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DISCUSSION PAPER NO. 261

An Economic Analysis of the Venture Development Project and Hibernia

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Les perspectives qu'offre la zone au large de la côte atlantique du Canada pour le développement des ressources pétrolières et gazières du Canada sont fort prometteuses. Elles ont d'ailleurs contribué à l'accélération de l'activité économique dans les provinces de l'Atlantique. Les opérations ont débuté dans la région de l'Île de Sable en 1959, puis dans les Grands Bancs en 1964. L'exploration dans cette zone trois fois plus étendue que la Mer du Nord a jusqu'ici été couronnée de succès, nécessitant un nombre beaucoup moindre de forages par découverte.

Le champ gazier Venture a été déclaré rentable en juin 1982. Déjà, la phase du développement approche, le plan d'exploitation ayant été soumis en janvier 1984.

Les conditions matérielles d'exploitation du champ Venture sont généralement très favorables.

Les conditions environnementales sont meilleures que celles de la Mer du Nord, de la mer de Beaufort et de la zone Hibernia. Le champ Venture se trouve dans des eaux peu profondes et libres d'icebergs et on peut l'exploiter à l'aide de techniques de production sous-marine déjà connues. Contrairement à ce qui se passe dans le cas du champ Hibernia, aucun conflit de compétence ne risque de retarder son exploitation. Cependant, l'Entente Canada-Nouvelle-Ecosse, telle qu'elle existe présentement, pourrait entraîner certaines frictions ultérieurement.

Les perspectives économiques et commerciales sont un peu moins favorables. À l'heure actuelle, il existe un excédent de gaz naturel sur le marché nord-américain et on ne peut déterminer avec certitude qui seront les acheteurs du gaz de Venture ni quel en sera le prix. Une proportion importante de la production gazière devra être exportée, mais les marchés d'exportation sont incertains. Les marchés intérieurs les plus proches se trouvent dans les provinces de l'Atlantique, où la demande est relativement faible et les systèmes de distribution ne sont pas encore en place.

La production gazière tirée du champ Venture est relativement coûteuse. Si l'on se fonde sur l'hypothèse que renferme le scénario de référence, le coût social (c'est-à-dire, sans les taxes et les redevances) dit de "demi-cycle" (c'est-à-dire, abstraction faite des coûts de prospection) de la production de mille mètres cubes de gaz est de 138 \$ (3,86 \$ par mpc), en supposant un taux d'actualisation réel de 10 %. Le coût privé de demi-cycle est de 200 \$ par mille mètres cubes (5,66 \$ par mpc). En Alberta, le coût social de demi-cycle va de 9,50 \$ à

29,00 $ par mille mètres cubes (de 27 cents à 82 cents par mpc), lorsqu'on exclue les coûts de transformation.

Divers facteurs contribuent à ces coûts plus élevés. Bien que la technologie utilisée dans le champ Venture ne soit pas nouvelle et qu'elle ait déjà fait ses preuves, le système de production est beaucoup plus coûteux que celui de la production de gaz conventionnel dans l'ouest du Canada. Deux facteurs influent particulièrement sur l'augmentation des coûts, soit les plates-formes marines et le réseau de pipelines sous-marins requis pour amener le gaz à la côte. De plus, comme les projets gaziers au large de la côte atlantique sont éloignés et qu'ils sont très spécialisés comparativement à la structure industrielle des provinces de l'Atlantique, on peut s'attendre à ce que les coûts y soient supérieurs à ceux de l'Alberta, qui dispose déjà des compétences et du matériel nécessaires. Hibernia a été le premier champ pétrolifère à être découvert (en 1979) au large de la côte atlantique, et il n'est pas impossible qu'il s'agisse du plus important dans l'histoire du Canada. Malheureusement, la production de ce champ sera retardée en raison de problèmes techniques et de conflits de compétence.

On n'a pas encore réussi à concevoir un système de production qui puisse tenir compte entièrement du défi que posent les icebergs et les conditions climatiques très défavorables. On envisage un certain nombre de solutions mais, à l'heure actuelle, l'exploitation marque le pas.

Un autre obstacle au développement du champ Hibernia a trait à la controverse que soulève toujours, entre Ottawa et Saint-Jean, la question de la sécurité des installations de forage et de sauvetage au large de la côte. Terre-Neuve tente de faire interdire les forages d'hiver jusqu'à ce que le gouvernement fédéral ait amélioré les normes de sécurité. Pour sa part, ce dernier rejette l'argument, en soutenant que les installations sont parfaitement sécuritaires. Les entreprises sont au centre du débat; en effet, elles doivent s'intéresser aux questions de sécurité mais elles doivent aussi payer pour chaque journée de location des foreuses, qu'il y ait effectivement forage ou non, et savoir quel gouvernement elles doivent écouter. Jusqu'ici (février 1984), les forages se poursuivent.

Aux termes du régime fiscal applicable aux Terres du Canada, si on suppose que le prix réel unique sera de 252 $ le mètre cube de pétrole (40 $ le baril) et qu'on utilisera les plates-formes à attraction gravifique, l'exploitation du champ pétrolier Hibernia semble être rentable. Le coût privé de demi-cycle du pétrole livré à Montréal est de 210 $ le mètre cube (33 $ le baril), sur la base d'un taux d'actualisation réel de 10 %. Le coût social est d'environ 93 $ le mètre cube (15 $ par baril). Ces résultats dépendent évidemment du rythme de développement, du type de système de production utilisé, ainsi que des hypothèses relatives aux prix et aux coûtx réels.

Le régime fiscal des Terres du Canada qui s'applique à la phase de développement des activités pétrolières et gazières comprend la taxe sur les recettes pétrolières et gazières TRPG - 12 % des revenus d'exploitation), la redevance de base (10 % des revenus bruts), la redevance additionnelle progressive (RAP - 40 % des profits), les subventions accordées dans le cadre du programme d'encouragement au secteur pétrolier (PESP - 20 % des dépenses d'exploitation intangibles), l'impôt fédéral sur le revenu imposable des sociétés (46 % des revenus de développement et de production) et l'option de participation gouvernementale (25 %).

La redevance additionnelle progressive est destinée à recueillir les profits excessifs dans un champ déterminé. Elle a fait son apparition dans le cadre du PEN, en même temps que d'autres mesures qui ne varient pas en fonction du niveau de rentabilité, notamment les redevances de base et la TRPG. Nos résultats montrent que les rapports réciproques entre ces mesures insensibles au niveau des profits et la RAP contredisent le but avoué de la détermination du champ d'application de la RAP. On pourrait immédiatement améliorer la situation en éliminant les redevances de base et la TRPG et en permettant à la RAP de s'appliquer plus tôt en réduisant le plancher des bénéfices qui y sont admissibles.

Le PEN introduisait une mesure supplémentaire applicable aux Terres du Canada, qui permettait à la Couronne d'acquérir un intérêt direct de 25 % dans tout projet entrepris dans une région éloignée. Cette disposition permet aux entreprises prospectrices de choisir leur projet dans l'ensemble des meilleures terres plutôt que de s'astreindre à la sélection "en damier". Elle paraît raisonnable et acceptable, pourvu que le gouvernement paie sa part.

Il nous semble que la disposition prévoyant une participation publique de 25 % élimine la nécessité de taxes successives et qu'on pourrait la considérer comme un substitut aux redevances de base et à la TRPG.

Pour ce qui a trait aux subventions du PESP qui seront disponibles pendant l'étape de développement dans les Terres du Canada, elles ne semblent pas jouer un rôle très important dans l'analyse économique des projets de demi-cycle. Elles équivalent à 20 % des dépenses de développement intangibles. Il convient de souligner que ce taux ne semble pas s'appliquer à la phase de prospection qui précède une découverte. Les subventions à la prospection sont effectivement importantes pour les entreprises qui doivent poursuivre leurs activités dans les régions éloignées.

Nous croyons qu'en l'absence de cette aide aux activités de prospection dans les régions éloignées, ces activités n'auraient pas atteint leur niveau actuel dans les Terres du Canada. Les subventions jouent le rôle le plus important pour les entreprises qui font constamment des forages coûteux.

Le PESP et les déductions au titre de l'impôt sur les bénéfices permettent de réduire considérablement le coût privé de la prospection. Dans l'éventualité d'une découverte rentable, cependant, les bénéfices après soustraction des impôts et des redevances sont très restreints. Nous croyons qu'il serait préférable de récompenser les entreprises dont les activités de prospection se soldent par un succès et de leur faire assumer l'essentiel des risques d'échec. En d'autres mots, la politique devrait respecter davantage les règles du marché.

Dans le cas du projet Hibernia, nous avons testé un deuxième régime qui serait fondé sur "les règlements de Terre-Neuve". Ce scénario suppose que la propriété des ressources relève de la province et que seule cette dernière peut en tirer des redevances. La Newfoundland Labrador Petroleum Corporation peut prendre une participation économique directe de 60 % dès le début du projet, ou encore seulement un intérêt passif de 60 % une fois que l'entreprise a récupéré trois fois sa mise de fonds.

Nous croyons que l'option de l'intérêt passif de Terre-Neuve pourrait se révéler avantageuse si on voulait améliorer le régime fiscal applicable aux projets entrepris dans les Terres du Canada.

EXECUTIVE SUMMARY

The East Coast offshore region of Canada is an area that is showing great promise in the unfolding of Canada's oil and gas supply prospects. In addition, the promise of better times ahead for the Atlantic provinces is spurring on activity. Activity in this frontier region began in the Sable Island area in 1959 and in the Grand Banks in 1964. Exploration in the area which is 3 times as large as the North Sea has been very successful requiring far fewer holes per discovery by comparison to the North Sea.

The Venture gas field was stated to be commercially viable in June 1982. Activity in the Venture field is moving into the development phase with the filing of the development plan occurring in January 1984.

The physical conditions surrounding the development of the Venture field are for the most part quite favourable.

The environmental conditions are less harsh than those in the North Sea, the Beaufort Sea and around Hibernia. The field is located in shallow iceberg-free waters and can be developed with known offshore production technology. Unlike Hibernia, no jurisdictional dispute exists which could potentially stall development. However, the Canada-Nova Scotia Agreement, as presently defined, could lead to some frictions at a later date.

The economic and market conditions are somewhat less certain. Currently surpluses of natural gas exist in the North American market therefore it is uncertain who will buy Venture gas and at what price. A significant portion of sales gas production is to be exported but export markets are uncertain. The closest domestic markets are within the Atlantic provinces but the market is relatively small and distribution systems have yet to be put in place.

Offshore gas from the Venture field is relatively high cost gas. Given the base case assumption the (half cycle) social supply cost to develop and produce a thousand cubic metres of gas is $138 ($3.86 per mcf), at a 10 percent real discount rate. The private (half cycle) supply price is $200 per thousand cubic metres ($5.66 per mcf). Comparable half cycle social supply prices in Alberta are in the $9.50 to $29.00 per thousand cubic metre (27¢ to 82¢ per mcf) range excluding processing.

A number of factors contribute to the higher costs. While the technology used in the Venture Project is not new or unproven, the project does require a much more costly production system vis-ã-vis conventional gas production in western

Canada. Two large contributing factors are the higher costs of the offshore platforms and the subsea pipeline system required to get the gas to shore. Further, because eastern offshore gas projects are isolated and specialized by comparison to the industrial make-up of the maritime region, costs are expected to be inflated above those in Alberta where the required skills and hardware are readily available.

The Hibernia oil field was discovered in 1979. Hibernia was the first oil field to be found in the eastern offshore and it may prove to be the largest in Canadian history. Production from the field unfortunately will be delayed because the development is plagued by jurisdictional difficulties and the technology that will be used has yet to be decided upon.

Because of the challenge posed by the iceberg infested waters and harsh weather conditions, a feasible production system has not yet been designed. A number of alternatives are being considered but for the time being development is stalled.

Jurisdictional constraints rise from the unresolved dispute between the federal government and the province of Newfoundland over the management of the resources. The ownership dispute has been settled in favour of the federal government. Before any oil can be brought ashore from

Hibernia, settlement between the province and the federal government over the way in which development proceeds will have to be reached.

One further hurdle has been placed in the path of development as the federal government and the province argue over the adequacy of offshore search and rescue facilities. The province is attempting to ban winter drilling until the federal government improves the levels of safety. The federal government dismisses the argument claiming that the facilities are adequate. Caught in the middle are the companies who must be concerned with safety but who also pay for each drillrig day whether making hole or not, and who must know which government to listen to. So far (February 1984) drilling has been continuing.

Under the present Canada Lands fiscal regime, an assumption of a flat real oil price of $252 per cubic metre ($40 per barrel), and an assumption of a gravity base platform, the development of the Hibernia oil field appears to be economic. The (half cycle) private supply price for oil delivered to Montreal is about 210 per cubic metre ($33 per barrel) at a 10 per cent real discount rate. The social supply price ignoring taxes and royalties is about $93 per cubic metre ($15 per barrel). These results are of course contingent upon the pace of development, the type of production system used and price and real cost assumptions.

The existing Canada Lands fiscal regime applicable to the development phase of oil and gas activity includes the PGRT at 12 per cent of operating revenues, the Basic Royalty at 10 per cent of gross revenues, the Progressive Incremental Royalty (PIR) at 40 per cent of profits, the 20 per cent PIPs on intangible development expenditures, the 46 per cent federal income tax on company taxable income from development and production revenues, and the 25 per cent government back-in provision.

The PIR is a royalty that has been designed with the intent of capturing the above normal profits of a particular ("ring fenced") field. With the inception of the NEP, the PIR was introduced along with other measures that lack responsiveness to profitability; in particular the Basic Royalty and the PGRT. Our findings suggest that the interaction between these profit insensitive measures and the PIR contradict the intent and spirit of ring fencing a field for the PIR. An immediate improvement would be the elimination of the Basic Royalty and the PGRT while allowing the PIR to be imposed at an earlier date by lowering the profit floor of the current PIR.

The NEP introduced an additional feature for the Canada Lands allowing the Crown to enter as a 25 per cent working interest into any project on frontier lands. The provision allows the explorationist to select from the whole of the best lands for development rather than be subject to checker board selection. This appears to be a reasonable and workable provision provided that the government pays for its share.

It occurs to us that the 25 per cent back-in provision precludes the need for layer upon layer of taxes and could be considered as a substitute for the Basic Royalty and the PGRT.

