THE VALUE OF BRITISH COLUMBIA'S NATURAL GAS USED AS LIQUEFIED NATURAL GAS (LNG) FOR EXPORT TO JAPAN

by

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We accept this thesis as conforming to the required standard

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ABSTRACT

The objective of this thesis is to determine the value of British Columbia's natural gas used as liquefied natural gas (LNG) for export to Japan. This value is calculated by a computer model simulating an LNG project in B.C. The model starts with an estimate of the landed price of LNG in Japan and works backward, costing every step, to the input-end of the pipeline delivering the natural gas from the field to the liquefaction plant. The value obtained is the opportunity cost of the natural gas used as LNG and can be compared to the opportunity cost in other uses and to the cost of supplying the natural gas. We calculate this value for both society and the private firm - the difference accounted for by the particular tax structure which would apply to an LNG export project.

The base case estimates of the social opportunity cost of the natural gas used as LNG range from $3.645 to $4.12 (1981 Canadian dollars) per thousand cubic feet (MCF), depending on the scale of the liquefaction plant. The estimates of the private opportunity cost are very close to the social values - a difference of about 3%. A comparable estimate for the opportunity cost in use as exports to the United States by pipeline is $4.68/MCF although this figure is based on present and not potential contracts.

A sensitivity analysis is performed and the capital cost and the landed price are found to be the variables with the largest relative impact on the base case estimates.
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ACKNOWLEDGEMENT

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I. INTRODUCTION

Natural gas was liquefied for the first time at the turn of the twentieth century "...by a combination of compression and cooling."\(^1\) The liquefaction of natural gas was interesting because of the volume reduction produced by the process; liquefied natural gas (LNG) occupies only \(1/600\)th of its original volume. Until the mid-1960's, natural gas was essentially liquefied only for storage purposes and not transportation.

In the mid-1960's, ships able to carry very cold liquids were developed. This development opened a completely new use for LNG; LNG ships could now be used to transport natural gas between two locations that could not be economically linked by a pipeline.

The production of LNG can thus be viewed as a typical case of the impact of developments in the transportation industry on the value of the production elsewhere in the economy. In this specific case, the development is the new ability to economically transport by ship very cold liquids, and the impact is on the value of natural gas in the ground.

1. Statement of the Objective of this Thesis

Many proposals for the export of B.C. natural gas to Japan as LNG have come up in the last year. These proposals, dealing with the export of energy resources, are all subject to Government approval. The debate over these approvals deals with two types of issues: the first is to decide the uses to which B.C. natural gas will be put; the second, at a more macro level, is to decide the
allocation of capital amongst alternate energy projects. In this context, the contribution of this thesis to the debate is the estimation of the social opportunity cost of natural gas used as LNG for export to Japan. Also, we will look at the impact of taxes, as they would apply to an LNG project, on private decisions concerning use of natural gas.

The opportunity cost is calculated at the well-head and enters the determination of social value of B.C.'s natural gas in the following way: the social value of B.C.'s gas is the difference between the highest opportunity cost in use and the social cost of extracting the natural gas at the well-head. Putting this definition in the form of a decision-making rule, we obtain the following: if we have $O_L$ for the opportunity cost in use as LNG, $O_{0,X}$ for the opportunity cost in other use $X$ and $C_S$ the cost of supplying the natural gas, an LNG project should go ahead only if

$$O_L > O_{0,X}$$

for all $X$ and

$$O_L > C_S.$$  

If these conditions are met, it will mean that LNG for export to Japan is the best use for B.C. natural gas and that the necessary capital should be allocated to this type of project.

We will limit ourselves to the estimation of the opportunity cost in use as LNG here, this being a significant undertaking of its own. Separate studies would be necessary to estimate the value of natural gas in other uses, and the costs of extracting the gas to the well-head.
The impact of taxes on private decision-making with reference to the use of B.C. natural gas will be analyzed through the estimation of what is identified as the "private opportunity cost of natural gas used as LNG". The private opportunity cost differs from the social opportunity cost only in that it accounts for the tax payments particular to an LNG project; the social opportunity cost, on the other hand, accounts for the average tax payments which could be expected from other investments of similar size as that required for an LNG project. The private opportunity cost is the key in the decision-making of the private firm regarding the use of natural gas as LNG. A comparison of this value to the social opportunity cost will indicate the type of incentive implied in the tax structure of Canada with regard to the use of natural gas as LNG. For instance, an estimated private opportunity cost far below the estimated social opportunity cost may suggest the need for a revision of the tax structure as it applies to potential LNG projects so that private decision-making satisfies the social criteria (which is the social decision-making rule defined above).

2. **The LNG Plant Proposals in British Columbia**

As of July 1981, there are four publicly known LNG plant proposals in British Columbia. Each proposal includes an LNG plant as part of a larger scheme focusing on the petro-chemical industry. The four groups involved are: Dome Petroleum, Carter Oil and Gas, Petro-Canada and Westcoast Transmission, and Norcen Energy Resources.

All four projects aim at serving the Japanese market and the LNG plant would be located in the Prince Rupert area in each case.
The feedstock for these plants would come from fields north of Fort St. John, a distance of about 500 miles.

The international LNG market is aware of these plans in B.C. as a mention of them is made in the 1980 Petroleum Economist's survey of this market.\(^3\)

Despite the general knowledge of these plans, one important element remains unclear. It is difficult to identify the projected size of these LNG plants. The size of each plant is generally measured in million cubic feet per day (MMCF/D). The Petroleum Economist's report refers to a 400 MMCF/D plant for Dome Petroleum.\(^4\) An article in The Province newspaper\(^5\) announced plans for a 250 MMCF/D plant by Petro-Canada and Westcoast Transmission, with possible expansions to 760 MMCF/D and 1,200 MMCF/D. Pre-feasibility studies done for Carter Oil and Gas\(^6\) consider plants of 250 and 500 MMCF/D. All of these schemes suggest a 20 year contract with deliveries starting in the latter part of 1986.

The apparent indecision regarding the plant capacity may be related to the uncertainty of the capital cost estimates. The indication seems to be that the proponents would be willing to build a small scale plant, foregoing potential economies of scale, to obtain more information about the capital cost involved. The public strategy of Petro-Canada most clearly represents this strategy. The group filed a "pre-application" with the B.C. government for a 250 MMCF/D plant and a "planned" expansion to 760 MMCF/D with an "option" for an ultimate 1,200 MMCF/D.\(^7\) The expansion to 760 MMCF/D (and probably even the expansion to
1,200 MMCF/D) has not been delayed in the prospect of an improving Japanese market since the Japanese are looking right now for over 3,000 MMCF/D of new LNG deliveries.\(^8\)

The reason for the delay is thus likely to be found on the supply side where the proponents either feel that the "social value" of the present reserves of natural gas is too large for the government to accept a long-term export commitment this large, or the firms do not want to get involved in large scale projects of such capital intensiveness without more information. Our analysis should provide useful information in the latter context.

II ANALYSIS

1. Description of the Methodology

The social and private opportunity costs are estimated by a computer model simulating an entire LNG project, from the input end of the pipeline delivering the natural gas to the liquefaction plant to the dock in Tokyo, Japan. The computer model starts with an estimate of the landed price of LNG in Japan and works backward, costing every step, to the well-head. The study does not investigate various environmental impacts of an LNG project. This would entail a substantial study in its own right; there is considerable uncertainty as to what type of impacts are likely and the monetary value to assign to these impacts. If environmental effects were found to be significant, they would have to be added to the estimate of social costs calculated here. In addition to the estimation of the private and social opportunity costs defined here, the model is also used to perform a sensitivity analysis. The purpose of the sensitivity analysis is to
identify the variables that have the largest relative impact on the estimated opportunity costs.

2. **Cost and Price Estimates**

For modelling purposes, the LNG project has been divided into three components: the pipeline; the liquefaction plant including storage and port facilities; and the ships. For each component, capital and operating cost functions were estimated. It proved difficult to find cost estimates in the literature; the amount of information collected is relatively meager.

Since the data were limited, it was impossible to apply sophisticated estimation methods e.g., econometrics; so a very simple method was used. The cost functions are simply a set of straight lines linking the cost observations gathered. The following graph illustrates this method:

![Figure 1](image)

Obviously, we can expect such cost functions to be only rough estimates but it seems that this reflects the incomplete state of knowledge in the industry about the costs involved.
The sensitivity analysis will permit one to identify the cost elements that are the most important sources of variation in the estimated social and private opportunity cost; this information should be used to manage efforts directed at the refinement of the assumed cost functions.

a) Pipeline Costs

The pipeline is the one component of the project which is the least exotic. Still, we are dealing with very rough terrain and cost functions estimated in the south-eastern U.S. cannot be expected to apply. The pipeline envisaged here will run about 500 miles from just north of Fort St. John to Prince Rupert. We are considering volumes upward from 290 MMCF/D, because it takes 1.16 MCF of natural gas to produce one MCF of LNG, the 0.16 MCF being required as fuel for the liquefaction plant. With these volumes, it seems most likely that a new pipeline will have to be built over the entire distance.\(^9\) The estimation of the capital cost function is based on three observations:

<table>
<thead>
<tr>
<th>Capacity</th>
<th>Cost per Mile</th>
<th>Cost 10 (1981 Can.Dol.)</th>
<th>Project</th>
</tr>
</thead>
<tbody>
<tr>
<td>290 MMCF/D</td>
<td>$0.7 MM (1979 Can.Dol.)</td>
<td>$0.847 MM</td>
<td>Carter(^11)</td>
</tr>
<tr>
<td>576 MMCF/D</td>
<td>$1.16 MM (1979 Can.Dol.)</td>
<td>$1.4036 MM</td>
<td>Carter(^12)</td>
</tr>
<tr>
<td>1200 MMCF/D</td>
<td>$1.28 MM (1976 U.S.Dol.)</td>
<td>$2.4737 MM</td>
<td>Algeria(^13) (ARZEW)</td>
</tr>
</tbody>
</table>

Using this method, the capital cost function obtained is the following:

Let \(x\) be the capital cost of the pipeline in $Million
(1981 Can.Dol.) and y be the capacity of the pipeline in MMCF/D;

\[
\begin{align*}
\text{if } (y < 290), & \quad x = 500 (y \times 0.0029206) \\
\text{if } (290 \leq y < 580), & \quad x = 500 \left[0.847 + (y - 290) \times 0.0019193\right] \\
\text{if } (y \geq 580), & \quad x = 500 \left[1.4036 + (y - 580) \times 0.0017259\right]
\end{align*}
\]

The estimation of the operating cost function poses a problem in that the operating costs of a pipeline include the natural gas used as fuel for the compression stations. This means that the operating cost observed is strictly dependent on the price charged the operator of the pipeline for this fuel. This is a problem since we are trying to figure out what this price should be. This problem could be circumvented if we could find a formula defining the ratio of the quantity of fuel to the quantity moved; with this ratio, the operating cost could simply remain in quantity (and not value) terms and still be treated endogeneously.\textsuperscript{14} But the operation of a pipeline involves two different margins (diameter and pressure) which makes it impossible to define such a ratio. A pipeline of a larger diameter will require less pressure (and thus less fuel) to move a given quantity of natural gas. Also, the operating costs of a pipeline involve a relatively small amount of money as it is a very capital intensive proposition.

