

Heenan Blaikie

SOCIÉTÉ EN NOM COLLECTIF

Montréal, le 18 septembre 1998

PAR MESSAGER

A V O C A T S

AVOCATS - CONSEILS

Le très honorable Pierre Elliott Trudeau, c.p., c.r.
L'honorable Donald J. Johnston, c.p., c.r. (1974-1996)
Peter M. Blaikie, c.r.

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LIGNE DIRECTE

Me Véronique Dubois
Secrétaire de la Régie
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Gouvernement du Québec
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Objet : ● Cause tarifaire de SCGM 1999
● R-3397-98
● Notre référence : 3070-206

Chère consoeur,

Nous vous transmettons sous pli quinze (15) exemplaires des documents suivants constituant la preuve de l'ACIG relativement au dossier mentionné en rubrique :

- a) Pièce ACIG-1, doc. 1 constituant la preuve de notre expert, Hugh W. Johnson, relativement au mécanisme de rendement incitatif proposé par Gaz Métro;
- b) Pièce ACIG-2, doc. 1 constituant la preuve de notre expert, le Dr. William W. Waters, au sujet du taux de rendement.

Compte tenu que nous avons fait traduire du français à l'anglais plusieurs segments de la preuve de Gaz Métro dans les matières qui intéressent nos deux (2) experts, nous apprécierions que la Régie, Gaz Métro ou les autres intervenants nous informent s'ils désirent obtenir une version française de la déposition de ces deux (2) experts.

Nous profitons de cette occasion pour rappeler à la Régie, à Gaz Métro ainsi qu'aux autres intervenants que nous avons déjà produit au dossier une version anglaise des documents suivants :

- a) Pièce SCGM-15, doc. 1 constituant la proposition principale de Gaz Métro au sujet de l'encadrement réglementaire (rendement incitatif) ainsi que sur la formule automatique d'ajustement du taux de rendement;

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- b) Pièce SCMG-15, doc. 3 constituant l'expertise du Dr. Rabeau au sujet de l'encadrement réglementaire (rendement incitatif).

Enfin, nous désirons informer la Régie, Gaz Métro et les autres intervenants que nous avons en notre possession une version anglaise des documents suivants que nous avons fait traduire pour nos experts et que nous serions disposés à déposer au dossier :

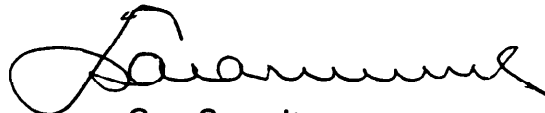
1. Extrait de la décision D-93-51 du 1^{er} octobre 1993 concernant la structure de capital, le taux de rendement et le mécanisme de rendement incitatif;
2. Extrait de la décision D-94-65 du 1^{er} décembre 1994 concernant la structure de capital et le taux de rendement;
3. Extrait de la décision partielle D-95-48 du 21 juin 1995 au sujet du taux de rendement;
4. Extrait de la décision D-95-54 du 24 août 1995 au sujet de la structure de capital et du taux de rendement;
5. Extrait de la décision D-96-31 du 9 octobre 1996 au sujet de la structure de capital et du taux de rendement;
6. Extrait de la décision D-97-27 du 30 juillet 1997 au sujet du taux de rendement;
7. Version anglaise des pièces suivantes constituant les réponses de Gaz Métro à certaines questions de l'ACIG, de la Régie et de certains intervenants :
 - a) SCGM-15, doc. 1.2e) et doc. 1.2f);
 - b) SCGM-15, doc. 1.3c), doc. 1.3e) et doc. 1.3f);
 - c) SCGM-15, doc. 1.5a), doc. 1.5b), doc. 1.5c) et doc. 1.5d);
 - d) SCGM-15, doc. 1.6b);
 - e) SCGM-15, doc. 1.7b), doc. 1.7c), doc. 1.7d), doc. 1.7e), doc. 1.7f), doc. 1.7h), doc. 1.7i), doc. 1.7j), doc. 1.7k) et doc. 1.7l);
 - f) SCGM-15, doc. 1.8a) et doc. 1.8b);
 - g) SCGM-15, doc. 1.9a) et doc. 1.9b);
 - h) SCGM-15, doc. 1.10a) et doc. 1.10b);
 - i) SCGM-15, doc. 1.11a), doc. 1.11b) et doc. 1.11c);
 - j) SCGM-15, doc. 1.12a), doc. 1.12b), doc. 1.12d), doc. 1.12e), doc. 1.12f) et doc. 1.12g);

- k) SCGM-15, doc. 1.13b) et doc. 1.13c);
- l) SCGM-15, doc. 1.14a) et doc. 1.14b);
- m) SCGM-15, doc. 1.18;
- n) SCGM-15, doc. 2.1;
- o) SCGM-15, doc. 2.2;
- p) SCGM-15, doc. 2.3;
- q) SCGM-15, doc. 2.6;
- r) SCGM-15, doc. 3.2;
- s) SCGM-15, doc. 3.3;
- t) SCGM-15, doc. 3.4;
- u) SCGM-15, doc. 3.5;
- v) SCGM-15, doc. 3.6
- w) SCGM-15, doc. 3.7;
- x) SCGM-15, doc. 3.8;
- y) SCGM-15, doc. 3.9
- z) SCGM-25, doc. 3.10;
- aa) SCGM-25, doc. 3.11;
- bb) SCGM-25, doc. 3.12;
- cc) SCGM-25, doc. 3.14;
- dd) SCGM-25, doc. 3.15;
- ee) SCGM-25, doc. 3.16.

Nous apprécierions enfin que la Régie nous fasse part de ses suggestions et directives quant à l'opportunité ou non d'attribuer une cote quelconque aux versions anglaises des documents ci-dessus que nous avons déjà produits ou que nous serions disposés à déposer au dossier de la Régie.

Veillez agréer, chère consoeur, l'expression de nos sentiments les meilleurs.

HEENAN BLAIKIE



Guy Sarault

GS*dmd

p.j.

c.c.

- SCGM a/s Me Jocelyn Allard
- Intervenants (voir liste ci-jointe)
- ACIG
a/s M. Peter Fournier
a/s M. Hugh Johnson
a/s Dr. William Waters

R-3397-98
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**SOCIÉTÉ EN COMMANDITE GAZ MÉTROPOLITAIN
RATE CASE 1998-99 (R-3397-98)**

**EVIDENCE OF
HUGH W. JOHNSON
ON BEHALF OF THE
INDUSTRIAL GAS USERS ASSOCIATION
AS TO
THE INCENTIVE SCHEME
PROPOSAL**

SEPTEMBER 1998

**R-3397-98
ACIG-1, doc. 1**

1 **Q1: Mr. Johnson would you please state your full name and occupation?**

2 **A:** My name is Hugh Warren Johnson. I am a partner with the firm of
3 Stephen Johnson, Chartered Accountants. My business address is Suite 1810,
4 205 - 5th Avenue S.W., Calgary, Alberta.

5 **Q2: What is your academic and professional background?**

6 **A:** My Curriculum Vitae is attached as Appendix I.

7 **Q3: At whose request have you prepared this evidence?**

8 **A:** I have prepared this evidence at the request of the Industrial Gas Users Association
9 ("IGUA/ACIG").

10 **Q4: What is the purpose of your evidence?**

11 **A:** I have been asked to address the proposed incentive scheme of the Société En
12 Commandite Gaz Métropolitain ("SCGM")

13 **Q5: What conclusions have you reached in this evidence?**

14 **A:** The existing methodology used with respect to SCGM has a number of
15 shortcomings, however, it could be continued as an interim or stopgap measure until
16 a broader consensus based incentive mechanism could be achieved.

17 The proposed mechanism of SCGM is seriously flawed and should not be adopted.

18 The Régie should direct SCGM and the stakeholders to commence discussions in
19 order to arrive at an incentive mechanism that meets the goals and objectives of all
20 the stakeholders.

21 **Q6: Please describe your understanding of the reason and purpose behind
2 incentive regulatory schemes?**

1 A: Incentive regulation generally purports to overcome what are considered the
2 inefficiencies of traditional rate of return regulation. The two inefficiencies relate to
3 the lack of incentive under rate of return regulation to control costs and the incentive
4 to invest in capital assets, i.e. to construct facilities (Averch Johnson). An additional
5 reason given for incentive regulation is that it may reduce the regulatory burden.

6 Whether regulatory burden can be decreased under incentive schemes is very much
7 related to the circumstances of the utility and the nature of the incentive scheme.
8 The methods approved for TransCanada PipeLines Limited ("TransCanada" or
9 "TCPL") and BC Gas Utilities Ltd. (see Appendix IV) require annual filings and
10 regulatory determinations. A reasonably simple or very formulistic method may
11 operate for a number of years without regulatory scrutiny. The current incentive
12 methodology of SCGM does not eliminate the need for the regulatory proceeding for
13 both the annual rate case and the closing of the books. Further the proposal of
14 SCGM still requires and still proposes an annual rate case and a process similar to
15 the closing of the books.

16 A review of SCGM's filing, in particular SCGM-2, Document 5, the 1998 Budget
17 indicates that of the total 1998 Revenue Requirement of \$1.091 billion, only 9.17%
18 (99.997 million/1.091 billion) are costs that are both controllable by SCGM and
19 impacted by inflation over the shorter term, one year to the next. The balance of the
20 costs are either not affected by inflation directly in the test year and/or are not
21 controllable by SCGM. It is doubtful therefore that an incentive mechanism
22 designed to control costs is appropriate.

23 An incentive scheme for SCGM should address its specific factual situation. In
24 addition, the incentive scheme should address the issues that are of concern to the
25 customers. IGUA has indicated to me that although it is concerned with SCGM
26 controlling costs, it would like to see SCGM's facilities better utilized, with the
27 increased utilization resulting in the reduction of rates. The incentive mechanism

1 currently in place and the proposed method do not directly address this issue. These
2 methods do not differentiate earnings achieved from cost savings from earnings
3 achieved by obtaining new customers or improving the load factor utilization on the
4 existing system.

5 Ideally, the increased earnings achieved by obtaining new customers, and therefore
6 increasing the utilization of the system, would be differentiated from increased
7 earnings achieved by existing customers electing to use more gas. In the former
8 case, SCGM has to actively work at obtaining the additional revenue whereas they
9 have little or no influence on existing customers currently using gas whose changed
10 economic circumstances have resulted in increased gas usage.

11 Doctors Mansell and Church initiated a study of the principle objective of which was
12 to examine alternative regimes for the regulation of major natural gas pipelines in
13 Canada including clarifying and analysing key issues and advancing the debate
14 relating to these regulatory alternatives. In doing so, the study reviewed the
15 regulatory fundamentals and traditional regime and drew on regulatory changes and
16 experiments with respect to other regulated segments such as telecommunications
17 and electricity. In their concluding observations, Mansell and Church state:

18 "After examining the many complex issues in the regulation of
19 gas transmission and the various regulatory alternatives it
20 seems apparent that none of the new-style incentive regimes
21 represent a panacea. Nor is it possible to conclude that any
22 one of these is uniformly better in terms of key evaluation
23 criteria than the traditional COS approach, especially that
24 which incorporates streamlining.

25 Rather, all regulatory approaches embody trade offs that must
26 be considered in the context of the particular circumstances of
27 each transmission system. In determining whether a specific

1 alternative would be a significant improvement, several
2 fundamental questions must be answered. The first is whether
3 the regime is appropriate given the characteristics of the
4 system. For example, some approaches are well-suited for
5 stable, mature systems but deficient for those where frequent,
6 large expansions will likely be required. Similarly, some are far
7 better as short-term or transitional mechanisms than as
8 regimes which must be sustainable. A second important issue
9 is whether the trade-offs are acceptable. For instance, in many
10 cases the alternative may result in greater cost efficiency and
11 reduced regulatory burden, but at the expense of real or
12 perceived fairness or at the expense of the overall level of tolls
13 if the cost of financial capital or the equity ratio is increased. It
14 will be important in every case to recognize all such trade offs
15 and obtain a consensus on their acceptability." (emphasis
16 added)

17 "Given the particular circumstances of each system in terms of
18 factors such as the degree of competition, the level of capacity
19 utilization, and the rate of expansion, it will generally be
20 preferable to tailor the regime to some extent to the particulars
21 of the circumstances."¹ (emphasis added)

22
23 As indicated by Doctors Mansell and Church, it is important in implementing an
24 incentive mechanism, to consult with and obtain support of other stakeholders. The
25 incentive methodologies referred to in Appendix IV, were all the result of
26 negotiations and discussions amongst the stakeholders. In particular, the July 23,
27 1997 Reasons for Decision with respect to BC Gas Utility Ltd. ("BC Gas"), on the

¹
Mansell, Robert L. and Church, Jeffrey R., Traditional and Incentive Regulation 1995, The Van Home
Institute for International Transportation and Regulatory Affairs, page 172.

1 first page of the Consolidated Settlement document, indicated all the parties who
2 were involved in the negotiation sessions, by way of contrast to SCGM's scheme
3 which has been proposed in isolation.

4 TransCanada's incentive scheme (see Appendix IV RH-2-95 Summary) has been
5 tailored to specifically address certain costs and revenues over which TransCanada
6 has some control or influence. This is done by an incentive envelope using flow
7 through of certain costs such as depreciation, return on rate base, income tax,
8 foreign exchange, insurance deductible costs, and a provision for discretionary
9 revenue. Other costs such as foreign exchange and interest, TransCanada obtained
10 approval to enter into a foreign exchange and interest management programs,
11 rather than relying strictly on deferral accounts.

12 Discussing objectives and needs with customers allows a negotiation to take place
13 that should meet some of the objectives of each of SCGM and its customers, rather
14 than just SCGM. This is best done outside of the hearing room.

15 **Q7: Is it necessary to have an incentive scheme in order to simplify and adopt a**
16 **formulistic method of determining rate of return?**

17 **A:** The Régie could adopt a formulistic method of determining rate of return on
18 common equity such as that discussed by Dr. Waters, without an incentive scheme.
19 The National Energy Board ("NEB") approved a formalistic approach to determining
20 return on common equity before incentive schemes were adopted, as did the British
21 Columbia Utilities Commission and the Manitoba Public Utilities Board. (see
22 Appendix V, NEB's Decision RH-2-94, B.C.U.C. Decision of June 10, 1994 with
23 respect to rate of return and the Manitoba Public Utilities Board, Decision Order
24 49/95 May 5/95 with respect to Centra Gas Manitoba Inc.) The NEB's Decision RH-
25 2-94 Reasons for Decision on Cost of Capital, indicates that after the hearing had
26 been completed but before the decision was reached, Interprovincial Pipelines
27 Limited and the Canadian Association for Petroleum Producers had submitted a

1 multi-year toll settlement for approval by the Board. However, that agreement had
2 no impact on the National Energy Board's decision with respect to the cost of capital
3 and in particular, to the formula used.

4 **Q8: Please describe your understanding of the current incentive mechanism as**
5 **approved in Decision D-93-51.**

6 **A: Under this mechanism, at least (50%) of any excess return on equity (after tax and**
7 **after accounting for deferral or levelling account adjustments) above the authorized**
8 **return on common equity is returned to the customers. SCGM is entitled to the**
9 **remaining 50% if its performance under four indicators is at 95% or higher. Of**
10 **these four indicators, two relate to customer service and two relate to security. If**
11 **the average of the four indices is less than 85%, then SCGM does not retain any**
12 **of the excess and all of the excess goes to the customers. If the average of the four**
13 **indicators is between the 85% average and the 95% average, an amount between**
14 **42.5% and 50.0% of the excess goes to SCGM with the customers receiving the**
15 **balance. [SCGM-15 Document 1, page 7 and 1993 Annual Report, page 20]**

16 **Q9: Is the current incentive method satisfactory?**

17 **A: The current incentive mechanism is simple and easy to apply. However, it fails to**
18 **recognize that the excess earnings can be achieved from factors outside the control**
19 **of SCGM's management. Alternatively, the management activities may result in**
20 **savings, but factors beyond their control for which there are no deferral accounts,**
21 **results in minimal or no excess earnings.**

22 **The average of the four indices are key to determining the amounts benefiting**
23 **customers and SCGM. However, these indices are not rigorous nor easily**
24 **compared to other utilities, in order to determine whether the activities of SCGM**
25 **management are deserving of additional compensation or return. In addition, if the**
26 **quality of service declines from say 95% to 90%, the same share of additional**
27 **income is achieved as if the indicators went from 85% to 90%. However, although**

1 one is a reduction in service and the other is an increase, they both result in SCGM
2 receiving the same amount of additional income.

3 If these quality of services indicators are considered to be true indicators of the
4 quality of service, perhaps the criteria should be based upon the actual performance
5 for two or three years prior. If the current year does not meet or exceed the
6 previous year's performance, SCGM would receive a lesser amount.

7 In the future, SCGM may contract out, as other utilities are contemplating, some or
8 both of the customer service items that now result in quality of service indicators.
9 In those circumstances, the quality of service indicators would be a matter of
10 contract rather than a measure of service.

11 With respect to the security type indices, I understand that one relates to budget
12 versus actual for maintenance tests, while the other relates to response to
13 emergency situations. The time horizon on the response to emergency situations
14 seems to be too long. Further, just responding in a quick manner is not necessarily
15 providing good service if, once the response is made, the person responding is not
16 able to, or does not resolve the emergency situation satisfactorily. Getting to the
17 emergency situation in 30 minutes is no consolation, if having arrived there, the
18 personnel do not solve the emergency and a fire or explosion occurs. The second
19 item which is with respect to budget to actual comparison for maintenance tests
20 does not seem to be very rigorous. If tests were planned or budgeted and SCGM
21 later realized that, unless the budgeted number of tests were completed, it would
22 fail to earn its share of the additional earnings, the tests could be conducted in a
23 very superficial manner in order to achieve the appropriate level. If the Régie
24 considers that these are truly indicators of service quality, a more objective
25 approach would be to compare the performance to a historical period or other gas
26 LDC's performance. The current performance under the indicators as shown in

1 SCGM 15 Document 1.3(d) indicates that since 1993 SCGM has not been in
2 jeopardy of not sharing any of the over earnings.

3 Another consideration with respect to the current methodology is that there appears
4 to be an inherent bias in forecasting. The information provided in SCGM-15,
5 Document 1.3(a) indicates that only once in the last nine years was the *trop-perçu*
6 (*manqué à gagner*) negative and in every other year, there were positive amounts
7 (over earnings). Even in 1995, the year in which there was a shortfall, there appear
8 to be matters that were finalized after the year end which resulted in causing part
9 of the shortfall. (The 1995 Annual Report of SCGM indicated that the shortfall
10 would be approximately \$1.3 million, however, the above referenced document and
11 the 1996 Annual Report referred to a shortfall of \$1.8 million.)

12 One of the other reasons for the lack of earning shortfalls appears to be the liberal
13 use of deferral or levelling accounts by the Régie. In addition to the five accounts
14 listed in SCGM 15, Document 1, pages 6 & 7 of 32 and SCGM-12 Document 3,
15 lines 38 to 78, these minimize SCGM's risk and increases its ability to achieve over
16 earnings.

17 **Q10: What do you understand to be the incentive proposal of SCGM?**

18 **A:** In very general terms, SCGM's proposal provides for sharing of savings calculated
19 before the year starts. The savings are calculated by comparing a certain basket
20 of volume adjusted costs inflated plus the pass-through of certain other costs to a
21 forecast revenue requirement.

22 The basis of the proposal appears to be that if controllable cost increases are less
23 than inflation (CPI), SCGM should be rewarded up-front based on the forecast
24 savings. However, natural gas distribution companies tend to be natural
25 monopolies. By their nature, many costs are expected to increase at a rate less
26 than inflation because marginal costs should be less than average cost. In addition,

1 given the significant number of items included in the Revenue Requirement that
2 are not subject to short-term variations because of inflation rates, a natural gas
3 distribution company should have rates which decline in nominal as well as in real
4 terms over the medium term.

5 The terms used in the evidence are defined in Appendix II and are reflected in bold
6 type.

7 At the beginning of the Test Year, SCGM proposed that it will determine an
8 **Expected Service Cost**. The **Expected Service Cost** is the sum of:

- 9 1) **Base Service Cost** less:
10 a) the **Test Year** forecast of cost of gas
11 b) certain **Test Year** transportation and storage costs which SCGM
12 submits are outside its control, and
13 c) return on equity and income taxes based upon the base year
14 costs as a percentage, applied to the **Test Year** common equity.
15 2) inflation applied to **Base Operating Costs**, and
16 3) **Pass-Through Costs**.

17 Two-thirds of the difference (**Performance Bonus** (up-front) between the
18 **Expected Service Costs** and the **Required Revenue** is added to the **Required**
19 **Revenue** to determine the **Revenue Requirement** to be generated through rates.