As for the PIPs that are available in the development phase in the Canada Lands they do not appear to be enormously important in the half-cycle project economics. They are paid at a rate of 20 per cent towards intangible development expenditures. It may be noted that this does not appear to be the case during the exploration phase prior to a discovery. Exploration PIPs are indeed of value to the companies in order to sustain activity in the frontier.

It is our view that had there not been some equivalent form of assistance for exploration activities in the frontier these activities would not be proceeding in the Canada Lands as they are now. The PIPs, of course, are of most value to companies that continually drill costly wildcat explortion wells.

The PIPs in conjunction with income tax reductions reduce the private cost of exploration substantially. However, once a successful discovery is made the after tax and royalty profit is severely restricted. We believe that a more suitable policy should reward successful exploration and let the petroleum companies take most of the dry hole risk. In other words the policy should be more in step with the market place.

In the case of Hibernia a second regime "The Newfoundland Regulations" is tested. The regime assumes provincial ownership and only the province collects royalties. The Newfoudland Labrador Petroleum Corporation has the option of entering either as a 40 per cent working interest at the beginning of the project or as a 40 per cent carried interest once the companies collect 3 times payback.

We believe that the Newfoundland carried interest option may be a useful avenue to pursue in deriving better Canada Lands fiscal regimes.

1. INTRODUCTION

This study provides an overview of two offshore hydrocarbon projects located off of Canada's east coast. The first, the Venture Gas Project is located offshore Nova Scotia and will provide a system for the production and processing of natural gas and natural gas liquids. The second, Hibernia is located offshore Newfoundland and will provide a system for the production of crude oil.

The analysis assesses the projects in terms of the required technologies that are currently in use or being developed and in terms of the project economics. Although not the main focus of the paper, there is some discussion regarding the institutional arrangements affecting the development of the projects in terms of resource ownership and management. The agreement or lack of agreement on such arrangements may well determine the timing of project developments and even whether or not the projects go ahead.

The paper proceeds with a description of the Venture gas field and the technology that is required to produce from that field. The proposed development plan and the cost structure for the project are also documented.

The economic analysis of the Venture Project examines the project under a number of conditions of price, fiscal terms and the cost of money. One objective of the economic analysis is to show the effect of various fiscal measures and pricing assumptions on the corporate rate of return. A second objective is to investigate the share of revenues between the federal government and the company. Estimates of the social and private supply prices for gas from the project are also reported.

The second half of the paper looks at Hibernia in terms of the required technology and in terms of the project economics. The format and objectives of the economic analysis of Hibernia are the same as those used for Venture.

Conclusions regarding the appropriateness of current taxation policies are drawn from the economic analysis and the sensitivity tests for both projects. The conclusions are presented in the final section of the paper.

The price, cost, and inflation assumptions for the economic analyses are documented in the Appendices.

2. VENTURE DEVELOPMENT PROJECT

2.1 Introduction

The Venture gas field is located 210 km offshore Nova Scotia and 16 km East of Sable Island. The field covers an area of approximately 38 square km and is located in a relatively shallow water depth of about 22 metres. The location of the field is shown in Figure 1.

The operator for Venture is Mobil Oil Canada Limited. The development plan for the field includes a system for the production and processing of natural gas and natural gas liquids. Mobil estimates that there are 72 billion cubic metres (2.5 trillion cubic feet) of recoverable natural gas reserves.[1] We note that this estimate was provided in the 1983 Venture Environmental Impact Statement (EIS) however this estimate is still under evaluation and will likely be revised.

2.2 Drilling History

The Sable Island area was first surveyed by Mobil in 1959. The first exploratory well, the Mobil Sable Island C-67 was drilled in 1967. That well found non commercial gas and a trace of oil. The Venture D-23 was drilled in May 1979 to a depth of 4,945 metres. The well flowed gas at a rate of 1.23 million cubic metres per day and condensate at a rate of 103 cubic metres per day. The D-23 well was the first find of any commercial interest.

Two appraisal wells, the B-13 and the B-43 were drilled in 1981 and 1982 respectively. The B-43 was successfully tested at deeper intervals below 5,279 metres producing both gas and condensate. Two more wells, the Olympia A-12 and the South Venture O-59 have been drilled on new gas bearing structures but will require further appraisal.[2]

There have been other discovery wells in the Venture area, the Cohasset, Citnalta and Thebaud, that may become part of the development. The well locations are shown in Figure 2.

Currently, the participants in the Venture project are Mobil Oil Canada Limited as the operator, Texaco Canada Resources Limited, Petro-Canada Resources Inc., Nova Scotia Resources Limited and East Coast Energy Limited. The project share held by each of the participants is given in Appendix 4.

2.3 The Technology of the Venture Development Project

The Venture Development Project is a proposal to develop the Venture gas field. The development plan includes both onshore and offshore facilities. Gas and condensate will be extracted from the Venture field, transported via subsea pipeline to an onshore landfall terminal for separation and then transported via overland pipeline for processing at a gas plant. Each activity will be described below. This discussion is intended to provide an overview of the Venture technology.

The starting point for this analysis coincides with the decision to proceed with development of a previously discovered pool. The development phase includes the activities necessary in the preparation for operation. During the development phase production wells will be drilled, offshore platforms built and installed, and onshore facilities will be constructed. During the production phase, raw gas will be extracted from the field and then processed into a number of products. Exploration activities are not included in the analysis. The focus of study is on the "half cycle" which begins with the development stage. We note that the half cycle economics are also referred to as the development or decision economics.

2.3.1 Offshore Activities

Mobil has scheduled roughly 2.5 years to drill the 16 to 20 wells required to bring Venture into production. Development drilling is likely to begin in 1984.[3]

Drilling will be done from as many as four jackup drilling units i.e. mobile rigs that rest on the ocean floor, on a year round basis. Two groups of five wells each are proposed for the east lobe of Venture and two groups of three wells each are proposed for the west lobe. Wells may be added to each of the clusters to compensate for wells that do not produce as expected.[4]

The Venture Project proposes the construction of two offshore complexes each containing two wellhead platforms, a production platform, an accommodation platform, and an emergency flare structure as shown in Figure 3. Again we stress that our discussion is based on information that is provided in the EIS. Sone details of the production system may still be changed as more is determined about the reservoir.

The support structures for the platforms will be steel jackets (legs) which will be anchored to the ocean floor. The jackets have been successful in the North Sea where conditions are similar to those of the Venture area. This type of support structure is believed to be less costly and easier to build than gravity platforms. Floating systems have loading restrictions and were not considered because of the shallow waters.

The wellhead platforms will receive reservoir fluids (mixture of gas, gas liquids and water) for separation and treatment. The platforms will also serve as a base from which development drilling and well workovers will be undertaken. Well workovers will occur every five years. There will be one jackup rig located at each wellhead platform site.

Production platforms will be used for the cooling and separation of reservoir fluids into gas, natural gas liquids, and water. These platforms will be connected to the wells by flowlines across interconnecting bridges. The production platforms also provide space for utility systems and life support systems.

An emergency flare structure will provide for safe disposal of production gas and gas products, should an emergency situation occur.

The accommodation platform will house all personnel and associated life support systems. The platforms will also include a helicopter deck. The production system is shown in Figure 3.

Gas and natural gas liquids will be transported 210 km to the onshore landfall terminal through a 914 mm subsea pipeline. The line will be capable of carrying 14 million cubic metres (494,000 mcf) per day of gas and 4777 cubic metres (168,698 mcf) per day of condensate.

The pipeline will be concrete coated and trenched in the sea floor for stability. The maximum water depth under which the line will be placed is estimated to be 125 metres.

2.3.2 Onshore Activities

The onshore landfall terminal will receive and separate the gas and natural gas liquids delivered via the offshore pipeline system. The terminal site is located near Dung Cove in Guysborough County.

A certain volume of liquid condenses from the gas while in the subsea pipeline system and will be carried along in the gas stream. The gas and liquid will then be separated into separate streams and directed to their respective onshore pipelines for transport to the gas plant.[5]

Two overland pipelines are planned for the transport of gas and condensate to the gas plant which will be located approximately 65 km away near the Strait of Canso. The gas pipeline will be 610 mm in diametre and the natural gas liquids pipeline will be 324 mm.

The two lines will be laid in separate trenches about four metres apart over most of the distance however where soil thickness is not adequate or where blasting is necessary the lines will be laid in a single ditch.

Upon arrival at the gas plant the gas will be processed and the natural gas liquids will be fractionated. At the separation facility of the plant a portion of the heavier hydrocarbons are removed leaving what is called sales gas (ethane and methane). That gas will be sold to the main transmission system.

Selected light ends of the liquids will be boiled off and returned to the gas stream. This process leaves a stabilized liquid product. Following the stabilization process the natural gas liquids may be sold either as a natural gas liquid raw mix poduct or fractionated to produce separate liquid petroleum gases such as propane, butane and condensates.[6]

The analysis in this paper deals with all the costs up to the Canso gas plant gate. The prices used are those expected to be received at the Canso gate. The costs that are used include all costs incurred to develop, extract, deliver and process the sales gas and natural gas liquids.

2.4 The Production Profile and Cost Structure

The production data and cost data are those provided in the Venture Development Project Environmental Impact Statement (EIS) and in the Venture Gas Field Development: Benefit/Cost Analysis.[7]

2.4.1 Production

Production from Venture is assumed to consist of sales gas and natural gas liquids (NGL's). All production begins in 1988 and terminates 18 years later in 2005. The Venture field contains proven reserves that are currently estimated at 72 billion cubic metres (2.5 trillion cubic feet). Gas production will range from 11 million cubic metres (388 million cubic feet) per day to 2002 declining to 5.5 million, cubic metres (194 million cubic feet) per day in 2005.[8]

The NGL's are assumed to include propane, butane, and condensate. On average condensates account for roughly two thirds of the NGL production.

The sales gas production is assumed to be used for export sales and for domestic consumption in New Brunswick and Nova Scotia. In the first four years of production, sales-gas production is predominantly for export sales. The EIS assumptions state that only surplus gas is exported, assuming that domestic markets receive first priority. Export volumes are set equal to the difference between sales-gas production and forecast domestic requirements.[9]

Towards the middle of the production life export sales gas accounts for about half of total gas sales. As production winds down the proportion of sales gas that is exported becomes less significant.

Total sales-gas production (export + domestic) represents about 80 per cent of total gas produced. NGL's account for the remaining 20 per cent.

Over the first 15 years of the field's producing life about 3.7 billion cubic metres (131 billion cubic feet) of sales-gas will be produced annually and declining thereafter. Over the same period about 1.2 billion cubic metres (41 billion cubic feet) of NGL's are produced annually and declining thereafter.

2.4.2 Costs

The total estimated capital expenditure for the half cycle of the Venture Gas Project is about $3.3 billion (1983 $) based on EIS assumptions. The start year in the analysis is 1983 which is the year in which development is assumed to begin. All pre 1983 exploration expenditures are considered to be sunk.

Operating expenditures are estimasted to be about $120 million (1983 $) annually during the first five years of production. Operating costs are $145 million (1983 $) thereafter.

The project construction is scheduled to take place over a five year period 1983-87. The investment costs and timetable are as follows (all costs in millions of 1983 dollars):

Site Development	:	1983-85,	$ 25
Engineering Services	:	1983-87,	$ 233
Development Drilling	:	1984-87,	$ 607
Offshore Platform	:	1984-87,	$ 658
Platform and Facility Installation	:	1984-85,	$ 210
Offshore Pipeline	:	1985-86,	$ 365
Landfall Terminal and Onshore Pipeline	:	1986,	$ 123
Gas Plant	:	1984-87,	$ 390
Compressor Platform	:	1996-97,	$ 109
Insurance During Construction	:		$ 175
Contingency Funds (15% of annual costs exluding insurance)	:		$ 408
		TOTAL	$3,300

2.5 The Canada Lands Fiscal Regime

Revenues generated from gas sales from the Venture Project will be subject to the taxes and royalties applicable to the Canada Lands. The basic structure of the Canada Lands fiscal regime consists of a 46 per cent corporate income tax, a 16 per cent PGRT on operating revenues, a 10 per cent royalty on gross revenues and a 40 per cent progressive incremental royalty (PIR) on net profits. PIP grants are paid at a minimum rate of 25 per cent on post 1980 exploration expenditures for the lowest level of Canadian ownership and at a maximum rate of 80 per cent for the highest level of Canadian ownership. Intangible development expenditures in the Canada Lands earn PIPs at a minimum rate of 0 per cent up to a maximum rate of 20 per cent.

2.5.1 The Crown Back-in

An additional feature of the Canada Lands fiscal regime is that the federal government has the option to take a 25 per cent working interest in petroleum development and production operations. At the time at which a project enters the development phase the Crown can enter into the project as a 25 per cent working interest partner. The Crown incurs 25 per cent of all subsequent expenditures and receives 25 per cent of all production. The legislation provides that the entry is made at the time that the development plan is approved.

Crown contributions to expenditures made by private interests prior to the back-in are made as follows. First, pre 1981 eploration expenditures made on a field declared significant by 1983 and which was drilled before 1981 qualify a company for an 'ex gratia' payment. Ex gratia payments are not based on Canadian ownership levels. The ex gratia payment is equal to 1/4 of 250 per cent of all pre 1981 exploration costs associated with discovering the field, grossed up 15 per cent per annum to the end of 1980. The 15 per cent gross-up is intended to account for the impact of interest and inflation. The payment is made out of the Crown share of production after the back-in option is exercised which means in the first year of production. Second, the

Crown is deemed to contribute, in relation to the back-in, through the PIPs, although this was not the original intention of PIPs which of course are available on exploration whether or not a discovery is made and whether or not the Crown elects the back-in. The Crown contributes a minimum of 25 per cent of exploration expenditures made post 1980 in the form of PIPs. For companies with the highest Canadian ownership ratings (COR) an additional 55 per cent of post 1980 exploration expenditures is contributed for a maximum contribution of 80 per cent.

There is a category of expenditures that is not compensated for through the ex-gratia payments or through PIPs. The expenditures are those related to studies such as the EIS. These studies are related to development and they are necessary in order to move into the development stage as they must be approved before development can begin. Expenditures related to the EIS are not eligible for PIPs. While the expenditures related to such studies are not enormous by comparison to other development expenditures, they do amount to millions of dollars. Although not a major issue industry finds it somewhat contentious in that the Crown entrant does not contribute to such expenditures although the expenditures are necessary if development is to proceed.

Typically the Crown back-in is expected to occur at the time at which the project development plan is approved by the minister. We note that the private sctor participants would not likely proceed with any development expenditures in the face of a delay in the Crown's entry or without a full committment from the Crown.

