IN THE MATTER OF THE UTILITIES
COMMISSION ACT, SBC 1980, c. 60

and

IN THE MATTER OF APPLICATIONS
BY INLAND NATURAL GAS CO. LTD.

<u>DECISION</u>

March 18, 1981

Before R. Smith, Deputy Chairman,
D. B. Kilpatrick and J. D. V. Newlands, Commissioners

The Applications of Inland Natural Gas Co. Ltd. dated June 16, 1980 to amend its filed tariffs were heard on November 3, 4, 5, 6 and 7, 1980 in Kamloops, British Columbia and in Vancouver, British Columbia on November 26, 1980.

The division of the Commission comprised R. Smith, Deputy Chairman; D.B. Kilpatrick, Commissioner; and J.D.V. Newlands, Commissioner.

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APPEARANCES

I.G. NATHANSON	Commission Counsel
D.M.M. GOLDIE/P. LLOYD	for Applicant, Inland Natural Gas Co. Ltd.
R.B. WALLACE	for Forestry Group: - B.C. Forest Products Ltd. - Canadian Cellulose Co. Ltd. - Caribou Pulp & Paper Company - Weyerhaeuser Canada Ltd. - Prince George Pulp & Paper Ltd.
K.E. GUSTAFSON	for Consumers Glass Company Limited
F.H.P. DEWDNEY	for Cominco Ltd.
R. DYCE	for Pacific Northern Gas Ltd.
B. FEHRMANN	for Corporation of the District of Summerland
O.J. FRANK	for Village of Chase
HEARING SECRETARY	A.C. Michelson
COMMISSION STAFF	R.J. Fletcher W.J. Krampl W.D. Alexander
COURT REPORTER	Audiotron Enterprises Ltd. (W.G. Bemister)

LIST OF EXHIBITS

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I. INTRODUCTION

This Decision deals with Applications by Inland Natural Gas Co. Ltd. (hereinafter referred to as "Inland" or the "Applicant") dated June 16, 1980 for both interim and permanent relief.

The Commission by Order No. G-44-80 dated June 26, 1980 granted interim rate relief effective July 1, 1980 of approximately $3,100,000. This interim rate relief, which was granted subject to refund with interest at 11%, represented approximately 87% of the relief sought.

The Commission by Order No. G-47-80 set down the above Applications for public hearing commencing in Kelowna, British Columbia on September 8, 1980, with the direction to Inland that each customer be sent a copy of the notice of hearing.

On August 25, 1980 by Order No. G-53-80 the Commission rescheduled the public hearing for Kamloops, British Columbia commencing on November 3, 1980 to permit Inland to adjust its industrial forecast to reflect the increased availability of natural gas from Westcoast

Transmission Company Limited and to prepare for consideration of its extension policy by the Commission.

On September 15, 1980, Inland filed revised material which had the effect of increasing the interim award to approximately 91% of the relief sought.

In addition to the increased availability of interruptible gas, it became apparent that the Interior lumber producers had been more successful in withstanding the impact of the U.S. recession than originally contemplated in the Widman Report. Accordingly the estimated requirements of these customers had to be increased.

The service area of Inland stretches from Hudson's Hope in the North, through the Central Interior of British Columbia and includes rapidly growing areas, such as Prince George, Kamloops and Kelowna, and adjacent areas. The growth in consumption of gas in Prince George and Quesnel (new 500 ton per day pulp mill due to require gas on November 1, 1981) is attributable to the forest products industry. In Kamloops, it is a combination of forest products and mining in the Highland Valley, whereas in the Okanagan it is attributable to population growth and related industrial migration from Alberta.

In the West Kootenays, a $450 million expansion is currently underway by Cominco Ltd. in Trail. In the Okanagan and West Kootenay regions, however, the growth prospects for natural gas will be restrained to some extent, in the near term at least, due to competition in the residential and commercial markets from West Kootenay Power and Light Company, Limited.

The Applicant in presenting its case was represented by R.B. Stokes, the Executive Vice-President and Chief Financial Officer, as policy witness, supported by G.M.O. Solly, Vice-President, Operations; C.I. Kleven, Vice-President, Finance; J.L. Randall, Manager of Marketing, and J.O. Wessler, Manager of Rates and Forecasting, participating as required.

In addition, the Applicant retained A.S. Fell, Chairman and Chief Executive Officer of Dominion Securities Limited, to give evidence as to financial markets and rate of return, D. Mawhinney, Vice-President of Widman Management Ltd. to testify as to the outlook for the Interior lumber producers, and C. Porter from Arthur Andersen & Co. to testify to inventories in response to the concern raised by the Commission in the two previous Decisions.

II. TEST PERIOD

The Applicant in this proceeding has based the request for interim and permanent rate relief on a forecast test year ending June 30, 1981, which coincides with the Applicant's fiscal year end. This is consistent with the test period adopted in the previous proceeding.

In its March 12, 1979 Decision the Commission at page 8 stated, "Should Inland's annual report to the Commission as required by the Energy Act disclose results significantly different from those anticipated, appropriate adjustments or reversion to the annualized, normalized historical method will be considered." The unadjusted results of that report indicate a return of 15.88% on equity which is within the range of reasonableness (14-16%) established by the Commission at that time.

These same rates remained in effect throughout the 1980 fiscal year, resulting in earnings per share of $1.52. If adjusted for normal weather these earnings would have increased by approximately 9 cents per share (transcript page 402). The resulting return on equity would then have been 15.22% (Exhibit 9).

The Commission does not at this time consider it appropriate to revert to a historic year. In fact, in view of the Applicant's market and growth prospects, the concomitant capital requirements, and continuing inflationary pressures, a longer test period may be in the public interest, to ensure equitable treatment for both the customers and shareholders.

III. RATE BASE

The 1981 mid-year rate base has been considered by the Commission and has been accepted with certain minor adjustments.

However, the Commission is of the view that three items require comment at this time; namely, the capital budget process with special emphasis regarding the Special Projects Budget of $3,923,070, the use of outside contractors for installation at substantial additional cost, and unresolved inventory matters.

(i) Capital Budget/Special Projects Budget

The 1981 capital budget is $10,777,149 of which $3,923,070 or approximately 36% is represented by the Special Projects Budget.

The evidence at transcript page 447 indicates that of the 1980 budgeted special projects at June 30, 1980 in excess of $1.1 million had not been spent. This represents 40.5% of the 1980 Special Projects Budget. The Commission is pleased that unnecessary capital expenditures appear to have been avoided but is concerned with the accuracy of the Special Projects Budget, as suggested by that degree of underspending.

Although the Commission recognizes and accepts the fact that departures from forecasts may be required by changing circumstances, the Commission strongly suggests that the Applicant take the necessary steps to improve its planning process for capital expenditures.