The assumed operating cost is based on figures from an N.E.B. rate hearing.\textsuperscript{15} The annual operating costs of ICG Transmission Ltd., from the statements presented at this hearing are estimated at $0.081931 (1979 Can.Dol) per MMCF per mile or $59.976 (1981 Can.Dol.) per MMCF for a 500 mile pipeline.
To get an idea of the relative size of this number, for a 250 MMCF/D plant this works out to about six million (1981 Can.Dol.) a year or about $0.06 (1981 Can.Dol.) per MCF. In other words, even if ICG Transmission paid only half of the social value of B.C. gas, we would get an overvalue of only 6¢ per MCF, representing an anticipated margin of error of 1.5%. We will come back to this subject in the sensitivity analysis.

Using the value mentioned above, the operating cost function is: \( y = 59,976 \times \text{capacity} \times \text{number of operating days in a year} \), where \( y \) is the annual operating cost.

b) Liquefaction Costs

The liquefaction plant as defined here includes all the facilities required between the output-end of the pipeline and the ships. These facilities constitute a complex system which is not analyzed in detail here. We use the total reported project cost of existing or planned facilities for the purpose of estimating our cost function.

The capital cost function has been estimated with three observations:

### Table 1

**Capital Cost of the Liquefaction Plant**

<table>
<thead>
<tr>
<th>Capacity</th>
<th>Cost ($Million)</th>
<th>Cost ($Million) (1981 Can.Dol.)</th>
<th>Project</th>
</tr>
</thead>
<tbody>
<tr>
<td>250 MMCF/D</td>
<td>$366</td>
<td>$442</td>
<td>Carter Oil and Gas 16</td>
</tr>
<tr>
<td></td>
<td>(1979 Can.Dol.)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>500 MMCF/D</td>
<td>$571</td>
<td>$691</td>
<td>Carter Oil and Gas 17</td>
</tr>
<tr>
<td></td>
<td>(1979 Can.Dol.)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1000 MMCF/D</td>
<td>$929</td>
<td>$1022</td>
<td>Example from the literature 18</td>
</tr>
</tbody>
</table>
Using our simple estimation method, the capital cost function obtained from these observations is the following; letting $x$ be the capital cost in $\text{Million (1981 Can.Dol.)}$ and $y$ the capacity in MMCF/D,

if $Y < 250$, $x = y \times 1.768$

if $250 < y < 500$, $x = 442 + [(y - 250) \times .996]$

if $y > 500$, $x = 691 + [(y - 500) \times .662]$

The liquefaction plant is the component of the project where we find the greatest uncertainty as to the level of the capital costs. While natural gas pipelines are fairly common and there exists an international market with strong competition for LNG tankers, the LNG plants must be costed individually. The plant is in fact a complex set of buildings and equipment and the cost of erection depends on local factors, e.g., local construction's inflation rate, isolation of the plant, etc.

Considering this, our estimated capital cost function seems to represent the state of the knowledge of the parties involved in B.C. This fact underlines the importance of the sensitivity analysis for this particular element of the total cost; indeed, it is more important to know how the value of the natural gas varies with the capital cost of the liquefaction plant than to know the value given a point estimate of the capital cost.

The operating cost of the liquefaction plant is much easier to deal with because it essentially consists of the fuel in a well-accepted approximated ratio. It is held as general knowledge that it takes about 1.16 CF of natural gas to produce 1 CF of LNG, 0.16 CF being required as fuel. This aspect of the operating cost is thus treated endogene-
ously in the formula determining the value of the natural gas.

The remaining part of the operating cost has been embodied in an estimated function using the same method again. We have three observations:

Table 2

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>250</td>
<td>$13</td>
<td>$15.73</td>
<td>Carter Oil and Gas</td>
</tr>
<tr>
<td>(1979 Can.Dol.)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>500</td>
<td>$21</td>
<td>$25.41</td>
<td>Carter Oil and Gas</td>
</tr>
<tr>
<td>(1979 Can.Dol.)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1000</td>
<td>$27</td>
<td>$43.12</td>
<td>Example from the literature</td>
</tr>
<tr>
<td>(1978 U.S.Dol.)</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

From these observations we estimate the following annual operating cost function:

Letting $x$ be the annual operating cost in $\text{Million (1981 Can.Dol.)}$ and $y$ the capacity in MMCF/D:

- If $y < 250$, $x = y \times 0.06292$
- If $250 < y < 500$, $x = 15.73 + [(y - 250) \times 0.03872]$
- If $y > 500$, $x = 25.41 + [(y - 500) \times 0.03542]$

This part of the operating cost is relatively small, about $0.16 (1981 Can.Dol.)$ per MCF or 4% of the total value, so we will not discuss this estimate further but simply include it in the sensitivity analysis and perform an overall check on the total cost of liquefaction (appendix 1) to satisfy ourselves that the cost estimates are "in the ballpark."
c) **Shipping Costs**

The estimation of the costs of shipping involves a set of problems very different from those encountered with the pipeline or liquefaction. In this case there are no economies of scale because the shipbuilding industry produces almost exclusively a standard size LNG tanker—125,000 cubic meters ($m^3$), 44,143 gross tons. The problem thus shifts to the determination of the cost of each tanker and of the number of tankers required.

The cost of a 125,000 $m^3$ tanker has been set for the base case a $225 MM (1981 Can.Dol.). A first source\textsuperscript{23} quotes a range for the capital cost of $115 MM to $155 MM (1979 U.S.Dol.). I use the figure of $155 million (1979 U.S.Dol.) because other sources\textsuperscript{24} quote prices more in line with the upper part of this range. In fact, at present there is over-capacity in the LNG tanker building industry so that the most important factor in the variability of the estimates is the amount of governmental subsidization in shipbuilding.

The capital cost function is thus simply:

\[ x = \left(\frac{y}{36430}\right) \times 225, \text{ where } x \text{ is the cost in $million (1981 Can.Dol.) and } y \text{ is the total annual production in MMCF.} \]

The parameter "36,430" is obviously the key to this function. The perspective taken is that the shipping capacity has to equal the production capacity on a yearly basis. The capacity of a ship times the number of return trips travelled in a year is 36430 MMCF. The detailed calculation is presented below:
1 cubic meter = 21,885 Cf

125,000 m³ = 2,735.6 MMCF

number of trips in a year = 13.32

total capacity of a ship = 36430 MMCF.

The capital cost function has been made linear to deal simply with the fact that shipping capacity must somehow equal production capacity over a long enough period of time. This cost equation should be reliable because it rests on a sound estimate of the cost; sensitivity analysis will deal with the variability introduced by the governmental subsidization in shipbuilding.

As was the case for the liquefaction, the operating cost of the ships is considered in two parts: fuel and other costs. Most of the fuel originates in boil-off of the LNG. On the return-trip to Japan, the boil-off is of the order of 5% of the capacity. This aspect of the operating cost is treated endogenously in the formula determining the value of the natural gas used. The remaining part of the operating costs will be set equal to the detailed estimate provided by the U.S. government of $38MM (1976 U.S. Dol.) for six ships on the El Paso Project. This estimate works out to a $12.24 MM (1981 Can.Dol.) annual operating cost per ship and the cost function becomes:

\[ x = \left( \frac{y}{36430} \right) \times 12.24 \]

where \( x \) is the annual operating cost in $million (1981 Can.Dol.) and \( y \) is the annual production.

d) **C.I.F. Prices in Japan**

We need to estimate a C.I.F. specific to this project because there is no international price for LNG, similar to the world oil price, that can be used as a general reference.
While natural gas and oil are considered substitutable fuels by many, prompting illogical requests for BTU parity of prices, they are very different products in terms of marketing. In fact, there is no marketplace where natural gas is traded; thus, for example, we do not have such a thing as a spot price for natural gas equivalent to the spot price of oil. This is because of the costly infrastructure required to carry through a natural gas purchase agreement; in most cases this infrastructure takes the form of a pipeline, as over 95% of the world's gas consumption is pipelined.

An LNG project allows more flexibility than a pipeline but still requires specialized port facilities. The fact that suppliers and buyers have to be linked through an expensive infrastructure means that the flow of natural gas can only be changed at a high cost which effectively prevents the working of a market.

In addition to the limitations it poses on the working of a market, natural gas is found in reserves widespread around the world which, in actuality, makes it impossible for a group of supplying countries to dominate the gas sales and set prices.

In this context, one should not be surprised by the large spread in the prices at which natural gas is traded around the world. For instance, in 1979, "the Netherlands (the world's biggest international supplier) realised C.I.F. prices ranging from $1.25 - 3.65 million BTU on five different markets."
Each trade agreement involves in fact a negotiated price. The right price to use in evaluating B.C.'s gas used in LNG exports to Japan is thus the price that the Japanese pay for this type of product i.e., we can limit our attention to the Japanese LNG imports.

It is a well-known fact that Japan depends heavily on imported energy - for about 98% of its total supplies. The Japanese purchasing policy has stressed diversification of products and sources. LNG is one of the numerous products and it is already supplied from four different sources. In addition, talks are now in progress with five new sources besides Canada. In this perspective, it is not likely that Canada will be able to draw a great advantage from playing its "security of supply" card. A reasonable assumption is to expect a price equal to the weighted average of the current Japanese C.I.F. prices, since this weighted average already reflects the Japanese need for diversification in this period where more countries are willing to agree to LNG trading.

The weighted average has been calculated at $7.38 (1981 Can.Dol.) per MCF. The data follow:

<table>
<thead>
<tr>
<th>Source</th>
<th>Price</th>
<th>Date</th>
<th>Price (1981 Can.Dol.)</th>
<th>Quantity (MMCF/D)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Abu Dhabi</td>
<td>$5.75</td>
<td>U.S. Sept '80</td>
<td>7.84</td>
<td>240</td>
</tr>
<tr>
<td>Alaska</td>
<td>$4.93</td>
<td>U.S. Aug. '80</td>
<td>8.086</td>
<td>105</td>
</tr>
<tr>
<td>Brunei</td>
<td>$5.21</td>
<td>U.S. Aug. '80</td>
<td>7.104</td>
<td>774</td>
</tr>
<tr>
<td>Indonesia</td>
<td>$5.43</td>
<td>U.S. Aug. '80</td>
<td>7.404</td>
<td>1145</td>
</tr>
</tbody>
</table>
3. The Computer Model

We review the model by looking first at its general functioning. We then look in detail at each section of the model.

a) General Working of the Model

The model works on an annual basis. It is initiated in 1981 and terminated in 2005. The first five years (1981-1985) are construction years and the plant operates for 20 years from 1986 to 2005. All annual revenues and costs are assessed at the end of the year in the current year's dollars.