2.6 The Canada-Nova Scotia Agreement

The focus of this paper is on the project economics from the company's and society's point of view. The generation of revenues from the project and the split of those revenues between the private participants and the governments, fall within our depth of focus.

The collection of above normal profits, i.e. economic rents from projects on Canada Lands is under federal jurisdiction. However, in the case of Venture, provisions have been made to share the revenues with the province of Nova Scotia according to the conditions outlined in the March 1982 Canada-Nova Scotia Agreement on Offshore Oil and Gas Resource Management and Revenue Sharing.[10]

The net economic effect of this revenue sharing agreement on the Nova Scotia and Canadian economies is beyond the scope of this paper. However, the provisions of the agreement are deserving of attention because they set precedents for the future and it is their existence that has pushed along the Venture project.

The Canada-Nova Scotia Agreement says that in any year that the Nova Scotia government's per capita fiscal capacity (including its share of offshore revenues) does not exceed 110 per cent of the national average (plus a margin to account for the province's unemployment rate relative to the national average), the province shall receive 100 per cent of proceeds from the basic royalty, the PIR, and revenues that would be generated by a provincial corporate tax. Proceeds from the PGRT will also be available to Nova Scotia if the collection of the foregoing revenues is not sufficient to meet the per capita fiscal capacity requirement.

The Agreement also sets out a formula which systematically limits the sharing of offshore revenues by the province as the province's fiscal capacity begins to exceed 110 per cent of that of the national average. The Agreement further states that in no case shall the total offshore revenues received by Nova Scotia have the effect of raising the province's per capita fiscal capacity beyond 140 per cent of the national average.

At first glance these conditions for sharing seem benign but we are concerned that efficient resource management is being scrambled with the objectives of the equalization program.

The goal of efficient resource management, the ultimate responsibility in this case of the federal government may conflict with provincial revenue aspirations. As on provincial lands the companies may be caught in the squeeze, for example, economically efficient resource management might call for the reduction or elimination of the Basic Royalty and the PGRT. How would this be resolved? It is not difficult to think of other situations which would appear to pit the federal government against the province.

We understand that it is assumed that additional resource revenues accruing to the province through the Agreement would not materially affect their equalization payments. The revenues would in fact be net revenues to the province.

Another aspect of the Agreement provides that the Nova Scotia government has the right to acquire a 50 per cent portion of the 25 per cent Crown Share of a natural gas field.

2.7 Economic Analysis

2.7.1 Introduction

The economics of the Venture Project are assessed in this section in terms of the corporate rates of return earned by the participants, present value of net revenue shares, and supply prices. The economics are assessed with and without taxes and royalties and under various assumptions for price and the system of royalties and taxation. Assumptions for natural gas and NGL prices, inflation, the fiscal regime and cost of money are given in the Appendices.

The economic analysis of the Venture project focusses on the half cycle development and production phase rather than the full cycle which includes exploration. Exploration costs are considered to be sunk. We note that for purposes of the PIR pre-discovery exploration costs are deductible (Appendix 3). However since we do not incorporate exploration expenditures into the analysis the PIR will be slightly biased upwards.

Some questions that are of importance in this analysis are: Is the current system of taxation appropriate and does it tax efficiently? What are the relative merits of the various fiscal measures within the Canada Lands fiscal regime? How will the Crown's 25 per cent back-in affect the project's economics both from society's view point and that of the private participants? Finally would a delay in the back-in seriously damage the position of the private participants?

The conclusions to the economic analysis for both Venture and Hibernia are given in the final section of the paper.

2.7.2 The Base Case

In the base case analysis prices and costs remain flat in real terms. The prices used in the base case and the assumptions behind the prices are outlined in Appendix 1. Inflation and cost assumptions are in Appendix 2. The base case fiscal regime is the standard Canada Lands fiscal regime as outlined in Appendix 3. The Crown backin is assumed to take place at the beginning of the development phase (1983), in the base case. The base case analysis pertains to the private sector's 75 per cent participation. The COR ratings of the private interests are such that in the base case 40 per cent of the company's 75 per cent share is eligible for PIPs.

2.7.3 Results: Rates of Return

The discounted cashflow (DCF) returns for the Venture Project are given in Table 1. In the social case a nominal return of 24.5 per cent (16.7 per cent real) is generated under the base case assumptions. In this case the project economics are assessed without any taxes or royalties.

The imposition of full taxes and royalties in the base case impacts quite heavily on the project economics. The real DCF return falls by about 7 percentage points to 9.6 per cent when the fiscal regime is imposed.

Sensitivity Tests

Sensitivity tests on the price and fiscal regime assumptions indicate the degree to which the project economics are preserved under changing conditions. The relative impacts of the various measures within the regime are revealed through their impact on the base case private rate of return.

Base

The nominal rate of return in the base case is 24.5 per cent (16.7 per cent real). In this case the imposition of the Progressive Incremental Royalty (PIR) does not occur until the final year of the project. The imposition of the PIR is prompted by the project's profitability. The overall royalty payment is only marginally higher than it would be if only the Basic Royalty was collected.

No PIPs

Forty per cent of the private share of the project is eligible for the 20 per cent PIPs on intangible development expenditures in the base case. In this case no PIP grants are paid to offset capital expenditures. The resulting real return is 9.4 per cent which is marginally lower than the base case return. Because in the base case only 40 per cent of the private share earns PIPs and only on intangible development expenditures, removal of the grants has little effect on the overall project economics in this case. When no PIPs are earned the profitability is such that the PIR is never imposed and only the 10 per cent Basic Royalty is collected over the project life.

Full PIPs

PIP grants are earned by 100 per cent of the private sector's 75 per cent share of the project in this case. The grants are paid at a rate of 20 per cent towards all intangible development expenditures. The real return improves by about 7 percentage points in this case to 16.7 per cent. This marked improvement reveals the value of the PIP grants from the private participants point of view if the entire projet were eligible for the grants.

No Taxes or Royalties Until Payout and No PIPs

In this case no royalties or taxes are collected until the cumulative net cashflow becomes positive. This takes place during the ninth year of the project. In this sensitivity the private sector share is not taxed until profits are being earned. The result is an improvement in the real return of nearly two percentage points to 11.7 per cent. Since the PIP grants earned in the base case do not affect the project economics significantly their removal is not enough to offset the positive impact of delayed taxes and royalties. The profitability of the project prompts the imposition of the PIR in the final few years of the project.

No PGRT

The effect of removing the PGRT levied at a rate of 12 per cent on net operating revenues is substantial. The real return increases by more than 3 percentage points to 12.9 per cent.

The PGRT when imposed, is applied to a base of net operating revenues. Therefore, the tax is capable of creaming off gains earned under rising prices but it offers no protection from rising capital costs. The PGRT can be damaging to the project economics from the private sector's viewpoint both under improving and deteriorating economic conditions.

The profitability of the project in the absence of the PGRT warrants the imposition of the PIR 4 years before shutdown. The PGRT is deductible from the PIR net profits base. Therefore, in the absence of the PGRT the PIR base becomes positive sooner prompting the earlier imposition of the PIR. The total royalty payment is 14 per cent higher in undiscounted terms than it would be if the Basic Royalty had been the only royalty payable over the project life.

The basic design of the PIR is efficient in that it is only payable after a certain level of profitability is reached. However, its interaction with the PGRT detracts from the overall efficiency of the PIR and from that of the fiscal regime in general. Perhaps a more robust fiscal arrangement would include a PIR that is imposed earlier at a lower level of profitability and the PGRT would be removed.

PGRT Relief

In this sensitivity PGRT relief as it is defined in the April 1983 federal budget for Enhanced Oil Recovery projects, is assumed to apply to the Venture project.

The PGRT is not payable in this case until payout, meaning that the accumulated value of the PGRT base becomes positive (PGRT base = Gross Revenues - Operating Costs - Capital Costs). At that point the PGRT equals 12 per cent of the PGRT base.

No PGRT is collected until profits are earned causing the real return to increase by more than 1 percentage point to 10.9 per cent. The provision of capital deductibility for the purposes of the PGRT makes it more similar to the PIR than the basic royalty.

When PGRT relief is granted the PIR is not imposed until the final year of the project. The overall royalty collection is only marginally higher in this case than it would be if only the Basic Royalty had been collected.

No Basic Royalty

The 10 per cent royalty levied on gross revenues is removed in this case. The impact is the same as the removal of the PGRT. In this case the real return increases by more than 3 percentage points. The PIR is levied 3 years prior to the project shut-down. The Basic Royalty is deductible for the purposes of the PIR therefore the earlier imposition of the PIR dampens the gains made in the absence of the Basic Royalty. The Basic Royalty and the PGRT tend to weaken the efficiency sought by the design of the PIR.

Increasing Real Prices

The prices received at the Canso Gas Plant gate are assumed to be rising at an annual real rate of 5 per cent in this case. The real social rate of return improves by almost 10 percentage points to 26.1 per cent. In the private case the real return improves by just over 7 percentage points to 17 per cent.

Under rising real prices the imposition of the fiscal regime on the company's profitability is not as great as in the base case where conditions are less favourable. This suggests that the regime does not take a larger share of increasing rents that arise as economic conditions improve. This will become more evident in the discussion of present value net revenue shares.

In the rising real price scenario the project's profitability warrants the levying of the PIR in the ninth year of production. The overall royalty take is 58 per cent higher than would be the case if the Basic Royalty alone had be collected.

Decreasing Real Prices

Real prices decline at an annual real rate of 5 per cent in this case. The real return in the social case declines over 10 percentage points to 6.2 per cent. In the private case the real return becomes negative.

The economics of the project deteriorate greatly under worsening economic conditions. The fiscal regime appears to offer virtually no protection from worsening economic conditions. Regardless of the project's profitability the government is able to collect revenues through the Basic Royalty and the PGRT. No PIR is collected in this case.

The decrease in the rate of return as prices fall is proportionally greater than the increase experienced under rising prices. This suggests that the fiscal regime tends to result in significant downside risk. This will also be seen in the discussion of net revenues.

Stand-Alone Taxation

Under the assumption of full flow-through taxation which is used in the base case, the private participants are in fully taxable positions and are able to take advantage of all available tax deductions. In this case the full flow-through assumption is removed.

Taxation is done on a stand-alone basis in this case meaning that the private participants are not in taxable positions at the time that project expenditures begin. The participants are assumed to have no external income against which the available tax write-offs can be applied.

Under the stand-alone assumption the project economics diminish with respect to the base case. The real return declines by nearly 2 percentage points to 7.8 per cent suggesting that the present worth of the tax deductions in the early years is quite important to the private participants.

Return on Total Project

In this final sensitivity the Crown back-in occurs in 1983 as in the base case but we assess the economics of the total project rather than the private participant's 75 per cent share. Given the Crown's entry 55 per cent of the project is eligible for PIP grants.

The real return earned by the project is 10.1 per cent which is half of a percentage point greater than the return earned by the private participant's 75 per cent share. This increase occurs as a result of the increased eligibility for PIPs.

Conclusions to the Sensitivity Tests

The impact of the various fiscal measures and price conditions are revealed through the sensitivity tests. Under the base case assumptions our findings suggest that the PGRT and the Basic Royalty affect the project economics significantly. It appears that the interaction of the PIR with the PGRT and the Basic Royalty is counter-productive in that 3 different instruments are used where perhaps the PIR could be used alone to more efficiently capture above normal profits. The design of the PIR is a check on the project's profitability unlike the design of the PGRT and the Basic Royalty.

The effect of changing real prices on the project economics suggest that the fiscal regime offers little in the way of upside potential however the downside risk is significant.

2.7.4 Results: Present Value Net Revenue Shares

The present value net revenue shares earned by the companies and the federal government from the private sector's 75 per cent share are given in Table 2. Total net revenues are defined as total revenues less operating costs less capital costs.

Total net revenues above a normal cost of money are an indication of the potential economic rent that is available for distribution between the federal government and the company. We note however, that the total net revenues in this analysis are those that are generated within the half cycle of development and production ignoring the preceding exploration costs. Therefore, some of the present worth of the half cycle must be retained by the private sector in order to sustain exploration.

The share of each participant of present value net revenues serves as an indication of the effectiveness of the fiscal regime.

Base

The federal government receives the largest share of the present value of net revenues that are generated in the private sector's 75 per cent share of the project over all real discount rates. The federal share increases as the real discount rate increases. The companies' share declines over higher rates because its significant positive cashflows are received later in the project life after the front-end expenditures are made.

The federal government foregoes tax and royalty collection in the pre-production years and allows tax write-offs. However, relative to the companies' investments and subsequent revenues the government gives away less in earlier years.

The shares of the government net revenues captured by the royalty, the PGRT and the federal income tax are 31 per cent, 31 per cent and 38 per cent respectively.

Increasing Real Prices

Under the rising price scenario a portion of the federal share is transferred to the company. However, the federal government still earns the largest portion of the present value of net revenues over all discount rates. The share of net revenues taken by the royalty which includes the PIR is significantly lower in this case than in the base case. This is also true of the share of net revenues taken by the PGRT.

The share distribution is affected by the fact that under increasing prices net revenues are a much larger proportion of gross revenues. As a result, fiscal measures that are based on gross revenues or even net operating revenues take proportionately less of the available economic rent and therefore tend to increase the company's share, when compared to the base case assumptions.

The results of the increasing price case suggests that the PIR, along with the other royalties and taxes, does not enable the federal government to collect as higher share of rents from more profitable projects, but merely to approximately maintain its share.

Decreasing Real Prices

When prices fall in real terms the company's share is greatly diminished. At real discount rates of 7 per cent and greater total net revenues are negative. However, the government is able to earn positive revenues over all discount rates through the collection of the PGRT and the Basic Royalty. It might be noted that these measures would have to be waved or reduced under such circumstances at the discretion of the minister. The company incurs losses over all reported discount rates. Under this scenario the private sector participants tend to subsidize the project.

Conclusions

Some aspects of the fiscal regime appear to be quite rigid offering little protection to the company's share of net revenues under deteriorating economic conditions. Certain fiscal measures are more efficient than others within the regime but it appears that the efficiency of certain measures is undone to a degree by less efficient measures.

The structure of the PIR is efficient to the extent that it is only levied if a certain level of profitability is achieved. Profitability however, is not a factor which determines the collection of the PGRT or the Basic Royalty. Under worsening conditions they can be very damaging to the private sector share.

