SEA
GRANT
PROJECT
OFFICE

THE GEORGES BANK PETROLEUM STUDY

SUMMARY

by

Offshore Oil Task Group
Massachusetts Institute of Technology

Massachusetts Institute of Technology

Cambridge, Massachusetts 02139

Report No. MITSG 73-5
February 1, 1973

THE GEORGES BANK PETROLEUM STUDY

Summary

by

Offshore Oil Task Group
Massachusetts Institute of Technology

Report No. MITSG 73-5
Index No. 73-305-Nme

Acknowledgements

This study was sponsored by the National Sea Grant Program, the New England Regional Commission, and the New England River Basins Commission through the M.I.T. Sea Grant Program. Supplemental support was provided by NSF-RANN through the M.I.T. Energy Laboratory.

In the course of this study, we have made a number of trips and solicited information from a large number of people. Invariably we have been received with hospitality and, in almost all cases, all the information we requested was furnished. We'd especially like to thank Commander Daniel Charter of the Coast Guard for making available the 1971 spill survey data to us even before the Coast Guard had a chance to review it, saving valuable months. We'd like to thank Messrs. J. R. Jackson and H. B. Barton of Exxon and Mr. O. J. Shirley of Shell for their hospitality in the Gulf, and Phillips Petroleum, especially Messrs. R. P. Willis and Neal Boyd, for an unprecedented trip to their North Sea operations. We are particularly grateful to Mr. J. Bradley O'Hare and the crew of the trawler "Tremont" for accepting one of us as a crew member for a trip on the Bank and to Commander McCann for providing us access and transport to the "Tamano" spill. Captain Barton of the Milford Haven Conservancy Board and Dr. Jennifer Baker of the Orielton Research Station spent many hours going over the Milford Haven experience with us while Dr. Lyle St. Amant of the Louisiana Fish and Wild Life Commission did the same for the Gulf. Various district offices of the Corps of Engineers provided at considerable trouble the Refinery Discharge Permits request, the N.O.A.A. Office for the Nantucket and Portland wind data, and we are particularly grateful to Mr. Jacob Lowenhaupt of the U.S. Geological Survey for detailed data on the Gulf, lease bids, production and allowables, and to Mr. Richard Hennemuth of the National Marine Fisheries Service for extracting data from his Georges Bank fishery tapes for us. We'd like to thank Messrs. Ossie Beals and B. Norton for showing us around Machiasport, Dr. David Buben of Exxon for a great deal of information on refinery effluents, Captain Pedersen of Gulf for an inspection of Bantry Bay, Mr. Michael Latham of Westinform Ltd. for allowing us access to a proprietary study of large tanker spills, Mr. Charles Martin of Charles Martin Associates for fishery information and costs, Mr. Mark Dubbledam of Stichting Maritime Research for an inspection of Rotterdam, Mr. Jacob Rivetz of the Norwegian Ministry of Industry for an explanation of the Norwegian continental shelf management system, and Dr. W. Nelson for comments on his refinery model publications. Finally, we'd like to thank the Woods Hole Community for their hospitality during our two-month stay there, especially Mr. Dean Bumpus and Drs. Max Blumer, Howard Saunders, John Todd, John Farrington, Oliver Zafiriou, Roland Wigley, and Ivan Valiela, all of whom allowed us access to all their work, published and unpublished, and spent a good deal of time patiently answering our many questions. We of course remain responsible for the results of the study but we are certain the report is a better document for the efforts of all these people.

The report was prepared by a study group under the direction of Professor J. W. Devanney III, Department of Ocean Engineering, with the advice of a Steering Committee composed of Professor M. A. Adelman (Economics) and Professor J. A. Fay (Mechanical Engineering). Reservoir modeling and offshore production simulation was the responsibility of Professor J. B. Lassiter III (Ocean Engineering); Mr. H. S. Lahman was in charge of programming of the overall petroleum development simulation model. Mr. Jack Price researched the Georges Bank fishery. Inputs with respect to refinery modeling were received from Professor E. Gilliland (Chemical Engineering). Professor D. Hoult (Mechanical Engineering) and Mr. R. Stewart were responsible for the spill probability, trajectory, and containment analyses, Professor S. Moore (Civil Engineering) was responsible for the biological analyses with the aid of Mr. Robert Dwyer, Dr. Arthur Katz, and Mr. Sid Greenleaf. The analysis of refinery atmospheric effluents and impact of gas on air quality was performed by Professor Fay and Mr. Manuel Alvarez. Ms. B. Parkhurst had the unenviable task of collecting and editing our ramblings.

Table of Contents

MASSACHUSETTS INSTITUTE OF TECHNOLOGY
DEPARTMENT OF OCEAN ENGINEERING
CAMBRIDGE, MASS. 02139
Room 5-326

March 9, 1973

Mr. R. Frank Gregg
New England River Basins Commission
Mr. Russell F. Merriman
New England Regional Commission
55 Court Street
Boston, Massachusetts 02108

Gentlemen:

We hereby submit "The Georges Bank Petroleum Study," a report based on analyses performed under a joint New England Regional Commission, New England River Basins Commission, and Sea Grant contract to investigate the regional implications of petroleum developments on the New England continental shelf.

We solicit comments on all aspects of the report. They should be addressed to Professor Joseph Lassiter, Room 5-336, Department of Ocean Engineering, M.I.T. (617-253-4496).

Sincerely,

J. W. Devanney III
Associate Professor
of Marine Systems

bmp

MASSACHUSETTS INSTITUTE OF TECHNOLOGY
CAMBRIDGE, MASS. 02139

SEA GRANT PROJECT OFFICE

Administrative Statement

The Georges Bank Petroleum Study is presented in a three part report giving the study details for the impact of hypothetical regional petroleum developments on "New England Real Income," Volume I, and on "New England Environmental Quality," Volume II, along with this Summary analysis of the study results. The Summary is intended to be a convenient digest and reference of the full study results. Careful reading of Volumes I and II is necessary for a complete understanding of the entire study, its methodology, hypotheses and results.

This study effort is, I believe, a milestone accomplishment for this Project Team and the M.I.T. Sea Grant Program in several respects. The significant aspects include:

- attacking a major regional problem from both the economic and environmental viewpoints simultaneously using consistent hypotheses and assumptions;
- developing a reliable information base for rational discussion among persons and groups having normally divergent opinions and adversary positions;
- providing the information and the analytic tools by which regional authorities, both state and federal, can approach relevant policy decisions;
- uniting the talents of experts having diverse interests into an effective team effort separating their professional analytical responsibilities from personal bias; and
- uniting for the first time the interest, participation and support of the New England Regional Commission, the New England River Basins Commission and the Sea Grant Program in a common research project of regional importance.

Funds to do this research came in part from a contract with the New England River Basins Commission, from grant support by the New England Regional Commission and the NOAA Office of Sea Grant, U.S. Department of Commerce, Grant Nos. 2-35150 and NG-43-72, and from the Henry L. and Grace Doherty Charitable Foundation, Incorporated.

Alfred H. Keil
Director

March 1973

Chapter S.1
Introduction

In June of 1971, the Secretary of the Interior announced a tentative schedule for the letting of petroleum leases on the Atlantic Continental Shelf. In later announcements, the Georges Bank, a large fishing ground east of Cape Cod (Figure S.1.1),was cited as an area of special interest. The Bank has been the subject of considerable seismic activity over the last few years. Subsequently, the U.S. Geological Survey announced plans for a coring program, once again emphasizing the Georges Bank. By these and a variety of other sources, it has become clear to New England that there is a real possibility that the Georges Bank area contains commercially exploitable petroleum reserves.

This possibility raises a number of important issues for the region. The original announcement was followed by a flurry of claims for the potential of substantial increases in regional income which were met by a groundswell of resistance stressing the danger of significant degradation to the environment and the effect this degradation would have on some of the traditional sources of New England wealth. However, the region has had absolutely no experience with offshore petroleum production, and almost no experience with petroleum processing. Thus, the information upon which to base an informed public discussion of this issue was simply nonexistent.

To correct this deficiency, the New England Governors' Conference, the New England Regional Commission and the New England River Basins Commission recognized that a study of the economic and environmental impact of offshore oil and ancillary shoreside developments would have to take place. The two commissions agreed to jointly support a study on <u>both</u> the regional income and environmental quality implications of Georges Bank oil. This conjunction of

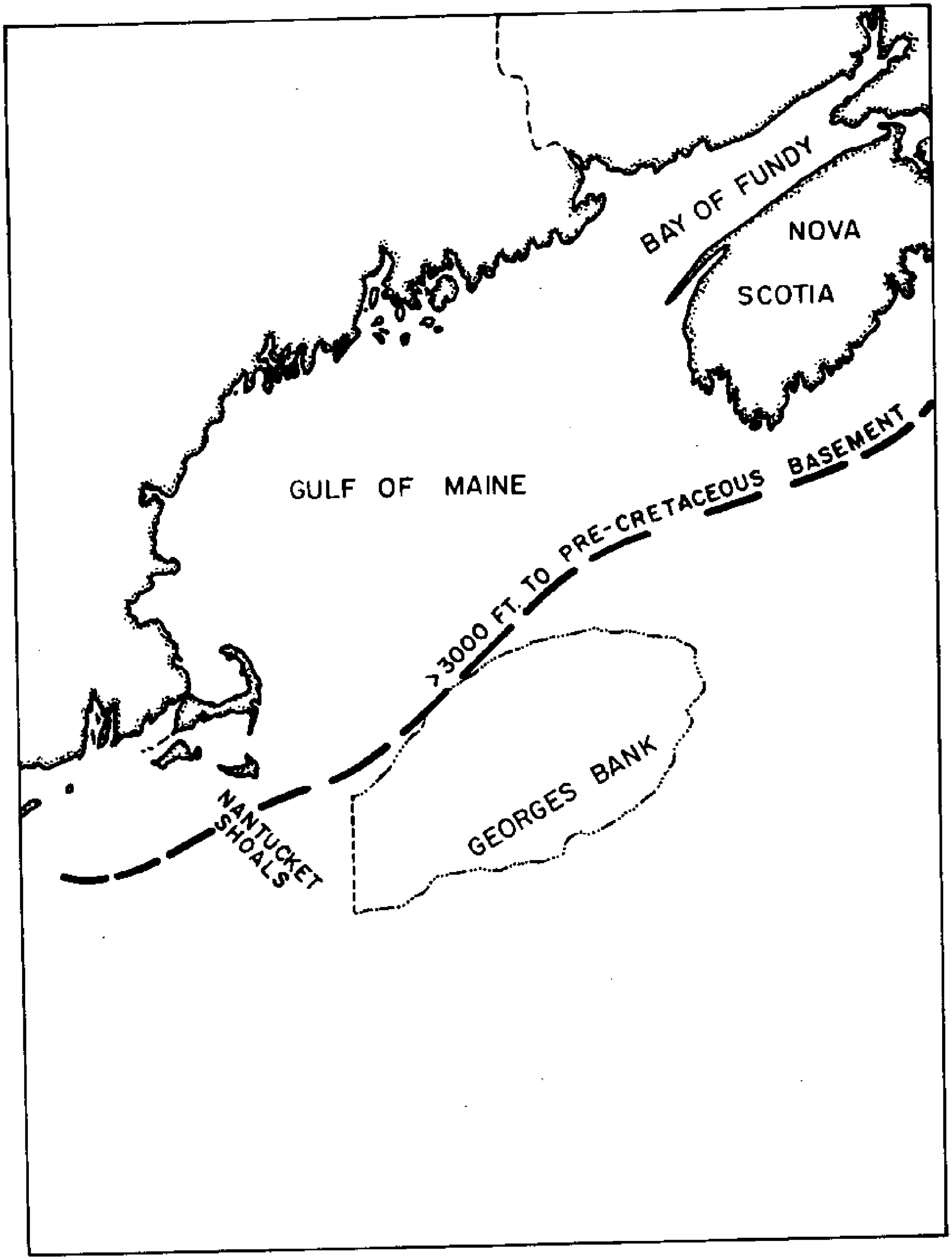

FIGURE S.1.1 ORIENTATION CHART FOR GEORGES BANK environmental and economic interests is, we believe, unique, and in our opinion, a healthy improvement over the conventional adversary system for articulating economic and environmental values, which, at least at the research level, has severe limitations in assessing environmental-economic tradeoffs. The Commissions approached the M.I.T. Sea Grant Program, which enlisted the aid of the National Sea Grant Program, who, recognizing the implications for such a study for other regions, generously agreed to supply matching funds. Supplemental support for the offshore reservoir modeling was provided by NSF-RANN through the M.I.T. Energy Laboratory under the direction of Professor D. C. White. The study group is deeply grateful to all our sponsors for the opportunity to attempt to supply the region with the information upon which policy judgements concerning Georges Bank petroleum can be made.

In order to do so, we have found it necessary to broaden the study's horizons beyond Georges Bank proper. Neither regional income nor environmental judgements about regional offshore oil can be made independently of such variables as foreign crude price, import quota policy, gas regulatory policy, refinery location, and products distribution system. We have been forced to study a wide range of combinations of these variables coupled with a range of possible Georges Bank discoveries, including no Georges Bank development at all. Thus, the study addresses the region's future with respect to petroleum in general. Indeed, some of the study's most important results, both environmentally and from the point of view of regional income, hold independently of whether or not petroleum is developed on the Georges Bank.

However, before we outline these results, it is extremely important to understand what the study does <u>not</u> attempt to do - the restrictions which the study group placed on itself in conducting the research.

1) The study does not attempt to tell New Englanders or their representatives what their decision with respect to offshore oil should be. Rather, it attempts to determine the implications of each of a number of hypothetical regional petroleum developments ranging from essentially no change in the present system to very sweeping shifts in petroleum production source, crude transport system, processing location, and products distribution system. The fact that we analyze a particular development does not imply that we hold any brief for or against this alternative. All our statements are of the "if the region does 'such and such', then this is our best estimate of what will happen" variety without making or implying any judgement about whether or not the region should do "such and such".

2) We have chosen to operate with a precisely circumscribed view of what we mean by the "implications" of a proposed development. In the first volume of the study, by implications we mean the net effect on real regional income. Real regional income is the market value of the goods, priced at 1972 prices, which the region as a whole can consume. Our economic analyses attempt to estimate how much this market value changes with various changes in the region's economic well-being as a whole and takes no cognizance of intraregional transfers of income either across intraregional political boundaries (states) or across income classes. We do not deal with the individual changes in New Englanders' incomes, some of which will be greater than others and some of which will be up and some down, but only the sum of all these changes.

By the same token, we have made no attempt to analyze the impact of these hypotheses on real national income. A change in regional income is not necessarily a change in national income, and vice versa. In general, one can obtain quite different results on the economic side, depending on whose income one is estimating. In this report, our income analysis is entirely focused on the residents of New England. We deal with neither smaller nor larger groups of people.

3) In the second volume of the report, the word "implications" is defined as measurable changes in regional water and air quality and the presently identifiable effects these changes will have on the biota. We have made no attempt to assess what values New Englanders place on these changes, nor, more fundamentally, have we investigated psychological and aesthetic values associated with further industrialization of the region, nor have we addressed the impact of the various development hypotheses on the region's political structure and the functioning of its legislative process.

   Our reason for limiting ourselves to this circumscribed set of implications is not that we believe these other values are unimportant but rather that this self-limited set of values represents the boundaries of useful quantitative analysis to which we claim special expertise.