20 At the end of the year, to the extent that actual revenues, net of gas costs, actually
21 collected exceed the costs incurred, net of gas costs, including the up-front bonus,
22 the surplus will be split two-thirds to the customer and one-third to SCGM (SCGM-
23 15, Document 1.15, page 6 of 6, Scenarios 2 and 3). If the actual revenues, net of
24 gas costs, are less than the costs incurred, net of gas costs but equal to at least the
25 costs incurred, excluding the **Performance Bonus** (up-front), there would be no
26 adjustment at the end of the year. If the actual revenues, net of gas costs, were

1 less than the costs incurred, net of gas costs, excluding the **Performance Bonus**
2 (**up-front**), then the shortfall would be shared two-thirds to the customer and one-
3 third to SCGM. This differs from the current method where SCGM would bear the
4 entire shortfall. Based on the response to SCGM-15, Document 1.15, page 6 of 6
5 and SCGM-15, Document 1.66, it does not appear that there is any differentiation
6 at the end of the year between cost savings or increased revenues or the causes
7 of the excesses, as all surpluses are shared in the same proportion under SCGM's
8 proposal.

9 **Q11: What type of incentive mechanism is SCGM proposing?**

10 **A:** SCGM describes its mechanism as targeting several sets of actions with a more
11 global perspective (SCGM 15 Document 1 page 14 of 32 of the English translation).
12 The incentive mechanism that SCGM is proposing could be described as a form of
13 revenue cap with a very significant exogenous (flow-through of costs beyond its
14 control) factor of approximately 47% (\$333.331/\$697.519) of the **Base Service**
15 **Cost**, as reflected in SCGM-15, Document 1, Appendix I, lines 5-9. SCGM has
16 presented in this proposal a concept that all costs over which it believes it has some
17 influence are also impacted by inflation and could be expected to increase by CPI
18 annually. While all costs are influenced, to some degree, by the management of
19 SCGM, it is generally recognized that in natural monopolies such as natural gas
20 distribution systems, the costs that can be changed significantly in a one or two year
21 period are few. This is particularly the case if it is assumed that the accounting
22 policies and practices (e.g. capitalized overhead) don't change and changes to
23 depreciation and amortization periods require regulatory approval.

24 For purposes of this evidence, I am using the definition of controllable costs found
25 in Appendix II. I have also assumed that costs for which there are deferral accounts
26 are generally not controllable, otherwise a deferral account would not be necessary.
27 I understand, however, that certain of the deferral accounts used by SCGM are for
28 items which the Régie has determined should be recovered over a period of longer

1 than one year. The fixed nature of many of SCGM's costs and its ability to
2 generally increase throughput at less than its average cost makes it reasonable to
3 expect that the costs (Required Revenue) should increase at less than inflation
4 and perhaps should decline on a per unit of throughput basis year over year.
5 As the SCGM system matures, it would be expected that additions to rate base,
6 and in particular, to plant in service would be less than the depreciation expense
7 resulting in a declining rate base for a period of years. A significant shortcoming
8 of SCGM's mechanism is that it does not incorporate an explicit reduction in
9 costs for productivity improvements nor does it provide for what is often described
10 as a consumer productivity dividend or "stretch factor".

11 **Q12: Would you comment on the base cost of service used by SCGM.**

12 **A: The SCGM proposal uses a Base Service Cost, which for the 1999 Test Year**
13 **(\$697.519 million), is not related to the approved 1998 cost of service (Base**
14 **Cost of Service), but rather relates to the 1999 revenue that would be collected**
15 **using the 1998 rates (SCGM-2, Document 3) applied to the 1999 forecast sales.**
16 **The Base Cost of Service is \$681.7 million, (the 1998 approved Revenue**
17 **Requirement less the 1998 forecast cost of gas). The result of SCGM's**
18 **methodology is that it applies an inflation factor to a higher Base Operating Cost**
19 **than would be the case if 1998 amounts approved by the Régie were used. As**
20 **indicated above, increased sales should provide more than enough revenue at**
21 **prior year's rates to cover all costs except perhaps, some increases in Pass-**
22 **Through Costs.**

23 SCGM has also assumed that all costs that are within SCGM's control are subject
24 to inflation on an annual basis. That certainly is not true with respect to items
25 such as depreciation, embedded debt costs, and amortization of deferred charges
26 whether they are controllable or not. Other costs such as real estate and
27 property taxes and levies from the Régie are potentially affected by inflation but
28 are not directly impacted in the manner by which the SCGM proposal implies.

1 For example, SCGM-2, Document 6, page 4 of 5 indicates that real estate and
2 property taxes, as well as levies from the Régie's are expected to decline by
3 17.3%.

4 **Q13: If the Régie were to accept SCGM's general approach, what costs would**
5 **you exclude out of the controllable category in addition those proposed**
6 **non-controllable by SCGM?**

7 **A: I would classify depreciation, amortization of deferred charges, financing charges**
8 **including interest and dividends, and certain additional items in the cost of**
9 **transportation and storage as Non-Controllable Costs.**

10 Depreciation is a cost which is not directly affected by inflation on a yearly basis.
11 The depreciation rates are set by the Régie and I would anticipate that SCGM
12 cannot change the depreciation rates without the approval of the Régie. Additions
13 to rate base may cost more because of inflation, although CPI is probably not the
14 correct indicator of inflation for those costs. The historical amount of depreciation
15 expense is unaffected by the current year or future years' inflation. Therefore it
16 is inappropriate to include depreciation expense in the Base Operating Costs to
17 which inflation is applied to arrive at the Expected Operating Costs.

18 The amortization of deferred charges is a cost item which is not controllable by
19 SCGM nor is it impacted by inflation in the current year. The occurrence of these
20 charges is a direct result of items which were either not within the control of
21 SCGM or were placed in a deferral account to smooth the impact of their
22 incurrence. In either case, these are historical costs that are being amortized.
23 Therefore, it is inappropriate to include the amortization of deferred charges in
24 the **Base Operating Costs** to which inflation is applied to determine the
25 **Expected Operating Costs.**

1 Financing charges including interest and the deemed cost of preferred shares are
2 another cost item which is not controllable by SCGM. It is my understanding that
3 SCGM has a deferral account for financing costs. The need for a deferral
4 account and the ability to control costs are inconsistent. SCGM's decisions on
5 how to finance its debt may impact the overall cost of capital. SCGM has no
6 influence on the interest rates or charges it must pay. Past decisions are
7 reflected in the embedded cost of outstanding debt issues. These costs are not
8 impacted by the current year's inflation. The financing charges should be
9 excluded from the Base Operating Cost to which is applied to determine the
10 Expected Operating Cost. These costs should be treated as Pass-Through Costs
11 like depreciation and the amortization of deferred charges.

12 Real estate and property taxes as well as other charges including the royalty to
13 the Régie are also costs which are essentially beyond the control of SCGM. It
14 is the municipalities who will determine the amount of the property taxes. The
15 increases in those taxes reflect inflation only to the extent that the municipality
16 increases its millrate by an amount equivalent to inflation. In addition, the royalty
17 paid to the Régie may or may not increase by the rate of inflation, depending on
18 how the Régie allocates the royalty amongst the companies that it regulates. For
19 1999, both of these amounts decrease notwithstanding inflation (SCGM-2,
20 Document 6, page 4 of 5). For both of these categories of costs, the influence
21 that SCGM has on the annual amount is virtually non-existent. It was the
22 Government's decision, for instance, to create the new Régie and put Hydro
23 Quebec under its jurisdiction, providing a reduction in SCGM's share of the costs.

24 SCGM has indicated that it considers only the transportation and storage costs,
25 principally for TransCanada and Union Gas Limited ("Union"), as charges outside
26 of its control. These costs are shown in SCGM-15, Document 1, Appendix I,
27 Note 1.

1 SCGM has no more control over the TCPL costs than it has over interest costs.
2 SCGM determines the volumes contracted and operationally determines the
3 utilization. While it does not have any control over the rates approved by the
4 regulator, SCGM participates in rate proceedings before the NEB and the Ontario
5 Energy Board ("OEB"), presumably in order to influence the decisions of those
6 regulators.

7 For purposes of the items treated as **Non-Controllable Costs**, I have looked
8 principally at the storage and transportation costs for TCPL and Union as the
9 benchmark or standard. I understand that SCGM may, if TCPL or Union's rates
10 increase significantly, request an adjustment in its rates. Alternatively, the
11 change may be placed in a deferral account. Further, I have compared the costs
12 that are included in Note 1 (SCGM-15, Document 1) with the other storage and
13 transportation costs shown in SCGM-15, Document 8.

14 SCGM-5, Document 8 indicates at line 25 that the forecast cost of transportation
15 and storage is \$302.793 million. Of this, SCGM has considered \$237.667 million
16 to be non-controllable. However, in reviewing SCGM-5, Document 8, there does
17 not appear to be any significant difference between the \$237.7 million included as
18 non-controllable and the other approximately \$65 million which are treated implicitly
19 as controllable. For example, compression gas which is forecast to have a cost of
20 \$40.5 million (SCGM-5, Document 8, page 1 of 2, line 11) is in the same category
21 as the commodity charges of TCPL which are shown on lines 11 and 12 of the
22 same document. However, SCGM considers that the two amounts for the
23 commodity charges for the Eastern Zone and the Northern Zone (\$10.193 and
24 \$.162 million respectively) are **Non-Controllable Costs** while the \$40.5 million of
25 compressor fuel is a **Controllable Cost**. TCPL determines the fuel ratios and
26 requires shippers such as SCGM to supply the fuel. The only control that SCGM
27 has over this amount is to determine the flow of gas on the TransCanada facilities.

1 That same control is applicable to the variable tolls on TransCanada which SCGM
2 has included as non-controllable transportation and storage costs.

3 Further, included in the costs of transportation and storage is the amount for lost
4 and unaccounted-for gas (forecast at \$4.9 million, SCGM-5, Document 8, page 2
5 of 2, line 20). Lost and unaccounted-for gas is a function of both the cost of gas
6 and throughput. This item is generally expressed as a percentage of throughput.
7 The control that SCGM has on this item is related to reducing the percentage, not
8 the dollar amount since the cost of gas is beyond its control. While I am not
9 completely familiar with all of the other items included in the cost of transportation
10 and storage, there does not appear to be any one item that is any more controllable
11 than others. As such, I would suggest that all of the costs of transportation and
12 storage should be considered as **Non-Controllable Costs** by SCGM. In addition,
13 the driving factor for many of these costs is the cost of gas, rates determined by
14 other regulators or through contract, and are generally not impacted by inflation in
15 the simple and straight forward manner.

16 The approximate \$65 million of storage and transportation costs included by SCGM
17 as **Controllable Costs** are approximately 65% of the forecast O&M expense shown
18 on SCGM-2, Document 5 of \$104.4 million. The inclusion of these storage and
19 transportation costs as **Controllable Costs** allows SCGM to increase its operating
20 expenses by approximately 4.4% (SCGM-2, Document 6, page 3 of 5) when
21 inflation is projected at 1.7% and still under its proposal, receive a **Performance**
22 **Bonus (up-front)**.

23 One cost under the complete control of SCGM is the consumer price discounts
24 offered to certain customers. The amount of new discounts to be offered is a
25 decision SCGM may make. However, the continuation of previous discounts for
26 which SCGM is still contractually obligated to pay (historical amounts) in the
27 upcoming year are certainly not controllable. For instance, it is not clear that

1 inflation, for example, has anything to do with the forecast reduction from \$24.9
2 million to \$20.5 million (SCGM-2, Document 5, line 4) in consumer price discounts..

3 **Q14: Is your interpretation of costs within SCGM's control consistent with**
4 **decisions and agreements that have been taken elsewhere and by the Régie**
5 **in past decisions?**

6 **A:** It is my view that for purposes of SCGM's proposal the only costs over which
7 SCGM has any significant control or influence is operating expenses. Even with
8 respect to these, there is a certain minimum level that would be incurred
9 irrespective of volume or other factors. However, operating costs make up only
10 8.7% of the Required Revenue (104.4/1194.5, SCGM-2, Document 5, lines 11 and
11 3), the influence of SCGM's management on the costs is relatively small. And
12 within the category of costs within its control i.e. operating and maintenance
13 expense, SCGM has not been able to limit that to inflation as indicated above.

14 **Q15: In addition to your concerns over the classification of costs between**
15 **Controllable and Non-Controllable, are there other concerns with respect to**
16 **the methodology that make it inappropriate?**

17 **A:** The SCGM proposal is a departure from most of the incentive based mechanisms
18 in that it proposes that shortfalls between allowed and achieved return on common
19 equity (ROE) would be shared. As SCGM's witness, Dr. Rabeau indicates (page
20 14 of the English translation, 15 of the French version, particularly lines 26 and 27)
21 in an incentive based system, any lower yield or shortfall is generally absorbed by
22 the shareholders. This is appropriate since utilities such as SCGM have the
23 information to monitor their performance, have deferral accounts to reduce and
24 insulate them from certain risks, have the ability to go to the regulator to introduce
25 new programs if necessary and in the case of SCGM, have most of their large
26 volume customers under long term contracts. Reducing SCGM's exposure to loss
27 from failing to control costs is not appropriate. While there may be a level at which
28 SCGM would have to come back before the Régie, if its earnings fell too low, this

1 should not be built into the methodology. It should be up to SCGM to determine
2 whether its financial integrity would be impaired and therefore the need to take
3 steps to reduce the potential for earnings shortfalls.

4 The methodology proposed by SCGM is that it would receive two thirds of the
5 projected differential between the **Expected Service Costs** and the **Required**
6 **Revenue** at the beginning of the year and one third of any actually achieved
7 savings in addition to the **Performance Bonus (up-front)** at the end of the year.
8 This creates an obvious incentive to utilize what otherwise would be a surplus at the
9 end of one year to incur costs or expenses which by the mere timing of their
10 occurrence would result in a greater saving in the subsequent year for which SCGM
11 would, under their proposal, retain two thirds. If the excess otherwise calculated
12 before the expenditure was \$1 million and SCGM were to incur an expense in year
13 X of \$1 million, there would be no savings in year X and SCGM would have
14 foregone the potential of \$333,000 of **Performance Bonus**. However, if, as a result
15 of the expenditure of \$1 million in year X, in year X + 1, SCGM would have a
16 projected excess of \$1 million, then under its proposal, SCGM would retain two
17 thirds, i.e. in this example \$666,000. The timing of the expenditure produces an
18 increased **Performance Bonus** of \$333,000.

19 SCGM wants its compensation for "efficiency" built into the rates. SCGM suggests
20 that it is in its best interest to ensure that sales projections are as realistic as
21 possible in order to ensure that it does not forfeit its compensation for efficiency
22 (SCGM-15, Document 1.7(d)). It appears to me that SCGM's risk is reduced by
23 including the **Performance Bonus (up-front)** in the rates. This produces a built-in
24 cushion so that SCGM could still earn its allowed return even though costs
25 increased by the amount of its forecast **Performance Bonus (up-front)** or sales
26 were less than that amount. The SCGM methodology of providing compensation
27 before it has proven that the costs or revenues can be maintained, appears to make

1 it easier for SCGM to achieve those goals since the rates will be higher than they
2 otherwise would have been.

3 The SCGM proposal also appears to allow for the continued collection of the first
4 year's **Performance Bonus** in every subsequent year, provided that the revenue
5 from the prior year's rates, when applied to the current year's volume is equal to
6 or exceeds the subsequent year's costs. (SCGM-15, Document 1.66)

7 Under SCGM's proposal, there is no distinction between factors that give rise to a
8 difference, either at the beginning of the year or at the end of the year. Nor does
9 it differentiate between a gain attributable to cost cutting, failing to expend a
10 budgeted amount, increased revenue due to an aggressive marketing campaign or
11 increased revenues from existing customers whose business increased.

12 The SCGM proposal seeks to have SCGM benefit from the increased utilization of
13 its system without explicitly considering the nature of the incentives and rewards
14 that should be provided to achieve the increased utilization, or the degree to which
15 SCGM can influence its utilization. In the SCGM proposal, if an industrial customer
16 has the good fortune to be awarded a major contract and increases the operation
17 of its plant from one shift to two, SCGM would benefit from such increase in the first
18 year by one third increased earnings. The **Base Service Cost** for a subsequent
19 year would be higher since it is calculated using the prior year's rates applied to the
20 current year's increased throughput. As a result, under SCGM's methodology, the
21 **Expected Service Costs** will be higher providing a **Performance Bonus (up-front)**
22 in subsequent years.

23 SCGM's proposal appears to fail to recognize that it has been the customers of
24 SCGM that have borne the financial consequences of the underutilized distribution
25 system. The SCGM proposal does not appear to properly compensate customers
26 for these costs that they have borne.

1 Normally incentive mechanisms will contain restrictions on what changes can be
2 made on such things as operating and maintenance expense capitalized, and the
3 mix of debt financing terms, as well as other significant changes in business
4 operations.

5 **Q16: Are there other adjustments required to the SCGM methodology?**

6 SCGM proposals use a forecast Consumer Price Index ("CPI") for Canada.
7 However, with respect to the **Controllable Costs**, being essentially operating and
8 maintenance expense, I would think that a forecast Consumer Price Index for the
9 Province of Quebec, or if available for Montreal should be used. For example the
10 B.C. Gas incentive methodology, a B.C. CPI forecast is used. This forecast is to
11 based on Canadian bank forecasts, the Conference Board forecasts and forecasts
12 done by the Provincial Department of Finance. If however, the SCGM proposal
13 were adopted and many of the costs, which I do not consider controllable, were
14 included for the purposes of calculating an inflationary impact, then another index
15 would likely be more appropriate.

16 SCGM proposes that the year-end performance adjustment that would be credited
17 to customers in the subsequent year would be based on the after-tax amount
18 (SCGM-15, Document 1.66). It is unclear from the information provided by SCGM
19 whether their method results in the customer benefitting by the before-tax amount
20 of their share of the savings. It should be noted that, in the TransCanada incentive
21 proposal, the methodology used by TransCanada, i.e. deferral accounts, results in
22 the customers receiving a before-tax benefit. In the Nova Gas Transmission Ltd.
23 incentive methodology, there is a specific provision for the amount to be adjusted
24 before-tax (Appendix IV, Nova Gas Transmission Ltd., Cost Efficiency Incentive
25 Settlement, Article 6).

26 The methodology proposed by SCGM creates a situation where customers are
27 initially worse off than they would have been, absent the proposal. As indicated in

1 Appendix I of SCGM-15, Document 1, absent the proposal, rates would be
2 designed to recover \$709.547 million, some \$1.9 million more than the Required
3 Revenue. The Scenario outlined in SCGM-15, Document 1.12(a) shows, contrary
4 to what SCGM suggests, that customers are worse off by \$2.5 million than they are
5 under the current mechanism. (\$1.9 million in higher rates and \$.647 million as a
6 Performance Adjustment (year-end), as compared to the current method that would
7 have the rates designed to recover \$707.605 million and the shortfall would be
8 borne by SCGM.

9 **Q17: SCGM indicates that it would place a cap on its increased rate of return at 400**
10 **basis points. Do you have any comments?**

11 **A.** The 400 basis point upper-limit appears to be high compared to the numbers
12 provided in Exhibit SCGM-15, Document 1.3(a). This exhibit provides the realized
13 return and the amount of the trop-proçu (manqué á gagner). In addition, it is
14 interesting that SCGM proposes no lower limited. In that response, it appears that
15 the largest increase achieved was 137.5 basis points in 1993. 400 basis points
16 appears to be particularly high, as well, in light of the most likely source of increased
17 earnings being increased utilization of the system. Under these circumstances I
18 would recommend that after an excess of between 50 to 100 basis points, there
19 should be an adjustment to the sharing mechanism so that the customers receive
20 an additional portion since customers bore the cost of the underutilised facilities for
21 a number of years. However, this recommendation should not be interpreted as an
22 endorsement of the proposal

23 **Q18: How sensitive is the SCGM methodology to cost changes?**

24 **A.** The SCGM methodology is quite sensitive to changes in **Non-Controllable Costs**.
25 This can be seen in SCGM-15, Document 1.39. In that example, a reduction of
26 \$2.667 million with respect to transportation and storage costs increased the
27 **Performance Bonus (up-front)** payable to SCGM to \$3.7 million as compared to
28 \$1.9 million in the example in SCGM-15, Document 1, Appendix I.

1 Another example of the sensitivity of the methodology is found in SCGM-15,
2 Document 1.9(b), page 2 of 2. In this latter example, including certain costs as
3 **Non-Controllable Cost** eliminates the **Performance Bonus (up-front)**.

