BRITISH COLUMBIA UTILITIES COMMISSION

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

and

IN THE MATTER OF
a Rate Design Application by
BC Gas Inc.

DECISION

February 21, 1992

BEFORE:

John G. McIntyre, Chairman
Norris Martin, Commissioner
Harold J. Page, Commissioner

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1.0 BACKGROUND

1.1 Changing Natural Gas Markets

On October 31, 1991 the long-term gas supply contracts between BC Gas Inc. ("BC Gas", "the Company", "the Utility") and Westcoast Energy Inc. ("Westcoast") expired. As a result, BC Gas has replaced its previous supply with a broad portfolio of gas supply purchased in a competitive marketplace. This Decision, in determining the methodology to allocate gas costs to end-use customers, represents a key step in the progression to deregulate markets which began with the Western Accord in March of 1985.

Some of the issues to be decided in this Decision build on previous determinations made by the British Columbia Utilities Commission ("the Commission") over the course of the past seven years. Therefore, it is important to reflect briefly on the steps that have led to the deregulated market that exists now.

The Western Accord between the Federal Government and the western Provinces established that wellhead deregulation of oil prices would occur and directed that a companion agreement on natural gas prices be negotiated by November of 1985. The Government of British Columbia then moved quickly to establish the British Columbia Natural Gas Price Act which allowed the two largest gas users in the province to contract for separate gas supplies. Thereafter, on October 31, 1985, the Federal Government and the western Provinces entered into an Agreement on Natural Gas Prices ("the Hallowe'en Agreement").

A "Backgrounder" to the Hallowe'en Agreement stated the objectives of the Agreement as follows:

> "The agreement among participating governments is intended to create the conditions for a new market-responsive pricing system consistent with the regulated character of the transmission and distribution sectors of the gas industry. It signals an end to government administered prices and a return to market forces characterized by choices for buyers and sellers. While the agreement provides for a transition period of one year, access will be immediately enhanced for Canadian buyers to natural gas supplies and for Canadian producers to natural gas markets.

> The new regime will provide the framework for negotiated prices between buyers and sellers. Prices will be affected by conditions in the marketplace; both supply and demand will influence the price. Competition will be fostered which should increase the industry's ability to react quickly to changing conditions."

British Columbia was the first province in Canada to facilitate the situation wherein large industrial customers could purchase their natural gas supplies directly from producers. In previous Decisions, the Commission dealt with such matters as the unbundling of rates, by-pass legislation and the fundamental determinations with respect to the benefits and costs to be assumed by Core Market customers or transportation customers when a customer chose to leave the Core Market. On the subject of transportation rates, the Commission established the principle that customers leaving the Core Market to buy gas directly should be entitled to take with them the inherent benefits that they had previously provided to the Core Market. The Commission also ordered that the costs to the utilities resulting from the departure of industrial customers should be covered by these customers. This order served as a basis for the allocation of the costs and benefits of the many transportation options now available to industrial customers.

1.2 Core Market Policy

In June of 1988, the Minister of Energy, Mines and Petroleum Resources issued a policy paper entitled "British Columbia Natural Gas Core Market Policy". The Commission also received new responsibilities with the contract review requirements established under Section 85.3 of the Utilities Commission Act ("the Act"). To facilitate the review by the Commission of energy supply contracts under Section 85.3, the Commission established "Rules" in August of 1988. The Core Market Policy and current Rules are appended to this Decision (Appendix A).

The Core Market Policy and the Commission's Rules are currently more conservative and security oriented than practices in other provinces. From time to time in the past, some marketers and smaller customers have suggested that the Commission is too conservative in its requirements for customers to enter the competitive gas market. The Commission does not necessarily endorse these views, but nevertheless is sensitive to these concerns and, following this Decision, considers that it is timely to examine its Rules in the light of the development of competitive markets here and elsewhere in Canada. The Commission has operated on the assumption that the prices obtained previously by the Utility on behalf of Core Market customers were competitive with those available in the open market place. This assumption must be reviewed now that BC Gas has entered into freely negotiated contracts with producers on behalf of the Core Market. Until this contract year, BC Gas was tied to purchases from CanWest Gas Supply Inc. ("CanWest"—previously the B.C. Petroleum Corporation) for the bulk of its supplies. The related gas supply contracts are commonly referred to as the "Westcoast Contracts" a description that dates from the time when Westcoast was the supplier. Only now is there a sufficiently competitive market to compare the purchasing ability of the Utility with prices available to individual customers. The Commission will, therefore, monitor this situation to ensure that the provision of security and competitive prices by the Utility is fairly compared with the option of more customers purchasing their gas directly, with the Utility providing basic transportation service.

1.3 Approval of the BC Gas Long-Term Gas Supply Portfolio

When the Core Market Policy was developed, it was assumed that residential and commercial customers would lack the size, sophistication, and inclination to make it practicable for them to negotiate secure and adequate gas supplies from non-utility suppliers. Therefore, the onus remained with the Utility to secure a diverse, long-term supply portfolio to meet the needs of the Core Market. This was done, as described in the evidence of Mr. Lechner at Exhibit 2, Tab 2. Twenty-one gas purchase contracts were submitted to the Commission for approval. By Order No. E-4-91, the pricing mechanism contained in the contracts was found to be in the public interest. In approving the gas purchase contracts, the Commission distinguished between the pricing formula for purposes of gas purchases and the use of this formula to allocate gas supply costs among customers. The allocation of gas supply costs was to be the subject of a future hearing. Section 4 of this Decision considers how the gas supply costs should be allocated to the various classes of customers.

2.0 THE APPLICATION

2.1 BC Gas Inc.

BC Gas Inc. is the result of an amalgamation of three formerly affiliated companies (Inland Natural Gas Co. Ltd., Columbia Natural Gas Limited, and Fort Nelson Gas Ltd.), with the former Gas Division of British Columbia Hydro and Power Authority. The latter entity became a part of the present corporate body as a consequence of a privatization initiative by the Provincial Government in 1988. The amalgamated utility is divided into four Divisions for operating purposes; namely, The Lower Mainland, Inland, Columbia and Fort Nelson.

The Hydro and Power Authority Privatization Act transferred the regulation of the Utility from the Commission to the Lieutenant Governor in Council until October 1, 1991. The present Application is the first formal proceeding by BC Gas before the Commission which reflects the many changes that have occurred since early 1988.

2.2 The Original Filings

On August 8, 1991, BC Gas applied to the Commission for approval of (i) a revised methodology for allocating gas supply costs to customers, (ii) tariff Schedules 10 and 13 relating to the sale of large volume interruptible and peaking gas respectively, and (iii) Schedule 22 relating to large volume transportation service. All three Schedules were to be applicable to the Lower Mainland and Inland Divisions effective November 1, 1992. The Columbia and Fort Nelson Divisions have separate gas supply arrangements which were not the subject of this hearing.

The Commission determined that expeditious input from affected parties was required in order to provide adequate customer notice of any rate changes prior to the proposed effective date of November 1, 1991. By Order No. G-80-91, dated August 15, 1991, the Commission requested BC Gas to provide copies of the Application to its large volume (consumption greater than 1 MMCF/day) sales and service customers and a group of interested parties. In addition BC Gas was required to provide clarification of its Application at an August 27, 1991 information meeting convened by Commission staff. By Order

No. G-80-91 the Commission requested comments on each part of the Application from the interested parties on or before September 16, 1991 as well as responses from BC Gas on all written comments by September 23, 1991. Upon a review of all the information submitted, the Commission ordered that a public hearing was required before a final determination on the Applications could be made. By Order No. G-92-91, dated September 23, 1991, the Commission established an agenda to deal with the various Rate Design and Revenue Requirement Applications anticipated from BC Gas over the next year. Two phases (A and B) for BC Gas rate design were created with Phase A dealing with three issues:

- gas supply cost allocation methodology;
- Rate Schedules 10, 13 and related matters including Rate Schedule 22; and
- confidentiality of gas purchase prices.

The Phase A public hearing commenced on Tuesday, December 3, 1991 and ended with final argument on January 10, 1992. The Revenue Requirements hearing is scheduled for March 24, 1992 and the Phase B Rate Design hearing will occur in the fall of this year.

On October 15, 1991 BC Gas filed its updated Application for approval of:

" A. The methodology for allocating gas costs to customers as described in Tab 3 of their filing;

B. A deferral account to be established into which long-term gas purchase negotiating costs be charged, with amortization of those costs over the weighted average contract years of the new gas supply;

C. Tariff Schedules 10 and 13 for the Lower Mainland and Inland Divisions, with accompanying Sales Agreement;

D. Tariff Schedule 22 for the Lower Mainland and Inland Divisions, with accompanying Transportation Agreement;

E. Withdrawal of the Inland Division General Terms and Conditions Applicable to Transportation Service effective November 1, 1992 and the introduction of General Terms and Conditions Applicable to Large Industrial Transportation Service for the Lower Mainland and Inland Divisions effective November 1, 1992;

F. Withdrawal, effective November 1, 1992, of the Inland Division General Terms and Conditions applicable to Industrial Gas Sales-Schedules 10 to 13;

G. Withdrawal, effective November 1, 1992, of the Inland Division Tariff Schedules 10, 11, 12, 13, 16, 19, 20, 21 and 22 and withdrawal of the applicable Sales and Transportation Agreements;

H. Withdrawal, effective November 1, 1991, of Inland Division Tariff Supplement No. 6;

I. Continuation of the deferral account established by item 7 of Commission Order G-92-91 until a decision is rendered in Phase B of the rate design hearing of BC Gas;

J. Continuation of the deferral account established by item 8 of Commission Order G-92-91 until a decision is rendered in Phase B of the rate design hearing of BC Gas;

K. Implementation of adjustments to the rates of industrial customers in the Lower Mainland and Inland Divisions resulting from this Application as of November 1, 1992;

L. Application costs and hearing costs associated with the August 8, 1991 Applications and this updated Application be taken into account in the rate changes resulting from this Application and be amortized over a period of three years;

M. A deferral account to be established effective November 1, 1991 to record: (a) the revenue to BC Gas if a supplier should make use of Westcoast capacity for which BC Gas is paying, (b) the gas cost savings from volume incentive adjustments, and cost savings from volume incentive adjustments, and (c) gas inventory charges if BC Gas is required to pay such charges [(a) and (b) only to the extent that they are beyond that already reflected in the calculation of the 1991-1992 gas costs];

N. An incentive mechanism whereby BC Gas would receive a portion of the difference between the negotiated price at which gas is sold pursuant to Tariff Schedules 10 and 13 and the cost of that gas; and

O. A deferral account to be established, effective November 1, 1992, to record the difference between the revenue (less the incentive to BC Gas) received from sales of gas at negotiated prices pursuant to Rate Schedules 10 and 13 and the cost of that gas."