4) The report makes no attempt to assess the likelihood that a certain amount of oil and gas will be found, nor its exact location. Such an attempt without access to the seismic data already taken would be severely and unnecessarily

handicapped. Further, even if the seismic data is made available to the region, a wide range of possibilities will still exist. Rather, we have taken the tack of hypothesizing a spectrum of possible offshore finds ranging from no discovery to a discovery so large that it is extremely unlikely to be exceeded. For each of these hypothetical possibilities we analyze the implications for regional income and environmental quality. In analyzing a particular geology we are not implying anything about its likelihood, only that it is possible. As we shall see, we can make many important statements independently of the exact nature of the find. We will, however, take advantage of one set of geological facts. Sediment depths on the New England continental shelf west of a line running roughly from Cape Sable to the outer edge of Nantucket Shoals and southwest to the slope are so shallow as to make this area an extremely unlikely prospect for petroleum. All our hypothetical discoveries are assumed to be located to the east of this line on Georges Bank proper, as shown in Figure S.1.1.

In summary, the report is intended to be an information source to which each New Englander will have to apply his own values rather than an argument for or against development. While our analysis should of course be given sharp scrutiny, we hope the report can come to be regarded as an essentially neutral document stating facts upon which all can agree, a point of departure for rational debate. We have also developed a number of analytical tools which could be used for monitoring and managing the region's petroleum system, whatever policy choices are made. These tools are capable of updating and refinement as additional information becomes available.

Finally, we urge all New Englanders sincerely concerned with the offshore oil issue to work their way through Volumes I and II. It is not always easy reading and very rarely fun but it is simply impossible to capture the full flavor of the analyses, to completely state the reasoning behind all the arguments used and the concomitant qualifications in a concise summary. The Summary is an attempt to demonstrate the bare bones of our sometimes involved arguments. It lacks the flesh and skin, which only the report itself can provide.

Chapter S.2
Summary of Volume I - Regional Income Analyses

S.2.1 The key variables specifying a hypothetical regional petroleum system

The first volume of the report is aimed at estimating the change in real regional income associated with one petroleum development hypothesis rather than another. To this end, a computer program has been developed which simulates the petroleum flows, transport, processing and distribution activities and the financial flows through time associated with a particular hypothesis about the future. This program begins at the specified crude source(s), produces the crude and delivers it to a specified refining location. It then processes the crude into four refined product classes:

1) gasoline
2) aviation fuel
3) distillate fuel oil (home heating oils)
4) residual fuel (power plant and heavy industrial fuel)

according to the region's product consumption pattern. Next it distributes the products to each of eight regional products reception ports (Searsport/Bucksport, Portland, Portsmouth, Boston/Salem, New Bedford/Fairhaven, Providence, New Haven, and Bridgeport) according to the regional spatial demand pattern. The system is simulated up to the storage tank batteries in the products reception ports.

This program takes as input twelve key variables describing the development hypothesis currently under analysis: (1) regional oil consumption growth rate; (2) regional cost of capital; (3) the foreign price of imported oil through the future; (4) federal import policy; (5) federal natural gas pricing policy; (6) federal or regional ownership of Georges Bank petroleum; (7) amount of Georges

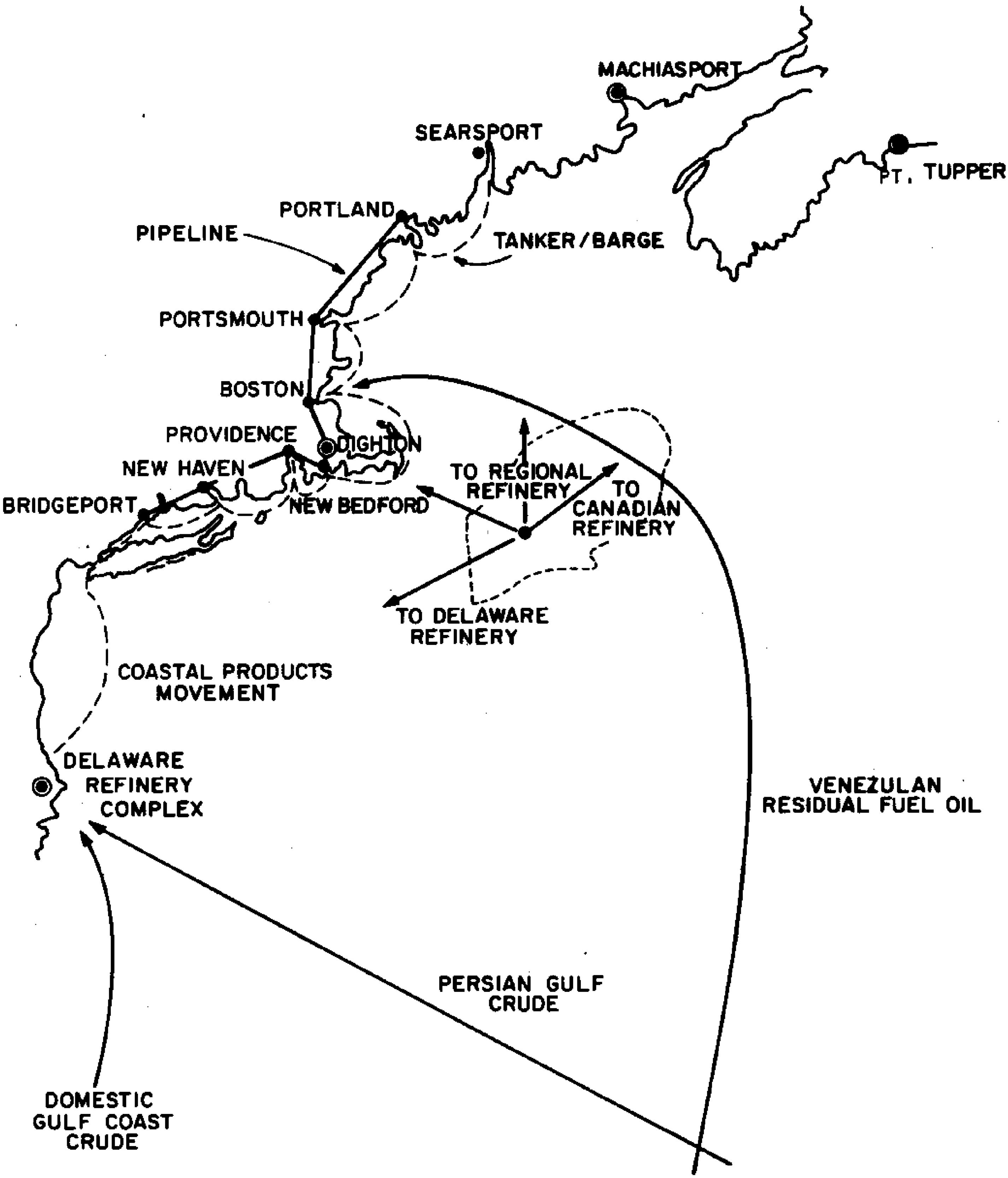

FIGURE S.2.1 PETROLEUM DEVELOPMENT HYPOTHESES FOR NEW ENGLAND

Bank oil in place; (8) amount of Georges Bank gas in place; (9) number of fields discovered; (10) refinery location; (11) whether or not residual fuel (resid) is imported directly; (12) what type of products distribution system is employed.

In addition, the program takes as input a large number of variables of secondary importance, describing the Georges Bank discovery, the refinery, and the various crude and products distribution systems in some detail.

The program as presently constituted considers the following variations of the key variables. Other values can be examined by minor changes to the program.

With respect to consumption growth rate, the program examines two alternatives: 2% and 4% per year. These numbers have been selected to represent low and high estimates of future regional consumption respectively. The growth rate over the past decade has been slightly in excess of 4% but will almost certainly drop. The growth rate is applied to the 1970 regional consumption by product and reception port. Notice that having specified a growth rate, we assume that the petroleum energy consumed is not dependent on market price within the range of prices analyzed. In this report all our analyses cover the period 1978 to 2018. 1978 was chosen as representative of the earliest a major change in the region's petroleum system could be in operation. The choice of a 40-year analysis period is arbitrary. Similar results would be obtained if one selected a cut-off date of 25 years or 50 years.

The program investigates two alternatives with respect to regional cost of capital: 8% and 15% per annum - once again chosen to represent low and high estimates of what regional investors could earn on their capital. Equivalently, this can be regarded as the interest rate at which regional consumers would be willing to borrow money. The significance of this variable is discussed below.

The size of the payments to the exporting countries for imported oil, the foreign crude cost f.o.b. loading port, turns out to be an extremely important variable from the point of view of regional income. The program considers two hypotheses:

1) Payments to exporting nations remain at 1972 level in terms of 1972 dollars, about $1.45 per barrel for medium quality Persian Gulf crude.

2) Payments to exporting nations rise to four 1972 dollars per barrel (medium quality, Persian Gulf) and remain at that level thereafter.

The first assumption is a low estimate. It assumes the importing nations immediately organize to take advantage of the fact that they have essentially the only market for Organization of Petroleum Exporter Nations (OPEC) crude and find means of generating bargaining power based on this fact. The second assumption is a moderately high estimate. It assumes that the importer nations do not find means of effectively countering the newly effective exporters' cartel but continue to follow policies which in the last three years have seen the real payments to the exporting nations almost double. Under this latter hypothesis, the actual payments to the exporters in the future could go still higher than $4.00. However, comparing the results for these two assumptions will allow us to demonstrate the swings in regional income associated with this important variable.

The program considers two alternatives with respect to import quota policy. One: no import quota; two: a quota policy which maintains domestic crude prices about $1.00 in excess of what they would be without the quota.

Two alternatives with respect to federal natural gas regulatory policy are investigated: an approximation of present regulatory policy in which the landed price of gas is held to 30¢ per thousand cubic feet and complete deregulation, where gas price is determined by supply and demand.

The program investigates two situations with respect to control over Georges Bank petroleum:

1) Federal control of the Bank. All lease payments and royalties accrue to the federal government.

2) Regional control of the Bank. All lease payments and royalties accrue to regional governments.

As can be seen, our philosophy throughout has been to bracket the problem in order to display the swing when one moves from one extreme to another.

The remaining major variables are physical in nature. We have investigated a range of finds running from 0 to 10 billion barrels of oil in place and 0 to 10 trillion cubic feet of gas, which petroleum can be contained in from 1 to 10 separate fields. The analysis is limited to discoveries such that even at maximum production, all the oil and gas produced would be consumed in New England. We shall see that it would take an extremely large find before this is not the case.

The program as presently set up can analyze any one of five refinery locations:

1) Middle Atlantic employing current terminals

2) Middle Atlantic with terminal(s) capable of handling 65' draft tankers

3) Canadian Maritime Provinces

4) Deepwater Maine

5) Southeastern New England

The program operates under the assumption that all of New England's future oil consumption will be either imported or will come from the Georges Bank. It appears clear that in the future a substantial portion of the nation's oil consumption will have to be imported and, for all but Georges Bank crude, New England is the most distant market for domestic oil. Thus, it will pay the industry to market non-Georges Bank domestic oil elsewhere and supply New England from overseas. The industry cost of foreign crude is assumed to be determined by the landed cost of Persian Gulf oil. This is the source on the margin and as such determines the cost to the United States of imported crude.* Foreign oil that is nearer to the U.S. will command a premium which is determined by the difference in transport expenses between the point of origin and the Persian Gulf.

The program also operates under the assumption that all New England oil consumption between 1978 and 2018 (less possibly residual fuel, depending on the refinery output option) is refined at exactly one of the above five locations. This is unrealistic. For one thing, it would require the establishment of a new one and a half million barrel per day refining complex by 1978 for locations (3), (4) and (5). The industry would be unwilling to bring on this much capacity in such a short time due to the temporary overcapacity that would be generated. For another thing, it is at least possible that the various companies supplying the refining capacity would do so from different locations. Nonetheless, the assumption of a single refining site is consistent with our basic philosophy of operating with the extremes in order to demonstrate the swings. Thus, for example, our deepwater Maine option might be thought of as an extreme case of the basic policy of accepting a large refinery in northern New England. In actual fact, we can be quite sure that even if this policy were followed, some of the region's consumption would be refined elsewhere, at

*See Chapter I.2 for a complete discussion of this reasoning.

least for a while. From an overall policy point of view, this single refinery site assumption is quite useful. At a more detailed level such as the evaluation of a products reception terminal off Boston, it causes us some problem. For computational purposes, it is necessary to specify an exact location representing each of these five policy options. In the runs displayed in this report, the Middle Atlantic refineries are assumed to be located on Delaware Bay, the foreign refinery at Pt. Tupper in eastern Nova Scotia. The deepwater Maine option is represented by Machiasport and the southeastern New England option by Dighton, Massachusetts, serviced by an offshore terminal in Rhode Island Sound. These choices are, of course, arbitrary, and other locations can easily be investigated.*

Two options with respect to <u>refinery output</u> have been examined:

1) Above refineries produce a mix of products which is consistent with the 1971 regional consumption of gasoline, kerosene/jet fuel, distillate fuel and residual fuel. This is known as the ALL N.E. option.

2) Above refineries produce only the region's consumption of gasoline, kerosene, and distillate but no residual fuel, the NORESID option. For this option, .5% sulphur resid is imported directly.

The program considers three different <u>products distribution systems</u>:

1) The present tanker/barge system based on present terminals;

---

*We are aware that some of these hypotheses would require changes in present legislation before they could be implemented. The same thing is true of many of the federal policies studied.

2) The present system with the exception of a single point mooring (SBM) in 72 feet of water off Boston;

3) A pipeline system extending from Bridgeport to Portland. As presently constituted, the program evaluates this option only for the southeastern New England refining option.

By selecting various combinations of the above twelve variables, a wide range of possible hypotheses about the region's future petroleum system can be investigated. By minor modifications to the program, still other values of these variables can be examined.

S.2.2 The basic approach

The basic rationale used in computing an estimate of the change in regional income associated with a given change in the region's petroleum system is:

1) For a given oil consumption growth rate, all the hypotheses have been designed to perform exactly the same function: to supply the region the stipulated amounts of energy by product delivered to the eight products reception ports through the period 1978 to 2018.

2) For each such hypothesis, the program performs a rather extensive set of computations whose final output is the cost to the region of obtaining this energy by this hypothesis, that is, the market value of the alternate consumption forgone in order to obtain the petroleum products.

3) Since for a given consumption rate, all the hypothetical developments perform the same function, the <u>difference</u> in regional real cost between two such hypotheses is the difference in the market value of what the region can consume associated with moving from one hypothesis to the other. This is the change in real regional income associated with this switch. The cheaper of the two in regional cost terms performs the same service but leaves the region something left over, which something can be spent as the region desires.

Thus, our basic approach is to obtain an estimate of the regional cost for each hypothesis and then to compare these estimates across hypotheses.

The regional cost of a hypothesis is made up of four terms:

1) The actual direct payment made by the regional consumer for his petroleum products f.o.b. the products reception terminals. By expending this income the regional <u>consumer</u> forgoes alternative consumption whose market value is the amount of the payment for petroleum.

2) However, some of the consumer's payments are not costs to the region as a whole, for they represent <u>increases</u> in the real income of other regional entities. Therefore, from the direct payments made by regional consumers we must deduct several items:

   a) the difference between the real income of regional investors with and without the development - the regional shareholder's share of after-tax profits:

   b) the region's share of federal revenues associated with the hypotheses - alternatively the decrease in the regional taxpayer's federal tax bill resulting from the federal revenues generated by the development;

   c) the revenues accruing to regional public bodies net of the increase in regional public costs associated with the development - the decrease in the regional taxpayer's state and local tax bill resulting from the development;

   d) the increase in the income of regional labor over what it would have been without the development hypotheses.

The key point here is that not all the regional consumer payments which end up in the hands of New Englanders should be deducted from regional cost, but only those which represent income which New Englanders would not have had without the development hypotheses. Thus, if a New Englander earns $5.00 an hour working at a refinery and would have earned $4.00 an hour without the refinery, then the deduction should be $1.00, not $5.00. When one applies this differential viewpoint to the indirect effects of the developments in the respending markets, the so-called multiplier effect, the net impact of respending in most cases is quite small and in this report we have, with few exceptions, ignored it. This fact is argued at length in Volume I, since this point is often obscured in public debate.