We need to use current dollars because of our intent to identify the impact of the tax structure, as it applies to an LNG project, on the decision-making in the use of natural gas. In capital intensive projects, the capital cost allowance (CCA) is an important determinant of the tax payments due; the CCA is based on historical costs, so its impact on the tax payments varies with the inflation rate. In the base case, the rate of inflation is pegged at 10% per annum. Dollars of different years are compared using an estimate of the rate of social time preference; the nominal rate of social time preference (STPNOM) is equal to \((1 + \text{real S.T.P.}) \times (1 + \text{rate of inflation})\). The choice of a discount rate is a very contentious issue. In Baumol's words, "few topics in our discipline rival the social rate of discount as a subject exhibiting simultaneously a very considerable degree of knowledge and a very substantial level of ignorance." There exists a considerable degree of knowledge because, "economists
understand thoroughly just what this variable (social rate of discount) should measure: the opportunity cost of postponement of receipt of any benefit yielded by a public investment."

Despite this basic understanding, two fundamentally different approaches to the estimation of the rate of discount have emerged. A first one advocates the use of the social rate of time preference (S.T.P.) while the second proposes the use of the opportunity cost of the capital invested. As Baumol mentions, these two approaches will never yield the same estimate because of the presence of taxes; the S.T.P. is estimated by the after-tax rate of return on investment, while the opportunity cost is usually estimated by the before-tax rate of return.

According to E.J. Mishan, the appropriate approach depends on the public investment to be analysed. Where the public investment is financed from postponed consumption and the money raised can only be used for this specific investment (because of some political or administrative constraints), the S.T.P. is the appropriate approach. The S.T.P. will ensure that the rewards from the public investment will at least compensate the postponed consumption and that the project will go ahead if it more than compensates for this postponed consumption. (Viewed in this way, the S.T.P. approach is only a special case of the opportunity cost approach, which agrees with Baumol's statement that economists understand thoroughly what is to be measured.)
Again according to Mishan, in any cases where the money raised for a public investment could be rechannelled towards the private sector, the appropriate approach is the opportunity cost of capital. This approach ensures that society will at least be compensated for the foregone private investment. There is a hybrid approach consisting of a weighted average of the S.T.P. and the opportunity cost which applies in cases where money is raised for a specific project by reducing consumption and private investment.

We opted for the S.T.P. approach, estimated by the after-tax rate of return on private investment, because of the particular characteristics of the project to be analysed. An LNG project, like the other proposed "energy mega-projects", would proceed in close cooperation with the Government. The S.T.P. is a uniform rate which Government can apply across diverse industries with different degrees of risk and tax rates. The average after-tax rate of return on capital in Canada has been estimated by John P. Helliwell at 7.5% (real).

The calculation of present values, or the actual comparison of different years' dollars, is done in two steps. First we find the total value in dollars of the final year of the project in this way:

\[
\text{total current value} = (\text{total current value at the end of the previous year} \times \text{STPNOM}) + \text{this year's value}
\]

or, \( y = y_{t-1} \times \text{STPNOM} + x \) where \( x \) is the value of \( y \) for the current period.

When the current year is the final year, the total current value is equal to the total value (costs or revenues) in
dollars of that year; second, we take this last year value and divide by a discount factor equal to STPNOM at the power (last year - first year of construction), e.g. 2005-1981. This produces a present value for the stream of revenues or costs (this procedure is also applied to quantities to get a present value in volume for a flow of quantities, either consumed or produced). There are other ways to calculate present values but this one has been chosen and will be used every time a present value is calculated.

b) Specific Working of Each Section

The model can be divided in seven sections: revenues, capital costs, operating costs, natural gas used, taxation, private valuation and social valuation. Each section will be reviewed individually. Of course, the general working rules of the model apply to every section.

i) Revenues

The C.I.F. price of LNG is assumed constant in real terms. It is thus revised annually to increase at the rate of inflation. The plant is assumed to be in operation 340 days a year, operating at full capacity and 100% of the production is sold under contract. The determination of the quantity sold allows for the en-route boil-off. The annual revenues are simply the product of quantity sold and price in dollars of the year. The present value of revenues is calculated.

ii) Capital costs

The cost function estimated in the previous section gives an estimate of the capital costs in 1981 Can.Dol. The
calculation of the actual amount invested starts with this estimate and allows for the construction schedule and inflation. The construction schedule has been fixed as follows:

- **pipeline:** 33% in 1983, 34% in 1984, 33% in 1985
- **plant:** 20% in 1982, 30% in 1983, 40% in 1984
- **ships:** 33% in 1983, 34% in 1984, 33% in 1985

The financing of this investment follows a debt-equity ratio of 60/40 with both debt and equity bearing a real cost of capital of 7.5% per annum. The debt is repaid on equal annual instalments over twenty years.

The economic depreciation, as opposed to the capital cost allowance, follows a straight line over twenty years; in other words, we assume that the capital stock lasts twenty years and is worn out evenly throughout these years.

### iii) Operating costs

The treatment of operating costs is very similar to that of the capital costs. The cost functions produce estimates of annual costs in 1981 Can.Dol. which are then adjusted for inflation to produce the current annual operating costs. It must be noted that only the dollar costs are considered here, which excludes the natural gas used as fuel for the liquefaction plant and the ships; this fuel is treated in quantity terms.
iv) Quantity of natural gas used

We want to determine here how much gas is necessary to generate the figures produced by the model. Since our objective is to figure out the value of B.C. gas in this use, it is essential to be clear as to the quantity of gas used in every case studied. The amount we are looking for can be visualized simply as the quantity of natural gas purchased annually by the operator of the entire project from the B.C. Petroleum Corporation. This amount equals: annual capacity times 1.16, where the annual capacity is as described in the revenues section.

v) Taxation

The plant envisaged here is a "transformation plant" which is not involved with exploration or extraction of natural resources. It is thus taxed like a "normal" manufacturing plant despite its natural resources intensiveness i.e., it is not subject to any kind of direct royalty payment. The taxes for a "normal processing plant" in B.C. are:

13% of taxable income as provincial taxes
36% of taxable income as federal taxes, with the same taxable income in both cases.\(^{45}\)

The taxable income is defined by the following equation:

\[
\begin{align*}
\text{taxable income} &= \text{Revenues} - \text{Capital Cost} - \text{Operating Cost} - \text{Cost of Natural Allowance} - \text{Cost of Debt} - \text{Cost of Natural Gas}.
\end{align*}
\]

Revenues, cost of debt, and operating have been discussed earlier. The capital cost allowance (CCA) is the "taxation
analogue" of the economic depreciation; in general terms, it is an accelerated depreciation allowed for taxation purposes as an investment incentive. Each year, the CCA will be equal to an allowed percentage of a declining balance, starting with the year when the investment is made without regard as to whether or not it is actually operated in that year; the allowed percentage is determined by the nature of the investment with different types of investments being grouped by classes. In the case of the LNG project, I identified five classes which are shown below with their allowed rate:

- pipeline: 6%
- building: 5%
- machinery: 20%
- tank: 10%
- ship: 15%

The total investment has been divided between these classes in the following proportions:

- pipeline: 100% "pipeline"
- liquefaction plant: 20% "storage tanks"
  20% "building"
  60% "machinery"
- ships: 100% "ships".

In calculating the actual tax payment related to the project, the hypothesis is made that the firm has a large taxable income relative to the capital cost allowances derived from investment in the LNG Project. It is most unlikely that a small corporation would go alone in a project of this size requiring an investment of over $1.5 billion (1981 Can.Dol.).
Indeed, it is most likely that at least one large firm, with a large immediate cash-flow, will get involved so that the tax savings will be used as soon as they occur.

The net value of the tax payments is calculated according to the following equation:

\[
\text{net value of tax payments (in present value)} = \text{present value of tax payments} - \text{average tax payments on the amount of capital invested}.
\]

The average tax payments have been estimated for Canada by John F. Helliwell at 3% (real) of the capital invested. This equation accounts for the fact that projects requiring the same amount of capital can produce streams of tax payments having a different present value because of the structure of the capital cost allowances. In this perspective, the present value of the average tax payments is a measure of the opportunity cost, to the government, of the capital invested in LNG projects.

vi) **Private Valuation**

The estimation of the private opportunity cost of the natural gas used as LNG starts with this technical definition of opportunity cost: it is that price for the natural gas that will make the present value of the project equal to zero for the firm. From this definition, we derive the basic equation estimating the private value: \( PV \) of the project = 0, and expand in the following way:

\[
PV (\text{Revenues}) - PV (\text{Cost}) = 0, \text{ or }
\]

\[
PV (\text{Revenues}) - PV (\text{All Cost Except Natural Gas}) = PV (\text{Cost of Natural Gas})
\]

And \( PV (\text{Cost of Natural Gas}) = \sum \frac{Q_p \cdot P_p \cdot \alpha_i}{b^5} + \ldots + \frac{Q_p \cdot P_p \cdot \alpha_i}{b^{24}} \)
where $Q_p$ is the quantity purchased annually, $a$ is the annual rate of increase in the initial Price ($P_p$) and $b$ is the annual rate of discount. (I.E. $b = (1 + STP) \times (1 + \text{inflation})$)

We can isolate $P_p$ from this series and call the remaining part A, so that:

$$P_p = \frac{PV(\text{Revenues}) - PV(\text{Of all cost except Natural Gas})}{A}$$

The detailed final equation, lines 274 to 249 of the computer model, and its elaboration are shown in Appendix 2.

vii) Social Valuation

The equation estimating the social value was derived in a similar way to the equation for the private value. So we can proceed more rapidly in this case, essentially highlighting the differences.

We have $PV(\text{Revenues}) - PV(\text{Social Cost}) = PV(\text{Natural Gas})$ or $PV(\text{Revenues}) - PV(\text{Cap. Cost}) - PV(\text{A.R.G.}) - PV(\text{Op. costs}) = Z$, then,

$$Z = PV(\text{Natural Gas}), \text{ and}$$

$$Z = PV(Q_p \times P_s \times s), \text{ so that}$$

$$PV(\text{Revenues})-PV(\text{Cap.Costs})-PV(\text{A.R.G.})-PV(\text{Op.Costs}) \times \frac{1}{PV(s)^{P_s}} Q_p$$

the social value in 1981 Can.Dol, where

$$PV(s) = \frac{(1+STP)^{20} \times (1+\text{P.I.})^5 - (1+\text{P.I.})^{25}}{(1+STP)^{25} - (1+STP)^{24} \times (1+\text{P.I.})}$$
The social value is thus expressed in a manner similar to the private value. We multiply $P_s$ by 1000 to get a figure in 1981 Can.Dol./MCF. As was mentioned in the introduction this value is of little use by itself but it has a significant potential importance when used in the proper context. It can play the dual role of helping to determine the opportunity cost of B.C. gas, and to estimate the social value of an LNG project given this opportunity cost. We will not turn to the actual calculation of these private and social values ($P_p$ and $P_s$).