2.3 Amendments

As a result of the Commission's ruling on confidentiality discussed in Section 3.2.1 of this Decision, BC Gas withdrew its proposal regarding negotiable, confidential gas sales prices. In its place, it proposed published tariff rates for large volume interruptible sales. At the same time, it further modified the October 15, 1991 Application by deleting the item N incentive mechanism and the item O deferral account. BC Gas also informed the Commission that it was considering an auction process which would provide for the interruptible sale of gas that was excess to tariff sales commitments. On December 6, 1991, and during the course of the hearing, BC Gas filed its newly revised tariff Schedule 10 and auction process (Exhibits 29 and 30), together with the terms and conditions of the proposed auction for interruptible sales gas. Finally, in Exhibit 3A BC Gas amended its Application to include a deferral account for item L which deals with costs related to the Application and hearing.

3.0 ISSUES OF COMMISSION JURISDICTION

3.1 Obligations of the Commission

The Commission was created by the Utilities Commission Act which sets out its duties and obligations. These are directed specifically at public utilities as defined in the Act, to customers of those utilities and generally to "the public interest". Beyond this, the legislation provides that the Commission shall comply with any general or special direction made by regulation of the Lieutenant Governor in Council. No such special direction applies to this Application.

It is not uncommon for regulatory tribunals, particularly in times of rapidly changing social and economic circumstances, to find themselves in a position where there are apparent conflicts between their statutory duties and the evolving social and economic circumstances. Trends develop within regulated industries which may influence the approach of regulators. Similarly, government policy statements are made from time to time which also may affect regulatory decision-making. The pace of the legislation may not keep up and this can lead to difficulties in the correlation between evolving views and policies and the statutory framework within which the Commission must function. In the final analysis, the statute must remain paramount.

So it is in this case. The competitive marketplace has replaced monopoly utility service in some, but not all, of BC Gas' operations. Cost-based pricing and open disclosure remain appropriate for the monopoly sector, while market level pricing and confidentiality in negotiations are typical in the competitive sector. With both activities available to the Utility, inconsistencies can develop in the interface between them. The Act requires every public utility to furnish service to all persons reasonably entitled thereto (Section 45). On the other hand, it does not impose any duties upon the Commission to promote competition.

Much was said in the hearing about the desirability of "a level playing field". Questions arose as to the practicability of the concept in the circumstances and what would constitute "level". There were fundamental differences between the Applicant and intervenors that cannot be ignored and are not resolved by the Act. The Company is a regulated public utility and as such is inescapably bound to processes that involve regulatory lag, public filings of its tariffs, and obligation to serve all customers on a non-discriminatory basis. When requesting a level playing field, the Company's competitors do not suggest that they assume similar burdens. BC Gas is required to serve the Core Market with a load factor that is unattractive to producers. This market is potentially vulnerable to the spiral of increasing costs linked to shrinking size unless offset by utility sales in a competitive marketplace. One of the obligations imposed upon the Commission under Section 65 is to protect utility customers from rates that are more than fair and reasonable for service of the nature and quality furnished by the utility.

As part of its current review of the Act, the Commission intends to recommend amendments to bring the Act into conformity with the reality of competition in various sectors of the utility market and, in particular, with the relationships between the monopoly and competitive sectors. The requirements of the regulated monopoly transportation system are not fully compatible with the characteristics of competitive markets at the wellhead and the greatest challenge facing regulatory tribunals is to deal with the needs of both systems at their interface so that consumers are provided a high quality service at competitive prices.

3.2 Confidentiality

3.2.1 Industrial Sales Rates

In its original filings, BC Gas sought approval to negotiate the prices at which it would sell gas to the interruptible market and to keep those prices confidential. Counsel for The British Columbia Public Interest Advocacy Centre ["CAC (B.C.)"] raised a preliminary question regarding the Commission's jurisdiction to entertain a request for confidential gas sales contracts. Submissions on this issue were heard, commencing at transcript page 134. With the exception of the Applicant, all intervenor submissions were to the effect that there is no specific provision in the Act which would allow the Commission to keep industrial sales rates confidential. Relying on Sections 67 and 68, Counsel for CAC (B.C.) argued that the whole momentum of the Act was towards open disclosure of rates and that the request for confidentiality was beyond the Commission's jurisdiction under the Act. The submissions of all counsel were considered by the Commission and a ruling was made which reads, in part, as follows (T. 177):

> "The Commission is compelled to agree with the positions generally expressed by Mr. Gathercole and Mr. Fingarson that it does not have jurisdiction on the issue of confidentiality of sales contracts, and therefore will not hear evidence on that particular aspect of the Application."

As a result of this ruling, the Company amended its Application as discussed in Section 2.3 of this Decision.

3.2.2 Gas Purchase Prices

The same letter challenging the Commission's jurisdiction to approve confidential pricing for gas sales contracts also asked BC Gas to specify the legal basis for its position that prices in its gas purchase contracts be kept confidential. This led to the Commission's letter request issued prior to the hearing (Exhibit 21) that intervenors file submissions in point form on the question of confidentiality with respect to gas purchase contracts as well. In the submissions that resulted, reference was made to the fact that the Act makes specific provision for gas purchase contracts. Section 85.3(4) states:

> "An energy supply contract or other information filed with the commission under this section shall be made available to the public except where the commission considers that disclosure is not in the public interest."

BC Gas further pointed to the Commission's Rules for Energy Supply Contracts, dated October 18, 1990, wherein Rule 1.2 states:

> "A gas supply contract or other information filed with the Commission under Section 85.3 will be kept confidential except where the Commission considers that disclosure is in the public interest."

Intervenors agreed that the Commission clearly has jurisdiction to keep gas purchase pricing confidential if it deems it necessary to do so. Counsel for The Council of Forest Industries and Cominco Ltd. ("COFI" and "Cominco" respectively) argued that while complete confidentiality is not required, as a minimum aggregated gas purchase costs must be publicly available during rate cases (T. 2107). Counsel for CAC (B.C.) adopted a narrower view and argued that Rule 1.2 is contrary to the Act and its emphasis on a public hearing process (T. 2340).

In applying Rule 1.2 to date, the Commission has approved mainly direct purchases for industrial customers where there was no public interest issue of price disclosure. **The Commission shares the view that aggregated gas purchase costs for gas utilities must be publicly available during rate cases and will be instructing all gas utilities to file such aggregated costs.** The Commission does believe, however, that the publication of individual contract purchase prices could impair a utility's future negotiations.

3.3 Auction Sales

The question of the Commission's jurisdiction also arose with regard to the proposed auction. Inasmuch as some features of the proposed auction sales contained in the amended Application by BC Gas had some similarity to negotiated sales, the Commission sought submissions from the intervenors on the issue of whether the Commission has jurisdiction to sanction an auction as a sales device. Those written submissions were entered as Exhibits 50 through 50F. The subject was also addressed in oral argument.

Discussion centred mainly on the level of disclosure of pricing information required to meet Sections 67 and 68 of the Act. The Applicant and some intervenors took the position that statutory provisions requiring the filing for public information of all rates of the Utility would be met by filing a schedule which set out the process by which the auction would be held. Mr. Wallace (Exhibit 50B) and Mr. Miller (Exhibit 50F) both addressed a concern raised by the Commission regarding the application of Section 69. Mr. Wallace reasoned that the auction would be a process by which BC Gas could establish the rate that it would propose to charge but that no service could be charged at that rate until it had been filed. The Commission's consent would be necessary for any subsequent change to a rate set in that manner. Mr. Miller reasoned that the auction process may represent a delegation by the Commission of its power to fix rates, and cited a Federal Court precedent which would not support the Commission exempting the Company from filing rates as an accommodation of the competitive marketplace.

In final argument, Counsel for the Applicant took the position that there is no requirement to publish any price information (T. 2074). All intervenors who spoke to the subject disagreed with this position and held that actual rates—not just procedures—must be published (T. 2132; 2163; 2176; 2280; 2337).

The Commission concludes that it does not have the jurisdiction to approve the pricing mechanism in the auction proposal as presented by BC Gas. The Commission would prefer a level of disclosure in an auction process which provides assurances to Core Market customers that the interruptible sales are made on a fair basis.

4.0 GAS COST ALLOCATION

4.1 Description of Costs

4.1.1 Long-Term Gas Supply

The terms of the 21 new gas purchase contracts to supply the base load requirements of the Lower Mainland and Inland Divisions vary from 2 to 15 years, with the average volume weighted term for all contracts being approximately 12 years. The pricing terms of the contracts were structured to include both a demand and a commodity charge for gas such that 70 percent of the 100 percent load factor price is payment for the commodity cost of the gas and 30 percent is payment for the demand cost. Although the individual contracts vary, in general, the price of gas was negotiated assuming that BC Gas would take gas from each long-term supplier at an 80 percent load factor, giving rise to an average price of $1.35 per gigajoule ("GJ"). A summary of these contracts is contained in Appendix B.

4.1.2 Peaking and Storage Gas Supply

BC Gas also has access to peaking and storage gas at costs in excess of those associated with the long-term contracts. As with the long-term contracts, these costs generally have both a demand and commodity component, the amount of which varies with the particular source.

4.1.3 Westcoast Charges

In addition to the foregoing costs, the Utility has costs associated with bringing the gas to market through the use of the Westcoast system. These tolls are set by the National Energy Board to include both commodity and demand elements with the majority of the costs of use of the Westcoast system being collected through the demand portion of the toll.

4.2 Description of Allocation Methodology

In its Application, BC Gas proposed the following methodology for the allocation of gas purchase costs:

1. All gas supply costs, including the East Kootenay Link, storage and LNG facilities, are considered to be for the benefit of customers in both the Lower Mainland and Inland Divisions. Only the lower Westcoast tolls applicable to the Inland Division are recognized as a specific cost difference between the Divisions.

2. Commodity costs associated with long-term gas supply are allocated to customer classes on the basis of forecasted volumetric usage.

3. Commodity costs associated with peaking and storage volumes are allocated based on volumetric usage. Assuming normal winter weather, BC Gas estimates that 40 percent of winter interruptible volumes are supplied from peaking and storage gas sources while 60 percent is supplied from long-term gas contracts (T. 1066).