4 **Q19: Would you compare the results of the currently approved incentive scheme**
5 **and the proposed new incentive scheme as well as providing the results of**
6 **your recommendations with respect to Controllable and Non-Controllable**
7 **Costs.**

8 **A:** If SCGM's revenues for 1999 were to be \$709.547 million while their costs were
9 \$707.608 million, there would be a *trop-perçu* of \$1.939 million. Under the existing
10 incentive method, assuming the average of the four quality of service indicators was
11 95% and temperatures were normal i.e. the amount of \$709.5 was based on normal
12 temperatures, SCGM would receive an enhancement to its rate of return of
13 \$969,000 and the customers would receive an equivalent amount. Under SCGM's
14 proposal, it would retain the full \$1.939 million. The other significant difference is,
15 under the existing method, customer rates would be set to recover the \$707.608
16 million whereas under the new proposal, the rates would be set to recover the
17 \$709.547 million. This results in the customers being worse off by the additional
18 \$1.9 million.

19 The schedule attached as Appendix III provides the calculation that indicates, using
20 the recommendations contained in this evidence that there would be no
21 **Performance Bonus (up-front)** for SCGM.

22 **Q20: Could you summarize your views with respect to SCGM and the incentive**
23 **methodologies.**

24 **A:** Based on the foregoing, it would appear that the current incentive methodology has
25 shortcomings. However, it could continue as an interim measure for 1999, perhaps
26 with the introduction of a little more rigor to the performance indicators. The
27 proposed incentive mechanism of SCGM has serious shortcomings. Rather than

1 propose specific remedies of behalf of my client IGUA, it would be preferable that
2 the Régie direct SCGM to sit down with its customers to discuss and work out an
3 incentive mechanism which meets the goals and objectives of all the stakeholders.
4 This approach would be consistent with the various incentive methodologies which
5 have been referred to in this evidence and the comments of Doctors Mansell and
6 Church who have indicated that it is very important to recognize, in any incentive
7 methodology, that there will be tradeoffs and that there needs to be a consensus
8 on their acceptability.

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 - 5. Cost Efficiency Incentive Settlement for Nova Gas Transmission Ltd, July 31, 1996, Order U96119
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 - 2. British Columbia Utilities Commission, June 10, 1994, Return on Common Equity
 - 3. Manitoba Public Utilities Board, Order 49/95, May 5, 1995

APPENDIX I

CURRICULUM VITAE

HUGH W. JOHNSON

- Residence:** Calgary, Alberta
- Position:** Partner of Stephen Johnson, Chartered Accountants, and formerly a partner of Deloitte Haskins & Sells (now Deloitte & Touche), Chartered Accountants.
- Education:** Bachelor of Commerce, University of Calgary, 1970.
- Professional Designation:** Member of the Institute of Chartered Accountants of Alberta since 1972.
- Other Memberships:** Member of Canadian Tax Foundation since 1976.
Correspondent of The Canadian Institute of Chartered Business Valuators since 1981.
- Experience:** Actively engaged in the practice of public accounting as a chartered accountant in the Province of Alberta since 1972.
- Consultant with respect to an Inquiry respecting the Accounting for Income Tax on Utility Income in 1977 and 1978, held by the Public Utilities Board of Alberta.
- Consultant to certain oil and gas producers in the preparation of responses to the review and rehearing applications of NOVA Corporation of Alberta (formerly Alberta Gas Trunk Line Company Limited) to the Public Utilities Board of Alberta in 1978.
- Consultant to the Canadian Association of Petroleum Producers (formerly the Canadian Petroleum Association) with respect to the appropriate method of accounting for income taxes for TransCanada PipeLines Limited in 1978, 1979 and 1980.

Consultant to the Canadian Association of Petroleum Producers (formerly the Canadian Petroleum Association) with respect to interventions in hearings held before the National Energy Board on tolls applications of TransCanada PipeLines Limited (1978, 1979, 1980, 1981, 1982, 1984, 1985, 1986, 1987, 1988, 1989, 1991, 1992, 1994 and 1995), Westcoast Energy Inc. (1979, 1980, 1981, 1983, 1984, 1986, 1987, 1989, 1990, 1992, 1993 and 1995) and Trans Québec & Maritimes Pipeline Inc. (1983 and 1984).

Consultant to the Alberta Petroleum Marketing Commission with respect to its intervention in a hearing held before the National Energy Board on an application by Foothills Pipe Lines Ltd. (1982).

Consultant to a group of oil producers in respect to their intervention in a hearing held by the National Energy Board on an application by Inter-Provincial Pipe Line Limited (1983).

Consultant to various groups of industrial and/or municipal intervenors in hearings held by the British Columbia Utilities Commission on applications by Inland Natural Gas Co. Ltd. (1982, 1983 and 1984), Pacific Northern Gas Ltd. (1982, 1991 and 1992), West Kootenay Light & Power Company Limited (1984) and Columbia Natural Gas Limited (1984).

Consultant with respect to various interventions by The City of Calgary before the Canadian Radio-television and Telecommunications Commission.

Consultant with respect to various interventions by The City of Calgary and the City of Edmonton before the Public Utilities Board of Alberta.

Witness before the National Energy Board in the matters of an appropriate method of regulation for Westcoast Transmission Company Limited (1981 and 1984), TransCanada PipeLines Limited (1981) and Trans Québec & Maritimes Pipeline Inc. (1983).

Witness before the National Energy Board in the matter of an appropriate method of accounting for income taxes by TransCanada PipeLines Limited (1982), Trans Québec & Maritimes Pipeline Inc. (1983), Westcoast Transmission Company Limited (1983) and Trans Mountain Pipe Line Company Ltd. (1993).

Witness before the British Columbia Utilities Commission in the matter of an appropriate method of accounting for income taxes by Inland Natural Gas Co. Ltd. and Columbia Natural Gas Limited (1982), West Kootenay Light & Power Company Limited (1984) and Pacific Northern Gas Ltd. (1985).

Witness before the Ontario Energy Board in the matter of an appropriate method of accounting for income taxes for Union Gas Limited (1983).

Witness before the Regie de l'Electricite et du Gaz in the matter of appropriate methods of cost allocation for gas utilities in Quebec (1985).

Witness before the National Energy Board with respect to matters of toll design for Westcoast Transmission Company Limited (1986).

Witness before the Public Utility Review Commission of Saskatchewan with respect to matters relating to a gas cost adjustment mechanism for Saskatchewan Power Corporation (1986) and on a rate design for Saskatchewan Power Corporation (1987).

Witness before the National Energy Board in the matter of the availability of services on TransCanada PipeLines Limited (1986), the tolls of TransCanada PipeLines Limited (1987, 1988/89, 1991, 1992, 1993 and 1995) and the tolls of Westcoast Energy Inc. (1987, 1989, 1990, 1992, 1993 and 1995).

Witness before the National Energy Board in the matter of facilities applications by TransCanada PipeLines Limited (1989 and 1990).

Witness before the Public Utilities Board of Alberta with respect to deferred gas accounting (1990), cost allocation and rate design matters (1991) for Canadian Western Natural Gas Company Limited.

Witness before the Public Utilities Board of Alberta with respect to the appropriate method of accounting for income taxes for Canadian Western Natural Gas Company Limited, Alberta Power Limited and TransAlta Utilities Corporation (1991) and before the Alberta Energy and Utilities Board with respect to Alberta Power Limited and TransAlta Utilities Corporation (1996).

Witness before the National Energy Board in the matter of an appropriate method of accounting for income taxes by Interprovincial Pipe Line Inc. and accounting treatments in respect to the Montreal Extension of Interprovincial Pipe Line Inc. (1992).

Witness before the Canadian Radio-Television and Telecommunications Commission with respect to the appropriate treatment of additional tax deductions arising from the privatization of AGT Limited and the appropriate method of accounting for income taxes (1993).

Witness before the Public Utilities Board of Alberta with respect to an application for interim rates on Peace Pipe Line Ltd. (1993).

Witness before the British Columbia Utilities Commission with respect to the calculation of returns and the treatment of rate stabilization under the special direction to the Commission relating to B.C. Hydro and Power Authority (1993).

Witness before the Natural Resources Conservation Board of Alberta with respect to an application by Chem-Security (Alberta) Ltd. (1994).

Witness before the Alberta Energy and Utilities Board with respect to the tolls of Nova Gas Transmission Ltd. (1995).

Witness before the National Energy Board in the matter of an appropriate method of dealing with the deferred taxes of Foothills Pipe Lines Ltd. (1995).

Witness before the Deputy Comptroller of Water Rights of British Columbia with respect to the determination of rate base, capital structure and return on equity of the Greater Victoria Water District (1996).

Witness before the National Energy Board with respect to an abandonment application by Manitoba PipeLines Ltd. (1996).

Witness before the Alberta Energy and Utilities Board with respect to a load retention rate application by Nova Gas Transmission Ltd. (1997).

Witness before the Joint Public Review Panel and the National Energy Board with respect to the proposed toll design and treatment of laterals on the Maritimes & Northeast Pipeline Project (1997).

Witness before the National Energy Board with respect to toll design and cost of service for the Interprovincial Pipe Line Inc. Line 9 Reversal Project (1997).

Submitted evidence to the Canadian Radio-Television and Telecommunications Commission in its proceeding on the implementation of price cap regulation with respect to the appropriate treatment of additional tax deductions arising from the privatization of MTS Netcom Inc. and on the appropriateness of changes in accounting policies and procedures by Telus Communications Inc. (1997).

Witness before the National Energy Board in the facilities application of Alliance Pipeline Limited Partnership.

DEFINITIONS

The incentive methodology of SCGM has a number of terms. The following outlines my understanding of and/or use of those terms.

Base Cost of Service

The **Base Year Revenue Requirement** less the **Base Year** forecast of the cost of gas to be sold.

Base Operating Costs

Remainder of **Base Service Cost** minus **Pass-Through Costs**.

Base Service Cost

Test year volumes multiplied by the **Base Year** rates less the forecast **Test Year** cost of gas to be sold.

Base Year

Last year for which the Régie has approved the rate forecast; in this application 1998.

Controllable Costs

Costs over which SCGM has control that are impacted by yearly changes in inflation and that can be changed year by year or within a year.

Expected Operating Costs

The product of **Base Operating Costs** and (1 plus Inflation).

Expected Service Costs

The sum of **Expected Operating Costs** and **Pass-Through Costs** adjusted for some prior period amounts.

Inflation

Forecast of the Consumer Price Index for Canada in SCGM's proposal and for Montreal or Quebec in the recommendations.

Non-Controllable Costs

Cost over which SCGM has minimal control or influence and are not impacted directly by yearly changes in inflation rates. Also referred to as **Pass-Through Costs**.

Pass-Through Costs

Test Year forecast of costs beyond the control of SCGM. In its proposal SCGM has limited these to Return on Equity, income taxes and transportation and storage charges from TransCanada and Union. The evidence includes more items.

Performance Bonus (up-front)

Two thirds of the difference, if any, between the **Required Revenue** and **Expected Service Costs**.

Performance Adjustment (year end) - SCGM

One third of the difference between the actual revenues, after adjustments for deferral accounts and the removal of gas costs and the actual costs, after adjustments for deferral accounts and excluding gas costs, i.e. the amount that would result in an adjustment to the Return on Common Equity, absent the proposal. This amount may be positive or negative.

Required Revenue (Required Service Cost)

The forecast cost of service for the **Test Year** determined in the normal way using the projected **Test Year** costs and the forecast **Test Year** rate base.

Revenue Requirement

The sum of **Expected Service Costs** and **Performance Bonus (up-front)**. The revenues to be collected from rates.

Test Year

The year for which the approval of the Régie for new rates, in this application 1999.

APPLICATION

OF THE INCENTIVE MECHANISM

FOR 1999

Application of Gaz Metropolitan's Incentive Proposal

1	Base cost of service		697,519
	Items out of company's control		
2	Transportation and storage		
3	Transportation and storage at source (TCPL & Union)	237,667	
4	Rate revision	(9,837)	
5	Compression Gas	40,511	
6	Unaccounted for gas	4,976	
7	Other transportation and storage	19,629	
8	Transportation and storage and related Non- Controllable	292,946	
9	Amortization of fixed assets	55,419	
10	Amortization of deferred charges	29,024	
11	Consumer price reductions	20,479	
12	Real estate taxes and other charges, including Regie	24,343	
13	Financing charges including interest and preferred dividends	70,436	
14	Return on equity & income taxes	105,481	<u>598,128</u>
15	Base Operating Costs		99,391
16	Inflation	1.7%	1,690
17	Expected Operating Costs		101,080
	Elements out of the direct control (Non-Controllable)		
18	Transportation and storage at source (TCPL & Union)		237,667
19	Compression Gas		40,511
20	Unaccounted for gas		4,976
21	Other transportation and storage		29,466
22	Amortization of fixed assets		55,419
23	Amortization of deferred charges		29,024
24	Rate base returns		127,881
25	Real Estate taxes and other charges, including Regie		24,343
26	Income Taxes		45,603
27	Expected Service Cost		695,970
28	Required Revenue		707,608
29	Transportation and storage	302,793	
30	Operating expenditures	104,353	
31	Amortization of fixed assets	55,419	
32	Amortization of deferred charges	29,024	
33	Real estate and other charges	24,343	
34	Return on Rate Base	127,881	
35	Income tax	45,603	
36	Consumer price reductions	20,479	
37	Other operating revenues	(2,286)	
38		707,609	
39	CONTRIBUTION TO RATE REDUCTION		-
40	Customers Share 1/3	-	
41	Company Share 2/3	-	

DECISIONS

RE:

INCENTIVE MECHANISM



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EW
DBM
File

IN THE MATTER OF

BC Gas Utility Ltd.

**REVENUE REQUIREMENTS
APPLICATION
1998 - 2002**

Reasons for Decision

July 23, 1997

BEFORE:

**Lorna R. Barr, Deputy Chair
and Acting Chair
Ken L. Hall, Commissioner
Paul G. Bradley, Commissioner**

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REASONS FOR DECISION

Introduction

BC Gas Utility Ltd. ("BC Gas") filed an application dated February 5, 1997 (the "Application") with the British Columbia Utilities Commission (the "Commission", "BCUC") to establish the method for determining its revenue requirements and for approval to set rates for the five years ending December 31, 1998 to 2002.

On February 10, 1997, the Commission issued Order G-13-97 setting a pre-hearing conference to commence February 28, 1997. Following the pre-hearing conference, the Commission issued Order No. G-24-97 which included a regulatory timetable, setting a second pre-hearing conference for April 24, 1997 and a public hearing, if required, to commence June 3, 1997. Subsequent to the second pre-hearing conference the Commission issued Order No. G-47-97 setting down a revised regulatory timetable which provided for, among other matters, rescheduling the public hearing to June 23, 1997. The timetable also provided for public workshops regarding the Application; a process for filing information requests by parties and responses by BC Gas; and an Alternative Dispute Resolution process ("ADR") to negotiate a settlement of issues related to the Application. BC Gas conducted public workshops on March 10, 11 and April 16, 1997. Information requests were filed and an additional 3 volumes of information responses and other data were provided by BC Gas.

The negotiation sessions commenced on June 2, 1997 and continued on various dates through to June 26, 1997 when a negotiated settlement was reached between BC Gas and the parties to the negotiation. The three year proposed settlement agreement was circulated to the ADR participants. Endorsements of the proposed settlement agreement by all of the ADR participants were received at the Commission by July 10, 1997. Subsequently, the proposed settlement agreement was circulated to all registered intervenors for comments by July 18, 1997 and no comments were received. The Commission panel for this proceeding also received a copy of the proposed settlement agreement and letters of endorsement.

The impact of the applied-for rates and the proposed settlement agreement on customer costs for natural gas service (gross margin) is as follows:

	1998	1999	2000	2001	2002
Rate Impact as a % of Gross Margin applied for in original application (May 5, 1997 revision)	6.40	3.40	2.70	1.90	1.60
Rate Impact as a % of Gross Margin (proposed settlement agreement)	1.85	2.00	2.00	N/A	N/A

The Commission notes that the participants expect that the gross margin rate impact on the Company's firm sales customers will be further reduced as a result of amortization of Gas Cost Reconciliation Account balances.

The Commission Panel has now reviewed the proposed settlement agreement as well as the letters of endorsement and comment from the ADR participants and has concluded that it should accept the settlement. Many of the elements within the proposed settlement agreement do not require special comment. However, the Commission did wish to express its views on several key issues that it noted in arriving at its decision and these Reasons for Decision provide those views.

Table 1 sets out key comparisons between the proposed settlement agreement and the Application as revised on May 5, 1997 by BC Gas.

Table 1
Key Aspects of proposed Settlement Agreement

	BC Gas Application	Proposed Settlement Agreement
Term	5 years	3 years
Productivity	1998 - 1% 1999 - 1% 2000 - 1%	1998 - 2% 1999 - 2% 2000 - 3%
Capital Structure	35%	33%
Capitalization of Overhead	1998 - 10.27% 1999 - 10.27% 2000 - 10.27%	1998 - 20% 1999 - 20% 2000 - 16%

The Commission has also created a new document called the Consolidated Settlement Document which incorporates editorial changes as proposed by BC Gas, and one other change as follows. In the subsection entitled "DSM Achievement Incentive" paragraph 6 originally read "The Company will apply to the Commission for funding of new programs where required". The Commission has changed this wording to "The Company will apply to the Commission for program changes where required". The Commission made the change as it concluded that the proposed wording may have arguably fettered the Commission in its discretion as provided for in the B.C. Utilities Commission Act.

Commission Comments on Key Issues:

Term

BC Gas applied for a five year term while the parties to the agreement agreed to a term of three years. The Commission considers a three year term is appropriate. It provides a long enough period to allow incentives to perform and at the same time balances the risks and other concerns with respect to changes that could occur over an extended period of time. The Commission is aware of some five year settlements which have been implemented for pipelines, but the Commission is of the view that the number of variables of change that can occur for a Local Distribution Company ("LDC") make it more appropriate to look at shorter terms. Pipelines typically have a limited number of shippers and more discrete cost projections.

Operating and Maintenance Costs ("O&M")

The formula used to develop O&M costs has been previously utilized in the settlements with respect to BC Gas and West Kootenay Power. From this experience, the Commission is satisfied that the methodology of adjusting a base cost for the growth in customers, productivity and inflation has provided appropriate targets for developing incentives. Attached to the Consolidated Settlement Document is a letter from Commission staff dated July 15, 1997 (Appendix B) which provides three examples of how productivity from capital projects will be eligible for inclusion within the O&M productivity targets.

Demand Side Management ("DSM")

The DSM Achievement Incentive represents the second time the Commission has endorsed a mechanism to pursue cost effective DSM resources. However, it is still a new feature in the regulatory environment and very little knowledge has yet been accumulated as to its success or failure. The Inland/Industrial group, in their letter of acceptance of the settlement, pointed out that "the settlement agreement should explain that the DSM programs and incentives are to be accounted for within the rate classes to which they relate." In the Commission's view, this is adequately covered in the settlement agreement, paragraph 9 in the subsection entitled "DSM Achievement Incentive".

Capital Efficiency Mechanism

This is the first significant capital efficiency mechanism that the Commission has approved. It is designed to provide an incentive for the utility to improve its costs of installing mains, services, meters and "other" plant. The range of incentive has been narrowed and the amount of the efficiency adjustment reduced from that originally filed in the Application. Due to the innovative nature of this particular mechanism, the Commission will be closely monitoring both the operation and results flowing from the use of the mechanism.

Overhead Capitalization

The Commission is in agreement with the move to reduce the capitalization of overheads from 22.5% to 16% over the three year period. The change is directionally correct in that a mature utility such as BC Gas should be lowering its overhead charges as capital projects are reduced as a proportion of total expenditures, and the customers that are benefiting from the capital projects are paying for them in an accelerated manner. The Commission also believes that, in undertaking and achieving the changes in overheads capitalization, the reductions should not lead to significant rate impacts.

Annual Review and Quality of Service

The Commission endorses the provision for an annual review. This allows the Commission to discharge its responsibility to maintain oversight of the utility and establish rates for each year. The Commission views the inclusion of service quality indicators as an important component of any incentive rate scheme. Such indicators ensure a utility will appropriately balance its obligation to provide safe, secure, high quality and non-discriminatory service to customers at the lowest rates possible while also providing an opportunity for shareholders to earn a fair return on their investment.

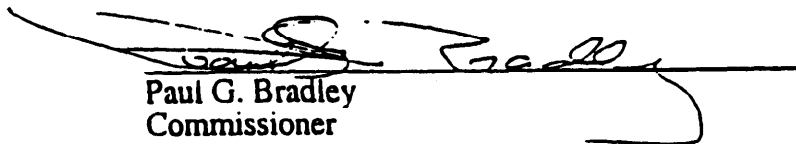
DATED at the City of Vancouver, in the Province of British Columbia, this 21st day of July, 1997.