Under more favourable economic conditions the fiscal regime does not appear to capture a larger share of net revenues. Given that the analysis deals only with the half cycle this may be a reasonable feature. In view of the uncertainty of the preceding exploration activities some present worth of the half cycle must be retained by the private sector in order to sustain exploration.

A combination of a modified PIR and no PGRT would perhaps be more symmetrically responsive to the project's profitability. A more efficient PIR would perhaps be one that is based on a lower profit floor and is imposed earlier.

2.7.5 Results: Supply Costs

The real dollar half cycle supply cost (supply price) to produce a cubic metre of oil or gas from a project is given by the total discounted cost divided by the total discounted production. From society's point of view, the supply cost of a cubic metre of oil or gas excludes taxes and royalties. The supply cost to the private company include the cost of taxes and royalties.

The half cycle supply costs of Venture gas at the Canso gas plant gate are given in Table 3 over a range of discount rates. Supply costs are reported for 3 cases; the social supply costs (at a 10 per cent discount rate) without taxes or royalties of $136 per thousand cubic metres ($3.86 per mcf), the private supply cost to the private sector's 75 per cent share (40 per cent of that share gets PIPs) of $200 per thousand cubic metres ($5.66 per mcf), and the private supply cost for 100 per cent of the project (55 per cent of the project gets PIPs) of $199 per thousand cubic metres ($5.58 per mcf).

The effective selling prices at the Canso gate for domestic sales of $171 per thousand cubic metres, export sales of $209 per thousand cubic metres, and natural gas liquids of $213 per thousand cubic metres are also reported over a range of discount rates. They are of course the same for each case since the same price assumptions are used for each of the 3 cases. The effective selling prices are obtained by dividing total discounted revenues by total discounted production. The effective prices reflect the time value of money and the production profile.

The discounted supply costs reported in each case include of costs incurred for production. Note that domestic and export sales are the same product simply bound for different markets. NGL's must be separated from the gas in order to produce sales-gas regardless of whether or not an NGL's market exists. For these reasons there is no distinction made for the cost of different gas products.

The difference between the real social supply cost without taxes and royalties and the selling price is an indication of the amount of economic rent that is available to the owner of the resource. In the foregoing discussion of net revenue shares we observed the total rents available from production. In this analysis we are simply looking at those rents on a per unit basis.

In the social base case the selling price is greater than the supply cost in all instances but one; domestic sales gas at a real discount rate of 15 per cent. The selling price in the domestic market at that discount rate is not great enough to cover the cost of production. However, the loss on domestic sales is compensated for by the prices received in the other two markets. The average selling price received at a real discount rate of 15 per cent is $203 per thousand cubic metres ($5.75 per mcf) which is slightly higher than the discounted supply cost. This would be expected given that the real rate of return in the social case is just over 16 per cent.

The real return in the private base case is slightly less than 10 per cent. Therefore, the average selling price received from all 3 markets would be expected to be slightly below the supply cost of $200 per thousand cubic metres ($5.66 per mcf). In fact it is $199 per thousand cubic metres ($5.62 per mcf).

The price received for the sale of gas in the domestic market is insufficient to cover the private per-thousand cubic metre supply costs over all discount rates. Export and NGL prices are also below private supply cost at the 15 per cent real discount rate.

3. HIBERNIA

3.1 Introduction

The Hibernia oil field is located on the Grand Banks about 300 km southeast of St. John's Newfoundland as shown in Figure 4. The field is located in Jeanne D'Arc sub-basin which is the southwest extension of the east Newfoundland Basin. The Continental Margin offshore Labrador and Newfoundland consists of a series of subsea basins and sub-basins. The largest of which is the East Newfondland Basin.[11] Water depth in the region is about 76 metres.

The structure contains 2 non communicating zones of oil bearing sands known as the Hibernia and Avalon reservoirs. A third reservoir, Jeanne d'Arc has been discovered but it has yet to be determined whether the reserves in this reservoir are commercially exploitable.[12] A diagrammatic section of Hibernia can be seen in Figure 5.

The Avalon zone is located about 2,500 metres below the ocean floor. Hibernia is an elongated reservoir covering an area of about 20,000 acres. The reservoir interval is about 88 metres thick at a depth of about 3,500 metres.[13] Both zones have been penetrated but the greater flow has come from the deeper regions of the well.

The operator in the Hibernia field is Mobil Oil Canada Limited. Mobil had at one time suggested that the field might hold about 286 million cubic metres (1.8 billion barrels) of oil. However re-evaluation has suggested that this estimate is somewhat optimistic. Other estimates put the field in the 190-240 million cubic metre (1.2-1.5 billion barrel) range. The partners in the Hibernia field and their interests in the project are given in Appendix 4.

3.2 Drilling History

In May of 1979, Chevron Standard, in partnership with Mobil, Gulf, Petro-Canada and Columbia spudded the Hibernia P-15 well from the drillship Glomar Atlantic. The Hibernia block had been farmed out to Chevron by Mobil. Expectations for the success of the well were not particularly high but on August 13 of that year Chevron announced that it had encountered indications of hydrocarbons in the 3,200-4,100 metre interval. This discovery of Hibernia was announced in September 1979.

It had been decided in the fall of that year that the Glomar Atlantic drillship was not suited for the approaching winter. While waiting for the completion of Hibernia in order to take over operations, Mobil lined up the Zapata Ugland, a 27,000 tonne semi-submersible rig as a replacement for the drillship. The Zapata completed the Hibernia P-15 and in the early months of 1980 Mobil began simultaneous delineation and further wildcatting.[14]

As of the fall of 1983, 8 evaluation wells had been drilled since oil was discovered in 1979. A ninth well the Hibernia K-14, remains to be tested. It is expected to provide information on the expanse of the Avalon Sands.[15]

Exploration activities on the Grand Banks had taken place for a number of years prior to the Hibernia discovery. The first exploration well was drilled in 1971. To December 1983, 33 wells had been drilled in the Grand Banks. Discoveries in addition to Hibernia include Nautilus C-92 (1982), Ben Nevis I-45 (1980), Hebron I-13 (1981), South Tempest G-88 (1981)[16] and the North Dana (1983) which is a gas discovery.

3.3 Technology for the Development of the Hibernia Field

To date no decision has been made on which production system is the preferred system or which will be used. Studies are ongoing on all systems. The Environmental Impact Statement for Hibernia is expected to be filed by November 1984. In this section a general overview of some of the alternatives is provided.

The driving force behind the choice of a production system is the inclement weather off Newfoundland's Coast. The high winds and waves and the frequency of fog make the conditions very similar to conditions in the North Sea. There is one important exception in this comparison and that is the presence of icebergs and floe ice. In view of the physical conditions, the choice has generally been considered to be between a platform that could be quickly moved from the area if ice occurs (floating concept) and a platform that remains fixed to the sea bottom and is able to withstand ice occurances (gravity or fixed concept). A platform whose legs could be detatched from the ocean floor is also being considered, i.e. a moveable fixed type platform.

3.3.1 Floating Systems

Semi-Submersible Production System

Semi-submersible drilling units have already been in use in the Hibernia area. The suitability of this type of unit to the area's conditions has been in question since the Ocean Ranger disaster in February 1982.

A semi-submersible production system (SSPS) includes a floating platform capable of housing a flare structure, accommodation, utility systems and the drilling platform.

Subsea wellhead installations can be placed some 25 feet below the sea floor so as to be protected from iceberg damage. Also imbedded in the seafloor are gathering units which collect oil from the flowlines that are connected to the producing wells and direct it on to a central loading unit which is also imbedded in the seafloor. From the loading unit the oil can flow to nearby storage tankers for transport to the coast. Shuttle tankers are an option for transport of the oil to the coast. This system is easily expanded to include more than one semi-submersible drilling unit.

The key feature of the SSPS design is that the semi-submersible unit could be released from the subsea production facilities and removed from the area in the event of ice danger.

Ship-Shape Production System

Another floating system that has been considered but that has not received much support for use in Hibernia is a self-contained, self-propelled ship-shape vessel with storage capacity for 183 thousand cubic metres (1.15 million barrels) of oil. The vessel would be over 294 metres long and 47 metres wide.[17] The subsea production facilities could be similar to those mentioned above.

A key drawback to this type of system design is that a ship of tanker size that could be permanently moved in a severe environment has never been built. Experts have also questioned the feasibility of tandem moving and offloading to a shuttle tanker.

3.3.2 Fixed Systems

Gravity Base Production System

Gravity Base Production Systems (GBPS) have been proven in the North Sea. However, their suitability in iceberg infested waters is not yet fully known. In general terms the system would include a platform fixed to the ocean floor and extending above the ocean surface. The portion of the structure which extends above water would house the utility systems, accommodation, flare structure, heliport, and drilling platform. The above water platform could be supported by storage silos which could be fixed to the ocean floor. Silos would eliminate the need for storage tankers in addition to the shuttle tankers. The subsea production facilities could be similar in design to the facilities described in section 3.3.1 except that the gathering units would send the oil to the central platform to be stored rather than to storage tankers or sent on to the shuttle tankers. In the semi-submersible case the oil is sent through a loading unit and then to storage tankers. The GBPS is still in the planning stages and has yet to be designed and approved for Hibernia. Some variation of it does however seem to be the most likely system to be put in place.

Caissons

A recent proposal for a pilot project suggests the construction cement-lined caissons on the ocean floor that could protect equipment from bottom scouring icebergs.[18] The proposal suggests that wellheads and oil storage operations could be installed inside the caissons. Oil could be piped to storage silos installed below the ocean floor or to tankers. The top of the caisson would be above water, housing a processing terminal, utility system, accommodation, flare structure and heliports.

3.3.3 Transport of Hibernia Oil

Hibernia oil could be transported to the coast either by shuttle tanker or subsea pipeline. The tanker option appears to be more likely.

A number of problems arise with the pipeline option. To avoid damage from icebergs and iceberg scour the pipeline must be buried. However, burial in the seabed poses a number of problems. The pipeline would have to be cement coated requiring a pipeline diametre of about 4 feet.[19] The pour point for Hibernia oil is about 50°F but the water temperature at the seabed is about 33°F meaning that if the flow is ever stopped the oil would solidify or gel within 6 to 8 hours. In order to induce flow again large pipeline diametres are needed to keep the restart pressures within the limits of available linepipe pressure design. It is not believed that pipeline burial can be accomplished within a reasonable time frame and within reasonable economic limits using existing technology.

In this study a gravity base production system is assumed. It is assumed that only one platform will be used. One half of the 80 wells required are assumed to be subsea completions. Transportation to the coast is by shuttle tanker from Hibernia to Portland Maine thence by overland pipeline to Montreal.

3.4 The Production Profile and Cost Structure

The production data and cost data used in this analysis have been provided by the Newfoundland Petroleum Directorate.[20] The data has been generalized by the Directorate from numerous industry and government sources. The data apply to a gravity based platform.

3.4.1 Production

Production from the field is assumed to begin in 1991 with production shutdown occuring in 2015. We note that most recent forecasts (December 1983) suggest that Hibernia will not likely come on stream until 1993 or after. In the first year of production 4.3 million cubic metres (27.4 million barrels) are produced. By 1994 annual production peaks at 14.5 million cubic metres (91.3 million barrels) and continues at that peak rate for 3 years. Over the remaining life of the project production slowly declines until production shut down. The Hibernia field is assumed to produce some 190 million cubic metres (1.2 billion barrels) of crude oil. Associated gas is assumed to be re-injected.

3.4.2 Costs

The analysis focusses on the half cycle development and production phase of the Hibernia. Exploration expenditures are considered to be sunk and are ignored for the purpose of the analysis. The start year is 1983 however the approval of the development plan and therefore the first development expenditures are not assumed to occur until 1986. Based on information supplied by the Petroleum Directorate, half cycle capital costs are estimated to be about 5.4 billion dollars (1983$).

Operating expenditures are estimated to be about $190 million annually (1983$) for a total of about 4.7 billion (1983 dollars). We note that development costs include the costs for re-injector wells.[21]

The investment costs and the scheduling of costs are as follows (all costs in millions of 1983 dollars):

Construction of Platforms :	1986-89	$3,231
Dredging :	1986	32
Subsea Equipment :	1989-97	500
Development Drilling :	1989-97	1,545
Articulated Loading Column:	1995-96	87
	Total	$5,395

3.5 The Federal/Provincial Ownership Dispute

3.5.1 Introduction

As a starting point for the following economic analysis of the Hibernia field, production from the field is assumed to be subject to the present Canada Lands fiscal regime. In the federal government's view the resources in this area are part of Canada Lands and under federal jurisdiction. In February 1984 the Supreme Court of Canada ruled that the federal government does have jurisdiction. Prior to the Court's decision the federal view had drawn the Canadian government into a heated debate with the Newfoundland provincial government over ownership and management of resources in the province's offshore.

The focal point of Newfoundland's initial argument for provincial ownership of the resource was based on the circumstances surrounding the province's entry into Confederation in 1949. The province argued that prior to 1949 it was granted jurisdiction over its territorial sea by the British.[22]

The federal government's victory in the court has provided new certainty to the companies operating in the area. Although the legal decision has been made the companies must now await a political settlement between the province and the federal government regarding joint management of the development. It is generally believed that the court ruling will not affect exploration activity now under way in the Hibernia area.

The events preceding the jurisdictional debate are worthy of brief mention although the complexities and implications of the legal disputes are beyond the scope of the paper.

Under the Maritime Agreement of 1977 all the Maritime provinces except Newfoundland agreed in principle to leave jurisdiction of offshore resources in the hands of the federal government while allowing 75 per cent of resource revenues to accrue to the provinces concerned. Nova Scotia and Prince Edward Island later withdrew from the agreement.

In 1979, the federal government made an offer to the Maritime provinces allowing the sharing of resource management responsibility between federal and provincial governments. An exception to this sharing formula was made in the event of matters of great concern to Canada in which case the federal government assumed responsibility. The offer was rejected.

In a document tabled in Montreal at the January 1982 Canada-Newfoundland Offshore Negotiations, the provincial government outlined the details of 2 concessions made on its part. The first is the permanent setting aside of its claim to exclusive ownership of the offshore resources. The second concession involved the province's willingness to enter into a revenue sharing formula within which the traditional provincial share would decrease after an agreed level of wealth is reached. The details of the province's view of what the formula should entail is explained in the foremen-tioned document.[23]

The 1982 Canada-Nova Scotia Agreement on Offshore Oil and Gas Resource Management and Revenue Sharing has not been acceptable to the Province of Newfoundland as a possible arrangement between Ottawa and the province. The details of the province's grievances with the agreement are set out in a study by the Newfoundland Labrador Petroleum Directorate which examines the impact of a Nova Scotia type agreement on Newfoundland.[24]

The study is quick to point out that the split of revenues under such an agreement is unacceptable to the province. The province doubts the agreement's permanence and appears to be most concerned about the terms used to define fiscal maturity which is really the driving factor behind the way in which the revenues will be shared.