III RESULTS

In this section we will present our base case estimates of the social opportunity cost of natural gas used as LNG ($P_s$) and estimates of the private opportunity cost of this natural gas ($P_p$). We will also perform a sensitivity analysis on these estimates with the objective of identifying the relative impact of the different potential sources of variation in the estimates.

1. Private and Social Values

The point estimation of $P_p$ (private opportunity cost) and $P_s$ (social opportunity cost) represent our base case. The essential parameters and their values, determining this base case are listed below;
- annual rate of inflation: 10%
- real rate of increase of \( P_p, P_s \) and the C.I.F. price: 1
  (referred to as the "price inflator")
- cost figures: as estimated by the relevant cost functions
- debt/equity ratio: 60/40

\( P_s \) and \( P_p \) were estimated for four different plant sizes, from the smallest to about the largest envisaged, 250, 500, 750 and 1000 MMCF/D. The results follow;

**Table 4**

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>250</td>
<td>3.751</td>
<td>3.645</td>
</tr>
<tr>
<td>500</td>
<td>4.008</td>
<td>3.908</td>
</tr>
<tr>
<td>750</td>
<td>4.144</td>
<td>4.049</td>
</tr>
<tr>
<td>1000</td>
<td>4.212</td>
<td>4.120</td>
</tr>
</tbody>
</table>

These results can be easily graphed for a continuous approximation: \( P_s, P_p \) (1981 Can.Dol./MCF)

**Figure 2**

Private and Social Opportunity Costs
These results present in a tangible way the economies of scale involved in an LNG project; the private and social values depend significantly on the size of the commitment accepted. On one hand the firm can pay British Columbia Petroleum Corporation up to $0.461 (1981 Can.Dol.) per MCF more if it is willing to commit the capital necessary for a 1000 MMCF/D plant versus a 250 MMCF/D plant. Similarly, society can get up to $0.475 (1981 Can.Dol.) per MCF more for its natural gas if it is ready to commit the quantities of natural gas necessary to feed a 1000 MMCF/D plant versus a 250 MMCF/D plant over 20 years.

This question of commitment has to do with what was presented as the probable strategy of the present proponents of a B.C. LNG plant. It is difficult to accept a capital commitment of an order of magnitude of three to four billion 1981 Can.Dol. when it is known that the initial estimate may easily be wrong by a billion dollars. By the same token, it is difficult for the B.C. government to commit 7,888,000 MMCF of natural gas over 20 years without having a reasonable idea of the opportunity cost of this gas. On the other hand, the cost of a non-commitment must also be considered. Using the graph above and the following table where the quantities involved are calculated it is possible to estimate how much of the value of the natural gas (in 1981 Can.Dol) is lost by operating a smaller plant. An example will illustrate how to make this estimation.
Table 5 Present Value of Quantities Produced

<table>
<thead>
<tr>
<th>Plant Size (MMCF/D)</th>
<th>Present Value of Quantity (MCF)</th>
</tr>
</thead>
<tbody>
<tr>
<td>250</td>
<td>218,375,563</td>
</tr>
<tr>
<td>500</td>
<td>436,750,500</td>
</tr>
<tr>
<td>750</td>
<td>655,126,688</td>
</tr>
<tr>
<td>1000</td>
<td>873,503,063</td>
</tr>
</tbody>
</table>

Example: if we operate two 250 MMCFD plants instead of one 500 MMCFD plant, the value lost will be

\[(\$4.008-\$3.751) \times 436,750,500, \text{(1981 Can.Dol.)}\]

i.e. value of the natural gas with a 500 MMCFD plant minus value with a 250 MMCFD plant (smaller because of the economies of scale) times the present value of the quantity of natural gas involved.

2. Sensitivity Analysis

The sources of variation in the estimates \( P_p \) and \( P_s \) can be grouped into three categories; (1), the C.I.F. price in Japan could be different than the one used in the base case; (2), the actual costs can differ from the estimated costs; and (3), some assumptions for values used in the model (e.g. inflation rate) can turn out to be wrong. The analysis of the effect on \( P_p \) and \( P_s \) of each of these sources of variation constitutes an analysis of the sensitivity of these estimates which helps determine how valuable is a strategy of non-commitment. That is, it will highlight how much we do not know about \( P_p \) and \( P_s \).
a) **C.I.F. Price in Japan**

The initial C.I.F. price and its annual rate of increase are two sources of variation in the estimated private and social values. In the base case, the initial C.I.F. price is $7.38 (1981 Can.Dol./MCF) and its annual rate of increase is equal to the general rate of inflation--10%. This represents our guess of what is going to happen; we do not intend to qualify this forecast here--but simply to measure how a given deviation from this forecast will affect the estimated values of the gas. We first look at the impact of a different initial C.I.F. price. Table 6, which follows, shows the estimated values for different initial prices.

<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>7.00</td>
</tr>
<tr>
<td>250</td>
<td>3.334</td>
</tr>
<tr>
<td>500</td>
<td>3.597</td>
</tr>
<tr>
<td>750</td>
<td>3.738</td>
</tr>
<tr>
<td>1000</td>
<td>3.809</td>
</tr>
</tbody>
</table>
The regularity of the figures, which is to be expected allows us to capture the impact of the initial C.I.F. price in a simple rule; for each deviation from the base case of $0.01 (1981Can.Dol.) the estimated values will be off by about 0.82%. This means that if, for example, B.C. only gets the lowest price paid currently by Japan for LNG($7.10/MCF) the estimated values of $p$ and $ps$ are about 23% too high, i.e. the actual $p$ and $ps$ are about 7% smaller.

With a project covering such a long period as 25 years it is easy to imagine how important the rate of increase in the C.I.F. price is. In fact the issue of the annual rate of increase on agreed prices for LNG has been the subject of numerous conflicts around the world in recent years - and the escalation systems in place vary widely. To measure the impact of this source of variation, we calculated the effect of a real growth in the C.I.F. price on values of $p$ and $ps$ constant in real terms. This way our basis for comparison is the same as in all other cases. The results are shown below for a 250 MMCF/D plant;

<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>7.00</td>
</tr>
<tr>
<td>250</td>
<td>3.440</td>
</tr>
<tr>
<td>500</td>
<td>3.697</td>
</tr>
<tr>
<td>750</td>
<td>3.832</td>
</tr>
<tr>
<td>1000</td>
<td>3.901</td>
</tr>
</tbody>
</table>
Table 7

Sensitivity of $P_p$ and $P_s$ to the assumed real rate of growth of the C.I.F. price

<table>
<thead>
<tr>
<th>Real Rate of Growth of C.I.F. Price</th>
<th>1.0</th>
<th>1.02</th>
<th>1.05</th>
</tr>
</thead>
<tbody>
<tr>
<td>$P_p$</td>
<td>3.751</td>
<td>5.445</td>
<td>8.962</td>
</tr>
</tbody>
</table>

We can see that the impact is indeed very important but it must be remembered that this table assumes a constant real value for B.C.'s gas. In other words, if we assume that the social value of B.C.'s gas should grow at 2% real per annum (because of increased scarcity or whatever), then the figures "3.751" and "3.645" for $P_p$ and $P_s$ will be associated with a 2% annual increase in the real C.I.F. price of LNG ("1.02" in the above table) and the other figures will be different. Since the measurement of the impact of the rate of growth of the C.I.F. price involves directly the question of the rate of growth of the value of B.C.'s gas in alternate uses - an issue beyond the scope of this paper - it is not discussed further. However, the above calculations illustrate the magnitude of growth in the opportunity cost of B.C. natural gas.
b) Variation of the Cost Estimates

i) Capital Costs

It was mentioned before that the capital costs are a large unknown in the study of the desirability of an LNG plant in B.C. This section examines how $P_p$ and $P_s$ vary with variations in the capital costs.

Table 8, below, shows the results of different simulations using multiples of the estimated capital costs of the base case.

**Table 8**

Sensitivity of Private and Social Opportunity Costs to Changes in Assumed Capital Costs

**Estimated Social Value (1981 Can.Dol./MCF)**

<table>
<thead>
<tr>
<th>Plant Size (MMCFD)</th>
<th>Multiples of the Estimated Capital Costs</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>0.5</td>
</tr>
<tr>
<td>250</td>
<td>4.590</td>
</tr>
<tr>
<td>500</td>
<td>4.737</td>
</tr>
<tr>
<td>750</td>
<td>4.814</td>
</tr>
<tr>
<td>1000</td>
<td>4.853</td>
</tr>
</tbody>
</table>

**Estimated Private Value (1981 Can.Dol./MCF)**

<table>
<thead>
<tr>
<th>Plant Size (MMCFD)</th>
<th>Multiples of the Estimated Capital Costs</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>0.5</td>
</tr>
<tr>
<td>500</td>
<td>4.787</td>
</tr>
<tr>
<td>750</td>
<td>4.681</td>
</tr>
<tr>
<td>1000</td>
<td>4.899</td>
</tr>
</tbody>
</table>
In dealing with the capital costs, we lose the regularity that allowed the definition of a simple rule in the case of the C.I.F. price because of economies of scale and taxation factors. Some element of regularity remains however. For a given plant size, the impact of a variation in the capital cost is a constant proportion but different between the social and private values. We can summarize the impact in a table 9.

This table shows the variation of the estimated value, in 1981 Can.Dol./MCF, associated with a deviation from the estimated cost of 1% (the impact will be in the opposite direction from the deviation).

Table 9
Effect of a Variation of 1% in the Assumed Capital Cost on \( P_p \) and \( P_s \)

<table>
<thead>
<tr>
<th>Plant Size (MMCF/D)</th>
<th>( P_p ) Variation From ( P_p )</th>
<th>( P_s ) Variation From ( P_s )</th>
</tr>
</thead>
<tbody>
<tr>
<td>250</td>
<td>0.0178 (.5%)</td>
<td>0.0189 (.5%)</td>
</tr>
<tr>
<td>500</td>
<td>0.0156 (.4%)</td>
<td>0.0166 (.4%)</td>
</tr>
<tr>
<td>750</td>
<td>0.0143 (.35%)</td>
<td>0.0153 (.37%)</td>
</tr>
<tr>
<td>1000</td>
<td>0.0137 (.32%)</td>
<td>0.01466 (.35%)</td>
</tr>
</tbody>
</table>

We can see that the impact of a given variation in the assumed capital costs is smaller the larger the plant and is smaller for the \( P_p \) because part of the total impact is passed on to the government through taxes. Despite the non-uniformity of the impact, we can summarize it roughly in this way:
each 10% of deviation between the actual and estimated capital costs will result in a deviation from $P_p$ and $P_s$ of about 15.5¢/MCF (or about 4%). This value of 15.5¢ is only a rough index of the order of magnitude involved and the reader should refer to the table above for more precise measures of the impact of variations in the capital costs.

ii) Operating costs

Table 10, below, shows the estimated private and social values for different multiples of the base case level of operating costs.

