OFFSHORE PETROLEUM AND NEW ENGLAND

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OFFSHORE PETROLEUM AND NEW ENGLAND
A Study of the Regional Economic Consequences
of Potential Offshore Oil and Gas Development

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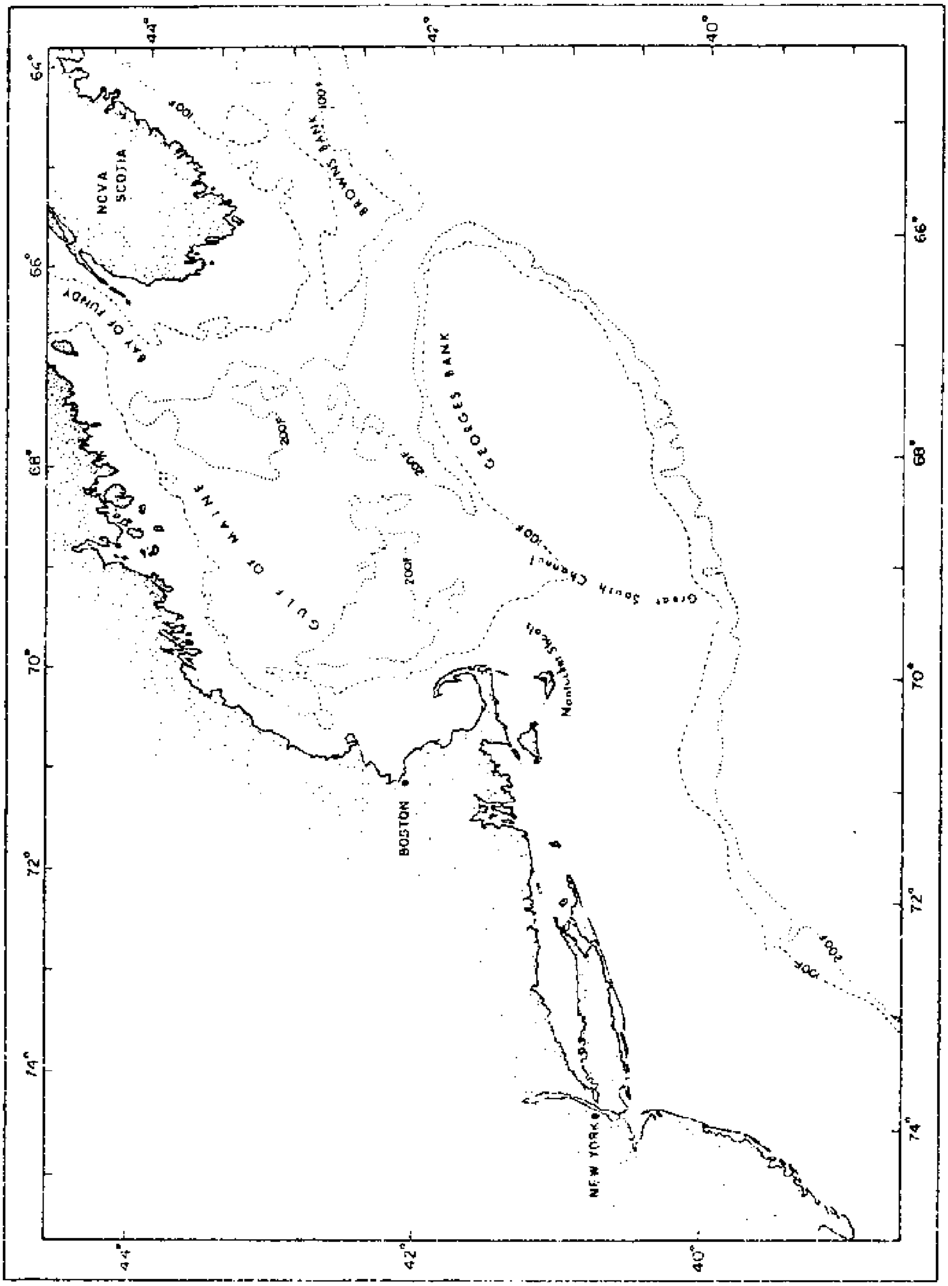
Contents

Figures

Tables



Georges Bank and the North Atlantic coastal area.