Lorna R. Barr
Deputy Chair and Acting Chair



Ken L. Hall, P.Eng.
Commissioner



Paul G. Bradley
Commissioner

CONSOLIDATED SETTLEMENT DOCUMENT

BC GAS UTILITY LTD. 1998 - 2000 REVENUE REQUIREMENTS

Background

BC Gas Utility Ltd. ("BC Gas") filed an application dated February 5, 1997 (the "Application") with the British Columbia Utilities Commission (the "Commission", "BCUC") to establish the method for determining its revenue requirements for the years 1998 to 2002.

On February 10, 1997, the Commission issued Order G-13-97 setting a pre-hearing conference to commence February 28, 1997. Following the pre-hearing conference, the Commission issued Order No. G-24-97 which included a regulatory agenda and timetable, setting a second pre-hearing conference for April 24, 1997 and a public hearing, if required, to commence June 3, 1997. Subsequent to the second pre-hearing conference the Commission issued Order No. G-47-97 setting down a revised regulatory agenda and timetable rescheduling the public hearing to June 23, 1997. The regulatory agenda included public workshops regarding the Application; a process for filing information requests by parties and responses by BC Gas; and an Alternative Dispute Resolution process ("ADR") to negotiate settlement of issues related to the Application. BC Gas conducted public workshops on March 10, 11 and April 16. Information requests were filed and an additional 3 volumes of information responses and other data were provided by BC Gas.

The negotiation sessions commenced on June 2, 1997 and continued on various dates through to June 26, 1997. Parties represented during the settlement negotiations were BC Gas; Consumers Association of Canada (B.C.), B.C. Old Age Pensioners' Organization, Council of Senior Citizen's Organizations of B.C., Federated Anti-Poverty Groups of B.C., Senior Citizen's Association of B.C., West End Senior's Network, and the End Legislative Poverty & Tenant's Right Coalition, represented by the British Columbia Public Interest Advocacy Centre; Lower Mainland Large Volume Gas Users Association; R.T. O'Callaghan & Associates (not available for the final two negotiating sessions); Fording Coal Ltd.; Association for the Advancement of Sustainable Energy Policy; Cominco Ltd., Weyerhaeuser Canada Ltd. and Celgar Pulp Company; and British Columbia Utilities Commission Staff.

Multi-Year Settlement

This document sets out the terms of a three year settlement reached during the negotiations for setting the revenue requirements and rates of BC Gas. The margin and rate impacts arising from the settlement are summarized on the schedules in Appendix A. The impacts are estimates and are based on several assumptions (subject to vary in the manner as discussed below). These are subject to change each year and relate to factors including:

- | | |
|--|---|
| a) the rate of return on common equity | f) short and long term debt interest rates |
| b) revenues | g) rate base additions |
| c) customer additions | h) effect of capital efficiency mechanism |
| d) taxes | i) capital projects approved under applications for Certificate |
| e) inflation | of Public Convenience and Necessity (CPCN's) |

The estimated gross margin impacts resulting from the settlement, as set out in Appendix A, are:

	1998		1999		2000	
	Core	Non-Core	Core	Non-Core	Core	Non-Core
Rate Impact as a % of Gross Margin	1.85	1.85	2.00	2.00	2.00	2.00

Based on the underlying assumptions, the gross margin rate impact on Core market customers are expected to be further reduced to about 0% in each year as a result of amortization of GCRA balances.

The settlement is the culmination of negotiations among parties who have many diverse interests. The settlement represents numerous compromises among the parties and consists of a settlement package from which no part can be severed. The issues resolved in the settlement negotiations are numerous and complex. Taken as a whole, the settlement represents a balance of interests and an overall consensus among the participating parties.

Term

The parties have agreed to a term of 3 years, namely the calendar years 1998, 1999 and 2000 (the "Term").

Productivity

Productivity shall be 2% in 1998, 2% in 1999 and 3% in 2000. References to "Productivity" in this document are references to those productivities except where stated otherwise.

Inflation

Several elements of the revenue requirement determination methodology are dependent on an inflation rate forecast. The forecast rate of inflation to be applied will be the consumer price index forecast for British Columbia.

The BC Gas proposal utilizing the forecasts for the next calendar year B.C. CPI by the Toronto-Dominion Bank, the Royal Bank of Canada, B.C. Ministry of Finance and the Conference Board of Canada (produced July to September) is accepted (hereinafter referred to as "forecast B.C. CPI").

References to "Inflation" in this document are references to this forecast of B.C. CPI except where stated otherwise.

Capital Structure

The common equity thickness for BC Gas will remain at 33%. In respect to its preference shares which are redeemable in 1999 and 2000, BC Gas will redeem such preference shares and replace the same with long term debt as redemption occurs.

Rate Of Return On Common Equity

The rate of return on common equity for BC Gas will be reset annually in accordance with the Commission's automatic rate of return adjustment mechanism.

Gas Costs

- The gas costs of BC Gas will be set in the manner currently approved by the Commission and customer rates will be adjusted in accordance with the currently approved gas cost allocation methodology.
- The Gas Cost Reconciliation Account will continue in the manner as approved by the Commission.
- The current Off System Incentive Plan will expire November 1, 1997. The parties agree to enter into discussions to determine the form of a successor gas cost incentive plan both for the short term and the long term. Any subsequent plan will be reviewed by interested parties before being submitted to the Commission for approval.

Revenues

- Both core market and non-core market revenues will be forecast each year in accordance with the methodologies employed by BC Gas and will be reviewed at the Annual Review before being submitted.
- The methodology for forecasting residential and commercial sales is established but industrial sales forecasts will be reviewed annually.
- The Rate Stabilization Adjustment Mechanism ("RSAM") will continue in the manner as approved by the Commission.
- Customer Additions will be forecast for each year of the Term, in accordance with the methodology employed by BC Gas and approved by the Commission.

Operating & Maintenance Costs ("O&M")

The O & M levels for each year of the Term will be determined in accordance with the following formula:

[Base Cost x (1 + Growth in Customers - Productivity) x (1 + Inflation)] + Cost of Defined Required Incremental Activities

Where:

Base Cost means: for 1998 this will be \$142,760,000.

e.g., 1998 O&M level base cost \$142,760,000 x (1 + 2.10% - 2.00%)
x 1.01 = \$144,334,000 allowed O&M for 1998 excluding DRIA

for calculating the allowed O&M level for each subsequent year, the previous year's allowed O&M adjusted for projected actual customers will be the revised base to which customer growth, productivity and inflation will be added.

e.g., 1999 O&M level \$144,334,000 x $\frac{1998 \text{ Projected Actual Customers}}{1998 \text{ Forecast Customers}}$

= revised base x formula = 1999 allowed O&M excl. DRIA

Growth in Customers means:	the forecast percentage growth in the average number of customers for the year over the previous year.
1998 Projected Actual Customers:	The estimate of actual average customers during 1998 at the November 1998 workshop
1998 Forecast Customers:	The forecast of average customers during 1998 at the November 1997 workshop.

In the event BC Gas files an application for a revenue requirement increase in 2001, the Base Cost O&M level to be reflected in rates for 2001, before any increase for inflation and growth in customers, will be that arising from 2000, subject to exogenous factors and DRIA.

Productivity and Retail Markets Downstream of the Meter (RMDM)

One instrument that the Company may use to achieve the targeted productivity gains is shedding, altering or reducing utility activities pursuant to the Commission's policy on RMDM.

BC Gas will be entitled to capture the benefits of improved efficiencies, reduced costs, or other financial savings achieved through RMDM, for the duration of the test period. Adjustments in utility rates during the test period arising from RMDM will be limited to reflecting the reduction of services that had been previously included in customers' bundled utility services. For further clarity the following hypothetical example distinguishes between improved efficiencies eligible for productivity and reduced services not eligible for productivity

Example:

BC Gas determines that outsourcing customer billing will reduce the cost of this function from \$1.00/per customer to \$0.79 and the third party will charge customers directly. The efficient gain of \$0.21 is eligible for productivity but the rates will be rebased to reflect the \$0.79 now paid directly to the third party.

O&M Productivity and Capital Projects

Improved efficiencies, reduced costs, or other financial savings achieved by BC Gas as a result of capital projects approved by the Commission pursuant to applications for Certificates of Public Convenience and Necessity may also be used by BC Gas to achieve the targeted O&M productivity levels.

DEMAND SIDE MANAGEMENT AND INCENTIVES

The Demand Side Management expenditure levels are forecast to remain constant over the Term, namely \$1.624 million per year as a DRIA.

DSM Achievement Incentive

The following DSM Achievement Incentive is to be implemented. It is designed to encourage BC Gas to pursue cost effective demand side management resources.

1. Only energy efficiency programs are included in the mechanism.
2. A threshold level of 75% of the annual forecast gas savings must be achieved before any incentive is earned.
3. Calculation of incentive payments for gas savings greater than the threshold will be based on the net TRC benefits.
4. Recognizing that incremental energy savings become progressively more difficult to achieve, incentive payments will be earned according to the following schedule:

<u>% of Annual Forecast GJ Savings</u>	<u>Before Tax Earnings as % of TRC Net Benefits</u>
75% up to 100%	3%
100% and above	5%

5. DSM results (both positive and negative) from programs developed within the Utility but which at some point are moved outside the utility will be included in the DSM calculation where those program results are tracked by the Utility. This is consistent with the Company's goal of maximizing customer value in offering cost effective, competitive DSM services.
6. In order to maximize DSM efficiencies, BC Gas will be allowed to reallocate resources to modify existing programs, discontinue programs and develop new programs as the Company considers necessary. The Company will apply to the Commission for program changes where required.
7. A protocol for measuring DSM savings and TRC benefits needs to be established with the Commission and interested parties prior to the incentive mechanism taking effect.

8. The status of all DSM programs will be reviewed on a semi-annual basis with one of the reviews timed to coincide with the Annual Review of Service Quality Indicators.
9. The incentive mechanism will operate through the RSAM. The DSM Achievement Incentive operates outside of the Earnings Sharing Mechanism.

DSM Achievement Incentive Sample Calculations

Three cases are provided below representing the range of possible incentive payments for BC Gas achieving a minimum of 75% of forecast DSM gas savings.

Case A	Assuming:	75% of forecast gas savings achieved total TRC net benefits = \$2,581,000
		Incentive = 3% of TRC net benefits (before tax) = \$77,430
Case B	Assuming:	100% of forecast gas savings achieved total TRC net benefits = \$3,848,000
		Incentive = 5% of TRC net benefits (before tax) = \$192,400
Case C	Assuming:	110% of forecast gas savings achieved total TRC net benefits = \$4,350,000
		Incentive = 5% of TRC net benefits (before tax) = \$217,500

Restructuring Deferral Account

A deferral account to record the costs incurred by BC Gas in restructuring its work force to achieve enhanced productivity is to be created and is to be effective upon the approval by the Commission of this settlement. The costs recorded in this deferral account will be recovered in customer rates. The deferral account will not exceed \$3 million.

The amortization of this deferral account for restructuring costs will be no greater than \$1 million for each year of the Term.

New Revenue Opportunities

The parties recognize that BC Gas should not be dis-incented from seeking legitimate new revenue opportunities which would serve to reduce future revenue deficiencies. To the extent such opportunities arise, but require expenditures greater than those arising from the formula, such revenues and expenditures will be addressed during the Annual Review each year.

Capital Expenditures

Capital expenditures for each year of the Term are established by class and by formula for certain of the classes. The classes are:

- | | |
|-------------------------|---------------------------------------|
| 1. Mains - Recurring | 5. System Improvements/Reinforcements |
| 2. Services - Recurring | 6. All Other Plant |
| 3. Gas Measurement | 7. Special Projects and CPCN's |
| 4. Transmission Plant | |

Formulae for determining the expected capital expenditures for each year have been established for classes 1, 2, 3, 4, 5 and 6 as follows:

Note: the operation of the formulae for each class is shown for 1998 and 1999 and applies similarly to year 2000.

1. Mains - Recurring:

1998 Allowed Unit Cost = Base Unit Cost x (1+ Inflation - Productivity)
 1998 Allowed Cost = 1998 Allowed Unit Cost x Service Additions x 21.6 metres of main per Service Addition

Where: Base Unit cost = \$25.03/metre main
 Service Additions = 95.1% of forecast Customer Additions

1999 Allowed Unit Cost = 1998 Allowed Unit Cost x (1+ Inflation - Productivity)
 1999 Allowed Cost = 1999 Allowed Unit Cost x Service Additions x 21.6 metres of main per Service Addition

2. Services:

1998 Allowed Unit Cost = Base Unit cost x (1 + Inflation - Productivity)
 1998 Allowed Cost = 1998 Allowed Unit Cost x Service Additions

Where: Base Unit cost = \$884/Service Addition
 Service Additions = 95.1% of forecast Customer Additions

1999 Allowed Unit Cost = 1998 Allowed Unit Cost x (1+ Inflation - Productivity)
 1999 Allowed Cost = 1999 Allowed Unit Cost x Service Additions

3. Meters:

1998 Allowed Unit Cost = Base Unit cost x (1 + Inflation - Productivity)
 1998 Allowed Cost = 1998 Allowed Unit Cost x (Customer Additions + Meters Recalled)

Where: Base Unit cost = \$242/meter
 Customer Additions = forecast Customer Additions
 Meters Recalled = forecast of meters to be Recalled

1999 Allowed Unit Cost = 1998 Allowed Unit Cost x (1+ Inflation - Productivity)
 1999 Allowed Cost = 1999 Allowed Unit Cost x (Customer Additions + Meters Recalled)

4. Transmission Plant:

1998 Allowed Unit Cost = Base Unit cost x (1 + Inflation - Productivity)
 1998 Allowed Cost = 1998 Allowed Unit Cost x Transmission System Forecast Peak Day Throughput

Where: Base Unit cost = \$439.50/10³m³
 Transmission System Forecast Peak Day Throughput = forecast
 Transmission System Forecast Peak Day Throughput
 productivity = 1%

1999 Allowed Unit Cost = 1998 Allowed Unit Cost x (1+ Inflation - Productivity)
 1999 Allowed Cost = 1999 Allowed Unit Cost x Transmission System Forecast Peak Day Throughput

5. System Improvements/Reinforcements:

1998 Allowed Unit Cost = Base Unit Cost x (1 + Inflation - Productivity)
 1998 Allowed Cost = 1998 Allowed Unit Cost x Customers End of Year ("EOY")
 Where: Base Unit cost = \$6.52/customer EOY
 Customer EOY = forecast end of year total customers
 productivity = 1%

1999 Allowed Unit Cost = 1998 Allowed Unit Cost x (1+ Inflation - Productivity)
 1999 Allowed Cost = 1999 Allowed Unit Cost x Customers EOY

6. All Other Plant:

The Allowed Costs for All Other Plant for each year of the Term will be set with an aggregate base level of \$29,317,000 adjusted for Inflation each year less Productivity.

1998 Allowed Cost = \$29,317,000 x (1+ Inflation - Productivity)
 1999 Allowed Cost = 1998 Allowed Cost x (1+ Inflation - Productivity)

BC Gas has divided its capital expenditures into 4 categories. They are:

- A. Mains, Meters and Services
- B. System Integrity and Reliability

- C. All Other Plant
- D. CPCN's and Special Projects

The costs related to each category will be identified by the accounts prescribed by the BCUC Code of Accounts and the Company's sub-accounts as follows:

	<u>BCUC Account</u>	<u>BC Gas Sub-Account⁽¹⁾</u>
Category A		
Distribution Plant - Service Installations	473	xxx excl. 62X ⁽²⁾
Distribution Plant - Meter and Regulator Installations	474	xxx
Distribution Plant - New Mains	475	640
Distribution Plant - Main Installations General	475	649
Distribution Plant - Meters	478	xxx
Category B		
LNG	440 -	xxx
Transmission Plant	449	xxx
Distribution Plant - Main Corrosion Control	460 -	653 TS ⁽³⁾
Distribution Plant - System Improvements	469	657/659
Distribution Plant - Gate and Regulator Stations	475	671
Distribution Plant - Telemetry	477	672 TS ⁽³⁾
	477	
Category C	All other BCUC Capital accounts and BC Gas sub-accounts	
Category D	N/A	N/A

- (1) xxx includes all BC Gas sub-accounts in the BCUC account
- (2) Account 473-62X- Distribution Plant Renewals and Alteration
- (3) TS refers to charges from Technical Services to these Accounts

Special Projects and CPCN's

Special Projects and Certificate of Public Convenience and Necessity ("CPCN") projects are capital projects which BC Gas foresees as being required within the Term, but have not been developed sufficiently (certain of such projects were identified and described in the Application, they include: Southern Crossing, Automated Meter Reading, Single Vendor System, Interior LNG Satellite Facility, Customer Information Systems, Coastal Facilities, SCADA, muster stations), or projects which are not foreseen but could be required, such as the relocation of an urban transmission pipeline. Such projects are subject to approval by the Commission through applications for Certificates of Public Convenience and Necessity. To the extent such applications are approved and the capital projects undertaken, the capital project will form part of the rate base of BC Gas in the year following the year in which the capital project is completed. BC Gas will be entitled to accrue AFUDC on the expenditures associated with the capital project until the capital project is part of rate base.

BC Gas will be entitled to include the prudently incurred total capital expenditures and AFUDC in rate base at the commencement of the year following completion of the capital project.

Capital Efficiency Mechanism

BC Gas should be incented to employ capital more efficiently. A capital efficiency mechanism will operate as set out below. The categories in respect of which the mechanism will operate are categories A and C as described above.

To the extent the actual unit costs for a year vary from the Allowed Unit Costs for Category A, this difference is to be multiplied by the actual number of units (e.g. in the case of Mains - Recurring it would be actual metres of main installed for the year). This amount, together with the difference between the actual and allowed capital expenditures for that year in Category C, will form the basis for an efficiency adjustment to the utility rate base. This adjustment will be an aggregate dollar sum (the "Capital Efficiency Adjustment") which will be added or subtracted from the utility rate base. This mechanism will operate similarly in the case of positive and negative variances in unit costs.

The Capital Efficiency Incentive Adjustment to rate base will be phased out over three years. More specifically, in the immediately following year 66.7% of this variance will be an adjustment to the utility rate base and 33.3% in the subsequent year. This phasing will apply to each year of the Term so that the effect of variances in the second and third year of the Term will continue beyond the Term, e.g., phasing of the year 2000 variances will occur through the year 2002. For examples of the effect of the Capital Efficiency Mechanism, see Cases A1, B1, C1 and D1 in the response to Item 6 of Information Request No. 1 of the Inland Industrial Group (Volume 2, Tab E6).

Depreciation and Amortization Expense

The depreciation rates for BC Gas currently approved by the Commission will continue. BC Gas has indicated that it intends to file a depreciation study. The Commission will consider the study and any changes arising upon receipt and consideration of the study and the recommendation for changes in rates, if any, applied for by the Company.

Deferral Accounts

The following deferral accounts are to be continued or created:

- Continuation of the debt interest deferral accounts.
- Continuation of the NGV conversion grants deferral account for 1998 - 2000 to be amortized over three years.
- Revenue requirement hearing costs to be amortized over three years.
- DSM expenditures for 1998 - 2000 to be amortized over three years.
- IRP costs for 1998 - 2000 to be amortized over three years.
- Deferral of property tax expense variances from forecast and amortized in the following year. 1996/1997 credits amortized as per Appendix A.

- BC Hydro DRIA - amortization as per Appendix A.
- DSM DRIA - amortization as per Appendix A.
- Continuation of Coastal Facilities relocation costs deferral account.
- April 29, 1997 application for Phase 2 of BC 21 Power Smart costs - \$303,000.
- Continuation of RSAM and GCRA accounts as described above.
- Deferral of restructuring costs as described above.

Further details of the deferral accounts are found in Appendix A.

Overhead Capitalization

Pursuant to a term of the 1996 and 1997 Negotiated Settlement, BC Gas filed a study on its overheads capitalization policy. The study recommended a significant reduction in the capitalization ratio. The impact of this study was to reduce overhead capitalization from 22.5% to 10.27% as shown in Volume 1, Section C, Tab 9-02 Revised (line 20) of the Application.

The BC Gas study and proposal is accepted, however, the capitalization ratios will be limited to 20%, 20%, and 16% for the years 1998, 1999 and 2000 respectively based on total Gross O&M excluding DRIA. The Company may apply for additional reductions in overheads capitalized in subsequent revenue requirement filings.

Taxes

Changes in taxes and similar costs will continue to be flowed through to customers with variances recorded in deferral accounts and amortized in rates in the following year.

The methodology for determination of the level of taxes for each year of the Term will be determined in the manner as specified in the Application, Volume 1, Section C Tabs 10 and 13 as revised.

Other Cost of Service Categories

All other categories of the cost of service not specifically referred to above will be determined in the manner as specified in the Application, Volume 1 as revised.

