ROBERT J. PELLATT
COMMISSION SECRETARY
Commission.Secretary@bcuc.com
web site: http://www.bcuc.com

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. CANADA V6Z 2N3
TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

Log No. 1482

VIA FACSIMILE/EMAIL

January 14, 2003

Mr. Geoff Higgins
Manager, Regulatory Affairs
Centra Gas British Columbia Inc.
1675 Douglas Street
P.O. Box 3777
Victoria, B.C. V8W 3V3

Dear Mr. Higgins:

Re: Centra Gas British Columbia Inc.
Approval of 1999 to 2001 Actual Revenue Requirements and Revenue Deficiencies
and 2003 to 2005 Forecast Revenue Requirements

Enclosed is Commission Order No. G-2-03 approving the Negotiated Settlement issued on December 24, 2002 with respect to the above noted Applications.

Yours truly,

Original signed by:

Robert J. Pellatt

cms
Enclosure
cc: Registered Intervenors/Interested Parties
Via Facsimile/Email

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. V6Z 2N3 CANADA
web site: http://www.bcuc.com

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-2-03

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

the Special Direction to the British Columbia Utilities Commission
by the Lieutenant Governor in Council through
Order in Council No. 1510, dated December 13, 1995

and

An Application by Centra Gas British Columbia Inc.
for Approval of 1999 to 2001 Actual Revenue Deficiencies
and 2003 to 2005 Forecast Revenue Requirements

BEFORE:	P. Ostergaard, Chair	)	
	P.G. Bradley, Commissioner	)	January 9, 2003
	K.L. Hall, Commissioner	)	

O R D E R

WHEREAS:

A. On July 31, 2002, Centra Gas British Columbia Inc. (“Centra Gas”) applied, pursuant to Section 23 of the Utilities Commission Act (“the Act”) and the Special Direction (Order in Council 1510, 1995), for approval of its 1999 to 2001 actual revenue deficiencies and its forecast 2003 to 2005 revenue requirements for its Vancouver Island and Sunshine Coast service areas. Centra Gas proposed that the Application be reviewed through a Negotiated Settlement Process; and

B. By Order No. G-76-02 the Commission determined that the Application should proceed to a Negotiated Settlement Process and established a regulatory timetable; and

C. On November 25 and 26, 2002, a Settlement Conference was held in Victoria, B.C. Representatives from the Commission staff, British Columbia Hydro and Power Authority (“B.C. Hydro”), the Vancouver Island Gas Joint Venture (“VIGJV”), the British Columbia Public Interest Advocacy Centre (“BCPIAC”), Calpine Island Cogeneration, the Ministry of Energy and Mines and the Vancouver Island Public Sector Natural Gas Consumers Group (“Public Sector Consumers”) attended, all of whom participated in settlement discussions; and

. . . /2

D. A Negotiated Settlement was reached among the participants and circulated to all Registered Intervenors, Interested Parties and the Commission on December 24, 2002; and

E. The Commission received letters on the Negotiated Settlement from Centra Gas, BCPIAC, B.C. Hydro, the Public Sector Consumers and the VIGJV; and

F. The Commission has reviewed the Negotiated Settlement for Centra Gas' 1999 to 2001 Actual Revenue Deficiencies and the 2003 to 2005 Forecast Revenue Requirements and finds that it should be approved.

NOW THEREFORE the Commission approves for Centra Gas the Negotiated Settlement as issued on December 24, 2002 and attached as Appendix A to this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 14th day of January 2003.

BY ORDER

Original signed by:

Peter Ostergaard
Chair

Attachment

WILLIAM J. GRANT
EXECUTIVE DIRECTOR,
REGULATORY AFFAIRS & PLANNING
bill.grant@bcuc.com
web site: http://www.bcuc.com

BRITISH COLUMBIA UTILITIES COMMISSION

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. CANADA V6Z 2N3
TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

Log No. 1482

~~CONFIDENTIAL~~

VIA FACSIMILE

December 19, 2002

Dear Participants:

Re: Centra Gas British Columbia Inc. ("Centra Gas")
Negotiated Settlement
Approval of 1999 to 2001 Actual Revenue Requirements and Revenue Deficiencies
and 2003 to 2005 Forecast Revenue Requirements

Enclosed is the Negotiated Settlement Agreement on the Centra Gas Application for Approval of 1999 to 2001 Actual Revenue Deficiencies and 2003 to 2005 Forecast Revenue Requirements. Thank you for your edits to the draft Settlement document which have been incorporated in this final Agreement. It was evident from the responses received from some of the participants on December 16, 2002 that further edits were required. Those edits have now been incorporated in this document and are shown in a black-lined version for your reference. Centra Gas has updated the supporting schedules to the Negotiated Settlement Agreement and has included a written explanation.

Please review the Negotiated Settlement Agreement and provide your written correspondence confirming your acceptance of this settlement by Monday, December 23, 2002. On Tuesday, December 24, 2002, the Negotiated Settlement Agreement and letters of comment from the participants will be made public and forwarded to the Commission for its review.

Prior to consideration by the Commission, intervenors who did not participate in the settlement negotiations will be requested to provide to the Commission their comments on the settlement package by January 6, 2003. Thereafter, the Commission will consider the settlement package. A public hearing may not be required unless there is significant opposition to the proposed settlement.

Yours truly,

W.J. Grant

WJG/cms
Attachments
cc: Mr. Geoffrey Higgins
Manager, Regulatory Affairs
Centra Gas British Columbia Inc.

~~**C O N F I D E N T I A L**~~

IN THE MATTER OF the Utilities Commission Act, RSBC 1996, c. 473, Section 23

- and -

IN THE MATTER OF the Special Direction to the British Columbia Utilities Commission issued by the Lieutenant Governor in Council through Order in Council 1510, dated December 13, 1995

- and -

IN THE MATTER OF an Application by Centra Gas British Columbia Inc.
for approval of its 1999, 2000 and 2001 Actual Revenue Requirements and Revenue Deficiencies, and 2003, 2004 and 2005 Forecast Revenue Requirements

NEGOTIATED SETTLEMENT

On July 31, 2002, Centra Gas British Columbia Inc. ("Centra Gas" or the "Company") filed a Revenue Requirements Application (the "Application") with the British Columbia Utilities Commission (the "Commission"). The Application was for approval of Centra Gas' actual revenue requirements and revenue deficiencies for 1999 through 2001, and forecast revenue requirements for the test period 2003 through 2005. The Application was Phase one of a two phase process to establish future test period costs (Phase 1) and an appropriate rate design for customers of Centra Gas, effective January 1, 2003 (Phase 2).

Commission Order No. G-71-02 established a workshop and pre-hearing conference for both the Phase 1 and Phase 2 Applications, which was held in Nanaimo, B.C. on October 22, 2002. The pre-hearing conference provided a forum for review of the Applications, determination of issues to be resolved, establishment of the regulatory agenda and timetable to review the Applications, and determination of whether or not to proceed with a negotiated settlement. At the pre-hearing conference, no party opposed the request by Centra Gas to proceed to a negotiated settlement process.

The Commission issued Order No. G-76-02 establishing a Negotiated Settlement Process, and set out the Regulatory Agenda pertaining to the Application. The timetable for the Applications included Information Requests ("IR's") to be issued by Commission staff and Intervenors by Friday, November 1, and Wednesday November 6, 2002 respectively. Responses from Centra Gas to the IR's were due to the Commission and Intervenors by November 18, 2002. Negotiations were to be held in Victoria commencing on Monday, November 25, 2002 for the Phase 1 Application, and Tuesday, December 3, 2002 for the Phase 2 Application.

The Commission Staff issued IR's pertaining to both the Phase 1 and Phase 2 Applications in writing on November 1, 2002. In addition to these, Centra Gas also received information requests from British Columbia Hydro and Power Authority ("B.C. Hydro") on October 28, 2002 (BCH 1), and November 6, 2002 (BCH 2 and BCH 3), the Vancouver Island Gas Joint Venture ("VIGJV") on November 6, 2002 (JV 1) and November 14, 2002 (JV 2), the Consumers Association of Canada (B.C.) et al ("CAC BC") on October 30, 2002 (PIAC 1) and November 6, 2002 (PIAC 2), the Ministry of Energy & Mines ("MEM") on October 28 (MEM 1), November 5, 2002 (MEM 2) and November 6, 2002 (MEM 3 and MEM 4), OK Industries (OK 1) on October 31, 2002, and Willis Energy Services ("Willis") on behalf of the Vancouver Island

Public Sector Natural Gas Consumers Group (Camosum College, Victoria School District, University of Victoria and the Sooke School District) (Willis 1) on November 6, 2002. Centra Gas responded to BCH 1 on November 1, 2002 and all of the other IR's on November 18, 2002.

A settlement conference was held in Victoria on November 25 and 26, 2002. In attendance were Commission Staff, the VIGJV, CAC BC, B.C. Hydro, MEM, Willis, Camosun College, Victoria School District, Calpine Canada, and Centra Gas, all of whom participated in the settlement discussions.

The following is the negotiated settlement arrived at between Centra Gas and the parties attending the settlement conference as shown on the Negotiated Settlement schedules attached to and forming part of this Agreement. This settlement was achieved with the participation of the Commission Staff.

1. Items At-Risk for Centra

On BCUC IR 1-6.2, Centra interprets the Special Direction as meaning "the BCUC will continue to approve variations (as they have since 1995), in other words 'true-up to actual' between forecast test year cost of service and actual costs (other than O&M) unless reasonable evidence exists to conclude variations not be approved."

The items that will continue to be fixed (and not trued-up) will be gross OM&A, equity component, and rate of return on common equity.

2. Revenue Forecast

The load forecasts in the Application indicate residential energy sales of 4,057,547 GJ for 2003, 4,227,538 GJ for 2004 and 4,405,574 GJ for 2005. Forecast energy sales for commercial customers from 2003 to 2005 are 7,114,422 GJ, 7,196,997 GJ and 7,280,358 GJ respectively.

The underlying assumptions in the forecasts were based on the expected total customer additions of approximately 3,000 each year during the forecast period, resulting in an average use per customer of 59.4 to 59.5 GJ/year for residential customers, and 836.0 to 836.9 GJ/year for the various commercial classes. Centra Gas provided further information to support the assumptions and supporting information that includes the predicted new home attachments, its conversion rate, Centra Gas' current market share and its "on main" potential. Based on the supporting information, it is reasonable to accept that the overall customer additions have stabilized at approximately 3,000 customers per year. The forecast use rates are also acceptable against the historical usage trend.

Variances in revenue as a result of the differences between the actual and forecast sales will flow to the RDDA. The forecast sales volumes will be 'trued-up' to actual.