1. INTRODUCTION, SUMMARY AND OVERVIEW

Introduction

Background of the Study. For the past several years there has been considerable interest in the petroleum potential of the Atlantic Outer Continental Shelf (OCS). Georges Bank, an historically prolific fishing ground off the coast of New England, is one of three areas along the Atlantic OCS of particular interest in terms of potential oil and gas reserves and production.

Georges Bank covers approximately 11,000 square miles, an area larger than any of the New England states except Maine (see map). Despite their considerable distances from shore, substantial areas of Georges Bank are in water depths of less than 30 fathoms (one fathom equals six feet), and there are notably shallow areas such as Georges Shoal and Cultivator Shoal where water depths range from about one to twelve fathoms. Its water depths increase rapidly toward the edge of the continental shelf and landward toward the Gulf of Maine, reaching depths in excess of 100 to 200 fathoms. In addition, the southwestern portion of Georges Bank is bordered by the comparatively deep water in the Great South Channel which ranges from 25 to 50 fathoms. Water depths just to the south of the Channel range from about 40 to 50 fathoms, and just north of the Great South Channel toward the Gulf of Maine, they range from 50 to 80 fathoms (U.S., Department of Commerce).

There has been no exploratory drilling on Georges Bank to date, and until considerable drilling and actual development take place, discussions of possible total oil and gas reserves and the size and distribution of individual oil and gas fields must be considered hypothetical. However, the U.S. Geological Survey (USGS) has estimated that the entire Atlantic OCS could contain recoverable resources of 10 to 20 billion barrels of oil, including natural gas liquids, and 55 to 110 trillion cubic feet of natural gas (U.S., Department of Interior, Geological Survey, 1974). In comparison, the giant Prudhoe Bay Field on Alaska's North Slope, for which the Trans-Alaskan Pipeline (TAPS) has been designed, may contain reserves on the order of ten billion barrels of oil. And the reported proven reserves of natural gas and crude oil for the state of Louisiana on January 1, 1970, were 5.7 billion barrels of oil and 85 trillion cubic feet of gas (American Gas Association, 1970, pp. 42, 140).

The considerable current interest in the petroleum potential of Georges Bank has several interrelated dimensions.

First, can the offshore oil reservoirs be tapped at economic and environmental costs that are less than the cost of imported oil, and what would be the size and the distribution of the returns from offshore oil development to the nation as a whole and to the coastal areas?

Second, to what extent will oil and gas from the OCS help the nation achieve greater self-sufficiency in petroleum and energy production? This point ignores the broader question of what combination of energy sources at what rates of supply is most favorable for the United States in terms of economic and environmental costs (Cummings et al., 1975). While the precise role of oil and gas resources in the national energy strategy is as yet undefined, offshore leasing and production clearly are expected to play a key part in planning for greater national energy self-sufficiency.

Third, in addition to national considerations, the potential development of OCS petroleum resources is of interest at local, state and regional levels. For example, what will be the short- and long-run impacts of offshore development and petroleum refining activity on the region in terms of total or per-capita income, employment, and other variables? If the effects of major activity should be concentrated in particular coastal areas, what will be the likely dimensions of some of the consequences for the areas concerned in terms of economic activity, employment, income, population and the associated demand for public services?

A fourth issue is the extent to which the various uses of the ocean and shoreline will conflict with each other. We need to consider how such activities as fishing, boating, swimming, tourism, and enjoyment of the shoreline might be affected by petroleum development, and to what extent such development might alter or disrupt coastal ecosystems or alter the aesthetic assets of coastal areas.