In an attempt to address alternative means for revenue collection the following section outlines the measures of the Newfoundland Regulations.

3.5.2 Newfoundland Regulations

The Newfoundland Petroleum Directorate has suggested an alternative fiscal regime to the Canada Lands fiscal regime. The regime assumes provincial ownership of the resource and is laid out in the 'Newfoundland and Labrador Petroleum Regulations', 1977 under 'The Petroleum and Natural Gas Act'.

The regime's strucure is not unlike those of the western provinces where resource ownership is in provincial hands. The Newfoundland Regulations allow the province to collect a portion of the Hibernia revenues through the collection of provincial royalties, a 16 per cent provincial income tax, and through participation by a provincial Crown corporation.

The proposed arrangements do not allow the federal government to collect any royalties because under provincial ownership the federal government would not be entitled to royalties. Federal revenues are generated from the PGRT which remains unchanged and the federal Corporate Income Tax levied at a rate of 36 per cent (46 per cent less a 10 per cent abatement). PIPs are administered by the province (as is the case for Alberta) at rates pertaining to the provinces. Companies with maximum COR ratings receive 35 per cent grants towards eligible exploration expenditures and 20 per cent towards eligible development expenditures.

There are two royalties defined in the Newfoundland Regulations and both are contingent upon certain conditions of profitability being met. A 10 per cent Basic Royalty is imposed on gross revenues at the wellhead if the project is capable of generating a 20 per cent nominal rate of return. If the specified return is not met the Basic Royalty falls to 5 per cent. In addition the Regulations allow for a Sliding

Scale Royalty (SSR) which is imposed on gross revenues at rates that are phased in over production. The imposition of the SSR depends on a 25 per cent nominal after tax and royalty rate of return to the companies from the Hibernia field. If the 25 per cent return is not met the SSR can be reduced or eliminated until the 25 per cent return is achieved. The details of the SSR are outlined in Appendix 4.

The pre-specified rates of return were at one time felt to appear quite high. It was argued that they were nominal returns and they did not reflect an average profitability for the oil industry as a whole only that of an individual field. The required rates of return from a successful field are expected to be higher given the high levels of risk involved in exploration activity in general. The levels of profitability defined for the purposes of the Newfoundland royalties attempt to reflect this phenomenon. However, in the face of today's uncertainty and today's prices the 25 per cent nominal required rate of return may in fact be considered to be low and might possibly be revised before being implemented.

Adjustments to the royalty structures and profitability conditions may be necessitated if the anticipated returns that are defined ex ante are not achieved. The actual return to the field will only be determined ex post, therefore some flexibility must exist in order to resolve this possible problem through negotiation between the province and the companies.

A final provision in the Regulations, and perhaps a key element, is the options held by the Newfoundland government to take either a working interest or a carried interest in the project. The options would be exercised by the Newfoundland and Labrador Petroleum Corporation (NLPC).

Firstly, the working interest option lets the provincial company become a full partner in the project within one year of the start of the production lease. The company enters with a 40 per cent direct equity position and assumes 40 per cent of all costs.

Secondly, the carried interest option allows the NLPC to acquire a 40 per cent share without contribution towards any exploration or development costs, but the company cannot become a partner until the private participants have received cumulative net operating revenues which are in excess of three times cumulative exploration and development costs. Royalties are deductible for the purposes of net operating revenues.

The decision whether to exercise the working interest or carried interest option will depend on a number of factors including the expected profitability and Newfoundland's financial position. The carried interest option, which is similar to private deals in the oil patch, has tough conditions but it could be preferred in some circumstances. We examine the alternatives below.

The fiscal regime defined by the Newfoundland Regulations is examined further in sections 3.6.3 and 3.6.4.

3.6 Economic Analysis

3.6.1 Introduction

The economic analysis of the Hibernia field follows the guidelines set out in section 2.7 of the Venture analysis. We examine the project economics both from society's point of view (without taxes and royalties) and from the point of view of the private interests in the project (with full taxes and royalties). The objectives of the analysis include 1) a review of the Canada Lands fiscal regime in terms of its appropriateness and efficiency as it could affect the Hibernia project; 2) an examination of the relative merits of the various fiscal measures within the regime; 3) a review of alternative regimes that are favoured by the province of Newfoundland.

It may be noted that all analyses refer to development economics rather than exploration economics. They deal with the delineation and development "half cycle" only.

3.6.2 The Base Case

The wellhead price for Hibernia oil is based on a 1983 price of \$252 per cubic metre (\$40 per barrel) for oil delivered to Montreal. The transportation tariff from Hibernia to Montreal is assumed to be \$7.48 per cubic metre (1.19 per barrel) leaving a wellhead price of \$244.25 per cubic metre (\$38.81 per barrel).

Prices and costs remain flat in real terms. The inflation and cost assumptions are given in Appendix 2. The base case fiscal regime is the standard Canada Lands regime discussed in section 2.5 and detailed in Appendix 3. The federal Crown back-in is assumed to take place in 1985 just as the development phase begins. The base case analysis pertains to the private sector's 75 per cent share in the project.

The project participants and the interest held by each participant before and after the back-in are given in Appendix 4. Twenty five per cent of the private sector's 75 per cent share is assumed to be eligible for PIPs in the base case.

3.6.3 Results: Rates of Return, Canada Lands

The discounted cashflow rates of return for the Hibernia project are given in Table 4. It should be noted that these returns relate to the investment in the development and production of oil and not the investment in transportation facilities. The rates of return reveal a broad range between the returns generated under the most favourable economic conditions and those generated under the least favourable conditions.

When no taxes or royalties are imposed the nominal return generated in the social base case is 39.5 per cent (31.1 per cent real). The imposition of the fiscal regime impacts quite heavily resulting in a private nominal rate of return of 27.7 per cent (20.1 per cent real).

Sensitivity Tests

A number of variations to the price and fiscal regime assumptions are made in order to determine the relative effects of certain fiscal measures within the regime. The sensitivity tests also indicate the degree to which the economics of the project are preserved under changing conditions.

Base

The real return in this case is just over 20 per cent. The profitability of the project under the base case conditions prompts the imposition of the PIR in the tenth year of production. The overall cumulative royalty payments are 63 per cent higher, in undiscounted terms, than they would be if only the 10 per cent basic royalty had been imposed.

No PIPs

The PIPs grants that are normally available at a rate of 20 per cent towards intangible development expenditurs are removed in this case. Since only 25 per cent of the company share is assumed to be eligible for PIPs, removing them has negligible impact on the overall project economics. The removal of the PIP grants causes the rate of return to fall by less than one percentage point.

Full PIPs

In this scenario 100 per cent of the private sector's interest is eligible for PIPs. The PIP grants are paid at a rate of 20 per cent on all intangible development expenditures. The increased eligibility for the grants improves the real return marginally over the base case, to 20.3 per cent.

It may be noted that the minimal effect that the PIP grants appear to have in the Hibernia case are owing to the fact that the project is not eligible for PIPs until a number of years after the start year for the analysis, 1983. The observed impact of the PIP grants is lessened by the discounting. In addition there are offsets to PIPs through their effect on PIR. Intangible development expenditures for Hibernia are not incurred until 1989. In the case of Venture, the project begins to earn PIPs in 1983 and their effect is more evident.

No Taxes or Royalties Until Payout, and No PIPs

No taxes or royalties are imposed in this case until after the project becomes profitable and the cumulative cashflow becomes positive. This occurs in the third year after production start up. PIPs are excluded in this case. The real return declines very slightly to 19.8 per cent. Although PIP grants earned in the base case appear to be of minimal value, their removal is enough to offset the positive impact of delayed taxes and royalties. Because of the project's profitability level there are only 2 years of production during which the participants are not liable for taxes and royalties in this case.

No PGRT

The removal of the 12 per cent PGRT on net operating revenues in this case has a significant impact on the project economics. The real return increases by nearly 4 percentage points to 23.5 per cent.

The PGRT is deductible from the PIR base of net profits. Therefore in the absence of the PGRT the PIR base becomes positive sooner and the PIR is imposed at an earlier time. In this case the PIR becomes payable in the fourth year after production start-up. The total royalty payment in undiscounted terms is 97 per cent higher than it would be if only the Basic Royalty were payable. The higher royalty payment serves to dampen the improvement gained in the absence of the PGRT, but overall the earlier imposition of the PIR appears to be a more responsive fiscal arrangement.

PGRT Relief

PGRT relief as it is explained in section 2.7.3 is granted in this sensitivity. The allowed deduction of capital expenditures and the delayed imposition of the PGRT in this case are obviously of some value as the real rate of return increases by a percentage point to 21.3 per cent. The PGRT in this case is profit sensitive due to the provision of capital deductibility and the fact that it is not imposed until profits are being earned.

The impact of PGRT relief is not enormous because the project profitability is such that although the PGRT is delayed, it is only delayed until shortly after production start-up. Further, after the imposition of the tax there are only 4 more years of capital expenditures. Once there is no capital to deduct from the PGRT base the modified PGRT is identical to the conventional PGRT on net operating revenues.

No Basic Royalty

The 10 per cent Basic Royalty on gross revenues is removed in this case. The effect is very similar to that of removing the PGRT. The real rate of return increases to 23.3 per cent, an increase of over 2 percentage points above the base case return. The PIR is levied in the fourth year of production. The Basic Royalty is also deductible for the purposes of the PIR. There is a 3 year period towards the middle of the production life when neither the basic royalty nor the PIR is levied. The total royalty payment in this case is marginally less than would be taken by the Basic Royalty.

Increasing Real Prices

Wellhead prices are allowed to increase at a real rate of 5 per cent annually in this case. The real social return increases by about 12 percentage points above the base case return to 43.7 per cent. In the private case the increase is somewhat smaller. The real private return increases about 9 percentage points above the base case to 29.4 per cent.

Under the rising real price scenario the PIR is imposed in the third year of production and is collected over the life of the project. The overall royalty revenue taken in this case is more than twice the amount that would be taken in undiscounted terms if the Basic Royalty alone had been collected.

Decreasing Real Prices

In this scenario prices at the wellhead decline in real terms at an annual rate of 5 per cent. The real social return falls by nearly 14 percentage points to 17.5. The private real return falls by nearly 12 percentage points to 8.5 per cent.

The project economics are significantly diminished under the deteriorating economic conditions. The profitability of the project in this case does not warrant the imposition of the PIR. The total royalty payment in undiscounted terms is exactly 10 per cent of gross revenues. Regardless of the project's profit level the government is able to collect revenues from its royalty on gross revenues and the PGRT on net operating revenues.

The proportional decrease in the private rate of return as prices fall is greater than the proportional increase in the private return as prices rise. This suggests that the fiscal regime offers little protection for private sector price risks. This is primarily due to the Basic Royalty on gross revenues. This will also be evident in the discussion of present value net revenue shares.

Stand-Alone Taxation

The assumption of stand-alone taxation is explained in section 2.7.3. In this case the private sector is assumed not to be in a taxable position at the time that project expenditures begin and taxation is done on a stand-alone basis.

Under the stand-alone assumption the real return falls by more than 2 percentage points to 17.9 per cent. It appears that the present worth of the tax deductions in the early years is important to the private participants.

Return on Total Project

In this sensitivity the Crown back-in occurs in 1986 as in the base case but the economics of the entire project are assessed rather than the economics of the private sector's 75 per cent share in the project. The key difference between this scenario and the base case is the project's eligibility for PIPs. In the overall project analysis 43.75 per cent of the project is eligible for PIPs. Only 25 per cent of the private sector's 75 per cent share is eligible for PIPs in the base case.

The real private rate of return generated by the total project is 20.4 per cent. This is only marginally greater than the base case return as would be expected since the sensitivities carried out on the Hibernia base case reveal that PIPs do not significantly affect the project.

3.6.4 Results: Rates of Return, Newfoundland Regulations

In this final sensitivity a fiscal regime is tested that has been suggested by the Newfoundland Petroleum Directorate and is outlined in section 3.5.7. The rates of return for the private sector's 60 per cent share of the project are reported in Table 4a under both the working interest option and the carried interest option.

The private sector real return with the proposed Newfoundland fiscal arrangement falls below the return generated in the base case where the Canada Lands regime is assumed. This occurs under both the carried and working interest options. The results are not surprising. The private sector revenues are subject to a royalty on gross revenues. The PGRT remains unchanged from Canada Lands base case and the federal income tax is lowered to 36 per cent. In addition, the revenues are also subject to the Newfoundland provincial income tax levied at a rate of 16 per cent and in one instance the Sliding Scale Royalty. We note that in order to observe the true impact of the Newfoundland regime the PGRT should be set to zero. Given our findings for the PGRT impact we conclude that the rates of return under the Newfoundland regime without the PGRT are greater than under the federal regulations.

In the carried interest case the provincial Crown Corporation, NLPC does not enter until 1997. The after tax and royalty nominal rate of return is below the 25 per cent required rate therefore the project is assessed without the SSR. When only the Basic Royalty (10 per cent on gross revenues) is imposed the private sector real rate of return is 17.2 per cent which is noticably below the Canada Lands base case return but the PGRT is included.

Under the working interest assumption the nominal rate of return is above the 25 per cent required rate although just slightly. The project economics are therefore assessed with the Basic Royalty and the SSR resulting in a real rate of return of 18.2 per cent which is a percentage point above the carried interest case but below the Canada Lands base case return. In this case the impact of the SSR is not great. Given the structure of the SSR the assumed annual production does not trigger high additional royalties.

It appears from the company's point of view that the working interest option provides a slightly higher rate of return but the company would maximize its present worth in the carried interest case and presumably would therefore prefer it. Risk exposure however would also be considered.

In the working interest case NLPC carries its share of costs from the beginning. The private sector investment risk is therefore reduced.

To get a sense of the regime's ability to preserve the project economics, 2 sensitivities are tested on the case where the provinces participate as a working interest: rising real prices, declining real prices. The results are shown in Table 4a).