4. Westcoast commodity tolls are allocated to all customers on a volumetric basis.

5. All demand costs, whether Westcoast demand tolls, producer demand charges or fixed peaking/storage tolls and charges are allocated using a coincident peak methodology. This method allocates demand costs based on each customer class' forecasted percentage use of demand during the peak day (T. 894). Customer classes which do not receive service during the peak day are not allocated any demand costs. Since Exhibit 3, Item 12 shows that interruptible customers do not receive any service at peak, and since BC Gas' Application states that it contracts gas supply to meet the demand of firm or Core Market customers only, the fixed or demand charges associated with gas supply are allocated essentially to the firm or Core Market customers (Exhibit 2, Tab 1, page 9).

6. This methodology results in interruptible gas customers being allocated only the variable or commodity costs associated with gas supply. However, BC Gas does not intend to price the interruptible gas at the allocated cost of serving these customers but rather to price the gas sold to interruptible customers at its market value but never below the commodity cost of gas. To the extent that the market value exceeds the commodity cost of the gas, a "profit" on interruptible sales will be generated. This profit will be allocated back to firm customers and will offset the fixed charges (Exhibit 2, Tab 1, page 10). Throughout the Appli-cation this is called the "Core Market contribution".

7. The gas purchase arrangements in the new supply contracts contain volume incentive adjustments which provide relief to BC Gas if takes exceed a certain specified load factor and penalties if takes decline below a specified load factor. Any benefits or costs associated with these provisions are allocated to firm customers based on coincident peak allocation factors.

With respect to the gas cost allocation methodology, the Commission has identified three primary issues:

(i) the appropriate allocation of producer demand charges to firm or Core Market customers;

(ii) the appropriate level of producer demand charges; and

(iii) the sales structure and pricing for interruptible gas.

In addition, the Commission has also considered the rate for NGV customers, the impact on the Burrard Thermal Agreement, the loss of the margin on sales to the Columbia Division and the proposed amortization of the long-term gas supply negotiation costs.

4.3 Discussion of Gas Cost Allocation Issues

4.3.1 BC Gas

Allocation of Producer Demand Charges

BC Gas has allocated the demand costs associated with long-term gas supply ("producer demand charges"), as well as all other demand costs (e.g. Westcoast demand charges), through the use of the coincident peak allocation methodology. The Utility stated that it considered four facts in choosing this method of cost allocation. These are:

(i) BC Gas' system load is characterized by needle peaks created by the core customers during extremely cold days.

(ii) A valley in the Company's load profile exists during most of the year. There are no non-winter peak days when the capacity requirements of the customer group approach that of the winter peak.

(iii) Interruptible customers are denied the use of the system during extremely cold days.

(iv) BC Gas must contract for gas supplies and transportation to adequately and reliably meet the extreme peak load requirements of its core customers on a very few days per year (Exhibit 3, Item 12, page 4).

Use of this method has resulted in the allocation of demand costs to firm or Core Market customers only. With respect to producer demand charges, the Utility stated that this was appropriate since it only considered the needs of the Core Market when making its long-term gas supply arrangements and did not contract for gas with a view to interruptible sales and, as indicated above, interruptible customers were denied the use of the system at system peak. Therefore, the Core Market needs caused BC Gas to incur the fixed or demand costs associated with these contracts. BC Gas witness, Mr. Lechner, stated:

> " ... if BC Gas lost its entire interruptible sales market the only volume today, of 936 million cubic feet a day of firm Core Market long-term supply plus all of the various peaking arrangements, the only volume that it would drop today would be three million cubic feet a day for the Schedule 10 and six and a half million cubic feet for the 2502A's and 2502B's. Otherwise it would contract for exactly the same amount of gas, even if it didn't have any interruptible market.
>
> So in my view that indicates that all the costs that are there are really borne by the Core Market." (T. 423)

Further, BC Gas adduced evidence that the producer demand charge was a replacement for the traditional take-or-pay obligations contained in the Westcoast sales agreements between Westcoast and producers (Exhibit 1, Tab 4, page 2) and were viewed by the producer as a means of recovering the fixed costs associated with production (T. 510-511).

Level of Producer Demand Charges

In support of its proposed 30/70 demand commodity price split, BC Gas presented evidence from two expert witnesses. Sproule Associates Limited ("Sproule"), a firm of geological and petroleum engineering consultants, was asked to consider the following three questions:

(i) the relationship between the load factor of a natural gas purchase in British Columbia and the price in a long-term contract;

(ii) the extent to which the load factor/price relationship, determined above, can be reflected in a demand/commodity price structure; and

(iii) the reasonableness of allocating the costs associated with a 30 percent demand charge in the long-term gas purchase contracts to the firm customers of the Utility as a cost associated with the supply of natural gas for the firm customers.

Sproule addressed these questions in a report to BC Gas which was filed as Exhibit 6. In response to the first question, Sproule assumed that producers, when offered alternative contracts with differing load factors, would choose among contracts based on the discounted net present value of each contract. For the net present value of the contracts to be equalized, the unit gas price associated with contracts with lower load factors would need to be higher than the unit gas price associated with contracts with higher load factors. The Sproule report concludes that:

> "Given the option of differing load factors in various markets, it is our opinion that the negotiated gas price should give consideration to the specific load factor included in a contract; thereby allowing the producer to be indifferent to which market and load factor he could choose to accept." (Exhibit 6, page 2)

In response to the second issue, the Sproule report compared the producer's load factor - price relationship with a contract pricing mechanism that included a 30 percent demand component and a 70 percent commodity component and concluded that the demand/commodity contract price followed the same trend as the producer's load factor/price relationship although at a lower rate (Exhibit 6, page 3).

Finally, the Sproule report addressed the reasonableness of the magnitude of the 30 percent demand charge allocated to firm customers. The Sproule report concluded that a 30 percent demand charge did not entirely compensate the producer for the impact of a reduced load factor so that a buyer of the producer's gas would be unlikely to achieve a better price from the producer than that inherent in the 30/70 demand/commodity price structure (Exhibit 6, pages 3 & 4). Accordingly, the Sproule report concluded that the 30 percent demand charge in the long-term gas purchase contracts was reasonable (Exhibit 6, page 4).

Gordon Engbloom, representing the energy economics consulting firm of Confer Consulting Ltd. ("Confer"), was asked to address how the 30 percent demand/70 percent commodity relationship found in the long-term gas purchase contracts compared with price adjustments made for load factor in other gas purchase contracts. Confer stated that it was aware of other contracts for long-term gas supply with demand components or other pricing mechanisms which reflected load factor considerations and that the price adjustments found in the BC Gas contracts tended to be more load factor responsive than the relationships found in many other long-term contracts (Exhibit 2, Tab 7, pages 4 & 5).

Implications for Pricing of Interruptible Gas

BC Gas' proposal results in interruptible customers being allocated only the commodity costs of gas and variable costs associated with the supply of gas. However, as indicated in an earlier section, BC Gas anticipates that the market value of the interruptible gas is likely to be in excess of this amount. Therefore, the Utility proposes to price interruptible gas in such a way as to capture as much as possible of the value of the gas in excess of cost and credit this excess value back to the Core Market customers to offset some of the fixed costs which firm market customers bear. Under the BC Gas proposal this would be accomplished through the combination of a posted tariff (Schedule 10) and the proposed auction of excess gas. At no time would interruptible gas be sold for less than its allocated cost of service which includes producer commodity charges, Westcoast commodity charges, the cost of fuel gas and an allocation of peaking and storage costs (T. 988-991). This would result in interruptible rates being set in relation to the value of the gas in the market place and not with respect to the cost of serving interruptible customers, except in so far as costs provide a floor below which rates will not fall.

BC Gas did not specify a method by which the Core Market contribution will be passed back to Core Market customers. The intervenors, with the following two exceptions, supported BC Gas' flow-through allocation methodology for gas supply costs.

4.3.2 CanWest

CanWest did not adduce evidence at the hearing. In final argument, Counsel for CanWest disputed the appropriateness of allocating 30 percent of the gas purchase costs to firm or Core Market customers as a demand charge for long-term gas supply, although he supported the use of the coincident peak method for the remaining demand costs, arguing instead that the producer demand charges:

> "simply represent a portion of the gas price or commodity cost of gas negotiated under the long-term purchase agreements." (T. 2212)

CanWest suggested that the Utility's decision to allocate 30 percent of the costs of long-term gas supply to Core Market customers was taken:

> "to shift gas commodity costs to the Core Market customers who in BC Gas' view have virtually no choice but to buy their gas from BC Gas and pay the additional commodity costs. This results in BC Gas being in the position where it will be able to sell gas in the non-Core Market at prices which will limit competition." (T. 2213)

Instead of allocating the producer demand charges to the Core Market customers, CanWest proposed that all the gas supply costs be flowed through to all customers, a methodology which would result in core and non-core customers being allocated the same unit cost of gas (T. 2241).

4.3.3 CAC (B.C.)

Counsel for CAC (B.C.) disputed the Utility's position that its gas supplies were determined solely by the needs of the Core Market and suggested that at the time of negotiating the gas supply contracts the Utility "had to have in mind its total existing and potential customer base" and that the gas purchased under the contracts "would be used to serve [interruptible] customers as well as the core customers" (T. 2315). He argued that the quality of interruptible service offered by BC Gas was very high. He stated:

> "there are generally very few interruptions and the service they receive is very close to firm service." (T. 2316)

Counsel suggested that the decision to allocate the producer demand charges to Core Market customers was not dictated by objective cost allocation principles but was instead made by the Utility,

> "based on its assessment of what is required by the competitive deregulated market." (T. 2392)

In support of this view, he directed attention to the evidence given by BC Gas' expert witness, Mr. Reed, in answer to the question as to whether the market dictated the cost allocation methodology.

> "No, I don't think that, well, yes and no. The yes part is with deregulation the fixed costs need to be spread to those customers or allocated to those customers that cause a cost to be incurred. The corollary to that is you do not spread the fixed costs to the interruptible customers because competition might take them away from you." (T. 637)

Counsel queried whether a more appropriate allocation of producer demand costs would be one which spread the costs over all customers (T. 2325). He submitted that it had not been proven that such an allocation would result in a dramatic reduction in revenues from interruptible customers (T. 2326). In determining the potential reduction in revenues from interruptible customers, he argued that the Commission would need to take into account non-price factors such as the existence of monthly balancing, the relationship between sales and transportation tariffs, the sophistication of existing and potential non-core customers, the nature and extent of potential competition for those interruptible customers, BC Gas' pricing policies, the development of the competitive market and the impact of government policy on the development of that market (T. 2326-2332).