Our assumptions about regional cost of a development are summarized in the following equation:

REGIONAL COST = PAYMENTS MADE BY REGIONAL CONSUMERS
- .05(PROFITS + FEDERAL REVENUES)
- .50(REGIONAL SHORESIDE REVENUES)
- 1.00(REGIONAL OFFSHORE REVENUES)
- Correction for the difference between the regional payrolls of the development and what the labor would have been earning in the absence of the development

The first term depends on the market price of the products which will obtain under the development hypotheses. This is by far the most important term in the regional cost equation. Our treatment of market prices is outlined in the next section.

The second term assumes that the percentage of the corporation(s) supplying products to the reception ports owned by New Englanders is roughly equal to New England's share of the national wealth. Similarly, the equation assumes that New England pays 5% of all federal taxes based roughly on the region's percentage of the national population. In general, differentials associated with this particular term are small, so whether we assume, for example, 5% or 6%, will have little effect on our final results.

The third term assumes that the cost to the region of supplying the public services associated with the shoreside facilities generated by the development is one-half the regional revenues (property taxes, state income taxes, etc.) paid by the development. Once again, differentials associated with this term are small compared to some of the other numbers we will be dealing with so that the results are not sensitive to the percentage selected. A study of the lease and royalty payments which have been made in the Gulf was undertaken. This analysis indicated that, by shrewd leasing, the public body controlling the resource could appropriate to itself the bulk of the difference between the developer's costs and the landed price of offshore oil. On this basis, the percentage of the additional profits associated with an offshore development which is turned over to the public body has been set at 75%. This assumes informed, effective management of the Bank.

The fourth term assumes that the costs of collecting and administering offshore leases are negligible compared to the revenues. This is before environmental costs, which are treated separately in Section S.2.7. This term will be zero if the region doesn't control the Bank. With respect to the last term, it turns out that all the regional payrolls generated by the various developments are small compared to some of the other numbers with which we will be dealing, with one notable exception: the payrolls associated with the construction and operation of regional refining capacity sufficient to supply all the regional petroleum products consumption. As indicated earlier, the impact of regional payrolls on regional income depends critically on the alternative opportunities for the labor so employed. A preliminary study of the structure of unemployment in the two hypothesized regional refinery locations, Machiasport and Dighton, was undertaken. For Machiasport, a preliminary estimate is that 60% of the refineries' payrolls would go to relatively low-skilled New Englanders who would make about one-third more on the average than they would if there were no refinery. That is, roughly 20% of the refineries' payrolls would represent a net increase in regional income. Examination of the southeastern New England labor market indicated that, under present conditions, sufficient excess labor suitable to meet the refineries' requirement for low-skilled labor existed. Under the extreme assumption, that no other employment opportunities would develop, perhaps 60% of the refineries' payroll would represent an increase in regional income. With this as a background, we have decided to investigate and present the results for three different assumptions:

a) Full employment: refinery payroll has no net effect on regional income, for refinery labor would be employed at approximately same wage if refinery were not there.

b) Best guess: 60% of refinery payroll goes to New Englanders, who earn one-third more than they otherwise would.

c) Extreme unemployment: 60% of refinery payroll goes to New Englanders who would otherwise earn nothing.

S.2.3 Market price changes

The two basic assumptions underlying our treatment of market price changes are:

1) The payment to the exporting nation for imported oil does not depend on the transport cost of delivering that oil. In other words, the exporters' cartel does not appropriate any transport savings to itself.

2) The markets between the corporation supplying the products to New England and the New England consumers are sufficiently competitive so that any decrease in the delivered cost of the marginal unit of oil is passed on to the consumer.

There appears to be considerable evidence that the second assumption is true at least for the non-gasoline markets. The first assumption depends on the market nations breaking the exporters' cartel or the exporters' cartel not acting optimally from its point of view.

Under these assumptions, the delivered cost of the most expensive unit of oil delivered to the market, the marginal unit of oil, becomes all-important. The investor's cost of the marginal unit of oil delivered to New England will depend primarily on what combination of foreign crude prices f.o.b. and federal import policies obtains. We have examined four cases with respect to these variables:

1) NO IMPORT QUOTA - NO FOREIGN CRUDE PRICE ESCALATION (low estimate)
Marginal oil is Persian Gulf crude at \$1.65 (1972 dollars) per barrel at loading port. For NORESID option, marginal resid is .5% sulphur Venezuelan resid at \$3.10 per barrel, loading port.

2) NO IMPORT QUOTA - FOREIGN CRUDE ESCALATION (upper estimate)
Same as (1) except crude cost f.o.b. Persian Gulf rises to \$4.20 (1972 dollars) in 1980. Imported resid rises to \$5.55 per barrel.

3) IMPORT QUOTA - NO FOREIGN CRUDE ESCALATION
Marginal oil is Gulf Coast crude at $3.90 per barrel in Louisiana. Resid same as (1).

4) IMPORT QUOTA - FOREIGN CRUDE ESCALATION
Marginal oil is Persian Gulf crude but price support policy maintains domestic prices $1.00 in excess of crude price in (2). Resid same as (2).

The market price of the distillate products at the reception port storage tanks is determined by the program by delivering this oil to the specified refinery, whereupon it refines and distributes it just like any other oil for that particular development hypothesis. The total investor's cost of performing these functions, including all taxes, is determined, from which the price required to return his cost of capital is calculated. This price is then applied to all the distillate products consumed within the region to obtain our estimate of the direct cost to the consumer, which is of course equal to the industry's gross revenues used in the profits computations. Under these assumptions, a portion of the savings (all in the no-quota case) in national income due to differences in refinery location is passed on to the regional consumer. For the no-quota case, the situation is similar to that sketched in Figure S.2.2, which compares the present East Coast landed supply curve (no find) with that for a 65' draft terminal. The new terminal is equivalent to a downward shift in the horizontal position of the curve. Under competition, the price will drop from p to p*, the full differential.

Just as importantly, under these assumptions, Georges Bank oil will have no effect on regional products prices. The effect of a large Georges Bank oil find is sketched in Figure S.2.3. The find is equivalent to a rightward shift

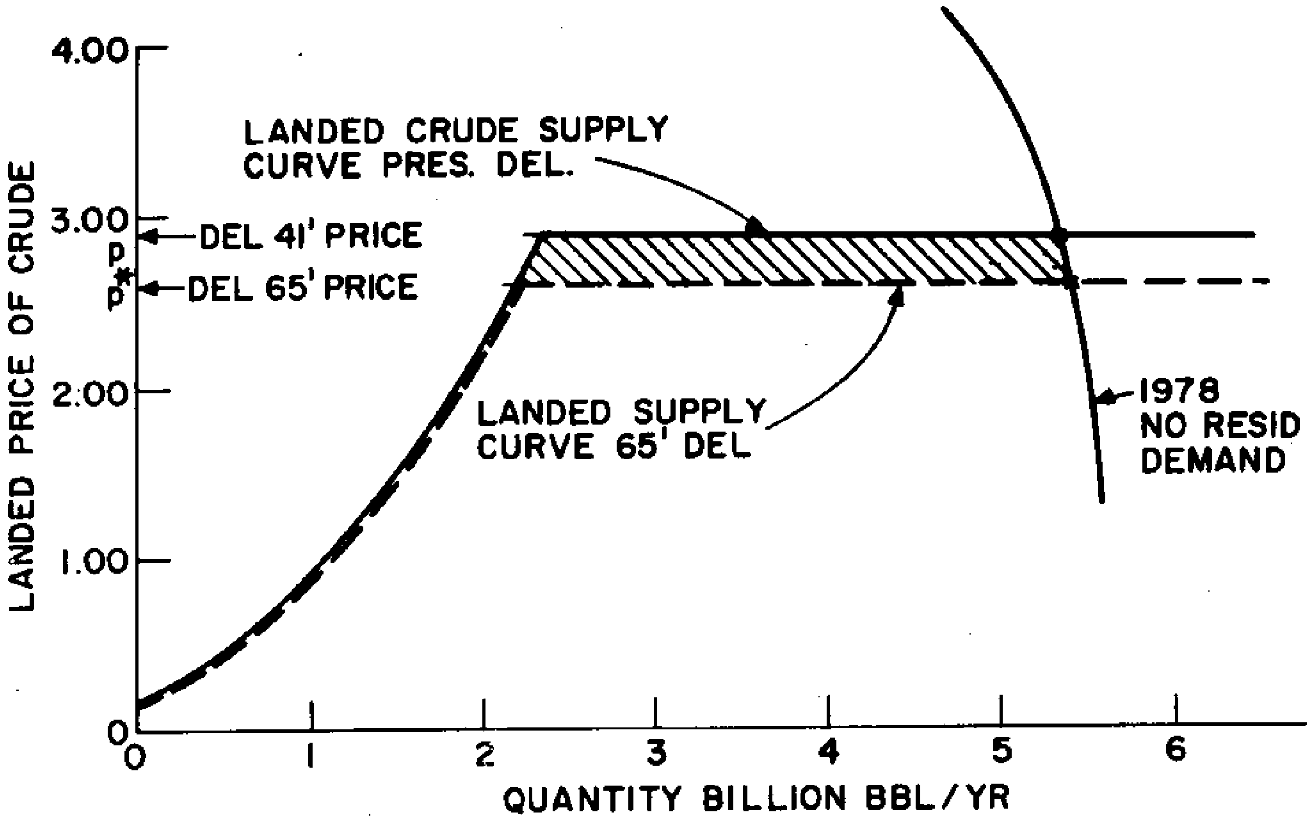

FIGURE S.2.2 SHIFT IN DIST. I-IV SUPPLY CURVE DUE TO SWITCH FROM 41' DEL. TO 65' DEL, 1978 @ 4% GROWTH RATE, NO IMPORT QUOTA

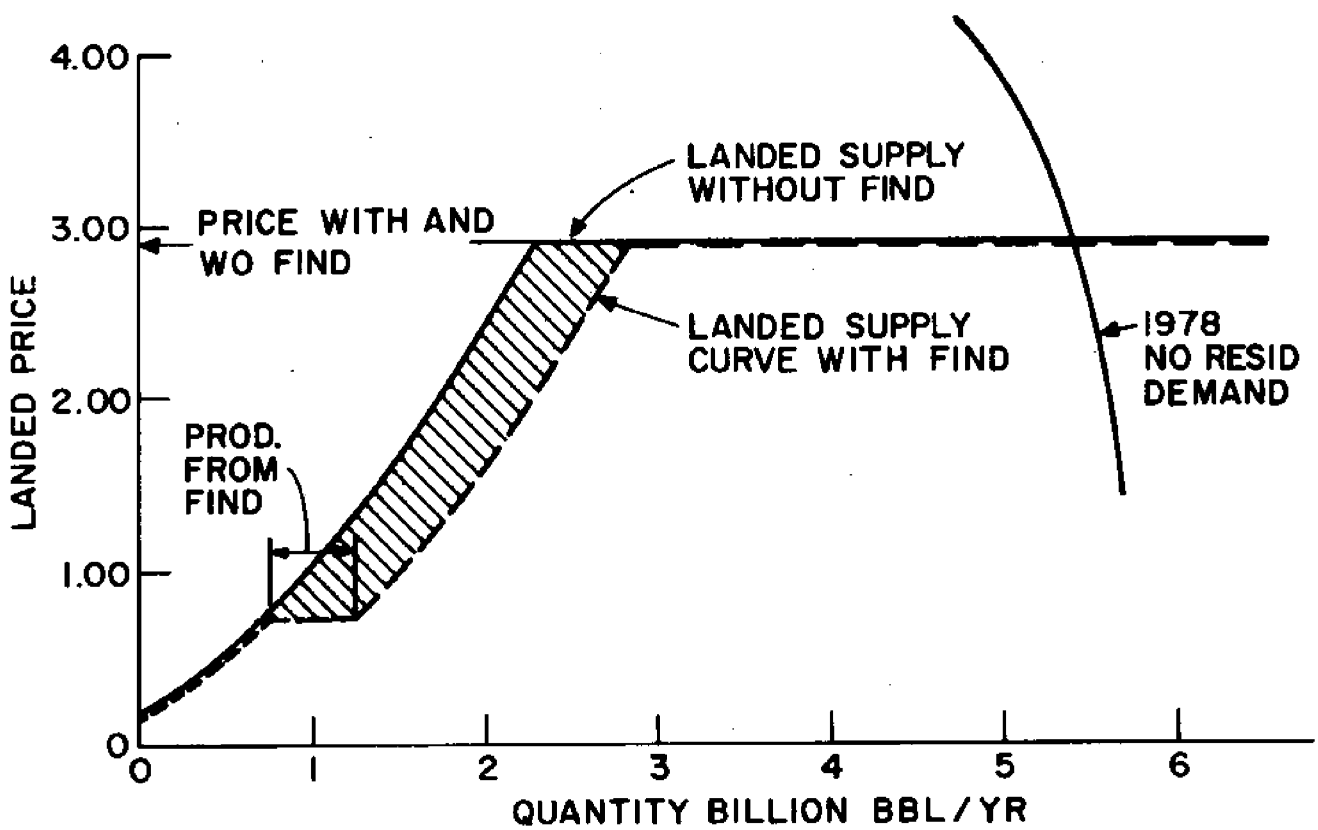

FIGURE S.2.3 SHIFT IN DIST. I-IV SUPPLY CURVE DUE TO GEORGES BANK DISCOVERY LANDING 500 MM BARREL PER YEAR AT PRES. DEL.

in the vertical portion of the curve. The investor's cost of the marginal unit has not been changed. Some oil will still be imported. The savings in national income associated with the oil find (the hatched area in Figure S.2.3) will be split between the developer and the public entity controlling the resource.

The situation with respect to gas is considerably different. Two cases have been studied:

1) continuation of present gas regulatory policy,

2) deregulation of gas price - price determined by supply and demand.

The basic assumption use is that the gas, if landed, will replace .5% sulphur resid. This is conservative with respect to the value of the gas for at least some of this gas will go to higher valued uses. Under present regulatory policy, the gas is assumed to be priced at 30¢/Mcf. For most of our gas finds, the marginal cost of landing gas is less than this. Under deregulation, the gas is priced at the value of the resid it replaces on an energy equivalent basis which ranges from 60¢ to $1.00 per Mcf, depending on whether resid cost is escalated or not.

S.2.4 Present value

The financial flows resulting from any of the petroleum development hypotheses will occur at different points in time through the future. The payment of $1.00 for petroleum 10 years from now is quite different from the payment of $1.00 now, for one could invest an amount considerably less than $1.00 now in order to have $1.00 10 years from now. The amount that one has to put aside now in order to have an amount x some time in the future is known as the present value of x. It depends on the interest rate which one can obtain and how far into the future one must make the payment. The average interest rate which the region could earn on its capital is known as the regional cost of capital.

In order to account for the region's opportunity to invest its capital at a positive interest rate, we have put all the regional costs associated with a particular development hypothesis on a present value basis. That is, for each hypothesis, we have computed the amount the region would have to put up now (1972) in order to be able to make all the payments associated with the hypothesis through the life of the analysis (1978 to 2018). This is known as the present valued cost of the hypothesis. This computation has been performed for two different regional costs of capital: 8% real and 15% real.

Suppose for one hypothetical development that the present valued regional cost turns out to be $22 billion and for another, $20 billion. This implies that we estimate that moving from the first alternative to the second would be equivalent to handing to the region in 1972, on a one-shot basis, two billion dollars' worth of income. Of course, the region would actually see this increase spread throughout the life of the analysis, some 40 years. However, this two billion dollars is the equivalent amount received now at the assumed regional cost of capital of all these future increases.