(ii) Use of Outside Contractors

The Applicant explained that the use of outside contractors has increased the cost of installation by an aggregate of approximately $1 million in 1980 and 1981. This use of outside contractors occurred due to a greater than anticipated demand for service and would continue to some extent into the future, due to the seasonal nature of the work and rigidity within the Company's union contracts.

The Commission appreciates that the Applicant in this matter is subject to market forces which are influenced by government initiatives, most recently the federal budget. The Commission further recognizes that it is not prudent to hire employees for a peak period and then have them under-utilized. Nevertheless, the Commission will expect the Applicant to review its use of outside contractors and adopt a course of action permitting continued provision of prompt service, while minimizing costs.

This matter will be reviewed again at the next rate proceeding.

(iii) Operating Materials Inventory and
Minimum Quantities for Construction Purposes

The Commission has adopted the position taken in the March 12, 1979 Decision and has disallowed $471,000 from the amount put forward by the Applicant for its investment in inventories.

Disallowance is an undesirable aspect of the regulatory process since it indicates the Commission's view that the items in question are unnecessary, unsubstantiated or inappropriate. It would normally be expected that such a disallowance would be a sufficient signal to the utility that some corrective action should be taken in order to prevent subsequent recurrences.

In this case, the Applicant chose to disregard both the disallowance and the cautions given in previous Decisions. The Applicant's stated reasons were that it had chosen to give low priority to implementation of the recommendations contained in an inventory study by Arthur Andersen dated September 1978. The Applicant further admitted that it had not been responsive to the Commission's specific requirements as expressed in the Decision of March 12, 1979. The Applicant's position was essentially based on a second report by Arthur Andersen. In the opinion of the Commission, these two reports generated a measure of conflicting evidence and the resulting total submission failed to support the Company's position, or respond to matters specifically required by the Commission.

The current situation is clearly unsatisfactory and the Commission believes that it is in the interest of all parties that the matter be resolved expeditiously. An inventory review will therefore form part of the Management Audit, pursuant to Commission Order No. U-G-23-80. Cost of the Audit will be payable by Inland and the disposition of such costs will be determined following the Commission's review.

IV. REVENUE AND COST OF SERVICE

(i) Revenue

The Applicant in Exhibit 48, Tab 17, is seeking the opportunity to earn revenues of approximately $88,300,000 of which some $3,200,000 would be generated from the existing interim, after incorporating the sales volumes set out in Exhibit 48.

The forecast provided by the Applicant, adjusted for normal weather, has been considered by the Commission and certain adjustments have been made.

Schedule 1 and Schedule 2

The Applicant has made a downward adjustment in the estimated use per customer for its Schedule 1 (Residential) and Schedule 2 (Commercial) to reflect the impact of energy conservation.

In the circumstances of this proceeding, the estimates of the Applicant have been accepted.

Schedule 11 (Industrial Firm)/
Schedule 12 (Industrial Interruptible)

The Commission has considered the Applicant's forecast 1981 requirements, 19,517,047 Mcf (Schedule 11) and 1,066,275 Mcf (Schedule 12) and has compared these to forecasts by the Applicant's customers. The Commission has also compared both the Applicant's and the customers' forecasts to the actual results achieved for the years ending June 30, 1979 and June 30, 1980.

Exhibit 30 shows that for fiscal 1979 the actual results exceeded the Applicant's forecast by 905,664 Mcf (Schedule 11) and 1,429,860 Mcf (Schedule 12) respectively. In the year ending June 30, 1980 the actual results exceeded the Applicant's forecast by 481,957 Mcf (Schedule 11) and 921,104 Mcf (Schedule 12).

If the same comparison is made between the customers' forecasts and that of the Applicant in both years, the interruptible sold exceeded the customers' forecasts by 720,359 Mcf in fiscal 1979 and 656,555 Mcf in fiscal 1980. The customers' firm volume forecasts for both fiscal 1979 and 1980 have proved broadly reliable in relation to actual volumes sold in those years.

The Commission believes that a comparison of the degree of accuracy between different forecasts is useful in making judgements with regard to the future. After reviewing the evidence, with particular reference to actual 1979 and 1980 volumes sold, the Commission accepts the Applicant's forecast 1981 firm volumes of 19,517,047 Mcf.

With regard to the interruptible volume the Commission has considered the evidence and in the circumstances of these proceedings has adopted 1,900,000 Mcf as the most likely volume of interruptible gas to be sold, excluding sales to Columbia.

The Commission accepts the Applicant's volume forecast for the balance of its customers, reflecting the assumption that there will be no revenue received from Schedule 13 due to the availability of interruptible gas, nor from Westcoast Transmission Company Limited for "wheeling" gas.

Strike Normalization

The Applicant indicated at the hearing that a strike normalization had been considered but not proposed in this Application.

At the hearing the Applicant indicated that over the last 10 years gas sales of approximately 5.8 Bcf (586,000 Mcf/Year) have been lost due to labour disruptions.

The Commission believes that an adjustment is appropriate to protect the shareholders' opportunity to earn the approved return and ensure that the customers are not penalized due to a perceived labour disruption. Therefore, to protect the interest of both parties the Commission has provided an allowance of 530,000 Mcf/Year.

Sales to Columbia Natural Gas Limited

With regard to sales to Columbia Natural Gas Limited, the Commission has considered the historical deliveries to Columbia which amounted to 796,580 Mcf in 1979 and 2,687,709 Mcf in 1980 (Exhibit 30).

In support of its current estimate of 2,433,000 Mcf the Applicant stated that this is the maximum amount which can be delivered within the existing contractual restraints.

The Commission accepts the Applicant's estimates and would encourage the Applicant, if circumstances permit, to make additional volumes available as this will benefit the Applicant, Columbia, and their customers.

Minimum Bill Revenue and Late Payment Charges

The Applicant in Exhibit 14, Tab 18 has estimated the minimum bill revenue will be approximately $62,000, a reduction of $140,000 from the amount received in the year ended June 30, 1980.

The previous Application eliminated this revenue entirely but this was adjusted and an allowance of $220,305 was made by the Commission.

The Commission has reviewed the historical experience with regard to this source of revenue and has adjusted the allowance provided by the Applicant upward by $140,000.

In addition to the above adjustments, R.B. Wallace, in argument, urged the Commission to include late payment charges previously excluded by the Commission, as part of utility revenue. The Commission has considered this matter, and has concluded that it is appropriate to include this item as a component of revenue. Accordingly, an upward adjustment of $118,360 (Exhibit 8, Tab 13, Page 1) has been made.

The required revenue adjustments are set forth on Schedule III inclusive of the required increase in franchise and property taxes which result from the above revenue adjustments.

(ii) Cost of Service

The Applicant has estimated that the cost of service excluding return and before income taxes will be approximately $69,737,000 for the year ending June 30, 1981. The Commission has considered the cost of service provided by the Applicant and has made certain adjustments to cost of gas, and operation and maintenance expenses.