4.3.4 Commission Decisions

Basic Allocation Methodology

The major decision facing the Commission as a result of this hearing is the appropriate allocation of gas supply costs to individual customer classes. Under Section 85.3 of the Act, utilities entering into energy supply contracts must provide to the Commission information which will allow it to determine if the contracts are in the public interest. The public interest is maintained if the price paid for the energy reflects competitive market prices while also ensuring a secure source of supply as required by the Core

Market rules. In determining whether or not the prices contained in BC Gas' gas supply contracts are appropriate, the Commission must determine that the price paid in total reflects competitive market conditions.

In determining whether the individual costs allocated to any particular customer are appropriate, a similar test must be met, i.e. the Commission must determine that the cost allocated to any particular customer class also reflects competitive market conditions. Specifically, this means that the costs allocated to each customer class must reflect the costs that the class could expect to pay if it had negotiated an individual gas supply portfolio for its own use, in line with the Core Market rules.

Even though deregulated wellhead pricing has been in place for some six years, this is the first instance in which the Commission has been required to approve a methodology to apportion gas supply costs to individual classes of customers. In previous years the Commission's determination that gas costs allocated to particular customer classes were competitive was simplified by the fact that the Utility negotiated "streamed" prices for large industrial, small industrial/large commercial, and residential customer groups so that a direct comparison to the market could be made. With the undifferentiated prices contained in the current contract, the Commission must now make an assessment as to the appropriate allocation methodology.

In assessing whether the methodology proposed by the Utility results in gas costs to particular customer classes which reflect competitive market conditions, the Commission has had particular regard to the Sproule report. This evidence indicated that:

(i) producers considered load factor when negotiating the price of gas sales. Specifically, the evidence indicated that for producers to be indifferent between a contract offering a high load factor and one that offered a lower load factor, the lower load factor contract would need to contain a higher price; and

(ii) the 30 percent demand/70 percent commodity structure put forward by the Utility as a basis for allocating cost to customers followed the same trend as the producer's load factor price relationship.

This evidence indicates to the Commission that, at the current time, the 30 percent demand/70 percent commodity structure proposed by BC Gas for allocating gas supply costs results in customer classes being allocated prices that are generally reflective of what would be obtained if the gas supply for each customer class were individually negotiated. The Commission recognizes that the evidence of Confer (that the BC Gas gas purchase contracts tended to be more load factor responsive than the relationship found in many other long-term contracts) may be interpreted by some to mean that this methodology will result in low load factor customers being allocated too great a portion of costs. However, such an assumption would presume that those other long-term contracts were more properly priced. The Commission has no evidence before it to support this presumption.

The Commission accepts BC Gas' proposition that the excess or valley gas used to serve interruptible customers is essentially an asset of the Core Market. In making this determination, the Commission relies on the Utility's evidence that it has structured its gas supply to meet the needs of its Core Market customers. By this, the Commission understands that the daily contract demand associated with BC Gas' gas supply would be substantially unchanged if the entire interruptible load currently served by BC Gas were to be lost. The exceptions (for the 1991/92 gas year only) are those small peaking contracts undertaken to serve the interruptible load. **Therefore, it is clear that interruptible sales should be priced in such a way as to maximize the benefit to the Core Market. With respect to the Core Market contribution, the Commission orders the Utility to submit a complete proposal on the method by which the contribution will be allocated to specific customer classes by July 15, 1992. Following review of the submission, the Commission will decide on the form of a hearing.**

Given the requirement that the allocation of gas costs must reflect competitive market prices, the Commission cannot accept the methodology proposed by CanWest and supported by the CAC (B.C.), which would allocate gas costs to all customer classes on an average unit cost basis including interruptible sales. Further, the Commission is concerned that the rates which would result from the use of the average cost methodology would lead to a loss of interruptible load which would have deleterious effects on the remaining customers. Although the Commission agrees with the Counsel for CanWest and CAC (B.C.) that many factors other than price may affect the Utility's ability to make interruptible sales, the

Commission concludes that the volume of interruptible sales would decline substantially if gas costs were allocated on an average unit cost basis.

Nonetheless, the Commission is cognizant of the fact that interruptible customers receive a high level of service from BC Gas to which a comparatively high value may be attached. The Commission will consider this, as well as the non-price factors discussed above, when determining how and at what level interruptible sales should be priced so as to maximize the Core Market contribution.

Except as qualified elsewhere in this Decision, the Commission approves the methodology proposed in items A, I, J, K and M of the Application subject to amendments filed during the hearing. In finding that the proposed methodology results in an appropriate allocation of the costs associated with the Utility's gas supply at this time, the Commission does not find that a 30 percent demand/70 percent commodity split will be judged appropriate at all times and in all circumstances. The Utility will continue to be required to meet the test that the costs allocated to each customer class reflect competitive market conditions. This may require future adjustments to account for changes in market conditions at the field purchasing level or changes to the mix of customers remaining in the Core Market.

<u>Natural Gas for Vehicles Rates</u>

Presently, natural gas for vehicles ("NGV") is sold at a tariff rate. Some customers retail the product at market rates to vehicle owners. Others, such as municipalities or fleets, purchase the product essentially for their own consumption. In its Application and in testimony (T. 897), BC Gas proposed that the potential reduction ($423,900) to NGV customers due to the flow-through methodology be withheld and allocated to the other Core Market customers on the basis of their respective sales volumes. In justifying this treatment, Counsel for BC Gas stated that lowering the price to NGV customers would not serve a useful purpose since the current market rate was competitive and in fact was significantly below the price of gasoline (T. 2022).

While the Commission accepts that there is no guarantee that the "wholesale" price of NGV will be passed on to some "end-user" motorists, it is of the view that the proposed withholding of a credit to this customer class would set an unwarranted precedent and would not support government and BC Gas initiatives to promote NGV sales. A review of the evidence suggests that the primary reason for the proposal was that the retailer controlled the retail price of the product to the motorist and may or may not reduce the retail price. This rationale ignores the fact that some customers who purchase NGV for their own consumption are also being denied the savings. The Commission also considers that urban fleet users with dedicated filling facilities have been the one clear market niche which has supported the NGV programs to date. Therefore, this sector should enjoy fair pricing. Finally, there may be market resistance to NGV on the basis that some users suspect that prices will rise due to government taxes (road tax) or other actions after they had invested in vehicle conversions. The proposed pricing by BC Gas would support such allegations and potentially harm future market growth.

The Commission rejects the proposed allocation of the NGV credits and urges BC Gas to investigate all possible measures to ensure that in future such product cost reductions are enjoyed by the end-users who have made a substantial investment to use this fuel. In the meantime, the reduction in gas purchase costs should be allocated to NGV users on a volumetric basis as calculated in the response to item 1 of Exhibit 51 resulting in a rate reduction of $.443/GJ in the Lower Mainland and $.104/GJ in the Inland service areas.

<u>Pricing for Burrard Thermal</u>

BC Gas sells interruptible gas to B.C. Hydro for use in its Burrard Thermal generating unit. Under the terms of the 10-year agreement expiring in 1998, between BC Gas and B.C. Hydro (Exhibit 44A, "the Burrard Agreement"), the price paid for interruptible gas is equal to BC Gas' commodity cost of gas in the field (T. 2018). The Burrard Agreement was approved as part of the sale of the Lower Mainland Gas Division and is beyond the Commission's purview until it expires. A condition of the Burrard Agreement is that B.C. Hydro pays an additional $5 million dollars regardless of the amount of gas taken. The commodity price paid for gas by B.C. Hydro for use at Burrard Thermal was $.93/GJ. BC Gas suggests that under the terms of the proposed allocation methodology, this price would fall to $.89/GJ.

Clause 3.03 of the Burrard Agreement requires that the commodity cost be adjusted so that it is no greater than for any other sales customer of BC Gas. The Burrard Agreement also provides for collection of Westcoast commodity costs, fuel gas, and a negotiated distribution margin of $.25/GJ. The term "Commodity Cost" in the Burrard Agreement is defined to mean "the field commodity cost of natural gas negotiated by the company from time to time".

When the Burrard Agreement was entered into, all natural gas costs were streamed on a single variable cost basis for each customer class. The commodity cost identified in the Burrard Agreement was the total cost of gas for industrial purposes at the time. However, the Utility no longer buys its gas on a streamed basis. Therefore the Commission believes that the "commodity cost" of $.89/GJ derived by BC Gas is inconsistent with the definition in the Burrard Agreement. A more appropriate price might be the minimum price in Schedule 10 or the minimum price accepted at an auction.

The Commission orders BC Gas to submit for approval by April 30, 1992, a commodity cost which conforms to the intent of the Burrard Agreement and, in the interim, the current commodity cost of $.93/GJ is to be continued.

<u>Loss of Inland Division Margin</u>

Historically, Inland sold certain gas volumes to the Columbia Division each year at prices competitive with gas available through facilities located in the province of Alberta. Accordingly, the Inland Division sales price became the cost of gas for the Columbia Division. This resulted in a margin to Inland of $0.64/GJ (Exhibit 5A). As set out in the Application, BC Gas proposed to make the gas available to the Columbia Division at cost and to flow-through the loss of the present inter-divisional margin to the Inland Division Core Market on the basis of sales volumes.

Counsel for BC Gas stated that the Utility's proposal should be accepted since there were no longer two separate utilities, but only one company, so that there was no profit being made on the transfer of gas (T. 2029).

BC Gas stated that the treatment of the loss of margin was an appropriate part of the Gas Cost Allocation hearing since to postpone the Commission decision on how to treat the loss of margin would result in a larger than necessary deferral fund being created.

The Commission finds that the proposed loss of margin for sales to the Columbia Division is reasonable only if there is a merging of the gas supply costs. The BC Gas Application is explicit that the gas supply costs of Inland and the Lower Mainland are common and that Columbia and Fort Nelson are separate. **The Commission finds that the BC Gas proposal would result in a subsidy from the customers of the Inland Division to customers of the Columbia Division. Accordingly, the proposal including item H of the BC Gas Application is not allowed.**

Deferred Long-Term Gas Purchase Negotiation Costs

In obtaining its long-term gas supply portfolio, BC Gas incurred an out-of-pocket expense of approximately $869,000. The Utility proposed to charge these costs to a deferral account, amortize them over a period of 11.5 years and recover them in rates as part of rate changes related to the new gas purchase costs.