3. Cost of Gas and Gas Cost Variance Account ("GCVA")

In the period 2003 to 2004, the forward curve of natural gas commodity costs for April 1, 2002 was used and inflation was applied to forecast 2005. Based on the gas contracting plan, hedging programs, and the provincial Royalty credits, Centra Gas' cost of gas is effectively hedged out by October for the following year. The anticipated effect on gas costs for 2002/03 is in the range of +/- one percent as a result of the 2002/03 Price Management program. The April 1, 2002 forward curve is accepted. The differences between actual and forecast gas costs on a royalty adjusted basis will flow to the GCVA.

The establishment of the GCVA is consistent with other gas distribution utilities in the Province and is accepted effective January 1, 2003. The balance of the GCVA will be provided and reviewed with the Company's quarterly reports to the Commission to be used for determining future customer rates. The account will serve to hold and recover/refund the differences between actual and forecast cost of gas of the core market over a shorter timeframe than if the variance flowed directly to the RDDA.

4. <u>Gross OM&A</u>

Gross Operating, Maintenance and Administrative (OM&A) expense is to be reduced from filed amounts of $32,972,352, $34,878,353, and $35,228,397 in 2003, 2004, and 2005 respectively (including the adjustments to fired hours, pension expense, and head office lease costs) to $31,700,000 in 2003, $32,500,000 in 2004, and $32,600,000 in 2005. The above amounts exclude the expense related to stock option grants, pending the outcome of the BC Gas Utility Ltd. hearing into the appropriate treatment of stock options (among other things). If the cost of stock options is accepted as part of the revenue requirements of BC Gas Utility Ltd., the cost of the stock options of Centra Gas will be added back to the above agreed OM&A amounts.

Included in the amounts agreed to above for Gross OM&A are Employee Pension expense and Insurance expense. Employee Pension expense is forecast to be $2,536,911, $2,720,781, and $2,720,541 in 2003, 2004 and 2005 respectively. To the extent actual Pension expenses are different from forecast, the variance will be recorded in a deferral account, to be amortized in the same period as incurred. Insurance costs, as included in the settlement amounts above are $634,713, $646,137, and $659,060 in 2003, 2004 and 2005 respectively. To the extent actual Insurance costs are different from forecast, the variance will be recorded in a deferral account, to be amortized in the same period as incurred.

Pension costs attributable to rate payers is to include pensionable amounts for Executive salaries and short term bonuses, which is consistent with past practice for Centra Gas (BCUC IR 1-1.1 of the 2000-02 revenue requirement application).

With the purchase by BC Gas, Centra Gas will continue to explore synergies. If further cost reduction opportunities are found, these would be reflected in the re-basing of costs in a future revenue requirements application.

Centra Gas receives Customer Information services from Enlogix. Centra Gas agrees to provide a report by June 30, 2003 on the financial assessment of continuing with Enlogix compared to moving to CustomerWorks, or other customer information service providers.

Centra Gas is proposing to purchase Greenhouse Gas Credits of $153,800 per year commencing 2003, and is recording these costs in the Gas Supply department, which is fully allocated to Cost of Gas (BCUC IR 1-4.11). This cost of gas item will not be spent unless legally required.

5. <u>Depreciation and Gannett Fleming Study</u>

On page 8.2 of the Application Centra Gas is proposing a change to the calculation of depreciation expense in accordance with a study by Gannet Fleming in Tab 22B of the Application. The study proposes that annual depreciation expense increase by $89,200 starting in 2003. The proposed changes are acceptable.

6. <u>Plant Additions</u>

The actual plant additions for 1999 to 2001 in transmission, distribution and general plant were reviewed and the explanations of variance were acceptable.

In Tab 8 of the Application Centra Gas characterizes significant additions as expenditures that are about one percent of rate base or $4 million. Centra Gas intends to apply for a Certificate of Public Convenience and Necessity ("CPCN") if a project exceeds one percent of rate base or $4 million; however, the Commission may designate that projects with an expected cost of less than one percent of rate base also require a CPCN. The annual review will consider material changes to the approved capital forecast that Centra Gas or customers believe are important.

System Betterment Expenditures – (Transmission and Distribution)

System Betterment Expenditures		**2003**	**2004**	**2005**
Transmission				
	Compressor Stations	$ 845,000	$ 845,000	$ 820,000
	Regulating Meter Stations	$ 115,000	$ 200,000	$ 90,000
	Pipelines	$1,215,000	$1,165,000	$1,165,000
Distribution				
	Services, Meters & Regs	$ 120,000	$ 120,000	$ 120,000
	Mains	$ 346,000	$ 306,000	$ 306,000
Total		$2,641,000	$2,636,000	$2,501,000

The proposed expenditure levels are accepted for the three years, however Centra Gas remains at risk for the prudency of the costs. The System Betterment Expenditures are forecast to be $2,641,000, $2,636,000 and $2,501,000 for the periods 2003 to 2005 inclusive. The largest expenditures, over $800,000 in each year are described as follows:

- In 2003 the relocation of the high pressure transmission mainline that crosses the Coquitlam Dam requires a $1,000,000 expenditure. A second item, an upgrade to units #1 and #2 at V1 Coquitlam compressors allows for the installation of dry gas seals on the rotating shaft. It is estimated to cost $825,000.

- An expenditure of $1,000,000 in 2004 allows for the lowering of the high-pressure transmission line between Parksville and Nanaimo that crosses the Englishman River. This is a preventative measure to ensure safety and reliability of the pipeline that may be exposed by river erosion.

- In 2005 directional drilling of the Haslam River will require an outlay of $1,000,000. This action will protect the high pressure transmission mainline between Nanaimo and Ladysmith from river erosion. Compressor upgrades account for a further expenditure of $800,000. The Greater Vancouver Regional District emission reduction targets necessitate emission upgrades to units #1 and #2 compressors at the Coquitlam station.

General Plant additions for 2003 to 2005 are about $1.3 million per year as shown on page 10.24, Table 10.7 of the Application and are accepted as filed.

7. Deferred Charges and Amortization

Centra Gas recorded the costs of preliminary survey and investigation costs in non-rate base, interest bearing deferral accounts commencing with a request for service from B.C. Hydro in 1997. The referenced deferral accounts are shown on Schedule 39 of Tab 19 in the Application and include:

T-Service for ICP	$ 423,551
Woodfibre Compressor V2	$ 276,035
Mainland Looping	$ 183,964
Second Marine Crossing	$ 691,956
Port Alberni Looping	$ 479,790 *
Total	$2,055,296

* This is the amount net of B.C. Hydro/ATCO recoveries of $131,589 shown in response to BCH 2-2.7.1, p. 5.

In respect to this total ($2,055,296) Centra Gas will charge $1,568,411 to capital overheads in 2002, and then allocate to Account 465. For rate design purposes, Centra Gas will assign $300,000 as a direct assignment to B.C. Hydro and $1,268,411 to HPTS Transmission Mains Account 465 for allocation to all shippers on the Centra HPTS (including the Centra Distribution System) on the same basis as the revenue requirements for the balance of Account 465. The balance ($486,885) will be written off (net of any income taxes thereon) as a shareholder cost in 2002 and not as adjusted cost of service.

In future, Centra Gas will provide, at no charge, preliminary assessments only for large capital projects required to serve new loads for potential or existing customers. If detailed project costs and design details are required, Centra Gas will obtain a signed commitment from the customer that Centra Gas will be reimbursed for costs incurred should the project not proceed.

In future revenue requirements applications, Centra Gas will include a continuity of non-rate base deferral accounts, segregated from rate base deferral accounts, as part of the Application Schedules.

8. BC Capital Tax Audit and Appeal Costs

In Tab 18 of the Application and BCUC IR 1-15.0, Centra describes the BC Capital Tax assessment of $6.2 million and its appeal. Centra Gas requests recovery in cost of service for any re-assessed capital taxes including interest and penalties and any legal or other costs incurred to defend its position.

In BCH IR 2-2.20.2 Centra Gas states “In the event it is determined that Centra is liable for all or some portion of the reassessment, Centra will assess the appropriate treatment and, either apply for an interest bearing deferral account, to be amortized over 5 years, which is the same period over which the tax assessment occurred, or roll the amount directly into the RDDA”.

Parties support Centra Gas’ efforts to appeal this issue. The prudency of the costs incurred and the assessed taxes, interest and penalties will be reviewed by the parties when the appeal is finalized along with a determination of the method of recovery.

9. Pension Charges

See Item 4.

10. Capital Structure and Financing Costs

It is agreed that for a Utility of Centra Gas’ size and circumstance, an average level of 35 percent common equity is appropriate. Centra Gas has maintained a 65 percent debt/35 percent equity capital structure since its inception and this structure is considered appropriate.

Return on Common Equity

The use of the automatic adjustment mechanism is appropriate for Centra Gas in the setting of its allowed equity rate of return commencing in 2003. A risk premium over the benchmark utility rate of return on common equity of fifty (50) basis points is appropriate for Centra Gas. Centra Gas will re-assess its basis point premium in its next revenue requirement application.

Short-term Debt

Centra Gas has proposed a short-term debt cost of 30 day Bankers Acceptances (BA’s) plus 80 basis points, which is accepted.

Long-term Debt

When Centra Gas’ long-term debt is due for renewal, it will apply to the Commission for approval of the new financing arrangement and the cost, as required under the Utilities Commission Act.

11. Actual 1999 to 2001 Revenue Deficiencies

Centra Gas has shown the actual 1999 to 2001 revenue deficiencies in Tab 19, Schedule 2 of the Application. The allowed gross OM&A for 1999 to 2001 was set by settlement agreements with 2000 and 2001 allowing adjustments for customer growth and Customer Information System costs (“CIS”) as shown in BCUC IR 1-18.1. The actual 1999 to 2001 revenue deficiencies were reviewed and are accepted.

12. RDDA

In BCUC IR 1-6.1 to 6.8 Centra Gas shows the recording of Annual Revenue Deficiencies and Surpluses in the Revenue Deficiency Deferral Account (“RDDA”) and the financing of those deficiencies. Centra Gas’ responses on the recording of activity in the RDDA appear to be consistent with the Special Direction. The financing of the RDDA through Class A preferred shares or Class B debt is described in BCUC IR 1-6.2 and 1-6.6.1. The net after tax cost of Class B instruments is identified as 5.08 percent compared to a Class A dividend cost of 5.65 percent. Therefore, with Centra Gas becoming taxable in 2003, the RDDA financing should be cheaper with Class B debt. For 2002 onward, Centra Gas should finance the RDDA by Class B instruments if the net after tax cost, including loss carry forwards from 2002, results in a lower financing cost than Class A instruments. Centra Gas will ensure that the least cost financing of the RDDA is included in adjusted cost of service.