S.2.5 Brief description of subsystem analysis

The development simulation program consists of four major subroutine packages. The first, known as EXCRUDE, designs and costs the system which delivers extraregional crude to the refinery. The second package, REFINE2, designs and costs the refinery itself, and the third package, PRODIST, designs and costs the system which delivers the products from the refinery to eight selected New England products reception ports. The fourth package, called OFF-SHOR, contains the reservoir model and handles the Georges Bank discovery proper. In addition, there are a number of subroutines which perform such functions as:

1) estimating regional petroleum products prices under the development hypotheses, according to the reasoning outlined in S.2.3, and thereby developing the direct cost to the regional consumer of his oil consumption and the gross revenues of the suppliers;

2) computing the suppliers' federal and regional tax payments and after-tax profits;

3) combining regional consumer costs, regional payrolls, investor profits and public revenues into an estimate of the overall present valued regional cost of the development over the life of the analysis.*

---

*The program is written in PL/1 under the Optimizing Compiler. In total it contains some 4,000 executable statements. It presently exists in object form as a load module located on disk at the M.I.T. Information Processing Center. The load module occupies approximately 175,000 bytes of storage and requires approximately 230,000 bytes of main storage to execute. In addition to the program proper, there are several files containing semi-permanent data on disk which is referenced by the program during execution.

S.2.5.1 The extraregional crude package

The function of the extraregional crude package, EXCRUDE, is to estimate both the national cost and investor cost of foreign crude landed at a specified refinery for the hypothesis currently under analysis. EXCRUDE takes as input the annual amount of crude to be delivered at the refinery through the life of the project, the distance from the crude oil source to the refinery, draft limitations at loading and discharge ports, the time the vessel is at reduced speed in the vicinity of the loading and discharge points, the cost of the crude to the investor at the loading flange before payments to the exporting nation and the amount of these payments to the exporter through time.

EXCRUDE examines the draft limitations at each end of the route and compares them with a vessel capacity versus draft table to determine the largest conventional tanker which can serve this route. It then considers the amount of oil to be moved in the first year of the project, determines the number of tankers of this size required to move this amount and charters that number at a charter rate which over the life of the ship will return the shipowner his cost of capital. It then moves on to the second year and repeats this process and so on through the life of the project. Finally, it determines the present value of the national cost and investor cost of this crude transport system.

Table S.2.1 summarizes the EXCRUDE results for the set of variable values used in this paper. Under the assumptions we have employed, the decrease in investor's landed cost on Persian Gulf crude resulting from moving from present East Coast draft limitations to a port capable of handling a 65' draft tanker is about 30¢ per barrel. Notice the sharp rise in present valued f.o.b. cost of crude under the assumption of escalated payments to exporting countries.

Table S.2.1

Some EXCRUDE Results

UNIT PRESENT VALUED COST OF FOREIGN CRUDE f.o.b.

Cost of Capital	8%	15%
No escalation	$1.65	$1.65
Escalation	$4.15	$4.12

CRUDE TRANSPORT SYSTEM FOR 4% CONSUMPTION GROWTH

	Transport Cost		Tanker	Number of Arrivals	
	8%	15%	Size	1978	2011
Pres. Del.	.98	1.24	65,000	1,080	3,930
65' Del.	.69	.92	230,000	290	1,050
Pt. Tupper	.67	.89	230,000	290	1,050
Machias.	.68	.90	230,000	290	1,050
Dighton	.68	.90	230,000	290	1,050

CRUDE TRANSPORT SYSTEM FOR 2% CONSUMPTION GROWTH

	Transport Cost		Tanker	Number of Arrivals	
	8%	15%	Size	1978	2011
Pres. Del.	.98	1.24	65,000	925	1,772
65' Del.	.69	.92	230,000	250	470
Pt. Tupper	.67	.89	230,000	250	470
Machias.	.68	.90	230,000	250	470
Dighton	.68	.90	230,000	250	470

The EXCRUDE routine is also used to compute the landed cost of imported residual fuel. The resid is assumed to cost \$3.10 per barrel in Venezuela before escalation. The cost of transporting this oil to the region depends on the products distribution system employed. If there is a deepwater terminal within the region, then draft constraints at the loading port (set at 45') are limiting. Otherwise draft constraints in the products reception ports determine the resid tanker size. EXCRUDE estimates the cost of resid transport from Venezuela at 20¢ per barrel at 8% and 25¢ at 15% assuming present products distribution system, and at 18¢ and 23¢ assuming a deepwater terminal within the region.

S.2.5.2 The refinery package

The refinery package (REFINE2) is employed to compute the present value investor costs associated with refinery crude oil into various products. The refinery model is based on W. L. Nelson's model for crude oil realization. The basic model examines the laboratory analysis of a particular crude oil and then determines the product mix which may be obtained from this crude. The product mix determines the complexity of the refinery which in turn determines capital and operating costs.

Of all the cost packages in the program, REFINE2 is subject to the greatest possible error in cost estimation. However, for the purposes of this study, these errors are of little import. The costs generated for the refinery processing are the same for each case considered, irrespective of refinery locale. For most of the cases considered in this paper, refinery costs are simply a function of crude input and New England products mix. Thus, for purposes of comparing one strategy to another, inaccuracies in total cost are cancelled. The only situation for which this cancellation does not occur is the comparison between cases involving the NO RESID refinery output and the ALL NEW ENGLAND output option.

S.2.5.3 The products distribution package

The function of the products distribution package (PRODIST) is to develop and simulate the liquid petroleum transport system which a profit-maximizing investor would use to move petroleum products from a specified refinery to each of eight major New England ports (Searsport/Bucksport, Portland, Portsmouth, Boston, New Bedford, Providence, New Haven, and Bridgeport) throughout the life of the project. In addition, the package has as inputs refinery location and capacity, refinery and discharge port draft limitations, the time the vessel is at reduced speed in the vicinity of loading and discharge ports, an indicator which specifies whether the discharge terminal is offshore, an indicator which specifies whether the nationality of the products carrier is foreign or domestic, and an indicator which specifies what combinations of barges, tankers or pipelines are to be considered as candidates for the transport system. The program also has available to it in semi-permanent secondary storage tables of tanker, barge and pipeline specifications and cost for a variety of sizes, speeds and flags as well as terminal costs for both onshore and offshore terminals. The output of the program includes the particulars of the vessel system which it selects including type and size of vessel serving each port, number of such vessels through time and number of port calls per year through time as well as the present valued cost to the investor and to the nation of this system. For the Dighton refinery locale, the program prints out particulars on the selected pipeline system including pipe size and horsepower of each link and investor and national costs.

With respect to vessel systems, the program considers each products reception port separately. There are no multiple-stop delivery routes. For each port, the package combines loading and unloading rates, fuel consumption at sea and in port, service speed, construction, crew, insurance, maintenance expenses for a range of combinations of vessel type (barge or tanker), and size within the draft limitations of the ports involved to obtain the overall cost of each such combination. After investigating tankers ranging from 20,000 to 300,000 tons and barges ranging from 20,000 to 40,000 tons, the program selects that vessel type and size for that particular port pair which serves the link at minimum cost. It repeats this process for each products reception port. Thus, there will in general be a different ship or barge size for each discharge port.

The pipeline products distribution system consists of two trunk lines emanating from Dighton, each consisting of three links. Westward, the line runs to Providence, thence to New Haven and thence to Bridgeport. Northward, the line runs to Boston, then to Portsmouth and then to Portland. Pumping stations are provided at Providence, New Haven, Boston and Portsmouth as well as Dighton. Searsport is assumed to be served from Portland by tanker/barge which the program selects in the same manner as described earlier. New Bedford/Fall River consumption is assumed to be served directly from the refinery site. Each ten years the package examines the throughput increase on each link through ten years in the future and chooses that combination of pipeline diameter and pumping power which handles the increase in the minimum present value cost manner.

All products distribution costs are taken up to the present storage tank batteries. However, neither the cost of products storage nor the cost of the secondary redistribution to minor ports, presently handled primarily by small barges, is included.

Per-barrel products distribution system costs for the eight refinery-products distribution system combinations studied are given in Table S.2.2. These are pre-tax investor's costs. For the present vessel-based system,

Table S.2.2

Unit Products Distribution Costs

Consumption Growth Rate	2%		4%	
Cost of Capital	8%	15%	8%	15%
Present Prod. Dist. Sys.				
Present Delaware	.21	.25	.20	.24
65' Delaware	.18	.22	.17	.21
Pt. Tupper	.23	.27	.22	.26
Machiasport	.16	.18	.14	.17
SBM off Boston				
Present Delaware	.20	.24	.19	.23
65' Delaware	.18	.22	.16	.20
Pt. Tupper	.22	.27	.20	.25
Machiasport	.15	.18	.14	.17
Pipeline Prod. Dist.				
Dighton	.04	.05	.03	.04

PRODIST invariably chooses barges. For the larger ports, these barges are sized to the maximum draft limitation: 40,000 tons for Portland, 30,000 tons for Boston, Providence and New Haven. For the other ports, PRODIST chooses either 20,000 or 30,000 ton barges, depending on how close the refinery is to the port. For the Boston offshore terminal, PRODIST picks a 40,000 ton barge if the refinery is present Delaware and a 230,000 ton tanker if the refinery has deepwater capability.

As can be seen from Table S.2.2, the off-Boston SBM barely pays for itself on the basis of distillates distribution. However, this does not give the terminal credit for the imported resid it handles under the NO RESID option. This, as we shall see, is quite significant from the terminal's point of view, for this resid travels much greater distances than the distillate and thus is able to take much greater advantage of the additional vessel size allowed.

The most striking feature of Table S.2.2 is the superiority of the pipeline distribution system. This is at least partially due to the fact that the southeastern New England refinery is located considerably closer to the market than the other refineries. We believe out pipeline costing is conservative. In general, it is based on the highest pipeline cost numbers reported by the industry for non-urban lines. The program does not give the pipeline credit for any savings which it engenders in secondary redistribution. We have not investigated this issue but these savings may be substantial. Some tank truck hauls will be shortened and tank truck traffic in congested areas may be reduced.

S.2.5.4 The offshore package

The offshore package (OFFSHOR) determines the national cost, regional payrolls, and investor cost associated with the development of a hypothetical petroleum province offshore New England.

OFFSHOR is used to determine that combination of production schedule and transportation system which the private investor would elect to employ in the development of a hypothetical petroleum province centered on Georges Bank subject to a set of user-specified variables. These variables are:

1) the aggregate oil and gas in place within the province;

2) the number, average depth, average thickness, and spatial separation of distinct reservoirs within the province;

3) the porosity, connate water content, absolute permeability, relative permeability, and compressibility of the potential reservoir rocks;

4) the pressure and temperature within the hypothetical reservoir(s);

5) the effects of temperature, pressure, and composition on the density, compressibility, and viscosity of the potential reservoir fluids;

6) the water depth, significant design wave height, and weather down time limitations at the offshore location;

7) the distances from the offshore location to the potential onshore receiving terminals for both tanker and pipeline transportation systems;

8) limitations on tanker draft at the receiving terminals;

9) limitations on pipeline diameter and throughput as implied by yield stress criteria;

10) the acquisition and operating costs together with the lead-time requirements for offshore

exploration, drilling, production, and transport related to the development of the province;

11) the prevailing market prices for delivered crude oil and natural gas;

12) any regulatory restrictions on per-well production, transport, royalties, and lease payments.

The package generates the resulting oil and gas production through time as constrained by the producibility of the formation, development decisions made by the investor, and possible regulatory constraints. The associated platform, drilling, pipeline, and tanker activity is displayed through time together with the revenues (private and public) and the outlays for equipment operation and acquisition.

A basic assumption used in the model is that the investor has a perfect knowledge of the petroleum province after the final stage of exploratory drilling. Therefore, given this perfect knowledge and treating <u>all</u> previous expenditures as sunk costs, the only variables under the control of the investor are:

1) the number of drilling platforms to be employed;

2) the rate at which these platforms, i.e. wells, will be deployed;

3) the mode of production transport to be employed;

4) the size (diameter, tonnage) of the particular transport mode to be employed;

5) the <u>net</u> production to be offered for sale;

6) when this production will be offered for sale.

The model iterates over these decision variables as they will determine that combination of production schedule and transportation system which the after-tax profit maximizing investor will elect to employ in the development of the hypothetical petroleum province offshore New England.

The model assumes that the aggregate oil and gas in place is distributed among a specified number of identical, homogeneous reservoirs.

The program as presently constituted can handle only internal gas drive. No water drive fields have been investigated. In general, this is conservative with respect to the value of a find, for almost any field is capable of gas drive.

We have employed the Muskat-Hoss variation of the Schilthuis mass balance equation to determine the response of the hypothetical petroleum reservoirs under internal gas drive. This model provides for the reinjection of produced gas and for the presence of a gas cap. We have assumed that the reservoir rock is a well-compacted sandstone of uniform horizontal permeability and of low vertical permeability. The individual well rates are calculated assuming pure radial flow in a bounded drainage area with a flowing wellhead pressure of 500 psia. We have neglected fricitonal and turbulence losses between the sandface and the wellhead. The area of drainage has been calculated based on an even well spacing at a specified maximum vertical deviation. In those cases where well rates are legally constrained to some allowable rate, production per well is cut back to the allowable. Our field costing assumptions based on filtering a great deal of data provided by various industry sources are outlined in detail in Volume I. In general, we regard our costing as generous.