Purpose of this Study. This study examines the direct and secondary impacts on New England of alternative potential offshore oil and gas developments and possible petroleum refinery activity within the region. A number of specific Georges Bank oil and gas and petroleum refinery scenarios are postulated. For each alternative set of developments, estimates are made of their effects on total earnings, income and employment and, in some cases, on other socio-economic indicators, e.g., population. In addition, an estimate is provided of the possible direct and secondary impacts of alternative petroleum developments on broad industrial sectors of the regional economy. The impact estimates are primarily for New England as a whole, although results also are presented for a sample coastal area in southeastern New England.

The scope of this study does not permit a detailed examination of the multitude of planning issues resulting from potential OCS development and petroleum refinery activity. However, the results permit insights into the kinds of impacts that can be expected from alternative petroleum developments.

This type of information can provide a basis for gaining an understanding of a host of planning issues related to the types and levels of demands that will take place in the region, information which in turn is useful in assessing the adequacy of resources and planning mechanisms to deal with the demands.

Environmental issues are not examined in this report.[1] Nor is a detailed assessment made of the national returns from Georges Bank development or of the role of potential offshore production in contributing to regional petroleum and energy self-sufficiency, although the study results clearly shed some light on these issues.

Study Approach and Petroleum Cases Examined. A representation of the hypothetical development of individual Georges Bank oil and gas fields was constructed. Its results were used to make judgments about some of the implications of a buildup of a potential Georges Bank petroleum basin, i.e., a number of fields.

Two major Georges Bank oil and gas scenarios were considered (table 1.1). The low case assumes that Georges Bank contains recoverable reserves of 400 million barrels of oil and two trillion cubic feet of natural gas. In the high-find scenario, oil reserves are three billion barrels and ten trillion cubic feet of natural gas. The high and low finds are well within the USGS estimates for the entire Atlantic OCS.

Georges Bank contains four fields in the low-find case, and twenty-five in the high. The capital costs of development used to characterize all Georges Bank fields for the purposes of obtaining regional impact effects are on the order of $79 million for the oil field and $90 million for the gas field ($ 1973).

High and low oil and gas prices are used in the study. The low price used is $6 per barrel (bbl) and the high price is $9/bbl. For natural gas the low price is $.75 per thousand cubic feet (Mcf) and the high is $.95/Mcf.

Two petroleum refinery scenarios also were considered. The low refinery case involves one New England refinery, and the high, three. All are assumed to be integrated refineries with a throughput capacity of 250,000 barrels per day (B/D), and to involve an investment cost for each on the order of $475 million ($ 1970). Offshore oil production need not be tied to regional petroleum refinery activity; however, one refinery would be more than adequate for the low-find Georges Bank case, and three for the high. However, even if three 250,000 B/D refineries distributed all of their output in regional markets, New England still would need to import considerably more than 50 percent of its petroleum products.

A multi-industry, multi-regional economic model was adapted to provide insights into the kinds of direct and indirect effects alternative offshore oil and gas and petroleum refinery developments could have on the region. For each petroleum case considered, the following estimates were used as input into the regional model:

1. Investment taking place in New England through time as a result of (a.) offshore development, for example, platform fabrication, oil storage terminals and gas plants, pipeline preparation, and other capital investments; and (b.) the construction of one or three petroleum refineries.

2. Offshore oil and gas production and petroleum refinery output over time.

3. Public revenues received by the region over time in the form of (a.) real estate taxes on petroleum refinery investment and on oil storage and gas plant facilities related to Georges Bank petroleum production; and (b.) royalty and cash bonus payments received indirectly via additional federal government outlays taking place in New England.

Excluding the base-case regional model, in which it is assumed no petroleum developments take place, four regional impact cases were examined: high and low offshore finds, high and low prices for oil and gas, and one and three refineries. Four state control cases also were run with the regional model; however, in view of the Supreme Court decision upholding federal control over Georges Bank, these cases are not developed in the text (table 1.2).