In justifying the proposal to amortize these costs rather than expense them, BC Gas stated that the benefits of the gas supply contracts were long-term so that the costs should be similarly treated. Further, the Utility maintained that the gas negotiating costs were reasonable (T. 2027).

The Commission has many concerns with respect to the nature and amount of the expenditures made with regard to the completion of the Natural Gas Supply Agreements. Since the expenditures are unusually large and unique, the Commission would have expected the Utility to advise it of such costs if the Utility were intending to propose that they be deferred and recovered over a future period. The Commission is also concerned that the negotiations continued over a prolonged period with both the Commission and the Government intervening directly at various points to ensure timely completion. The Commission also had to deal with complaints from some parties involved in the process.

Finally, the Commission is concerned that the large monthly retainer paid to a Calgary law firm may not have assisted in the early completion of the agreements.

However, it is noted that no intervenor at the hearing argued in favour of any disallowance of the costs. Therefore, the Commission presumes that they found the costs to be acceptable. **Consequently the Commission allows the recovery of these costs as proposed by BC Gas in item B of their Application, notwithstanding the aforementioned Commission concerns.**

Hearing Costs

The Commission approves the establishment of a deferral account with respect to hearing costs as proposed by BC Gas in Exhibit 3A and item L of their Application. Amortization is to commence in the 1992 test year.

Deferral Accounts

The deferral accounts relating to items B, I, J, L and M of the BC Gas Application are approved in principle only. The method of recovery will be determined by the Commission in the Revenue Requirements hearing scheduled to commence March 24, 1992.

Impact on Rates

A summary table which shows the impact of the approved allocations on customer rates is included in Appendix C. This table assumes the minimum rate of $.89/GJ for Burrard Thermal. In the event this rate increases as a result of the Commission's decision on Burrard Thermal pricing, rates to other customers will be decreased.

5.0 AUCTION SALES

5.1 The BC Gas Proposal

In response to the Commission ruling on confidentiality of negotiated rates (Section 3.2.1) BC Gas introduced a new proposal to sell interruptible gas consisting of a posted tariff (Schedule 10) and, in addition, an annual and monthly auction at market prices of gas excess to the requirements of the Core Market and Schedule 10. The BC Gas auction proposal is described in detail in Exhibit 30 which is appended to this Decision as Appendix D. BC Gas stated that its proposal would allow the Utility to maximize revenue from the sales of interruptible gas. BC Gas proposed that Schedule 10 interruptible customers must commit to buying gas under the tariff by August 31 and would be required to purchase all of their interruptible gas under the tariff. BC Gas stated that requiring Schedule 10 customers to declare their intentions in advance of the auction would enable the Utility to forecast, with greater accuracy, the amount of interruptible gas that would be available for the auction process.

Excess gas under the proposed BC Gas auction plan would be available in the following order of priority:

- Schedule 10, Level 1
- Schedule 10, Level 2
- Annual auction volumes based on price
- Monthly auction volumes based on price.

During the hearing (T. 1557) BC Gas expressed its uncertainty regarding the Burrard Agreement and the relative positioning of that interruptible gas to the priority of interruptible auction gas. This issue will need to be resolved before the auction process can be implemented.

5.2 Other Submissions

Mobil Oil Canada ("Mobil") revised its written evidence in the opening statement by its witness Mr. R. Guerrant. Mobil endorsed the BC Gas auction proposal as an interim measure until storage and peaking services can be provided on an unbundled basis. The Mobil auction plan varied from BC Gas' plan by not having a Schedule 10 tariff, but rather including those sales in the auction. Mobil did qualify its proposal to eliminate Schedule 10 by suggesting that smaller industrials amounting to about 20 percent of the potential interruptible market could continue to be served under a tariff similar to Schedule 10. Mobil admitted that it was currently having difficulty selling into the deregulated BC Gas interruptible sales market. It stated that the competing BC Gas interruptible price is too low and that in past it could get a better return on sales made outside of the BC Gas market area.

This proposal would have greatly changed the scope of the auction in terms of the amount of gas to be sold as well as the potential number of buyers. Mobil argued that this increased scope was essential to maximizing the return to the Core Market. In addition, Mobil tried to alleviate any fears about lower priced export sales that had been voiced to that point in the hearing by stating that export sales would only occur with the appropriate government Energy Removal Certificates and they would occur in a truly competitive market supported by many domestic and export buyers and sellers.

In argument, two suggestions were developed by Czar Resources Ltd. ("Czar") and Coast Pacific Management Inc. ("Coast Pacific"). Czar characterized the two auction plans as "the Mobil Auction vs. Schedule 10" (T. 2264). Czar felt that Schedule 10 was necessary to ensure that benefits flowed to the large industrials, as well as the Core Market customers. Czar supported the BC Gas auction with Schedule 10 as it believed that the auction market price would be greatly changed by export pressures.

Coast Pacific reiterated Mobil's view with respect to Schedule 10, namely that there be a requirement for numerous purchasers and numerous buyers in order to have an effective auction. It also argued that if BC Gas became the only seller of gas, the objective of deregulation would be thwarted. While Coast Pacific favours the auction, it suggested that the Commission determine and set a Schedule 10 price for this contract year and delay the introduction of the auction until it can have the benefit of more time and study.

5.3 Commission Decision

The Commission recognizes the advantage for BC Gas to be able to sell gas that is excess to its basic requirements on an interruptible basis. It is also aware of the potential benefits to the Company and the Core Market customers if and when the gas is sold. The Commission believes that not only can such sales result in a net return on margin over cost but also that the profit can be directed to the reduction of Core Market costs. However, it notes the rapid development of the BC Gas proposed auction plan during the hearing and believes that there are a number of pitfalls that weaken the ability of the plan to have a wide appeal to potential users in the short-run.

BC Gas requires customers to sign up for Schedule 10 rates by a specific date in order to provide a reliable estimate of the volume of interruptible gas that would be available for auction during the upcoming year. However, by restricting Schedule 10 customers to the purchase of interruptible gas only from the Utility, the bulk of auction sales may be to customers outside of the BC Gas service area. This poses a concern to the Commission especially since the resultant auction price may be lower than the contracted interruptible price that BC Gas Schedule 10 customers would be required to pay. Thus, the exclusivity requirement may force higher interruptible prices on BC Gas Schedule 10 customers than those being obtained by auction gas purchasers outside of the BC Gas service area.

Another concern of the Commission is the reluctance of BC Gas to publish a "floor price" for the auction. At the same time, the Commission is uncomfortable with the prospect of receiving this information in confidence because that would compromise its ability to deal publicly with its obligations under Section 65 of the Act.

The Commission does not believe that the auction process can be embarked upon until the question of curtailment priorities is fully resolved. Burrard Thermal currently has a curtailment priority relative to other classes of service. If the auction were instituted, the Utility proposes that the auction gas would take a higher priority than Burrard Thermal interruptible gas. BC Gas has had indications that this curtailment priority would be challenged by B.C. Hydro since it was not contemplated in drafting their agreement and would work to B.C. Hydro's disadvantage. If gas is sold and contracted for under a stipulated curtailment priority relative to Burrard Thermal gas, and during the term of the auction sale, the Burrard Agreement is tested and found to vary that priority, the auction gas would take on different characteristics and probably should also take on a different price. This could give rise to serious complaints.

BC Gas does not provide a quid pro-quo in requiring the auction customers to take a minimum of 80 percent of their purchased volume (in the event that they do not, it will impose a 20 percent penalty). But on the other hand, it reserves the right to enter into other contractual arrangements to sell excess gas not offered for auction during the auction term.

The Commission observes that there was no serious disagreement among the intervenors with the concept of BC Gas auctioning gas which is surplus to its other utility requirements. Most were in favour of the idea; some because it is a practical way to determine what the competitive market price really is; some because they saw it as a useful alternative to acquire their energy needs. They saw the complication surrounding price disclosure and filing as an impediment to early implementation. A summary of the submissions seems to be that the Commission probably, but not clearly, has sufficient latitude to sanction an auction provided procedures can be worked out to satisfy the specific demands of the Act. Such procedures might be cumbersome, particularly as regards the monthly auction. This is a case where the existing legislation makes it difficult to accommodate the spirit of deregulation in the gas marketplace.

Nevertheless, the Commission would be inclined to approve it given the general acceptance by the parties to the hearing, and its understanding of the objectives of the Core Market Policy. The Commission is also mindful of Mobil's caution however, that the auction market would have to be large enough for it to operate effectively, requiring all the excess gas to be allocated to it. Against this are the positions of prospective Schedule 10 customers who do not want tariffed service withdrawn, leaving only the auction market to fill their interruptible gas requirements. In this case, the Commission is not prepared to terminate a schedule for which there is demonstrated demand. To ensure that service is provided to the public which is, in the terms of Section 44 "... in all respects adequate, safe, efficient, just and reasonable", is an obligation of the Commission that ranks ahead of improving the competitive opportunity for gas producers or certain customers.

The auction plan was speedily created and continued to evolve during the hearing through the development of particular concerns and discussions in cross-examination by many participants. The Commission believes that with time and more study a better plan could be developed. An industry task force was proposed by Czar and this added input might result in a more acceptable plan. However, the Commission believes that a task force approach would be premature. It is BC Gas' responsibility to make an auction proposal which reflects full consideration of the impacts on the Core Market, the industrials and the non-regulated competitive market.

Accordingly, BC Gas is directed to resubmit its auction proposal by July 15, 1992. The Commission expects that the submission will consider the concerns of parties in the hearing and, in particular, address the following matters:

- **Reserve bid pricing.**
- **Maximization of Core Market Contribution.**
- **Resolution of Burrard Thermal curtailment priority.**
- **Potential participation by Schedule 10 customers.**
- **Resale and export issues.**
- **Scope and timing for publication of price information.**
- **Auction timing relative to Schedule 10 pricing and Westcoast capacity deadlines.**

The Commission orders that Schedule 10 be implemented as proposed by BC Gas in item C of its Application and as amended by this Decision. The Commission believes that implementation of the Schedule 10 proposal will ensure that the interruptible sales market is served throughout the BC Gas service area on a consistent basis and will provide a significant contribution to the Core Market. The Commission also recognizes that there may be opportunities for BC Gas to sell interruptible gas beyond the quantities required by Schedule 10 customers before the auction review process is complete. The Commission therefore encourages BC Gas to consider filing such special contracts, as may be appropriate, for Commission approval during this period.