Exogenous Factors

During the Term, the BC Gas cost of service will be adjusted for exogenous factors (positive or negative) which are beyond the full control of the utility including: judicial, legislative or administrative changes, orders and directions; changes in generally accepted accounting principles and rules, catastrophic events, bypass or other similar events imposed on BC Gas which are not reflected in the rates of BC Gas.

Earnings Sharing Mechanism

BC Gas will share equally with its customers earnings variances (positive or negative) between the authorized level of earnings as determined annually under this settlement and the actual earnings of the

utility net of specific incentive programs; namely, the capital efficiency mechanism, the gas supply incentive plan and the DSM Achievement Incentive all of which will be considered to be non-utility income for the purposes of calculating the earnings of the utility.

The operation of the Earnings Sharing Mechanism is illustrated in Volume 1, Section C, Tab 15 of the Application.

Annual Reviews and Rate Adjustments

BC Gas will conduct an Annual Review of the operation of the settlement and rate adjustments prior to January 1 of each year of the Term with the Commission, its staff and interested parties. The Annual Review is a "proceeding" for purposes of participant cost awards. This process will provide the Commission and all interested parties an opportunity to remain informed about the activities of the Company. The Annual Review will attempt to obtain consensus on issues which must be decided by the Commission in advance of each fiscal year for the matters related to setting the rates for each year of the Term.

At the annual workshop to be held in November of each of the years 1998 through 1999, BC Gas will present projections for the year that is ending and forecasts for the next year. The projections for the year that is ending will include:

- projected utility volumes and revenues
- projected utility expenses
- projected year-end plant balances and other rate base information
- projected deferral account balances and amortization
- projected year-end customers and other cost driver information
- projected utility earnings.

Forecasts for the next year will include:

- forecast customer growth
- forecasts of cost drivers, such as peak day throughput
- forecast Inflation
- forecast utility volumes and revenues
- forecast utility expenses (revised allowed costs)
- forecast utility capital expenditures (revised allowed costs)
- forecast plant balances, deferral account balances and amortization to be included in rates.

Cost drivers for the next year will be updated to reflect the forecasts relating to the year. Cost drivers for the next year will also be updated for projected variances between actual customer growth in the past year and the customer growth that had been forecast for that year.

Opening plant balances and other rate base items for the next year will be adjusted to reflect projected variances which are not included in the capital efficiency mechanism discussed above.

Service quality results will also be reviewed at the Annual Review.

BC Gas proposes to commence its workshops in November of 1997. At that workshop forecasts for 1998 will be presented, together with the projected number of customers as of January 1, 1998 and projected plant balances and other rate base information as of January 1, 1998. Cost drivers for 1998 will be updated to reflect the forecasts for 1998. Rates for 1998 will be set by the Commission based on the projected opening rate base for 1998 and the forecasts for 1998 as agreed upon by the participants or as subsequently determined by the Commission.

Prior to each annual workshop, BC Gas will provide interested parties and the Commission advance information regarding the projections and forecasts to be presented by BC Gas at the workshop. This should be done 3 weeks prior to the workshop to allow parties to submit information requests and receive responses prior to the workshops.

In regard to projected year-end earnings, projected year end capital unit costs related to capital incentives presented for rate-making purposes in the November workshop BC Gas will provide an update in April or May once actual results have been determined and adjustments will be made at the following year end. Incentives will be trued up to the actual results at that time.

Service Quality Indicators

Principle:

Maintenance of existing high levels of service quality is an important feature of this Settlement. However, it is recognized that variance in these statistics may occur due to random events or events beyond the full control of BC Gas.

Process:

- **Service Quality Indicators will be reviewed at the Annual Review in November of each year.**
- **Participants will be given an opportunity to argue whether a deviation from the benchmark for any of the Service Quality Indicators is significant enough to establish that service quality is deteriorating generally or in specific areas.**
- **For those concerns which are not resolved at the review, participants will retain the option to make submissions to the Commission that it should limit the payments which BC Gas might otherwise earn from the financial incentives in this Settlement.**

Service Quality Indicators:

1. **Response time to emergency calls¹.**

¹ Applies to Coastal region only. Data for 1994 and 1995 not available. Measure for Interior region will be determined at a later date.

2. Response time for answering service centre calls by a person.
3. Leaks per kilometre of distribution mains due to system deterioration.
4. Transmission system annual reportable incidents.
5. Number of third party distribution system damage incidents per 1000 housing starts².

Annual Evaluation:

- Unless otherwise indicated, *benchmarks* will be calculated as the rolling average of the three years prior to the most current year; *performance indicators* will be calculated as the rolling average of the most current year plus the past two years.
- Each performance indicator will be evaluated on its own merits and a material deviation from the benchmark for any single performance indicator is sufficient basis to argue service quality deterioration and the need to limit payments to BC Gas.
- Each performance indicator will be given equal weight.

The onus of establishing that a benchmark has been met or why it is reasonable that it was not met rests with the utility.

- Interested parties should have access to the service quality evaluation prior to the Annual Review.
- Any party may argue that the benchmarks need to be modified

² Data for 1994 is not available. Initial benchmark will be set using 2 years of data.

Appendix A

1998 - 2002 Revenue Requirements Settlement

Illustrative Rate Impacts Summary

BC GAS UTILITY LTD.
SUMMARY
FOR THE YEARS 1998 TO 2000
(\$000)

APPENDIX A
1998-2000 SETTLEMENT
ILLUSTRATIVE RATE IMPACTS
SUMMARY

Line No	Particulars (1)	Volume 1 (Rev.) (2)	Difference (3)	1998-2000 Settlement (4)
1	<u>1998</u>			
2				
3	Rate Base	\$ 1,581,623	\$ (12,734)	\$ 1,568,889
4				
5	Revenue Requirement	\$ 24,448	\$ (17,552)	\$ 6,896
6	% Gross Margin Increase	6.37%	-4.57%	1.80%
7	Gross Margin (incl. Increase)	\$ 408,468	\$ (17,552)	\$ 390,916
8				
9	Operation and Maintenance			
10	Gross O&M excl. BC Hydro Costs	\$ 136,057	\$ (2,273)	\$ 133,784
11	O&M Expense (Net)	\$ 133,335	\$ (16,244)	\$ 117,091
12				
13	Plant Additions - Capital Expenditures	\$ 93,474	\$ (8,782)	\$ 84,692
14	- Overheads Capitalized	15,075	13,792	28,867
15	- All Other (WMP etc.)	2,445	0	2,445
16	Total	\$ 110,994	\$ 5,010	\$ 116,004
17				
18	<u>1999</u>			
19				
20	Rate Base	\$ 1,635,694	\$ (4,125)	\$ 1,631,569
21				
22	Revenue Requirement	\$ 14,278	\$ (6,570)	\$ 7,708
23	% Gross Margin Increase	3.44%	-1.50%	1.94%
24	Gross Margin (incl. Increase)	\$ 429,512	\$ (24,421)	\$ 405,091
25				
26	Operation and Maintenance			
27	Gross O&M excl. BC Hydro Costs	\$ 139,981	\$ (4,638)	\$ 135,343
28	O&M Expense (Net)	\$ 137,133	\$ (18,696)	\$ 118,437
29				
30	Plant Additions - Capital Expenditures	\$ 95,829	\$ (9,241)	\$ 86,588
31	- Overheads Capitalized	15,510	13,693	29,203
32	- All Other (WMP etc.)	8,420	0	8,420
33	Total	\$ 119,759	\$ 4,452	\$ 124,211
34				
35	<u>2000</u>			
36				
37	Rate Base	\$ 1,703,373	\$ (16,436)	\$ 1,686,937
38				
39	Revenue Requirement	\$ 11,984	\$ (3,961)	\$ 8,023
40	% Gross Margin Increase	2.73%	-0.79%	1.94%
41	Gross Margin (incl. Increase)	\$ 450,229	\$ (28,891)	\$ 421,338
42				
43	Operation and Maintenance			
44	Gross O&M excl. BC Hydro Costs	\$ 144,106	\$ (8,468)	\$ 135,638
45	O&M Expense (Net)	\$ 141,126	\$ (16,581)	\$ 124,545
46				
47	Plant Additions - Capital Expenditures	\$ 135,013	\$ (47,670)	\$ 87,343
48	- Overheads Capitalized	15,967	7,446	23,413
49	- All Other (WMP etc.)	140	0	140
50	Total	\$ 151,120	\$ (40,224)	\$ 110,896

BC GAS UTILITY LTD.

SUMMARY OF RATE INCREASE REQUIRED
FOR THE YEARS ENDED DECEMBER 31, 1998 AND 1999
(\$000)

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1998 - 2000 SETTLEMENT
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Line No.	Particulars	1998				1999			
		Core	Non-Core	Non-Captive	Total	Core	Non-Core	Non-Captive	Total
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	RATE INCREASE REQUIRED								
3	Gas Sales and Transportation Revenue, At Prior Year's Rates	\$721,248	\$33,574	\$15,139	\$769,961	\$742,055	\$33,520	\$15,108	\$790,683
6	Add - Other Revenue Related to Burrard Thermal / Central BC (PCEC)	0	336	8,806	9,142	0	336	8,888	9,224
10	Total Revenue	721,248	33,910	23,945	779,103	742,055	33,856	23,996	799,907
14	Less - Cost of Gas	(376,727)	(6,192)	(12,164)	(395,083)	(383,994)	(6,366)	(12,164)	(402,524)
18	Gross Margin	\$344,521	\$27,718	\$11,781	\$384,020	\$358,061	\$27,490	\$11,832	\$397,383
21	Revenue Deficiency - Volume 1 (Rev.)	\$22,628	\$1,820	\$0	\$24,448	\$13,260	\$1,018	\$0	\$14,278
23	Difference	(16,245)	(1,307)	0	(17,552)	(6,102)	(468)	0	(6,570)
25	Revenue Deficiency - 1998-2000 Settlement	6,383	513	0	6,896	7,158	550	0	7,708
27	Refund of Deferred Gas Cost Credits (GCRA)	0	0	0	0	0	0	0	0
29		\$6,383	\$513	\$0	\$6,896	\$7,158	\$550	\$0	\$7,708
32	Rate Increase as a % of Gross Margin	1.85%	1.85%	0.00%	1.80%	2.00%	2.00%	0.00%	1.94%
34	Rate Increase as a % of Total Revenue	0.88%	1.51%	0.00%	0.89%	0.96%	1.62%	0.00%	0.96%

BC GAS UTILITY LTD.

SUMMARY OF RATE INCREASE REQUIRED
FOR THE YEAR ENDED DECEMBER 31, 2000
(\$000)

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1998 - 2000 SETTLEMENT
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Particulars	2000			
	----- Captive ----- Core	Non-Core	Non-Captive	Total
(1)	(2)	(3)	(4)	(5)
RATE INCREASE REQUIRED				
Gas Sales and Transportation Revenue, At Prior Year's Rates	\$765,421	\$34,282	\$15,082	\$814,785
Add - Other Revenue Related to Burrard Thermal / Centra BC (PCEC)	0	336	8,885	9,221
Total Revenue	765,421	34,618	23,967	824,006
Less - Cost of Gas	(392,051)	(6,476)	(12,164)	(410,691)
Gross Margin	\$373,370	\$28,142	\$11,803	\$413,315
Revenue Deficiency - Volume 1 (Rev.)	\$11,144	\$840	\$0	\$11,984
Difference	(3,683)	(278)	0	(3,961)
Revenue Deficiency - 1998-2000 Settlement	7,461	562	0	8,023
Refund of Deferred Gas Cost Credits (GCRA)	0	0	0	0
	\$7,461	\$562	\$0	\$8,023
Rate Increase as a % of Gross Margin	2.00%	2.00%	0.00%	1.94%
Rate Increase as a % of Total Revenue	0.97%	1.62%	0.00%	0.97%

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BC GAS UTILITY LTD.

UTILITY RATE BASE
FOR THE YEARS ENDED DECEMBER 31, 1998, 1999 AND 2000
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Description (1)	1998			1999			2000		
	Present Rates (2)	Adjustments (3)	Revised Rates (4)	1998 Rates (5)	Adjustments (6)	Revised Rates (7)	1999 Rates (8)	Adjustments (9)	Revised Rates (10)
Plant in Service, Beginning	\$1,842,973	\$0	\$1,842,973	\$1,949,177	\$0	\$1,949,177	\$2,063,288	\$0	\$2,063,288
Additions	116,004	0	116,004	124,211	0	124,211	110,896	0	110,896
Disposals	(9,800)	0	(9,800)	(10,100)	0	(10,100)	(10,400)	0	(10,400)
Plant in Service, Ending	1,949,177	0	1,949,177	2,063,288	0	2,063,288	2,163,784	0	2,163,784
Add - Intangible Plant	967	0	967	967	0	967	967	0	967
	1,950,144	0	1,950,144	2,064,255	0	2,064,255	2,164,751	0	2,164,751
Contributions In Aid of Construction	(73,964)	0	(73,964)	(87,518)	0	(87,518)	(102,314)	0	(102,314)
Less - Accumulated Depreciation	(314,089)	0	(314,089)	(357,976)	0	(357,976)	(405,567)	0	(405,567)
Net Plant in Service, Ending	\$1,562,091	\$0	\$1,562,091	\$1,618,761	\$0	\$1,618,761	\$1,656,870	\$0	\$1,656,870
Net Plant in Service, Beginning	\$1,508,239	\$0	\$1,508,239	\$1,562,091	\$0	\$1,562,091	\$1,618,761	\$0	\$1,618,761
Net Plant in Service, Mid-Year	\$1,535,165	\$0	\$1,535,165	\$1,590,426	\$0	\$1,590,426	\$1,637,816	\$0	\$1,637,816
Adjustment to 13-Month Average	0	0	0	0	0	0	0	0	0
Construction Advances	(3,114)	0	(3,114)	(2,336)	0	(2,336)	(1,557)	0	(1,557)
Work in Progress, No AFUDC	4,048	0	4,048	4,333	0	4,333	3,833	0	3,833
Unamortized Deferred Charges	(7,215)	0	(7,215)	(1,384)	0	(1,384)	4,167	0	4,167
Cash Working Capital	10,024	71	10,095	10,401	(106)	10,295	10,881	40	10,921
Other Working Capital	29,910	0	29,910	30,235	0	30,235	31,757	0	31,757
Utility Rate Base	\$1,568,818	\$71	\$1,568,889	\$1,631,675	(\$106)	\$1,631,569	\$1,686,897	\$40	\$1,686,937

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BC GAS UTILITY LTD.

UTILITY INCOME AND EARNED RETURN
FOR THE YEARS ENDED DECEMBER 31, 1998, 1999 AND 2000
(\$000)

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1998 - 2000 SETTLEMENT
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Particulars	1998			1999			2000		
	Present Rates	---Revised Rates---		1998 Rates	---Revised Rates---		1999 Rates	---Revised Rates---	
		Revised Revenue	Total		Revised Revenue	Total		Revised Revenue	Total
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
ENERGY VOLUMES (TJ)									
Sales	158,624	0	158,624	161,357	0	161,357	164,379	0	164,379
Transportation	80,626	0	80,626	79,741	0	79,741	80,616	0	80,616
	239,250	0	239,250	241,098	0	241,098	244,995	0	244,995
Average Rate per GJ									
Sales	\$4.680		\$4.720	\$4.731		\$4.776	\$4.788		\$4.833
Transportation	\$0.343		\$0.348	\$0.342		\$0.348	\$0.345		\$0.351
Average	\$3.218		\$3.247	\$3.280		\$3.311	\$3.326		\$3.358
UTILITY REVENUE									
Sales - Present Rates	\$742,344	\$0	\$742,344	\$763,426	\$0	\$763,426	\$786,984	\$0	\$786,984
- Increase	0	6,436	6,436	0	7,220	7,220	0	7,526	7,526
Transportation - Present Rates	27,617	0	27,617	27,257	0	27,257	27,801	0	27,801
- Increase	0	460	460	0	489	489	0	502	502
Total	769,961	6,896	776,857	790,683	7,708	798,391	814,785	8,023	822,808
Cost of Gas Sold (Including Gas Lost)	395,083	0	395,083	402,524	0	402,524	410,691	0	410,691
Gross Margin	374,878	6,896	381,774	388,159	7,708	395,867	404,094	8,023	412,117
Restructuring Costs Amortization	555	0	555	555	0	555	555	0	555
Operation and Maintenance	117,091	0	117,091	118,437	0	118,437	124,545	0	124,545
Vehicle and FIS Leases	2,269	0	2,269	2,309	0	2,309	2,346	0	2,346
Property and Sundry Taxes	31,210	0	31,210	32,227	(1)	32,226	34,577	0	34,577
Depreciation and Amortization	54,904	0	54,904	58,799	0	58,799	61,801	0	61,801
Other Operating Revenue	(14,169)	0	(14,169)	(14,399)	0	(14,399)	(14,545)	0	(14,545)
	191,860	0	191,860	197,928	(1)	197,927	209,279	0	209,279
Utility Income Before Income Taxes	183,018	6,896	189,914	190,231	7,709	197,940	194,815	8,023	202,838
Income Taxes	49,878	3,072	52,950	53,054	3,429	56,483	53,693	3,562	57,255
EARNED RETURN	\$133,140	\$3,824	\$136,964	\$137,177	\$4,280	\$141,457	\$141,122	\$4,461	\$145,583
UTILITY RATE BASE	\$1,568,818	\$71	\$1,568,889	\$1,631,675	(\$106)	\$1,631,569	\$1,686,897	\$40	\$1,686,937
RATE OF RETURN ON UTILITY RATE BASE	8.49%		8.73%	8.41%		8.67%	8.37%		8.63%

APPENDIX A
1998 - 2000 SETTLEMENT
ILLUSTRATIVE RATE IMPACTS
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BC GAS UTILITY LTD.