When prices increase annually at a 5 per cent real rate the returns are the same as the increasing price scenario for the Canada Lands regime. In both cases the real return is about 29 per cent. However the improvement as measured by the proportional increase in the return over the base case return is greater under the Newfoundland Regulation case. This is primarily because of differences in the royalty take.

Under the Canada Lands regime the effective average royalty rate as prices rise is about 20 per cent. In the Canada Lands base case the effective rate is about 14 per cent. Under the Newfoundland Regulations the effective royalty rate is about 11 per cent under both flat real prices and increasing real prices. While the royalty conditions in the Newfoundland Regulations attempt to guarantee a given level of profitability they are not responsive to increasing profitability levels in the range tested by these simulations.

In the declining real price case the only royalty that is imposed is the Basic Royalty at a rate of 5 per cent on gross revenues. The real rate of return in this case is 8.6 per cent. The return is very close to the return in the declining price case under the Canada Lands regime. However the proportional decline from the flat real price case is less because of the decreased royalty payment.

It should be noted that the "private" rates of return that are generated from the overall project will be higher than those experienced by the private companies because of higher PIPs and because NLPC, as a crown corporation, is not subject to income tax.

3.6.5 Results: Present Value Net Revenue Shares, Canada Lands

The shares of present value net revenues earned by the private sector participants and the federal government from the private sector's 75 per cent share are given over a range of discount rates in Table 5. The derivation of the total net revenues and their importance as indicators of the available economic rent are explained in section 2.7.4. Again we note that the total net revenues in this analysis are those generated within the half cycle of development and production. Preceding exploration costs are ignored.

The general results of the Hibernia present value net revenue analysis are similar to the results obtained for the Venture project. The overall conclusions reached regarding the impact and appropriateness of the Canada Lands fiscal regime are similar for the two projects.

Base

The recipient of the largest share of net revenues over all discount rates is the federal government. The government share increases as the real discount rate rises. This occurs in the Venture case also. The reason for this phenomenon is given in section 2.7.4. The share of net revenues taken by the royalty, PGRT and federal income tax are 20 per cent, 17 per cent, and 36 per cent respectively.

Increasing Real Prices

The shares earned by the companies and the federal government are not significantly altered under increasing real prices. The company does appear to gain a portion of the federal share over higher discount rates however the federal government still maintains the largest share.

The share of net revenues captured by the royalty (including the PIR) increases slightly above the share taken in the base case. The share of net revenues captured by the PGRT declines under the rising real price scenario. As in the case of Venture, when total net revenues become a greater proportion of gross revenues fiscal measures that are based on gross revenues and net revenues are less damaging to the company share.

It appears that the fiscal regime does not capture an increasing share of available rents. This is primarily due to the existence of royalties and taxes based on gross revenues and net operating revenues. The overall royalty take as a portion of net revenues increases in this case illustrating that the PIR is profit sensitive. In this case the PIR is imposed early in the production life.

Decreasing Real Prices

As prices fall in real terms the companies' share becomes negative over higher real discount rates. The federal share exceeds 100 per cent over higher real discount rates and the private sector interests are in a loss position. The federal government is always able to collect revenues through the Basic Royalty and the PGRT regardless of project profitability. Under deteriorating economic conditions the private sector share of net revenues is greatly eroded.

Conclusions

The conclusions reached in the Venture analysis, section 2.7.4, are applicable to the net present value revenue share analysis for Hibernia. In brief, the regime offers little protection to the private sector interest under deteriorating economic conditions. Under improved economic conditions the regime does not appear to capture a larger share of net revenues for the federal government. Although this may be a reasonable feature given that the analysis deals only with the half cycle, the different royalties and taxes, i.e. the basic royalty, the PGRT and the PIR, tend to be contradictory.

3.6.6 Results: Present Value Net Revenue Shares, Newfoundland Regulations

Under the Newfoundland Regulations there is an additional direct recipient of revenues: namely the province. The present value net revenue shares between the 3 parties are shown in Table 5a for the case that assumes the province participates as a working interest. The reported revenue shares pertain to the company's 60 per cent share in the project.

Constant Real Prices

In the case where prices remain flat in real terms the federal government receives the largest share of revenues generated by the private sector's 60 per cent interest. The company receives the smallest. The province receives roughly a third of the net revenues generated by the 60 per cent private interest. It should be noted however that in addition to these revenues the province receives the total net revenues generated by its 40 per cent share in the project. Those additional net revenues are not subject to corporate income taxes. Overall the province is capable of picking up a large portion of the project net revenues when it participates as a working interest.

When prices increase at an annual real rate of 5 per cent the private interest is able to pick up a portion of the net revenues that were previously enjoyed by the province and the federal government. The private interest gains because as net revenues become a larger proportion of gross revenues fiscal measures that are profit insensitive (Basic Royalty, SSR, PGRT) become less damaging.

Under the declining real prices the private sector fares badly. The federal government collects the largest share of total net revenues. The private sector tends to "subsidize" the governments over higher discount rates.

3.6.7 Results: Supply Costs, Canada Lands

The real dollar social supply costs (without taxes and royalties) and private supply costs (with full taxes and royalties) are shown over a range of real discount rates in Table 6. The derivation of the supply costs is explained in section 2.7.5 of the Venture analysis. The supply cost for oil delivered to Montreal is given by the sum of the supply cost to produce a unit of crude oil at the wellhead plus the unit cost for the transportation of that oil by tanker and overland pipeline from the Hibernia field to Montreal. The difference between the selling price for oil delivered to Montreal ($252 per cubic metre, $40 per barrel) and the real dollar supply cost to deliver that oil is an indication of the half cycle rents that are available for distribution to the resource owners. Three cases are assessed in Table 6; social supply costs, private supply costs to the private sector's 75 per cent share (25 per cent of share gets PIPs), private supply cost for 100 per cent of the project (43.75 per cent of project gets PIPs).

In all cases the supply costs for oil delivered to Montreal are less than the real dollar selling price over all reported discount rates. The base case private real return is 20.1 per cent therefore the real dollar supply cost approaches the selling price as the real discount rate approaches 20 per cent. At a 20 per cent real rate the supply cost is $248 per cubic metre ($39.40 per barrel).

This difference between the social and private supply costs reveals the impact of the fiscal regime on the supply costs. The supply costs in Case 3 are marginally lower than those in Case 2. The slightly lower costs reflect the slightly higher PIPs received in Case 3.

Supply costs for Hibernia oil under the Newfoundland Regulations are not reported. The social supply costs will of course be the same as those already reported. The private supply costs will be in the same range as those reported for the Canada Lands case given the similar rates of return.

4. CONCLUSIONS TO THE ECONOMIC ANALYSES OF VENTURE AND HIBERNIA

1. The sensitivity tests help to reveal the relative impacts of various fiscal measures and price conditions. The findings of both cases suggest that under deteriorating economic conditions the downside risk to the company is quite large.

2. The PGRT and the Basic Royalty are found to affect the project economics significantly. Neither tax is related to project profitability. The measures are capable of creaming off gains earned under rising prices while offering no protection from rising capital costs.

3. The PIR is designed to tax above normal profits however, our findings suggest that interaction of the PGRT and the Basic Royalty with the PIR is counter-productive. Perhaps the replacement of the PGRT and the Basic Royalty with a PIR that is based on a lower profit floor and imposed at an earlier time would be a more efficient approach to taxation in the Canada Lands. If the PIR base remains the same but the rate is increased the resulting marginal tax rate (considering also the income tax) would be very high and could potentially create incentives for inefficienly "padding" costs.

4. PIPs are obviously of some value to the company. At the rate at which they are earned in the base case however, they do not affect the "half cycle" economics significantly. We note that PIPs are completely unrelated to efficiency and profitability and in view of their intent, Canadianization of exploration, we believe there are more suitable means of encouraging Canadian participation.

5. We believe that the proposed Newfoundland carried interest option may be a useful avenue to pursue in trying to derive better Canada Lands fiscal regimes.

Table 1

RATES OF RETURN - BASE CASE AND SENSITIVITY TESTS

Venture	Nominal Return	Real Return
1. Base Case[1]		
1.1 Social (no taxes or royalties)	24.5	16.7
1.2 Private (full taxes and royalties, 40% of company share gets PIPs)	16.9	9.6
2. Sensitivity Tests		
2.1 No PIPs	16.6	9.4
2.2 PIPs on 100% of Company Share	24.5	16.7
2.3 No PIPs, no Taxes or Royalties Until After Payout	19.3	11.7
2.4 No PGRT	20.4	12.9
2.5 PGRT Relief	18.3	10.9
2.6 No Basic Royalty	20.4	12.9
2.7 Prices Increasing (5% real per year)	34.5 social 24.8 private	26.1 social 17.0 private
2.8 Prices Decreasing (5% real per year)	13.3 social 6.3 private	6.2 social -.33 private
2.9 Base Case Done on a Stand-Alone Basis	14.9	7.8
2.10 Return on Total Project (55% of Project Gets PIPs)	17.4	10.1

1) The base case examines the company's 75 per cent share assuming back-in occurs in 1983.

Table 2

PRESENT VALUE NET REVENUE SHARES FOR COMPANIES' 75 PER CENT INTEREST - VENTURE
in millions of 1983 dollars (per cent of total)

Real Discount Rate	Total Net Revenue	Federal Government	Company
1. Base Case, full taxes and royalties, PIPs on 40% of company's share			
5%	2855 (100%)	2158 (76%)	697 (24%)
7%	1999 (100%)	16 (82%)	361 (18%)
10%	1110 (100%)	1089 (98%)	21 (2%)
15%	269 (100%)	555 (206%)	-286 (-106%)
2. Increasing Real Prices			
5%	7873 (100%)	5443 (69%)	2440 (31%)
7%	5819 (100%)	4114 (71%)	1705 (29%)
10%	3704 (100%)	2755 (74%)	950 (26%)
15%	1705 (100%)	1461 (86%)	245 (14%)
3. Decreasing Real Prices			
5%	227 (100%)	668 (294%)	-441 (-194%)
7%	-43 (100%)	481* (-1100%)	-523 (1200%)
10%	-317 (100%)	282 (-89%)	-598 (189%)
15%	-560 (100%)	85 (-15%)	-645 (115%)

* Note that when the total net revenues are negative, a negative share percentage indicates that the party did not incur a portion of the loss, i.e. this was the case for the federal government in case 3.

Table 3

SUPPLY COSTS - VENTURE

in 1983 dollars per 1000 cubic metres (per mcf)

Real Discount Rate	Selling Prices: Domestic Sales Gas	Selling Prices: Export Sales Gas	Selling Prices: Natural Gas Liquids	Supply Cost for Gas
1. Social Base Case (No tax or royalties)				
5%	167 (4.73)	205 (5.80)	212 (6.00)	102 (2.88)
7%	169 (4.79)	207 (5.86)	214 (6.06)	115 (3.25)
10%	171 (4.84)	209 (5.92)	218 (6.17)	136 (3.86)
15%	175 (4.96)	211 (5.97)	223 (6.31)	181 (5.12)
2. Private Base Case - Companies' 75 Per Cent Share (Full Taxes and Royalties, 40 Per Cent of Share Gets PIPs)				
5%	167 (4.73)	205 (5.80)	212 (6.00)	173 (4.88)
7%	169 (4.79)	207 (5.86)	214 (6.06)	183 (5.18)
10%	171 (4.84)	209 (5.92)	218 (6.17)	200 (5.66)
15%	175 (4.96)	211 (5.97)	223 (6.31)	234 (6.63)
3. Total Project (Full Taxes and Royalties, 55 Per Cent of Project Gets PIPs)				
5%	167 (4.73)	205 (5.80)	212 (6.00)	171 (4.84)
7%	169 (4.79)	207 (5.86)	214 (6.06)	181 (5.12)
10%	171 (4.84)	209 (5.92)	218 (6.17)	197 (5.58)
15%	175 (4.96)	211 (5.97)	223 (6.31)	229 (6.48)

mcf = thousands of cubic feet

1 cubic metre = 35.3147 cubic feet

Table 4

RATES OF RETURN - BASE CASE AND SENSITIVITY TESTS

HIBERNIA	Nominal Return %	Real Return %
1. Base Case[1]		
1.1 Social (no taxes or royalties)	39.5	31.1
1.2 Private (full taxes and royalties, 25% of company share gets PIPs)	27.7	20.1
2. Sensitivity Tests		
2.1 No PIPs	27.6	20.0
2.2 PIPs on 100% of Company Share	28.0	20.3
2.3 No PIPs, no Taxes or Royalties Until After Payout	27.5	19.8
2.4 No PGRT	31.4	23.5
2.5 PGRT Relief	28.9	21.3
2.6 No Basic Royalty	31.1	23.3
2.7 Prices Increasing (5% real per year)	53.0 social 37.7 private	43.7 social 29.4 private
2.8 Prices Decreasing (5% real per year)	24.9 social 15.3 private	17.5 social 8.5 private
2.9 Base Case Done on a Stand-Alone Basis	25.5	17.9
2.10 Return on Total Project (PIPs on 43.75 of Project)	28.1	20.4

1) The base case examines the company's 75 per cent share assuming back-in occurs in 1985.

Table 4a

RATES OF RETURN - UNDER THE NEWFOUNDLAND REGULATIONS

HIBERNIA[1]	Nominal Return	Real Return
	%	%
1. Carried Interest (no Sliding Scale Royalty)		
1.1 Constant Real Prices	24.6	17.2
2. Working Interest (full Sliding Scale Royalty)		
2.1 Constant Real Prices	25.7	18.2
2.2 Increasing Real Prices	37.3	29.1
2.3 Decreasing Real Prices	15.5	8.6

1) The analysis assesses the company's 60 per cent share.

Table 5

PRESENT VALUE NET REVENUE SHARES FOR COMPANY'S 75 PER CENT INTEREST - HIBERNIA - CANADA LANDS

in millions of 1983 dollars (percent of total)

Real Discount Rate	Total Net Revenue	Federal Government *	Company
1. Base Case, full taxes and royalties, PIPs on 25% of Company's share			
5%	12117 (100%)	8316 (69%)	3802 (31%)
7%	8806 (100%)	6148 (70%)	2658 (30%)
10%	5521 (100%)	3995 (72%)	1526 (28%)
15%	2568 (100%)	2044 (80%)	524 (20%)
2. Increasing Real Prices			
5%	32446 (100%)	22609 (70%)	9838 (30%)
7%	23374 (100%)	16348 (70%)	7026 (30%)
10%	14645 (100%)	10347 (71%)	4298 (29%)
15%	7071 (100%)	5153 (73%)	1918 (27%)
3. Decreasing Real Prices			
5%	3200 (100%)	2640 (83%)	559 (17%)
7%	2214 (100%)	1988 (90%)	225 (10%)
10%	1216 (100%)	1312 (108%)	-96 (-8%)
15%	317 (100%)	665 (210%)	-349 (-110%)

* The Nova Scotia government receives the revenues taken by the federal share as per the Canada/Nova Scotia Agreement.