<table>
<thead>
<tr>
<th>Plant Size (MMCF/D)</th>
<th>Estimated Social Value</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Multiples of the Estimated Operating Costs</td>
</tr>
<tr>
<td></td>
<td>0.5</td>
</tr>
<tr>
<td>250</td>
<td>3.899</td>
</tr>
<tr>
<td>500</td>
<td>4.147</td>
</tr>
<tr>
<td>750</td>
<td>4.282</td>
</tr>
<tr>
<td>1000</td>
<td>4.350</td>
</tr>
</tbody>
</table>
Estimated Private Value (1981 Can.Dol./MCF)

<table>
<thead>
<tr>
<th>Plant Size (MMCFD)</th>
<th>Multiples of the Estimated Operating Costs</th>
<th>0.5</th>
<th>1.0</th>
<th>2.0</th>
</tr>
</thead>
<tbody>
<tr>
<td>250</td>
<td></td>
<td>4.006</td>
<td>3.751</td>
<td>3.242</td>
</tr>
<tr>
<td>500</td>
<td></td>
<td>4.247</td>
<td>4.008</td>
<td>3.530</td>
</tr>
<tr>
<td>750</td>
<td></td>
<td>4.376</td>
<td>4.144</td>
<td>3.678</td>
</tr>
<tr>
<td>1000</td>
<td></td>
<td>4.442</td>
<td>4.212</td>
<td>3.753</td>
</tr>
</tbody>
</table>

Economies of scale are present in the operating costs so that again the impact varies with the size of the plant. There is no wedge created by the tax structure, i.e. no CCA equivalent for the operating costs, hence the impact of a variation in the operating costs is the same on the private and social values. The table below (11) measures this impact, for the different plant sizes in 1981 Can.Dol./MCF variations associated with a variation of 1% of the operating costs from the base case estimate (again in opposite directions).

Table 11
Effect of a Variation of 1% in the Assumed Operating Costs on $P_p$ and $P_s$

<table>
<thead>
<tr>
<th>Plant Size (MMCF/D)</th>
<th>Variation</th>
</tr>
</thead>
<tbody>
<tr>
<td>250</td>
<td>0.00509 (.13%)</td>
</tr>
<tr>
<td>500</td>
<td>0.00478 (.12%)</td>
</tr>
<tr>
<td>750</td>
<td>0.00465 (.11%)</td>
</tr>
<tr>
<td>1000</td>
<td>0.00459 (.10%)</td>
</tr>
</tbody>
</table>

To get an idea of the order of magnitude involved, we can
refer to the simple rule that follows: for each deviation of the operating costs of 10% from the base case estimate, the private and social values will vary by about 4.8¢/MCF (or about 1.2%) in the opposite direction.

c) Variation in the Assumed Values of the Parameters

The heading of this section well represents the type of sources of variation involved here. We can have the correct estimate for the C.I.F. price and the costs and still find our estimated values differing from the actual values because some assumptions of values turn out to be wrong. A model is a simplified representation of reality; it is possible that our model represents a scenario different from what would actually happen; we will measure here the impact of this source of variation. There are four assumptions that need to be analysed here: the rate of inflation, the debt-equity ratio, the CCA, and the investment schedule. The table below shows the results with different general rates of inflation (plant size equals 500 MMCF/D).

<table>
<thead>
<tr>
<th>Rate of Inflation (% per annum)</th>
<th>8%</th>
<th>10%</th>
<th>12%</th>
<th>14%</th>
</tr>
</thead>
<tbody>
<tr>
<td>4.045</td>
<td>4.008</td>
<td>3.971</td>
<td>3.933</td>
<td></td>
</tr>
<tr>
<td>3.924</td>
<td>3.908</td>
<td>3.891</td>
<td>3.872</td>
<td></td>
</tr>
</tbody>
</table>

(1981 Can. Dol./MCF)
The impact differs between the private and social values because of taxation (CCA) but is uniform for both. We can expect the impact to vary with the size of the plant but we still can summarise it in a simple rule for easy reference; for each 1% of variation in the rate of inflation from the base case 10%, the estimated private value will vary by about 2¢/MCF and the estimated social value will vary by about .8¢/MCF, both in the opposite direction.

The corporate organization of the project can also be different from that modelled. Two such sources of difference are: the debt-equity ratio and the CCA. The impact of this source of variation is limited to the private value of the natural gas since the corporate organization simply determines the sharing of social costs between the firm and the government and not the magnitude of these social costs; the sharing of costs is in fact done through taxation. The impact of the CCA is measured below.

<table>
<thead>
<tr>
<th>Multiples of the Estimated CCA</th>
<th>0.8</th>
<th>1.0</th>
<th>1.2</th>
</tr>
</thead>
<tbody>
<tr>
<td>$P_p$</td>
<td>3.881</td>
<td>4.008</td>
<td>4.135</td>
</tr>
<tr>
<td>$P_s$</td>
<td>3.908</td>
<td>3.908</td>
<td>3.908</td>
</tr>
</tbody>
</table>

The private value becomes smaller than the social value when the actual tax payments become larger than they are on
average for a capital investment of this size. The impact of variations in the CCA is uniform for a given plant size and is equal to about $6.5\sigma$/MCF for each 10% of variation in the CCA. A 10% variation in the present value of the CCA can be brought about by a number of changes in the classification of the total investment where a slower allowed depreciation will mean a lower CCA. For instance, if storage tanks for LNG were allowed a CCA of 5% as opposed to the 10% allowed for a "conventional" storage tank (water or fuel), the present value of the CCA would decrease. Such a situation could arise because there are no base-load LNG plants in Canada. The classification decision has yet to be formally made by the government officials.

The debt-equity ratio has been set at 60/40 for the base case. But, we could find that the type of firms interested in this type of project are much less risky than anticipated because of their diversification. A higher debt-equity ratio of 75/25 was tested and the results are shown below.

Table 14

Sensitivity of $P_p$ and $P_s$ to the Assumed Debt/Equity Ratio

<table>
<thead>
<tr>
<th></th>
<th>250</th>
<th>500</th>
<th>750</th>
<th>1000</th>
</tr>
</thead>
<tbody>
<tr>
<td>$P_p$</td>
<td>3.938</td>
<td>4.171</td>
<td>4.294</td>
<td>4.356</td>
</tr>
<tr>
<td>$P_s$</td>
<td>3.645</td>
<td>3.908</td>
<td>4.049</td>
<td>4.12</td>
</tr>
<tr>
<td>$P_p (60/40)$</td>
<td>3.751</td>
<td>4.008</td>
<td>4.144</td>
<td>4.212</td>
</tr>
</tbody>
</table>

The impact of a different debt-equity ratio can be estimated roughly at $.6\sigma$/MCF for each 1% increase in the proportion
of debt, which means that it would take a decrease of about 15% (from the base case) in the proportion of debt to make the private value roughly equal to the social value.

IV CONCLUSION

The social value of B.C.'s natural gas used as LNG for exports to Japan was estimated at between $3.645 and $4.12 1981 Can.Dol./MCF, depending on the plant size. To put this estimate in perspective, we can compare it to the similar value for the gas exported by pipeline to the U.S. The border price of this gas is $5.38/MCF and the total cost of the pipeline transportation is about $0.70/MCF which leaves a value of about $4.68 1981 Can.Dol./MCF at the input-end of the pipeline. But this value of $4.68/MCF is not necessarily a guide to the future social value of B.C.'s natural gas. For one thing, we need to know if we can sell more to the U.S. than we are selling now and at what price, secondly, the values of $3.645 to $4.12/MCF are simply point estimates and not the social values of B.C.'s gas used as LNG. Being interested in the social value of B.C.'s gas used as LNG, we expanded these point estimates through a sensitivity analysis where we measured the impact of different sources of variation. The importance of the sensitivity analysis can be illustrated with the following example relating to the figures above: if the C.I.F. price of LNG turns out to be 50¢/MCF higher than in the base case i.e., $7.88 or 21¢ lower than the highest price paid by Japan for LNG, and the actual capital costs turn out to be 10% less than estimated,
the netback of a 1000 MMCF/D LNG plant would be about $4,675 1981 Can.Dol./MCF or about the same as the netback from exports to the U.S.

To talk seriously about the social value of B.C.'s gas used as LNG we must include an identification of the different sources of variation of the point estimate and a measure of the impact of these sources of variation. The sensitivity analysis revealed that the C.I.F. price and the capital costs are, as should have been expected, the most important sources of variation in terms of impact. This study stopped at the measurement of these impact. The next step would be to analyse individually each of these sources of variation, with more emphasis on those with the more significant impacts, and come up with some sort of probability distribution of possible states.