13. Overhead Capitalization

Centra Gas describes its overhead capitalization policy on page 9.23 of the Application. On Tab 19 Schedule 112 the gross O&M before capitalization is shown on line 16 with the capitalized gross O&M on line 17. For the years 2003 to 2005 the overhead capitalization percentage is 16.43 percent, 15.88 percent and 16.18 percent respectively. These overhead percentages are accepted. Centra Gas will continue to apply its overhead capitalization policy in the determination of OM&A capitalized, and will request Commission approval of each year's OM&A capitalization commencing with the amount for 2004 according to past practice.

14. BC Gas Wheeling Charge

There is no issue regarding the BC Gas Wheeling Charges to Centra as described in BCUC IR 1-5.1 to 1-5.2.2.

15. Re-Amortization of Repayable Loans

On page 11.1 of the Application, Centra Gas describes that a $75 million federal/provincial refundable contribution was partly amortized as a reduction to the cost of service and the RDDA, totaling about $8.7 million. The amortization occurred because the contribution was not expected to be refundable but, in response to JV 1-14, Centra Gas describes that the expectation has changed and repayments to government will likely commence in 2012, subject to the ability of Centra Gas to obtain non-government debt financing on reasonable, BCUC approved commercial terms. Centra Gas is proposing to reverse the amortization by a charge against the annual surplus, which will vary with the amount of annual surplus. Centra's proposal is accepted.

16. Annual Review

In BCUC IR 1-6.7 Centra Gas proposes that it hold an annual meeting with Intervenors and Commission staff in November of each year in preparation for rate setting for the following year. The annual meeting will review Centra Gas' performance that year and its proposed activities in the upcoming year. In addition, Centra proposes to provide quarterly reports to Commission staff and Intervenors to review competitive prices and determine if core customer sales rates should change. Intervenors may comment to the Commission on the quarterly reports but the Commission would not normally initiate quarterly meetings unless it determines that such a meeting is desirable. The parties accept this proposal.

17. Insurance Costs

Centra Gas will report on the market survey of insurance costs for 2004 and 2005 at the November 2003 Annual Review.

18. Compressor Fired Hours

The Compressor Fired Hour Liability will be recorded as a rate base deferral account.

19. Rate Design Costs

Subject to prudency review under item 25 below, Phase 2 Application and study costs (COSA and Rate Design) will be recorded at actual costs.

20. Unaccounted-For-Gas (UAF)

UAF will be forecast based on the five year rolling average of the UAF calculation (excluding 2000 UAF), and will be zero percent in 2003. UAF will be adjusted to actual in the determination of each years adjusted cost of service in accordance with Section 2.10(f) of the Special Direction.

21. On System Peaking Costs

Centra Gas will remove on-system peaking costs from its cost of gas forecast for a normal year.

22. Large Customer Concerns

Centra Gas commits to working with the customers in the LCS-3 rate classes (including LCS-13, HLF and ILF and those public sector customers with total annual natural gas consumption exceeding 6,000 gigajoules) to determine issues important to them, including but not limited to, bill aggregation for administrative efficiency, unbundling of cost of gas, competitive considerations and position for alternative fuels.

23. Plant Addition Overheads

Centra Gas will provide the participants with a schedule showing the overheads capitalized as a comparison to plant additions, explaining the responses to IR's that appear to be of differing outcomes.

24. Mains Extension Tests

Centra Gas will review with Commission Staff and the participants its mains extension test to determine if the test is providing the appropriate results such that Centra Gas is making capital investments for new mains extensions and customer additions that are beneficial to existing customers. As part of the review, Centra Gas will provide evidence on the appropriateness of including an allowance for future capacity expansion, and the appropriate amount of that allowance.

25. Rate Design Deferral Accounts

Centra Gas will provide Commission Staff and the participants with the details of COSA and Rate Design deferral accounts including activities performed, results provided and the level of expenditures incurred.

Centra Gas has incurred approximately $775,000 of consulting costs over the past three years to prepare its cost of service studies and Rate Design Application and anticipates this amount to be $850,000 in the event of a hearing. The prudency of these expenditures are to be reviewed in the Phase 2 proceeding.

The Company and the participants agree to hold confidential the discussions held on November 25th and 26th, 2002. Any position taken or statement made during the discussions, by the participants or the Company, will not be made public or restrict in any way, positions taken in future proceedings should this settlement not be approved by the Commission, or in future proceedings concerning other applications.

Centra Gas British Columbia Inc
Revenue Requirements Application
Negotiated Settlement Process
Supporting Schedules to the
Negotiated Settlement

The following schedules form part of the negotiated settlement package, provide support for, and the numeric representation of, the settlement pertaining to the Centra Gas Revenue Requirement Application, negotiated November 25th and 26th, 2002, between Centra Gas, registered intervenors, and the Commission Staff. During the comments phase for the settlement package, it was determined that payments received from proponents of the Port Alberni cogeneration investigation were not included within the deferral account balance. Centra Gas and the BCUC changed the wording in Item 7 of the Negotiated Settlement package to reflect the payments, but the supporting schedules were not updated at that time. Therefore, the attached schedules have now been updated to match the wording of the Negotiated Settlement package, and as of December 19, 2002 are correct and accurately reflect the terms of Centra Gas's Revenue Requirements Negotiated Settlement.

CENTRA GAS BRITISH COLUMBIA INC.

Schedule 1

2003/04/05 Revenue Requirement Application

Revenue Deficiency Continuity Schedule

LINE		1995 Actual	1996 Actual	1997 Actual	1998 Actual	1999 Actual	2000 Actual	2001 Actual	2002 Outlook	2003 Forecast	2004 Forecast	2005 Forecast	Year of Deficiency/ (Surplus)
1	Annual Revenue Deficiency/(Surplus)	$ 16,904,100	$ 9,135,807	$ 6,410,061	$ 13,045,336	$ 11,819,960	$ 1,358,754	$ 7,525,971	$ (163,570)	$ (10,186,160)	$ (9,680,190)	$ (10,282,206)	
2	Deemed Preferred Share Dividend - 1996	0	1,195,503	1,195,503	1,195,503	1,195,503	1,195,503	1,022,449	1,018,074	1,018,074	1,018,074	1,018,074	1995
3	Deemed Preferred Share Dividend - 1997	0	0	620,485	620,485	620,485	620,485	620,485	620,485	580,400	580,400	580,400	1996
4	Deemed Preferred Share Dividend - 1998	0	0	0	500,774	500,774	513,863	513,863	513,863	507,738	507,738	507,738	1997
5	Deemed Preferred Share Dividend - 1999	0	0	0	0	862,761	861,030	861,030	861,030	861,030	634,314	390,101	1998
6	Deemed Preferred Share Dividend - 2000	0	0	0	0	0	965,921	965,921	965,921	965,921	965,921	873,968	1999
7	Deemed Preferred Share Dividend - 2001	0	0	0	0	0	0	344,702	344,702	344,702	344,702	344,702	2000
8	Deemed Preferred Share Dividend - 2002	0	0	0	0	0	0	0	760,993	760,993	760,993	760,993	2001
9	Deemed Preferred Share Dividend - 2003	0	0	0	0	0	0	0	0	304,044	304,044	304,044	2002
10	Deemed Preferred Share Dividend - 2004	0	0	0	0	0	0	0	0	0	0	0	2003
11	Deemed Preferred Share Dividend - 2005	0	0	0	0	0	0	0	0	0	0	0	2004
12	Deemed Preferred Share Dividends	0	1,195,503	1,815,988	2,316,762	3,179,523	4,156,802	4,328,450	5,085,068	5,342,901	5,116,185	4,780,019	
13	Adjusted Annual Revenue Deficiency/(Surplus)	16,904,100	10,331,310	8,226,049	15,362,098	14,999,483	5,515,556	11,854,421	4,921,498	(4,843,258)	(4,564,005)	(5,502,186)	
14	Interim Revenue Deficiency Financing Rate (Note 1)	6.839%	5.836%	5.812%	5.853%	6.253%	5.876%	5.459%	5.998%	5.650%	5.650%	5.650%	
15	Interim Revenue Deficiency Financing	578,036	301,447	239,065	449,572	468,974	162,053	323,543	147,596	0	0	0	
16	Final Adjusted Annual Revenue Deficiency/(Surplus)	17,482,136	$ 10,632,757	$ 8,465,114	$ 15,811,670	$ 15,468,457	$ 5,677,609	$ 12,177,964	$ 5,069,094	$ (4,843,258)	$ (4,564,005)	$ (5,502,186)	
	LESS:												
17	Redemption of Preferred Shares				4,584,876								
18	Net Annual Deferral				11,226,794								
	LESS:												
19	Redemption of Preferred Shares				4,322,356								
20	Net Annual Deferral				6,904,438								
	LESS:												
21	Redemption of Preferred Shares				5,132,439								
22	Net Annual Deferral				$ 1,772,000								
23	Accumulated Deferral Balance as calculated	$ 17,482,136	$ 28,114,893	$ 36,580,007	$ 52,391,677	$ 67,860,134	$ 73,537,742	$ 85,715,706	$ 90,784,800	$ 86,199,923	$ 81,877,568	$ 76,745,129	
24	Note 1: Calculation of Rate:												
25	5 Year Canada Bond Rate at June 30 of Following												
26	Year Published by Bank of Canada Review	7.05%	5.32%	5.28%	5.35%	6.04%	5.39%	4.67%	5.60%	5.00%	5.00%	5.00%	
27	Multiply by	58%	58%	58%	58%	58%	58%	58%	58%	58%	58%	58%	
28		4.089%	3.086%	3.062%	3.103%	3.503%	3.126%	2.709%	3.248%	2.900%	2.900%	2.900%	
29	Add	2.750%	2.750%	2.750%	2.750%	2.750%	2.750%	2.750%	2.750%	2.750%	2.750%	2.750%	
30	Interim Revenue Deficiency Financing Rate	6.839%	5.836%	5.812%	5.853%	6.253%	5.876%	5.459%	5.998%	5.650%	5.650%	5.650%	
31	Note 2: Preferred Share Redemption & Reamortization of Repayable Loan												
32	Final Adjusted Annual Revenue Deficiency/(Surplus)									$ (4,843,258)	$ (4,564,005)	$ (5,502,186)	
33	Original Balance of Repayable Loan									75,000,000			
34	Unamortized Balance as at Jan. 1, 2000									66,279,067			
35	Accumulated Amortization									$ 8,720,933			
36	Accumulated Deferral Balance as at Dec. 31, 2002									$ 90,784,800			
37	Accumulated Deferral Balance as at Dec. 31, 2003										$ 86,199,923		
38	Accumulated Deferral Balance as at Dec. 31, 2004											$ 81,877,568	
39	Ratio of Line 32 and Line 23									5.33%	5.29%	6.72%	
40	Prorated Amount avail. for Reamortization of Loan									(258,382)	(241,649)	(369,748)	
41	Prorated Amount avail. for Redemption of Preferred Shares									(4,584,876)	(4,322,356)	(5,132,439)	
42	Check Total									$ (4,843,258)	$ (4,564,005)	$ (5,502,186)	

CENTRA GAS BRITISH COLUMBIA INC.