The values for the various OFFSHOR variables used in this report are shown in Table S.2.3. Figures S.2.4 and S.2.5 indicate some of the results. The general pattern is one of extremely sharp economies of scale up to the point where one platform per field is fully utilized and very little in the way of scale economies thereafter. Unit

Figure S.2.4
The Effect of Allowables on Investor Cost

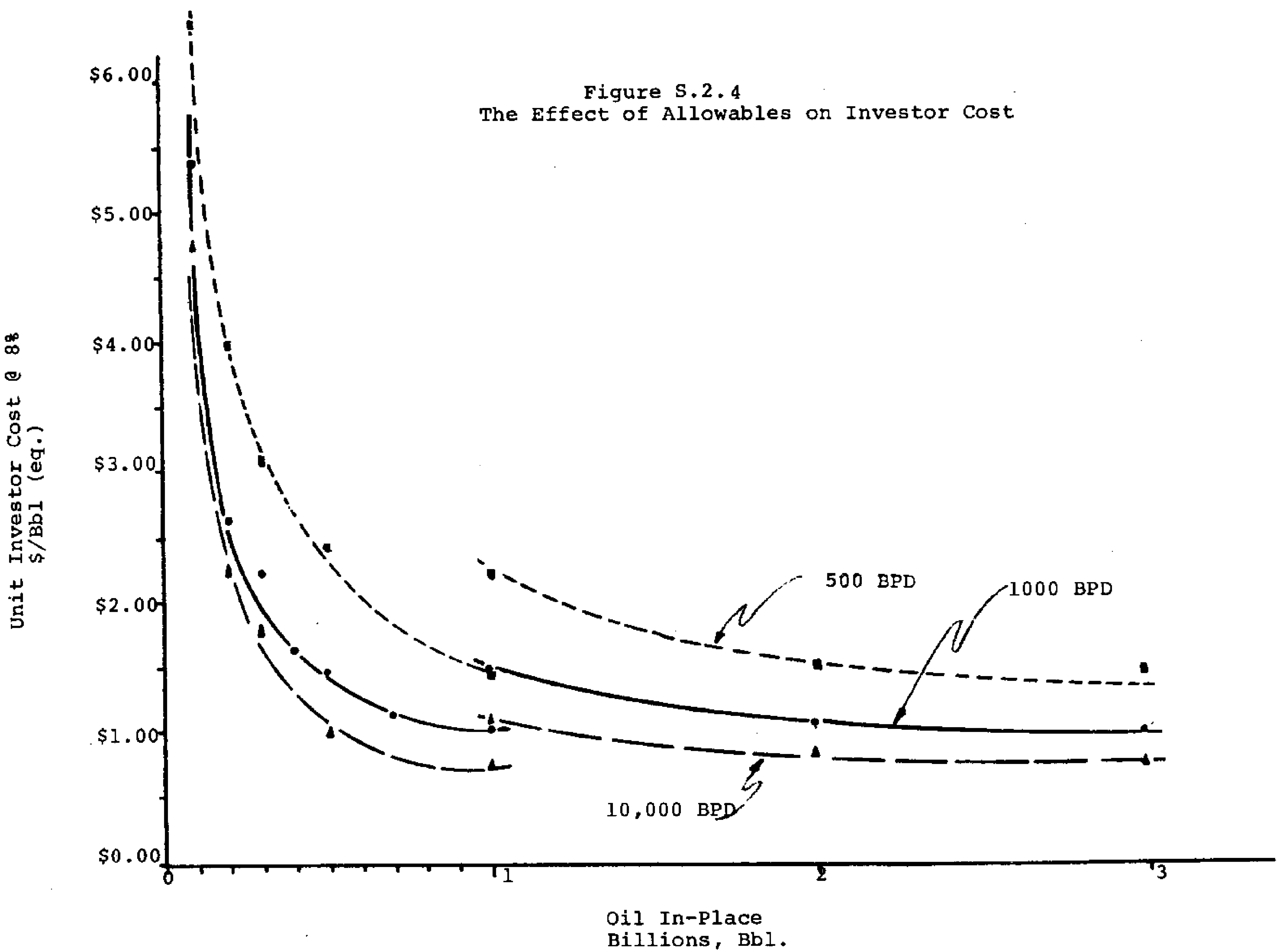

Figure S.2.5

Tanker v. Pipeline Crude Unit Cost @ 8%

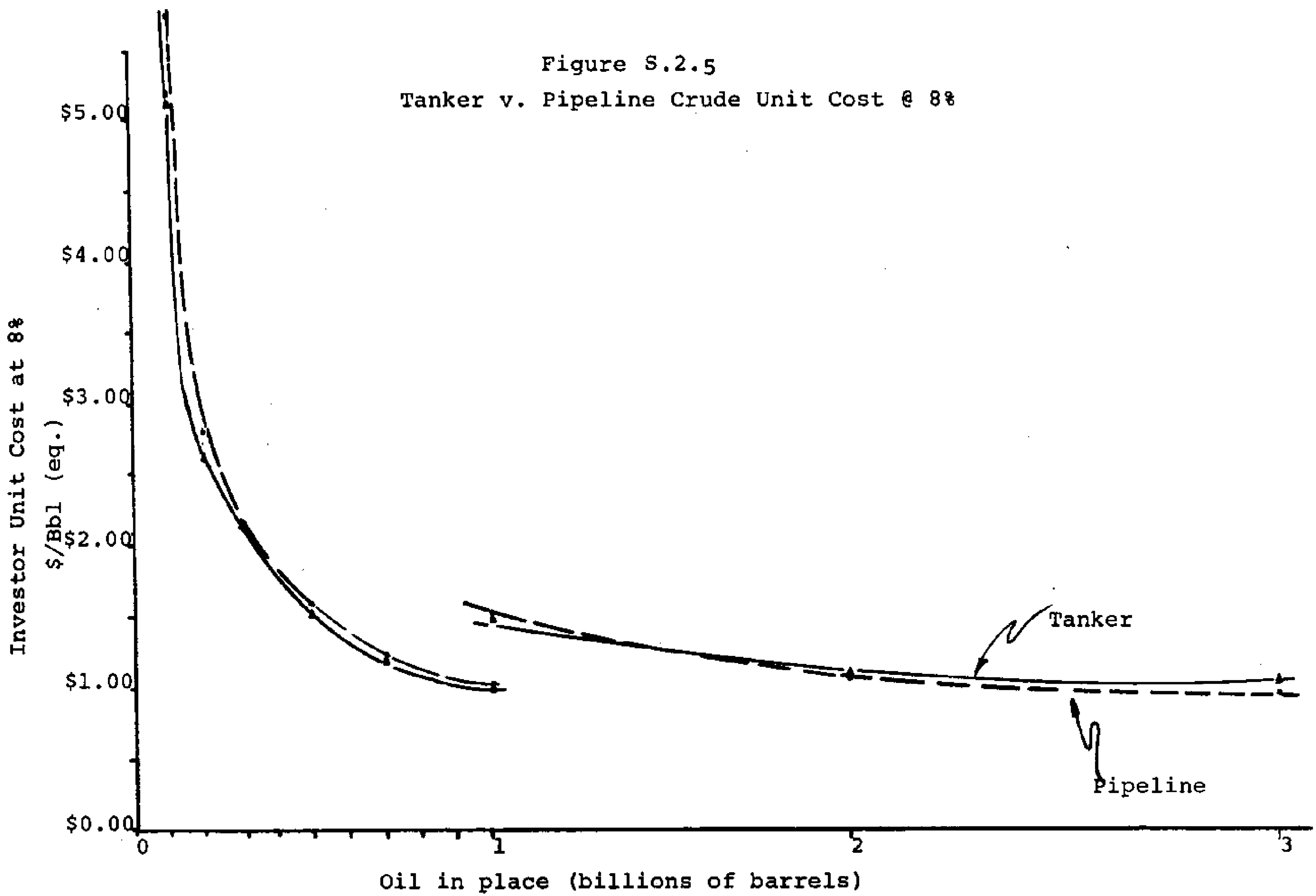

Table S.2.3
OFFSHOR Input Variables - Values Used in Runs Shown in S.2.4

Oil in place	50 million to 10 billion barrels
Gas in place	80 billion to 10 trillion cu ft
No of fields	1 to 10
Flowing wells per platform	20
Max platforms erected/year	5
Landed gas price under regulation	30¢/Mcf
Landed gas price-deregulation	\$1.01↔62¢/Mcf
Max platforms/field	1 to 10
Oil allowable	1000 bpd
Gas allowable	15 million cubic feet per day
Connate water	30%
Permeability	100 millidarcies
Porosity	20%
Oil gravity	30 API
Condensate gravity	45 API
Gas gravity	0.6 Sp.G. (air=1)
Formation thickness	75 feet
Vertical depth	10,000 feet
Max deviation	45°
Temperature	200°F
Pressure	5,000 psi
Reinjection	0%
Water depth	210 feet
Oil viscosity	4 cp
Field separation	10 miles
Pipeline distance to shore	127 miles
Terminal downtime	10%
Royalty	45¢/bbl & 12.5¢/Mcf
Lease fraction	75%
Pipeline range	6" to 42"
Tanker range	20,000 to 230,000 dwt.

costs prior to royalties and lease payments range from \$5.35 to 70¢ per barrel equivalent. There appears to be surprisingly little difference between tanker and pipeline transport to shore (distance to nearest landfall was assumed to be 127 miles), the crossover point being about 1.5 billion barrels in place. The costs, however, are rather sensitive to the allowable for these gas drive fields. The number of platforms chosen by the program ranged from 1 to 30. Oil recoverabilities ran from 15% to 23% depending primarily on gas-oil ratio. Gas recoverabilities ranged from 56% to 80% for the oil fields and as high as 89% for the all-gas fields.

For all the discoveries we investigated, the regional market was large enough to absorb all the oil and gas produced. In all these cases, the bulk of the region's petroleum for the next 40 years is imported from outside the region.

S.2.6 Results

Sample results of the analysis for the no-offshore-find case are shown in Table S.2.4. Remember it is the differentials that count. The differentials relative to the system based on present domestic terminals, import quota, and no escalation of foreign crude price are shown in Table S.2.5. Clearly, the single most important variable with respect to the cost of New England oil consumption is the size of the payment to the exporting country. Swings due to this variable simply overwhelm all the other differentials. For 2% growth rate and 8% cost of capital, the swing associated with moving from no increase in the 1972 payment to the $4.00's projected for 1980 is equivalent to the region giving up ten billion dollars now on a one-shot basis.

Offshore discoveries aside, the next most important variable is the import quota. The change in regional income associated with removing the import quota is about 40% to 25% as large as the change associated with varying foreign crude pricing.

The next most important swing is that associated with moving away from dependence on shallow water refining to deepwater refining. For example, going from present Delaware to 65' Delaware increases present valued regional income from $230 million to over $800 million at 2% and 8%, depending on quota and foreign crude cost.

The three numbers listed for each regional refinery option represent the full employment assumption, the middle employment assumption and the extreme unemployment assumption respectively. Under full employment, the deepwater Maine option is slightly superior to deepwater Delaware (+$40 to +$120 million). Under the middle estimate, regional income is increased by an additional $230 million by a regional refinery and under the extreme estimate by $700 million. The southeastern New England refinery policy generates the lowest regional costs of all the options

Table S.2.4
P.V. Regional Costs-No Offshore
8% Cost of Capital-No Resid
2% Consumption Growth Rate
(Billions of 1972 Dollars)

	Import Quota	No Import Quota
No Escalation of Foreign Crude Cost		
Present Products Distribution System		
Present Delaware	22.37	18.61
65' Delaware	22.14	17.73
Pt. Tupper	22.35	17.80
Machiasport	22.08, 21.85, 21.39	17.61, 17.38, 16.92
Off Boston SBM		
Present Delaware	22.31	18.55
65' Delaware	22.08	17.67
Pt. Tupper	22.28	17.73
Machiasport	22.03, 21.80, 21.05	17.56, 17.33, 16.86
Pipeline		
Dighton	21.77, 21.53, 21.05	17.32, 17.08, 16.60
Escalation of Foreign Crude Cost		
Present Products Distribution System		
Present Delaware	32.77	30.16
65' Delaware	31.89	29.28
Pt. Tupper	31.96	29.35
Machiasport	31.77, 31.54, 31.08	29.16, 28.93, 28.47
Off Boston SBM		
Present Delaware	32.71	30.11
65' Delaware	31.82	29.22
Pt. Tupper	31.89	29.29
Machiasport	31.72, 31.48, 31.02	29.11, 28.88, 28.42
Pipeline		
Dighton	31.48, 31.24, 30.76	28.87, 28.63, 28.16

Table S.2.4a
Change in P.V. Regional Costs-No Offshore
8% Cost of Capital-No Resid
2% Consumption Growth Rate
(Billions of 1972 Dollars)

	Import Quota			No Import Quota		
	FE*	MU*	SU*	FE	MU	SU
No Escalation of Foreign Crude Cost						
Present Products Distribution System						
Present Delaware	0			+3.76		
65' Delaware	+ .23			+4.64		
Pt. Tupper	+ .02			+4.57		
Machiasport	+ .29	+ .52	+ .98	+4.76	+4.99	+5.45
Off Boston SBM						
Present Delaware	+ .06			+3.82		
65' Delaware	+ .29			+4.70		
Pt. Tupper	+ .09			+4.64		
Machiasport	+ .34	+ .57	+1.32	+4.81	+5.04	+5.51
Pipeline						
Dighton	+ .60	+ .84	+1.32	+5.05	+5.29	+5.77
Escalation of Foreign Crude Cost						
Present Products Distribution System						
Present Delaware	-10.40			-7.79		
65' Delaware	- 9.52			-6.91		
Pt. Tupper	- 9.59			-6.98		
Machiasport	- 9.40	-9.17	-8.71	-6.79	-6.56	-6.10
Off Boston SBM						
Present Delaware	-10.34			-7.74		
65' Delaware	- 9.45			-6.85		
Pt. Tupper	- 9.52			-6.92		
Machiasport	- 9.35	-9.11	-8.65	-6.75	-6.51	-6.05
Pipeline						
Dighton	- 9.11	-8.87	-8.39	-6.50	-6.26	-5.79

*FE=Full Employment; MU=Moderate Underemployment; SU=Severe Unemployment

Table S.2.5

Present Valued Regional Cost of Selected Discoveries-65' Delaware
(Billions of 1972 Dollars)
Growth Rate=2% Cost of Capital=8% Full Employment Present Products Distribution System

Oil in place (billion bbl)	Gas in place (trillion cu ft)	No. of fields	No Escalation of Foreign Crude Cost								Escalation of Foreign Crude Cost							
			Import Quota				No Import Quota				Import Quota				No Import Quota			
			Region		Federal		Region		Federal		Region		Federal		Region		Federal	
			Reg.	Der.	Reg.	Der.	Reg.	Der.	Reg.	Der.	Reg.	Der.	Reg.	Der.	Reg.	Der.	Reg.	Der.
None			22.14	22.14	22.14	22.14	17.73	17.73	17.73	17.73	31.89	31.89	31.89	31.89	29.28	29.28	29.28	29.28
05,	1,	1	21.95	21.97	22.01	22.13	17.54	17.56	17.60	17.71	31.48	31.53	31.58	31.85	28.87	28.93	28.97	29.25
05,	3,	1	21.45	21.53	21.69	22.08	17.04	17.12	17.28	17.67	30.56	30.74	30.84	31.78	27.96	28.14	28.24	29.17
05,	5,	1	21.08	21.20	21.41	22.05	16.67	16.79	17.00	17.64	29.80	30.10	30.17	31.72	27.19	27.49	27.57	29.11
05,	10,	1	20.12	20.36	20.76	21.97	15.71	15,95	16.35	17.56	27.93	28.49	28.59	31.56	25.31	25.89	25.98	28.95
4,	.08,	1	22.12	22.12	22.14	22.14	17.71	17.71	17.73	17.73	31.79	31.77	31.88	31.88	29.18	29.16	29.27	29.27
.4,	.4,	1	22.07	22.08	22.09	22.14	17.66	17.67	17.68	17.72	31.68	31.70	31.76	31.87	29.08	29.10	29.15	29.26
.,	.2,	1	22.07	22.08	22.12	22.14	17.66	17.67	17.71	17.73	31.57	31.58	31.82	31.86	28.96	28.97	29.21	29.25
.,	1,	5	21.95	21.98	22.01	22.13	17.54	17.57	17.60	17.72	31.36	31.41	31.56	31.84	28.75	28.81	28.95	29.24
3,	.6,	5	21.81	21.82	22.07	22.11	17.40	17.41	17.66	17.70	30.90	30.92	31.70	31.79	28.30	28.31	29.09	29.18
3,	3,	5	21.49	21.54	21.79	22.08	17.07	17.13	17.38	17.67	30.31	30.46	31.00	31.75	27.71	27.85	28.40	29.14
5,	1,	5	21.56	21.57	22.03	22.08	17.15	17.16	17.62	17.67	30.27	30.29	31.59	31.72	27.66	27.69	28.98	29.12
5,	5,	5	21.13	21.21	21.59	22.05	16.71	16.80	17.18	17.64	29.44	29.66	30.51	31.66	26.83	27.06	27.91	29.06
10,	2,	5	21.03	21.04	21.95	22.03	16.62	16.63	17.54	17.62	29.10	29.14	31.41	31.60	20.50	26.53	28.80	28.99
10,	10,	5	20.17	20.31	21.22	21.96	15.76	15.90	16.81	17.55	27.52	27.88	29.62	31.48	24.91	25.27	27.02	28.87

Reg. = Present gas pricing policy
Der. = Deregulation of gas prices

Region = Lease and royalties go to region
Federal = Lease and royalties go to federal government

Table S.2.6

Increase in Regional Income Between No Find and a Number of Selected Finds as a Function of Policy Variables

Delaware 65' Present Products Distribution System 2% Growth Rate
8% Cost of Capital (Billions of Dollars)