Summary of Selected Results

Hypothetically, production from Georges Bank would begin during the fifth year after an initial lease sale. Peak annual production would be reached in the ninth year with the low find and in the sixteenth with the high (figures 1.1 and 1.2). Should an initial lease sale be held in 1975, then, production would begin in 1980 and peak in about 1985 with the low find and in 1990 with the high. These results are based on the assumption that substantial areas of Georges Bank are leased rapidly, and that there are no delays in developing offshore fields.

Potential Offshore Production and Regional Demand. None of the offshore oil scenarios considered comes near to equalling the region's demand for petroleum products. For example, maximum annual production in the high-find case is about 219 million barrels in 1990, equivalent to about one-half the region's consumption of refined products in a base year, 1972 (table 1.1). Even if Georges Bank proves to contain six billion barrels of recoverable oil -- twice the high-find oil reserves considered here -- peak annual production still is only about the equivalent to the region's consumption of oil products in 1972. This is not to suggest that Georges Bank oil production would be unimportant in any sense; instead, the results indicate that very large commercial oil finds will be needed before production from frontier OCS areas even begin to approach oil demands in the region. In the low-find oil case, Georges Bank production is only a fraction of the region's consumption of oil in 1972.

On the other hand, peak gas production from Georges Bank under the high-find assumptions exceeds by a wide margin New England's consumption of gas in 1972. Thus if Georges Bank contains ten trillion cubic feet of gas, New England could become self-sufficient in natural gas and conceivably an exporter, depending on the growth in the region's demand for gas, the relative costs of energy sources, and how Georges Bank gas production is distributed. In the low-find gas case, however, the maximum production of gas from Georges Bank would be the equivalent of slightly more than one-half of the region's consumption of gas in 1972.

Regional Economic Impact. Detailed economic effects are presented in chapter 4, and what follows is only a brief summary of some of the major impact findings and aggregated results. Table 1.3 contains economic indicators of the estimated impact of the low- and high-find offshore petroleum developments on the region, averaged for selected years. The offshore petroleum results assume federal control over Georges Bank, and the initial lease sale is regarded as taking place in 1975.

Offshore development investment exceeds $2 billion in the high-find case and is over $325 million in the low. The offshore regional impact results are based on the assumption that a share of the development investment takes place in the region. It also is assumed that New England indirectly shares in offshore revenues through increased spending by the federal government in the region. In addition, real estate taxes are assessed on oil terminal and gas plant facilities, and reach a maximum of about $1 million annually in the high-find case and slightly under $200,000 a year in the low.

In the low-find case, direct and indirect employment in the region increases by about 3,000 during the period of major field development activity, 1977-79. Field development activities, a share of which take place in New England, include well drilling and exploratory work, platform fabrication, pipeline preparation and laying, the construction of oil terminals and gas processing plants, the manufacture of pumps, compressors and instruments, and associated investment. Field development activities are comparatively short-run; employment declines sharply in later periods as the development phase is completed and the fields are brought into production. Annual regional payrolls could be as high as $33 million and income as high as $39 million during the years of peak activity related to offshore development.

With the high-find offshore petroleum case considered in this study (25 offshore fields), annual employment in the region as a result of development and production activities could be in the range of 6,000 to 7,500 from 1977 to 1990, and average annual earnings could range from $70 to $100 million during this period.

Selected total indicators of the regional impacts resulting from both the one- and three-refinery cases are contained in table 1.4. As presented here, the regional impact results for the refinery construction cases are in addition to results for the offshore petroleum cases.

Refinery construction in both cases would begin in 1977, and the refineries would come on stream in 1979. The impact results include direct and secondary effects of state and local real estate tax revenues, estimated to be $4.18 million annually for each refinery -- considerably more than the property revenue from the onshore oil storage and gas plant facilities associated with Georges Bank petroleum operations.

Table 1.5 contains a summary of all the petroleum impact cases stated in terms of the aggregate present value of regional earnings and income resulting from each alternative. Part A of the table deals with the various Georges Bank oil and gas alternatives, while part B summarizes the results of the refinery cases. Three discount rates are used, but the discussion below is based on the eight-percent discount rate.

