMPACTS REVISED APPLICATION**

| Customer Class | Low | High |
|---|---|---|
| SGS* | -1.9% | -2.1% |
| LGS** | -2.0% | -2.5% |
| HVF*** | -2.5% | -2.7% |
| Mainline | -2.7% | -2.9% |
| Interruptible | -2.5% | -2.7% |

*SGS – Small General Service
**LGS – Large General Service
***HVF – High Volume Firm

On October 23, 2001, Centra submitted a report to the Board evaluating alternatives to the use of a 12-month forward price strip for forecasting gas prices and recommended that Centra continue the current practice of using the 12-month forward price strip, with the option of updating the forward strip price prior to rate implementation.

The Board ordered that the existing methodology be followed until a further order of the Board.

The following table provides a summary of gas costs and customer impacts, including the updated application for February 1, 2002.

| Date | Cost of Gas<br>12- month strip | Customer Bill | Percent Change |
|---|---|---|---|
| November 1, 2000 | $6.451/Gj | $ 1,123 | 14.9% |
| February 1, 2001 | $ 9.251/Gj | $ 1,381 | 23.0% |
| August 1, 2001 | $ 5.517/Gj | $ 1,233 | -3.4% |
| November 1, 2001 | $ 3.974/Gj | $ 1,147 | -6.9% |
| February 1, 2002 | $ 3.812/Gj | $ 1,124 | -2.0% |

**AN APPLICATION BY CENTRA GAS MANITOBA INC. TO VARY BOARD ORDER 168/01 Order No. 44/02 – March 13, 2002**

**On February 8, 2002 Centra applied to vary Order 168/01 "with respect to the timetable associated with Centra's next General Rate Application." Centra submitted that the timetable in Order 168/01 could no longer be met as a result of events that have transpired since Order 168/01 was issued, including:**

1. The expansion of the scope of the Hydro status update hearing which, in Hydro's view, initially did not include a review of the reasonableness of Hydro's existing sales rates.

2. The rescheduling of the start of the Hydro hearings to April 15, 2002 from the March 11, 2002 date originally proposed.

3. The Hydro hearings were originally expected to last for approximately two weeks, but now are scheduled into May or June 2002.

4. The Hydro hearings have attracted at least eight Intervenors, and 12 potential Intervenor witnesses.

5. Hydro has received a significant number of information requests that must be addressed by Hydro staff, including review by senior management.

Centra submitted that it did not have sufficient resources to engage in two rate applications at the same time, and could not adequately prepare the Centra General Rate Application (GRA) until the Hydro hearings were completed. Centra also suggested that Intervenors might experience similar resource availability problems.

Centra proposed the following amendments to the timetable set out in Order 168/01:

1. Centra will file a 2002/03 non-Primary Cost of Gas Application as soon as possible with a public hearing to commence in June 2002. This Application will address the Supplemental Gas Rates, Transportation to Centra Rates, and the Unaccounted for Gas component of the Distribution to Customer Rates. Alternatively, should the Board be unable to accommodate this schedule, the filing date could be delayed to September 2002 with a hearing to commence in December 2002.

2. The non-Primary Cost of Gas Application would include:
   - A review of non-Primary gas costs and deferral account balances to March 31, 2002.
   - A review of estimated non-Primary Gas costs from April 1, 2002 to March 31, 2003.
   - A request for confirmation of outstanding interim Board orders issued since the 1998 GRA.
   - A review of Centra's responses to previous Board directives with respect to Derivatives Hedging Policy, Derivatives Hedging Training Program, Value of Interruptible Customer's Report, Blank Page Analysis update, and the Inter Utility Rate Study.

3. Centra will file a GRA based on a 2003/04 test year after the November 2002 meeting of Centra's Board of Directors, and request a hearing to commence in the spring of 2003.

Centra's current Integrated Financial Forecast ("CGM01-1"), prepared on a weather-normalized basis, indicates that Centra will break-even in 2001/02, and realize a $5 million loss in 2002/03. Centra's Board was willing to accept the forecasted loss in 2002/03 because of the significant cost of gas increases that customers had experienced over the last few years. Centra has further forecast a break-even position in 2003/04, assuming a 1.9% general revenue increase. CGM01-1 currently assumes annual revenue increases of 0.5% and each year after 2003/04.

The current estimate of actual results for 2001/02 indicates that Centra will realize a loss of between $6 and $10 million. Centra indicated that because of the expected 2001/02 loss, the requested rate increase for 2003/04 may be marginally higher than the 1.9% reflected in the CGM01-1.

Despite the expected loss in 2001/02 and 2002/03, Centra remained of the view that it was in the best interest of its customers to avoid the costs of having a GRA for 2002/03 when no rate increase was being requested. Centra further suggested that it would be more appropriate to incur those costs when Centra required a general rate increase, which currently is expected to be in the 2003/04 test year.

Centra stated that it did not want to mix gas cost reduction issues with distribution rate change issues that may be required as a result of a GRA application.

The Board noted that this application to vary was substantively more than a simple request to amend the timetable, as suggested by Centra in its application. In addition to the requested changes in timetable, this application also contemplated a change in process with respect to the review of non-Primary Gas Costs separate from the review of distribution rates, and a change in test year for the GRA application from 2002/03 to 2003/04.

Board Order 168/01 provided, in part, that the filing requirements for Centra's GRA, as set out in Order 106/01, will remain unchanged noting that on a best efforts basis, Centra will assist the Board to discharge its statutory obligation.

As a result of these cost reductions, Supplemental, Transportation, and Distribution rates will change, resulting in rate reductions, according to Centra, in the range of 7.9% for residential customers, and 9.3% to 21% for larger volume customers.

In order for all customers to receive the benefits of these rate reductions as soon as possible, the Board approved this aspect of the application to vary Order 168/01, and directed Centra to file its 2002/03 Cost of Gas application with the Board immediately.

It was the long passage of time since the last GRA, as well as a number of issues related to the acquisition of Centra by Hydro effective August 1, 1999 that are key drivers that made this GRA particularly important.

The Board had to balance the competing interests of the various parties, together with efficiencies in the public hearing process.

The Board notes that a decision was taken in early November to not file a General Rate Application.

The Board notes that the distribution sales rate comprises 25% of the total base rate, and that some of the outstanding issues will at least be touched on in a public hearing process dealing with integration matters to commence in April 2002. The Board was further concerned with the fact that Centra projected a loss of $6 to $10 million in the fiscal year ending March 31/02 and a further loss of $5 million for the fiscal year ending March 31/03.

While no rate increase was sought this alone cannot lead one to conclude that Centra's costs were not increasing or remain reasonable. In fact, of concern to the Board was Centra's position to defer a possible need for rate increases and to incur operating losses to be recovered at a later date. While the Board cannot pre-judge these operating costs, the desirability of such an approach needs to be reviewed as soon as possible otherwise inter-generational inequities may occur. Additionally, there were monies currently being collected in rates for cost of service components such as income taxes and rate of return on shareholders equity which existed when Centra was privately owned and no subsequent review has been made as to the allocation of these monies. While there are many issues which require review, and except for inter-generational issues, there was no evidence currently before the Board that existing rates were unjust and unreasonable and that a deferral of the GRA was prejudicial to gas consumers.

The Board approved the application to vary Order 168/01 with respect to the GRA timing and test year, and directed that a comprehensive GRA application, based on a 2003/04 test year, be filed with the Board by December 1, 2002 regardless of whether a rate change is sought.

**AN APPLICATION BY CENTRA GAS MANITOBA INC. FOR AN INTERIM ORDER APPROVING: 1. PRIMARY GAS SALES RATES TO BE EFFECTIVE FOR ALL GAS CONSUMED ON AND AFTER MAY 1, 2002; 2. THE REMOVAL OF EXISTING RATE RIDERS IMPOSED ON JUNE 1, 2001 PURSUANT TO BOARD ORDERS 91/01 AND 94/01 FOR SUPPLEMENTAL GAS, TRANSPORTATION TO CENTRA AND DISTRIBUTION TO CUSTOMER RATES - Order No. 77/02 – May 3, 2002**

Centra applied to the Board on March 26, 2002 for approval of increased Primary Gas sales rates to be effective May 1, 2002.

Centra filed updated forward price information as at April 17, 2002, which information reflected a continuing increase in primary gas costs.

Centra also requested the termination of certain non-primary gas rate riders approved by the Board in Orders 91/01 and 94/01. The balance in these non-primary gas cost deferral accounts at March 31, 2002 was estimated to be approximately $16.2 million owing to customers.

The current Primary Gas rate, effective February 1, 2002, included a primary cost of gas of $3.556 per Gj, based on the forward market strip at January 17, 2002 close. Centra's March 26 application contained a primary cost of gas of $4.178/Gj, based on the forward market strip at March 1, 2002, while the updated information showed a forecast gas cost of $5.209 per Gj, based on a forward market strip close on April 17, 2002. Thus, the market had shown increases in forecast gas cost of over 45% since January 17, 2002.

The Board noted that the Consumers' Association of Canada (Manitoba) Inc./Manitoba Society of Seniors and Municipal Gas urged the Board to continue to utilize the most current available information in setting rates. While conceding that this could result in greater rate instability, both parties suggested that the continued use of this principle would enhance price transparency and better reflect market conditions.

In its decision the Board ordered the immediate disposition of the Primary Gas PGVA estimated to be $2.27 million and the non primary gas cost deferral accounts estimated to be approximately $16.2 million owing to consumers.

In this decision, the Board directed Centra to file, for Board approval, revised rate schedules and customer impact information to be effective May 1, 2002 to reflect:

a) The most current forward price as of April 17, 2002
b) Refund of the revised Primary Gas PGVA balance at April 30, 2002 of approximately $2.27 million and refund of the balance in the non-primary gas costs accounts at April 30, 2002 of approximately $16.2 million.
c) Termination of the existing rate riders for non-primary gas costs pursuant to Orders 91/01 and 94/01.