Oil in place (billion bbl)	Gas in place (trillion cu ft)	No. of fields	No Escalation of Foreign Crude Cost								Escalation of Foreign Crude Cost							
			Import Quota				No Import Quota				Import Quota				No Import Quota			
			Region		Federal		Region		Federal		Region		Federal		Region		Federal	
			Reg.	Der.	Reg.	Der.	Reg.	Der.	Reg.	Der.	Reg.	Der.	Reg.	Der.	Reg.	Der.	Reg.	Der.
None			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
.05,	1,	1	.19	.17	.13	.01	.19	.17	.13	.02	.41	.36	.31	.03	.41	.35	.31	.03
.05,	3,	1	.69	.61	.45	.06	.69	.61	.45	.06	1.33	1.15	1.05	.11	1.32	1.14	.04	.11
.05,	5,	1	1.06	.94	.73	.09	1.07	.94	.73	.09	2.09	1.79	1.72	.17	2.09	1.79	1.71	.17
.05,	10,	1	2.02	1.78	1.38	.17	2.02	1.78	1.38	.17	3.97	3.40	3.30	.33	3.97	3.39	3.30	.33
.4,	.08,	1	.02	.02	.00	.00	.02	.02	.00	.00	.10	.12	.01	.01	.10	.12	.01	.01
.4,	.4,	1	.17	.06	.05	.00	.07	.06	.05	.01	.21	.19	.13	.02	.20	.18	.13	.02
1,	.2,	1	.07	.06	.02	.00	.07	.06	.02	.00	.32	.31	.07	.03	.32	.31	.07	.03
1,	1,	5	.19	.16	.13	.01	.19	.16	.13	.01	.53	.48	.33	.05	.53	.47	.33	.04
3,	.6,	5	.33	.32	.05	.03	.33	.32	.07	.03	.99	.97	.19	.10	.98	.97	.19	.10
3,	3,	5	.65	.60	.35	.06	.66	.60	.35	.06	1.58	1.43	.89	.14	1.57	1.43	.88	.14
5,	1,	5	.58	.57	.09	.06	.58	.57	.11	.06	1.62	1.60	.30	.17	1.62	1.59	.30	.16
5,	5,	5	1.01	.93	.56	.09	1.02	.93	.55	.09	2.45	2.23	1.38	.23	2.45	2.22	1.37	.22
10,	2,	5	1.11	1.10	.19	.11	1.11	1.10	.19	.11	2.79	2.75	.48	.29	2.78	2.75	.48	.29
10,	10,	5	1.97	1.83	.92	.18	1.97	1.83	.92	.18	4.37	4.01	2.27	.41	4.37	4.01	2.26	.41

Reg. = Present gas pricing policy
Der. = Deregulation of gas prices

Region = Lease and royalties go to region
Federal = Lease and royalties go to federal government

investigated with an estimated increase in regional income of about $300 million over 65' Delaware and deepwater Maine for full employment.

Table S.2.5 gives sample results for a case involving a range of offshore discoveries. Thousands of such cases have been analyzed. Table S.2.6 presents the results in a somewhat more meaningful way, displaying the differential in regional income between find and no find. A given find is more valuable to the region under foreign crude cost escalation for the Georges Bank petroleum is displacing more costly oil in this situation. The value of a given find to the region is largely dependent on:

a) who receives the lease and royalty payments;

b) if the region doesn't control the find, on whether or not gas prices are decontrolled.

Under the situation of federal control of the Bank and deregulation of natural gas prices, even a very large find increases regional income by $200 million (no escalation) and $400 million (escalation), while a large range of finds increase present valued regional income by less than $50 million. On the other extreme, if the region controls the Bank and gas prices are not deregulated, an extremely large find would result in a net increase of over $4 billion (escalation) and $2 billion (no escalation), while the value of rather small finds ranges from $70 million to $300 million. The other combinations of control and gas pricing are intermediate in value to the region. These numbers are all computed under the assumption of 2% consumption growth rate and 8% cost of capital.

Table S.2.7 summarizes the overall results. The <u>relative</u> importance of the various variables is not strongly sensitive to growth rate or cost of capital.

Table S.2.7
Range of Differentials in Present Valued Regional Income Associated With
Alternative Values of Various Key Variables
(Billions of 1972 Dollars)

Change in Hypothesis	Cons.Growth Rate=2% Cost of Cap.=8%		Cons.Growth Rate=4% Cost of Cap.=8%		Cons.Growth Rate=2% Cost of Cap.=15%		Cons.Growth Rate=4% Cost of Cap.=15%	
	Low Change	High Change	Low Change	High Change	Low Change	High Change	Low Change	High Change
rom Present Foreign Crude Payments o Escalated Crude Payments	-8.5	-10	-13.5	-17	-3.4	-4.1	-4.5	-5.6
rom Import Quota o No Import Quota	+2.6	+ 4.4	+ 3.9	+ 6.6	+1.0	+1.4	+1.4	+2.3
rom No Georges Bank Find o Find	nil	+ 4.3	nil	+ 4.3	nil	+2.2	nil	+2.2
rom Shallow Water Extraregional Refining o Deepwater Extraregional Refining	+ .2	+ .8	+ .3	+ 2.3	+ .09	+ .36	+ .14	+ .5
rom Deepwater Extraregional Refining To Deepwater Regional Refining (Full Employment)	+ .04	+ .3	+ .08	+ .6	+ .06	+ .18	+ .03	+ .24
<u>Employment Effect</u>								
From No Regional Refining To All Regional Refining	nil	+ .7	nil	+ .9	nil	+ .27	nil	+ .35

S.2.7 Regional income impact of environmental effects

The analysis includes an investigation of two of the possible effects on regional income associated with changes in environmental quality resulting from the various petroleum development hypotheses:

1) the impact on regional income due to changes occasioned in the Georges Bank fishery;

2) the impact on regional income due to changes in the amount of oil spilled nearshore.

These are not the only ways in which changes in environmental quality could affect regional income but they are certainly two of the most important.

S.2.7.1 Impact through effect on Georges Bank fishery

The environmental analyses of the Georges Bank investigated essentially three phenomena:

1) larval kills resulting from a very large spill;

2) dissolved hydrocargon concentrations associated with oil/water separator discharge;

3) area made unavailable to fishermen due to platforms.

With the help of some rather severe assumptions, it was concluded that the percentage of a year class killed by a single small spill would be small enough to have no noticeable effect on adult population levels and that toxic concentrations of dissolved hydrocarbons in the seawater due to separator discharge would be limited to areas ranging from a few hundred square feet to at most a square mile per production platform. Neither effect is expected to be noticeable in the long run although both bear watching. No economic analysis of these two effects was undertaken.

With respect to the third phenomenon, a study was made of National Marine Fisheries Service data in order to obtain the distribution of yield across the Bank. It was found that some areas are markedly more productive than others. A large number (25) of platforms were assumed to be placed in the highest productivity area and the fishermen denied access to that portion of the Bank within one-half mile of these platforms. Under the assumption that the fish presently caught in the precluded areas would not be caught and that the diverted effort would yield no return, the loss in regional income under two different hypotheses about the future was investigated.

1) In the absence of petroleum development, Georges Bank yields would continue at 1969-1970 levels.

2) In the absence of a petroleum development, Georges Bank yields would be at present estimates of maximum sustainable yield.

The second assumption, which presupposes a much more efficient management of the Bank than we presently have, is the more severe. Under this assumption, the present value loss in regional income associated with this very severe set of assumptions about number and placement of platforms is estimated at roughly ten million dollars at 8% cost of capital and four million dollars at 15%. Less severe assumptions drop these estimates sharply. For example, assuming that the 25 platforms were placed on the Bank in areas of average productivity decreases these estimates by a factor of ten.

Other effects (navigational hazard/aid, provision of additional surface area and shelter for flora and fauna, seabottom obstructions, interference between trawling and seismic activities) were deemed to have no noticeable effect on regional income assuming all pipelines were buried.

S.2.7.2 Regional income impact of nearshore spills

The other environmental effect for which the impact on regional income was investigated was the nearshore spill. There exists only one complete, dispassionate post mortem analysis of the economic effects on a large nearshore spill, Mead and Sorensen's study of the Santa Barbara spill. These authors categorize the cost associated with a spill as follows: (1) clean-up cost and property damage; (2) damage to tourism; (3) damage to commercial fishing; (4) decline in shorefront property values; (5) damage to non-commercial marine environment; (6) loss of oil; (7) reduction in recreational opportunities for the resident population. Meade and Sorensen estimate that the net loss in income associated with the spill was about 15 million dollars, or five dollars a gallon. They find that the bulk of this loss (about two-thirds) was borne by the oil company in the form of clean-up and well control expenses. While Meade and Sorensen's analysis may be optimistic in certain respects in terms of a New England spill, it does give us a very rough idea of what an uncontrolled nearshore spill might cost. Table S.2.8 indicates our high estimates of the present value at 8% of the average amount spilled nearshore for eight development hypotheses. Assuming in the long run the region bears the cost of all nearshore spills in the region, multiplying these differentials in the amount spilled by one's estimate of the unit cost of a spill (say, $5.00 per gallon) leads to an estimate of the change in regional income due to nearshore spillage associated with the various hypotheses. For example, at a 2% growth rate and $5.00 per gallon, the decrease in regional income due to nearshore spillage associated with moving from the present system (1) to the region refining its own distillate products and distributing these products by vessel (2) is 7 5 million dollars, while if the regional refinery employs pipeline products distribution the decrease is estimated at

Table S.2.8

Present Value of High Estimate of Mean Amount Spilled Between 1978 and 2018 Assuming Regional Cost of Capital = 8%

Plan No.	Option	Consumption Growth Rate 2%	4%
1	No Find No Reg. Ref.	20 million gals.	30 million gals.
2	No Find Reg. Ref. Pres. P.D.S.	35 " "	52 " "
3	No Find Reg. Ref. Pipeline P.D.S.	23 " "	34 " "
4	Large Find No Reg. Ref.	20 " "	30 " "
5	Small Find Reg. Ref. Pres. P.D.S.	35 " "	52 " "
6	Small Find Reg. Ref. Pipeline P.D.S.	23 " "	34 " "
7	Large Find Reg. Ref. Pres. P.D.S.	35 " "	52 " "
8	Large Find Reg. Ref. Pipeline P.D.S.	23 " "	35 " "

$15 million. According to our analysis, a Georges Bank find in itself has little effect on nearshore spillage. Once again, there is a large range of uncertainty in both our estimates of the amount which will be spilled and in the cost of an individual spill. These should be regarded as order of magnitude estimates. However, it is of interest that this estimate of the decrease in regional income due to nearshore spillage associated with a vessel-serviced, regional refining complex is roughly the same size as the increase in regional income (before spillage) associated with moving from a deepwater extraregional refinery to deepwater regional refining using vessel distribution under full employment. However, this estimate of the decrease in regional income due to a pipeline-served regional refinery complex is roughly a factor of ten smaller than the increase (before spillage) in regional income due to moving to a pipeline-serviced regional refinery from deepwater extraregional refining at full employment.

In any event, regional income swings associated with nearshore spillage were the largest of all the environmental effects on regional income studied. In view of this and in view of the large possible range of errors in the estimates, the nearshore spill problem deserves top priority in any further investigations.

Chapter S.3
Summary of Volume II - Environmental Analyses

The second volume of the report attempts to assess the environmental implications of the various changes in the region's petroleum production, processing and distribution system hypothesized in Volume I. By chapter, Volume II estimates average spillage and average time between large spills, offshore and nearshore, for each of a number of such hypotheses, the likely trajectories these spills will take, the prospects for containment and collection, the biological impact of oil in the ocean in general, the specific biological impacts associated with hypothesized spills and discharges, and the impact of regional refining and a gas find on regional air quality. The volume restricts itself to investigating measurable changes in regional water and air quality and the presently identifiable effects these changes will have on specific organisms. No attempt is made to assign values to these effects.

The summary briefly reviews the major results of each chapter.

S.3.1 Spill probabilities

An examination was made of U.S. Coast Guard records of oil spills in U.S. waters in 1971. The oil industry-related spills were categorized according to five major sources:

1) Tanker and barge traffic,
2) Bulk storage and transfer,
3) Refineries,
4) Offshore oil production,
5) Pipelines.

According to the Coast Guard, in 1971 the U.S. spillage from oil industry sources was 6.3 million gallons, of which 2.6 million was tanker/barge traffic--almost all of which was in restricted waters--2.2 million was refinery, 900,000 emanated from pipelines, 500,000 from storage and transfer facilities, and 117,000 from offshore towers. The Coast Guard records indicated that 750,000 gallons were spilled in New England, almost all from tankers and barges. These figures do not include inland spills, sewer discharges, or planned emissions.

We feel that the 1971 Coast Guard data is reasonably complete with respect to sizable nearshore spills and offshore spills emanating from towers in the Gulf of Mexico. The data may be less complete with respect to offshore ship traffic and non-Gulf towers.

On the basis of the Coast Guard data, most of the spills are quite small. Over half the spills were reported at less than 100 gallons. However, the great bulk of the total volume spilled is spilled in a few very large spills. This was reflected in the fact that the 1970 total spillage was 40% higher than the 1971 spillage, despite the fact that the Coast Guard reporting system was not in full operation in 1970. A single three million gallon spill

(1/10 the size of the "Torrey Canyon" spill) represents 40% of all the oil spilled in the U.S. in 1971.

The fact that the bulk of the oil spilled is made up of a few very large spills has one analytical advantage and one very serious disadvantage:

1) We can use data gathered over the last ten years in which only large (> 42,000 gallons) spills were reported and be confident that the volume of oil left out is not large.

2) In order to estimate the statistics of the spillage with confidence we need a very large sample. With the sample sizes available, the average spillage rates estimated by our procedures could easily be off by a factor of three.

Using worldwide data on large spills from a variety of sources, covering the period 1964 to 1971 and operating under the assumption that the average amount spilled in each category is proportional to the amount of oil handled (in and out), the average spillage rates in the left column of the following table were obtained. Applying the same assumptions to the Coast Guard 1971 data, the figures in the right column resulted.

Table S.3.1
Spillage as a Fraction of Oil Handled
(parts per million)

	Worldwide Large Spill Data 1964-1971	1971 Coast Guard U.S. Data
Tankers/barges	30	25
Transfer & storage facilities	10	1
Offshore towers	55	7
Offshore pipelines	10	1
Refineries	30	3

The estimate of the average spillage rate for tanker/barges for New England in 1971 was slightly less than that arrived at from the worldwide data, several times that for the nation as a whole in 1971, and twenty times that experienced in Milford Haven, a large oil port in Wales. The difference between the offshore tower spillage in the Gulf in 1971 and worldwide 1964-1971 is a factor of eight. There were no very large offshore tower spills in 1971 in the U.S. In general, 1971 appears to have been a good year for spillage and it is reflected in the lower estimates.

Applying these higher spillage rates, with the exception of refineries, which we have based on an upper confidence limit on the 1971 data rather than giving full weight to a single very large spill, the estimates of the average amount spilled within the region in 1978 for a number of different development hypotheses are shown in the following table:

Table S.3.2
Estimate of Mean Amount Spilled in 1978 in Region
(gallons)
(Does not include planned discharges)

		Offshore	Nearshore
1.	NO FIND, NO REGIONAL REFINING	0	1,410,000
2.	NO FIND, ALL DISTILLATES REFINED IN N.E., PRESENT PRODUCTS DISTRIBUTION SYSTEM	0	2,780,000
3.	NO FIND, ALL DISTILLATES REFINED IN N.E., PIPELINE PRODUCTS DISTRIBUTION SYSTEM	0	1,800,000
4.	100,000 BPD FIND, ALL DISTILLATES REFINED IN N.E., PRESENT PRODUCTS DISTRIBUTION SYSTEM	125,000	2,780,000
5.	100,000 BPD FIND, ALL DISTILLATES REFINED IN N.E., PIPELINE PRODUCTS DISTRIBUTION SYSTEM	125,000	1,800,000
6.	1,000,000 BPD FIND, NO REGIONAL REFINING	1,240,000	1,410,000
7.	1,000,000 BPD FIND, TANKER TO SHORE, ALL DISTILLATES REFINED IN N.E., PRESENT PRODUCTS DISTRIBUTION SYSTEM	1,240,000	1,800,000
8.	1,000,000 BPD FIND, PIPELINE TO SHORE, ALL DISTILLATES REFINED IN N.E., PIPELINE PRODUCTS DISTRIBUTION SYSTEM	1,364,000	1,910,000

It is important to recognize the large range of uncertainty in these estimates due to the limited sample size in comparison with the effect of a single very large spill. For example, Table S.3.2 should not be taken to imply that a tanker-serviced offshore find will result in less offshore spillage than a pipeline-serviced find, but rather that on the basis of present information, there is little to choose between them.