We must not be fooled by the fact that the estimated private and social values are very close and let the firms make the decision as to whether or not to go ahead assuming that because of the similarity of these values, what will be good for the firm will be good for society. We must remember the decision rule of the firm: the firm will go ahead only if the private opportunity cost of the natural gas used as LNG is greater than the private opportunity cost in any other use and greater than the private cost of supplying natural gas. The fact that the private opportunity cost in use as LNG is close to the social opportunity cost in this use does not say anything about the relation between
the opportunity cost in other uses and the social opportunity cost in these uses. We can trust the private firm to make the best decision in terms of social welfare only if the tax system does not alter the ranking of the different opportunity costs in use and if the private cost of supplying natural gas is made equal to the social cost. These conditions go far beyond a similarity between the private and social opportunity cost in use as LNG.
Footnotes

4. loc. cit.
5. April 22nd, 1981, Section C, page 1
6. Carter Oil and Gas Limited (1979)
7. The Province, April 22nd, 1981, Section C, page 1
8. J. Segal (1980), pp. 515-516
9. Between Prince George and Prince Rupert a new pipeline will definitely be required as the availability on the existing Northern Gas Pipeline is limited to an additional 40 MMCF/D. Between Fort St. John and Prince George, a new pipeline would not be necessary if natural gas destined for the LNG plant displaces natural gas destined to the U.S.; but our statement about the need for a new pipeline over the entire distance between Fort St. John and Prince Rupert remains valid if we equate the opportunity cost of the pipeline capacity taken away from the U.S. exports to the cost of a new pipeline - which can not be completely wrong.
10. All cost figures are transformed into 1981 Can.Dol. by using a 10% a year inflation rate and a 1.2 Can.Dol/U.S. Dol. exchange rate. 10% is used because we judged that no existing index could predict well the cost escalation of an LNG project in B.C. In this context, the cost escalation was set equal to the general rate of inflation.
11. Carter Oil and Gas Limited (1979)
12. Ibid
13 Office of Technology Assessment, Congress of The United States
14 To find the value of natural gas we will use this type of formula:

\[
\frac{PV(\text{revenues}) - PV(\text{all costs except natural gas})}{PV(\text{quantity of natural gas purchased})} = \text{Value of nat. gas}
\]
16. Carter Oil and Gas Limited (1979)
17. Ibid
18. P.J. Anderson and E.J. Daniels (1977)
19. See for example, Alternative Energy Futures p.81
20. Carter Oil and Gas Limited (1979)
23. Ibid, p.16
24. For example, A.H. Schwendtner (1977) p.54
25. It takes 28.4 days for a round trip of 10,150 nautical miles between Arzew (Algeria) and La Salle (U.S.A.). (Alternative Energy Futures, p. 83). The return distance between Prince Rupert and Tokyo is about 8800 nautical miles. A ship operates about 330 days per year.
26. Vedeler (1981) p.88 or J. Segal (1980) p. 376. Some LNG must be kept in the tanks of the ships at all times to keep those tanks cold, so the 5% applies to the return trip.
27. Office of Technology Assessment, Congress of the U.S., p.85
28. BTU parity assumes that oil and gas are valued according to their BTU content. This is the opposite of what we observe in reality. The crude oil buyer is usually interested in light-end yields (which have low BTU content) while the gas buyer is interested in the BTU content. This situation arises from the fact that oil and gas are essentially used for different purposes.
31. Ibid, p.377
32. Abu Dhabi, Brunei, Indonesia and U.S.A.
33. Chile, Malaysia, Australia, Sumatra and Kalimatan
34. J. Segal and F.E. Niering (1980) p.375

36. loc. cit.

37. loc. cit.

38. The variability of the prices is misleading because in fact only Brunei and Indonesia represent major projects and we can be fairly sure that the Japanese are paying, in these instances, what they are really ready to pay for LNG. (The project with the U.S.A. expires in 1984 while the one with Abu Dhabi has been caught in the "BTU parity" dispute).

39. W.J. Baumol (1968) p.788

40. Ibid p.788

41. E.J. Mishan (1973)

42. loc. cit.

43. There is assumed to be only one general rate of inflation -- 10%.

44. Based on the flow presented in Carter's projections. Carter Oil and Gas Ltd. Prefeasibility Study.

45. Most of the information in this section comes from Price Waterhouse (1976)

46. From Commerce Clearing House Canadian Limited (1980)

47. J.F. Helliwell, Impact of a Mackenzie Pipeline on the National Economy.

48. The amount of natural gas necessary to feed a 1000 MMCF/D plant.

BIBLIOGRAPHY


McCUNE, Shane, "Gas-for-Japan Race Heating Up", The Province, Section C, p. 1, Wednesday April 22nd, 1981


SCHWENDTNER, A.H. "LNG Transportation Costs", Pipeline and Gas Journal, August, 1977, p.52 Vol.204, No. 32


Overall Check of the Cost Estimates

The cost estimates come from many different sources and one can not be sure that estimates are on a comparable basis. This could make one suspicious of the validity of the overall picture created. To eliminate these doubts an "overall check" on the cost estimates was carried out. An "overall check" is a comparison between the total cost per MCF implied by our cost estimates and various figures for total cost taken from the literature ¹ - cost per MCF is a standard way of presenting costs in the trade literature.

In the table below, I present my total cost estimate per MCF, as implied by the cost estimates of section B-2, and the reference figures (all in 1981 Can.Dol.):

<table>
<thead>
<tr>
<th></th>
<th>Estimate</th>
<th>Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pipeline</td>
<td>0.638 to 0.87</td>
<td>0.2572 to 0.5145²</td>
</tr>
<tr>
<td>Liquification</td>
<td>1.307 to 1.733</td>
<td>1.452 to 1.848³</td>
</tr>
<tr>
<td>Shipping</td>
<td>1.522</td>
<td>1.83⁴</td>
</tr>
</tbody>
</table>

¹ These figures can only be used for such rough comparison purposes because the way they are obtained is usually not mentioned e.g. implied discount rate, depreciation rate is not known.
² Uhl, A.E., and J.M. Giese, p.42
³ Special Report, Segal, p.377
⁴ Special Report, p.376. The estimate used is the current cost adjusted for inflation because I do not believe that the new ships will be much more expensive given the prevailing market conditions.
My cost figures for the pipeline are significantly higher than the reference figures but I can feel comfortable with that; as I mentioned in discussing pipeline costs, capital costs are overwhelmingly important here and it should be expected that the capital costs for the B.C. LNG project's pipeline will be higher than "normal" because of the ruggedness of the terrain. In fact, if I adjust the reference range to account for the ruggedness of the terrain, I get a reference range of $0.47 to $0.9404 (1981 Can.Dol./MCF) which covers entirely my estimates. Furthermore, the economies of scale factor is similar to that of the reference - about 24¢/MCF between 290 and 1160 MMCF/D.

My liquefaction cost estimates are uniformly low by about 10%; but, my base case estimates should be taken with an accuracy of plus or minus 20% - because the basic information is quoted this way - so this result is acceptable.

The shipping estimate is about 15% lower. But, the market for LNG tankers is very soft and there is no market price but only individually negotiated prices that account for heavy Import-Export Banks support. In fact, 15% on $225MM (1981 Can. Dol.) is about $34MM(1981 Can.Dol.) and one of our sources actually quotes a range of over $40MM (1981 Can.Dol.) in the price of LNG tankers.

These overall checks thus should satisfy the reader that the preferred estimates, composing the input in the base case, create a reasonable picture of the actual costs to be expected if this kind of project goes ahead.

APPENDIX 2

Elaboration of the equation determining the private value.

We start with:

$$PV(REVENUES) - PV(COSTS) = 0$$
or,

$$PV(REVENUES) - PV(CAP.COSTS) - PV(OP.COSTS) - PV(NAT.GAS) - PV(TAXES) = 0$$

where, \( PV(TAXES) = 0.49 \times PV(REVENUES - OP.COSTS - DEBT COSTS - CCA - NAT.GAS) \)
so that, \( 0.51 \times PV(NAT.GAS) + 0.49 \times PV(DEBT COSTS) + 0.49 \times PV(CCA) = 0 \)
or, \( 0.51 \times PV(REVENUES) - PV(CAP.COSTS) - 0.51 \times PV(OP.COSTS) + 0.49 \times PV(DEBT COSTS) + 0.49 \times PV(CCA) = 0.51 \times PV(NAT.GAS) \).

To further modify this last equation we need to better define our objective; we are looking for a price \( P^p \) defined in 1981 Can.Dol. which, while increasing at a given % per annum, will produce the flow of annual disbursements by the firm for natural gas purchases that will satisfy the equation above. We will call the left-hand side of the above equation \( L \),

\[
L = 0.51 \times PV(REVENUES) - PV(CAP.COSTS) - 0.51 \times PV(OP.COSTS) + 0.49 \times PV(DEBT COSTS) + 0.49 \times PV(CCA)
\]

We thus have

\[
L = 0.51 \times PV(NAT.GAS)
\]
or, \( L = 0.51 \times PV(Q_p \times P^p \times s) \), where \( Q_p \) is the quantity of natural gas purchased annually and "s" is a series element that transforms \( P^p \) into the current price of natural gas.

We are looking for \( P^p \):

\[
L = 0.51 \times Q_p \times P^p \times PV(s)
\]
and

\[
P^p = \frac{L}{0.51 \times Q_p \times PV(s)} \times \frac{1}{PV(s)}
\]
where \( PV(s) = \frac{(1+STP)^{20} * (1+P.I.)^5 - (1+P.I.)^{25}}{(1+STP)^{25} - (1+STP)^{24} * (1+P.I.)} \)

STP = real rate of social time preference

\( P.I. \) (price inflator)\(^1\) = rate of inflation of the price of nat.gas

general rate of inflation (10%)

In the actual computer model, the units are millions of dollars (MM$) and millions of cubic feet so that the \( P \) calculated is expressed in 1981MM$ per MMCF, hence multiplied by 1000 to get a figure in 1981 Canadian dollars per MCF.

The equation of lines 274-279 in the computer model thus produces a price that can be easily compared with similar prices for other uses because it is expressed in standard units ($/MCF) and furthermore, it is expressed in 1981$.

---

1. In the base case P.I. is equal to one.
APPENDIX 3

The computer model

Identification of the Parameters

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>A(1)</td>
<td>Capacity in MMCFD</td>
</tr>
<tr>
<td>A(40)</td>
<td>Quantity of natural gas, in MCF, necessary to produce one MCF of LNG</td>
</tr>
<tr>
<td>A(41)</td>
<td>Percentage of the amount of natural gas bought that is used as feedstock</td>
</tr>
<tr>
<td>A(42)</td>
<td>Percentage of the amount of natural gas bought that is used as fuel for the liquefaction plant</td>
</tr>
<tr>
<td>A(43)</td>
<td>Percentage of the amount of natural gas bought that is used as fuel for the ships</td>
</tr>
<tr>
<td>A(44)</td>
<td>Social value of B.C.'s natural gas</td>
</tr>
<tr>
<td>A(50)</td>
<td>Price of the natural gas used as feedstock ($/MCF)</td>
</tr>
<tr>
<td>A(51)</td>
<td>Price of the natural gas used as fuel ($/MCF)</td>
</tr>
<tr>
<td>A(52)</td>
<td>C.i.F. price in Japan ($/MCF)</td>
</tr>
<tr>
<td>A(59)</td>
<td>Price inflator for the C.i.F. price in Japan</td>
</tr>
<tr>
<td>A(66)</td>
<td>Adjustment factor for the total capital cost of the pipeline (for sensitivity analysis)</td>
</tr>
<tr>
<td>A(67)</td>
<td>Adjustment factor for the total capital cost of the liquefaction plant (for sensitivity analysis)</td>
</tr>
<tr>
<td>A(68)</td>
<td>Adjustment factor for the total capital cost of the ships (for sensitivity analysis)</td>
</tr>
<tr>
<td>A(85)</td>
<td>(1-CCA) for pipelines</td>
</tr>
<tr>
<td>A(86)</td>
<td>(1-CCA) for ships</td>
</tr>
<tr>
<td>A(87)</td>
<td>(1-CCA) for storage tanks</td>
</tr>
<tr>
<td>A(88)</td>
<td>(1-CCA) for buildings</td>
</tr>
<tr>
<td>A(94)</td>
<td>1 plus the real rate of social time preference</td>
</tr>
<tr>
<td>A(100)</td>
<td>Number of days of production per year</td>
</tr>
<tr>
<td>A(101)</td>
<td>Capital cost of a 125,000 m³ LNG tanker (in MM '81C$)</td>
</tr>
</tbody>
</table>
A(102) Capital cost of one mile of pipeline per MMCFD of capacity, if capacity is smaller than 290 MMCFD (in MM '81C$)