2003/04/05 Revenue Requirement Application

REVENUE REQUIREMENT

Schedule 2

LINE		1999 Actual	2000 Actual	2001 Actual	2002 Outlook	2003 Forecast	2004 Forecast	2005 Forecast	Reference
1	Gross Operating and Maintenance Expenses	$ 30,376,220	$ 30,983,127	$ 31,619,797	$ 32,480,760	$ 31,700,000	$ 32,500,000	$ 32,600,000	Schedule 112
2	Operating and Maintenance Capitalization	(6,682,768)	(6,886,324)	(6,999,600)	(4,912,300)	(5,208,310)	(5,161,000)	(5,274,680)	Schedule 112
3	Direct Charges and Allocations to Affiliates	(317,187)	(223,660)	(208,386)	(212,554)	(216,593)	(220,492)	(224,902)	Schedule 112
4	B.C. Gas Wheeling Charge	3,838,894	3,838,894	3,838,894	4,093,998	4,121,313	4,215,770	4,297,060	Schedules 97-103
5	Rent For Compressor Equipment Leased From Others	0	1,747,900	1,747,900	1,747,900	1,747,900	1,747,900	1,747,900	Schedule 34
6	Depreciation	12,106,762	12,899,198	13,336,400	13,613,092	14,118,100	14,330,643	14,788,524	Schedules 12-18
7	Reamortization/(Amortization) - CIAC	(1,594,296)	0	0	0	258,382	241,649	369,748	Schedules 19-25
8	Municipal Taxes	5,007,363	5,391,258	5,926,402	6,146,000	6,399,506	7,139,288	7,567,217	Schedule 34
	Amortization of Deferreds								
9	Financing Costs	254,176	254,176	254,176	254,175	204,175	204,175	204,175	Schedules 35-44
10	Unamortized Manufactured Gas Plant	314,221	314,220	314,221	347,588	347,588	347,588	347,588	Schedules 35-44
11	NGV Conversion Expense	1,603	1,603	1,603	1,603	1,599	0	0	Schedules 35-44
12	Regulatory Expense	28,492	0	0	0	55,000	55,000	55,000	Schedules 35-44
13	PCEC Start Up Costs	43,900	43,900	43,900	43,900	43,900	43,900	43,900	Schedules 35-44
14	Gas Supply Management Study	17,533	0	0	0	0	0	0	Schedules 35-44
15	Customer Grants and Incentives	255,620	292,053	272,043	113,605	367,600	251,841	259,773	Schedules 35-44
16	Ccompressor Lease	850,042	0	0	0	0	0	0	Schedules 35-44
17	Deferred Rate Increase	(25,800)	0	0	0	0	0	0	Schedules 35-44
18	CIS Implementation	50,142	113,841	115,798	115,799	115,799	115,799	115,799	Schedules 35-44
19	Marine Inspection	0	409,264	0	0	0	0	0	Schedules 35-44
20	Direct Purchase Administration Costs	0	4,774	0	0	0	0	0	Schedules 35-44
21	2000-2002 Regulatory Expenses	0	18,893	18,968	18,968	0	0	0	Schedules 35-44
22	Cost of Gas Passthrough	0	0	0	0	(704,483)	0	0	Schedules 35-44
23	Cost Allocation & Rate Design	0	0	0	0	283,333	283,333	283,333	Schedules 35-44
24	Incremental CIS Operating Costs	0	291,802	0	0	0	0	0	Schedules 35-44
25	Texada Compressor Operating Costs	0	0	0	0	25,216	25,216	25,217	Schedules 35-44
26	ICP Cogen Project Commissioning	0	0	0	0	17,423	0	0	Schedules 35-44
27	Large Corporations Tax	1,121,074	1,142,982	1,115,996	1,182,000	1,143,875	1,151,393	1,157,564	Schedule 53
28	British Columbia Capital Tax	1,503,711	1,532,545	1,323,574	867,000	0	0	0	Schedule 54
29	Motor Fuel Tax	348,012	361,303	435,998	560,472	603,179	634,532	634,222	Schedules 97-103
30	Provincial Sales Tax	38,668	55,096	61,366	61,955	76,633	83,828	83,842	Schedules 97-103
31	Proposed Return on Rate Base	32,400,991	35,945,863	34,591,559	33,497,715	34,570,873	31,710,486	30,830,345	Schedules 55-61
32	Less Special Direction Provision	(1,867,000)	(1,867,000)	(1,867,000)	(1,867,000)	(1,867,000)	(1,867,000)	(1,867,000)	
33	Income Tax Expense	0	0	0	0	5,474,434	12,055,637	13,442,299	Schedule 45
34	Total Revenue Requirement-Cost of Service	78,070,373	86,665,708	85,943,609	88,154,675	93,679,443	99,889,487	101,486,924	
35	Total Revenue Requirement-Cost of Sales	35,377,333	47,332,594	69,793,260	54,860,902	72,306,351	75,247,605	78,485,792	Schedules 105-111
36	Total Revenue Requirement	$ 113,447,706	$ 133,998,302	$ 155,736,869	$ 143,015,577	$ 165,985,794	$ 175,137,092	$ 179,972,716	
	Reconciliation of Revenue Requirement								
37	Natural Gas Sales Revenue	$ 77,004,981	$ 95,399,226	$ 96,365,040	$ 103,032,053	$ 129,410,542	$ 135,944,447	$ 140,578,169	Schedules 62-75
38	Transportation Revenue	13,531,537	13,941,396	16,753,216	21,175,951	20,774,567	22,323,168	22,401,823	Schedule 96
39	Royalty Income	10,411,856	22,695,583	34,664,448	18,511,350	25,536,120	26,093,904	26,804,994	Schedule 104
40	Other Revenue	679,372	603,342	428,193	459,793	450,725	455,763	469,935	Schedule 104
41	Total Revenue	101,627,746	132,639,547	148,210,897	143,179,147	176,171,954	184,817,282	190,254,921	
42	Revenue (Surplus) / Deficiency	**11,819,960**	**1,358,754**	**7,525,971**	**(163,570)**	**(10,186,160)**	**(9,680,190)**	**(10,282,206)**	
43	Total Revenue Requirement	$ 113,447,706	$ 133,998,301	$ 155,736,868	$ 143,015,577	$ 165,985,795	$ 175,137,092	$ 179,972,716	

CENTRA GAS BRITISH COLUMBIA INC.
2003/04/05 Revenue Requirement Application
RATE BASE

Schedule 3

LINE		1999 Actual	2000 Actual	2001 Actual	2002 Outlook	2003 Forecast	2004 Forecast	2005 Forecast	Reference
	GROSS PLANT IN SERVICE								
1	Beginning of Year	$500,426,694	$536,725,356	$558,973,436	$573,973,833	$591,160,130	$602,112,933	$618,613,826	Schedules 5-11
2	Add: Previous Year Closing WIP adjustment	225,635	1,910,987	296,716	325,957	-	-	-	Schedules 5-11
3	Adjusted Beginning of Year	500,652,329	538,636,343	559,270,152	574,299,791	591,160,130	602,112,933	618,613,826	
4	End of Year	536,725,356	558,973,436	573,973,833	591,160,130	602,112,933	618,613,826	635,601,743	Schedules 5-11
5	13 Month Average Adjustment - V3 Compressor	(4,636,696)	0	0	0	0	0	0	Schedules 5-11
6	Average Balance - Mid-Year	514,052,147	548,804,889	566,621,992	582,729,960	596,636,532	610,363,379	627,107,784	
	ACCUMULATED DEPRECIATION								
7	Beginning of Year	(56,896,671)	(66,546,830)	(78,197,961)	(90,050,520)	(102,354,594)	(110,175,396)	(123,397,286)	Schedules 12-18
8	End of Year	(66,546,830)	(78,197,961)	(90,050,520)	(102,354,594)	(110,175,396)	(123,397,286)	(137,288,294)	Schedules 12-18
9	Average Balance - Mid-Year	(61,721,750)	(72,372,396)	(84,124,241)	(96,202,557)	(106,264,995)	(116,786,341)	(130,342,790)	
10	NET MID-YEAR PLANT IN SERVICE	452,330,396	476,432,494	482,497,752	486,527,404	490,371,537	493,577,038	496,764,994	
	MID-YEAR ALLOCATED NET COMMON PLANT								
11	Centra Gas Whistler Inc.	(95,771)	(86,475)	(104,335)	(104,335)	(104,335)	(104,335)	(104,335)	
12		(95,771)	(86,475)	(104,335)	(104,335)	(104,335)	(104,335)	(104,335)	
13	MID-YEAR CONTRIBUTIONS	(67,076,214)	(66,279,067)	(66,279,067)	(66,279,067)	(66,408,258)	(66,658,273)	(66,963,972)	Schedules 19-25
14	WORKING CAPITAL	15,182,010	17,236,903	18,518,759	17,186,658	16,555,580	16,617,852	16,263,760	Schedule 26
15	MID-YEAR RATE BASE	$400,340,421	$427,303,855	$434,633,109	$437,330,660	$440,414,524	$443,432,282	$445,960,447	

LINE	Thirteen Month Adjustment:	
16	Total Project Costs for Compressor Addition	$ 13,394,900
17	13 Month Average X Months in Service	2,060,754
18	Mid Year Effect of Compressor Addition	6,697,450
19	Adjustment (Line 17 - Line 18)	$ (4,636,696)

CENTRA GAS BRITISH COLUMBIA INC.