**APPROVAL OF INTERIM PRIMARY GAS SALES RATES TO BE EFFECTIVE FOR ALL GAS CONSUMED ON AND AFTER MAY 1, 2002, PURSUANT TO BOARD ORDER 77/02 - Order No. 79/02 - May 3, 2002**

On May 3, 2002, the Board, in Order 77/02, directed Centra to file revised rate schedules and customer impact calculations for rates to be effective for all gas consumed on and after May 1, 2002.

Centra filed the required information on May 3, 2002. The Board approved the rate schedules as filed by Centra.

The 12-month forward price strip including price management impacts ranged from a low of $3.812/Gj in February 2002 to a February 1, 2001 high of $9.251/Gj, with the May 1, rates based on a price of $5.084/Gj. The May 1, 2002 billed rates reflect a Primary gas cost and Primary Gas PGVA rate rider in the amount of $0.1956 per cubic metre. The total billed rate including the PGDA rate rider is $0.2319 per cubic metre.

The following table shows the estimated increase in annual gas bills for the various customer classes, relative to the February 1, 2002 billed sales rates.

| Customer Class | Low | High |
|---|---|---|
| SGS | 8.3% | 9.7% |
| LGS | 8.2% | 10.5% |
| HVF | 14.2% | 15.1% |
| Mainline | 14.9% | 17.3% |
| Interruptible | 3.8% | 4.1% |

The following table provides a summary of annual customer bills for the typical residential consumer, based on 12-month forward estimated gas costs (including price management activities), and corresponding customer impacts for the typical residential consumer.

| Date of Rate Change | Annual Customer Bill | Percent Change in Bill |
|---|---|---|
| **November 1, 2000** | $ 1,123 | 14.9% |
| February 1, 2001 | $ 1,381 | 23.0% |
| August 1, 2001 | $ 1,233 | -3.4% |
| November 1, 2001 | $ 1,147 | -6.9% |
| February 1, 2002 | $ 1,124 | -2.0% |
| May 1, 2002 | $ 1,225 | 9.0% |

**CENTRA GAS MANITOBA INC. APPLICATION FOR AN INTERIM EX-PARTE ORDER OF THE BOARD: 1. AUTHORIZING AND APPROVING AN AMENDMENT TO THE EXISTING FRANCHISE AGREEMENT BETWEEN CENTRA GAS MANITOBA INC. AND THE RURAL MUNICIPALITY OF ROCKWOOD; 2. APPROVING THE FINANCIAL FEASIBILITY TEST FOR THE EXPANSION OF NATURAL GAS SERVICE TO THREE CUSTOMERS WITHIN THE RURAL MUNICIPALITY OF ROCKWOOD - Order No. 134/02 - July 30, 2002**

On June 28, 2002, Centra applied to the Board for interim ex-parte approval and authorization of an amendment to the existing franchise agreement between Centra and the Rural Municipality of Rockwood ("Rockwood"), and interim ex-parte approval of the financial feasibility test for expansion of Centra's distribution system to serve two commercial customers and one residential customer within the expanded franchise area.

Centra currently has a franchise agreement with Rockwood covering a portion of the Municipality. Centra was requested to extend natural gas service to a commercial establishment located in the SE ¼ of Section 22, Township 16, Range 2 EPM, located south of the existing franchise area, for the summer of 2002. Additionally one other commercial customer and one residential customer located in the same quarter have requested service. In total, there are potentially 2 commercial and 5 residential customers that could be served by this expansion project, all located within SE1/4-22-16-2 EPM.

A total of three customers have signed up and are included for purposes of the feasibility test. The estimated annual consumption of 31,333 cubic metres is based on the equipment-input and square footage load for the commercial customers, while the residential consumption of 2,833 cubic metres was the Small General Class ("SGC") average used for all recent expansion applications

Estimated capital costs for the project are $18,488 to be spent in the first three years.

The amendment to the existing Franchise Agreement and the feasibility test as submitted by Centra was approved, on an interim ex-parte basis.

**AN APPLICATION BY CENTRA GAS MANITOBA INC. REGARDING: 1. FINAL APPROVAL OF VARIOUS GAS COSTS; 2. APPROVAL OF SALES RATES TO BE EFFECTIVE AUGUST 1, 2002 BASED ON FORECAST 2002/03 NON-PRIMARY GAS COSTS; 3. APPROVAL OF DISPOSITION OF VARIOUS GAS COST DEFERRAL ACCOUNT BALANCES; 4. APPROVAL OF INTER-COMPANY DEBT; 5. FINAL APPROVAL OF VARIOUS EX-PARTE**

**ORDERS RESPONSES TO PREVIOUS BOARD DIRECTIVES - Order No. 135/02 – July 31, 2002**

Centra filed its Application with the Board on March 14, 2002, and revised the Application on May 22, 2002. The revised Application requested the following:

1. Approval of Supplemental Gas, Transportation (to Centra), and Distribution (to customers) rates to be charged by Centra for the sale of gas and the provision of transportation and distribution services to its customers, effective with respect to all gas consumed on and after August 1, 2002. The only component of Centra's Distribution rate addressed in the Application was the portion related to Unaccounted For Gas.

2. Final approval of January 1 to December 31, 2000, and January 1 to March 31, 2001 gas costs, and the various Purchase Gas Variance Accounts ("PGVA's") (excluding Primary Gas PGVA) and gas cost deferral account balances as at March 31, 2001.
3. Final approval of April 1, 2001 to March 31, 2002 gas costs, and gas cost deferral account balances as at March 31, 2002.

4. Approval of the disposition of the non-primary PGVA's and gas cost deferral account balances accumulated to March 31, 2002, plus carrying costs to July 31, 2002.

5. Approval of the establishment of two deferral accounts related to the capital tax impact of the gas cost deferral accounts for the fiscal years ended March 31, 2001 and 2002 including carrying costs, as well as the establishment of a deferral account to capture the capital tax impacts in future years, commencing April 1, 2002.

6. Final approval of the interim tariff approved by the Board in Order 58/00 to be charged to all Agents, Brokers and Marketers for the provision of the Agency, Billing and Collection Service.

7. Final approval of interim ex-parte Order 154/00 amending the Terms and Conditions of Service related to payment due dates and late payment charges.

8. Final approval of interim ex-parte Orders 181/99, 109/00, 123/00, 140/00, 154/01, 164/01, and 172/01 related to the approval of new or amended franchise agreements, feasibility tests and a connection fee schedule within various Rural Municipalities in Manitoba.

9. Final approval of interim ex-parte Orders 18/01, 119/01, 170/01 and 15/02 related to the approval of interim quarterly Primary Gas rates commencing February 1, 2001 and ending February 1, 2002.
10. Final approval of interim ex-parte Order 14/02 to amend the Terms and Conditions of service related to Western Transportation Service and Agency, Billing and Collection Service.

11. Approval of a rate to be charged by Centra for reconnections of service performed outside of normal work hours, to be effective August 1, 2002.

12. Approval of the removal of the Service Abandonment Fee from the Schedule of Miscellaneous Charges for Service as part of the Terms and Conditions of Service, and a redefinition of "Service Relocations" as included in the Schedule of Miscellaneous Charges.

13. Approval of the collection of the Basic Monthly Charge from all customers, including those whose services are temporarily disconnected, inactive, or vacant, effective August 1, 2002, as

currently included in the Terms and Conditions of Service.

Based on the updated Application, Centra forecasted the 2002/03 fiscal year non-primary gas costs to be approximately $12.8 million lower than the revenues generated by current rates. Additionally, Centra forecasted the March 31, 2002 PGVA and other gas cost deferral account balances (except for the Primary Gas PGVA) plus carrying costs to July 31, 2002, net of the revenues collected by existing rate riders, to be approximately $17 million owing to customers.

In addition to the above, Centra provided responses to previous Board directives respecting Centra's Inter-Utility Rate Study, the Derivative Hedging Policy and the Derivative Hedging Training Program, the Report on the status of Centra's "Blank Page" Gas Supply Portfolio Analysis, and a Report on the Value of Interruptible Customers.

Natural gas is a commodity subject to market fluctuations. Natural gas prices respond to supply and demand forces in the unregulated market. Natural gas prices in Canada and the United States appear to have stabilized over the past year. In March 2001, the spot price for natural gas was approximately $7.60/Gj, the forward price at April 22, 2002, used in Centra's 2002/03 forecast was $4.57/Gj.

The Board was satisfied that the 2000/01 and 2001/02 final gas costs were reasonable and appropriate. The Board also found the PGVA and other gas cost deferral accounts properly reflect differences between amounts included in sales rates and actual gas costs with the exception of the capital tax deferral accounts.

The Board found that capital taxes are a revenue requirement issue and should not be considered a Cost of Gas issue and any further examination of Centra's capital taxes to occur at Centra's next General Rate Application, expected to be in the fall of 2002.

The Board found Centra's estimates for 2002/03 gas costs to be reasonable, and approved forecast non-Primary Gas costs of $80,012,875.

Consumers should be aware of the potential impact on transportation and other tolls that may arise from a pending National Energy Board ("NEB") decision in respect of TransCanada Pipelines Ltd. toll application. The Board directed Centra to seek new Transportation Rates, if required as a result of the NEB decision.

In addition to the matters above, the Board approved a number of interim orders relating to Primary Gas, and rural expansion. The Board approved the financing of inter-company debt and a number of changes to Centra's Terms and Conditions of Service.