Unaccounted for Gas

The Applicant in Exhibit 11, has determined its gas purchase volumes from its metered sales volumes and then added an allowance of 0.6% for unaccounted for gas representing the average historical experience of the Company from 1975 through 1979. With reference to most recent experience, Exhibit 14, Tab 19 shows unaccounted for gas for fiscal 1980 to represent 0.22% of metered sales volume.

Rather than rely on an average historical gas loss percentage dating back to 1975, the Commission has adopted for the test year the gas loss experience for the immediately preceding year, believing there is every liklihood it will continue. Accordingly the Commission has reduced the unaccounted for gas allowance from 0.6% to 0.22%. This change results in the forecast cost of gas being reduced by approximately $175,000.

BTU Content of Metered Gas

The Applicant has forecast an average Btu content of 1.040 Million Btu per Mcf of metered gas purchased from Westcoast Transmission Co. Ltd. As the Applicant sells on a Btu basis and purchases, apart from daily interruptible, on a metered basis, any change in the Btu content of gas has an effect on the Applicant's gas purchase costs.

Westcoast deliveries to the Applicant averaged 1.0459 Million Btu per Mcf in 1979, 1.0472 Million Btu per Mcf in 1980. The Applicant has forecast a 1.040 Million Btu content per Mcf for 1981.

The Applicant's forecast was based on information received from Westcoast Transmission Co. Ltd. who had forecast a 1.040 Million Btu content per Mcf for the years 1980 and 1981.

The Applicant was requested to file latest available figures showing the average Btu content of gas delivered by month from July 1979 to September 1980. While the Commission considers that it would be unreasonable to take one period in isolation it is apparent that the evidence shows historical deliveries over a protracted period greatly in excess of the forecast 1.040 Million Btu content per Mcf.

The Commission has also considered that historical evidence may not necessarily portend future circumstance. However, in this instance it is apparent that Westcoast delivery circumstances for fiscal 1981 will not be unlike those occurring in fiscal 1980. The Commission has, therefore, accepted the 1980 average Mcf content of 1.0472 Million Btu as being the most appropriate for fiscal 1981 and have made a downward adjustment to cost of gas of approximately $297,000.

Demand Charges

Per Exhibit 11, Tab 8 the Applicant has calculated demand charges of $3,897,953 based on approximately 148 million cubic feet per day for four months, 153 million per day for two months and 160 million per day for the remaining six months. For its 1981 projection the Applicant has found it necessary to revise its daily nominated billing demand by 7 million cubic feet per day resulting in an increased test year cost of $88,200.

The transcript pages 607 to 609 show that the Applicant has demonstrated a record of successfully predicting its annual peak day load in its annual nomination to Westcoast. For fiscal 1979 and 1980 the original billing demand nomination made to Westcoast was not exceeded and 1979 was 10% colder than normal.

After review of the evidence the Commission has no reason to believe that the original billing demand nomination will be exceeded and has reduced cost of gas by $88,200.

Operations and Maintenance Expense

Per Exhibit 38 and transcript page 769 it is apparent that normalized operation and maintenance expense has declined from $114.05 per customer in 1979 to $113.88 for 1980. For the test year the Applicant has forecast operation and maintenance costs per customer of $121.32, an increase of approximately 6.5%.

The Applicant at transcript pages 770 and 771 stated that one factor which might explain lower 1980 costs was the 1980 customer additions which, being substantially greater than 1979 additions, might give a lower 1980 weighted average cost per customer. The Applicant stated another factor was the introduction of the new overhead accounting policy, but as was pointed out, Exhibit 38 had been adjusted for its impact.

In explaining the amount of the forecast 1981 increase per customer the Applicant stated that increases for

1981 resulted from manpower additions that are not necessarily related to customer growth.

The Commission has given careful consideration to the evidence: Exhibits 8 and 34 show an increase of customers occurring in fiscal 1980 and 1981 which are greatly in excess of immediate prior experience. Exhibit 14 shows additional employee hirings of nine occurring in 1979, 15 in 1980 and approximately 15 for fiscal 1981.

The Commission believes that operation and maintenance costs per customer will increase in fiscal 1981 due to inflation, additional hirings and programs sponsored by the Applicant. However, the Commission considers that an increase of 6.5% per customer is beyond a reasonable expectation of the cost to maintain safe and reasonable service to a greatly enlarged customer base where economies of scale should reflect some efficiencies. Accordingly the Commission has allowed the Applicant's forecast increased costs to the extent of 4% per customer, thereby reducing the cost of service by approximately $245,000.

Further to transcript page 790 the Applicant has restated forecast fiscal 1981 wage costs taking into account revised hiring dates. The Commission has therefore reduced the cost of service by $72,300 basing this adjustment on the Applicant's revised figure.

Hearing Costs and Related Matters

The Commission is concerned not only with the costs to all parties of both producing and analyzing material but also with the physical amount of material required in order that a proper understanding is achieved and a just and reasonable Decision rendered in a timely manner.

In its recent Pacific Northern Gas Ltd. Decision dated December 22, 1980 the Commission expressed the same concern and believes it is useful to reiterate the views expressed therein. That Decision, commencing on page 14 states:

"In the absence of any minimum filing guidelines, it is apparent that the hearing is made more difficult and costly, not only for the Commission and its staff but for all other participants. Without guidelines it is virtually impossible to achieve any degree of consistency and comparability.

Moreover, unless the appropriate evidence and explanatory material is available in advance of the hearing, it is very difficult to achieve a timely Decision, through which a just and reasonable result may be attained for all involved. Insufficient material tends to delay the establishment of a hearing date whereas excessive material tends to delay the Decision. Both operate to extend the hearing time.

The Commission proposes to work with the regulated utilities to develop guidelines which will permit the expeditious review of the required material at the minimum cost. In the above regard and in view of current inflationary and uncertain economic circumstances the Commission believes that Rate Applications should contain a base year and also a forecast period of at least one year. The base year would be the Applicant's fiscal year, comprising year-to-date actual plus estimates for the balance of the year.

In addition, the analytical test submitted should be supported by sufficient written or graphical material, located in reasonable proximity to the analytical, so that individual sections are self-explanatory.

The above comments are not intended to limit the Applicant in preparing his case but rather to indicate the Commission's views as to minimum requirements."

In addition to the above, and since the Utilities Commission Act of British Columbia is in essence prospective, the Commission believes that Applicants should make every effort to have their Application prepared sufficiently in advance of the commencement of their fiscal year that it may be heard and decided prior to the commencement of the period. Where this is not practical interim refundable relief can be applied for and granted to minimize the impact on all parties.