Schedule 26

2003/04/05 Revenue Requirement Application

WORKING CAPITAL SUMMARY

LINE		1999 Actual	2000 Actual	2001 Actual	2002 Outlook	2003 Forecast	2004 Forecast	2005 Forecast	Reference
1	Cash Working Capital Requirements	$2,298,742	$2,575,203	$2,778,414	$3,012,062	$3,696,323	$4,441,290	$4,623,940	Schedule 34
2	Inventory - Materials and Supplies	3,086,433	3,371,450	3,263,313	2,990,997	3,112,675	3,112,675	3,112,675	Schedule 27
3	Line Pack/Gas Storage	3,316,162	5,585,257	8,468,054	7,443,400	7,572,589	8,458,906	9,329,228	Schedule 28
4	Employee Housing Loans	119,538	193,385	188,385	170,692	176,385	157,308	158,077	Schedule 29
5	Finance Contracts Receivable	1,565,776	926,771	535,604	392,310	273,361	224,521	214,435	Schedule 30
6	Customer Deposits	(256,011)	(371,746)	(388,966)	(484,858)	(535,788)	(535,788)	(535,788)	Schedule 31
7	Refundable Contribution	(414,230)	(415,796)	(584,725)	(626,278)	(632,069)	(632,069)	(632,069)	Schedule 32
8	Employee Witholdings	(1,323,730)	(1,313,269)	(1,550,756)	(1,286,200)	(1,286,200)	(1,286,200)	(1,286,200)	Schedule 33
9	Total	8,392,680	10,551,256	12,709,324	11,612,127	12,377,276	13,940,644	14,984,298	
	Deferred Expenses, Mid-Year:								
10	Financing Costs	1,416,560	1,212,385	1,008,209	804,034	599,859	395,684	191,509	Schedules 35-44
11	Unamortized Manufactured Gas Plant	2,513,766	2,199,545	1,885,325	1,661,196	1,420,382	1,072,794	725,206	Schedules 35-44
12	NGV Conversion Costs	4,960	5,607	4,004	2,401	800	0	0	Schedules 35-44
13	Direct Purchase Administration Costs	4,774	2,387	0	0	0	0	0	Schedules 35-44
14	Regulatory Expense-2003-2005	14,246	0	0	0	55,000	82,500	27,500	Schedules 35-44
15	PCEC Start Up Costs	1,600,530	1,556,630	1,512,730	1,468,830	1,424,930	1,381,030	1,337,130	Schedules 35-44
16	Deferred Rate Increase	(12,786)	0	0	0	0	0	0	Schedules 35-44
17	Gas Supply Management Study	8,767	0	0	0	0	0	0	Schedules 35-44
18	Customer Grants and Incentives	273,837	282,048	192,824	240,603	307,500	251,442	255,817	Schedules 35-44
19	Compressor Lease	38,313	0	0	0	0	0	0	Schedules 35-44
20	CIS Implementation Costs	691,009	1,073,419	935,849	820,244	704,445	588,646	472,847	Schedules 35-44
21	Marine Inspection	204,632	204,632	0	0	0	0	0	Schedules 35-44
22	2000-2002 Regulatory Expenses	30,725	49,618	28,377	9,484	0	0	0	Schedules 35-44
24	Cost Allocation & Rate Design	0	99,377	242,118	567,741	708,333	425,000	141,667	Schedules 35-44
25	Texada Compressor Operating Costs	0	0	0	0	25,216	37,825	12,608	Schedules 35-44
26	ICP Cogen Project Commissioning	0	0	0	0	0	0	0	Schedules 35-44
26	Fired Hours	0	0	0	0	(1,068,162)	(1,557,713)	(1,884,822)	Schedules 35-44
27	Total Deferred Expenses	6,789,330	6,685,647	5,809,435	5,574,531	4,178,303	2,677,208	1,279,462	
28	Total Working Capital Requirements	$15,182,010	$17,236,903	$18,518,759	$17,186,658	$16,555,580	$16,617,852	$16,263,760	

CENTRA GAS BRITISH COLUMBIA INC.

Schedule 39

2003/04/05 Revenue Requirement Application

DEFERRED EXPENSES (Pre 2003) - RATE BASE

Line	Year	Description	Opening Balance	Adjustments	Additions	Amortization	Interest	Ending Balance	Mid-Year Balance
	2003 Forecast								
1		Financing Costs	$701,946			($204,175)		$497,771	$599,859
2		Unamortized Manufactured Gas Plant	1,594,177			(347,588)		1,246,588	1,420,382
3		NGV Conversion Costs	1,599			(1,599)		$0	$800
4		2003 Regulatory Expense	-	165,000		(55,000)		110,000	55,000
5		Build Smart Program	38,700			(38,700)		0	19,350
6		Conversion Incentives	100,200			(100,200)		0	50,100
7		PCEC Start Up Costs	1,446,880			(43,900)		1,402,980	1,424,930
8		Texada Compressor Operating Costs	-	75,649		(25,216)		50,433	25,216
9		Cost Allocation & Rate Design	850,000			(283,333)		566,667	708,333
10		CIS Implementation Costs	762,344			(115,799)		646,545	704,445
11		Marketing Incentives	228,700			(228,700)		0	114,350
12		ICP Cogen Project Commissioning	-	17,423		(17,423)		0	0
13			$5,724,546	$258,072	$0	($1,461,634)	$0	$4,520,984	$5,122,765

CENTRA GAS BRITISH COLUMBIA INC.

Schedule 40

2003/04/05 Revenue Requirement Application

DEFERRED EXPENSES (Pre 2003) - RATE BASE

Line	Year	Description	Opening Balance	Adjustments	Additions	Amortization	Interest	Ending Balance	Mid-Year Balance
	2004 Forecast								
1		Financing Costs	$497,771			($204,175)		$293,596	$395,684
2		Unamortized Manufactured Gas Plant	1,246,588			(347,588)		899,000	1,072,794
3		2003 Regulatory Expense	110,000			(55,000)		55,000	82,500
4		PCEC Start Up Costs	1,402,980			(43,900)		1,359,080	1,381,030
5		Texada Compressor Operating Costs	50,433			(25,216)		25,217	37,825
6		Cost Allocation & Rate Design	566,667			(283,333)		283,333	425,000
7		CIS Implementation Costs	646,545			(115,799)		530,746	588,646
8		Marketing Incentives	-			0		0	0
9		Cost of Gas Passthrough	-			0		0	0
10			$4,520,984	$0	$0	($1,075,011)	$0	$3,445,973	$3,983,479

CENTRA GAS BRITISH COLUMBIA INC.

Schedule 41

2003/04/05 Revenue Requirement Application

DEFERRED EXPENSES (Pre 2003) - RATE BASE

Line	Year	Description	Opening Balance	Adjustments	Additions	Amortization	Interest	Ending Balance	Mid-Year Balance
	2005 Forecast								
1		Financing Costs	$293,596			($204,175)		$89,421	$191,509
2		Unamortized Manufactured Gas Plant	899,000			(347,588)		551,412	725,206
3		2003 Regulatory Expense	55,000			(55,000)		0	27,500
4		PCEC Start Up Costs	1,359,080			(43,900)		1,315,180	1,337,130
5		Texada Compressor Operating Costs	25,217			(25,217)		(0)	12,608
6		Cost Allocation & Rate Design	283,333			(283,333)		0	141,667
7		CIS Implementation Costs	530,746			(115,799)		414,947	472,847
8		Marketing Incentives	-			0		0	0
9		Cost of Gas Passthrough	-			0		0	0
10			$3,445,973	$0	$0	($1,075,012)	$0	$2,370,961	$2,908,467

CENTRA GAS BRITISH COLUMBIA INC.

Schedule 42

2003/04/05 Revenue Requirement Application

DEFERRED EXPENSES (Post 2003) - RATE BASE

Line	Year	Deferred Item	Opening Balance	Gross Additions/ (Deductions)	Adjustments	Less Taxes	Net Additions	Less: Amortization	Ending Balance	Mid-Year Balance
	2003 Forecast									
1		Build Smart Program	$ -	$ 39,600		$ 14,898	$ 24,702	$ -	$ 24,702	$ 12,351
2		Propane Incentives	0	240,000		90,288	149,712	0	149,712	74,856
3		Spring Barbecue Promotion	0	0		0	0	0	0	0
4		Marketing Incentives	0	117,000		44,015	72,985	0	72,985	36,492
5		Cost of Gas Passthrough	0			0	0	0	0	0
6		Financing Costs	0	50,000	$ (50,000)	0	0	0	0	0
7		Fired Hours	(845,901)	(712,602)		(268,081)	(444,521)	0	(1,290,422)	(1,068,162)
8		Total Deferred Items	$ (845,901)	$ (266,002)	$ (50,000)	$ (118,880)	$ (197,122)	$ -	$ (1,043,023)	$ (944,462)

CENTRA GAS BRITISH COLUMBIA INC.

Schedule 43

2003/04/05 Revenue Requirement Application

DEFERRED EXPENSES (Post 2003) - RATE BASE

Line	Year	Deferred Item	Opening Balance	Gross Additions/ (Deductions)		Less Taxes	Net Additions	Amortization	Ending Balance	Mid-Year Balance
	2004 Forecast									
1		Build Smart Program	$ 24,702	$ 40,313		$ 14,359	$ 25,953	$ 25,146	$ 25,510	$ 25,106
2		Propane Incentives	149,712	244,320		87,027	157,293	152,400	154,605	152,159
3		Spring Barbecue Promotion	0	0		0	0	0	0	0
4		Marketing Incentives	72,985	119,106		42,426	76,680	74,295	75,370	74,177
5		Cost of Gas Passthrough	0			0	0	0	0	0
6		Financing Costs	0	50,000	$ (50,000)	0	0	0	0	0
7		Fired Hours	(1,290,422)	(830,353)		(295,772)	(534,581)	0	(1,825,003)	(1,557,713)
8		Total Deferred Items	$ (1,043,023)	$ (376,614)	$ (50,000)	$ (151,960)	$ (274,654)	$ 251,841	$ (1,569,518)	$ (1,306,271)

CENTRA GAS BRITISH COLUMBIA INC.