The following table illustrates the annualized impacts of this Order on customer's bills, relative to May 1, 2002 rates.

| **Customer Class** | **Annualized Rate Impact** |
|---|---|
| SGC | -2.0 to -2.2% |
| LGC | -2.4 to -3.0% |
| HVF | -2.0 to -2.4% |
| Mainline | -2.4 to -31% |
| Interruptible | -3.0 to -3.4% |

**AN APPLICATION BY CENTRA GAS MANITOBA INC. FOR AN INTERIM ORDER APPROVING PRIMARY GAS SALES RATES TO BE EFFECTIVE FOR ALL GAS CONSUMED ON AND AFTER AUGUST 1, 2002 Order No. 136/02 – July 31, 2002**

On June 14, 2002, Centra applied to the Board pursuant to Order 99/01 for approval of interim Primary Gas sales rates to be effective August 1, 2002 and to remain in effect until a further Order of the Board.

Centra filed an updated forward price strip with the Board on July 23, 2002 with supporting documentation and a Schedule of Rates to reflect the updates. The price strip for the period from August 1, 2002 to July 31, 2003, based on closing prices at July 17, 2002, without incorporating revised hedging impacts, was $4.526/Gj compared to the $4.832/Gj contained in the June 14, 2002 application. Nova Tolls remained unchanged from the June 14 application, while the AECO/Empress differentials for the months of August to October 2002 were changed from $0.1400/Gj to $0.1450/Gj to reflect revised actual and forecast unit prices.

Additionally, Centra revised the gas costs from those reported in the initial application as a result of hedging transactions based on the updated price strips.

The impact of the transactions shown above was estimated to be $0.01580 per Gj.

In addition to the above transactions, Centra placed hedges for 7,080,000 Gj for the months of May, June and July, 2002 on July 17, 2002.

Using the 100% inclusion rate, and fuel, overhead and storage gas costs would result in a Primary Gas cost embedded in the base sales rate of $0.1842/cubic metre, compared to the original request of $0.1897/cubic metre.

Thus, the applied for August 1, 2002 billed Primary Gas Rate using the updated application, including the PDGR rate rider of $0.0363/ cubic metre, was $0.2158/cubic metre, compared to the June 14 request billed of $0.2213/cubic metre, and $0.2319/cubic metre in current rates.

The following table shows the changes to annual natural gas bills of different customer classes that result when the July 17, 2002 forward price curves were incorporated into the rates. These impacts were based on the existing May 1, 2002 rates for Primary Gas, Supplemental Gas, Transportation and Distribution.

**ANNUALIZED AS BILLED CUSTOMER IMPACTS - REVISED APPLICATION**

| Customer Class | Bill Decreases |
|---|---|
| SGS | -4.0% to –4.3% |
| LGS | -4.1% to –5.1% |
| HVF | -5.0% to –5.5% |
| Mainline | -5.3% to –5.9% |
| Interruptible | -5.6% to –6.0% |

**AN APPLICATION BY CENTRA GAS MANITOBA INC. FOR AN INTERIM ORDER APPROVING PRIMARY GAS SALES RATES TO BE EFFECTIVE FOR ALL GAS CONSUMED ON AND AFTER NOVEMBER 1, 2002 Order No 188/02 – November 5, 2002**

On September 20, 2002, Centra applied to the Board for approval of the continuation of the approved interim Primary Gas sales rates to be effective November 1, 2002 and to remain in effect until a further Order of the Board.

Because the September 30, 2002 application did not request any rate increase, the Board required Centra to up-date the application on October 15, 2002 instead of 10 days prior to the effective date of the rate change, as required by the RSM. The Board took this action in order to inform the public in advance of the implementation of new rates, if prevailing market circumstances at that time dictated that rate changes were necessary.

Centra filed an updated forward price strip with the Board on October 15, 2002 with supporting documentation and a Schedule of Rates to reflect the updates. The price strip for the period from November 1, 2002 to October 31, 2003, based on closing prices at October 10, 2002, without incorporating revised hedging impacts, was $5.330/Gj compared to the$5.029/Gj contained in the September 20, 2002 application. Nova Tolls remained unchanged, while the AECO/Empress differentials for the months of August to October 2002 changed to $0.1600/Gj for November, 2002, $0.1700 from December, 2002 to April, 2003 and to $0.1863/Gj, reflecting revised actual and forecast unit prices.

Centra revised the gas costs from those reported in the initial application as a result of hedging transactions based on the updated price strips. Centra estimated the impact of the above transactions to be a decrease of ($0.1050/Gj).

Using the 100% inclusion rate, and fuel, overhead and storage gas costs would result in a Primary Gas base rate of $0.1939 per cubic metre, compared to the $0.1865 per cubic metre included in the September filing and the $0.1842 in the existing base rate.

Thus, the applied for November 1, 2002 billed Primary Gas Rate using the updated application was $0.2239 per cubic metre, compared to $0.2165 included in the September application and $0.2158 per cubic metre in current rates.

The following table details the changes to annual natural gas bills of different customer classes that result when the October 10, 2002 forward price curves were incorporated into the rates. These impacts were based on the existing August 1, 2002 rates for Primary Gas, Supplemental Gas, Transportation and Distribution.

**ANNUALIZED AS BILLED CUSTOMER IMPACTS - REVISED APPLICATION**

| Customer Class | Bill Increases |
|---|---|
| SGS | 2.1% to 2.3% |
| LGS | 2.2% to 2.8% |
| HVF | 2.7% to 3.0% |
| Mainline | 2.9% to 3.2% |
| Interruptible | 3.1% to 3.3% |

After analysis by the Board and with input from the interested parties, the Board approved the Application for revised rates.

The Board noted that some of the presentations dealt with matters previously considered by the Board in the RSM review process and commented on above and to assist them further provided the following:

1. The price that Centra pays for natural gas is in accordance with the pricing mechanisms contained in its long-term supply contract, which was extensively reviewed by the Board in 2000. The basis of the price is the daily published index price at AECO – C NIT, in Alberta. Additionally gas costs can and usually are impacted by Centra's price hedging activities that are also reviewed by the Board.

2. Natural gas prices are determined in a competitive marketplace over which Centra has no control. Centra makes no profit on the commodity cost of gas but because of market characteristics is required to reflect such changes in its rates. In this regard the following table reflects historic market fluctuations including all November 1, 2002 rate changes:

| Date | Commodity Cost | Average annual bill | % change in bill |
|---|---|---|---|
| December, 1999 | $3.003/Gj | $ 856 | Base |
| August 1, 2000 | $5.187/Gj | $ 993 | 16.1% |
| November 1, 2000 | $5.894/Gj | $ 1,123 | 12.6 % |

| | | | |
|---|---|---|---|
| February 1, 2001 | $9.251/Gj | $ 1,381 | 23.0% |
| August 1, 2001 | $4.614/Gj | $ 1,233 | (10.7 %) |
| November 1, 2001 | $4.168/Gj | $ 1,147 | (6.9 %) |
| February 1, 2002 | $ 4.028/Gj | $ 1,124 | (2.0 %) |
| May 1, 2002 | $ 5.094/Gj | $ 1,237 | 10.0% |
| August 1, 2002 | $ 4.759/Gj | $ 1,146 | (7.4 %) |
| November 1, 2002 | $ 5.024/Gj | $ 1,171 | 2.2% |

**A FILING BY MANITOBA HYDRO REGARDING INTEGRATION ACTIVITIES AS A RESULT OF THE ACQUISITION OF CENTRA GAS MANITOBA INC. AND RESPONSES TO THE DIRECTIVES IN ORDER 146/99**
**Order No. 208/02 – December 6, 2002**

In May 1999, Westcoast Energy Inc. ("WEI") and Manitoba Hydro ("Hydro") executed an agreement for the purchase and sale of all of the issued and outstanding shares of Centra Gas Manitoba Inc. ("Centra") for a price of approximately $245 million ("the Transaction"), subject to certain conditions and adjustments. After a public hearing, the Board issued Order 146/99 dated July 30, 1999, wherein the Board approved the Transaction and commented on several matters. The Board expressed concerns but concluded that, on balance, the Transaction would not unduly impact the continued provision of safe and reliable service, and would not negatively impact competition in either the gas or electric industry. The Board also concluded that while there would be risks, the Transaction, if well managed, should have no significant negative impact on the rates charged to ratepayers of the gas or electric utilities.

The Board stated, that "Approval of the Transaction does not confer any approval for Hydro to functionally integrate or corporately merge Centra's operations into Hydro's operations." Order 146/99 also included a number of specific directives which would require subsequent follow-up by the Board.

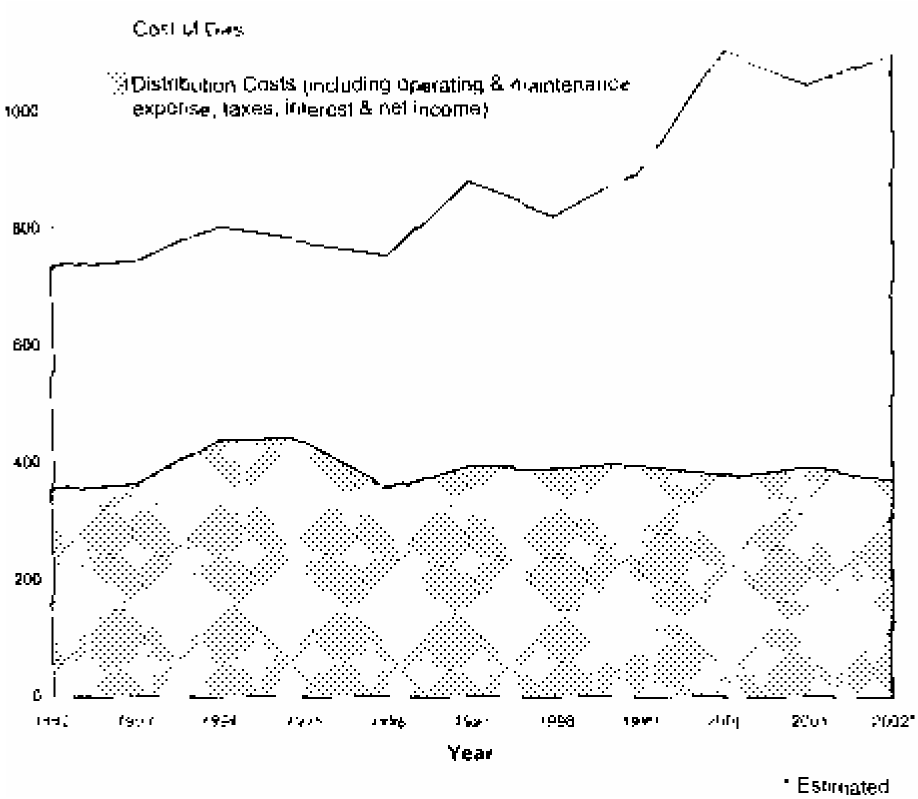
On November 30, 2001, Hydro provided the Board with an update on the Integration of Centra, including information on how costs and synergies are allocated between the electric and gas utilities. The filing also responded to the Board's recommendations and directives from Order 146/99.