During the course of the hearing, the matter of the physical amount of material filed by the Applicant was raised, as it has been in previous proceedings. The Commission is pleased to observe that although the volume of the Applicant's material has not decreased, the overall cost of the hearing has declined substantially.

Prior to the most recent Pacific Northern Gas Ltd. Decision the policy of the Commission has been to exclude hearing costs from rate base and to amortize them to the cost of service over two to five years. The Commission has considered this matter and believes that a two year amortization period for Rate Application expenses is appropriate in this case. The Commission has further concluded that it would be unjust in the interval to exclude the entire amount of such expenses from the rate base, thereby depriving the shareholders of a return thereon.

To determine the appropriate amount for inclusion in rate base the Commission has multiplied the total costs incurred, by the ratio of the increment of the revenue requirement approved in relationship to that requested. The Commission believes that this treatment is fair to both consumers and shareholders. The entire amount has been amortized to the cost of service over a two year period with the period commencing on July 1, 1980.

The appropriate adjustments have been made to both the rate base and cost of service.

(iii) Other Matters

Wholly-Owned Subsidiaries

The Applicant, in addition to its utility operations in its service area, owns Columbia Natural Gas Limited, Grande

Prairie Transmission Co. Ltd., Peace River Transmission Company Limited, St. John Oil & Gas Ltd., Inland Development Co. Ltd., Inland Development (1975) Co. Ltd. and Inland Transmission Co. Ltd., the latter two companies being inactive.

The Commission's interest is related to the impact of these subsidiary companies on the consolidated results on which the Applicant is judged in the financial markets and the level of inter-corporate charges which directly affect the rates paid by Inland's utility customers.

Subsidiary Companies

In Exhibit 34, the Financial Statements for the year ended June 30, 1980 indicate that with the exception of Columbia Natural Gas Limited and Peace River Transmission Company Limited (and excluding the inactive companies), profit was either minimal or non-existent, as illustrated by Grande Prairie Transmission Co. Ltd. (loss of $30,020), and Inland Development Co. Ltd. (loss of $23,419).

Moreover, the equity investment in Grande Prairie Transmission Co. Ltd., St. John Gas & Oil Co. Ltd. and Inland Development Co. Ltd., is negative, ranging from a low of $23,415 (Inland Development Co. Ltd.) to a high of $119,508 (St. John Gas & Oil Co. Ltd.).

The above three companies are financed entirely by debt from the parent, the major portion being inter-company loans at prime. The balance of the debt is represented by \$800,000, 9 1/4% debentures issued by Grande Prairie Transmission Company Limited (price represents the market price at time of issue) to its parent and an interest free loan of \$241,128 to St. John Gas & Oil Co. Ltd.

It is apparent that the Applicant's subsidiaries, apart from Columbia Natural Gas Limited are not contributing to the consolidated financial results, and, in fact, to a limited extent are suppressing the earnings of the Applicant, and to a larger extent, reducing the coverage on its bonds, both of which affect the price for gas paid by the utility customers.

While the Commission has not made specific adjustments in this Decision, other than in capital structure, it is concerned by the undesirable impact which these subsidiaries, other than Columbia, have on Inland's consolidated earnings. A review by the Company would appear highly desirable.

Inter-Company Charges

The Commission has considered the level of intercorporate charges, which range from a low of approximately

$1,200 per year, in the case of St. John Gas & Oil Co. Ltd., to a high of approximately $50,000 per annum for Grande Prairie Transmission Co. Ltd. and Columbia Natural Gas Limited respectively.

The evidence tendered by the Applicant was insufficient to permit the Commission to conclude whether or not the charges are appropriate, or what adjustment, if any, should be made. As in the case of the inventories, these matters will form part of the Management Audit.

Columbia Natural Gas Limited

Columbia Natural Gas Limited ("Columbia") provides natural gas service to residential, commercial and large industrial customers in the East Kootenay region of British Columbia. The major customers are Cominco Ltd., Fording Coal Ltd., Kaiser Resources Ltd. and Crestbrook Forest Products Ltd.

Pursuant to Commission Order No. G-19-79, dated June 26, 1979 approval was given to Columbia for the purchase by and transfer to Inland of all the issued and outstanding shares in the capital of Columbia. A companion Application made by Inland, which amongst other matters, would have permitted a merger, pursuant to Section 43 of the Energy Act, was subsequently withdrawn by letter dated June 25, 1979, on the basis that Inland's proposal did not come within the scope of that Section. The Inland proposal at that time was to do no more than provide direction and management to Columbia albeit in this proceeding the evidence was submitted that a merger of the companies is the logical conclusion.

The Applicant, as the evidence indicates, has long been interested in providing natural gas service to this region in British Columbia, and, in fact, was one of the original unsuccessful Applicants for the construction and operation of the system in the early 1960's.

There is no doubt that the purchase of Columbia has increased the size of the Applicant and that some benefits accrue to Columbia and its customers. It was submitted that, if the companies were merged and "postage-stamp" rates established, the rates in the Columbia service area would be reduced by approximately nine cents per MMBtu (.9¢/billing unit), whereas the rates throughout the Inland service area would increase by approximately two cents per MMBTU (.2¢/billing unit) assuming the transaction took place at June 30, 1980.

If Inland and Columbia were to merge, the impact of Alberta gas on the Columbia system would be substantially reduced. On the other hand, all of the customers served by Inland throughout the Interior of British Columbia would then be subject to price changes resulting from changes in the Alberta border price. Such changes are based upon the Toronto City gate price which in turn is adjusted by Decisions made by the National Energy Board with regard to Trans Canada Pipelines Ltd. These and other factors will require careful consideration by the Commission if and when any application to merge these two companies is received.

V. RATES

The Applicant's proposed rates have been developed by adjusting all classes of service upward by approximately 4%, which the Applicant states is consistent with the Decision of the Commission dated August 31, 1977.

A resident of Hudson's Hope, Mrs. Belanger, indicated by letter to the Commission that although the proposed increase may be justified, she objected to people in the north having to subsidize customers in the Okanagan. Mrs. Belanger stated that "Gas prices should be established on the basis of transportation costs. We, near the source, pay the same price as customers 600 miles or more further south." (Transcript page 1013)

The Commission understands Mrs. Belanger's concern and will be reviewing this matter during Phase II of the Natural Gas Price Inquiry currently in progress. The Commission believes it would be inappropriate to make any adjustment pending completion of that Inquiry, at which the rates charged by Inland's supplier will be considered.

The Commission accepts the Applicant's submission with regard to the Company's extension policy (Transcript p.1098) that, due to the number of unknowns at this time, consideration of this matter be deferred. The Commission has concluded that it would be inappropriate to do otherwise before the results of the Natural Gas Price Inquiry are known.