With federal control over Georges Bank and the high prices assumed, the present value of direct and indirect income to the region ranges from about $207 million to about $1 billion, depending on whether the low or high offshore oil and gas find proves to be the case.

A single petroleum refinery will lead to considerably higher discounted regional earnings and income than the low-find, federal-control offshore petroleum case considered in this study. The three-refinery alternative has only a somewhat higher present value of income and earnings than the high-find case with federal control, but if each estimate is off by as much as five percent, the two potential petroleum developments would have about the same effects on total earnings and income in the region.

For either the low- or high-find case, the present value of regional income and earnings is somewhat higher in the high-price case than in the low. The results in table 1.5 do not include losses in the real income of the region due to higher petroleum prices. Instead, the results reflect earnings and income in the region resulting from a particular petroleum development alternative, given that the high or low set of prices prevails and is independent of the development of Georges Bank.

In perspective, the expansion in economic activity described here cannot be expected to substantially increase New England's employment rate or annual per-capita income. Given the size of the regional labor force and the fact that population does increase as a result of OCS or petroleum refinery developments, this is not surprising.

The regional impact estimates presented in table 1.5, with some exceptions for public expenditures, environmental factors and other considerations, correspond with what one would expect to see reflected in a system of economic accounts measuring employment, earnings, income, output, and other variables, if the region maintained a unified set of accounts. Regions understandably may wish to measure the total impacts of prospective economic developments. However, it also is of interest in terms of national goals to provide estimates of the extent to which increases in regional earnings and income represent an increase in national earnings or income or instead merely a transfer of resources and income into the region (or even among sections of the region).

In order to estimate the share of total regional effects that represents a true increase in national earnings and income, all payments to labor must be adjusted to reflect the real, or opportunity, cost of the labor used in the region. The results of this adjustment are summarized in table 1.6.

The adjustment for resource costs brings into sharp focus the difference between estimates of the total regional impacts experienced by a region -- the results in table 1.5 -- and estimates of the increase in national earnings and income associated with the petroleum activities taking place in the region, as indicated in table 1.6. For example, at a discount rate of eight percent, the total or unadjusted regional earnings and income in the low-find, high-price, federal-control case is \$196 million and \$207 million (table 1.5). These figures represent an estimate of the direct and indirect impacts on the region of this offshore find scenario, and the estimates would be reflected in a system of regional economic accounts for New England. However, when adjusted for resource costs, the share of regional earnings and income that contributes to national earnings is \$49 million and to total national income is \$60 million. Similarly, the total discounted earnings and income accruing to the region with one refinery is about \$324 million and \$353 million, respectively. The component of regional income and earnings that represents a gain in national earnings and income, however, is about \$82 million and \$109 million, respectively.

In summary, both the total regional impact results and the total results adjusted for resource costs are of interest, although from different points of view. There is, however, a substantial difference between the two measurements of regional economic effects. The total effects include the use of unemployed regional and non-regional labor and regional capital, the location effects from a transfer of resources and income into the region, and perhaps a re-allocation of resources among activities and areas within the region. The total results adjusted for resource costs, on the other hand, provide an estimate of the share of the total earnings and income accruing to or taking place in the region that also represents an addition to national earnings and income, after subtracting the opportunity costs of the resources used in the region.

<u>Economic Impact on Example Central Coastal Site</u>. Impact results also were presented for an example coastal area in southeastern New England, Bristol County, Massachusetts. A

large fraction of field-development investment activities and offshore-production support activities are assumed to be based in the county, and the county is also assumed to be the location of a petroleum refinery. These results provide insights into the magnitude and kinds of effects on coastal areas that are central sites for petroleum activities.

In the high-find, no-refinery case, total Bristol County employment could range from 2,400 to 3,600 during different periods of offshore oil and gas activity. The location of economic activity in the county in turn could lead to a population increase as high as 6,600. Total direct and indirect employment in Bristol County associated with petroleum activities in the high-find, one-refinery case could range from about 4,500 to 5,900. The population in the county could increase by as much as 11,500. The employment-population figures cited here in fact almost certainly overstate changes in Bristol County since not all the labor associated with petroleum developments, e.g., tanker crews or production-drilling crews for offshore platforms, may live within the county. Offshore drilling and production crews work a seven day on-seven day off schedule, and, as in the Gulf of Mexico, it is reasonable to expect that crew members who commute only twice a week may be willing to travel considerable distances.