Schedule 44

2003/04/05 Revenue Requirement Application

DEFERRED EXPENSES (Post 2003) - RATE BASE

Line	Year	Deferred Item	Opening Balance	Gross Additions/ (Deductions)	Adjustments	Less Taxes	Net Additions	Amortization	Ending Balance	Mid-Year Balance
	2005 Forecast									
1		Build Smart Program	$ 25,510	$ 40,392		$ 14,388	$ 26,004	$ 25,938	$ 25,576	$ 25,543
2		Propane Incentives	154,605	244,800		87,198	157,602	157,200	155,007	154,806
3		Spring Barbecue Promotion	0	0		0	0	0	0	0
4		Marketing Incentives	75,370	119,340		42,509	76,831	76,635	75,566	75,468
5		*Cost of Gas Passthrough	0			0	0	0	0	0
6		Financing Costs	0	50,000	$ (50,000)	0	0	0	0	0
7		Fired Hours	(1,825,003)	(922,631)	736,800	(66,193)	(119,638)	0	(1,944,641)	(1,884,822)
8		Total Deferred Items	$ (1,569,518)	$ (468,099)	$ 686,800	$ 77,901	$ 140,800	$ 259,773	$ (1,688,492)	$ (1,629,005)

CENTRA GAS BRITISH COLUMBIA INC. **Schedule 45**
2003/04/05 Revenue Requirement Application
INCOME TAXES

Line #		1999 Actual	2000 Actual	2001 Actual	2002 Outlook	2003 Forecast	2004 Forecast	2005 Forecast	Reference
1	Allowed/Proposed Earned Return After Tax	$ 32,400,991	$ 35,945,863	$ 34,591,559	$ 33,497,715	$ 34,570,873	$ 31,710,486	$ 30,830,345	Schedules 55-61
2	Add: Equity Portion of AFUDC	0	32,666	0	0	0	0	0	
3	Less Special Direction Provision	1,867,000	1,867,000	1,867,000	1,867,000	1,867,000	1,867,000	1,867,000	Schedule 2
4	Add Variance in OM&A Expenses	1,461,876	1,170,402	2,000,791	2,551,956	0	0	0	
5	Add Revenue (Deficiency)/Surplus	(11,819,960)	(1,358,754)	(7,525,971)	163,570 #	10,186,160 #	9,680,190	10,282,206	
6	Less Financing Expenses	19,659,957	21,495,729	20,359,063	19,333,012	19,279,681	16,314,518	15,346,598	Schedules 55-61
7	Accounting Income After Tax	515,950 #	12,427,449 #	6,840,316 #	15,013,229 #	23,610,352 #	23,209,159 0	23,898,952	
	ADD:								
8	Depreciation Expense	12,106,762	12,899,198	13,336,400	13,613,092	14,118,100	14,330,643	14,788,524	Schedules 12-18
9	Re-amortization/(Amortization) of CIAC	(1,594,296)	0	0	0	258,382	241,649	369,748	Schedules 19-25
10	**Amortization of Deferreds:**								
11	Financing Costs	254,176	254,176	254,176	254,175	204,175	204,175	204,175	Schedules 35-44
12	Unamortized Manufactured Gas Plant	314,221	314,220	314,221	347,588	347,588	347,588	347,588	Schedules 35-44
13	NGV Conversion Costs	1,603	1,603	1,603	1,603	1,599	0	0	Schedules 35-44
14	Regulatory Expense	28,492	0	0	0	55,000	55,000	55,000	Schedules 35-44
15	PCEC Start Up Costs	43,900	43,900	43,900	43,900	43,900	43,900	43,900	Schedules 35-44
16	Gas Supply Management Study	17,533	0	0	0	0	0	0	Schedules 35-44
17	Intergrated Resource Plan Expenses	0	0	0	0	0	0	0	Schedules 35-44
18	Customer Grants and Incentives	255,620	292,053	272,043	113,605	367,600	251,841	259,773	Schedules 35-44
19	Compressor Lease	850,042	0	0	0	0	0	0	Schedules 35-44
20	Deferred Rate Increase	(25,800)	0	0	0	0	0	0	Schedules 35-44
21	Marine Inspection	0	409,264	0	0	0	0	0	Schedules 35-44
22	CIS System	50,142	113,841	115,798	115,799	115,799	115,799	115,799	Schedules 35-44
23	Incremental CIS Operating Costs	0	291,802	0	0	0	0	0	Schedules 35-44
24	Direct Purchase Administration Costs	0	4,774	0	0	0	0	0	Schedules 35-44
25	2000-2002 Regulatory Expenses	0	18,893	18,968	18,968	0	0	0	Schedules 35-44
26	Cost of Gas Passthrough	0	0	0	0	(704,483)	0	0	Schedules 35-44
27	Cost Allocation & Rate Design	0	0	0	0	283,333	283,333	283,333	Schedules 35-44
28	Texada Compressor Operating Costs	0	0	0	0	25,216	25,216	25,217	Schedules 35-44
29	ICP Cogen Project Commissioning	0	0	0	0	17,423	0	0	Schedules 35-44
30	Dues and Entertainment and Non Allowable Car Lease	132,504	134,338	133,089	117,700	117,000	117,000	117,000	
31	Pension Expense	607,088	850,701	791,000	0	0	0	0	
32	Charitable donations	20,643	18,770	24,215	0	0	0	0	
33	Interest Income Tax and Penalties	2,058	0	0	0	0	0	0	
34	Large Corporations Tax	1,121,074	1,142,982	1,115,996	1,182,000	1,143,875	1,151,393	1,157,564	Schedule 53
35	**Total Additions**	14,185,761	16,790,514	16,421,409	15,808,430	16,394,508	17,167,537	17,767,621	
	DEDUCT:								
36	Capital Cost Allowance	12,934,532	20,835,912	24,863,653	23,239,300	20,514,173	19,594,803	18,781,499	Schedules 46-52
37	Cumulative Eligible Capital (T2S8A)	693,825	659,045	618,943	474,801	553,626	519,335	487,444	
38	Indirect overheads capitalized for book purposes	1,915,000	2,092,500	2,385,400	1,572,800	1,700,000	1,700,000	1,700,000	
39	AFUDC	387,189	93,332	3,270	0	0	0	0	Schedules 5-11
40	Cost of Abandonment of Fixed Assets	58,814	40,255	0	0	0	0	0	
41	Interest on Deferred Capital Projects	101,231	113,892	125,846	147,833	567	608	651	
42	Interest on Deferreds	12,269	6,619	11,912	18,166	0	0	0	
43	Financing Expenses per 20(1)(e)	496,235	446,235	10,634	10,634	0	0	0	
44	**Current Additions Deferred Expenses:**								
45	Financing Costs	50,000	50,000	50,000	50,000	0	0	0	Schedules 35-44
46	Unamortized Manufactured Gas Plant	0	0	0	0				Schedules 35-44
47	NGV Conversion Cost	4,500	0	0	0				Schedules 35-44
48	Regulatory Expense	61,450	(4,771)	23,245	136,691				Schedules 35-44
49	Customer Grants and Incentives	292,053	272,043	113,605	367,600				Schedules 35-44
50	Compressor Lease	773,417	0	0	0				Schedules 35-44
51	Marine Survey	409,264	0	0	0				Schedules 35-44
52	Cost of Gas Passthrough	2,684,528	(1,416,311)	(3,204,526)	1,231,826				Schedules 35-44
53	Cost Allocation and Rate Design	0	198,754	86,728	564,518				Schedules 35-44
54	Incremental CIS Operating Costs	298,467	(6,665)	0	0				Schedules 35-44
55	Texada Compressor Operating Costs	0	0	843	73,764				Schedules 35-44
56	2000-2002 Regulatory Expenses	0	0	150	0				Schedules 35-44
57	T-Service for ICP	63,111	91,280	137,172	100,000				Schedules 35-44
58	T-Service for BC Hydro	0	0	372	0				Schedules 35-44
59	Georgia Strait Crossing	0	4,499	0	40,000				Schedules 35-44
60	ICP Cogen Project Commissioning	0	8,572	2,465	5,225				Schedules 35-44
61	Non Allowable Items in Deferred	(2,240)	(2,988)	0	0				
62	Interim Revenue Deficiency Financing	468,974	162,053	323,543	147,596	0	0	0	Schedule 1
63	Pension Contributions	613,766	709,149	517,725	0	0	0	0	
64	Total Deductions	22,316,386	24,353,405	26,070,979	28,180,754	22,768,366	21,814,746	20,969,594	
65	Income(Loss) for Tax Purposes (After Tax)	(7,614,674)	4,864,559	(2,809,255)	2,640,904	17,236,494	18,561,950	20,696,979	
66	Less Charitable Donations Utilized	0	39,413		24,215				
67	Taxable Income(Loss) (After Tax) before application of Loss Cfwd.	(7,614,674)	4,825,146	(2,809,255)	2,616,689	17,236,494	18,561,950	20,696,979	
68	Customer Loss Carryforward Opening	6,087,315	13,701,989	8,876,844	11,686,098	9,069,409	0	0	
69	Additions	7,614,674	0	2,809,255	0	0	0	0	
70	Utilized	0	4,825,146	0	2,616,689	9,069,409	0	0	
71	Customer Loss Carryforward Closing	13,701,989	8,876,844	11,686,098	9,069,409	0	0	0	
72	Taxable Income (After Tax) after application of Loss Cfwd.	0	0	0	0	8,167,084	18,561,950	20,696,979	
73	Tax Gross Up	54.38%	54.38%	55.38%	60.38%	62.38%	64.38%	64.38%	
74	Taxable Income	$ -	$ -	$ -	$ -	$ 13,092,473	$ 28,831,857	$ 32,148,150	
	Income Tax Calculation	1999 Rates	2000 Rates	2001 Rates	2002 Rates	2003 Rates	2004 Rates	2005 Rates	
75	Federal Tax	38.00%	38.00%	38.00%	38.00%	38.00%	38.00%	38.00%	
76	Less Tax Abatement	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	
77	Less: General Tax Reduction	0.00%	0.00%	1.00%	3.00%	5.00%	7.00%	7.00%	
78	Net Federal Tax	28.00%	28.00%	27.00%	25.00%	23.00%	21.00%	21.00%	
79	Federal Surcharge	1.12%	1.12%	1.12%	1.12%	1.12%	1.12%	1.12%	
80	Provincial Tax	16.50%	16.50%	16.50%	13.50%	13.50%	13.50%	13.50%	
81	Composite Income Tax Rate	45.62%	45.62%	44.62%	39.62%	37.62%	35.62%	35.62%	
82	Federal Tax	0	0	0	0	4,975,140	10,956,106	12,216,297	
83	Less Tax Abatement	0	0	0	0	1,309,247	2,883,186	3,214,815	
84	Less: General Tax Reduction								
85	Net Federal Tax	0	0	0	0	3,665,892	8,072,920	9,001,482	
86	Federal Surcharge	0	0	0	0	41,058	90,417	100,817	
87	Provincial Tax	0	0	0	0	1,767,484	3,892,301	4,340,000	
88	Income Tax Expense	$ -	$ -	$ -	$ -	$ 5,474,434	$ 12,055,637	$ 13,442,299	

CENTRA GAS BRITISH COLUMBIA INC.
2003/04/05 Revenue Requirement Application
CAPITAL STRUCTURE AND COST OF CAPITAL

Schedule 59

2003 Forecast

LINE		CAPITALIZATION AMOUNT	CAPITALIZATION %	ANNUAL RATE %	COST COMPONENT %	EARNED RETURN $	ANNUAL DEBT COST $
1	Short Term Debt	$ 64,914,624	14.74%	5.70%	0.84%	$ 3,700,134	$ 3,700,134
2	New Long Term Debt Issue	0	0.00%	0.00%	0.00%	0	0
2	Existing Long Term Debt (1)	221,354,817	50.26%	7.04%	3.54%	15,579,547	15,579,547
3	Common Equity	154,145,083	35.00%	9.92%	3.47%	15,291,192	
4	MID-YEAR RATE BASE	$440,414,524	100.00%		7.85%	$34,570,873	$19,279,681

(1) Long Term Debt Continuity Schedule

LINE		Balance Opening	Additions	Repayments	Balance Closing	Mid-Year Balance	% of Total	Interest Expense	Annual Effective Rate	Weighted Average %
5	Annual Agency Fee							$ 50,000		0.02%
6	Swap 2	$ 60,000,000		$ (60,000,000)	$ -	$ 30,000,000	13.55%	1,468,800	4.896%	0.66%
7	Swap 3	95,000,000			95,000,000	95,000,000	42.92%	8,113,000	8.54%	3.67%
8	Swap 4	16,870,390		(1,101,370)	15,769,020	16,319,705	7.37%	990,117	6.067%	0.45%
9	Swap 5	42,625,000		(4,375,000)	38,250,000	40,437,500	18.27%	2,393,091	5.918%	1.08%
10	Unswapped	9,597,612	60,000,000		69,597,612	39,597,612	17.89%	2,564,539	6.477%	1.16%
11	Total	$224,093,002	$60,000,000	($65,476,370)	$218,616,632	$221,354,817	100.00%	$15,579,547	7.04%	7.04%

CENTRA GAS BRITISH COLUMBIA INC.