Table 5a

PRESENT VALUE NET REVENUE SHARES FOR COMPANY'S 60 PERCENT INTEREST
HIBERNIA NEWFOUNDLAND REGULATIONS

in millions of 1983 dollars (percent of total)

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
1. Constant Real Prices, full taxes and royalties including SSR				
5%	9597 (100%)	2859 (30%)	4057 (42%)	2681 (28%)
7%	6965 (100%)	2136 (31%)	3008 (43%)	1821 (26%)
10%	4357 (100%)	1409 (32%)	1961 (45%)	987 (23%)
15%	2015 (100%)	738 (36%)	1002 (50%)	275 (14%)
2. Increasing Real Prices				
5%	25861 (100%)	6949 (27%)	10400 (40%)	8512 (33%)
7%	18619 (100%)	5074 (27%)	7554 (41%)	5991 (32%)
10%	11656 (100%)	3255 (28%)	4807 (41%)	3594 (31%)
15%	5618 (100%)	1654 (29%)	2406 (43%)	1558 (28%)
3. Decreasing Real Prices				
5%	2464 (100%)	727 (30%)	1275 (52%)	462 (18%)
7%	1691 (100%)	545 (33%)	952 (56%)	194 (11%)
10%	912 (100%)	357 (39%)	617 (68%)	-62 (-7%)
15%	215 (100%)	179 (83%)	299 (139%)	-264 (-122%)

Table 6

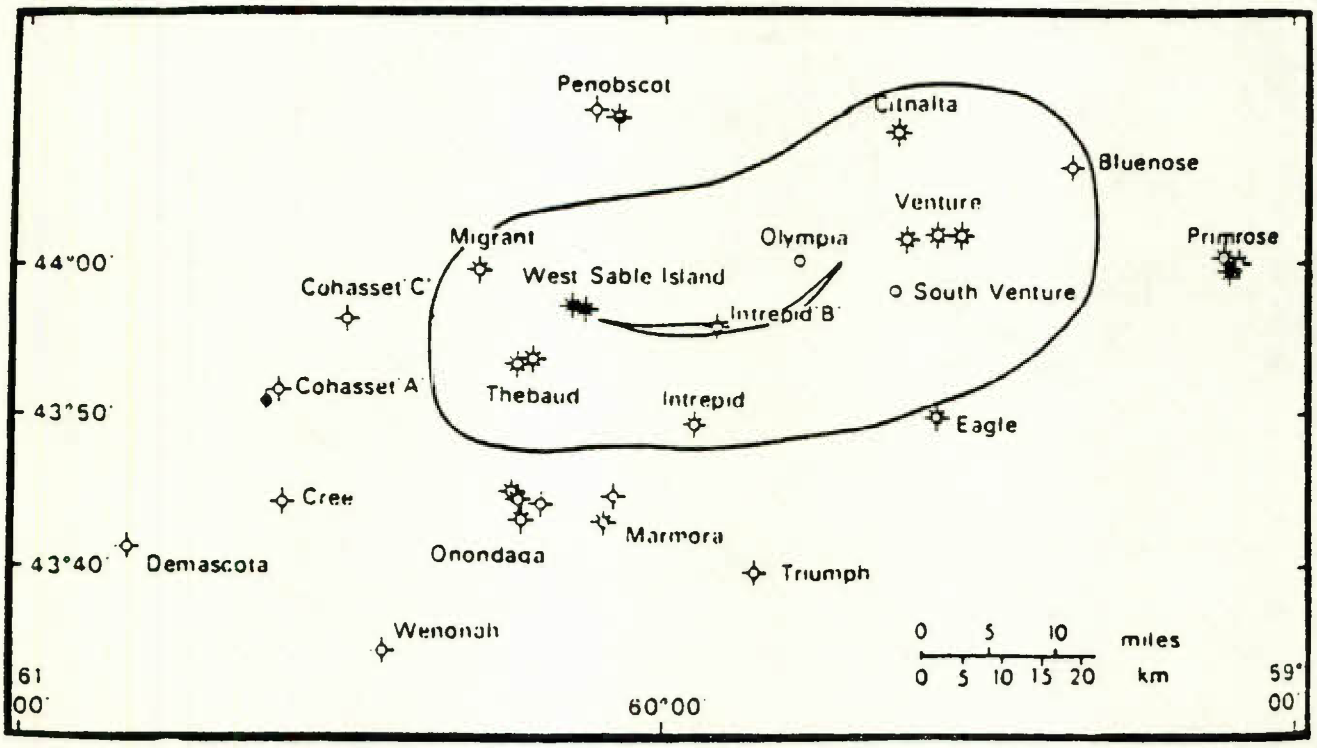
SUPPLY COSTS - HIBERNIA

in 1983 dollars per cubic metre (per barrel)

Real Rate of Discount	Supply Cost at Wellhead	Transportation + Tariff	Supply Cost = Delivered to Montreal
1. Social Base Case (No Taxes or Royalties)			
5%	66.18 (10.52)	7.48 (1.19)	73.66 (11.71)
7%	73.12 (11.61)	7.48 (1.19)	80.60 (12.80)
10%	85.07 (13.52)	7.48 (1.19)	92.55 (14.71)
15%	105.63 (16.79)	7.48 (1.19)	113.11 (17.98)
2. Private Base Case - Companies' 75 Percent Share, PIPs on 25 per cent of company share (Full taxes and royalties)			
5%	188.53 (29.95)	7.48 (1.19)	196.02 (31.15)
7%	193.67 (30.78)	7.48 (1.19)	201.15 (31.96)
10%	202.57 (32.19)	7.48 (1.19)	210.05 (33.97)
15%	216.02 (34.32)	7.48 (1.19)	223.50 (35.52)
3. Total Project - (Full Taxes and Royalties) PIPs on 43.75 percent of project			
5%	187.97 (29.87)	7.48 (1.19)	195.46 (31.06)
7%	191.89 (30.49)	7.48 (1.19)	199.37 (31.68)
10%	199.11 (31.64)	7.48 (1.19)	206.59 (32.82)
15%	215.14 (34.18)	7.48 (1.19)	222.62 (35.37)

Figure 1

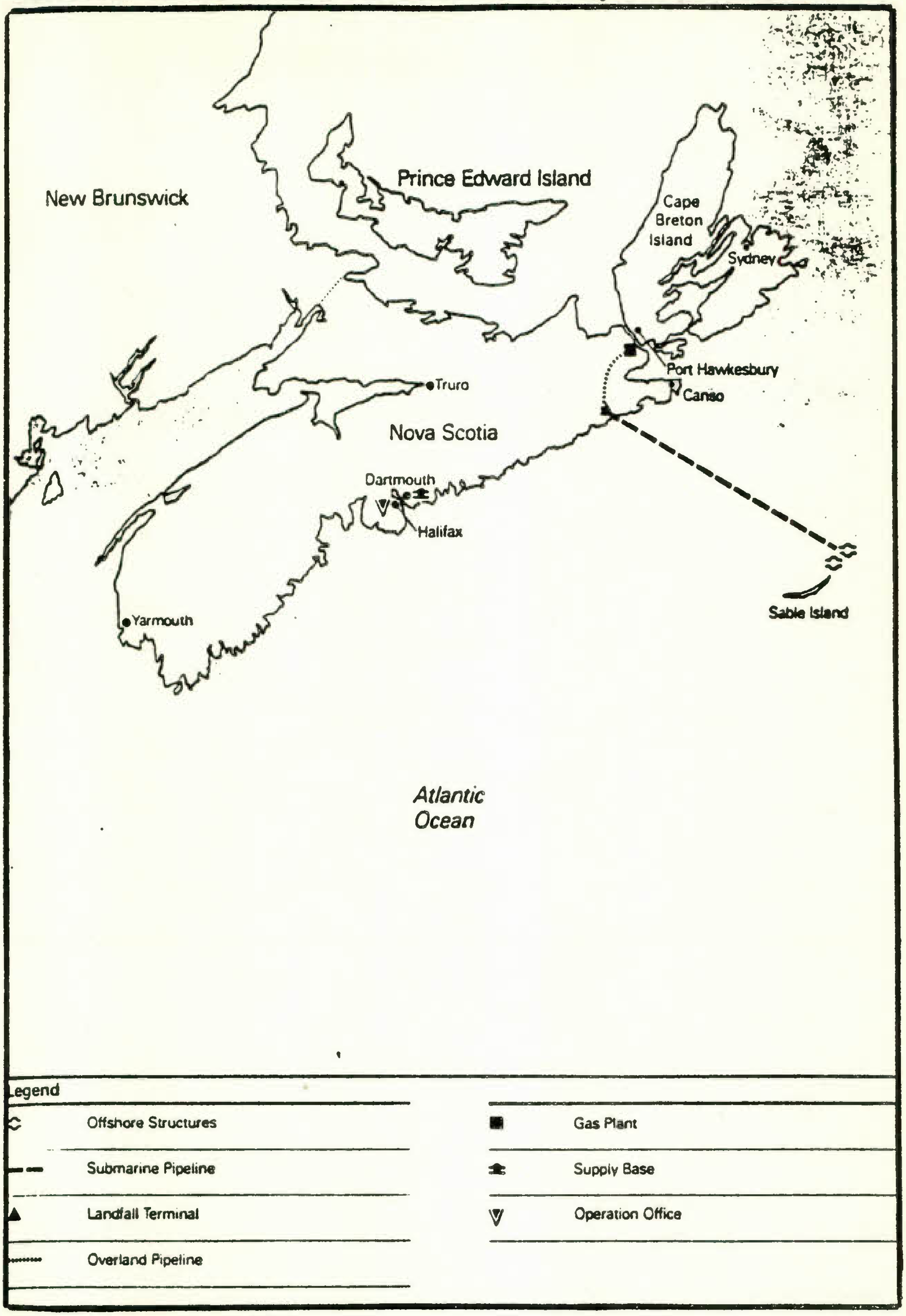
Location of Discoveries of Natural Gas



Source: Environmental Impact Statement p. 13

Figure 2

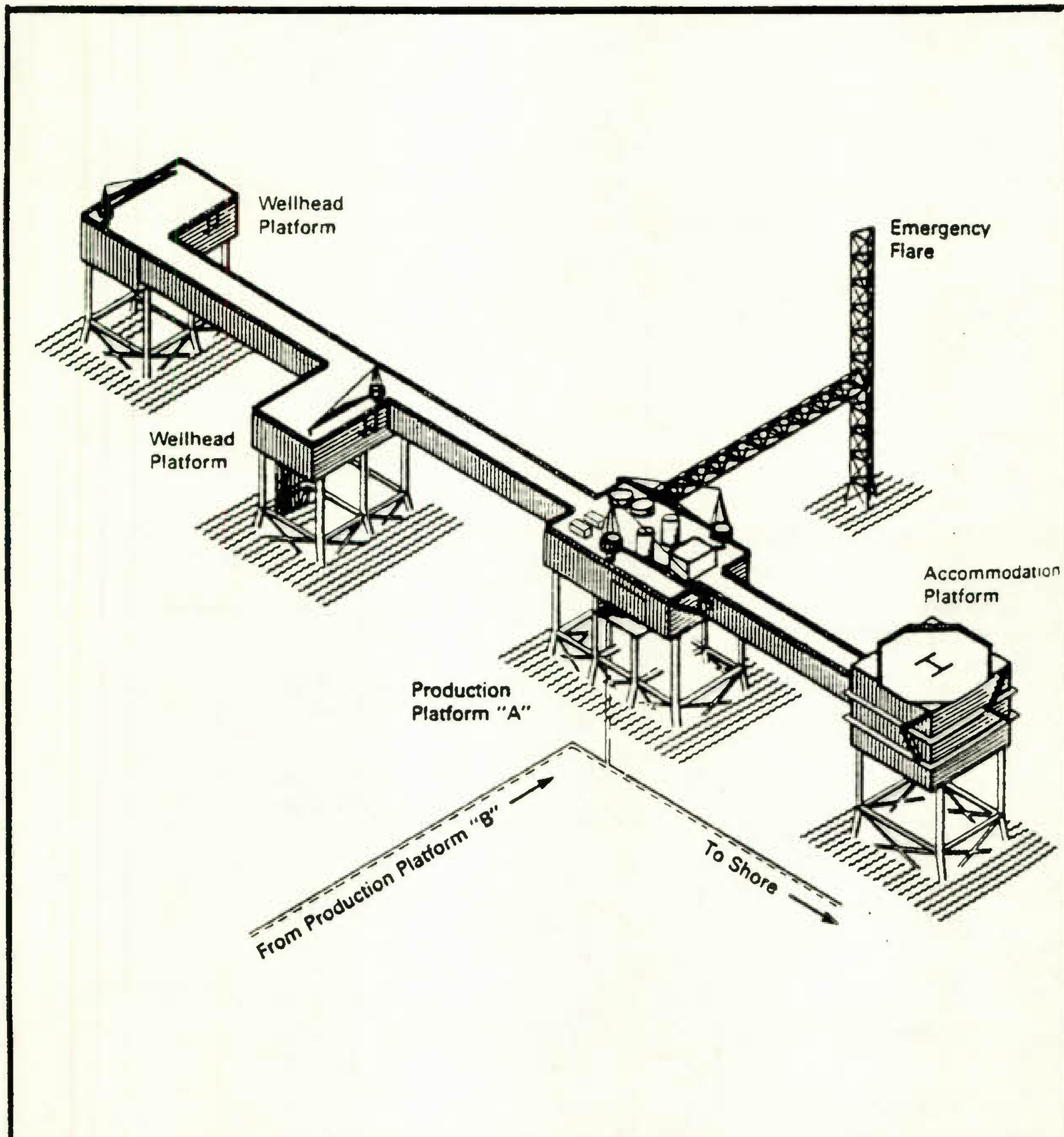
Location of the Venture Gas Development Project



Source: Report of the Sable Island Assessment Panel, p. 6.