In this Order, the Board directed Hydro to account for the Acquisition Transaction and Integration Costs in the books and records of Hydro as opposed to Centra for regulatory purposes. The Board also directed Hydro to file a revised listing of Acquisition Costs, Integration Costs and Integration Savings, as well as a revised Impact Analysis of the Transaction and Integration on consolidated Net Income and Rates based on specific directions contained in this Order. These matters will be reviewed as part of the Centra General Rate Application, based on a 2003/04 future test year.

The Board directed Centra to apply the full amount currently included in sales rates for income taxes of approximately $11 million each year to fully extinguish the one-time tax related debt and carrying costs as quickly as possible. The amortization period of 30 years for the acquisition and integration related costs was accepted.

In response to a number of concerns expressed by Intervenors, the Board requested Hydro and Centra to establish a more regular schedule for periodic rate reviews for each utility to improve the efficiency, effectiveness and timeliness of the regulatory process. The Board also directed that the time period between GRA's for each utility should not exceed three years, even if no rate changes are requested.

# FIGURE 1




**ANNUAL HEATING COST OF AN AVERAGE RESIDENTIAL CUSTOMER BASE RATES (Annualized Basis) Centra Gas Manitoba Inc.**

Based on usage of 3,201 m$^3$/year

2002 costs are based on November 1, 2002 Primary Gas Costs, 1998 Cost of Service and 2002 Other Gas Costs.

## GLADSTONE, AUSTIN NATURAL GAS CO-OP LTD.

**AN APPLICATION BY THE GLADSTONE, AUSTIN NATURAL GAS CO-OP LTD. FOR INTERIM EX PARTE APPROVAL OF THE CONTINUATION OF EXISTING SALES RATE TO BE CHARGED FOR ALL GAS CONSUMED ON AND AFTER NOVEMBER 1, 2002 - Order No. 189/02 - November 5, 2002**

In Order 166/01, dated October 26, 2001, the Board approved rates for the sale of natural gas by the Gladstone, Austin Natural Gas Co-op Ltd. (" the Co-op") to be effective for all gas consumed on and after November 1, 2001. The approved sales rate included a basic monthly charge of $10.00 per service and a commodity rate of $9.95 per Gigajoule ("Gj"). A weighted average gas commodity purchase price, estimated at $5.25/Gj and an average delivered commodity price, estimated at $6.60/Gj were embedded in the overall sales rate.

On October 24, 2002 Campbell Ryder Engineering Ltd. ("Campbell Ryder"), on behalf of the Co-op, provided a forecast gas cost for a 12-month period from November 1, 2002 to October 31, 2003 and Purchase Gas Variance Account ("PGVA") balances for October 31, 2002 and October 31, 2003. The forecasts were based on a new gas supply arrangement for that period of time with a new supplier, PremStar Energy Canada Ltd. ("PremStar").

The PremStar arrangement consists of a variable price contract, determined as the daily index price at AECO-C NIT as reported in the Canadian Gas Price Reporter, plus $0.10/Gj. The PremStar arrangement allows the Co-op to lock in at a fixed price at the beginning of any month and that price would then apply for the balance of the contract period.

The forecast for the 2002/03 average commodity cost of gas was $5.388/Gj, with a delivered city gate price of $6.863/Gj. Additionally, the October 31, 2002 PGVA balance was estimated to be approximately $20,000 owing to customers. The PGVA balance that would accumulate during the 2002/03 supply period was expected to be approximately $19,800 owing to the Co-op. Thus, if existing sales rates continue, the net PGVA balance at October 31, 2003 would be near zero. The Co-op was therefore requesting that there be no change in sales rates and that existing rates be extended until a further order of the Board.

The Board was of the view that the new supply arrangement, and attendant pricing structure with PremStar, was reasonable.

The Board noted that if rates were established to reflect the forecast average gas costs for 2002/03, the increase in the delivered commodity cost would have been approximately 4%. The Board also noted that the PGVA balance at October 31, 2002 was estimated to be in excess of $20,000. The Board is of the view that imposing a rate increase when the PGVA balance was in favour of the customer was neither fair nor practical. The Board accepted the recommendation of the Co-op to extend the existing sales rates.

The Board expected the Co-op to determine when and if it would be appropriate to implement the fixed supply price, as allowed in the supply arrangements and to assess the resultant impact on rates of such an action.

## SWAN VALLEY GAS CORPORATION

Swan Valley Gas Corporation is a wholly owned Local Distribution Company of SaskEnergy. SaskEnergy is a Saskatchewan Crown Corporation.

Swan Valley Gas provides gas service commencing at a metering station just inside the Manitoba border and serves the three communities of Benito, Swan River, and Minitonas, in addition to the industrial customer Louisiana Pacific Canada Ltd. To transport the natural gas from the TransGas system at Norquay, Saskatchewan to the Swan Valley Gas system in Manitoba, a 37 kilometre transmission pipeline was constructed. A wholly owned subsidiary of SaskEnergy that provides inter-provincial transportation, Many Islands Pipeline, the owner of this pipeline is regulated by the National Energy Board.

The project was funded in part by the five local governments and the Federal and Provincial Government.

The Board in Order 161/00 dated December 15, 2000 granted approval of Authority to Operate to the Corporation.

The Board allowed the Corporation to establish a Purchase Gas Variance Account which accumulates differences between the sales rates and the price paid by the Corporation for gas.

No applications to the Board were made by Swan Valley Gas Corporation in 2002.

## DIRECT PURCHASE OF NATURAL GAS

As of December 31, 2002 and for the natural gas year November 1, 2002 to October 31, 2003 the Board registered 17 companies for the brokerage of natural gas supplies to Manitobans.

The Board continued to monitor and supervise this direct purchase market. A number of enquiries were handled through-out the year.

Centra Gas Manitoba Inc. reported that, during the calendar year 2002, 6473 direct purchase arrangements were submitted by Brokers. 2481 customers were conversions from Buy/Sell and 3,992 were new WTS customers. A total of 16,002 (Buy/Sell and WTS) accounts were terminated. 845 applications were rejected because of inadequate information or because the customer was already under a direct purchase arrangement. As of January 1, 2003 natural gas was flowing for approximately 40,118 accounts under direct purchase. 32,524 were WTS (ABC and non-ABC) customers and 7,594 were buy/sell customers.

Customers who receive marketing information from Brokers offering a fixed price contract continue to contact the office. Staff generally advise customers about the rules applicable to Brokers and the markets for gas without commenting on the merits of the offer.

Staff handled about 600 enquires from customers about gas broker activity. These enquiries dealt with door to door sales activity; adequacy of disclosure of information at the door, high pressure sales tactics, difficulty in contacting the Company. With the recent fall in natural gas prices a significant number of customers who signed a contract with a broker have been inquiring about terminating their contract with the Broker.

### Customer Disputes

Pursuant to the Code of Conduct governing a Broker's conduct in Manitoba, a customer who is not satisfied with a Broker's attempts to resolve a dispute can refer the matter to the Board for resolution.

Thirty-five such disputes were referred to the Board and hearings to consider whether the Code of Conduct was breached were held by the Board. In reviewing the Orders, the Board found in twelve applications that the Code of Conduct was breached.

# PROPANE GAS DISTRIBUTION

## STITTCO UTILITIES MAN LTD.

Stittco Utilities Man Ltd. (Stittco) provides propane by pipeline in the communities of Thompson, Snow Lake and Flin Flon. The pipeline activities are regulated by the Board with respect to rates under *The Public Utilities Board Act* and with respect to safety under *The Gas Pipe Line Act*. The following number of customers are served in each community:

| | Domestic | Commercial |
|---|---|---|
| Thompson | 920 | 133 |
| Flin Flon | 1 | 27 |
| Snow Lake | 0 | 12 |

An affiliate of Stittco provides propane in bulk through non-pipeline facilities which is not regulated by the Board.

The Board issued two (2) Orders in 2002, one (1) approving a change in rates for Stittco as a result of a change in market prices.

In Order No. 28/02 dated February 11, 2002, the Board approved an application for a decrease in rates to reflect declining commodity prices in the marketplace. Stittco proposed to remove a rate rider in the amount of $49.20 per cubic metre (liquid) or $0.186 per cubic metre (vapour). Stittco advised the Board that propane prices continued to decline since July 2001 when the rate rider was reduced to $49.20.

On July 31, 2002 Stittco filed a General Rate Application with the Board for revised rates effective September 1, 2002. This Application dealt with all aspects of the Company's operations including such matters as rate base, rate of return and operating expenses. These issues were last reviewed by the Board in 1998. This Application was seeking a reduction in rates.