INCOME TAXES / REVENUE DEFICIENCY
FOR THE YEARS ENDED DECEMBER 31, 1998, 1999 AND 2000
(\$000)

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1998 - 2000 SETTLEMENT
ILLUSTRATIVE RATE IMPACTS
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Particulars	1998			1999			2000		
	Present Rates	Revised Rates		1998 Rates	Revised Rates		1999 Rates	Revised Rates	
		Revised Revenue	Total		Revised Revenue	Total		Revised Revenue	Total
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
CALCULATION OF INCOME TAXES									
Earned Return	\$133,140	\$3,824	\$136,964	\$137,177	\$4,280	\$141,457	\$141,122	\$4,461	\$145,583
Deduct - Interest on Debt	(73,711)	5	(73,706)	(77,441)	(4)	(77,445)	(84,252)	(17)	(84,269)
Add - Non-Tax Ded. Expense (Net)	4,435	0	4,435	5,317	0	5,317	4,315	0	4,315
Accounting Income After Tax	63,864	3,829	67,693	65,053	4,276	69,329	61,185	4,444	65,629
Add (Deduct) - Timing Differences	(9,757)	0	(9,757)	(7,309)	0	(7,309)	(2,875)	0	(2,875)
Add - Large Corporation Tax	2,440	(76)	2,364	2,508	(86)	2,422	2,597	(90)	2,507
Taxable Income After Tax	\$56,547	\$3,753	\$60,300	\$60,252	\$4,190	\$64,442	\$60,907	\$4,354	\$65,261
Income Tax Rate (Current Tax)	45.620%	45.620%	45.620%	45.620%	45.620%	45.620%	45.620%	45.620%	45.620%
1 - Current Income Tax Rate	54.380%	54.380%	54.380%	54.380%	54.380%	54.380%	54.380%	54.380%	54.380%
Taxable Income (L10 : L14)	\$103,985	\$6,901	\$110,886	\$110,798	\$7,705	\$118,503	\$112,003	\$8,006	\$120,009
Income Tax - Current (L18 x L13)	\$47,438	\$3,148	\$50,586	\$50,546	\$3,515	\$54,061	\$51,096	\$3,652	\$54,748
- Large Corporation Tax	2,440	(76)	2,364	2,508	(86)	2,422	2,597	(90)	2,507
Total	\$49,878	\$3,072	\$52,950	\$53,054	\$3,429	\$56,483	\$53,693	\$3,562	\$57,255
REVENUE DEFICIENCY									
Earned Return		\$3,824	\$136,964		\$4,280	\$141,457		\$4,461	\$145,583
Add - Income Taxes		3,072	52,950		3,429	56,483		3,562	57,255
Deduct - Utility Income Before Taxes, Present Rates		0	(183,018)		0	(190,231)		0	(194,815)
Corporate Capital Tax		0	0		(1)	(1)		0	0
Deficiency After Corporate Capital Tax		\$6,896	\$6,896		\$7,708	\$7,708		\$8,023	\$8,023

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1998 - 2000 SETTLEMENT
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BC GAS UTILITY LTD.
RETURN ON CAPITAL
FOR THE YEARS ENDED DECEMBER 31, 1998, 1999 AND 2000
(\$000)

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Line No.	Particulars	Reference	Capitalization Amount	%	Average Embedded Cost	Cost Component	Earned Return	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	1998 PRESENT RATES							
2	Long-Term Debt			\$692,562	44.15%	9.420%	4.16%	
3	Unfunded Debt			211,701	13.49%	4.000%	0.54%	
4	Preference Shares			146,845	9.36%	6.995%	0.65%	
5	Common Equity			517,710	33.00%	9.515%	3.14%	
6								
7				\$1,568,818	100.00%		8.49%	
8								
9	1998 REVISED RATES							
10	Long-Term Debt			\$692,562	44.14%	9.420%	4.16%	\$65,239
11	Unfunded Debt		\$211,701					
12	Adjustment, Revised Rates		48	211,749	13.50%	4.000%	0.54%	8,470
13	Preference Shares			146,845	9.36%	6.995%	0.65%	10,272
14	Common Equity			517,733	33.00%	10.250%	3.38%	53,068
15								
16				\$1,568,889	100.00%		8.73%	\$137,049
17								
18	1999 AT 1998 RATES							
19	Long-Term Debt			\$734,940	45.04%	9.288%	4.18%	
20	Unfunded Debt			229,546	14.07%	4.000%	0.56%	
21	Preference Shares			128,736	7.89%	6.946%	0.55%	
22	Common Equity			538,453	33.00%	9.455%	3.12%	
23								
24				\$1,631,675	100.00%		8.41%	
25								
26	1999 REVISED RATES							
27	Long-Term Debt			\$734,940	45.05%	9.288%	4.18%	\$68,261
28	Unfunded Debt		\$229,546					
29	Adjustment, Revised Rates		(71)	229,475	14.06%	4.000%	0.56%	9,179
30	Preference Shares			128,736	7.89%	6.946%	0.55%	8,942
31	Common Equity			538,418	33.00%	10.250%	3.38%	55,188
32								
33				\$1,631,569	100.00%		8.67%	\$141,570
34								
35	2000 AT 1999 RATES							
36	Long-Term Debt			\$828,322	49.10%	9.016%	4.43%	
37	Unfunded Debt			239,399	14.19%	4.000%	0.57%	
38	Preference Shares			62,500	3.71%	6.631%	0.25%	
39	Common Equity			556,676	33.00%	9.455%	3.12%	
40								
41				\$1,686,897	100.00%		8.37%	
42								
43	2000 REVISED RATES							
44	Long-Term Debt			\$828,322	49.11%	9.016%	4.43%	\$74,682
45	Unfunded Debt		\$239,399					
46	Adjustment, Revised Rates		27	239,426	14.19%	4.000%	0.57%	9,577
47	Preference Shares			62,500	3.70%	6.631%	0.25%	4,144
48	Common Equity			556,689	33.00%	10.250%	3.38%	57,061
49								

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ILLUSTRATIVE RATE IMPACTS
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BC GAS UTILITY LTD.
 TARGET COSTS - CAPITAL EXPENDITURE SUMMARY
 FOR THE YEARS ENDING DECEMBER 31, 1998 TO 2000
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 1998 - 2000 SETTLEMENT
 ILLUSTRATIVE RATE IMPACTS
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Line No.	Particulars	Target Costs			
		Base Cost	1998	1999	2000
	(1)	(2)	(3)	(4)	(5)
1	SUMMARY - TOTAL COST				
2					
3					
4	CATEGORY:				
5					
6	A : MAINS, SERVICES & METERS	\$35,204	\$36,246	\$37,652	\$38,445
7					
8	B : SYSTEM INTEGRITY AND				
9	RELIABILITY	18,545	18,805	18,948	18,850
10					
11	C : ALL OTHER PLANT	29,317	29,641	29,988	30,048
12					
13	TOTAL - CATEGORIES A, B & C	83,066	84,692	86,588	87,343
14					
15					
16	D : SPECIAL PROJECTS 2300	0	0	0	0
17					
18	8400	0	0	0	0
19					
20	MISC.	0	0	0	0
21					
22					
23	TOTAL CAPITAL EXPENDITURES	83,066	84,692	86,588	87,343
24					
25	TOTAL PER 1998 - 2002 VOL. 1, PAGE 03-04 (REV.)	89,908	93,474	95,829	135,013
26					
27	INCREASE (DECREASE)	(\$6,842)	(\$8,782)	(\$9,241)	(\$47,670)
28					
29					
30	TOTAL CAPITAL EXPENDITURES - REAL (\$1997)	\$83,066	\$83,853	\$84,882	\$84,774

APPENDIX A
 1998 - 2000 SETTLEMENT
 ILLUSTRATIVE RATE IMPACTS
 PAGE 03-04

BC GAS UTILITY LTD.
 CAPITAL EXPENDITURE / PLANT ADDITIONS SUMMARY
 (\$000)

APPENDIX A
 1998 - 2000 SETTLEMENT
 ILLUSTRATIVE RATE IMPACTS
 PAGE 03 05

Line No.	Particulars (1)	Target Costs			
		Base Cost (2)	1998 (3)	1999 (4)	2000 (5)
1	CAPITAL EXPENDITURES				
2					
3	A : MAINS, SERVICES & METERS	\$35,204	\$36,246	\$37,652	\$38,445
4					
5	B : SYSTEM INTEGRITY AND				
6	RELIABILITY	18,545	18,805	18,948	18,850
7					
8	C : ALL OTHER PLANT	29,317	29,641	29,988	30,048
9					
10	D : SPECIAL PROJECTS	0	0	0	0
11					
12	TOTAL CAPITAL EXPENDITURES	<u>83,066</u>	<u>84,692</u>	<u>86,588</u>	<u>87,343</u>
13					
14					
15	WORK IN PROGRESS				
16	Add - Opening WIP		16,100	15,205	8,380
17					
18					
19	Less - Closing WIP		(15,205)	(8,380)	(9,770)
20					
21					
22					
23	Add - AFUDC		1,550	1,595	1,530
24					
25	Add - O'H Capitalized		28,867	29,203	23,413
26					
27	SUBTOTAL - PLANT ADDITIONS		116,004	124,211	110,896
28					
29	Add - 1996 and 1997 CPCN's		6,618		
30					
31	TOTAL PLANT ADDITIONS		122,622	124,211	110,896
32					
33	TOTAL PER 1998 - 2002 VOL. 1, PAGE 03-05 (REV.)		117,612	119,759	151,120
34					
35	INCREASE (DECREASE)		\$5,010	\$4,452	(\$40,224)

APPENDIX A
 1998 - 2000 SETTLEMENT
 ILLUSTRATIVE RATE IMPACTS
 PAGE 03-05

BC GAS UTILITY LTD.
OPERATING & MAINTENANCE EXPENSE
(\$000)

APPENDIX A
1998 - 2000 SETTLEMENT
ILLUSTRATIVE RATE IMPACTS
PAGE 09-02

Line No.	Particulars	Target Costs		
		1998 (2)	1999 (3)	2000 (4)
1	<u>Cost Drivers / Escalators</u>			
2	Average No. of Customers	734,710	750,609	767,317
3	Growth %	2.10%	2.16%	2.23%
4	Productivity Improvement			
5	Factor (PIF)	2.00%	2.00%	3.00%
6	Inflation (CPI)	1.00%	1.00%	1.00%
7				
8	<u>O&M (Gross)</u>			
9	O&M	\$133,784	\$135,343	\$135,638
10	BC Hydro Service Agreement	10,550	10,673	10,698
11	Total	144,334	146,016	146,334
12				
13	<u>DRIA's</u>			
14	- DSM / IRP	1,624	1,624	1,624
15	- Other	-	-	-
16		1,624	1,624	1,624
17	Total Gross O&M	145,958	147,640	147,958
18				
19	<u>OH Capitalized</u>	20.00%	20.00%	16.00%
20	O&M	28,867	29,203	23,413
21	BC Hydro Service Agreement			
22	<u>DRIA's</u>			
23	- DSM / IRP	-	-	-
24	- Other	-	-	-
25	Total OH Capitalized	28,867	29,203	23,413
26				
27	Total Per 1998 - 2002 Vol. 1, Page 09-02 (Rev.)	15,075	15,510	15,967
28	Difference	13,792	13,693	7,448
29				
30	<u>O&M Expense (Net)</u>			
31	O&M	115,467	116,813	122,921
32	<u>DRIA's</u>			
33	- DSM / IRP	1,624	1,624	1,624
34	- Other	-	-	-
35	Total O&M Expense	\$117,091	\$118,437	\$124,545
36				
37	Total per 1998-2002 Vol. 1, Page 09-02 (Rev.)	\$133,335	\$137,133	\$141,126
38				
39	Difference	(\$16,244)	(\$18,696)	(\$16,581)

APPENDIX A
1998 - 2000 SETTLEMENT
ILLUSTRATIVE RATE IMPACTS
PAGE 09-02

BC GAS UTILITY LTD.

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDED DECEMBER 31, 1998
(\$000)

APPENDIX A
1998 - 2000 SETTLEMENT
1998
PAGE 03-11.1

Line No.	Particulars	Account	Forecast Balance 12/31/97	Gross Additions	Less-Taxes	Net Additions	Amortization		Balance 12/31/98	Mid-Year Average 1998
							Expense	Other		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Deferred Interest	#179-008	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
2										
3	Market Rebate Incentive									
4	Water Heater Grants	#179-052	402	0	0	0	(100)	0	302	352
5	Commercial & Multi-family	#179-013	103	0	0	0	(55)	0	48	75
6										
7	NGV Conversion Grants	#179-018	20	0	0	0	(20)	0	0	10
8	NGV Conversion Grants 1996-1997		1,534	0	0	0	(527)	0	1,007	1,271
9	NGV Conversion Grants 1998-2002		0	1,500	(668)	832	0	0	832	416
10										
11	Local Gas Development	#179-053	2,908	0	(90)	(90)	(564)	0	2,254	2,581
12	Fraser Valley Gas Exploration	#179-092	457	0	0	0	(91)	0	366	411
13										
14	Revenue Req. Hearing - 1998-2002	#179-141	133	0	0	0	(44)	0	89	111
15										
16										
17	Demand Side Management #G-69-93	#179-063	45	0	0	0	(33)	0	12	28
18										
19	Demand Side Management 1996-97		327	0	0	0	(110)	0	217	272
20	Demand Side Management 1998-2002		0	1,585	(705)	880	0	0	880	440
21										
22										
23	Integrated Resource Plan #G-69-93	#179-064	133	0	0	0	(77)	0	56	94
24	Integrated Resource Plan #G-60-94		147	0	0	0	(49)	0	98	123
25	Integrated Resource Plan 1996-97		108	0	0	0	(36)	0	72	90
26	Integrated Resource Plan 1998-2002		0	100	(45)	55	0	0	55	28
27										
28										
29	Residential Thermostat Program	#179-109	30	0	0	0	(11)	0	19	24
30	Property Tax Deferral	#179-062	(890)	0	0	0	0	0	(890)	(890)
31	Westar Receivable	#179-069	134	0	0	0	(27)	0	107	121

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1998 - 2000 SETTLEMENT
1998
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BC GAS UTILITY LTD.

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDED DECEMBER 31, 1998
(\$000)

APPENDIX A
1998 - 2000 SETTLEMENT
1998
PAGE 03-11.2

Line No.	Particulars	Account	Recorded Balance 12/31/97	Gross Additions	Less-Taxes	Net Additions	Amortization		Balance 12/31/98	Mid-Year Average 1998
							Expense	Other		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
32	G.C.R.A.	#179-088	(13,500)	0	0	0	0	4,500	(9,000)	(11,250)
33	G.C.R.A. Interest	#179-188	0	0	0	0	0	0	0	0
34										
35										
36	Offsystem Sales Coord. Center	#179-120	23	0	0	0	(10)	0	13	18
37	Revelstoke Propane Cost	#279-024	293	0	0	0	0	(293)	0	147
38	B.C. Hydro DRIA	#179-144	(823)	0	0	0	0	0	(823)	(823)
39	DSM DRIA	#179-142	(489)	0	0	0	0	0	(489)	(489)
40										
41	Recovery of Non-Utility Service	#279-063	(98)	0	0	0	98	0	0	(49)
42	RSAM	#179-089	(7,500)	0	0	0	0	2,500	(5,000)	(6,250)
43										
44	NGV B.C. Transit Grants	#179-105	461	0	0	0	(159)	0	302	382
45	BC21 Power Smart Program	#179-119	444	0	0	0	(222)	0	222	333
46	BC21 Power Smart Phase 2		168	0	0	0	(34)	0	134	151
47										
48	Coastal Facilities (#C-6-95)									
49	· Relocation		2,387	1,049	(467)	582	(686)	0	2,283	2,335
50	· Lochburn NBV Amortization		1,108	0	0	0	(369)	0	739	924
51	· Fraser Valley NBV Amortization		878	0	0	0	(176)	0	702	790
52										
53										
54	Organizational Restructuring	#179-132	480	0	0	0	(96)	0	384	432
55	Non-Core Margin Deferral	#179-135	214	0	0	0	0	(214)	0	107
56										
57	Main Extension Hearing Costs	#179-138	18	0	0	0	(18)	0	0	9
58	1995 IRP Participant Awards	#179-140	7	0	0	0	(7)	0	0	4
59	Gain on Sale of Kamloops Property	#279-001	(193)	0	0	0	193	0	0	(97)
60										
61	Restructuring Costs		0	3,000	(1,335)	1,665	(555)	0	1,110	555
62										
63										
64										
65										
66										
67										
68	Total Deferred Charges for Rate Base		(\$10,531)	\$7,234	(\$3,310)	\$3,924	(\$3,785)	\$6,493	(\$3,899)	(\$7,215)

BC GAS UTILITY LTD.

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDED DECEMBER 31, 1999
(\$000)

APPENDIX A
1998 - 2000 SETTLEMENT
1999
PAGE 03-11.3

Line No.	Particulars	Account	Forecast Balance 12/31/98	Gross Additions	Less-Taxes	Net Additions	Amortization		Balance 12/31/99	Mid-Year Average 1999
							Expense	Other		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Deferred Interest	#179-008	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
2										
3	Market Rebate Incentive									
4	- Water Heater Grants	#179-052	302	0	0	0	(100)	0	202	252
5	- Commercial & Multi-Family	#179-013	48	0	0	0	(48)	0	0	24
6										
7	NGV Conversion Grants	#179-018	0	0	0	0	0	0	0	0
8	NGV Conversion Grants 1996-1997		1,007	0	0	0	(527)	0	480	743
9	NGV Conversion Grants 1998-2002		832	1,500	(668)	832	(277)	0	1,387	1,109
10										
11	Local Gas Development	#179-053	2,254	0	(81)	(81)	(544)	0	1,629	1,942
12	Fraser Valley Gas Exploration	#179-092	366	0	0	0	(91)	0	275	320
13										
14	Revenue Req. Hearing - 1998-2002	#179-141	89	0	0	0	(44)	0	45	67
15										
16										
17	Demand Side Management #G-69-93	#179-063	12	0	0	0	(12)	0	0	6
18										
19	Demand Side Management 1996-97		217	0	0	0	(109)	0	108	163
20	Demand Side Management 1998-2002		880	1,585	(705)	880	(293)	0	1,467	1,174
21										
22										
23	Integrated Resource Plan #G-69-93	#179-064	56	0	0	0	(56)	0	0	28
24	Integrated Resource Plan #G-60-94		98	0	0	0	(49)	0	49	73
25	Integrated Resource Plan 1996-97		72	0	0	0	(36)	0	36	54
26	Integrated Resource Plan 1998-2002		55	100	(45)	55	(18)	0	92	74
27										
28										
29	Residential Thermostat Program	#179-109	19	0	0	0	(11)	0	8	14
30	Property Tax Deferral	#179-062	(890)	0	0	0	0	429	(461)	(676)
31	Westar Receivable	#179-069	107	0	0	0	(26)	0	81	93

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BC GAS UTILITY LTD.

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDED DECEMBER 31, 1999
(\$000)

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1998 - 2000 SETTLEMENT
1999
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Line No.	Particulars	Account	Recorded Balance 12/31/98	Gross Additions	Less-Taxes	Net Additions	Amortization		Balance 12/31/99	Mid-Year Average 1999
							Expense	Other		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
32	G.C.R.A.	#179-088	(9,000)	0	0	0	0	4,500	(4,500)	(6,750)
33	G.C.R.A. Interest	#179-188	0	0	0	0	0	0	0	0
34										
35										
36	Offsystem Sales Coord. Center	#179-120	13	0	0	0	(13)	0	0	7
37	Revelstoke Propane Cost	#279-024	0	0	0	0	0	0	0	0
38	B.C. Hydro DRIA	#179-144	(823)	0	0	0	0	0	(823)	(823)
39	DSM DRIA	#179-142	(489)	0	0	0	0	0	(489)	(489)
40										
41	Recovery of Non-Utility Service	#279-063	0	0	0	0	0	0	0	0
42	RSAM	#179-089	(5,000)	0	0	0	0	2,500	(2,500)	(3,750)
43										
44	NGV B.C. Transit Grants	#179-105	302	0	0	0	(159)	0	143	223
45	BC21 Power Smart Program	#179-119	222	0	0	0	(222)	0	0	111
46	BC21 Power Smart Phase 2		134	0	0	0	(34)	0	100	117
47										
48	Coastal Facilities (#C-6-95)									
49	- Relocation		2,283	1,049	(467)	582	(802)	0	2,063	2,173
50	- Lochburn NBV Amortization		739	0	0	0	(369)	0	370	555
51	- Fraser Valley NBV Amortization		702	0	0	0	(176)	0	526	614
52										
53										
54	Organizational Restructuring	#179-132	384	0	0	0	(96)	0	288	336
55	Non-Core Margin Deferral	#179-135	0	0	0	0	0	0	0	0
56										
57	Main Extension Hearing Costs	#179-138	0	0	0	0	0	0	0	0
58	1995 IRP Participant Awards	#179-140	0	0	0	0	0	0	0	0
59	Gain on Sale of Kamloops Property	#279-001	0	0	0	0	0	0	0	0
60										
61	Restructuring Costs		1,110	0	0	0	(555)	0	555	833
62										
63										
64										
65										
66										
67										
68	Total Deferred Charges for Rate Base		(\$3,899)	\$4,234	(\$1,966)	\$2,268	(\$4,667)	\$7,429	\$1,131	(\$1,384)

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1998 - 2000 SETTLEMENT
1999
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BC GAS UTILITY LTD.

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDED DECEMBER 31, 2000
(\$000)

APPENDIX A
1998 - 2000 SETTLEMENT
2000
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Line No.	Particulars	Account	Forecast Balance 12/31/99	Gross Additions	Less-Taxes	Net Additions	Amortization		Balance 12/31/2000	Mid-Year Average 2000
							Expense	Other		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Deferred Interest	#179-008	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
2										
3	Market Rebate Incentive									
4	Water Heater Grants	#179-052	202	0	0	0	(100)	0	102	152
5	Commercial & Multi-Family	#179-013	0	0	0	0	(42)	0	(42)	(21)
6										
7	HGV Conversion Grants	#179-018	0	0	0	0	0	0	0	0
8	HGV Conversion Grants 1996-1997		480	0	0	0	(480)	0	0	240
9	HGV Conversion Grants 1998-2002		1,387	1,500	(668)	832	(555)	0	1,664	1,526
10										
11	Local Gas Development	#179-053	1,629	0	(73)	(73)	(520)	0	1,036	1,332
12	Fraser Valley Gas Exploration	#179-092	275	0	0	0	(91)	0	184	230
13										
14	Revenue Req. Hearing - 1998-2002	#179-141	45	0	0	0	(45)	0	0	23
15										
16										
17	Demand Side Management #G-69-93	#179-063	0	0	0	0	0	0	0	0
18										
19	Demand Side Management 1996-97		108	0	0	0	(108)	0	0	54
20	Demand Side Management 1998-2002		1,467	1,585	(705)	880	(587)	0	1,760	1,613
21										
22										
23	Integrated Resource Plan #G-69-93	#179-064	0	0	0	0	0	0	0	0
24	Integrated Resource Plan #G-60-94		49	0	0	0	(49)	0	0	25
25	Integrated Resource Plan 1996-97		36	0	0	0	(36)	0	0	18
26	Integrated Resource Plan 1998-2002		92	100	(45)	55	(37)	0	110	100
27										
28	Residential Thermostat Program	#179-109	8	0	0	0	(8)	0	0	4
29										
30	Property Tax Deferral	#179-062	(461)	0	0	0	0	461	0	(231)
31	Westar Receivable	#179-069	81	0	0	0	(27)	0	54	68

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BC GAS UTILITY LTD.