Figure 3

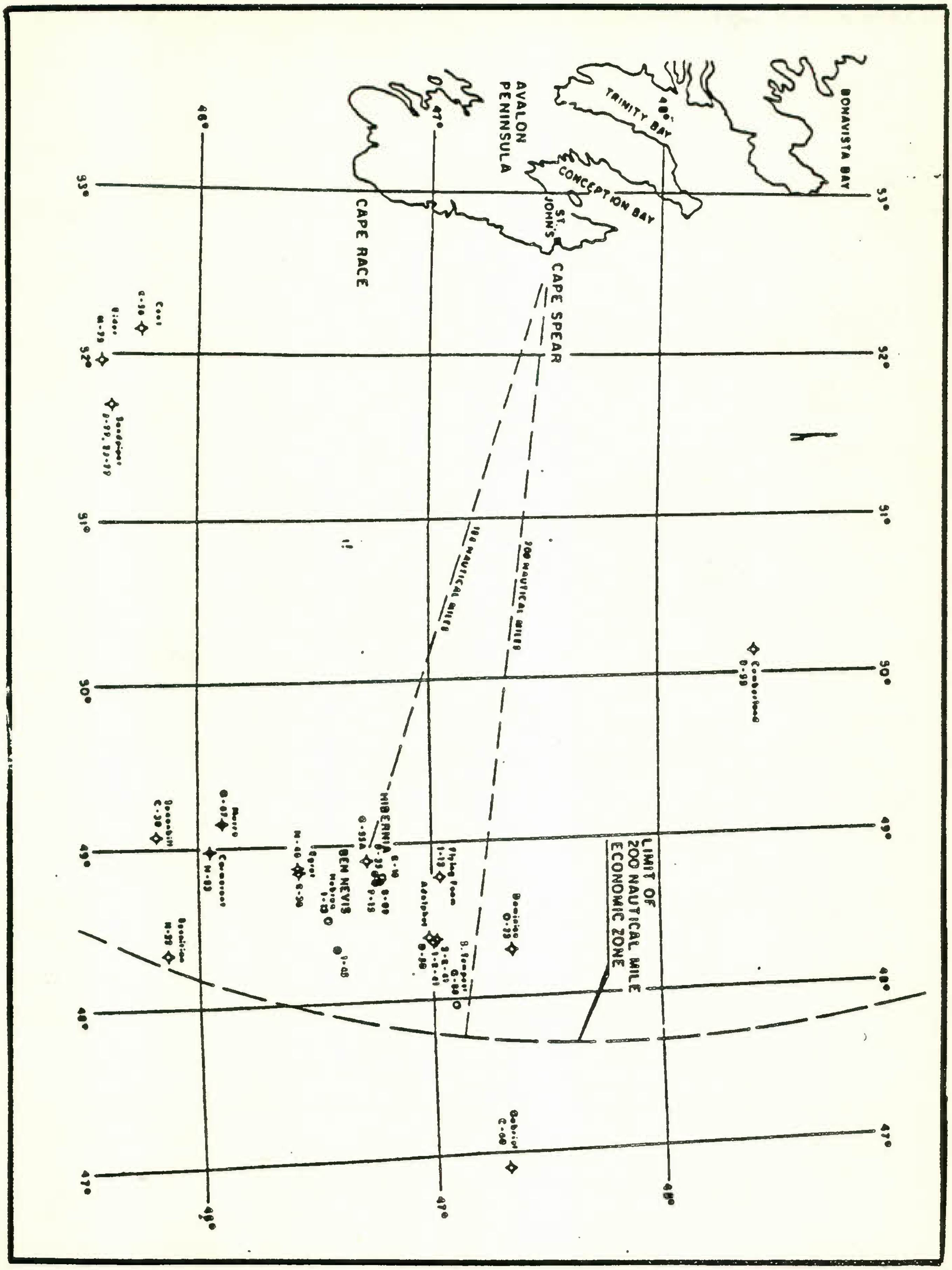
Venture Offshore Facilities



Source: Environmental Impact Statement, p. 126

Figure 4

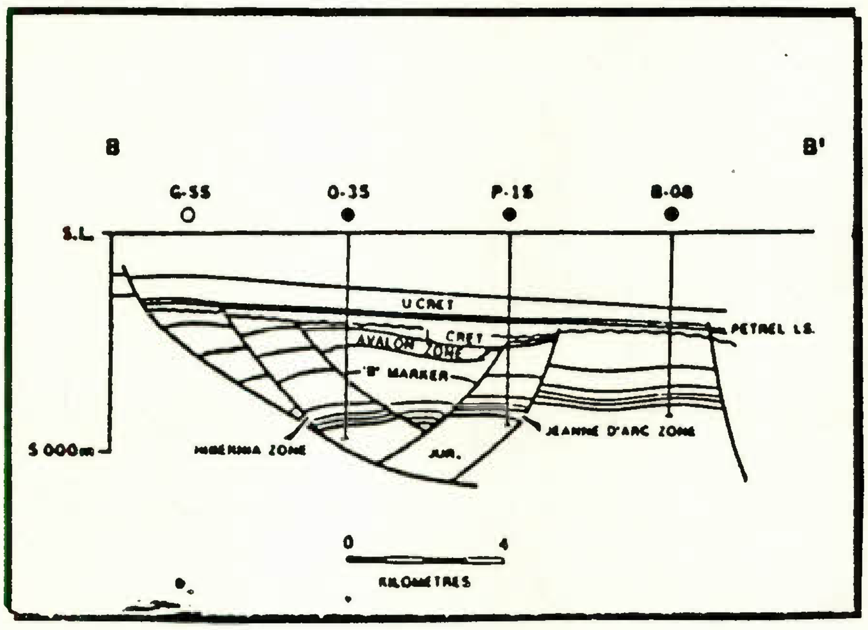
Hibernia Field Location



Source: A Preliminary Study of the Hibernia Field, D.D. Handyside and W.I. Chipman

Figure 5

Hibernia Diagrammatic Section



Source: Oilweek, August 7, 1981, p. 16

APPENDIX 1

Natural Gas and Natural Gas Liquids (NGL's) Pricing Assumptions

The pricing assumptions are based on an assumed 1983 NORP price at Montreal of $252 per cubic ($40 per barrel). This is the price assumption used for all of the Economic Council of Canada's Energy Group Hydrocarbon case studies. The assumed energy content of crude oil at Montreal is 38.5 GJ/m^3. This is the assumption used in the backup benefit/cost analysis done for the EIS.

The natural gas and NGL prices are derived on a BTU parity basis assuming the $252 per cubic metre ($40 per barrel) NORP price. The gas prices are given as the following percentages of the NORP price at Montreal:

1) Export price for natural gas is 75 per cent of the Montreal NORP in 1988 and is phased up to 85 per cent by 1995. The percentage remains constant after 1995.

2) Domestic price for natural gas is 60 per cent of NORP at the start of production in 1988 and phased up to 70 per cent by the end of production in 2005.

3) NGL's consist of condensate, propane, and butane. The condensate price is 90 per cent of Montreal NORP, butane and propane prices are both 72 per cent of Montreal NORP.

APPENDIX 2

Price, Cost and Inflation Assumptions

1. Social Base Case

   - prices remain flat in real terms

   - costs remain flat in real terms

   - annual inflation in 1983 is 8.8% then 7.8, 7.2, 7.0, 7.3, 7.0, 6.9, 6.5 then 6.0 (forecast for 1983-87 is taken from the Economic Council's CANDIDE forecast, Nineteenth Annual Review)

   - no taxes or royalties

2. Private Base Case

   - this case is the same as the Social Base Case but the Canada Lands fiscal regime is imposed

   - taxation is done on a full flow-through basis

3. Real Increasing Prices

   - base case assumptions are used but prices decline at an annual rate of 5 per cent

APPENDIX 3

Canada Lands Fiscal Regime

1. Income Tax Rate: 46%

2. Depletion is earned at a rate of 33.3 per cent. Depletion on exploration is phased out by 1984. (Allowable to a limit of 25 per cent of resource profits).

3. Investment Tax Credit = 10 per cent for expenditures on tangible assets except CEE.

4. C.C.A.:

CEE	100%	
CDE	30%	
cl 10	30%	(drilling rigs and well equipment)
cl 2	6%	(pipeline with life expectancy greater than 15 years)

5. Resource Allowance: 25%

6. Petroleum Gas Revenue Tax (PGRT): 16% on operating revenues (effectively 12%)

7. Basic Royalty: 10 per cent on gross revenues

8. Progressive Incremental Royalty (PIR): 40 per cent of net profits

where GROSS REVENUES
less operating costs
basic royalty
federal income tax allowance
investment allowancse
capital allowance
PGRT
equal NET PROFITS

Federal Income Tax Allowance: the allowance is equal to the amount of federal income tax that would be payable in the year. The notional deduction is calculated on the assumption that the firm is in a fully taxable separate entity situation.

Investment Allowance: 25 per cent of "total eligible investment" which includes costs for discovery, delineation, or development wells and other preproduction development activities, exploration costs prior to drilling a discovery well, and continuing developmental and delineation expenses. Deduction is given for current year costs plus prior year's depreciation at 10 per cent.

APPENDIX 3 (Cont'd)

Capital Allowance: The amount of the allowance that may be claimed is equal to the lesser of:

- 1/6 of "total eligible investment" costs
- the unclaimed balance of "total eligible investment"

A further provision grants exemption from the PIR for 3 consecutive years in cases where the original discovery is made prior to 1981 and declared significant prior to December 31, 1982.

9. PIPs: When applied are given at of a rate of 80 per cent on exploration expenditures and 20 per cent on intangible development expenditures.

10. Crown Backin: The federal government has the option of entering with a 25 per cent working interest at the beginning of the development phase. The private sector is compensated for post 1980 exploration expenditures through PIP grants payable at a minimum rate of 25 per cent for the lowest COR and 80 per cent for the highest COR. Pre 1981 exploration expenditures are offset by ex gratia payments that equal 1/4 of 250 per cent of the expenditure grossed up by 15 per cent per annum to the end of 1980. After the back-in the Crown assumes 25 per cent of all subsequent costs and receives 25 per cent of production.

APPENDIX 4

Partners in the Venture Gas Development Project

pre back-in

Mobil Oil Canada Ltd	(42%)	- operator
Texaco	(18%)	
Petro-Canada	(30%)	
Nova Scotia Resources	(9%)	
East Coast Energy	(1%)	

Partners in the Hibernia Field

pre back-in

Mobil Oil Canada	(28.1%)	- operator
Gulf Canada Resources Inc.	(25%)	
Petro-Canada	(25%)	
Chevron Canada Ltd	(16.4%)	
Columbia Gas Development of Canada Ltd	(5.5%)	

After the Crown back-in each of the above companies assumes 75 per cent of their pre back-in shares allowing for a 25 per cent Crown share. The companies listed here are assumed to make up the private sector interest.

The private sector participation after the back-in must be 50 per cent Canadian for Venture and Hibernia. That will not be a problem for Venture however currently private sector participation for Hibernia is 48 per cent Canadian leaving 2 per cent open.

APPENDIX 5

Newfoundland Regulations - Sliding Scale Royalty

For Production Between		The Additional Royalty is
0-8	$10^7 m^4$	0%
8-16	$10^7 m^4$	5%
16-24	$10^7 m^4$	10%
24-32	$10^7 m^4$	15%
32-40	$10^7 m^4$	20%
over 40	$10^7 m^4$	25%

FOOTNOTES

1. Mobil Oil Canada Ltd, The Venture Development Project Environmental Impact Statement, Vol. IV, Socio-Economic Assessment, 1983, p. XIII.

2. Oilweek, "Development Plans for the Venture Field", Vol. 34, No. 15, 1983, p. 12.

3. Province of Nova Scotia, Venture Development Project, Report of the Sable Island Environmental Assessment Panel, December 1983, p. 3.

4. Ibid

5. Ibid, p. 5

6. Ibid, p. 6

7. DPA Consulting Ltd, for Mobil Oil Canada Ltd, "Venture Gas Field Development, Benefit/Cost Analysis", February 1983. (A back-up study to Vol. IV of the EIS).

8. Ibid, p. 10

9. The EIS demand assumptions for sales gas are derived from ICG Scotia Gas Ltd, "Market Forecast", Section C, (December 12, 1981) Vol. 1, ICG Scotia Gas Feasibility Study, not published.

10. Canada, Department of Energy Mines and Resources, Canada-Nova Scotia Agreement on Offshore Oil and Gas Resource Management and Revenue Sharing, Ottawa, March 1982.

11. Oilweek, "Petro-Canada Plans to Complete Labrador Wells this Year", Vol. 34, No. 15, p. 34, 1983.

12. The Newfoundland Petroleum Directorate.

13. Leonard LeBlance, "Producing in Iceberg Lanes" in Offshore, Oct. 5, p. 57-58, 1980.

14. Oilweek, "Offshore 81, the Billion Dollar Year", August 17, p. 12-16, 1981.

15. The Financial Post, "New Tests Shed Light on Hibernia's Secret", December 1983.

16. Gulf Canada Resources, Exploration Frontier Division.

17. N.F. McIntyre, Mobil Oil Canada Ltd. "Hibernia floating system options would test production technology", in Resource Development, p. 10, spring 1981.

18. Globe and Mail, "Caissons Eyed for Hibernia Oil", November 30, 1983.

19. F.V. Weir, Mobil Oil Canada Ltd, "Pipeline Hinges on Berg Protection, in Resource Development, p. 18, spring 1981.

20. The authors wish to thank the Newfoundland Petroleum Directorate for the direction given in this study and for the provision of data.

21. Currently it is unclear what will happen to the associated gas from the Hibernia field. The Directorate recognizes that it will not be re-injected over the entire life of the project however current research indicates that transport of the gas may make the production of the gas uneconomic. A possible solution for lowering the offshore gas costs might be to design a transport system that uses throughput from the Venture field and the Hibernia field in order to increase volumes and lower costs. For the purposes of this analysis associated gas from Hibernia is not produced. At this point the economics of the gas production does not permit firm conclusions to be drawn.

22. Jonathan Wilby, Revenue Implications of Offshore Oil Under Different Taxation and Profit Sharing Regimes: The Case of Hibernia, Economic Council of Canada Discussion Paper no. 157, p. 4.

23. Government of Newfoundland and Labrador, Canada/Newfoundland Offshore Negotiations, A Proposal for Settlement, 1982.

24. Government of Newfoundland and Labrador, An Analysis of the Impact of a Nova Scotia Type Agreement on Newfoundland, 1982.