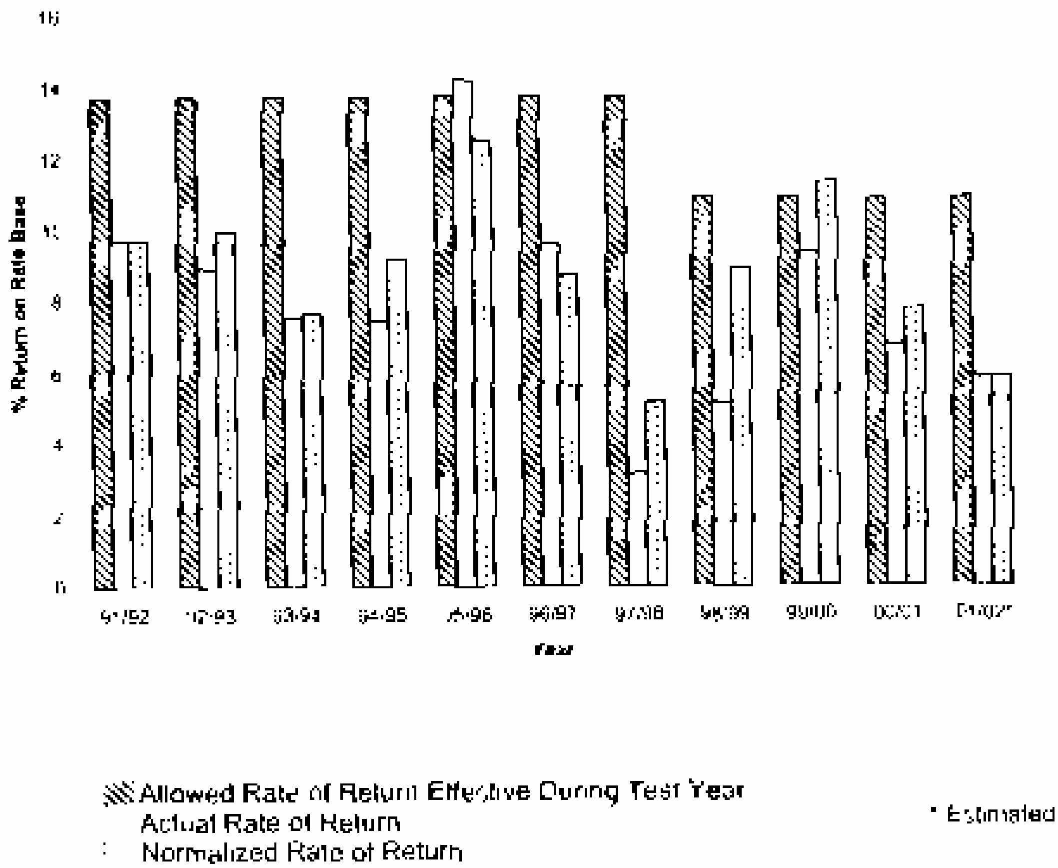
In the interest of minimizing regulatory costs the Board dealt with this Application following an adopted Least Cost Regulation model. Notice of the Application was provided to customers and no submissions were received.

Stittco submitted evidence to support a $12.75% return on equity based on an actual capital structure of 100% equity. In doing so, it noted on a projected basis the Company is expected to earn a return of 5.87% and 10.83% in 2001/02 and 2002/03 respectively. The Board found this to be reasonable under the circumstances.

The Board reviewed Stittco's new propane supply contract obtained on a tendered basis and found the results to be acceptable.

The Board, in Order No. 172/02, approved the Application of Stittco for lower rates noting that, on average, the proposed rates will be 10.6% lower than existing rates.

## FIGURE 2




## OVERALL RATE OF RETURN ON RATE BASE

### Stittco Utilities Man. Ltd.

NOTE: Overall rate of return is the return earned or allowed to be earned by a utility calculated as a percentage of its Rate Base i.e., investment in property, plant and equipment

NOTE: Normalized rate of return is that earned by the Company assuming normal weather.

## SERVICE DISCONNECTION AND RECONNECTION

Section 104(1) of The Public Utilities Board Act prohibits the disconnection of a residential gas customer's service for non-payment of arrears during the period October 1st to May 14th. The Board in Order No. 107/94 established the rules and procedures for the notice, monitoring and reporting responsibilities of the utility. As there is no requirement for service to be reconnected in the winter months and given the associated risks because of a lack of heat, the Board rigorously monitors the process and extensively liaise with the utility with regards to those customers who remain without gas service past September 30th.

Total disconnections (see Table) for the period May 14th to September 30th, 2002 showed an upward trend contrary to the steady declines over the past three years. This occurred in spite of the fact that the utility increased the dollar value of arrears at which disconnections would occur and did in fact not initiate disconnections promptly on May 14th. The growing number of customers with outstanding arrears is largely a result of the steep increases in gas prices starting in the fall of 2000. It is also due in some instances to customers entering into fixed price agreements with Brokers when gas prices were at their peak. This increase of accounts with arrears has occurred inspite of the fact that the Board attempted to mitigate the effects by passing on the rate increase over 24 months and Centra Gas extending its budget payments over 15 months instead of the usual 11 months. At this time accounts with arrears over 90 days are estimated to be about $5.2M, $4.3M of which is residential.

While a detailed analysis of the socio-economic status of each disconnected customer has not been done, anecdotal evidence indicates that many of the customers disconnected are single parents and the elderly, generally on fixed incomes. Unlike previous years, lack of employment did not appear to be an issue, but individuals in the process of changing jobs and or awaiting benefits from unemployment insurance or workers compensation were obviously affected.

During the period May 14th to September 30th customers about to be disconnected or who have been disconnected frequently contact the Board with inquiries as to their rights or for assistance in resolving disputes that they may have with the utility. In the period of review, no Board hearings were necessary.

The utility is required to file frequent reports on the number of customers disconnected as well as details as to the contact with the customer as well as information on the occupants - children, elderly, sick. These reports were duly submitted and audited by the Board.

Disconnected premises determined by the utility to be vacant based on the information collected over the summer requires contacts with the neighbours, real estate agents (if the building is listed), mortgage holder and owner. This category poses the greatest risk as an individual, not understanding the risk involved, could easily come to harm as the weather gets colder if the building is occupied.

The utility's report of September 27, 2002 indicated a total of 126 premises vacant. The utility's report was well done in that there was contact with the owners of the premises in most cases. These premises are largely located in the core of the City and often include rental properties. It is suggested that the utility enhance the relationship with the City to improve its information on these premises.

As of December 13, 2002, 62 premises remain in the vacant category.

The Board's Rules require that the utility maintain certain information on its file about each disconnected customer. Face to face contact with the customer is required in order to obtain this information. Some customers deliberately avoid face to face contact with the utility.

The utility initially submitted a list with a total of 99 such customers. The files were later reduced to 59 and were reviewed to evaluate the attempts on the part of the utility to contact these customers and the nature of the information on the customer's file.

The Board sent letters to each of those customers identified as intentionally avoiding the utility.

The file of each customer is carefully reviewed to ferret out any information that would indicate if the customer is not capable of understanding the risk they are facing. In two instances the utility enlisted the aid of the Seniors Mobile Geriatric Unit who visited and evaluated the situation at the person's home. The utility also had its staff make multiple visits to these premises to try and establish contact. Many of these individuals eventually resolved the matter with the utility as of December 13, 2002, 34 premises remained in this category.

The remaining disconnected files represent those disconnected customers who continue to occupy the premises and for whom the utility has all of the information on the files as required by the Board. The utility generally maintains contact with these customers. On September 27, 2002 there were 1,725 files in this category. As of December 13, 2002 there were 316 homes in this category. (This includes the 34 in the above category.)

In general the customers in this category are single parents, elderly individuals, those in between jobs and those awaiting payments from injury or unemployment insurance.

The work that was done on the files by the utility this year was exceedingly good. The utility contacted customers regularly by telephone. The utility also for the first time made site visits to those customers which they felt were at the greatest risk. A total of 67 premises were visited. In some cases the utility was able to make payment arrangements at the site and the customer's service was later reconnected. The utility indicated that in most cases customers were pleased to be visited by the utility. This new approach is a welcome one and provides significant reassurances to all that all efforts to identify individuals at risk have been undertaken. The utility makes use of the Mobile Geriatric Unit, the Child and Family Services and the Social Services Department where assistance is needed.

**STITTCO UTILITIES MAN LTD.**

Ten customers were disconnected in 2002. The Board did not receive any complaints from the customers of Stittco.

## GLADSTONE, AUSTIN NATURAL GAS CO-OP

Three customers were disconnected, of which two were residential, one being vacant and the other has electric heat. These two remain disconnected. The third account is commercial and has been reconnected. The Board did not receive any complaints from the customers of **Centra Gas Manitoba Inc.** Gladstone Austin Natural Gas Co-op Ltd.

## SWAN VALLEY GAS CORPORATION

No customers are disconnected. The Board did not receive any complaints from the customers of Swan Valley Gas Corporation.

## Residential

| | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 |
|---|---|---|---|---|---|---|---|---|---|---|
| Total Customers Disconnected | 3875 | 3346 | 3284 | 3924 | 3151 | 3650 | 4151 | 3177 | 2765 | 3389 |
| Total Customers Reconnected | 3800 | 3277 | 3158 | 3842 | 3065 | 3557 | 3922 | 2851 | 2418 | 3011 |
| Vacant, Alternative Heat, etc. and Disconnected | 75 | 69 | 126 | 82 | 86 | 93 | 229 | 326 | 347 | 387 |

**Residential - Currently occupied with no gas service - 316 homes**

**Commercial**

| | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 |
|---|---|---|---|---|---|---|---|---|---|---|
| Disconnected | 548 | 458 | 512 | 457 | 459 | 443 | 372 | 306 | 421 | 305 |
| Reconnected | 501 | 430 | 487 | 439 | 448 | 418 | 212 | 257 | 333 | 250 |
| Vacant, Alternative Heat, etc. and Disconnected | 47 | 28 | 25 | 18 | 11 | 25 | 160 | 49 | 88 | 55 |

# THE GAS PIPE LINE ACT

*The Gas Pipe Line Act* (the Act), administered by the Board, governs the public safety aspects of the distribution of natural gas by Centra Gas Manitoba Inc., Gladstone, Austin Natural Gas Co-op and Swan Valley Gas Corporation, of propane by Stittco Utilities Man Ltd. in Thompson, Snow Lake and Flin Flon, and of propane by Manitoba Housing Authority in Churchill.