The Commission appreciates the desire of the Village of Chase for natural gas service, as well as the concern expressed by Cominco Ltd. at the lack of natural gas for residential service between Trail and Castlegar. Mr. Dewdney, Counsel for Cominco Ltd., suggested that the Applicant did not appear to be exhibiting the entreprenurial enterprise that he thought they should (transcript page 1136), and further suggested that a more detailed study should be made and that perhaps even the Commission itself should look into the matter to determine whether or not the Applicant has been fulfilling its obligations.

The Commission will further review this matter in the course of an impending natural gas conversion and extension hearing. Service to the Village of Chase, where a transmission line does not currently exist will also be considered at that hearing.

VI. CAPITAL STRUCTURE FOR REGULATORY PURPOSES

Components of Capital Structure

In order to determine components of capitalization for rate-making purposes the Applicant has adopted the position taken in the two previous Applications. The underlying principle adopted by the Applicant assumed that investment in non-utility operations and the investment in rate base have both been financed in the ratio of the Company's overall capital structure.

Determination in this area involves a measure of judgement, but clearly where funds have been raised for non-utility purposes these must be excluded from the regulatory capital structure. Likewise, where funds have been raised from utility customers to pay for a future utility liability then these funds must be considered exclusively to be of a utility nature.

The Commission has concluded that the principle adopted by the Applicant should be continued except with respect to the treatment of funds collected to pay deferred income taxes and to the acquisition of Columbia Natural Gas Limited. Deferred income tax funds collected from the utility's customers have been recognised exclusively as utility financing and accordingly have been deducted from the rate base.

With respect to acquisition of Columbia Natural Gas Limited the Commission has concluded that funds used for the purchase may reasonably be deemed to have been provided from common equity (including internal cash generation) and short-term debt. In the period under review the ratio of common equity generation to short-term debt generation is approximately 1:4. An exclusion from the regulatory capital structure of the Applicant has accordingly been made on this basis.

Short-Term Debt

The Applicant has not disputed that in the past short-term debt has been excluded from capital structure but takes the position that this matter should be viewed in pragmatic terms in light of the current money markets.

The Applicant relies on the evidence of Mr. Fell and stated that as of November 26, 1980 it was able to achieve a lower interest rate than that which it could achieve in the long-term bond market. The Applicant further argued that in so doing it was making the most prudent use of the financial resources available to it, while awaiting the most opportune time to enter the long-term market. Mr. Wallace, Counsel for the Forest Industry Group, expressed concern with regard to the inclusion of short-term debt in the capital structure and made reference to Decisions of other Commissions which have excluded this item.

The Commission agrees with Mr. Wallace that both the amount and the embedded cost of short-term debt are more difficult to predict. On the other hand, unless a long-term issue can be placed for the precise amount at the precise time new facilities are being placed in service, similar difficulties arise. For a utility the size of Inland whose capital program, although substantial, comprises numerous small projects not attracting an allowance for funds used during construction, such precise funding is not practical.

In the circumstances of this proceeding, and considering in particular the volatility of interest rates, the Commission agrees with the Applicant's request to include short-term debt in the capital structure, in an amount sufficient to equalize the capital structure and the Rate Base.

With regard to the appropriate interest rate, the Applicant initially suggested a rate of 13% when the Application was filed in June of 1980, and subsequently revised the recommendation to 14.69% (Exhibit 48). The Commission believes that, where short-term debt is used in lieu of long-term financing, the rate should not exceed that which could have been achieved through timely long-term financing. To provide the Applicant with the best opportunity to achieve the appropriate financing, short-term debt has therefore been included at a rate of 13% per annum. To accommodate this necessary arbitrary action, the Commission further instructs the Applicant to create a deferred account (similar in nature to that established for Pacific Northern Gas) to absorb fluctuations in the interest rate from that assumed in this Decision, to ensure that equitable treatment is afforded to both the customers and the shareholders.

Rate of Return on Equity

The Applicant is seeking to increase its return on equity from the 15.25% permitted in the previous Decision, to 16%. The Applicant instructed Mr. Fell to determine a return on equity consistent with the assumption that the 15.25%, permitted in the 1979 Decision, was fair and reasonable. Mr. Fell concluded and the Commission concurs that the Applicant is entitled to a minimum of 16%.

The Applicant is planning a significant financing in mid-1981 and, excluding the impact of additional requirements for funds resulting from rural gasification and greater than anticipated market growth, further financing will be required in 1983.

In determining a just and reasonable rate of return, the Commission has considered the highly competitive market for equity issues, in terms of the business risk and financial integrity of the Applicant.

With respect to the financial integrity, the Commission has considered the required risk premium for equity over corporate bonds, as well as the interest coverages required to permit Inland to issue long-term debt at reasonable cost. As indicated in Exhibit 24, if existing coverages were to be maintained immediately following the proposed issue, a return on equity of approximately 24% would be required. The Commission recognises that these coverages are not immediately required and that, over time, they will improve.

However, there is no doubt that at the current rates, unless the equity component increases or a higher return on equity is approved, inadequate coverages may result. Apart from new capital requirements, the "roll-over" of existing debt at higher interest will exert a downward pressure on return on equity.

On occasion, Boards and Commissions have found that the equity component has become higher than they deem appropriate. In such circumstances either a lower imputed common equity has been adopted or the allowed return on equity has been reduced. Conversely, if common equity has become lower than deemed appropriate, then a higher common equity component should be adopted or a higher return allowed. In the circumstances of the Applicant, the Commission believes the common equity component is low in relationship to similar companies with similar risks.

Mr. Wallace, in his argument, did not focus on the amount of common equity, but took the position that the previously allowed return of 15.25% is just and reasonable today and in fact may be too high.

On the evidence, the Commission believes an increase from the existing 15.25% per annum is justified. The Commission further recognizes that a reasonable risk premium must exist over the first mortgage bond rate, sufficient coverages must be maintained, and, to some extent, the highly leveraged position of the common stock should be reflected in the rate of return.

Accordingly, the Commission has concluded that the Applicant should have the opportunity to earn a return on common equity of approximately 16.5% per annum.

VII. TARIFF

The Commission will accept for filing changes in tariff rate schedules which will permit the Company to generate the revenue requirement as set out in this Decision and calculated on Schedule III. New rates will be confirmed on this basis, effective April 1, 1981, and customer refunds will be made at the amounts per MMBtu by rate class as calculated on Schedule III note (k). Amounts per MMBtu as calculated will be applied to actual sales made in the period July 1, 1980 to March 31, 1981. Such refunds plus interest should be refunded or credited to customers during the course of April billing cycles.

DATED at the City of Vancouver, in the Province of British Columbia, this 18th day of March, 1981.

R. Smith

D.B. Kilpatrick

D.B. Kilpatrick

J.D.V. Newlands

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-20-81

PROVINCE OF BRITISH COLUMBIA

BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF the Utilities Commission Act, SBC 1980, c. 60

and

IN THE MATTER OF Applications by Inland Natural Gas Co. Ltd.