Schedule 60

2003/04/05 Revenue Requirement Application

CAPITAL STRUCTURE AND COST OF CAPITAL

2004 Forecast

LINE		CAPITALIZATION AMOUNT	CAPITALIZATION %	ANNUAL RATE %	COST COMPONENT %	EARNED RETURN $	ANNUAL DEBT COST $
1	Short Term Debt	$ 72,338,769	16.31%	5.70%	0.93%	$ 4,123,310	$ 4,123,310
2	New Long Term Debt Issue	0	0.00%	0.00%	0.00%	0	0
2	Existing Long Term Debt (1)	215,892,215	48.69%	5.65%	2.75%	12,191,208	12,191,208
3	Common Equity	155,201,299	35.00%	9.92%	3.47%	15,395,969	
4	MID-YEAR RATE BASE	$443,432,282	100.00%		7.15%	$31,710,486	$16,314,518

(1) Long Term Debt Continuity Schedule

LINE		Balance Opening	Additions	Repayments	Balance Closing	Mid-Year Balance	% of Total	Interest Expense	Annual Effective Rate	Weighted Average %
5	Annual Agency Fee							$ 50,000		0.02%
6	Swap 2	$ -			$ -	$ -	0.00%	0	0.00%	0.00%
7	Swap 3	95,000,000		(95,000,000)	0	47,500,000	22.00%	2,422,975	5.10%	1.12%
8	Swap 4	15,769,020		(1,073,835)	14,695,185	15,232,103	7.06%	922,608	6.06%	0.43%
9	Swap 5	38,250,000		(4,375,000)	33,875,000	36,062,500	16.70%	2,120,475	5.88%	0.98%
10	Unswapped	69,597,612	95,000,000		164,597,612	117,097,612	54.24%	6,675,149	5.701%	3.09%
11	Total	$218,616,632	$95,000,000	($100,448,835)	$213,167,797	$215,892,215	100.00%	$12,191,208	5.65%	5.65%

CENTRA GAS BRITISH COLUMBIA INC.

Schedule 61

2003/04/05 Revenue Requirement Application

CAPITAL STRUCTURE AND COST OF CAPITAL

2005 Forecast

LINE		CAPITALIZATION AMOUNT	CAPITALIZATION %	ANNUAL RATE %	COST COMPONENT %	EARNED RETURN $	ANNUAL DEBT COST $
1	Short Term Debt	$ 79,417,489	17.81%	5.70%	1.02%	$ 4,526,797	$ 4,526,797
2	New Long Term Debt Issue	0	0.00%	0.00%	0.00%	0	0
2	Existing Long Term Debt (1)	210,456,802	47.19%	5.14%	2.43%	10,819,801	10,819,801
3	Common Equity	156,086,156	35.00%	9.92%	3.47%	15,483,747	
4	MID-YEAR RATE BASE	$445,960,447	100.00%		6.91%	$30,830,345	$15,346,598

(1) Long Term Debt Continuity Schedule

		Balance Opening	Additions	Repayments	Balance Closing	Mid-Year Balance	% of Total	Interest Expense	Annual Effective Rate	Weighted Average %
5	Annual Agency Fee							$ 50,000		0.02%
6	Swap 2	$ -			$ -	$ -	0.00%	0	0.00%	0.00%
7	Swap 3	0			0	0	0.00%	0	0.00%	0.00%
8	Swap 4	14,695,185		(1,046,990)	13,648,195	14,171,690	6.73%	856,820	6.05%	0.41%
9	Swap 5	33,875,000		(4,375,000)	29,500,000	31,687,500	15.06%	1,847,698	5.83%	0.88%
10	Unswapped	164,597,612			164,597,612	164,597,612	78.21%	8,065,283	4.900%	3.83%
11	Total	$213,167,797	$0	($5,421,990)	$207,745,807	$210,456,802	100.00%	$10,819,801	5.14%	5.14%

CENTRA GAS BRITISH COLUMBIA INC.

Schedule 109

2003/04/05 Revenue Requirement Application

COST OF SALES - 2003 FORECAST

LINE		Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	TOTAL
1	Energy Sales - GJ	1,483,079	1,282,537	1,214,407	905,343	664,856	495,463	411,049	410,349	497,369	1,015,028	1,250,881	1,541,608	11,171,969
2	Total Energy Sales - GJ	1,483,079	1,282,537	1,214,407	905,343	664,856	495,463	411,049	410,349	497,369	1,015,028	1,250,881	1,541,608	11,171,969
	GAS PURCHASES													
3	Energy Purchases	1,483,079	1,282,537	1,214,407	905,343	664,856	495,463	411,049	410,349	497,369	1,015,028	1,250,881	1,541,608	11,171,969
4	Unaccounted and Own Use @	0	0	0	0	0	0	0	0	0	0	0	0	0
5	TOTAL PURCHASES - GJ (Line 2 + 4)	1,483,079	1,282,537	1,214,407	905,343	664,856	495,463	411,049	410,349	497,369	1,015,028	1,250,881	1,541,608	11,171,969
	COST OF SALES - $													
6	Gross Cost of Sales	$ 10,477,581	$ 9,114,845	$ 8,431,698	$ 5,147,981	$ 3,780,857	$ 2,923,045	$ 2,556,095	$ 2,580,761	$ 2,892,275	$ 5,783,002	$ 8,154,977	$ 10,504,562	$ 72,347,679
7	Gas Supply Costs Recov'd from Whistler	3,444	3,444	3,444	3,444	3,444	3,444	3,444	3,444	3,444	3,444	3,444	3,444	41,328
8	Net	10,474,137	9,111,401	8,428,254	5,144,537	3,777,413	2,919,601	2,552,651	2,577,317	2,888,831	5,779,558	8,151,533	10,501,118	72,306,351
9	Cost of Sales/GJ at $6.472													$ 72,306,351

CENTRA GAS BRITISH COLUMBIA INC.
2003/04/05 Revenue Requirement Application
COST OF SALES - 2004 FORECAST

Schedule 110

LINE		Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	TOTAL
1	Energy Sales - GJ	1,518,064	1,311,814	1,241,924	925,428	679,592	505,881	419,460	418,703	507,525	1,036,767	1,280,989	1,578,388	11,424,535
2	Total Energy Sales - GJ	1,518,064	1,311,814	1,241,924	925,428	679,592	505,881	419,460	418,703	507,525	1,036,767	1,280,989	1,578,388	11,424,535
	GAS PURCHASES													
3	Energy Purchases	1,518,064	1,311,814	1,241,924	925,428	679,592	505,881	419,460	418,703	507,525	1,036,767	1,280,989	1,578,388	11,424,535
4	Unaccounted and Own Use @	0	0	0	0	0	0	0	0	0	0	0	0	0
5	TOTAL PURCHASES - GJ (Line 2 + 4)	1,518,064	1,311,814	1,241,924	925,428	679,592	505,881	419,460	418,703	507,525	1,036,767	1,280,989	1,578,388	11,424,535
	COST OF SALES - $													
6	Gross Cost of Sales	$ 10,914,676	$ 9,488,048	$ 8,775,001	$ 5,354,356	$ 3,931,870	$ 3,036,012	$ 2,653,019	$ 2,678,135	$ 3,002,178	$ 6,010,838	$ 8,498,924	$ 10,945,876	$ 75,288,933
7	Gas Supply Costs Recov'd from Whistler	3,444	3,444	3,444	3,444	3,444	3,444	3,444	3,444	3,444	3,444	3,444	3,444	41,328
8	Net	10,911,232	9,484,604	8,771,557	5,350,912	3,928,426	3,032,568	2,649,575	2,674,691	2,998,734	6,007,394	8,495,480	10,942,432	75,247,605
9	Cost of Sales/GJ at $6.586													$ 75,247,605

CENTRA GAS BRITISH COLUMBIA INC. **Schedule 111**

2003/04/05 Revenue Requirement Application

COST OF SALES - 2005 FORECAST

LINE		Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	TOTAL
1	Energy Sales - GJ	1,555,889	1,343,290	1,271,178	946,648	694,819	516,207	427,582	426,769	517,529	1,058,854	1,311,446	1,615,721	11,685,932
2	Total Energy Sales - GJ	1,555,889	1,343,290	1,271,178	946,648	694,819	516,207	427,582	426,769	517,529	1,058,854	1,311,446	1,615,721	11,685,932
	GAS PURCHASES													
3	Energy Purchases	1,555,889	1,343,290	1,271,178	946,648	694,819	516,207	427,582	426,769	517,529	1,058,854	1,311,446	1,615,721	11,685,932
4	Unaccounted and Own Use @	0	0	0	0	0	0	0	0	0	0	0	0	0
5	TOTAL PURCHASES - GJ (Line 2 + 4)	1,555,889	1,343,290	1,271,178	946,648	694,819	516,207	427,582	426,769	517,529	1,058,854	1,311,446	1,615,721	11,685,932
	COST OF SALES - $													
6	Gross Cost of Sales	$ 11,407,012	$ 9,907,155	$ 9,158,153	$ 5,583,942	$ 4,097,872	$ 3,157,656	$ 2,756,113	$ 2,781,698	$ 3,120,233	$ 6,259,215	$ 8,872,240	$ 11,425,830	$ 78,527,120
7	Gas Supply Costs Recov'd from Whistler	3,444	3,444	3,444	3,444	3,444	3,444	3,444	3,444	3,444	3,444	3,444	3,444	41,328
8	Net	11,403,568	9,903,711	9,154,709	5,580,498	4,094,428	3,154,212	2,752,669	2,778,254	3,116,789	6,255,771	8,868,796	11,422,386	78,485,792
9	Cost of Sales/GJ at $6.716													$ 78,485,792