The Board reviews pipeline owners adherence to safety standards as adopted by the Board and/or by Regulations to the Act. The Board approves plans of proposed construction and monitors compliance using audit procedures.

The Board is also involved in the investigation of pipeline damages, explosions and/or fires. Such investigations may lead to recommendations related to the utilities' practices or procedures and also, to recommendations for other agencies and stakeholders in order to prevent similar incidents in the future.

In 2002, there were 135 reported incidents of pipeline damage, of which 114 resulted in "blowing" gas. The major causes of such occurrences were related to third party excavations for which clearance was not sought from the utility. Others were caused by excavators not following safe excavation procedures and by improper line location provided by the utility. Parties continue to meet with excavators to make them aware of the Regulations.

The Board is represented on the Canadian Standards Association (CSA) Steering Committee, Technical Committee and Gas Advisory Council on Oil and Gas Pipeline Systems.

## MANITOBA HYDRO

Manitoba Hydro rates are approved by the Board under *The Crown Corporations and Public Review and Accountability Act, The Manitoba Hydro Act* and *The Public Utilities Board Act.*

On November 30, 2001 Manitoba Hydro filed a status update with the Board including its financial results, forecasts, methodologies and processes and events that have transformed the electricity industry over the last few years. Hydro was not seeking any general rate changes, stating that for 2002/03, rates will have effectively been frozen for six years for residential customers and for eleven years for large industrial customers, except for the rate reductions to certain residential consumers as a result of province-wide implementation of Uniform Rates on November 1, 2001.

Hydro last requested a general rate increase in the fall of 1995, followed by a public hearing in early 1996. In light of the long passage of time since Hydro's sales rates were last reviewed in a public forum, the Board decided that one of the purposes of this hearing would be to determine whether the existing sales rates continue to be just and reasonable and whether any changes to existing sales rates may be required.

The public hearing to review Manitoba Hydro's submission adjourned on June 11, 2002 and reconvened on September 16, 2002 to deal with Cost of Service aspects of the hearing. This portion concluded on September 30, 2002. The decision of the Board is pending.

**Curtailable Services Program**

Manitoba Hydro offers to its large customers service under the Curtailable Services Program (CSP) that in exchange for a rate discount Manitoba Hydro reserves the right to curtail these customers in times of need to serve firm loads. Such an arrangement is an alternative to constructing reserve or peaking facilities and has become an important part of demand side management strategies of many utilities in North America. The ability to curtail service to large customers on short notice provides Manitoba Hydro with the added flexibility to respond to emergencies and to improve its ability to market short-term firm power to other markets. Pursuant to this service offering Manitoba Hydro submitted monthly reference discounts to the Board for approval.

**Surplus Energy Program**

On October 25, 1999 Manitoba Hydro applied to the Board for the establishment of the Surplus Energy Program (SEP) to supersede the Industrial Surplus Energy, Dual Fuel Heating and Surplus Energy Services to Self-Generators programs. The SEP is designed to allow eligible customers to have access to surplus energy on terms relatively similar to those available to export customers. SEP reasonably addresses the key rate design issues of fairness and cost recovery.

Throughout 2002, the Board issued interim ex parte Orders approving weekly spot market rates pursuant to the Surplus Energy Program.

On December 2, 2002 Manitoba Hydro applied to the Board to increase certain rates applying in communities served by diesel generation effective April 1, 2003. Manitoba Hydro applied to increase the rates applying to consumption in the tail block for General Service and Residential customers (full cost rate) and to all consumption by Government customers. The communities affected included Brochet, Lac Brochet, Shamattawa and Tadoule Lake.

This matter is scheduled to be heard in 2003.

# MANITOBA PUBLIC INSURANCE

The Manitoba Public Insurance Corporation ("MPI") filed an application with The Public Utilities Board ("the Board") on June 11, 2002 for approval of premiums to be charged for compulsory driver and vehicle insurance ("Basic insurance") for the insurance year commencing March 1, 2003 and ending February 29, 2004 ("fiscal 2004"). MPI did not request any change in overall vehicle and driver premium revenue. As well, MPI did not request any change in service and transaction fees or permit and certificate fees. Premium revenues will be greater because of the application of the vehicle upgrade factor projected to be 4.5% for 2003 and 3.5% for 2004, and an estimated 1% annual increase in the size of the vehicle population for the next several years. The Board found these factors to be reasonable at this time.

MPI's claims forecasting methodology had not changed in any material way from that used the prior year. In its Financial Forecast approach, the cost of claims incurred for fiscal 2003 was forecast to be $446.1 million, with these costs projected to increase by $22.2 million to $468.3 million in fiscal 2004. Collision and comprehensive claims were expected to increase by approximately $20 million due to the following factors:

- An increase in the number of claims due to a larger fleet;
- An increase in the cost of repair parts; and
- An increase in the average value of vehicle write-offs.

There were no significant changes anticipated for Personal Injury Protection Plan ("PIPP") accident benefits and weekly indemnity payments. Increased claims expenses, commissions and premium taxes were reflected in the anticipated increase in claims incurred costs. The Board found these, as well as MPI's operating expenses, to be reasonable.

MPI forecasted a net operating income of $10.2 million for fiscal 2003 and $9.8 million for fiscal 2004. The Board was of the view that "break-even" does not have to mean projected costs should be equal to projected revenues each and every year. Such an interpretation, in the Board's view, could lead to rate instability. However, the Board agreed with certain Intervenors that a projected net operating income of $9.8 million, together with a Rate Stabilization Reserve ("RSR") in excess of the range set by the Board, stretches the bounds of what might be considered "break-even". The Board does recognize, however, that uncertainty in the current investment markets could negatively impact MPI's investment income in 2004. Considering all of these factors, the Board ordered MPI to refile its rate schedules so as to reflect a decrease of 1% in overall vehicle premium revenue in fiscal 2004.

With the 1% premium revenue reduction contained in the Board's Order, the Board noted that the impact to the vehicle premium revenue may be less than shown below, but the impact to each Major Use classification may not necessarily be an identical 1% reduction.

| | |
|---|---|
| Private passenger Vehicles | 0.0% |

| | |
|---|---|
| Commercial | +3.6% |
| Public | +3.7% |
| Motorcycle | +15.0% |
| Trailers | -9.8% |
| Off-road vehicles | -8.7% |
| **Overall Premium Revenue Change** | **-0.0%** |

Experience based adjustments vary by vehicle within a range from –15% to +15%, taking into account claims history based upon insurance use, territory in which the vehicle is used, and type of vehicle. Those vehicle premiums do not cover the expected full cost of insurance benefits and coverage for those vehicles whose owners are facing experience adjustments. Some have their adjustments capped at 15%. The Board approved all experience based adjustments as applied for by MPI.

Another component affecting the requested premium changes is the continued implementation of the Canadian Loss Experience Automobile Rating System ("CLEAR") for passenger vehicles and light trucks, with only minor modifications from last year. The Corporation proposed a multi-year phase-in of CLEAR, on a revenue neutral basis. The impact of rate group changes, rate line differentials and offset adjustments to ensure revenue neutrality results in annual premium decreases for 46% of all vehicles, most receiving decreases of $50 or less, 1% remaining unchanged, and 53% having premium increases of $50 or less. The Board approved the CLEAR rate group premium changes.

The Board reaffirmed that the appropriate RSR target range for rate setting purposes is between $50 and $80 million. MPI's Board of Directors instituted a new policy, effective March 1, 2002 that established the upper limit for retained earnings in MPI's Special Risk Extension ("SRE") Division at $33 million until fiscal 2005. Funds in excess of that amount are to be transferred to the Basic RSR in accordance with MPI's policy. The transfer for fiscal 2003 was $14.5 million, with an estimated annual transfer thereafter of $3.0 million until fiscal 2005. The Board agreed with MPI's position that the funds should be considered a transfer, and not net income to the Basic program. After these transfers, the RSR was forecast to be $75.7 million at February 28, 2003, and projected to be $88.5 million at February 29, 2004.

MPI continued its attempts to control the costs of automobile repairs through the increased use of aftermarket and recycled parts, where suitable without sacrificing safety, and to train its staff in current repair technology. Although savings attributable to the use of aftermarket and recycled parts were $18.5 million in fiscal 2002, and $16.1 million in fiscal 2001, claims costs continue to increase. MPI initiatives to control bodily injury costs remain unchanged from last year. The Board encouraged MPI to continue and expand, if possible, efforts to control the costs of property damage and bodily injury claims.

MPI continues with its educational programs targeted to increasing the use of occupant restraints, reducing impaired driving and unsafe speed incidents, and promoting the high school Driver's Education program. MPI filed an independent report ("the Manifest Report") that evaluated MPI's road safety initiatives. Since the report was not filed until September 30, 2002, just prior to the hearing, the Board instructed MPI to prepare and file a report with the Board including MPI's response to the Manifest Report and MPI's future plans in respect of road safety programs at the next GRA.