BEFORE:	R. Smith, Deputy Chairman; D.B. Kilpatrick, Commissioner; and J.D.V. Newlands, Commissioner	March 18, 1981

O R D E R

WHEREAS Inland Natural Gas Co. Ltd. ("Inland") applied June 16, 1980 for both interim and permanent rate relief, requesting that interim increases be implemented not later than July, 1980; and

WHEREAS Commission Order No. G-44-80 authorized the implementation of amended tariff rate schedules effective July 1, 1980, with the interim increase subject to refund with interest at 11% per annum; and

WHEREAS a public hearing of Inland's Applications, scheduled to commence September 8, 1980 at Kelowna, B.C. but re-scheduled to commence November 3, 1980 at Kamloops, B.C. was heard during five days at Kamloops with a concluding evening session at Vancouver, B.C. on November 26, 1980; and

.../2

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-20-81

WHEREAS the Commission has considered the Applications and the evidence adduced thereon and finds that Inland has failed to justify the interim rates which became effective July 1, 1980 as well as the permanent rates proposed, all as set forth in a Decision issued concurrently with this Order.

NOW THEREFORE the Commission hereby orders Inland Natural Gas Co. Ltd. as follows:

1. The rate base for Inland for the test period is approximately $107,610,000.

2. The total cost of service including the return on capital employed is approximately $88,000,000.

3. Inland is directed to refund to its customers of record in the period July 1, 1980 through March 31, 1981, or such date as may permit the completion of any billing cycle underway prior to April 1, 1981, the calculated interim increase refund arising from the implementation of the interim tariff rate schedules effective July 1, 1980. Such refund amounts shall include a provision for interest at the rate of 11% per annum as prescribed and shall be remitted to the customers, or credited to the customer account during the month of April, 1981.

4. In instances where Inland experiences a difficulty in locating a former customer entitled to a refund the amount involved shall be recorded in its books of account as a liability and shall remain so for such period of time as required by the Statute of Limitations, or until Inland obtains sufficient information to enable the refund to be made, whichever first occurs. Amounts for refund remaining as a liability after the period required by Statute shall be recorded as miscellaneous utility income.

5. The Commission will accept for filing effective with consumption on and after April 1, 1981, subject to timely filing, amended tariff rate schedules which will permit Inland to generate the annual revenue requirement of $88,000,000. as set out in Schedule III of the Commission Decision dated March 18, 1981.

6. Inland is directed to carry out any and all instruction set forth in the Decision issued concurrently herewith.

DATED at the City of Vancouver, in the Province of British Columbia, this 18th day of March, 1981.

BY ORDER

~~Division~~
Chairman

INLAND NATURAL GAS CO. LTD.

SCHEDULE I

Utility Rate Base

	Per Application (Exhibit 11)	Applicant's Adjustments (Exhibit 48)	Final Application	Commission Adjustments	Final Adjusted Balance
Gas plant in service as at June 30, 1980	$127,803,985	-	$127,803,985	-	$127,803,985
Additions to gas plant in service (mean)	4,956,075	-	4,956,075	-	4,956,075
Intangible plant	987,727	-	987,727	-	987,727
Unamortized deferred depreciation	431,329	-	431,329	-	431,329
Meters and regulators held in reserve	750,000	-	750,000	-	750,000
Construction work in progress	426,748	-	426,748	-	426,748
Less: customer advances on construction	(255,000)	-	(255,000)	-	(255,000)
Gross Plant	135,100,864	-	135,100,864	-	135,100,864
Less: contributions in aid of construction	(3,365,756)	-	(3,365,756)	-	(3,365,756)
	131,735,108	-	131,735,108	-	131,735,108
Accumulated depreciation	(23,194,307)	-	(23,194,307)	-	(23,194,307)
Adjustment to accumulated depreciation	(1,241,624)	-	(1,241,624)	-	(1,241,624)
Net Plant	107,299,177	-	107,299,177	-	107,299,177
Working capital allowance (per Schedule II)					
Cash working capital	(1,247,138)	7,441	(1,239,697)	$ -	(1,239,697)
Other working capital items	1,651,222	350,000	2,001,222	(451,030)	1,550,192
	404,084	357,441	761,525	(451,030)	310,495
Deferred taxes (mid-year balance)	-	-	-	(a) (5,292,798)	(5,292,798)
Net utility rate base investment	$107,703,261	$ 357,441	$108,060,702	$(5,743,828)	$102,316,874

INLAND NATURAL GAS CO. LTD.

Notes to Schedule I

(a) Reflects deduction of Deferred Income Taxes from Rate Base as per Decision, page 29.

Balance - July 1, 1980 (Exhibit 11, Tab 16, page 4)	$4,631,652
Deferred Tax (1,368,960 - 46,669)	1,322,291
Balance - June 30, 1981	$5,953,943

Mid-year balance: $5,292,798

INLAND NATURAL GAS CO. LTD. SCHEDULE II

Allowance for Working Capital

	Per Application (Exhibit 11)	Applicant's Adjustments (Exhibit 48)	Final Application	Commission Adjustments	Final Adjusted Balance
Cash Working Capital					
Investment in cash operating expenses	$(1,016,938)	$ 7,441	$(1,009,497)	-	$(1,009,497)
Minimum bank balance	10,000	-	10,000	-	10,000
	(1,006,938)	7,441	(999,497)	-	(999,497)
Add: -reserve for bad debt	(65,200)	-	(65,200)	-	(65,200)
-employee deductions withheld	(175,000)	-	(175,000)	-	(175,000)
	(1,247,138)	7,441	(1,239,697)	-	(1,239,697)
Other Working Capital Items					
Rate hearing costs	-	-	-	(a) $ 19,970	19,970
Inventories	1,074,000	350,000	1,424,000	(b) (471,000)	953,000
Transmission line pack	120,000	-	120,000	-	120,000
Peak shaving gas	207,222	-	207,222	-	207,222
Merchandise accounts receivable	250,000	-	250,000	-	250,000
	1,651,222	350,000	2,001,222	(451,030)	1,550,192
Total working capital requirement	$ 404,084	$357,441	$ 761,525	$(451,030)	$ 310,495

INLAND NATURAL GAS CO. LTD.

Notes to Schedule II

(a) Allowance for rate hearing costs (per Decision, page 21)

Current hearing costs	$	90,772
Amortization per Schedule III (note (e))	(	45,386)
Ending balance June 30, 1981	$	45,386
Mid-year balance: $22,693		

Amount includable:

Approved increase equals approximately 88% x $22,693	$	19,970

(b) Revised allowance for inventories (per Decision, page 7)

Working capital allowance for operating materials (Exhibit 12, Item 1 (b))	$	452,000
Add: amount allowed for construction material per page 7 of the Decision ($1,002,000 (Exhibit 12, Item 1 (b)) x 50%)		501,000
Revised allowance for inventories	$	953,000
Less: allowance for inventories per Applicant $1,454,000 (Exhibit 8, Tab 5, page 2) less $30,000 (additional amount provided for loss per Exhibit 48)		1,424,000
Adjustment required	$(	471,000)

INLAND NATURAL GAS CO. LTD.