6.0 LARGE INDUSTRIAL TARIFFS

6.1 Sales Schedules 10 and 13

6.1.1 Schedule 10, Terms and Conditions

Applicability

Schedule 10 provides for two levels of interruptible sales, at the interconnection with the Westcoast pipeline, to industrial customers whose gas requirements exceed 1 MMCF/day. During the hearing, there was considerable discussion as to the definition of interruptible. The term quasi-firm was suggested as a better description of the 2-5 days of interruption forecast for Level 1 during normal weather. To the extent that BC Gas clearly identifies the expected days of interruption, the Commission accepts the term interruptible as an appropriate means of differentiation from firm sales.

Unbundling of Services

The change from the current Inland Schedule 10, to provide sales at the Westcoast interconnect rather than at the customer's meter, was generally well received by the hearing participants. This change means that a uniform margin will be collected from all industrial customers on the basis of transportation service under Schedule 22. This further unbundling of service by BC Gas is in the spirit of deregulation and facilitates the choice by the industrial customers of direct versus utility sales. In the case of industrial users who may wish to continue with a bundled sales schedule, BC Gas intends to retain all existing schedules of this type so that the choice will be open. **On this basis the Commission accepts the concept of sales under Schedules 10 and 13 taking place at the Westcoast interconnect.**

<u>Exclusivity</u>

BC Gas proposed that Schedule 10 must provide the entire interruptible gas requirements of the Buyer. The industrial intervenors questioned this restriction and suggested that some flexibility should be permitted to enable them to participate in the potential auction process. It was argued that limited participation in the auction was the only practical method for an unsophisticated purchaser to evaluate the auction. This concern will need to be considered prior to implementing an auction; however, the Commission believes that the restriction was aimed more at preventing the use of Schedule 10 for peaking purposes when the bulk of the customer's interruptible requirements were obtained through direct purchases. In this connection, Counsel for COFI/Cominco stated that they were not averse to purchasing all of their interruptible gas from BC Gas or, alternatively, purchasing all from the direct market depending on their evaluation of these alternatives (T. 2105). BC Gas argued that the exclusivity restriction was fundamental to the maximization of the return to the Core Market while serving industrial customers at competitive rates.

In the light of the foregoing, the Commission approves the Schedule 10 exclusivity provision at this time. The extent of exclusivity may be revised following the resubmission of the auction proposal by BC Gas (refer to Section 5.3 of this Decision).

<u>Levels 1 and 2</u>

The current Inland Schedule 10 provides for two levels of interruptibility on a somewhat different basis than that now proposed by BC Gas. The new proposal gives priority to Level 1 without specifying the extent of curtailments contractually. Some intervenors were opposed to this approach and preferred that the extent of interruption be specified. BC Gas has undertaken to provide annual estimates of interruptions which can be expected on the basis of normal weather and to include a definition of normal weather in the tariff. It is the Commission's view that to go any further than this would likely entail the purchase of dedicated gas supplies for Level 1, as was done for the 1991/1992 year. This would truly amount to providing a "quasi-firm" service. **As there was no evidence to indicate the need for any higher level of service than the 2-5 days of normal weather**

interruption now forecast for Schedule 10, Level 1, the Commission therefore accepts the establishment of two levels as proposed by BC Gas.

6.1.2 Schedule 10 Pricing

Throughout the hearing, BC Gas stated that its objective in establishing Schedule 10 pricing was to "firstly, foremost and only" (T. 1060) maximize the return to the Core Market. Since the Utility cost of service margin will be collected under Schedule 22 for transporting the gas, BC Gas proposes to price the sale of gas at market competitive rates which, so long as they exceed costs, will provide a return to the Core Market. A number of issues were raised in connection with evaluating the "correct" Schedule 10 price to achieve this objective.

Unfair Competition

The potential for unfair competition was raised primarily by the sales competitors of BC Gas; namely, CanWest, Mobil and Coast Pacific. There was, however, some echoing of this concern by industrial intervenors who feared that if BC Gas were to be too successful, competitors could be forced to abandon the interruptible market completely, resulting in BC Gas holding a monopoly position. These concerns centered around the potential for BC Gas to set the Schedule 10 prices too low. It was argued that higher prices would increase the contribution to the Core Market. BC Gas filed evidence (Exhibit 52, pages 8-10) which showed that it is necessary to consider the sales captured at a given price to maximize the total revenue. On this basis, BC Gas proposed a price so as to capture 65 percent of theoretical sales. This was a two-tiered price structure with seasonal rates as follows (Exhibit 29):

Level 1 $290/10^3m^3$ demand charge plus $1.15/GJ winter and $1.00/GJ summer commodity charges.

Level 2 $1.60/GJ winter and $1.10/GJ summer commodity charges.

Non-Price Considerations

Mr. Gathercole for CAC (B.C.) raised the issue of non-price considerations which would make BC Gas a more desirable supplier and enable it to charge prices somewhat higher than other competitors in the market without losing sales. At transcript page 2326, Mr. Gathercole listed a number of factors including the favourable terms and conditions of service available from BC Gas, the saving in administration costs to the industrial buyer, the expected lower level of interruption, the preference for dealing with a known supplier, and potential risks in the direct marketplace. BC Gas testified that some non-price factors were considered in setting the 65 percent capture target (T. 959). It does not appear from the evidence of company witnesses that significant weight was given to these factors in total. Rather, it would seem that prices have been based primarily on BC Gas' current estimate of market prices required to achieve its target.

Market Pricing Information

To the extent that market pricing forms the basis for Schedule 10 pricing, the issue becomes what market prices should be looked at in establishing the BC Gas prices and how should this market information be interpreted. The Utility relied, in its evidence (Exhibit 41), primarily on "Inside F.E.R.C." data for border sales at Huntingdon, B.C. In this Exhibit it also provided a comparison of Inside F.E.R.C. and prices published by the Ministry of Energy, Mines and Petroleum Resources ("MEMPR"). The latter prices did not show a significant difference. In its evidence Mobil relied upon the MEMPR figures (Exhibit 63) to demonstrate that the proposed BC Gas prices were too low.

The real issue here is not so much which data source to use, but how to interpret the data. Interpretation is hindered by a volatile market as demonstrated by the wide price swings shown in Exhibits 41 and 63. While the proposed Level 2 prices were markedly different from the border prices as recently as one year ago, over the last few months of 1991, these prices are in quite close agreement. This highlights the need to base pricing on very current data which in turn suggests that the setting of an annual price should be left as late as possible.

In this regard, the BC Gas proposal, as it evolved through cross-examination, suggests establishing the prices for Schedule 10 by August 1 of each year. However, for the 1992 year, the Company is reasonably confident that the prices proposed in Exhibit 29 will prove appropriate.

The Commission is less confident that the proposed prices will prove to be appropriate, particularly since the non-price factors discussed above do not appear to have been given sufficient weight. **On this basis the Commission does not approve the Schedule 10 prices at this time but rather requires BC Gas to file prices for approval later this year as discussed below.**

<u>Timing of Annual Price Setting</u>

BC Gas proposed that Schedule 10 signups be canvassed during the month of August and prices be established by August 1 of each year. Witnesses for COFI/Cominco indicated that this was too late since they finalize their gas supply arrangements prior to May 1 of each year in order to enable themselves or suppliers to complete capacity reservations on Westcoast's pipeline. While this argument has some merit, it appears to be more appropriate to the scheduling of firm supplies. The Commission observes that, in past years, purchasers have been making interruptible arrangements right up to the start of the gas year on November 1.

Considering these facts the Commission directs BC Gas to file Schedule 10 pricing for the November 1, 1992 gas year by July 15, 1992 so that an approved price may be published by August 1, 1992. The Commission expects these prices to maximize the return to the Core Market reflecting projected market prices at the time of filing. The Commission expects BC Gas to fully consider non-price factors and to canvass a variety of pricing data sources in justifying the proposed levels.

Level 1, Pricing Concept

BC Gas proposed a demand/commodity price structure for Schedule 10, Level 1. In cross-examination, the demand charge was characterized more accurately as a reservation fee which established the priority of interruption. Industrial intervenors objected to this approach and requested that a commodity-only rate be provided instead. BC Gas stated that such a rate was not consistent with its objective of maximizing the return to the Core Market, that it would be difficult to establish and that it would lead to subsidies of poor load factor customers by those with better load factors. The Company filed Exhibit 58 in response to the intervenor requests for a commodity-only rate, but made it clear that it did not support this approach. The Commission is concerned that this approach to setting a rate, to the extent it does not adequately consider load factor, could result in unfair pricing involving cross-subsidies that are not appropriate. Furthermore, since the commodity-only approach is attempting to duplicate the same total revenue provided by the demand/commodity approach, there is little advantage to the industrial purchaser even though the term "demand" seems contradictory to the whole interruptible concept. **The Commission nevertheless accepts the BC Gas proposition that in this case a demand or "reservation" charge is the most accurate method to establish priority and the Commission approves the pricing concept as proposed by BC Gas for Schedule 10, Level 1. As indicated earlier actual prices will be reviewed when submitted by July 15, 1992.**

6.1.3 Schedule 13

Applicability

This schedule provides peaking and backstopping gas on a similar basis to the current Inland Schedule 13 tariff. The main change is that, as with Schedule 10, sales will now occur at the Westcoast interconnect so that this schedule must be used with the appropriate transportation schedule. Generally, Schedule 13 did not attract much interest from intervenors except for issues discussed below.