CENTRA GAS BRITISH COLUMBIA INC.
2003/04/05 Revenue Requirement Application
OPERATING & MAINTENANCE EXPENSES - SUMMARY

LINE		1999 Actual	2000 Actual	2001 Actual	2002 Outlook	2003 Forecast	2004 Forecast	2005 Forecast	Reference
	OPERATING								
1	Manufactured Gas	$0	$0	$0	$0	$0	$0	$0	Schedule 113
2	Transmission	1,459,876	1,365,161	1,531,412	1,342,040	1,736,543	2,001,104	1,522,766	Schedule 113
3	Distribution	7,483,640	7,411,501	6,677,652	6,448,236	6,596,310	6,756,627	6,934,762	Schedule 113
4	General Operation	4,217,276	4,254,196	4,023,109	3,677,066	3,803,404	3,593,254	3,763,888	Schedule 113
5	TOTAL OPERATING	13,160,793	13,030,858	12,232,174	11,467,342	12,136,257	12,350,985	12,221,416	
	ADMINISTRATION & GENERAL								
6	Sales Promotion	2,773,598	2,518,975	2,406,783	2,349,950	2,487,320	2,592,195	2,656,803	Schedule 114
7	Customer Accounting	2,878,602	3,982,680	4,294,181	4,278,196	4,497,993	4,667,117	4,822,963	Schedule 114
8	Administration & General	8,007,557	8,325,165	8,600,791	9,278,428	10,949,865	11,767,886	12,083,046	Schedule 114
9	TOTAL ADMINISTRATION & GENERAL	13,659,757	14,826,820	15,301,755	15,906,574	17,935,178	19,027,198	19,562,812	
	MAINTENANCE EXPENSE								
10	Local Storage	0	0	0	0	0	0	0	Schedule 115
11	Transmission	1,327,614	1,128,388	1,245,709	1,763,064	1,999,220	2,539,159	2,459,448	Schedule 115
12	Distribution	764,735	826,659	839,368	791,824	901,697	961,011	984,721	Schedule 115
13	General	1,445	0	0	0	0	0	0	Schedule 115
14	TOTAL MAINTENANCE EXPENSE	2,093,794	1,955,046	2,085,077	2,554,888	2,900,917	3,500,170	3,444,169	
15	NEGOTIATED SETTLEMENT ADJUSTMENT	1,461,876	1,170,402	2,000,791	2,551,956	1,272,352	2,378,353	2,628,397	
16	TOTAL GROSS EXPENSES	30,376,220	30,983,127	31,619,797	32,480,760	31,700,000	32,500,000	32,600,000	
	CAPITALIZATION								
17	Gross O & M Capitalization	(6,682,768)	(6,886,324)	(6,999,600)	(4,912,300)	(5,208,310)	(5,161,000)	(5,274,680)	Schedules 116-136
18	TOTAL O & M CAPITALIZATION	(6,682,768)	(6,886,324)	(6,999,600)	(4,912,300)	(5,208,310)	(5,161,000)	(5,274,680)	
19	TOTAL NET EXPENSES	23,693,453	24,096,804	24,620,198	27,568,461	26,491,690	27,339,000	27,325,320	
	NET CHARGES TO AFFILIATES								
21	Whistler	(317,187)	(223,660)	(208,386)	(212,554)	(216,593)	(220,492)	(224,902)	Schedules 116-136
22	TOTAL CHARGES TO AFFILIATES	(317,187)	(223,660)	(208,386)	(212,554)	(216,593)	(220,492)	(224,902)	
23	TOTAL NET DIRECT O & M EXPENSES	$23,376,266	$23,873,144	$24,411,812	$27,355,907	$26,275,097	$27,118,508	$27,100,418	
24	Average Number of Customers	63,735	67,891	70,340	72,597	75,324	78,168	81,220	
25	Average Gross Expenses Per Customer (Line 16/Line 25)	477	456	450	447	421	416	401	
26	Average Net Direct Cost Per Customer (Line 24/Line 25)	367	352	347	377	349	347	334	

Centra Gas

Centra Gas British Columbia Inc.
1675 Douglas Street
P.O. Box 3777
Victoria, British Columbia
V8W 3V3
Tel: (250) 480-4300
Fax: (250) 480-4459
www.centragas.com

December 19, 2002

British Columbia Utilities Commission
Sixth Floor
900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Mr. W. J. Grant, Executive Director

Dear Mr. Grant,

Re: Centra Gas British Columbia Inc. 2003 to 2005 Revenue Requirement Application – Negotiated Settlement Agreement

Centra Gas has reviewed the revised Negotiated Settlement document arising from the Negotiated Settlement proceeding held November 25th and 26th, 2002 at Victoria for the above noted Application. Centra Gas believes that the Settlement Document is a fair and accurate representation of the settlement discussions, and accepts this settlement proposal as revised.

Thank you for your assistance, and the assistance of the Commission Staff in arriving at a negotiated settlement acceptable to all parties.

Yours truly,
Centra Gas British Columbia Inc

Geoffrey Higgins

Geoffrey Higgins
Manager, Regulatory Affairs

cc: ADR Participants
Ian Anderson
Cal Johnson
Jim Murray
Grant Bierlmeier

i:\planning\admin\rev req\bc\2003 to 2005\negotiated settlement\negotiated settlement acceptance rev 1.doc

BCUC Log # 2134
RECEIVED
DEC 2 0 2002
Routing

Vancouver Island Public Sector Natural Gas Consumers Group
Camosun College, Lansdowne Campus, 3100 Foul Bay Road, Victoria BC V8P 5J2

University of Victoria
Vancouver Island Health Authority
Camosun College
North Island College
District of Saanich
City of Victoria

Victoria School District #61
Sooke School District #62
Saanich School District #63
Campbell River School District #72
Capital Regional District

By Facsimile (604) 660-1102
Mr. W.J. Grant
Executive Director
BC Utilities Commission
Sixth Floor, 900 Howe Street, Box 250
Vancouver, B.C. V6Z 2N3

December 20, 2002

Dear Mr. Grant:

Re: Centra Gas British Columbia Inc.,
Negotiated Settlement
Approval of 1999 to 2001 Actual Revenue Requirements and Revenue Deficiencies and 2003 and 2005 Forecast Revenue Requirements

---

In response to your letter of December 19, 2002, the Vancouver Island Public Sector Natural Gas Consumers Group accepts the final Agreement sent by you yesterday as the Negotiated Settlement Agreement on the Centra Gas British Columbia Inc. Application for Approval of 1999 to 2001 Actual Revenue Deficiencies and 2003 and 2005 Forecast Revenue Requirements.

Respectfully submitted on behalf of
The Vancouver Island Public Sector Natural Gas Consumers Group

Penny Cochrane

Penny Cochrane,
Willis Energy Services Ltd.

c: Participants

BCUC Log # 2149
RECEIVED
DEC 23 2002
Routing

The
British Columbia
Public Interest
Advocacy Centre
815 - 815 West Hastings Street
Vancouver, B.C. V6C 1B4
Tel: (604) 687-3063 Fax: (604) 682-7896
email: bcpiac@bcpiac.com
http://www.bcpiac.com

Michael P. Doherty 687-3034
Richard J. Gathercole 687-3006
Sarah Khan 687-4134
Patricia MacDonald 687-3017
Natasha Edgar (articled student) 687-3044
Barristers & Solicitors

December 20, 2002

File #7223

W.J. Grant
Executive Director
British Columbia Utilities Commission
Sixth Floor, 900 Howe Street, Box 250
Vancouver, B.C. V6Z 2N3

BY FAX: (604) 660-1102

Dear Mr. Grant:

Re Centra Gas British Columbia Inc., Negotiated Settlement, Approval of 1999 to 2001 Actual Revenue Requirements and Revenue Deficiencies and 2003 to 2005 Forecast Revenue Requirements

In response to your letter of yesterday"s date, we confirm the acceptance by CAC(BC) *et al.* of the proposed settlement.

Sincerely,
B.C. PUBLIC INTEREST ADVOCACY CENTRE

Michael P. Doherty
Barrister & Solicitor

c: parties

P:\MSOFFICE\MICHAEL\7000\7223 Centra Gas 2003-2005\draft settlement acceptance.doc

BCUC Log # 2143
RECEIVED
DEC 2 0 2002
Routing

BChydro THE POWER IS YOURS

Ray Aldeguer
Senior Vice-President
Corporate Resources &
General Counsel
Phone: (604) 623-4513
Fax: (604) 623-4407

20 December, 2002

Mr. Robert J. Pellatt
Commission Secretary
British Columbia Utilities Commission
P.O. Box 250
600-900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Pellatt:

**RE: British Columbia Hydro and Power Authority ("BC Hydro")
Centra Gas British Columbia Inc.
Revenue Requirement Application (Phase 1) (the "Application")**

We refer to the Commission's staff letter of 19 December 2002 forwarding a revised version of the Negotiated Settlement for the Application. BC Hydro confirms acceptance of the Negotiated Settlement.

BCUC Log # 2148
RECEIVED
DEC 2 4 2002
Routing rec'd via fax
Dec 20/02

Yours very truly,

Ray Aldeguer
Senior Vice-President
Corporate Resources &
General Counsel

LSM Consulting

Lloyd G. Guenther

December 20, 2002

British Columbia Utilities Commission
Sixth Floor, 900 Howe Street, Box 250
Vancouver, BC V6Z 2N3

Attention: Mr. W.J. Grant
Executive Director

Dear Mr. Grant:

Re: Centra Gas British Columbia Inc.
Negotiated Settlement
Approval of 1999 to 2001 Actual Revenue Requirements and Revenue Deficiencies
And 2003 to 2005 Forecast Revenue Requirements

I have reviewed the Negotiated Settlement document received December 19. The document accurately reflects the understanding of the Vancouver Island Gas Joint Venture of the results of settlement discussions and the agreement on a revenue requirement for Centra Gas for 2003 to 2005. We understand that there continue to be some problems in the schedules and expect that these will be corrected as errors are identified.

BCUC Log # 2160
RECEIVED
DEC 24 2002
Routing

Sincerely yours,

Lloyd G. Guenther

VANCOUVER
802-283 Davie St. (#24)
Vancouver, BC V6E 2R3
Tel: (604) 683-3604
Fax: (604) 683-3704
e-mail: lguenther@novus-tele.net

VICTORIA
4300 Maltwood Close
Victoria, BC V8X 5C7
Tel: (250) 479-3236
Fax: (250) 479-3659
e-mail: lguenthe@direct.ca