SCHEDULE III

Adjusted Utility Income & Earned Return

	Per Application (Exhibit 11)	Applicant's Adjustments (Exhibit 48)	Final Adjusted Balance per Application		Commission Adjustments		Final Adjusted Balance
Gas sales volume (MMBtu)	47,129,806	(551,200)	46,578,606	(a)	867,074	(j)	47,445,680
Gas Sales Revenue							
Rate 1 - Residential	$ 22,089,692	$ 95,246	$ 22,184,938	(i)	$ (397,011)		$ 21,787,927
Rate 2 - General	18,988,004	85,278	19,073,282	(i)	(376,118)		18,697,164
Rate 4 - Dual fuel	223,862	1,725	225,587	(i)	(4,039)		221,548
Rate 5 - Large firm	11,972,178	25,007	11,997,185	(i)	(225,040)		11,772,145
Rate 10 - Gas engine	38,538	67	38,605	(i)	(672)		37,933
Rate 11 - Large volume firm	30,298,597	(527,736)	29,770,861	(i)	(544,359)		
				(b)	140,000		29,366,502
Rate 12 - Large volume interruptible	1,543,125	(32,711)	1,510,414	(a)	1,211,302		
				(i)	(46,490)		2,675,226
Columbia Natural Gas	3,481,945	16,011	3,497,956	(i)	(61,837)		3,436,119
(rounding difference)	(15,422)	24,313	8,891	(i)	(8,891)		-
Total sales revenue	88,620,519	(312,800)	88,307,719		(313,155)		87,994,564
Expenses							
Purchase of gas	51,541,797	(563,274)	50,978,523	(c)	320,104		51,298,627
Operation and maintenance	10,340,987	-	10,340,987	(d)	(317,821)		
				(e)	45,386		10,068,552
Property, franchise and sundry taxes	5,612,442	(6,907)	5,605,535	(f)	(11,000)		5,594,535
Depreciation	3,127,906	-	3,127,906		-		3,127,906
Transportation revenue	-	-	-		-		-
Other operating revenue	(316,272)	-	(316,272)	(g)	(118,360)		
				(h)	(46,669)		(481,301)
Total expenses	70,306,860	(570,181)	69,736,679		(128,360)		69,608,319
Net utility income before taxes	18,313,659	257,381	18,571,040		(184,795)		18,386,245
Deduct: Income taxes (per Schedule IV)							
- payable	5,363,128	37,584	5,400,712		24,071		5,424,783
- deferred	1,392,924	-	1,392,924		(23,964)		1,368,960
	6,756,052	37,584	6,793,636		107		6,793,743
Earned return	$ 11,557,607	$ 219,797	$ 11,777,404		$ (184,902)		$ 11,592,502
Utility rate base investment (per Schedule I)	$107,703,261	$ 357,441	$108,060,702		$(5,743,828)		$102,316,874
Rate of return on depreciated rate base	10.73%		10.90%				11.33%

INLAND NATURAL GAS CO. LTD.

Notes to Schedule III

(a) Adjustment to reflect increased interruptible gas sales volume per page 11 of the Decision

Interruptible gas sales volume per Decision (excluding sales to Columbia Natural Gas) [1,900,000 less 27,560 (strike adjustment)]	1,872,440 Mcf
Less: interruptible gas sales volume per Application (excluding sales to Columbia Natural Gas, Exhibit 48, Tab 6, page 1)	1,038,715
	833,725 Mcf
Volume adjustment required: 833,725 Mcf x 1.040 =	867,074 MMBt
Gas sales revenue adjustment: 867,074 MMBtu x $1.397 (average proposed rate) =	$1,211,302

(b) Upward adjustment to gas sales revenue of $140,000 (per Decision, page 13) to reflect increased minimum billing revenue.

(c) Adjustments to gas purchases:

(i)	Increase in gas purchase costs as a result of adjustment (a) 833,725 Mcf x $1.056 (average cost)	$ 880,414
(ii)	Removal of demand charges in excess of billing demand nomination of 152,635 Mcf per day: 7,000 Mcf x $12.60 (six months)	(88,200)
(iii)	Adjustment to take into account a 1.0472 MMBtu/ Metered Mcf factor	

	Mcf @1.04 MMBtu/Mcf	Mcf @1.0472 MMBtu/Mcf
Sales volumes per Decision (47,445,680 MMBtu converted)	45,620,846	45,307,181
Gas loss @0.6%	273,725	271,843
Required purchase	(A) 45,894,571	(B) 45,579,024

INLAND NATURAL GAS CO. LTD.

Notes to Schedule III
(cont'd)

(c) Adjustments to gas purchases (cont'd)

- Reduction in commodity cost

315,547 Mcf (A - B) @$1.036* $(326,907)

*Gas purchase cost represented by:

	Mcf @1.0472	$
Firm @$1.033	41,031,343	42,385,377
Interruptible @$1.063**	4,275,838	4,545,216
Average $1.036	45,307,181	46,930,593

**$1.033 (commodity cost) x 1.029 (1.0472 dry Btu factor converted to saturated basis)

- Increased cost of interruptible gas

4,275,838 x ($1.063 less $1.056) = 29,930

(296,977)

(iv) Adjustment to take into account an unaccounted for gas allowance of 0.22% of metered sales volume per page 15 of the Decision

Gas unaccounted for per Exhibit 48	268,723 Mcf
Less: gas losses on Decision metered sales volumes @0.22%	99,676
	169,047 Mcf

Reduction to gas purchase:

169,047 Mcf @$1.036 (average cost) (175,133)

Total adjustment to gas purchases $ 320,104

INLAND NATURAL GAS CO. LTD.

Notes to Schedule III
(cont'd)

(d) Adjustments to operation and maintenance expenses

(i)	Adjustment to take into account lower than forecast operation and maintenance costs per customer per page 18 of the Decision:	
	$113.88 (1980 normalized cost per customer) x 2.53% (disallowed amount) x 85,216 (fiscal 1981 average number of customers)	$(245,521)
(ii)	Adjustment to allow for revised hiring dates per page 18 of the Decision	(72,300)
	Reduction in operation and maintenance expenses	$(317,821)

(e) Hearing costs per page 21 of the Decision: 50% of total costs $90,772 — $ 45,386

(f) Franchise fees and property taxes:

Total sales revenue per final Application:	$88,307,719	
Total sales revenue per Decision (Schedule III)	87,994,564	
Reduction in sales revenue	$ 313,155	
Reduction in franchise fees and property taxes: $313,155 x 3.5%		$(11,000)

(g) Inclusion of late payment penalty charges as a component of utility revenue per page 13 of the Decision — $ 118,360

(h) Deferred tax adjustments:

Removal of 5% Federal surcharge on deferred income taxes: (0.528 - 0.51) x $2,592,727 (timing differences)	$(46,669)

INLAND NATURAL GAS CO. LTD.