The offshore find does not have a strong impact on nearshore spillage. The key determinants of nearshore spillage are whether or not the region does its own refining and, if so, whether or not it distributes the resulting products by tanker or pipeline. Several important aspects of the problem do not show up in the above table. For example, most of the spills in alternative (3) are crude, while those in (1) are all products, which has important biological implications. Also, most of the spills in (3) are at the refining receiving terminal(s), while those in (1) are spread through the region.

The average amount spilled is only one description of the actual amount spilled, which not only can be smaller or larger than the average, but which also will be made up of many small spills and a few very large spills. For the purposes of this report, we are as interested in the likelihood of the very large spill as we are in the total amount spilled. Table S.3.3 shows estimates of mean time between large spills of various size categories for the eight development hypotheses. The offshore discoveries suffer under this comparison more than they do under the total amount spilled. Sufficient data to estimate the mean times between very large spills for other than tankers and barges by means of classical statistics is not presently available.

Table S.3.3

Estimates of Mean Time Between Large Spills By Size Category Based on Worldwide Data (Table II.1.8)

Plan No.	Description	Refinery >42,000	Stor. & Trans. >42,000	Pipeline >42,000	Tower >42,000	Tanker & Barge >42,000	Tanker & Barge >300,000	Tanker & Barge >3,000,000	Overall >42,000
1	No Find No Reg. Ref.	-	18.1	-	-	2.2	4.4	11	2.0
2	No Find Reg. Ref. Pres. PDS	30	18.1	-	-	1.2	2.4	6	1.1
3	No Find Reg. Ref. Pipeline PDS	30	18.1	-	-	2.6	5.2	13	2.1
4	Large Oil Find No Reg. Ref.	-	18.1	-	.9	2.2	4.4	11	.6
5	Small Oil Find Reg. Ref. Pres. PDS	30	18.1	-	9.2	1.2	2.4	6	1.0
6	Small Oil Find Reg. Ref. Pipeline PDS	30	18.1	-	9.2	2.6	5.2	13	1.7
7	Large Oil Find Reg. Ref. Pres. PDS	30	18.1	-	.9	1.2	2.6	6	.5
8	Large Oil Find Reg. Ref. Pipeline PDS	30	18.1	1.4	.9	5.2	10.3	26	.46
9	Large Gas Find No Reg. Ref.								

S.3.2 Spill trajectories

Analysis of the spread and movement of both Georges Bank and nearshore spills was undertaken.

The following table indicates the final area covered by oil spills of a range of sizes and the time to reach that area. This table operates under the assumptions that the spill is unconstrained by land and that the current in one part of the spill is the same as in other parts. These assumptions will generally be true for the spills which remain offshore.

Table S.3.4

Spill Volume (gallons)	Example of Spill of Equiv. Volume	Final Area (sq mi)	Time to Final Area (hours)
100		.018	1
1,000		.104	5
42,000		1.71	33
105,000	North Falmouth	3.34	57
3,000,000	Santa Barbara	25.3	212
30,000,000	"Torrey Canyon"	142.0	680

The offshore spills will be moved about by a combination of wind, cyclic tidal currents, and steady geostrophic currents. For spills which are not in proximity to land, tidal excursions are of little importance, for they represent no net movement of the spill. In order to obtain insight into the movements of Georges Bank spills, a computer program was developed which simulates a given spill's movements given an assumption about the geostrophic currents and the random fluctuations of the wind. Wind statistics for each season were obtained and the frequencies with which the wind changes from one direction to another estimated. Information on the currents on the Bank is limited to drift bottle recoveries and ships' log data, both of which sources have inherent sources of error. Therefore, several different assumptions concerning the geostrophic currents were investigated.

The computer program tracks a hypothetical spill from a postulated launch point by randomly sampling the wind at three-hourly intervals and moving the spill according to the wind obtained and the current in the locale of the spill. The program tracks each such spill for 150 days or until it hits shore. This process is repeated for a large number (200) of spills for each season and launch point. Count is kept of the number of spills which hit shore by area, the time to reach shore, and the time that each spill remains on the Bank.

The results indicate that the likelihood of a spill reaching land from the Georges Bank is highly seasonal. In the fall and winter it is nil for a variety of assumptions about the geostrophic current. This is due to the strong northwesterly component in the wind during these seasons. In the spring and summer, under the current assumption most consistent with the drift bottle data, the likelihood of a Georges Bank spill reaching land is approximately 5%. Under this current assumption, if the spill does reach land, it will do so on the western or southern shores of Cape Cod. This result is due to the combination of the generally southwesterly current flow across the Bank together with the southerly component in the wind during the warm weather months.

For those spills which do reach shore, the minimum time to land is about 30 days; the average time to land about 60 days. The average time on the Bank in the summer is about 30 days.

All these results are in agreement with the drift bottle data. Some 20,000 drift bottles have been launched on the Bank over the last 45 years.

The major effect of our uncertainty concerning the geostrophic current pattern is on the Bay of Fundy region during the summer. Relatively small changes in the current pattern to the north and west of the Bank can change the probability of a spill entering the Bay of Fundy from nil to 10% during the summer. The drift bottle data would appear to indicate the lower value is more correct but further research on the current pattern off of Cape Sable is indicated. According to our model, about 1 in 10 of the spills which enter the Bay of Fundy region will reach the eastern Maine coast.

Information on the vertical dispersion of oil into water is fragmentary. Isolated experiments and observations indicate that one can expect concentrations of 10 to 20 ppb to depths of 30 feet, .5 to 3 ppb to depths of 100 feet and perhaps .2 ppb to 250 feet. In the completely mixed waters of the Bank, we believe it is reasonable to expect concentrations in the ppb range on the bottom under the spill. However, the uncertainty in this area is quite large. The Chevron Main Pass blowout data will yield considerable information on this aspect of the problem when it is released.

S.3.3 Oil spill containment and removal

The study included a survey of the state of the art with respect to oil spill containment and removal, the development of a model for determining boom parameters and simulating the effectiveness of a given containment and collection system faced with a given hypothetical spill. The results indicate:

1) A system for collecting and containing a spill on the Georges Bank would be an extremely expensive, hazardous, at best marginally effective, and sometimes completely ineffective proposition. Therefore, we concentrated on the near-shore spill containment and collection in our analysis.

2) The results of the boom design program indicate that a boom capable of containing 100,000 gallons in one-knot current, calm water will cost approximately $10,000, a boom capable of containing one million gallons, $25,000, and a boom capable of containing ten million gallons, $100,000.

3) While it is difficult to estimate the cost of an emerging technology, it appears that a skimmer capable of pumping 10,000 gallons per hour in calm water will cost about $100,000 and a skimmer capable of pumping 60,000 gallons per hour about $250,000.

4) The simulated spill incidents indicate that a 60,000 gph (gallons per hour) skimmer combined with a one million gallon boom deployed in two hours together with average barge availability in a large New England oil port (assuming a system where these barges can be commandeered) will collect about 50% of an extremely large

(ten million gallon, 100,000 gph) spill. The critical parameters are spill rate, boom deployment time, and barge deployment time. These parameters dictate that if a port is to be protected, a system must be permanently stationed in that port. The cost of such a system will be largely determined by whether it is manned by a special-purpose full-time staff or on an as-needed basis.

In general, comparing the cost of such a system with the estimates of the cost of future nearshore spills (S.2.7) indicates that the provision of such systems in the major oil ports merits careful consideration however the region chooses to handle its oil.

3) The "Tamano" spill suggests the first order of business should be the provision of a helicopter-deployable, submersible pump together with institutional arrangements to commandeer nearby barges to receive oil pumped out of damaged holds.

S.3.4 Biological effects of oil in the ocean

Both crude oil and petroleum products are made up of a large number of individual compounds. These individual compounds vary widely in physical and chemical properties and biological effect. For the purposes of this study, it was found sufficient to characterize a given oil by its percentage composition of each of eight classes or fractions of compounds. These classes are listed in Table S.3.5 along with the typical composition of a number of different oils. Table S.3.6 displays a few key physical properties of these fractions. The rates at which the various fractions can evaporate into the atmosphere and, more importantly, the rates at which they can dissolve into the water column vary over an extremely wide range.

A survey and compilation of known experiments and observations relating to the biological effects of oil was conducted. These impacts were categorized into five classes:

1) Immediate lethal toxicity,
2) Sublethal effects - interferences with feeding and reproductive behavior, due to cellular-level phenomena,
3) Coating,
4) Incorporation into organisms and distribution in food webs,
5) Habitat changes,

and the available knowledge about each type of impact investigated.

On the basis of present knowledge, the following statements can be made:

1) Although direct quantitative comparison of the experimental data on lethal toxicity is virtually impossible due to differences in experimental

Table S.3.5

Typical Fractional Composition (By Weight) of Various Petroleum Substances

FRACTION	DESCRIPTION	(HEAVY) CRUDE A	(MEDIUM) CRUDE B	#2 FUEL OIL	KEROSENE	RESID.
1	Low Boiling Paraffins	1	10	15	15	0
2	High Boiling Paraffins	1	7	20	20	1
3	Low Boiling Cyclo-Paraffins	5	15	15	20	0
4	High Boiling Cyclo-Paraffins	5	20	15	20	1
5	Low Boiling Aromatics	2	5	15	15	0
6	Polycyclic Aromatics	6	3	5	2	1
7	Naphtheno-aromatics	15	15	15	8	1
8	Residual	65	25	--	--	96
Estimated Maximum % Soluble		10	30	60	65	1
Estimated Maximum % Soluble Aromatic Derivatives		.1-10	.1-10	1-30	1-20	0-1
Reported % Soluble Aromatics Obtained In Seawater Extracts		.1	.01 ,.1		.01	

Table S.3.6

Some Physical Properties of Petroleum Fractions

Fraction	Description	% by wt. in Crude Oil	Density (gm/ml)	Boiling Point (°C)	Molecular Weight	Vapor Press. @ 20°C (mm)	Solubility ($gm/10^6 gm$ Distilled H_2O)
1	Paraffin C_6-C_{12}	.1-20	.66-.77	69-230	86-170	110-.1	9.5-.01
2	Paraffin C_{13}-C_{25}	0^+-10	.77-.78	230-405	184-352	.1	.01-.004
3	Cycloparaffin C_6-C_{12}	5-30	.75-.9	70-230	84-164	100-1.	55-1.
4	Cycloparaffin C_{13}-C_{23}	5-30	.9-1.	230-405	156-318	1.-0	1.-0
5	Aromatic (Mono- and di-Cyclic) C_6-C_{11}	0-5	.88-1.1	80-240	78-143	72-.1	1780.-0.
6	Aromatic (Poly-Cyclic) C_{12}-C_{18}	0^+-5	1.1-1.2	240-400	128-234	.1-0	12.5-0
7	Naphtheno-Aromatic C_9-C_{25}	5-30	.97-1.2	180-400	116-300	1.-0	1.-0
8	Residual (including non-hydrocarbons)	10-70	1.-1.1	>400	300-900	0	0

procedures and documentation, a definitive qualitative consistency is observed. Most importantly, the lower boiling, more soluble aromatic fractions are consistently implicated as the primary cause of mortality. This finding is consistent with our knowledge concerning the biochemical activity of these highly toxic compounds as compared to that of the bulk of other compounds occurring in oil.

Although low molecular weight paraffins can cause narcosis, the concentrations required to induce such responses are extremely high and would not occur from an oil spill. Certain heterocyclic compounds are also known to be quite toxic. However, given the concentrations with which these compounds occur in petroleum, it is unlikely that these poisons are the culprit.

Table S.3.7 indicates our estimates of the minimum concentration of soluble aromatics required to cause toxicity for a number of different classes of organism. The evidence is fragmentary; hence the factor of ten uncertainty. Larval stages appear to be considerably more sensitive than adult. Concentrations of soluble aromatics as low as .1 ppm may be toxic to certain marine larvae. Most adult marine organisms are sensitive to soluble aromatics in concentrations of 1 ppm and toxicity typically occurs at concentrations of 10-100 ppm. In general, crustaceans and burrowing animals are most sensitive, fish and bivalves moderately sensitive, and gastropods and flora least sensitive.

2) On the basis of fragmentary evidence, it appears the great bulk of the soluble aromatics fraction

Table S.3.7

Class of Organisms	Estimated Typical Toxicity Ranges (ppm) for Various Substances			
	SAD[1]	#2 Fuel Oil/Kerosene	Fresh Crude	Weathered Crude
Flora	10-100	50-500	$10^4 - 10^5$	Coating More Significant than Toxicity
Finfish	5-50	25-250	"	
Larvae	.1-1.	.5-5	$10^2 - 10^3$	
Pelagic Crustaceans	1-10	5-50	$10^3 - 10^4$	
Gastropods (e.g., snails)	10-100	50-500	$10^4 - 10^5$	
Bivalves	5-50	25-250	"	
Benthic Crustacaens (e.g., lobsters)	1-10	5-50	$10^3 - 10^4$	
Other Benthic Invertebrates	1-10	5-50	$10^3 - 10^4$	

1 - Soluble aromatic derivatives (aromatics and naphthenoaromatics)

will be depleted from within the slick within four days, less under higher wind speeds. Comparisons of volatilities and solubilities indicate that very roughly one-half of these compounds will evaporate and one-half will dissolve into the water column. Considerably more work on the oil weathering problem, especially in reference to these compounds, is indicated. However, at present it appears that an oil spill will exhibit almost all its toxic effects in the first day or two of the spill. Similarly, the toxic effect will be sharply dependent on the initial percentage of soluble aromatics in the oil, which as Table S.3.5 indicates, can vary widely with the lighter distillate oils at the high end and residual fuel at the low end.

3) Chemical communication plays an important role in the behavioral patterns of many marine organisms. The full implications of disruption of these patterns remains uncertain, as does the exact mechanism of disruption. However, concentrations of soluble aromatics as low as 10-100 ppb may cause problems.

4) The incorporation of hydrocarbons, particularly carcinogenic polycyclic aromatics, in the tissue of marine organisms is primarily of interest to public health. The individual organisms are apparently not affected. Whether or not cancer can be induced in humans from ingestion of carcinogens accumulated in seafood is as yet unknown. The actual mechanisms of the build-up in the food chain also remain uncertain, as does the ultimate fate of the carcinogens.

5) The development of objectionable taste in certain bivalves (10-50 ppm in the organism) can result

from low ambient concentrations in water (1-10 ppb) of hydrocarbons in a relatively short time (one to a few days). If the contamination of the water is short-lived and the concentrations not too high, self-cleaning of the organism may be 90% complete. However, maintenance of hydrocarbon concentrations over longer time periods may result in essentially permanent contamination.

6) The biological effects of weathered oil are limited to physical coating usually confined to localized areas in the intertidal zone. If coating is heavy, the effects may be semi-permanent due to smothering and substrate changes. Light coating of weathered oil is not, in general, a major problem biologically.