Usefulness for Backstopping

Tilbury Cement Limited ("Tilbury"), the only alternative fuel user to take an active part in the hearing, wanted to have a stand-alone backstopping tariff available for its particular purposes. Tilbury suggested that the requirement for minimum monthly charges under the applicable transportation schedule rendered Schedule 13 too expensive in a circumstance where they did not purchase any other gas from BC Gas. The Commission concludes that this schedule cannot be used for backstopping on a stand-alone basis. **The more logical use, in the Commission's view, is for peaking purposes in conjunction with Schedule 10. Therefore, Schedule 13 as proposed in item C of the BC Gas Application is approved for that purpose. The Commission encourages Tilbury and BC Gas to negotiate a special contract to cover Tilbury's unique requirements.**

Negotiability Provision

In Schedule 13, the Utility has incorporated the ability to negotiate price in special circumstances when to do so would be of benefit to the customer. For example, during very cold weather, BC Gas might be able to purchase extra gas at a high cost that might still prove attractive to an alternative fuel customer. The subject was raised (T. 726) as to whether rates could ever be negotiated downwards. BC Gas indicated that some discretion would be required, but it would consider filing such a rate where appropriate. The Commission foresees that, under certain limited circumstances, it could be mutually beneficial to the industrials and the Core Market to have a negotiated price under this Schedule 13 assuming gas is sold above cost. Sections 67(2) and 67(4) of the Act provide the latitude needed to deal with situations contemplated by this event. **The Commission therefore approves such a general provision subject to filing of prices for approval prior to gas flowing. The Commission is prepared to make suitable arrangements to facilitate approval on short notice in recognition that time would be of the essence in such sales.**

Schedule 13 Pricing

The prices contained in the Application represent (for the Inland Division) the current Schedule 13 rate adjusted to the Westcoast interconnect by deducting the $.35/GJ margin which will be collected in future under Schedule 22. A similar calculation was proposed for the Lower Mainland Division. **The Commission approves this methodology, at this time, subject to future rate adjustments arising out of the Phase B Rate Design hearing.**

6.1.4 Sales Agreement for Schedules 10 and 13

This document was not specifically referred to during the hearing. **In view of its similarity in format and basic content to currently approved equivalent BC Gas tariffs, the Commission approves it as to form. Since the various Commission decisions with respect to Schedules 10 and 13 require no changes to this sales agreement, the Commission also approves it as to content.**

6.2 Transportation Schedule 22

Complexity of Documents

Creation of a new Schedule 22 and related documents, as contained in this Application, is an attempt by BC Gas to simplify and consolidate its Inland and Lower Mainland large industrial transportation tariffs in a manner consistent with the objectives of the new sales Schedules 10 and 13. Even so, the issue of the complexity of the documents in this Application was raised during the hearing as a significant concern of industrial customers.

While the Commission acknowledges this issue, it notes that in this Application, the Company has responded to these concerns and has in fact achieved considerable simplification from the currently filed tariffs. Since both firm and interruptible transportation services for large industrial customers are now contained in a single Schedule (22), the separation of some of the documentation into the Transportation Agreement for Schedule 22 and the General Terms and Conditions Applicable to Large Industrial Transportation Service can be viewed merely as a method of organizing the information.

The resulting requirement to consider three documents is not, in the Commission's view, a significant complexity. Furthermore, in light of the nature and extent of discussions on many of the issues during the hearing, the Commission recognizes that some complexity is inherent in the deregulated gas marketplace. **The Commission approves the three documents comprising Schedule 22 as proposed by BC Gas in items D, E and F of their Application subject to the following qualifications.**

<u>Balancing</u>

By far the most controversial aspect of the BC Gas proposed Schedule 22 was the change from monthly to daily balancing during the winter. BC Gas pointed out that this was actually a compromise between the old Schedule 22 (monthly balancing) and Schedule 21 (daily balancing year around) and that for interruptible use it now places direct sales and BC Gas sales customers on an equal footing. Previously, customers choosing direct sales faced daily balancing year around and this was considered an impediment to direct sales.

As a policy matter, the Utility was asked whether daily balancing should be implemented if it was not required on the Westcoast system. It indicated it would make the proposal in any case because of the impact on the Core Market (T. 607). BC Gas estimates that, if daily balancing in the winter were not adopted, the Core Market customers would have to absorb an additional cost of somewhere between $300,000-$450,000 (Exhibit 46). This range of costs may be indicative of the consequences to the Core Market of providing monthly balancing year around.

Considering the impact on industrial customers, Exhibit 46 indicates a typical incremental cost to Inland captive industrial customers of 2.2 cents/GJ in the winter months if daily balancing is required. Further discussion (T. 1089) indicates that if the foregone benefit attributable to monthly balancing were optimized it could represent a market value of 5.4 cents/GJ to industrial customers based on historical winter gas prices.

In discussing the possibility of assigning costs incurred in monthly balancing, BC Gas indicated that any averaging approach could result in customers not having a balancing problem being assigned costs unfairly. BC Gas also suggests that the current by-pass agreements do not provide for balancing charges to be made to these customers. On this latter point, it is the Commission's view that the by-pass agreements must be viewed in the true light of alternatives. Under the by-pass alternative, the customer would be balancing on Westcoast not on BC Gas and in this case, the Commission believes the assignment of balancing costs incurred from Westcoast requirements is appropriate.

In its 1987 Decision on Inland Transportation Tariffs, the Commission recognized the desirability of monthly balancing for industrial customers and at page 18 of that Decision had encouraged Inland:

> "to investigate ways to provide this balancing without added cost to the Core Market. This could perhaps be accomplished ... so that the interruptible customer will absorb any remaining costs as a result of the provision of monthly balancing ..."

The Commission continues to believe this is the correct direction for a decision. To date, however, actual costs to be incurred from Westcoast for balancing in the 1992-93 gas year are unknown. Thus while BC Gas has estimated incremental gas supply costs of $73,000 (Exhibit 46), there is no estimate of incremental Westcoast charges. This suggests that the Commission would be required to make a decision on assignment of costs in principle without knowing the exact effect. The Commission believes that such a ruling would not be in the best interests of the Company's customers in general and industrial customers in particular.

Therefore, the Commission reserves its decision on daily versus monthly balancing pending a report from BC Gas on actual Westcoast costs. The Commission's decision will be made shortly after the Westcoast decision on daily balancing is known, but not later than October 1, 1992. To facilitate the Commission's decision, the report should include updated estimates of gas supply costs (now $73,000) and opportunity costs equating to the Core Market contribution (now $300,000-$450,000).

Curtailment and Options

The proposed Schedule 22 continues the 50 percent curtailment for five days for firm service contained in the current approved tariff. In previous rate design hearings, evidence has suggested that the value of curtailment has been recognized in the reduced industrial distribution margin. If curtailment were to disappear, the margin might have to be re-evaluated.

In addition, BC Gas has introduced the option of a "firm curtailment buyout" to enable customers to firm up their service level to 100 percent. Intervenors accepted this as a useful option and suggested during final argument that another option might be to allow the swapping of curtailments amongst customers. **While no significant evidence was presented on this latter option, the Commission accepts it as a useful suggestion and hereby directs BC Gas to give consideration to incorporating such an option in addition to the buyout option and to report to the Commission on this matter by April 30, 1992. Such consideration should include a process of consultation with the industrial customers.**

The curtailment provision, for reasons other than capacity constraints under Level 1 transportation, was questioned by the industrial intervenors. In response BC Gas pointed out that on certain laterals there are no capacity constraints, so that if curtailment were not imposed equivalent to that imposed on sales customers, this service would in effect be firm, inappropriately priced, and in practice unworkable since nominations would simply be changed from firm to Level 1. **The Commission accepts that defacto firm service should**

be priced as firm service and conversely, service priced as interruptible must be subject to interruption, and therefore approves the provision as filed.

Demand Surcharge and Unauthorized Overrun Rates

The Application proposed unauthorized overrun ("UOR") rates very similar to current tariff charges. **Since these rates were not questioned during the hearing, the Commission accepts them as filed**. In addition to these UOR rates however, BC Gas introduced an additional penalty when unauthorized gas is taken in excess of 102.5 percent of authorized level on more than two days per year. This demand surcharge is intended as a disincentive for those customers who have tended in past to be insufficiently deterred by UOR rates to curtail promptly and consistently. There was considerable opposition to this new provision by the industrial intervenors. The Commission is not swayed by this opposition. This is a charge which will be incurred only when a customer blatantly refuses to cooperate with the Company in meeting curtailments. The inclusion of two days grace each year provides for a reasonable number of unintentional or unavoidable circumstances. Furthermore, none of the opponents of this charge chose to suggest that it could be modified as to number of days grace or level of charge, but merely asked that it be disallowed. **Given the importance of the curtailment issue to Core Market security of supply and since it is essential to the Company's peak shaving strategy, the Commission approves the Demand Surcharge as filed.**

Failure to Deliver Surcharge and Indemnity

BC Gas took the position that given the importance to the Core Market of the gas supply obtained through curtailment, the Utility required strong assurances that it will always be there when needed. In the past this was provided by a third-party review of the suppliers' gas supply reserves and deliverability together with a statutory declaration. The Company is now prepared, at the request of industrial customers and producers, to waive this somewhat expensive requirement and simply replace it with a Failure to Deliver Surcharge. Alternatively, it is prepared to continue with the previous arrangement for those customers who wish it. Industrial intervenors raised the issue of the general damages provision included in the Company's tariff and argued that it duplicated the Failure to Deliver

Surcharge. BC Gas clarified (T. 400) that the Surcharge would be credited against any general damages. Based on this understanding, the Commission views the Failure to Deliver Surcharge simply as an alternative to the Reserves Test/Statutory Declaration as discussed above. **The Commission approves the concept of letting the industrial customer choose his preferred method of establishing security of supply. BC Gas is hereby ordered to amend Schedule 22 to provide these two choices and to clarify that the Surcharge is not additive to general damages.**

Return Period

BC Gas proposed reducing the return period for gas taken under the 5 day/50 percent curtailment provision from 180 days to 90 days. The industrial intervenors would like this to be "as soon as practically possible" rather than 90 days. BC Gas testified that this provision is intended as a disincentive for over-nominating and that it could only be lowered if a corresponding increase in the rate for imbalance charges is made (T. 1282-1286). **The Commission does not believe this matter has been explored sufficiently to enable a final decision on the matter to be rendered. The Commission instructs BC Gas to review the level of imbalance charges vis-a-vis return period and to file a final proposal by April 30, 1992. Specifically, the Company should calculate the appropriate imbalance charges for return periods of (i) as soon as possible, but not later than 30 days, (ii) 30 days, and (iii) 60 days.**

Variation of Nominations

The Utility proposed that it should be permitted to increase a customer's nomination up to the contract demand level and make use of that gas for the Core Market. The industrials' position was that such takings of gas could negatively impact on relationships with their suppliers. COFI/Cominco elaborated on this position (T. 2123-2124):

> "The only issue, in our submission, is fair compensation for the availability of that gas ... The rights should be negotiated and BC Gas has indicated a willingness to negotiate. I don't think there's a problem there."