A(103) Capital cost of one mile of pipeline per MMCFD for that portion of the capacity (in MMCFD) that is greater than 290 and smaller than 580 (in MM '81C$)

A(104) Capital cost of one mile of pipeline per MMCFD for that portion of the capacity (in MMCFD) that is greater than 580 (in MM '81C$)

A(105) Proportion of the total investment in the liquefaction plant spent in 1982

A(106) Proportion of the total investment in the liquefaction plant spent in 1983

A(107) Proportion of the total investment in the liquefaction plant spent in 1984

A(108) Proportion of the total investment in the liquefaction plant spent in 1985

A(109) Proportion of the total investment in the pipeline spent in 1983

A(110) Proportion of the total investment in the pipeline spent in 1984

A(117) (1-CCA) for machinery (equipment)

A(121) Proportion of the total investment in the pipeline spent in 1985

A(122) Proportion of the total investment in the ships spent in 1983

A(123) Proportion of the total investment in the ships spent in 1984

A(124) Proportion of the total investment in the ships spent in 1985

A(125) Percentage of the total capital cost of the liquefaction plant that goes for storage tanks

A(126) Percentage of the total capital cost of the liquefaction plant that goes for buildings

A(127) Percentage of the total capital cost of the liquefaction plant that goes for machinery (equipment)

A(132) Proportion of the total capital in the form of debt
A(168) Percentage of the production that is sold (the remaining part boils off during the trip)

A(169) Price inflator for the natural gas used as feedstock or fuel

A(173) 1 plus the general rate of inflation
SUBROUTINE SOLUI

C LNG MODEL
C
COMMON/KEEP/LABX(2,800),LARE(2,600),DATE(100),DUM(30),TEST(800),
1 TITLE(20),Z(800),TEMP(800),A(3000),X(7,800)
C
COMMON/SAVE/K,K1,K7,M,NED,NEX,NT,NL,NC,NDRR
EG,
1 INDRESHK,M7,M8,MAX,NCONTR,NCONV,NSKIP,FPOL,XYEAR,NREVA,NRIA
2 NCONV6,N2,NN,NUMSX,NUMSE
3 COMMON/LLL/L1,L2,L3,L4,L5,L6,L7
4 COMMON/SAVE/K,K1,K7,M,NED,NEX,NT,NL,NC,NDRR
EG,
1 COMMON/SAVE/K,K1,K7,M,NED,NEX,NT,NL,NC,NDRR
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1 COMMON/SAVE/K,K1,K7,M,NED,NEX,NT,NL,NC,NDRR
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EG,
1 COMMON/SAVE/K,K1,K7,M,NED,NEX,NT,NL,NC,NDRR
EG,
1 COMMON/SAVE/K,K1,K7,M,NED,NEX,NT,NL,NC,NDRR
EG,
1 COMMON/SAVE/K,K1,K7,M,NED,NEX,NT,NL,NC,NDRR
EG,
1 COMMON/SAVE/K,K1,K7,M,NED,NEX,NT,NL,NC,NDRR
EG,
1 COMMON/SAVE/K,K1,K7,M,NED,NEX,NT,NL,NC,NDRR
EG,
1 COMMON/SAVE/K,K1,K7,M,NED,NEX,NT,NL,NC,NDRR
EG,
C PRESENT VALUE OF THE CUMULATIVE PROD.
IF(K7.EQ.NYEAR) Y(4)=Z(4)/Z(99)

C PRICE OF LNG
A(3)=A(52)/1000
IF(NTIME.EQ.NSTAR1-5) Y(5)=A(3)
IF(NTIME.GT.NSTAR1-5) Y(5)=X(L1,5)*A(173)*A(59)

C ANNUAL GROSS INCOME
Y(6)=E(K,1)*Z(3)*Z(5)

C PRESENT VALUE OF REVENUES
Y(8)=X(L1,8)*STPNDM+Z(7)
IF (K7.EQ.NYEAR) Y(8)=Z(8)/Z(99)

C PRESENT VALUE OF REV. PER MCF
IF (NTIME.LT.NSTAR1) Y(9)=0
IF (NTIME.GE.NSTAR1) Y(9)=(Z(8)/Z(4))*1000

C CAP. COST PIPELINE
Y(12)=1.16*Z(1)
IF(Y(12).LT.290.0) Y(13)=500*(Z(12)*A(102))
IF(Y(12).GE.290.0.AND.Y(12).LT.580.00) Y(13)=500*(1.4036000+((Z(12)-290.0)*A(104)))
IF(Y(12).GE.580.0) Y(13)=500*(1.4036000+((Z(12)-580.0)*A(104)))

C CAP. COST LIQUE. PLANT
Y(15)=1.768*Z(1)
IF(Y(1).GE.250.0.AND.Y(1).LT.500.0) Y(15)=42.+(Z(1)-250.0)*0.996)
IF(Y(1).GE.500.0) Y(15)=691.+(Z(1)-500.0)*0.6620)

C CAP COST SHIPS
Y(19)=(Z(2)/36430.0)*A(101)
Y(20)=Z(19)*A(68)

C TOT CAP COSTS
Y(21)=Z(14)+Z(16)+Z(20)

C INV. IN PIPELINE
IF(NTIME.EQ.NSTAR1-5) Y(24)=0
IF(NTIME.EQ.NSTAR1-4) Y(24)=0
IF(NTIME.EQ.NSTAR1-3) Y(24)=Z(14)*A(109)*A(173)**3
IF(NTIME.EQ.NSTAR1-2) Y(24)=Z(14)*A(110)*A(173)**4
IF(NTIME.EQ.NSTAR1-1) Y(24)=Z(14)*A(121)*A(173)**5

C INV. IN LIQUE. PLANT
IF(NTIME.EQ.NSTAR1-5) Y(25)=0
IF(NTIME.EQ.NSTAR1-4) Y(25)=Z(16)*A(105)*A(173)**2
IF(NTIME.EQ.NSTAR1-3) Y(25)=Z(16)*A(106)*A(173)**3
87 IF(NTIME.EQ.NSTAR1-2) Y(25)=Z(16)*A(107)*A(173)**4
88 IF(NTIME.EQ.NSTAR1-1) Y(25)=Z(16)*A(108)*A(173)**5
89 IF(NTIME.EQ.NSTAR1) Y(25)=0
90 IF(NTIME.GT.NSTAR1) Y(25)=0
91 C INV. IN SHIPS
92 IF(NTIME.EQ.NSTAR1-5) Y(26)=0
93 IF(NTIME.EQ.NSTAR1-4) Y(26)=0
94 IF(NTIME.EQ.NSTAR1-3) Y(26)=Z(20)*A(122)*A(173)**3
95 IF(NTIME.EQ.NSTAR1-2) Y(26)=Z(20)*A(123)*A(173)**4
96 IF(NTIME.EQ.NSTAR1-1) Y(26)=Z(20)*A(124)*A(173)**5
97 IF(NTIME.EQ.NSTAR1) Y(26)=0
98 IF(NTIME.GT.NSTAR1) Y(26)=0
99 C TOT INV IN CURRENT $
100 Y(27)=(Z(24)+Z(25)+Z(26))
101 C CUMULATIVE INVESTMENT
102 IF(NTIME.EQ.NSTAR1-5) Y(28)=0
103 IF(NTIME.GT.NSTAR1-5) Y(28)=X(L1,28)+Z(27)
104 C PRESENT VALUE OF THE INVESTMENT
105 Y(29)=X(L1,29)*STPNOM+Z(27)
106 IF(K7.EQ.NYEAR) Y(29)=Z(29)/Z(99)
107 C ECONOMICALLY UNDEPRECIATED CAPITAL
108 IF(NTIME.LT.NSTAR1) Y(30)=Z(28)
109 IF(NTIME.GE.NSTAR1) Y(30)=X(L1,30)-.05*Z(28)
110 C PRESENT VALUE OF DEPRECIATION(ECONOMIC)
111 Y(31)=E(K,1)*.05*Z(28)
112 Y(32)=X(L1,32)*STPNOM+Z(31)
113 IF(K7.EQ.NYEAR) Y(32)=Z(32)/Z(99)
114 C CUMULATIVE INVESTMENT PIPELINE
115 IF(NTIME.EQ.NSTAR1-5) Y(34)=0
116 IF(NTIME.GT.NSTAR1-5) Y(34)=X(L1,34)+Z(24)
117 C NON-DEPRECIATED CAPITAL(ECON) PIP.
118 IF(NTIME.LT.NSTAR1) Y(35)=Z(34)
119 IF(NTIME.GE.NSTAR1) Y(35)=X(L1,35)-.05*Z(34)
120 C CUMULATIVE INVESTMENT LIQUE. PLANT
121 IF(NTIME.EQ.NSTAR1-5) Y(36)=0
122 IF(NTIME.GT.NSTAR1-5) Y(36)=X(L1,36)+Z(25)
123 C NON-DEPRECIATED CAPITAL(ECON) L.P.
124 IF(NTIME.LT.NSTAR1) Y(37)=Z(36)
125 IF(NTIME.GE.NSTAR1) Y(37)=X(L1,37)-.05*Z(36)
126 C CUMULATIVE INVESTMENT SHIPS
127 IF(NTIME.EQ.NSTAR1-5) Y(38)=0
128 IF(NTIME.GT.NSTAR1-5) Y(38)=X(L1,38)+Z(26)
C NON-DEPRECIATED CAPITAL (ECON) SHIPS
129 IF(NTIME.LT.NSTAR1) Y(39)=Z(38)
130 IF(NTIME.GE.NSTAR1) Y(39)=X(L1,39)-.05*Z(38)
131
C OP. COST LIQUE.
132 IF(Y(1).LT.250.0) Y(40)=Z(1)*.06292*E(K,1)
133 IF(Y(1).GE.250.0.AND.Y(1).LT.500.0) Y(40)=25.410+
134 5.73+((Z(1)-500.0)*.03542)*E(K,1)
135 Y(41)=Z(40)*A(60)
136 C OPERATING COSTS ESCALATED (FOR INFLATION)