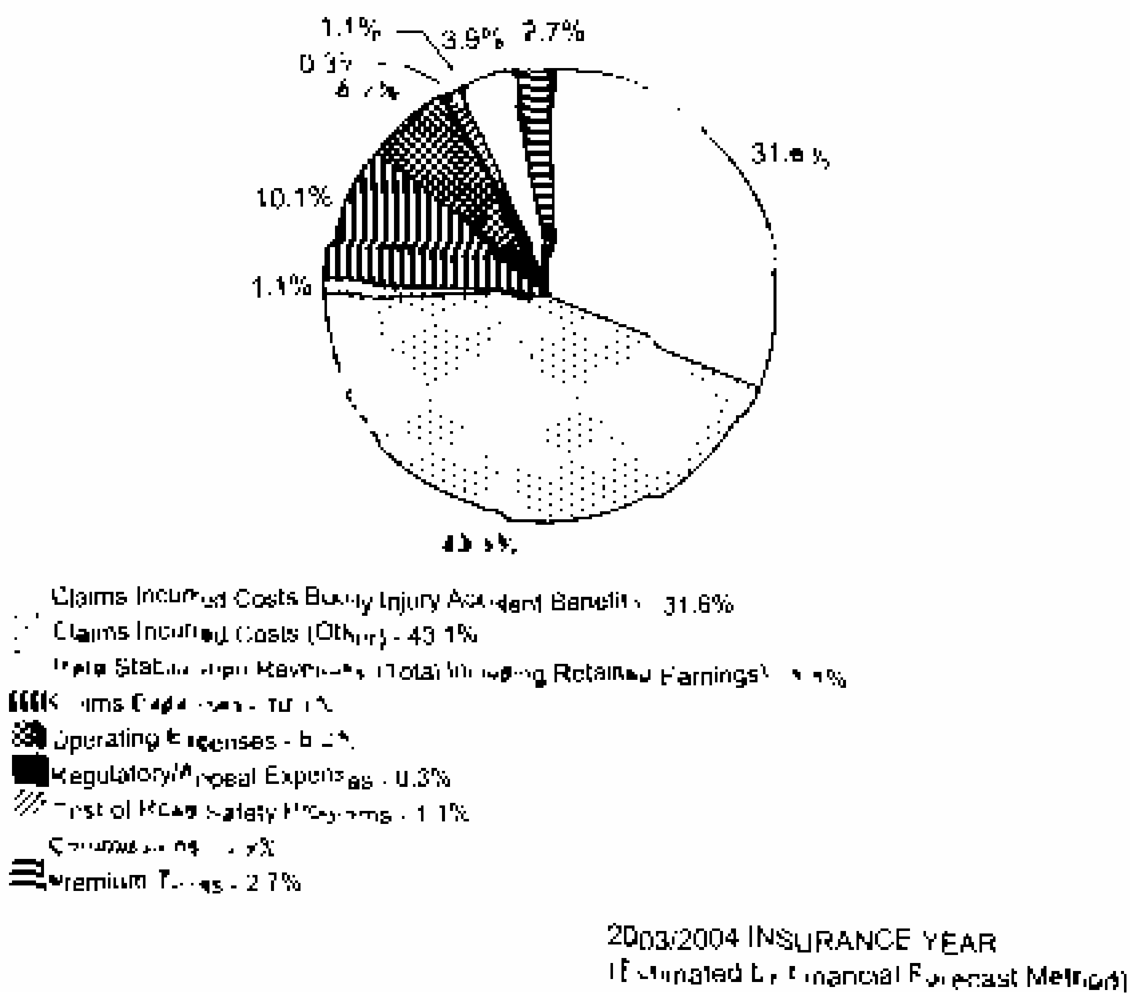
The Board had serious concerns about the rising claims costs associated with auto thefts, noting that claims costs for fiscal 2002 were $24.9 million and that since 1996, $145 million has been reported in such claims. The Board recognizes MPI alone cannot address this problem and that enforcement agencies must also play a critical role in dealing with this societal problem. The Board recommended that MPI inform other agencies of the Board's concerns. The Board encouraged MPI to work with other stakeholders to ensure a greater and more coordinated effort in achieving improvements in addressing this problem.

The Board noted that, as in past years, the loss experience of the motorcycle class indicates the required premium increase should be over 36%, but the requested increase had been capped by MPI at 15%. The Board further noted that unless driving attitudes change, claims costs will likely continue to increase. The Board recognizes that almost four years have elapsed since the Board first considered the use of a loss transfer model to determine premium rates. Circumstances such as the fleet mix of vehicles and the loss experience for the Major Use classifications may have changed, thus rendering MPI's current method worthy of review. The Board will require MPI to review the loss transfer model and to report its recommendations in this regard at the next GRA.

In response to concerns raised by the Manitoba Car and Truck Rental Association respecting MPI's Fleet Rebate Program, the Board accepted MPI's offer and directed MPI to co-ordinate meetings with all parties having an interest in this issue, and to report the results of those meetings to the Board at the next GRA.

## FIGURE 3

## DISTRIBUTION OF NET REVENUES

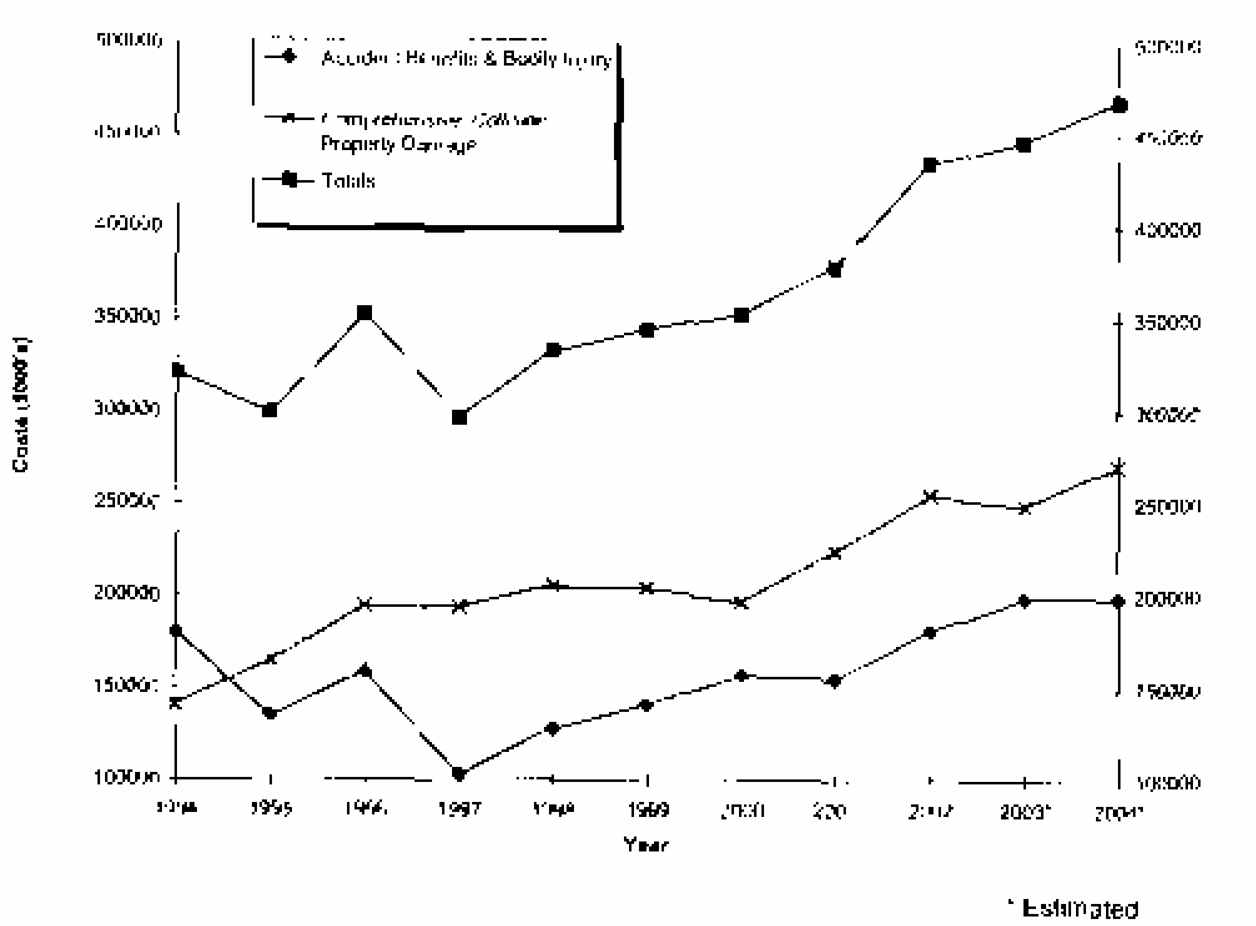



## BASIC DIVISION

## Manitoba Public Insurance

Driver's Premiums, Motor Vehicle Premiums, Investment Income less reinsurance ceded