Notes to Schedule III
(cont'd)

(i) Net adjustment to gas sales revenue necessary to compensate for revenue normalizations, cost of service, earned return and income tax adjustments per Schedule III. The final revenue requirement by class has been determined by applying a uniform percentage increase to the normalized pre-interim revenue.

(j) Annual sales volume by class of customer which should be used in the design of new tariff schedules:

Rates 1	9,031,432	MMBtu
2	8,086,169	
4	125,830	
5	5,928,110	
10	21,290	
11	19,775,191	
12	1,947,338	
13	-	
Columbia Natural Gas	2,530,320	
	47,445,680	MMBtu

(k) Calculation of amount per MMBtu to be refunded or credited to customers.

Total sales revenue using Decision volumes at average interim rate 47,445,680 MMBtu x $1.87 =	$88,723,422
Add: minimum billing adjustment not included in interim Application	140,000
	88,863,422
Deduct: final revenue requirement per Schedule III	87,994,564
Over-earning on annual basis at interim rates	$ 868,858

Amount to be refunded for the nine month period to March 31, 1981 =

$$\frac{37{,}576{,}565 \text{ MMBtu (Applicant's forecast as amended)}}{47{,}445{,}680 \text{ MMBtu (Decision volume)}} \times \$868{,}858 = \$\ 688{,}128$$

INLAND NATURAL GAS CO. LTD.

Notes to Schedule III
(cont'd)

(k) (cont'd)

Refund per MMBtu by class

Rate	Forecast sales to March 1981 (as adjusted) MMBtu	Forecast sales revenue @ interim rates	Refund Prorated	Refund ¢/MMBtu
1	7,686,547	$18,798,621	$181,774	2.36
2	6,818,757	15,942,809	154,160	2.26
4	85,090	151,387	1,464	1.72
5	4,560,130	9,161,491	88,588	1.94
10	13,480	24,253	235	1.74
11	14,988,017	22,366,321	216,272	1.44
12	1,518,224	2,095,895	20,266	1.33
Columbia	1,906,320	2,623,616	25,369	1.33
TOTAL	37,576,565	$71,164,393	$688,128	1.83

INLAND NATURAL GAS CO. LTD.

SCHEDULE IV

Calculation of Income Taxes on Utility Income

	Application (Exhibit 11)	Applicant's Adjustments (Exhibit 48)	Final Adjusted Balance for Application		Commission Adjustments	Final Adjusted Balance
Net utility income (per Schedule III)	$18,313,659	$257,381	$18,571,040		$(184,795)	$18,386,245
Non-tax deductible expenses	(143,308)	-	(143,308)		-	(143,308)
	18,170,351	257,381	18,427,732		(184,795)	18,242,937
Deduct: interest and expense on long term debt	(5,374,791)	(186,200)	(5,560,997)	(a)	184,997	(5,376,000)
Net income before timing differences	12,795,554	71,181	12,866,735		202	12,866,937
Deduct: timing difference adjustments	(2,638,113)	-	(2,638,113)	(b)	45,386	(2,592,727)
Taxable income	$10,157,441	$ 71,181	$10,228,622		$ 45,588	$10,274,210
Income tax rate	52.8%		52.8%			52.8%
Income taxes: - payable	5,363,128	37,584	5,400,712		24,071	5,424,783
- deferred	1,392,924	-	1,392,924	(c)	(23,964)	1,368,960
Income tax expense	$ 6,756,052	$ 37,584	$ 6,793,636		$ 107	$ 6,793,743

INLAND NATURAL GAS CO. LTD.

Notes to Schedule IV

(a) Debt interest calculation

Interest on long term debt (new issued adjusted to 13%)	$5,317,737
Other interest @13%	549,704
Amortization of debt issue cost (Volume 2, Tab 14, page 5)	14,788
Total adjusted debt interest	$5,882,229

Utility portion:

$$\frac{\text{(i) } 55,087,845}{\text{(ii) } 60,288,516} = 91.4\%$$

Utility debt interest = $5,882,229 x 91.4% = $5,376,000

(i) Total debt - final adjusted balance
(ii) Total debt - per Application (Exhibit 48)

(b) Timing difference adjustments

Add: amortization of 1980 rate hearing costs $ 45,386

(c) Deferred tax on amortization of current hearing costs to be included in timing differences adjustments (0.528 x $45,386) $ 23,964

SCHEDULE V

INLAND NATURAL GAS CO. LTD.

Return on Capital

	As Reported (Exhibit 48)	Commission Adjustments (Schedule V (a))	Final Adjusted Balance	% of Capital Structure	Embedded Cost	Cost Component
Long term debt	$ 56,086,000	$(7,770,023)	$ 48,315,977	47.22	8.871%	4.19%
Short term debt	4,202,516	2,569,352	6,771,868	6.62	13.000%	.86%
Deferred tax	5,328,114	(5,328,114)	-		-	-
Preference shares	17,795,000	(628,869)	17,166,131	16.78	8.545%	1.43%
Common Equity	32,274,055	(2,211,157)	30,062,898	29.38	16.50%	4.85%
	$115,685,685	$(13,368,811)	$102,316,874	100.00		11.33%

INLAND NATURAL GAS CO. LTD.

SCHEDULE V(a)

	Long-term Debt	Short-term debt	Deferred Tax	Preference Equity	Common Equity	Total
As reported (Exhibit 48, Tab 16, page 1)	$56,086,000	$4,202,516	$5,328,114	$17,795,000	$32,274,055	$115,685,685
Deferred tax removed per Decision, page 29	-	-	(5,328,114)	-	-	(5,328,114)
New debt transferred to short-term for allocation purpose	(6,000,000)	6,000,000	-	-	-	-
Non-utility investment other than Columbia removed per Decision, page 29	(1,770,023)	(360,554)	-	(628,869)	(1,140,554)	(3,900,000)
Columbia investment removed per Decision, page 29	-	(4,102,786)	-	-	(1,025,696)	(5,128,482)
Notional short-term debt per Decision, page 31	-	1,032,692	-	-	-	1,032,692
Net income reduced due to adjusted revenue per Schedule III	-	-	-	-	(44,907)	(44,907)
Final amount	$48,315,977	$6,771,868	-	$17,166,131	$30,062,898	$102,316,874