C SHIPPING
146 IF(NTIME.LE.NSTAR1) Y(46)=Z(43)*(A(173)**5)
147 IF(NTIME.GT.NSTAR1) Y(46)=X(L1,46)*A(173)
148 C LIQUEFACTION PLANT
149 IF(NTIME.LE.NSTAR1) Y(47)=0
150 IF(NTIME.EQ.NSTAR1) Y(47)=Z(41)*(A(173)**5)
151 IF(NTIME.GT.NSTAR1) Y(47)=X(L1,47)*A(173)
152 C PIPELINE
153 IF(NTIME.LE.NSTAR1) Y(48)=Z(45)*(A(173)**5)
154 IF(NTIME.GT.NSTAR1) Y(48)=X(L1,48)*A(173)
155 C COST OF PIPELINE PER MCF
156 IF(NTIME.LE.NSTAR1) Y(49)=X(L1,49)*STPNOM+
157 (((0.03+A(94))*A(173)-1)*Z(35))
158 1+(.05*Z(34))*Z(48)
159 IF(K7.EQ.NYEAR) Y(49)=Z(49)/Z(99)
160 Y(50)=((Z(49)/Z(3))*(Z(94)**25)-(Z(94)**2)
161 1(((A(94)**20)-1))*1000
162 C COST OF L. P. PER MCF
163 IF(NTIME.LE.NSTAR1) Y(51)=X(L1,51)*STPNOM+
164 (((0.03+A(94))*A(173)-1)*Z(37))
165 1+(.05*Z(36))*Z(47)
166 IF(K7.EQ.NYEAR) Y(51)=Z(51)/Z(99)
167 Y(52)=((Z(51)/Z(3))*(Z(94)**25)-(Z(94)**2)
168 1(((A(94)**20)-1))*1000
169 C COST OF SHIPPING PER MCF
170 IF(NTIME.LE.NSTAR1) Y(53)=X(L1,53)*STPNOM+
171 (((0.03+A(94))*A(173)-1)*Z(39))
171 IF(NTIME.GE.NSTAR1) Y(53)=X(L1,53)*STPNOM+((0.03*A(94))*A(173)-1)*Z(39))
172 1+(.05*Z(38))+Z(46)
173 Y(54)=((Z(53)/Z(3))*)((A(94)**25)-(A(94)**2))
174 1((A(94)**20)-1)))*1000
175 C PRICE OF FEED ESCALATED
176 A(128)=A(50)/1000
177 IF(NTIME.EQ.NSTAR1-5) Y(55)=A(128)
178 IF(NTIME.GT.NSTAR1-5) Y(55)=X(L1,55)*A(173)*A(169)
179 C PRICE OF FEED AS FUEL (ESCALATED)
180 A(131)=A(51)/1000
181 IF(NTIME.EQ.81) Y(56)=A(131)
182 IF(NTIME.GT.81) Y(56)=X(L1,56)*A(173)*A(169)
183 C ANNUAL QUANTITY OF N.G. PURCHASED
184 Y(58)=E(K,1)*Z(2)*A(40)
185 C SOCIAL COST OF THE NATURAL GAS
186 C SOCIAL VALUE
187 IF(NTIME.EQ.81) Y(59)=A(44)
188 IF(NTIME.GT.81) Y(59)=X(L1,59)*A(173)*A(169)
189 C P.V. OF NAT. GAS PRICED AT SOCIAL VALUE
190 Y(60)=Z(59)*Z(58)
191 Y(61)=X(L1,61)*STPNOM+Z(60)
192 IF(K7.EQ.NYEAR) Y(61)=Z(61)/Z(99)
193 C COST OF FEED
194 Y(62)=Z(55)*Z(58)*A(41)
195 C P. V. OF COST OF FEED
196 Y(63)=STPNOM*X(L1,63)+Z(62)
197 IF(K7.EQ.NYEAR) Y(63)=Z(63)/Z(99)
198 C COST OF FEED PER MCF PRODUCED
199 IF(NTIME.LT.NSTAR1) Y(64)=0
200 IF(NTIME.GE.NSTAR1) Y(64)=((Z(63)/Z(4)))*1000
201 C COST OF FEED FOR LIQUEFACTION (FUEL)
202 Y(65)=Z(56)*Z(58)*A(42)
203 C PRESENT VALUE OF FUEL FOR LIQUEFACTION
204 IF(NTIME.LT.NSTAR1) Y(66)=0
205 IF(NTIME.GE.NSTAR1) Y(66)=X(L1,66)*STPNOM+Z(65)
206 IF(K7.EQ.NYEAR) Y(66)=Z(66)/Z(99)
207 C COST OF FUEL FOR LIQUEF. PER MCF IN 81$
208 Y(67)=(((Z(66)/Z(3))*)((A(94)**25)-(A(94)**2))
209 1((A(94)**20)-1)))*1000
210 C COST OF FEED FOR SHIPPING (FUEL)
211 Y(68)=Z(56)*Z(58)*A(43)
212 C PRESENT VALUE OF FUEL FOR SHIPPING
213 IF(NTIME.LT.NSTAR1) Y(69)=0
214 IF(NTIME.GE.NSTAR1) Y(69)=X(L1,69)*STPNOM+Z(68)
215 IF(K7.EQ.NYEAR) Y(69)=Z(69)/Z(99)
216 C COST OF FUEL FOR SHIPPING PER MCF IN 81$
217 Y(70)=(((Z(69)/Z(3))*)((A(94)**25)-(A(94)**2)
218 1((A(94)**20)-1)))*1000
C TOTAL COST OF NAT. GAS
Y(71)=Z(62)+Z(65)+Z(68)

C TOTAL COST OF FEED AND OPERATING COSTS
Y(72)=Z(46)+Z(47)+Z(48)+Z(71)

C COST OF DEBT FINANCING
Y(73)=((A(94)*A(173)-1)*A(132)*X(L1,30)

C PRESENT VALUE OF COST OF DEBT
Y(74)=X(L1,74)*STPNUM+Z(73)
IF(K7.EQ.NYEAR) Y(74)=Z(74)/Z(99)

C COST OF EQUITY FINANCING
Y(75)=((A(94)*A(173)-1)*(1-A(132))*X(L1,30)

C PRESENT VALUE OF TOTAL FINANCING COSTS
Y(76)=Z(73)+Z(75)
Y(77)=X(L1,77)*STPNUM+Z(76)
IF(K7.EQ.NYEAR) Y(77)=Z(77)/Z(99)

C FED. DEF OF NON-DEPR CAP. STOCK PIPELINE
Y(78)=A(85)*(X(L1,78)+Z(24))

C SHIPS
Y(79)=A(86)*(X(L1,79)+Z(26))

C L. PLANT
Y(80)=A(87)*(X(L1,80)+(A(125)*Z(25)))
Y(81)=A(88)*(X(L1,81)+(A(126)*Z(25)))
Y(82)=A(117)*(X(L1,82)+(A(127)*Z(25)))

C DEPRECIATION ALLOWED
Y(83)=Z(78)+Z(79)+Z(80)+Z(81)+Z(82)
Y(84)=(X(L1,82)+Z(27)-Z(83))*A(58)

C PRESENT VALUE OF CCA
Y(85)=X(L1,85)*STPNUM+Z(84)
IF(K7.EQ.NYEAR) Y(85)=Z(85)/Z(99)

C FED DEF OF TAXABLE INCOME
Y(86)=Z(7)-Z(72)-Z(84)-Z(73)

C FED. TAX PAYABLE
Y(87)=.36*Z(86)

C PROV. TAX
Y(88)=.13*Z(86)

C PRESENT VALUE OF TOTAL TAXES
Y(89)=X(L1,89)*STPNUM+Z(87)+Z(88)-(X(L1,55)
* (.03*A(173)))

IF(K7.EQ.NYEAR) Y(89)=Z(89)/Z(99)

C PRESENT VALUE OF THE PROJ. TO THE FIRM
IF(NTIME.LT.NSTAR1) Y(90)=X(L1,90)*STPNUM-Z
(73)-Z(87)-Z(88)-Z(75)

C PRESENT VALUE TO THE GOVERNMENT
Y(91)=Z(89)-(Z(71)-Z(60))

C VALUE OF THE NATURAL GAS IN THIS USE
C SOCIAL VALUE
Y(92)=Z(93)*((A(94)**25)-((A(94)**24)*A(169)))*1000

Y(93)=X(L1,93)*STPNUM+Z(7)-Z(46)-Z(47)-Z(48)
-Z(73)-Z(75)
1-(.05*Z(28)*E(K,1))-(.03*A(173)*X(L1,30))
IF(K7.EQ.NYEAR)  Y(93)=(Z(93)/Z(9Y))
IF(K7.LT.NYEAR) Y(94)=0
IF(K7.EQ.NYEAR)  Y(94)=Z(92)/((Z(58)*(A(169)**5)
**5)
1*(A(94)**20))-(Z(58)*A(169)**25))
C PRIVATE VALUE
Y(95)=((.51*Z(8))-(.51*Z(97))-Z(77)-Z(32)
14.49*Z(85))+(.49*Z(74))/,51
IF(K7.LT.NYEAR) Y(96)=0
IF(K7.EQ.NYEAR)  Y(96)=((Z(95)*((A(94)**25)-
((A(94)**24)*
1A(169)))))/(Z(58)*((A(94)**20)*A(169)**5)-(A(169)**25)))
C PRESENT VALUE OF OPERATING COSTS
Y(97)=X(L1<97)*STPNOM+Z(46)+Z(47)+Z(4B)
IF(K7.EQ.NYEAR)  Y(97)=Z(97)/Z(99)
RETURN
END
SUBROUTINE CONS1
C CONS1 IS ONLY USED FOR PRODUCTION START
C CDNS1 IS ONLY USED FOR PRODUCTION START
COMMON/KEEP/LABX(2,800),LABE(2,600),DATE(100),DUM(30),TEST(800),
  TITLE(20),Z(800),TEMP(800),A(3000),X(7,800),E(7,600)
COMMON/SNATE/K,K,NED,NEX,NT,ML,NC,NDRR
COMMON/LLL/L1,L2,L3,L..4,L5,L6,L7,L8
COMMON ARG(200),PHIA(200),PHIGH(25),AREA(200)
LOGICAL DUM
INTEGER TITLE,NDATE
DIMENSION LD(7),Y(800),YP(800)
EQUIVALENCE (Y,Z),(L0,L1,L)
NTIME=ID-1901+K7
MD=IFIX(A<105))
NTID=NTIME-MD
NSTAR1=IFIX(A<162))
LIFE=IFIX(A<159))
NYEAR=NSTAR1-81+LIFE
RTIME=NTIME
RSTAR1=NSTAR1
RLIFE=NTIME
IF(NTIME.EQ.81) STPNOM=A(94)*A(173)
IF(NTIME.GT.81) STPNOM=A(94)*A(173)
C PRODUCTION START
IF(NTIME.LT.NSTAR1) E(K,1)=0.0
IF(NTIME.GE.NSTAR1) E(K,1)=1.0
RETURN
END