# FIGURE 4

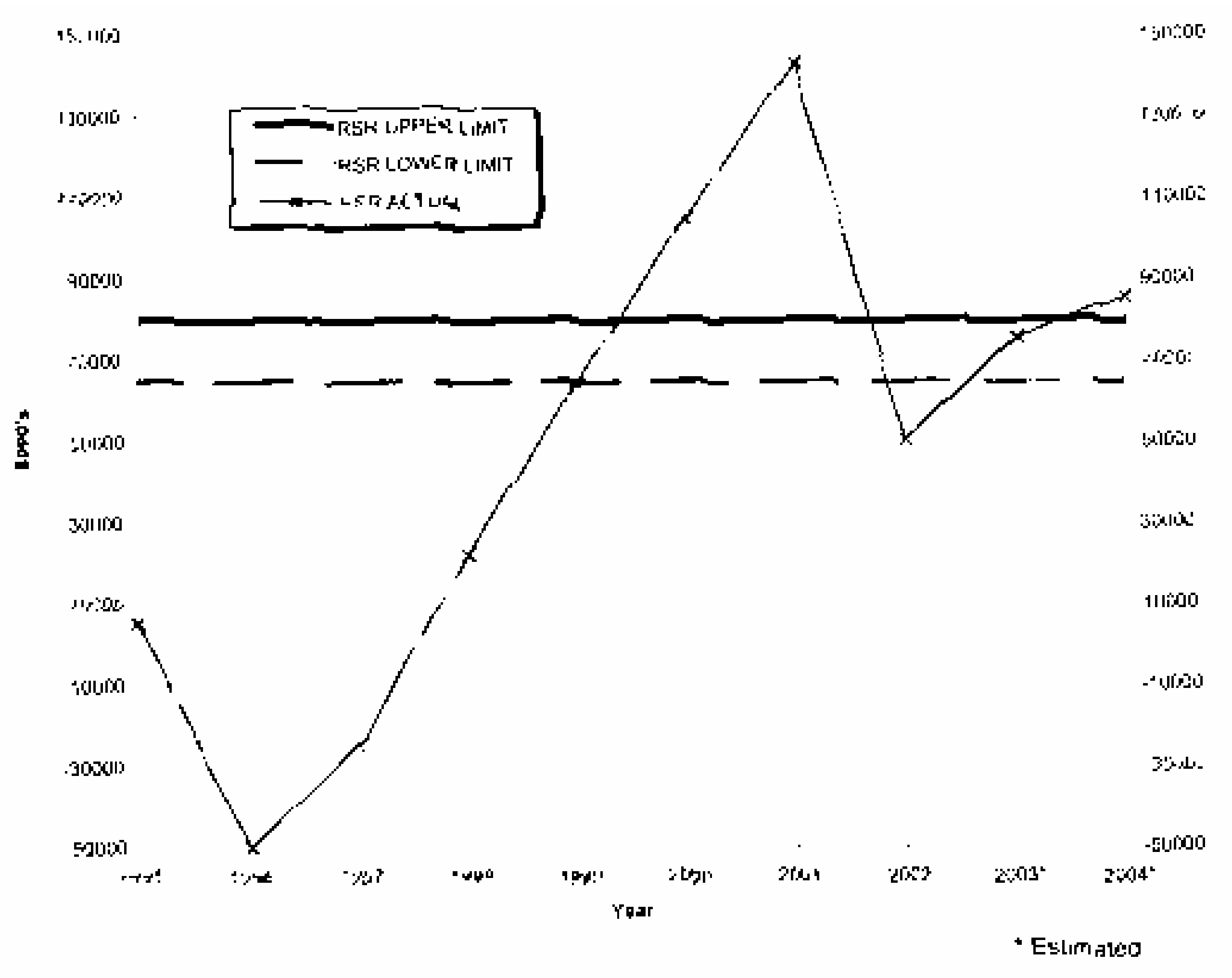



**MANITOBA PUBLIC INSURANCE**
**CLAIMS INCURRED COSTS**

**BASIC DIVISION**

**Insurance Year Ending Feb. 28**

**FIGURE 5**




## MANITOBA PUBLIC INSURANCE
## BASIC RATE STABILIZATION RESERVE

Upper RSR limit of $80,000 and Lower RSR limit of $65,000 as approved by PUB

### Insurance Year Ending Feb. 28

# THE MUNICIPAL ACT

## WATER AND SEWER UTILITIES

The Board issued a total of 75 Orders respecting applications filed with the Board by local municipal authorities, as set out below:

(i) 53 Orders were issued respecting applications for approval and authorization for methods of recovery pertaining to operating deficits.

(ii) 22 applications for revisions, amendments to or establishment of rates were processed and Orders were issued authorizing same. Board guidelines which have been prepared and distributed to local authorities were applied wherever possible to assist with rate design and to ensure that sufficient revenue would be provided to cover normally anticipated operating expenses plus an adequate contingency allowance. Applications were handled by public hearing or returnable date notice. In all cases the municipalities and affected water and sewer customers were served appropriate notice.

Board staff assisted applicant municipalities and others contemplating changes and seeking guidance in the preparation of their applications thus reducing the cost to the municipalities in preparing a report. Board staff met with municipal representatives to ensure that applications were filed in the form prescribed by the Board, pursuant to statute. In most instances, these applications required the preparation of rate studies, and when necessary, public hearings were held in the applicant municipalities.

## THE HIGHWAYS PROTECTION ACT

Pursuant to Section 21 of The Highways Protection Act the Board is the appeal body to decisions of The Highway Traffic Board respecting applications for permits for the change in use of an access driveway, the relocation of an access driveway, or the construction of an access driveway onto a Limited Access Highway (LAH) and also, the building of structures within the control limits of LAH.

The Board conducted two hearings in 2002. The first appeal was in respect to a change in use of a driveway with access to P.T.H. No. 9. The second appeal was with respect to access and traffic problems on a private landowners property arising from a service road. The Board denied the appeals in both instances.

## THE PREARRANGED FUNERAL SERVICES ACT

Pursuant to The Prearranged Funeral Services Act, the Board is responsible for licensing companies selling prearranged funeral plans and for reviewing the operations of these firms as to conformity with statutory requirements.

In 2002, the Board issued 22 renewal licences and 1 initial licence. Fifteen applications for revisions in fees for services were acknowledged.

The Board continued to review and monitor the annual reports filed by the licensees and their trustees in respect of the prearranged funeral plans being sold and the contracted funds maintained in trust.

## THE CEMETERIES ACT

Pursuant to Part III of The Cemeteries Act, the Board reviews applications and issues licences to the owners of cemeteries, columbariums and mausoleums that are owned and operated for gain and if not owned and operated for gain, where more than 15 sales of plots occur in any year. Cemeteries related to religious denominations or owned by municipalities are not required to be licensed by the Board.

Pursuant to Part II of the Act, the Board approves the plans of and issues licences for the operation of crematories.

During the year the Board issued renewal licences for the operation of 11 cemeteries, 31 columbariums, 5 mausoleums and 13 crematories. 82 licences and 1 transfer licence to sell cemetery services were issued either to owners or to their sales personnel. In addition, 16 applications for revisions in schedules of fees for spaces, materials and services were authorized.

The Board continues to monitor the licensee's compliance for the passing of accounts in respect of perpetual care funds collected and deposited in trust funds with authorized trustees pursuant to The Cemeteries Act.

## FINANCIAL INFORMATION

### REVENUES/EXPENDITURES

The financial affairs of the Board are conducted through the Estimates of the Department of Consumer and Corporate Affairs, which became a Division of the Department of Finance on September 25, 2002. Accordingly, the expenses of the Board are paid out of the Consolidated Fund and then these expenses are recovered from the regulated industries.

For the fiscal year ending March 31, 2002 the Board's expenditures and revenues were as follows:

| | | |
|---|---|---|
| Revenues | | $1,452,331.19 |
| Expenditures | | |
| Rate regulation and safety related costs | $652,656.21 | |
| Salaries and Per Diems | $506,498.89 | |
| | | $1,159,155.10 |
| Difference | | $293,176.09 |

Order No. 38/89 sets out the means by which the Board recovers its expenditures relating to proceedings before the Board. Order No. 2/94 together with Order-in-Council 142/1994 provide for the Board to recover costs including administration and salaries from the major regulated industries including Manitoba Public Insurance, Manitoba Hydro, Centra Gas Manitoba Inc. and Stittco Utilities Man Ltd.

## INTERVENER FUNDING

Pursuant to The Public Utilities Board Act and Order No. 163/87, the Board may award costs to parties making an intervention in matters before the Board. These costs are paid directly by the applicant entity and, therefore, do not form part of the expenditures of the Board. Details of awards in the calendar year 2002 are as follows:

| | Applied for | Granted |
|---|---|---|
| **Manitoba Public Insurance** | | |
| 2002 Insurance Rates | | |
| CAC/MSOS[1] | $ 59,881.45 | $ 59,881.45 |
| CBA[2] | $ 10,117.40 | $ 6,070.44 |
| CMMG[3] | $ 11,808.46 | $ 11,808.46 |
| MCTRA[4] | $ 87,898.50 | 0 |
| **Centra Gas Manitoba Inc.** | | |
| Primary Gas Sales Rates Effective February 1/02 | | |
| CAC/MSOS | $ 4,415.07 | $ 4,415.07 |
| Primary Gas Sales Rate Effective May 1, 2002 | | |
| CAC/MSOS | $ 4,955.11 | $ 4,955.11 |
| 2001/02 GRA and Subsequent Motions to Vary | | |
| CAC/MSOS | $ 28,354.37 | $ 28,354.37 |
| 2002/03 Cost of Gas | | |
| CAC/MSOS | $ 76,226.09 | $ 75,903.60 |
| GANG[5] | $ 1,145.96 | $ 1,145.96 |
| Primary Gas Sales Rates Effective August 1, 2002 | | |
| CAC/MSOS | $ 2,228.76 | $ 2,228.76 |
| Primary Gas Sales Rates Effective November 1, 2002 | | |
| CAC/MSOS | $ 2,644.15 | $ 2,644.15 |
| **Manitoba Hydro** | | |
| Integration Activities as a Result of the Acquisition of Centra | | |
| CAC/MSOS | $307,236.45 | $291,474.61 |
| MIPUG[6] | $ 47,547.86 | $ 47,547.86 |

| | Applied for | Granted |
|---|---|---|
| Status Update Filing | | |

| | | |
|---|---|---|
| MIPUG | $135,546.31 | 0 |
| TREE[7] | $ 48,676.72 | $ 48,676.72 |

[1]Consumers' Association of Canada (Manitoba) Inc./Manitoba Society of Seniors
[2]Canadian Bar Association (Manitoba Branch)
[3]Coalition of Manitoba Motorcycle Groups Inc.
[4]Manitoba Car and Truck Rental Association Inc.
[5]Gladstone Austin Natural Gas Co-op Ltd.
[6]Manitoba Industrial Power Users Group
[7]Time to Respect Earth's Ecosystems Inc.