The Utility, in cross-examination (T. 1290), stated that it did not wish to force the customer to take the gas back after 30 days and that it viewed the purchase option as one to which there could be mutual agreement as a result of negotiations. **The Commission believes that both sides have demonstrated flexibility on this issue and directs the Utility to revise the tariff (Special Provision 7, Sheet No. 22.09). The options should be left to the customer as to whether the gas can be taken by BC Gas at the price negotiated in Appendix A of the Transportation Agreement, or returned within 30 days or not taken at all.**

Withdrawal of Inland Division Tariffs

Inherent in the BC Gas proposal for Schedule 22 and the new sales Schedules 10 and 13, was the concept that these new schedules would make a number of existing Inland Division sales and transportation tariffs redundant and, hence, they should be withdrawn. This position went unchallenged at the hearing. The Commission, having reviewed the content of these tariffs, agrees that they will become redundant. **Therefore, effective November 1, 1992 and as proposed by BC Gas in item G of their Application, the Commission approves the withdrawal of the following Inland Division large industrial tariffs: Schedules 10, 11, 12, 13, 16, 19, 20, 21 and 22.**

Minimum Charge for Schedule 22

This issue was raised by Coast Pacific in final argument but was not addressed previously in the hearing. Counsel for BC Gas explained that the charge is simply the transportation margin times the minimum amount of gas required to be classified as a large industrial user. **The Commission accepts this explanation in principle and notes that the subject of the appropriate transportation margin will be determined later this year during Phase B of the BC Gas Rate Design hearing.**

DATED at the City of Vancouver, in the Province of British Columbia, this 21st day of February, 1992.

_____*Original signed by:*____________
J.G. McIntyre, Chairman

_____*Original signed by:*____________
N. Martin, Commissioner

_____*Original signed by:*____________
H.J. Page, Commissioner

<u>APPENDIX A</u>

B.C. UTILITIES COMMISSION
<u>ENERGY SUPPLY CONTRACTS - RULES</u>

The following rules have been developed to facilitate the review by the Commission of energy supply contracts pursuant to Section 85.3 of the Utilities Commission Act. The review is to ensure that the terms of the contract are in the public interest having regard to the following:

(a) the quantity of the energy to be supplied under the contract,

(b) the availability of supplies of the energy referred to in paragraph (a),

(c) the price and availability of any other form of energy, including but not limited to petroleum products, coal or biomass, that could be used instead of the energy referred to in paragraph (a),

(d) in the case only of an energy supply contract that is entered into by a public utility, the price of the energy referred to in paragraph (a), or

(e) any other factor that the Commission considers relevant to the public interest.

NATURAL GAS SUPPLY CONTRACTS

In the case of natural gas supply contracts, the review is also to ensure the availability of long-term supplies of natural gas at reasonable prices for the core market in keeping with the "British Columbia Natural Gas Core Market Policy".

1.0 GENERAL RULES FOR ALL NATURAL GAS CONTRACT CLASSES

1.1 Under Section 85.3(1)(a), all natural gas purchasers in British Columbia, other than those purchasing exclusively from a gas utility, must file their supply contracts and all subsequent amendments with the Commission and obtain approval where necessary before delivery of natural gas occurs.

1.2 A gas supply contract or other information filed with the Commission under Section 85.3 will be kept confidential except where the Commission considers that disclosure is in the public interest.

1.3 The reserves and deliverability of all gas supply contracts requiring approval will be reviewed by the Petroleum Engineering and Operations Branch of the Ministry of Energy, Mines and Petroleum Resources. The initial pre-approval review will be followed up with annual reviews for the life of the contract.

The review process and acceptance criteria will be identical to those applicable to long-term energy removal certificates ("ERCs"). This will be based on a flexible reserve dedication policy including provision for corporate pooling and warranties. The existence of a recent supply evaluation for ERC purposes would preclude the need for further review. An information package on the review process is available from either the Commission or the Ministry.

1.4 The Commission will issue Orders approving all gas supply contracts except those for category 2.1 which do not require approval. Notwithstanding Commission approval, customers who contract for direct purchase of their natural gas supplies do so at their own risk of availability and market prices.

1.5 Purchasers who wish to displace direct purchases with utility purchases will be accommodated providing the utility can contract sufficient gas to meet the additional load and providing the Commission is satisfied that there will be no resulting long-term negative impact on supply and price for existing utility customers. The Commission will normally allow utilities to require up to 13 months' notice to accommodate such load increases.

1.6 Notwithstanding 1.1 above, purchasers who have satisfied Commission requirements for long-term supply security as per Section 2.0 below and who wish to operate in the "spot" market will be permitted to make special arrangements with the Commission to facilitate timely approvals. Generally, this will consist of notification in advance of gas flow followed by filing of an executed contract as soon as possible thereafter.

1.7 It is the intention of the Commission to review and approve contracts expeditiously, normally without the requirement for a hearing. It is also the Commission's intention to avoid retroactive Orders. The hearing process, pursuant to Section 85.3(2) of the Act, may become necessary where the Commission and the purchaser cannot agree on the contents of a contract. A hearing could also arise as a result of a third-party complaint.

1.8 Recognizing both the current changing market environment and that a variety of contracts between producers and purchasers may be nearing expiry, or at the final stages of negotiations, the Commission will consider some phase-in of these revised Rules. Also, the Commission may reconsider the duration of energy supply commitments required by Section 2.0 as gas supply market conditions change. Any change would be prospective and it is the Commission's intent that parties honour existing contracts in all cases.

2.0 ADDITIONAL SPECIFIC RULES BY NATURAL GAS CONTRACT CLASS

2.1 Industrial Purchasers with Short-Term Natural Gas Supply Contracts

Industrial purchasers entering into contracts with a term of two years or less are required to file the following information with the Commission:

2.1.1 a copy of the gas supply contracts (excepting price information);

2.1.2 a description of the source of supply listing well locations and field names by producing company; and

2.1.3 written confirmation acceptable to the Commission that the purchaser's energy supply capability is such that they can maintain normal operations without returning to the utility for supply of natural gas for a period of up to 13 months as may be required by 1.5 above.

2.2 Industrial Purchasers with Long-Term Natural Gas Supply Contracts

Industrial purchasers entering into contracts which specify a term of more than two years, either directly or as a result of "evergreen" provisions, will be required to submit their gas supply contracts (excepting price information) to the Commission for approval, together with all other related contracts which support the gas supply and any information required by 1.3 above. In combination, each purchaser's portfolio of gas supply contracts (long-term, short-term and spot) should provide for:

2.2.1 a supply commitment sufficient to meet the purchaser's peak-day firm requirements in the current year for the duration of the contract as per 1.3 above; and

2.2.2 diversity of supply including where possible a range of suppliers positioned behind alternative processing facilities, or backstopping.

2.3 Other Purchasers

Commercial purchasers, institutional purchasers (such as hospitals and schools), municipalities, co-ops, associations, and any other purchasers who wish to contract for direct sales must submit gas supply contracts (excepting price information) to the Commission for approval, together with all other related contracts which support the gas supply and any information required by 1.3 above. In combination, each purchaser's portfolio of gas supply contracts (long-term, short-term and spot) should provide for:

2.3.1 a rolling 5-15 year supply commitment sufficient to meet the purchaser's peak-day requirements in the current year as per 1.3 above (5 years for loads equivalent to industrial, 15 years for loads equivalent to residential); and

2.3.2 diversity of supply including where possible a range of suppliers positioned behind alternative processing facilities, or backstopping arrangements.

2.4 Utilities

Utilities must submit their gas supply contracts to the Commission for approval, together with all other related contracts which support the gas supply and any information required by 1.3 above. In combination, each utility's portfolio of gas supply contracts (long-term, short-term and spot) should provide for:

2.4.1 a rolling 10-15 year supply commitment based on peak day firm load in the current year as per 1.3 above (if the utility has a high proportion of industrial load this figure may be reduced accordingly);

2.4.2 diversity of supply including where possible a range of suppliers positioned behind alternative processing facilities, or backstopping arrangements; and

2.4.3 a prudent combination of terms, conditions, and price.

Further to 1.8 above, the Commission will conduct periodic reviews of the utility's supply arrangements to ensure the development of a prudent balanced portfolio.

APPENDIX B

BC Gas Inc. Long Term Natural Gas Supply Portfolio Summary 91-11-01								
Supplier	Approx.	DCQ	VIA	Term	Weighted	Type	Main Supply Area	Approval
	MMcf/d	10^3m^3	10^3m^3	years	Term			Date
CanWest	140	3965	0	15	59475	deliv.	B.C. lands	10-Apr
A&S	70	1983	1983	10	19830	deliv.	B.C. lands	19-Jun
BP	44	1243	0	15	18645	res.	West Sukunka	28-Feb
Amoco	28	795	795	15	11925	deliv.	Kotaneelee*; Martin	10-Apr
Norpac [Pan Alta.]	25	710	0	10	7100	deliv.	B.C. lands	10-Apr
Petro Canada	25	708	0	15	10620	deliv.	Clarke Lake; Lily Lake	10-Apr
Canadian Hunter	20	570	570	10	5700	deliv.	Ring Border	19-Jun
Czar	20	564	0	2	1128	deliv.	Helmet; Peggo	10-Apr
Unocal	16	465	0	15	6975	deliv.	Clarke Lake	10-Apr
Amerada Hess	15	425	0	10	4250	deliv.	Boundary Lake	10-Apr
Columbia	13	375	375	15	5625	deliv.	Kotaneelee*	10-Apr
Czar	10	283	0	15	4245	res.	Helmet; Peggo;Misc.	10-Apr
Shell	10	283	283	15	4245	deliv.	Alberta Lands	10-Apr
Mobil	10	283	283	10	2830	deliv.	Sukunka	23-May
Canadian Hunter	7	200	200	10	2000	deliv.	July Lake	01-May
Esso	6	170	170	15	2550	deliv.	Kotaneelee*	10-Apr
Amerada Hess	5	142	0	10	1420	deliv.	Laprise	10-Apr
Penn West	5	142	0	15	2130	res.	Buick Creek	10-Apr
Unocal	4	115	0	15	1725	res.	Hossitl	10-Apr
Kerr-McGee	4	110	110	15	1650	res.	Stoddart	10-Apr
Total Pet.	4	100	100	15	1500	deliv.	Buckinghorse	10-Apr
Total	**481**	**13631**	**4869**		**12.88**			
Total Reserve	67	1893						
Total Deliver.	414	11738					*Yukon	
% Total with VIA			36%				"VIA"= Volume Incentive Adjustment	