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDED DECEMBER 31, 2000
(\$000)

APPENDIX A
1998 - 2000 SETTLEMENT
2000
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Line No.	Particulars	Account	Recorded Balance 12/31/99	Gross Additions	Less-Taxes	Net Additions	Amortization		Balance 12/31/2000	Mid-Year Average 2000
							Expense	Other		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
32	G.C.R.A.	#179-088	(4,500)	0	0	0	0	4,500	0	(2,250)
33	G.C.R.A. Interest	#179-188	0	0	0	0	0	0	0	0
34										
35										
36	Offsystem Sales Coord. Center	#179-120	0	0	0	0	0	0	0	0
37	Revelstoke Propane Cost	#279-024	0	0	0	0	0	0	0	0
38	B.C. Hydro DRIA	#179-144	(823)	0	0	0	823	0	0	(412)
39	DSM DRIA	#179-142	(489)	0	0	0	489	0	0	(245)
40										
41	Recovery of Non-Utility Service	#279-063	0	0	0	0	0	0	0	0
42	RSAM	#179-089	(2,500)	0	0	0	0	2,500	0	(1,250)
43										
44	NGV B.C. Transit Grants	#179-105	143	0	0	0	(143)	0	0	71
45	BC21 Power Smart Program	#179-119	0	0	0	0	0	0	0	0
46	BC21 Power Smart Phase 2		100	0	0	0	(34)	0	66	83
47										
48	Coastal facilities (#C-6-95)									
49	- Relocation	#179-128	2,063	1,049	(467)	582	(918)	0	1,727	1,895
50	- Lochburn NBV Amortization		370	0	0	0	(370)	0	0	185
51	- Fraser Valley NBV Amortization		526	0	0	0	(176)	0	350	438
52										
53										
54	Organizational Restructuring	#179-132	288	0	0	0	(96)	0	192	240
55	Non-Core Margin Deferral	#179-135	0	0	0	0	0	0	0	0
56										
57	Main Extension Hearing Costs	#179-138	0	0	0	0	0	0	0	0
58	1995 IRP Participant Awards	#179-140	0	0	0	0	0	0	0	0
59	Gain on Sale of Kamloops Property	#279-001	0	0	0	0	0	0	0	0
60										
61	Restructuring Costs		555	0	0	0	(555)	0	0	278
62										
63										
64										
65										
66										
67										
68	Total Deferred Charges for Rate Base		\$1,131	\$4,234	(\$1,958)	\$2,276	(\$3,665)	\$7,461	\$7,203	\$4,167

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1998 - 2000 SETTLEMENT
2000
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WILLIAM J. GRANT
EXECUTIVE DIRECTOR,
REGULATORY AFFAIRS & PLANNING

SIXTH FLOOR, 900 HOWE STREET, BOX 250
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VIA FACSIMILE

July 15, 1997

Mr. Jim Quail
The British Columbia Public
Interest Advocacy Centre
815 - 815 West Hastings Street
Vancouver, B.C.
V6C 1B4

Dear Jim:

Re: BC Gas Utility Ltd.
Revenue Requirements Application

Thank you for your two letters of July 10, 1997 indicating your consent to the terms of the proposed settlement document along with the letter recording your interpretation of two of the provisions of the proposed settlement of this matter.

With respect to O&M productivity gains from capital projects the settlement document records the method for recognizing productivity at page 5. During our discussions of this matter we explored several examples including the Southern Crossing Project and the construction of a new operations building in the Lower Mainland.

In the case of the Southern Crossing Project the approval and construction of the pipeline would come into rate base the year following its completion. A number of impacts would be felt including funding of the rate base addition, changes to Westcoast or other upstream transportation suppliers, new gas supply options at hopefully more efficient prices, and the potential of third party revenues from the use of spare capacity in the pipeline. None of these components would affect the O&M productivity levels unless BC Gas were also able to obtain a direct O&M productivity improvement from the existence of this new capital edition. If that were to occur it would be available to assist BC Gas in meeting its O&M productivity targets during the remaining term of the three year agreement.

The completion of a new operations centre in the Lower Mainland is probably a better example of where some real O&M productivity might occur. In this case, BC Gas may seek approval and then build the new operations centre allowing it to sell parts of the Boundary/Lougheed property and relocate personnel from a number of leased premises. Presumably, there would also be some down sizing of space requirements at the downtown office. The effect would be that the new capital costs would flow into rate base the year following their completion and the proceeds of the sale of the Boundary/Lougheed property would reduce rate base. These changes would not affect the O&M productivity levels but the Company will likely obtain a number of efficiencies resulting from the more efficient housing of employees, the avoidance of travel, and such matters as the updating of equipment. These benefits are all available to assist the Company in meeting its O&M productivity targets for whatever remaining period exists in the three year settlement.

A third potentially significant CPCN could be the completion of a new customer information system allowing consolidated billing and other links to the financial and work order systems within BC Gas. As with the other projects the capital costs related to the new system would come into rate base in the year following completion. At the same time the Unisys system would be retired from rate base and the billing contract with B.C. Hydro would be terminated. These changes would not effect the O&M productivity targets, but the existence of the new customer information systems would likely have a profound impact on BC Gas operations, allowing improved information and efficiencies in numerous O&M areas of the Company. All of these O&M benefits would assist the Company in meeting the O&M targets for the remaining period of the three year settlement.

I hope this assists by providing an assessment of three of the more significant capital projects which may come to realization late in the three year settlement horizon.

Yours truly,



W.J. Grant

JG/lm

cc: Mr. D.M. Masuhara, Vice President
Legal and Regulatory Affairs
BC Gas Utility Ltd.
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National Energy Board

Compilation of Key
Documents Related to
the Board's RH-2-95
Decisions

**TransCanada PipeLines
Limited**

RH-2-95 Summary

June 1996

1996 Tolls

National Energy Board

Compilation of Key Documents Related to the Board's RH-2-95 Decisions

In the Matter of

TransCanada PipeLines Limited

Application dated 5 July 1995

RH-2-95 Summary

June 1996

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Chapter 1

Introduction

With respect to an application by TransCanada PipeLines Limited ("TransCanada", "the Company" or "TCPL") dated 5 July 1995 ("RH-2-95") for 1996 tolls, the National Energy Board ("the NEB" or "the Board"), in its Letter Decision dated 22 February 1996, indicated that it would, at a later date, be issuing a consolidated version of the decisions which would include under one cover, key documentation for both Phase 1 and Phase 2 of RH-2-95. In addition, the NEB indicated that it would include the complete text of the Incentive Cost Recovery and Revenue Sharing Settlement. For ease of reference and in order to assist parties, the NEB is now issuing a blue-cover compilation of certain key documents produced with respect to 1996 tolls. The NEB believes that this blue-cover compilation will provide an important legacy/reference document. In this regard, the NEB has included the following information:

Chapter 2 FST Settlement Agreement dated 16 November 1995 between the Canadian Association of Petroleum Producers ("CAPP"), The Consumers' Gas Company Ltd. ("Consumers"), Union Gas Limited ("Union"), and TransCanada.

Chapter 3 NEB Reasons for Decision regarding RH-2-95 Phase 1.

Chapter 4 TransCanada Incentive Cost Recovery and Revenue Sharing Settlement.

Chapter 5 NEB Reasons for Decision regarding RH-2-95 Phase 2.

Chapter 6 Interim Toll Order AO-1-TGI-3-95.

Chapter 7 Final Toll Order TG-2-96.

Chapter 8 List of Other Relevant Key Documents.

In order to minimize the number of pages of this blue-book document, the NEB has electronically scanned and inserted the settlement agreements contained in Chapters 2 and 4. As a result, the page numbers reflected in the blue book do not reconcile with those in the original agreements. In addition, the NEB is concerned that Chapters 2 to 7, inclusive may contain some discrepancies with the original documents as they were filed with or issued by the NEB. Therefore, in case of any discrepancy, the NEB directs readers to refer back to the original documents which constitute the official versions.

Chapter 2

FST Settlement Agreement

FST SETTLEMENT AGREEMENT

THIS AGREEMENT made as of the 16th day of November, 1995

BY AND AMONG:

CANADIAN ASSOCIATION OF PETROLEUM PRODUCERS, a Canadian not-for-profit corporation ("CAPP")

- and -

THE CONSUMERS' GAS COMPANY LTD., an Ontario corporation ("Consumers Gas")

- and -

UNION GAS LIMITED, an Ontario corporation ("Union")

- and -

TRANSCANADA PIPELINES LIMITED, a Canadian corporation ("TransCanada")

WITNESSES THAT, WHEREAS:

- A. CAPP, Consumers Gas, and Union (collectively the "FST Parties" and individually an "FST Party") have a significant interest in TransCanada's transportation services and tolls in general and, in the context of this Agreement, Firm Service Tendered ("FST") and the FST differential and toll in particular.
- B. TransCanada is the applicant and the FST Parties are intervenors in the public hearing before the National Energy Board ("the Board") in respect of TransCanada's application for tolls effective January 1, 1996 (the "Application") pursuant to Hearing Order RH-2-95 (the "Hearing").
- C. Consumers Gas and Union have each exercised their contractual rights to convert two-thirds of their FST service entitlements to Firm Transportation Service entitlements, effective November 1, 1998, by giving TransCanada a timely notice to that effect, which TransCanada has accepted. The notice given by Consumers Gas also applies to the conversion of the remaining one-third of its FST service entitlement to a Firm Transportation Service entitlement, effective November 1, 1999.
- D. In the light of the conversion notices, TransCanada and the FST Parties have discussed and wish to implement a consultative process, involving a broad base of TransCanada's shippers and other

Table 2-1
Calculation of the FST Toll and Differential
for the Test Year ending December 31, 1996

LINE NO.	PARTICULARS	RATE DEMAND	COMMODITY	100% LF	VOLUME 10 ⁶ M ³	COST CDN(\$)	
	(a)	(b)	(c)	(d)	(e)	(f)	
<u>(A) EQUIVALENT COST OF FIRM TRANSPORTATION SERVICE</u>							
1	Union	1,048.75	0.954	35.433	2 694.0	95,456,502	
2	Consumers	1,048.75	0.954	35.433	2 295.0	81,318,735	
3	TOTAL COST BASED ON FIRM TRANSPORTATION TOLL				4 989.0	176,775,237	
<u>(B) COST BASED ON THE SUITE OF SERVICES</u>							
<u>(1) STFT COMPONENT (50%)</u>							
4	Winter			35.433	997.8	35,355,047	
5	Summer			35.433	0	0	
6	Total STFT Component				997.8	35,355,047	
<u>(2) IT COMPONENT (100%)</u>							
<u>200% LF TOLL</u>							
7	Summer	1,048.75	0.954	18.194	2 993.4	54,461,920	
<u>(3) CURTAILABLE COMPONENT (50%)</u>							
8	Winter	* 61 DAYS IT (MIN)		18.194	400.4	7,284,878	
9		* 91 DAYS WFS (MAX)		49.606	597.4	29,634,624	
					997.8	36,919,502	
10	TOTAL COST BASED ON THE SUITE OF SERVICES				25.403	4 989.0	126,736,469
11	TOTAL DIFFERENTIAL (Line 3 - Line 9)			10.030 \$/10 ³ m ³		50,038,768	

* Based on 152 days in the 1996 Winter Season

Chapter 3

NEB Decision - Phase 1 FST Settlement

**TransCanada PipeLines Limited ("TransCanada")
Application Dated 5 July 1995 for 1996 Tolls ("RH-2-95")
Reasons for Decision Regarding Phase 1**

Background

On 5 July 1995, TransCanada PipeLines Limited ("TransCanada") filed an application pursuant to Part IV of the *National Energy Board Act* ("the Act") for new tolls to be effective 1 January 1996.

On 1 September 1995, the National Energy Board ("the Board") issued Hearing Order RH-2-95 setting down the application for a public hearing to commence on 11 December 1995. Hearing Order RH-2-95 was amended by letters dated 12 October and 7 and 16 November 1995.

On 20 October 1995, the Board approved a request by TransCanada to divide the proceeding into phases. Phase 1 would deal with issues related to cost allocation, toll design and tariff matters. Phase 2, which would begin no earlier than 29 January 1996, would deal with cost of service and other matters. TransCanada submitted that phasing would allow it sufficient time to complete settlement negotiations respecting cost of service matters.

Phase 1 of the hearing took place in Ottawa, Ontario on December 11, 12, 13 and 14, 1995.

The matters considered in Phase 1 included: tolls and tariff issues resolved by the 1996 Tolls Task Force; issues related to Firm Service Tendered ("FST") and an application for interim tolls to be effective 1 January 1996.

The Board's Negotiated Settlement Guidelines

In examining agreements among parties to a proceeding, the Board is guided by its *Guidelines for Negotiated Settlements of Traffic, Tolls and Tariffs*, dated 23 August 1994, and the cover letter from the Board of the same date (the "Guidelines"). Of particular relevance in these proceedings are the following extracts from those documents:

- All parties having an interest in a pipeline's traffic, tolls and tariffs should have a fair opportunity to participate and have their interests recognized and appropriately weighed in a negotiated settlement. The settlement process should be open and all interested parties should be invited to participate in the actual settlement negotiations.
- Upon filing of [information related to the resolution of individual toll design, tariff or other matters], interested parties would be provided with an opportunity to comment on each resolution. Resolutions that were not opposed by any party would normally be accepted by the Board.
- The Board confirms that, when presented with a settlement package, it will either accept or reject the package in its entirety.

1996 Tolls Task Force Resolutions

TransCanada's application contained twenty-one resolutions which had received either the unanimous support of the 1996 Tolls Task Force or were unopposed. Three of the proposals had received expedited consideration and approval by the Board prior to the hearing. The remaining eighteen were unopposed at the hearing.

Decision

The twenty-one resolutions approved by the 1996 Tolls Task Force and put forward as part of this proceeding and as described in Attachment 1, meet the Board's Guidelines. The Board has considered and approves the resolutions in full and directs that they be incorporated into TransCanada's Transportation Tariff.

Firm Service Tendered ("FST") Settlement Agreement

In Phase 1 of the hearing, the Board was asked by The Consumers' Gas Company Ltd. ("Consumers"), Union Gas Limited ("Union") and the Canadian Association of Petroleum Producers ("CAPP"), collectively known as the FST Parties, and TransCanada to accept the FST Settlement Agreement dated 16 November 1995 (the "FST Agreement"), to which these parties were signatories. While acknowledging that certain interested parties were excluded from participation in the process which led to the signing of the FST Agreement and thus did not meet the requirements of the Board's Guidelines, the FST Parties characterized the FST Agreement as a joint proposal and urged the Board to accept it in its "substantial entirety". The proponents of the FST Agreement noted that it had been the intention of the FST Parties and TransCanada to include other parties in the negotiations; however, due to time constraints, this had not been possible.

The Northeast Group and ProGas Limited ("ProGas") opposed the terms of the FST Agreement and urged the Board to reject it. The Northeast Group also opposed the process which resulted in the FST Agreement on the basis that, while it had a direct interest in the outcome, it had been excluded from the negotiations. Further, the Alberta Department of Energy ("ADOE"), while taking no position on the FST Agreement, urged the Board to adhere to its Guidelines.

Views of the Board

In applying the Guidelines to the FST Agreement, the Board agrees that this is not an agreement within the meaning of those Guidelines. Accordingly, the Board believes that it would be inappropriate to accept or reject the FST Agreement *per se*. However, the Board can review the particular components of the FST Agreement, as it would with the common position of parties to a proceeding, to determine whether each of the components is acceptable to the Board. Based on the decisions taken by the Board, it will then be up to TransCanada and the FST Parties to determine whether the terms of their FST Agreement have been met as a whole.

The two components of the FST Agreement which address issues relevant to Phase 1 of RH-2-95 relate to the appropriate "suite of services" methodology to be used in calculating the FST Differential and the appropriateness and level of a split of the FST Differential between upstream and downstream. In respect of each of these components, the Board has examined the evidence put forward by all parties to these proceedings to determine the justness and reasonableness of each proposal proposed jointly by the FST Parties and TransCanada.

The Board also took note of the exclusion of other parties from the FST Agreement negotiations and the reasons provided for their exclusion.

FST Differential Methodology for 1996

In this proceeding, TransCanada applied for a change to the existing "suite of services" methodology which was first applied to calculating the FST Differential as a result of the Board's decision in RH-3-94. The proposed "suite of services", which in TransCanada's view is a more appropriate cost-based application of the generic "suite of services" approach to calculating the FST Differential, and the existing "suite of services" are detailed below:

Proposed Suite of Services*

- | | | |
|---------|-----------------|--|
| Winter: | 50% of volumes | • 151 days as Eastern Zone Short-Term Firm Transportation ("STFT") at the 100% load factor toll |
| | 50% of volumes | • 61 days at the 200% load factor Eastern Zone Interruptible Transportation ("IT") toll |
| | | • 90 days at the Winter Firm Service toll which is 1.4 times the Eastern Zone 100% load factor Firm Transportation ("FT") toll |
| Summer: | 100% of volumes | • 214 days at 200% load factor Eastern Zone IT toll |

Existing Suite of Services* (as clarified in Board letter dated 23 November 1995)

- | | | |
|---------|----------------|--|
| Winter: | 50% of volumes | • 151 days as Firm Transportation ("FT") at the 100% load factor toll |
| | 50% of volumes | • 151 days as the minimum Temporary Winter Service ("TWS") toll |
| Summer: | 50% of volumes | • 194 days as Firm Transportation ("FT") at the 100% load factor toll |
| | | • 20 days as the minimum Eastern Zone IT toll at the 200% load factor |
| | 50% of volumes | • 214 days as the minimum Eastern Zone IT toll at the 200% load factor |

- * The foregoing would be modified to add one additional day to account for the leap year which occurs in 1996.

TransCanada's proposed "suite of services" is based on two criteria: the level of operating flexibility which FST provides the system; and the contracting approach which a customer would likely take in order to ensure the highest degree of probability that it would receive its volumes during the respective seasons, in the most economical fashion. In order to appropriately reflect these criteria, TransCanada has developed a proposed "suite of services" which places greater reliance on the IT toll.

TransCanada was supported by the other parties to the FST Agreement, TransCanada Gas Services Limited ("TCGS") and the Ministry of Energy and Environment for Ontario. Opposition was expressed by The Northeast Group and ProGas, who submitted that there had not been a sufficient change in circumstances to warrant review of the existing "suite of services" approach, that the FST

Differential had been arrived at through negotiations and that the proposed "suite of services" injected an additional flavour of IT which did not accurately reflect the annual, seasonal and daily delivery obligations of TransCanada under FST service.

Views of the Board

The Board continues to support the use of the "suite of services" methodology in deriving the FST Differential.

The majority decision in RH-3-94 acknowledged that the "suite of services" approach, which was adopted at that time, might require reassessment in a future proceeding. Specifically, in that decision the majority stated:

"The Board recognizes that, if TransCanada or other parties believe that the value of FST service to its system is more appropriately reflected by an alternate suite of services from that proposed by CAPP or some other approach, there is an opportunity to bring forward a proposal either before the Tolls Task Force or in a future tolls application."

Upon reflection and after having experience with the "suite of services" approach, the FST Parties and TransCanada have brought forward a proposed "suite of services" for consideration by the Board. It is incumbent on those parties to satisfy the Board that the proposed "suite of services" will result in tolls that would be more just and reasonable than those which resulted from the decision of the Board in RH-3-94. As discussed above, the mere fact of agreement among some of the parties is not sufficient; each of those parties acknowledged that the negotiations of the FST Agreement involved compromises. Accordingly, the Board has carefully examined the evidence to determine whether the proposed "suite of services" is a better surrogate for the value of FST service than that approved in the RH-3-94 decision. No other alternatives were put forward for consideration by the Board.

The level of the FST Differential for 1995 which was calculated from the existing "suite of services" resulted in a decision by Consumers and Union to opt to convert FST volumes to FT volumes. This decision to convert the FST volumes to FT volumes is strong evidence, in the Board's view, that under the existing "suite of services", FST service is overpriced and, therefore, inappropriate.

The main difference between the proposed "suite of services" and the existing "suite of services" is the greater reliance on the IT toll. While certain assumptions made by TransCanada regarding the availability of IT and shipper behaviour may not be totally accurate, the Board is persuaded that, on balance, the proposed "suite of services" is a better proxy for the flexibility required by TransCanada and the surety of transportation service required by the customer.

Decision

The Board approves TransCanada's proposed "suite of services" proposal to calculate the FST Differential and the FST toll for the 1996 test-year.