S.3.5 Impacts of hypothetical spills and discharges

Our assessment of the biological impact of specific hypothetical oil spills and discharges is necessarily qualitative in nature as time and data constraints precluded the development of a quantitative model of the response of the biota to a given spill or discharge. Thus, the results summarized in this section are somewhat more speculative and perhaps more sensitive to our biases than in the others. Also, all our conclusions will be limited to the species level. It is not yet possible to predict the response of an ecological system the size and complexity of either the Georges Bank or portions of the New England coastal zone to specific oil spills and discharges. Nonetheless, considerable information on oil pollution has been amassed and we feel that one can reasonable make rather strong statements in certain areas.

S.3.5.1 The large Georges Bank spill

Given our conclusion that the direct toxic effects of a spill are almost entirely dependent on the soluble aromatic fraction together with the fact that the great majority of this fraction will have left the slick within four days, we expect almost all the toxic response to a spill to occur within the first few days.

In that period, a very large (3 million gallon) spill will have covered approximately 600 sq mi of the approximately 10,000 sq mi Georges Bank area. During the summer, the more critical months biologically, the spill will remain on the Bank an average of about 30 days.

Several possible consequences of such a spill have been investigated:

1) The larvae of most of the major Georges Bank species float on or near the surface for a period of their life. We have already seen that larvae are in general much more sensitive to oil

than adults. On the basis of present, somewhat fragmentary data, it appears that the species with the most concentrated spawning in space and time are the cod and the haddock, which spawn over roughly 1/4 of the Bank for a period of about 100 days. Under the assumption that all larvae which rise into a spill whose initial location and timing is such that it spends a peak amount of time over the spawning ground during the peak spawning period, a good deal less than 1% of a year class would be killed. Although large uncertainties exist as to the variation in egg production both in time during the spawning period and in space exist, it appears extremely unlikely that a single large spill will have a noticeable effect on the population of an individual species, especially in view of the fact that these species produce many more offspring than the environment can support at adulthood.

2) On the basis of fragmentary evidence, it appears that concentrations in the ppb range will be obtained on the bottom under a large spill in the shallower parts of the Bank. A very large spill will be over a single point on the Bank for very roughly two days. Thus, using Chapter II.4 results, it appears possible that scallops beneath a large spill will accumulate sufficient hydrocarbons to affect taste. A very large summer spill, unfortunately placed, could cover very roughly 20% of the scallop grounds. On the basis of present knowledge, it appears that the phenomenon would be transitory in nature, self-cleaning reducing hydrocarbon concentrations below the levels at which they can be tasted.

More information on both the vertical dispersion of oil in water and scallop feeding habits is needed.

3) We expect almost no biological effects from a Georges Bank spill at the shoreline. Such a spill will be at sea at least 30 days. Some biological effects may be occasioned by attempts to clean up the tarballs.

S.3.5.2 The large nearshore spill

We believe that the situation with respect to a large nearshore spill is biologically quite different from that associated with an offshore spill. Such a spill will with high probability come ashore while fresh. If the spilled material is a distillate product or a crude containing a substantial portion of aromatics, littoral and sublittoral adult as well as larval organisms will be subjected to toxic concentrations and substantial localized kills can be expected. Portions of the oil will be adsorbed into nearshore sediments, especially any marshes reached, within which degradation can be of the order of years. Severe tainting of shellfish grounds in less than 20 feet of water which are overlain by the spill during its early stages is foreseen. Cleansing times, from the point of view of taste, will be of the order of months, or even years if prolonged exposure occurs. For the heavier oils, extensive coating can be expected, resulting in localized kills and semipermanent changes in substrates. Biologically, we feel that all the evidence, both laboratory and in the field observatories, points to the fact that the environment is considerably more vulnerable to a large nearshore spill than to a large offshore spill due to shallower water depths, higher population densities, and less mobile populations, softer sediments, and constricted waters. Recovery times for certain nearshore species will be measured in months and years as opposed to the days and weeks we foresee for the large offshore spill. However, the bulk of the effect will be localized within the area the spill can reach in the first few tidal cycles. A very obviously needed research tool is a nearshore spill tracking model which accounts for current shear, stranding, dissolution and evaporation of aromatic fractions, and their vertical dispersion. It is important to restate at this point our earlier conclusion that the offshore find in itself will have little effect on nearshore spillage.

S.3.5.3 Chronic spills and discharges - Georges Bank

With respect to chronic spills and discharges offshore, there are three sources:

1) Small spills,

2) Discharge from oil/water separators,

3) Ballast water discharge from tanker loading.

The last source is, of course, applicable only to those offshore developments which employ tanker transport to shore.

1) A typical large production platform, operated to 1971 Gulf standards, would on the average suffer one small spill a week, the average size of which would be less than 100 gallons. Thus, chronic small spillage per platform would average something like ten gallons per day.

2) Assuming water is produced from the formation at the Gulf OCS average (about one barrel of water for every three barrels of oil), and this water is separated to present Gulf standards (50 ppm), a large production platform would discharge about 125 gallons of oil per day in a continuous fashion along with the produced water. The Gulf water/oil ratio is relatively high by offshore

standards. A large find would require about 5 such platforms.

3) If the find is shipped ashore by the tankers, the tankers will discharge ballast water offshore. Assuming 50% ballast and 100 ppm oil, tankers serving a very large find would discharge about 2,100 gallons of oil per day.

It is our estimation that biologically the most significant of these discharges is that from the oil/water separators, for this oil could contain a high percentage of water-soluble aromatics. There appears to be no data on the fractional composition of the oil remaining in the water after separation. However, it is known that the separation process used is essentially ineffective against that portion of the oil which is dissolved into the water.

Therefore, a dispersion model for estimating the hydrocarbon plumes emanating from the oil/water separator was developed. This model uses two-dimensional dispersion to obtain estimates of the area within which hydrocarbon concentrations exceeding a specified amount will be found. Under unrealistically worst case assumptions (very low mixing depth, very low diffusion coefficient), the .1 ppm contour encloses 10 sq mi and the 1 ppm contour, .0004 sq mi. Even if all the oil were soluble aromatics, toxic effects would be limited to the most sensitive phytoplankton and this effect would be localized in a very small portion of the Bank. Under still severe but much more likely assumptions with respect to percent aromatics (10% of oil in water), mixing depth (3 ft), and dispersion coefficient (10 ft^2/sec), the area in excess of .1 ppm aromatics is equivalent to a circle whose radius is 40 ft. In short, it is difficult to envision the impact of the oil/water separator discharge being noticeable at the population level. This is consistent with Gulf experience in which the area under the platforms supports high population densities. However, these calculations do show that some local water quality degradation can take place. Experimental data on the fractional composition of the oil in the separator water discharge would be most welcome.

With respect to the ballast water discharge, it is possible that the aromatic content may be rather low, since the oil will have undergone a certain amount of weathering on the two-way trip. However, no data exists. Such data could be easily obtained. Even if it turns out that the ballast water oil contains a substantial portion of aromatics, there is little point attempting to separate this oil to higher standards on board since vessel movement makes gravity separation below 100 ppm almost completely ineffective. Further, there may be little point in transferring the oil to a platform and separating it. The operation will be expensive and gravity separation is ineffective against the biologically active dissolved fractions. If this oil does contain appreciable amounts of soluble aromatics, segregated ballast may be required.

S.3.5.4 Chronic spills and discharges - nearshore

Chapter II.1 estimates that the average number of spills in the vicinity of a regional refining complex large enough to serve the entire region serviced on both the input and output side by tanker/barges in 1978 will be about 160, of which 100 is the estimate of the average number of vessel spills, 37 refining and 26 storage. The mean amount spilled per spill is estimated at about 1,000 gallons; however, the typical spill will be much smaller. These estimates are based on a reasonably pessimistic set of assumptions. For example, if the refinery is operated according to Milford Haven experience, the estimated average number of spills drops to about 40 and the average amount spilled per spill to 200 gallons. In any event, the near-terminal environment will be stressed at irregular intervals of a few days by small spills. A single spill in this size range will produce a slick with an area of a few acres. In terms of hydrocarbons dissolved in the water column, an individual spill of this size is insignificant. If the spill point is close to shore, and if the spill is not controlled artificially (booms, etc.), some of the oil may wash ashore. Although the length of shoreline hit with a single chronic spill slick is obviously much less than that contacted by a large spill, the time available for the biotic community on the shore to recover will be much shorter. Thus, permanent changes in the biota in the immediate vicinity of the terminal are almost inevitable. Some deterioration of marshes and flats within the range of tidal excursions at the terminal is possible. However, Milford Haven, an almost completely enclosed estuary with a very large tidal range (20'), still supports shellfishing as well as 400,000 barrels per day of refining. It appears there is a very significant difference with regard to the impact of chronic, small spills between a well-run and a casually-run terminal.

In order to obtain some idea of the planned discharges which would be generated by such a refinery, Corps of Engineers discharge permit applications prepared by 18 U.S. refineries were obtained. Also, data on the Milford Haven refineries was obtained from the South Wales River

Authority. A key variable in refinery discharge is water usage. Within the sample of refineries, reported water usages and oil and grease discharges varied by as much as a factor of 50 for the same size refinery. On the basis of the available data, it appears that a modern, carefully designed refinery can obtain the following standards:

Water usage	25 gallons per barrel, of which 50% is consumptive use
Oil in water discharge:	15 ppm average

Fragmentary evidence indicates that the percentage aromatics in this oil will be between 10% and 40%. A refinery complex sized to New England's 1978 requirements and designed to the above standards would discharge about 300 gallons of oil per day. The discharge of such a volume of oil in riverine or restricted estuarine bodies could have some rather striking consequences. A salt marsh in Southampton has been observed which has been essentially destroyed by refinery discharge combined with tidal action which deposits the surface film on the marsh with each outgoing tide.

Under the worst-case assumption that the bulk of this oil is soluble aromatics, to be reasonably safe from any sort of toxic effects, we shall need concentrations in the neighborhood of 100 ppb or approximately two to three orders of magnitude of dilution if the bulk of this oil is soluble aromatics. This is essentially the same problem as that of the continuous discharge from the platform oil/water separators except that the volumes are about ten times larger and the concentrations somewhat lower. Assuming enough net transport so that the outfall does not discharge into the same water twice, a mean current of .25 knots and 1 knot respectively, and the two-dimensional dispersion model used earlier, concentrations would be below 100 ppb outside a plume whose area under a variety of assumptions concerning mixing depth and diffusion coefficient is given below.

Table S.3.8

Areas Within 100 ppb Contour for 20,000,000 gallon/day Discharge (square n. miles)

Oil Concentration:		25 ppm		50 ppm	
Disp. Coeff.	Mix. Depth	.25 knt.	1 knt.	.25 knt.	1 knt.
10 ft^2/sec	3 10	3 .08	.4 .04	25 .7	3 .08
30 ft^2/sec	3 10	1 .03	.1 .01	8 .2	1 .03

For likely values of these parameters, it appears that the desired dilution could be accomplished without too much difficulty in open water by a properly positioned outfall. Whether or not one could do it in a semi-enclosed body such as Narragansett or Machias Bay would require some careful analysis.

A regional refinery served on the products side by tanker/barge would have one other source of oil discharges: the products carriers' ballast. The bulk of the incoming ballast will be transferred to the departing crude carriers, perhaps after skimming. However, occasionally arrival patterns will be such that ballast water is in oversupply, in which case a discharge will result. Also, the water separated from the recovered oil will be discharged. However, the volumes discharged are much lower than those discussed above. Bantry Bay claims 5 ppm oil in this water after long-term retention with heating and the oil companies are promising 15 ppm for similar facilities at the Tapline terminus. With proper care and design, ballast water transfer does not appear to be nearly as important a problem as refinery wastewater.

S.3.5.5 Non-petroleum effluents

In addition to oil, offshore drilling and production can generate a number of other effluents. These include produced water from the reservoir, already mentioned, which is likely to be about 50% saltier than Georges Bank sea water, drilling mud, and drill bit cutting. Our analysis indicates that any environmental effects of these discharges will be limited to purely physical alterations of the bottom. Moreover, these effects will be limited to the immediate locale of the drilling platforms. The one possible exception is ferrochrome lignin sulfonate, used as an additive in certain muds. Little is known about the biological effects of this compound. However, the volumes involved are so small that it is extremely unlikely that it could have more than a very localized effect.

The refinery outfall(s) will contain, in addition to hydrocarbons, other suspended and dissolved solids, and chemical and biological oxygen demand. Of these, the most important is probably the heavy metal content. According to Corps data, copper, lead, chromium and nickel concentrations run from .02 to .15 ppm by weight. Iron is considerably higher, with concentrations up to 2.5 ppm. Mercury is present at levels of 1 ppb in some of the reports.

Given the toxicity of copper to certain marine organisms, and the possibility of accumulation in sediments and food webs, the fates of this and other heavy metals deserve some study. However, we have not investigated this issue.

Chapter S.4
Recapitulation of Key Results

Below, we recapitulate the central findings of the study. This listing is meant to serve merely as a reminder to the reader of some of the things he has read. The list by itself offers almost no insight into either our study or the offshore oil issue. For that, one must turn to the entire Summary or, better yet, to the report itself.

Briefly, the key results on the economic side are:

1) The single most important variable with respect to the cost to the region of its future oil consumption is the size of the payment made to the exporting nations for imported oil. Differentials in real regional income due to changes in this variable overwhelm all the other differentials investigated.

2) The pressure on the Georges Bank does not depend on whether or not the import quota is in effect. At most, abolition of the import quota will decrease lease bids. However, even for the largest finds investigated, the region will be much better off without the import quota than with it.

3) A Georges Bank oil discovery will have no effect on regional oil products prices. The value of an offshore oil find to the region depends largely on whether the federal government or the region receives lease and royalty payments. The value of an offshore gas find depends on who receives lease and royalty payments and whether or not gas prices are deregulated.

4) Assuming exporting nations do not appropriate decreases in transport cost in the form of increased exporter payments, a deepwater terminal

on the East Coast is considerably superior to present shallow water terminals from the point of view of regional income. However, under full employment, a deepwater, vessel-serviced refining complex within the region is only marginally superior to a deepwater extraregional refinery. The lowest cost refining option examined was regional refining employing pipeline distribution of products.

5) An offshore find in itself will have little effect on regional employment. Regional refining can have considerable effect if either moderate underemployment or sharp unemployment obtains.

6) The regional income impact of offshore development on the Georges Bank fishery does not appear to be large. However, the impact on regional income of differences in nearshore spillage can be quite significant.

On the environmental side, we find:

1) At peak production, a large offshore find could increase the amount of oil spilled within the region by as much as a factor of two. Such a find is likely to increase the incidence of large spills (> 42,000 gallons) by more than a factor of two.

2) An offshore find in itself will have little effect on nearshore spillage. Only a few percent of the Georges Bank spills will reach shore and those that do will be well-weathered. We were unable to identify any environmental effect associated with offshore oil production which appears likely to materially upset the Georges Bank ecosystem.

3) Nearshore spillage was estimated to be increased by between 30% and 100% by the region's refining all its distillate products, depending on whether the regional refineries distributed their products by pipeline or vessels respectively. In general, we find the nearshore spill to be a more severe biological problem than the offshore. The key variable with respect to the biological impact of a spill appears to be concentrations of aromatic compounds dissolved in the water column.

4) Systems for the containment and collection of nearshore spills merit careful consideration on the basis of present estimates of their cost and effectiveness versus the cost of nearshore spills.

5) Planned discharges emanating from a refining complex large enough to process the bulk of the region's oil consumption will be quite significant, at least on a local basis. We have estimated the magnitude of these discharges but have not investigated their fate in detail. Considerably more work in this area is indicated.