FST Differential Split

Under the terms of the FST Agreement, it is proposed that an upstream and a downstream component to the FST Differential be designated for 1996. The allocation of the FST Differential was negotiated to be 4 cents/GJ to the upstream and 21 cents/GJ to the downstream, based on a 25 cents/GJ FST unit differential. In addition, it was agreed that, after TransCanada had applied an appropriate "suite of

services" approach and calculated an actual FST Differential, any difference between the calculated FST differential and the agreed-to 25 cents/GJ FST Differential would be applied equally (i.e. 50/50) to the upstream and downstream components.

Under the "avoided cost" methodology used prior to the Board's decision in RH-3-94, the FST Differential was designated between upstream and downstream components. Under that methodology, the split, which was first introduced in RH-1-88, Phase 2, was a recognition by the Board that both upstream suppliers and downstream shippers/users contributed to the flexibility and other benefits afforded by FST service. Certain parties, TCGS [formerly known as Western Gas Marketing Limited ("WGML")], Consumers and Union, in placing reliance on that split, included in their gas sales contracts a pass-through of the upstream component of the FST Differential to TCGS. The non-identification by the Board of a split of the FST Differential in its RH-3-94 decision has created contractual uncertainty among the parties to those contracts.

Parties supporting the allocation of the FST Differential between upstream and downstream components, although acknowledging that the split was a negotiated element of the FST Agreement, argued for the inclusion in the Board's decision of an approval of the split for the following reasons:

- It would assist parties to achieve their expectations under the contracts since the gas supply contracts contemplate cost sharing on the basis of a split of the FST Differential.
- It would recognize that the upstream component is an element of the value captured in the price for FST service.
- It would be consistent with the decision in RH-1-88, Phase 2, which recognized the appropriateness of an upstream component of the FST Differential.
- Non-FST tollpayers are unaffected by any splitting of the FST Differential between upstream and downstream components.

The parties who opposed the approval of the split argued that it was not required for toll-setting purposes, that it is only required to resolve a private contractual dispute and that the determination of the split was not an independent valuation of the components but was subject to private negotiations.

Views of the Board

The Board must first decide whether approval of a split of the FST Differential between upstream and downstream is within its jurisdiction. In that regard, the Board notes that its jurisdiction in respect of traffic, tolls and tariffs, as set out in Section 59 of the Act, is very broad and extends beyond the mere setting of tolls. The Board's decisions may properly affect private contractual rights provided that the impacts on contract arrangements are incidental to the Board's exercise of its regulatory powers. As discussed below, an element of the FST Differential is the value to the TransCanada system of the flexibility provided both upstream and downstream by FST. In these circumstances, the Board is satisfied that an identification and approval of an FST Differential split is a matter related to TransCanada's system flexibility and, thus, to traffic, tolls and tariffs. Therefore, after reviewing the arguments presented by parties on this point, the Board has concluded that an approval of the FST Differential split is within its jurisdiction.

Secondly, the Board must be satisfied that a recognition of the split, as put forward by TransCanada, is also appropriate. In that regard, the Board notes that:

- Parties to the FST gas supply contracts entered into those contracts, in part, in reliance on a pass-through of the split as set out in the then-existing FST methodology.
- The allocation is intended to recognize that the operating flexibility provided by FST is due to the ability of both suppliers and the FST shippers to accommodate the service characteristics of FST.
- Parties supporting the FST Differential split have asked for the approval of the split as a transitional measure to facilitate contractual matters and to encourage a positive and cooperative approach to the upcoming consultative process for addressing FST conversion issues.
- The "suite of services" methodology does not, in and of itself, require or produce a split of the FST Differential.
- While there is no direct evidence on the record which could lead to an objective calculation of a split of the FST Differential, all parties directly affected by the FST Differential split in this proceeding have agreed to the value of each of the upstream and downstream components.

Decision

The Board also approves, as a transitional measure, the allocation of the FST Differential between upstream and downstream components as per the terms of the FST Agreement for the 1996 test-year.

Process to Address FST Conversion Issues

The Board's 12 October 1995 amendment to Hearing Order RH-2-95 identified Issue 3 b) as the toll and tariff impact of conversion from FST to FT. It was evident during the hearing that, at this time, parties were of the view that this issue related to an upcoming process wherein the views of all parties would be sought with respect to determining the ways and means by which TransCanada might be able to maintain a suitable level of flexibility once existing levels of FST had been converted to FT.

Within the text of the FST Agreement, it was noted that TransCanada and the FST Parties would co-operate and work together in an FST Study in order to implement a consultative process, involving a broad base of TransCanada's shippers and other stakeholders. This FST Study would examine and eventually could determine the ways and means whereby TransCanada could maintain and possibly enhance, on a long-term basis, the operating flexibility that is currently provided by the service characteristics of FST, including the classes of transportation services that would achieve this end and the corresponding service characteristics and toll-making methodologies.

In final argument, TransCanada indicated that such an examination to effect the conversion would be broad in scope and a fully-open process. TransCanada indicated that the intent of this broad and open approach is to recognize and address as many concerns as may be raised by different stakeholders and that the objective of the discussions will be to identify the optimum scenario which considers both the economic and operational aspects of the conversion.

TransCanada also indicated that it supports the proposal made by The Northeast Group regarding an overall review of alternate firm transportation services and that this proposal would be addressed, as part of the FST Study in 1996, by all participants in the 1997 Tolls Task Force.

TransCanada further stated that the results and conclusions from all discussions and analyses in the consultative process will be included in the comprehensive FST Study. This Study will be filed with the Board when TransCanada ultimately seeks approval from the Board to effect the conversion of FST to FT.

Views of the Board

In the Board's view, the comprehensive nature of the Study and the consultative process to be used by TransCanada should address the concerns of all stakeholders to RH-2-95 including those of The Northeast Group and ProGas.

Decision

The Board does not consider it necessary to issue specific directions in this area at this time.

Interim Toll Request

By letter dated 6 December 1995, TransCanada applied, pursuant to Sections 19(2), 59 and 64 of the Act, for an Order establishing interim tolls effective 1 January 1996. The attached Order TGI-3-95 establishes revised interim tolls effective 1 January 1996 to reflect the approval of the proposed "suite of services" in this Decision as well as to reflect the change in TransCanada's approved rate of return on common equity in accordance with the Board's letter dated 6 December 1995. Order TGI-1-95 is not revoked and continues to apply for the 1995 test-year pending final disposition by the Board of the issue before it re: RH-3-94 on FST. TransCanada will be required to file all affected schedules and revised tolls in compliance with the Phase 1 decisions and the approved rate of return on common equity for 1996.

Disposition

The foregoing together with Order No. TGI-3-95 constitute our Decision and Reasons for Decision on this matter.

(signed by)

J.A. Snider
Presiding Member

K.W. Vollman
Member

R. Iling
Member

Calgary, Alberta
December 1995

1996 Tolls Task Force Resolutions

Resolution 96-1 Tariff Amendment - Sales Meter Stations Charges

The General Terms and Conditions ("GTC"), Section VII will be amended to lower the threshold volume to which additional charges apply to 100 10³m³ from 1 250 10³m³ for sales meter stations regardless of when the meter station was put into service.

Resolution 96-2 Tariff Amendment - FST Curtailment Responsibilities

The FST Toll Schedules will be amended to clarify the wording of the GTC - Section XV such that an FST Shipper is not obligated to accept a Revised Tender unless that Revised Tender is a curtailment.

Resolution 96-3 IT Toll Design Review

The IT Toll Design will remain in effect for the 1996 test-year as agreed upon in Resolution 95-1 by the 1995 Tolls Task Force and as approved by the Board in RH-3-94 with the exception of those changes to the IT Bidding Ceiling and the method of determining the applicable nominated toll level as described in Resolution 96-14. It was further agreed that this issue would be revisited by the 1997 Tolls Task Force.

Resolution 96-4 Tariff Amendment - Imbalances Held at Primary Receipt Points

The GTC, Section II - "APPLICABILITY AND CHARACTER OF SERVICE" and Section XXII - "NOMINATIONS AND UNAUTHORIZED VOLUMES" will be amended such that imbalances will be deemed to have occurred and shall be held at the primary receipt point for the purposes of paying back recorded imbalances.

Resolution 96-5 Tariff Amendment - Nomination Time Change

The nomination time will remain in effect as agreed in Resolution 95-14 by the 1995 Tolls Task Force, and as approved by the Board in RH-3-94, for the 1996 test-year. It was agreed that this issue would be reviewed by the 1997 Tolls Task Force.

Resolution 96-6 Tariff Amendment - IT Nominating Discipline

In an Application dated 23 August 1995, TransCanada requested that the Board approve the Tariff Amendments to the IT Nominating Discipline that were agreed upon by the Tolls Task Force members. In a letter dated 21 September 1995, the Board approved the applied-for tariff amendments. This issue is to be reviewed by the 1998 Tolls Task Force.

Resolution 96-7 Tariff Amendment - IT Bidding Process

In an Application dated 23 August 1995, TransCanada requested that the Board approve the Tariff Amendments to the IT Bidding Process that were agreed upon by the Tolls Task Force. In a letter dated 21 September 1995, the Board approved the applied-for tariff amendments.

Resolution 96-8 TransGas Tolling

The toll design for TransGas will be modified effective 1 January 1996 under which TransGas tolls will be based on the distance from weighted average receipt points to weighted average delivery points in either the Saskatchewan Zone or under the Intra-Saskatchewan contract.

Resolution 96-9 Tariff Amendment - Contract Pressure

The GTC, Section XII - "DELIVERY PRESSURE" will be amended to relieve TransCanada of the responsibility to maintain contract delivery pressure at times, such as during peak loads, when the delivery pressure falls despite reasonable preventative measures taken by TransCanada's to maintain it.

Resolution 96-10 Tariff Amendment - STS Service Classification

The GTC, Section XV - "IMPAIRED DELIVERIES" will be amended to reflect changes to the order of priority of both daily and seasonal curtailments of STS. This issue is to be reviewed by the 1997 Tolls Task Force.

Resolution 96-11 Expedited Processing of Resolutions 96-6 and 96-7

It was resolved that TransCanada would file an application with the Board requesting expedited processing of Resolutions 96-6 and 96-7.

Resolution 96-12 Winter Firm Service (WFS) Price Cap

In its applications dated 5 and 10 July 1995, TransCanada requested Board approval of deviations from TransCanada's Transportation Tariff as it applies to Winter Firm Service for the bid period covering the 1995/96 winter season. In letters dated 7 and 11 July 1995, the Board approved Resolution 96-12 in its entirety.

Resolution 96-13 Temporary Winter Service (TWS) Price Cap

The Tolls Task Force agreed to amend the TWS toll schedule to reflect changes to the TWS price cap and the length of service entitlement for the bid period covering service for the 1995/96 winter season.

Resolution 96-14 IT Service Bidding

The IT Toll Schedule will be amended to change the criteria for the determination of a successful IT bid to the basis of the maximization of financial benefit to the system. For the 1996 test-year, the ceiling for bids east of the Manitoba Delivery Area ("MDA") will be at the 50% load factor of the Philipsburg toll. The ceiling for bids from Empress to and including all of the MDA and south to Emerson ("the West") will be at the 50% load factor level of the Philipsburg toll less the East/West Differential. The IT Service Bidding floors will remain at the 200% load factor level for each domestic toll zone and export point. Nominations are to be evaluated on a maximum net revenue basis. The East/West Differential will be added to each bid from the West for the purpose of assessing financial benefit to the system.

Resolution 96-15 Appropriateness of Basing Other Tolls on the FST Downstream Differential

As a result of the approval of the "suite of services" approach in RH-3-94, there is no longer the identification of an upstream and downstream component of the FST Differential. Consequently, the derivation of certain tolls (i.e. PS, WFS and TWS) which previously relied upon the specification of a downstream differential were required to be changed for 1996. This Resolution is intended only as a temporary measure pending potential resolution by the 1997 Tolls Task Force.

Resolution 96-16 General Terms and Conditions Update

Amendments to various sections of TransCanada's GTC will be made to reflect several new services approved in RH-3-94: Long-term Winter Firm Service (LT-WFS), Enhanced Capacity Release Service (ECR) and Firm Backhaul Transportation Service.

Resolution 96-17 Tariff Update re: "TransCend"

Amendments to the GTC will be made to remove all references to the word "TransCend".

Resolution 96-18 Tariff Amendment - Billings and Payments

Amendments to the GTC will be made so that the billing date for all shippers will be the 10th of each month and the invoice payment date will be the 20th of each month. All export customers will continue to pay on the 25th of each month until expiration of each shipper's export contract. The payment date for all renewals and new export contracts will reflect a payment date of the 20th of the month.

Resolution 96-19 Diversion Policy Adjustment

The GTC, Section XV - "IMPAIRED DELIVERIES" will be amended to give the diversion of gas away from firm contractual delivery points, which are downstream of the system restriction, priority over the diversion of gas away from firm contractual delivery points which are not downstream of the system restriction.

Resolution 96-20 Single Handshakes

Single Handshakes will be incorporated into TransCanada's Transportation Tariff to provide shippers and gas suppliers assurances of service. This will also enable TransCanada to avoid operational imbalances in excess of a certain level by nominating against Handshake Account Holders where parties have not honoured their Handshake arrangements.

Resolution 96-21 Tariff Update re: "ISW-1"

The GTC, Section XVI - "DETERMINATION OF DAILY DELIVERIES" will be amended to update references to "ISW-1" to read "Maximum IT Toll between those two points or areas... " to reflect the removal of the IT tiers.

ORDER TGI-3-95

IN THE MATTER OF the *National Energy Board Act*
("the Act") and the Regulations made thereunder; and

IN THE MATTER OF a request dated 6 December 1995
by TransCanada PipeLines Limited ("TransCanada")
requesting the Board to issue an Order establishing interim
tolls effective 1 January 1996.

BEFORE the Board on 21 December 1995.

WHEREAS the Board has received a request from TransCanada, dated 6 December 1995, pursuant to Sections 19(2), 59 and 64 of the *National Energy Board Act*, for an Order establishing interim tolls effective 1 January 1996;

IT IS ORDERED, Pursuant to Sections 19(2), 59 and 64 of the Act that:

1. Effective 1 January 1996, TransCanada's current interim tolls pursuant to TGI-1-95 shall be revised by Order TGI-3-95 to reflect the approval of the proposed "suite of services" as set out in the Phase 1 Decision for RH-2-95 as well as the change in TransCanada's approved rate of return on common equity in accordance with the Board's letter dated 6 December 1995; and
2. TransCanada is directed to file with the Board and serve copies on parties to RH-2-95 and its shippers forthwith all schedules and resulting tolls reflecting this decision.

NATIONAL ENERGY BOARD

(signed by)

J.S. Richardson
Secretary

Chapter 4

Incentive Cost Recovery & Revenue Sharing Settlement

TransCanada PipeLines Limited Incentive Cost Recovery and Revenue Sharing Settlement

Article 1 Introduction

- 1.1 TransCanada PipeLines Limited ("TCPL") and its stakeholders, as represented by the Tolls Task Force, (collectively "the Parties") propose the implementation of this Incentive Cost Recovery and Revenue Sharing Settlement which will be applied to determine the Net Revenue Requirement utilized by TCPL in the calculation of tolls for the transportation of natural gas on the TCPL system, in accordance with the toll methodology and pursuant to the TCPL Transportation Tariff approved from time to time by the National Energy Board ("NEB").
- 1.2 The primary objectives of this Settlement are the following:
 - i) to more closely align the interests of the Parties by providing a framework which encourages efficiency gains, cost minimization and maximization of system utilization;
 - ii) to provide for the lowest possible costs and the highest possible throughput without compromising pipeline efficiency and reliability or adversely impacting safety or the environment;
 - iii) to result in tolls to shippers that will be lower than they otherwise would have been if determined under traditional cost of service regulation;
 - iv) to maintain or improve the historic high level of service quality of the TCPL system;
 - v) to maintain or improve the financial integrity of TCPL;
 - vi) to preserve firm shippers' flexibility and ability to fully utilize their transportation contracts. The service attributes of FT service such as diversions, single handshakes, assignments, capacity release and enhanced capacity release, each reflecting their current Transportation Tariff and TCPL policy provisions, will be maintained or enhanced, subject to possible change by the Tolls Task Force and the NEB; and
 - vii) to provide for the active management by TCPL of its foreign exchange and debt management programs in order to minimize costs.

- 1.3 This Settlement shall apply only to the mainline business of TCPL which is subject to the jurisdiction of the NEB.
- 1.4 The Parties enter into this Settlement with the understanding that no single component of the Settlement is to be construed as representing the position of either TCPL or any stakeholder on the appropriate result that would be obtained in the absence of the Settlement. The Parties intend this Settlement to be viewed as a whole, and that there should be no prejudice to the positions of TCPL or any stakeholder in the future. No element of the Settlement should be considered as acceptable to either TCPL or any stakeholder in isolation from all other aspects of the Settlement. All elements of the Settlement are inextricably linked.
- 1.5 The Parties intend that the Settlement be applicable solely to TCPL and will have no application to, or form a precedent for, TCPL beyond the term of this Settlement.
- 1.6 The Parties agree that if this Settlement is not approved in its entirety by the NEB, or if it is subsequently materially varied by an NEB Order, the Settlement will terminate.
- 1.7 The Parties acknowledge that the NEB has exclusive jurisdiction over the establishment of TCPL's tolls and that any matters respecting the derivation of tolls under this Settlement shall be determined by the NEB.
- 1.8 Furthermore, the Parties contemplate that the NEB will play the following role regarding the implementation of this Settlement and the resulting calculation of TCPL tolls:
 - i) review and approve the reasonableness of the forecast of items covered in the Flow-Through Cost Envelope;
 - ii) adjudicate all disputes which arise out of this Settlement and which cannot be resolved amongst the Parties in accordance with the terms of this Settlement;
 - iii) be the arbiter of matters involving additions or changes to Rate Base, except to the extent it is affected by a Capital Efficiency Mechanism;
 - iv) review and adjudicate on the disposition of Flow-Through Deferral Accounts pursuant to Section 8.5 and rule on any complaints filed in connection with such matter; and
 - v) generally fulfil its mandate as required under the *National Energy Board Act*.
- 1.9 The Parties intend this Settlement to be interpreted and applied in good faith and in a manner consistent with the spirit of the primary objectives set out in Section 1.2.

Article 2 Definitions

- 2.1 In this Settlement the following terms have the meanings set out below:
 - (1) **Actual Debt Portfolio** means TCPL's debt portfolio comprised of funded debt as at 31 December, 1995 and as amended from time to time to reflect fluctuations in TCPL's debt position.

- (2) **Base Discretionary Miscellaneous Revenue** means the annual benchmark revenue level for Discretionary Miscellaneous Revenue to be applied in the sharing mechanisms discussed in Article 15.
- (3) **Capital Efficiency Mechanism** means that mechanism referred to in Article 11.
- (4) **Carrying Charges** means the carrying charges that will be applied monthly to the average of the month's opening and closing balances in each deferral account at a monthly rate equivalent to i) in the case of deferral account balances related to the Interest Rate Management Program and the Foreign Exchange Management Program, the monthly average of the one month bankers acceptance rate for the month immediately preceding the current month, as reported by Reuters Information Services, page CDOR, plus applicable stamping fees, and ii) in the case of balances in all other deferral accounts, one-twelfth of TCPL's annual Rate of Return on Rate Base. Carrying Charges will apply to all Flow-Through Deferral Accounts and all Incentive Based Deferral Accounts.
- (5) **Cash Flow** means the net of all monies received and paid in each Test Year of this Settlement in respect of current Test Year hedge transactions under the Interest Rate Management Program. For greater certainty, monies received or paid in a Test Year in respect of future years shall be amortized over the term of the underlying hedge instrument.
- (6) **Cost of Service** means the annual owning and operating costs of the TCPL pipeline system.
- (7) **Depreciation Expense** means the product obtained by multiplying the depreciation rates for the TCPL system in effect at 31 December, 1995, by the actual balance of gross plant included in Rate Base.
- (8) **Discretionary Miscellaneous Revenue** means revenue calculated from the Imputed Fixed Cost component of the applicable toll for all new and existing services not included within the definitions of Firm Service Revenue and Non-Discretionary Miscellaneous Revenue. Discretionary Miscellaneous Revenue will include, but is not limited to, revenue from downstream diversions, STFT service, FBT service, ECR service, TWS, PS, IT service, IT Backhaul service, WFS, FT overrun and STS overrun.
- (9) **FERC** means the Federal Energy Regulatory Commission of the United States of America.
- (10) **FT, FST, LT-WFS, STS, STFT, TWS, PS, IT, IT Backhaul, FBT and ECR** have the meanings ascribed to such terms in the TCPL Transportation Tariff, as it may be amended from time to time (see Schedule 2.1).
- (11) **Fixed Cost Allocation Units** means the measurement units associated with the forecast of fixed volume and fixed volume distance for all firm transportation services not afforded by-product treatment for the Test Year.