Particular coastal areas that become centers for OCS-related activity, and possible sites for a refinery, may experience only a small increase in annual per-capita income -- less, and in most periods considerably less, than $50 per person -- and a slight reduction in area unemployment rates. Most developments in areas like Bristol County do not have a substantial effect on either per-capita income or unemployment rates because (1.) the base-case population is high, and population tends to increase along with income when new activities are introduced; (2.) southeastern New England is an open economy, and a good deal of commuting can be expected, so that local employment may not draw upon the local labor force; and (3.) except for labor used in construction, refinery and in most OCS petroleum operations, not all the additional employment is high wage. But results like these may need to be qualified somewhat if current unemployment rates persist.

Overall, population and employment in Bristol County as a whole could increase two to three percent as a result of the petroleum-related developments considered in this study. However, this kind of comparison can be misleading. Offshore petroleum and refining activities are particularly marine-oriented, so that much of the development activity in the county will tend to be concentrated along the coastline. One lesson from the North Sea experience is that a rapid influx of petroleum-related activity into particular coastal areas during the development phase of offshore operation can create a number of "dislocations." Wage rates, land and housing values and the cost of resources in limited supply are bid up, although market adjustments would be expected with time. Public services may prove inadequate. Pressures develop to convert existing facilities and land for use in activities associated with petroleum operations. The smaller the community, the more noticeable such consequences will be. In short, the obvious and subtle consequences of development occur, except within a telescoped time frame, given that offshore blocks may be developed quickly once a lease sale is held. The high-find refinery impact scenarios indicated here, then, imply noticeable changes for coastal areas in terms of population and economic activity and the general level of development.

Whatever the outcome of the federal-state dispute over the jurisdiction of Georges Bank, state and local authorities will be called upon to address a variety of onshore issues. These will include studies and hearings to evaluate alternative landfalls and pipeline corridors for offshore oil and gas; site selection for the location of oil terminals and gas processing plants; the adequacy of existing port facilities to accommodate offshore support vessels; the possible conversion of some coastal lands to support offshore development and production activities, and the effects of potential refinery activity.

As mentioned previously, no attempt has been made as part of this study to evaluate in detail the social costs, potential onshore conflicts and planning issues that can arise as a result of the development of offshore oil and gas fields and the location of petroleum refineries in the region. The results do indicate development pressures that will confront coastal areas as a result of the potential introduction of petroleum-related activities. Also, an effort is made to provide perspective on the kinds of management issues that will confront coastal areas. Additional work is needed, however, to examine in detail the activities and demands that are likely to be made in coastal areas and to inventory the stock of port, transportation, social service and other facilities and resources. Assessments then can be made of the extent to which potential OCS petroleum developments might encounter constraints or bottlenecks in the region's coastal sections as well as the adequacy of existing offshore leasing arrangements and coastal planning mechanisms to deal with these problems. This kind of a planning strategy would, among other things, provide guidance in dealing with potential planning problems, including a possible ranking of particular ports and coastal communities in terms of, say, lowest social cost of accommodating OCS development and socio-economic conflicts. Specialized studies of the potential onshore effects of OCS developments also would provide more refined measures than currently exist of the true social gains of offshore development and would indicate the onshore costs to coastal regions. This type of information would provide a rational foundation for examining the existing federal OCS leasing arrangements in which all offshore public revenues accrue to the federal government irrespective of the social costs borne by coastal areas in support of offshore oil and gas operations.

Overview of the Work

The first step in deriving estimates of the potential regional impacts of petroleum-related developments is to assess the economic aspects of potential oil and gas production. Chapter 2 contains a simple representation of potential Georges Bank petroleum development. Estimates are made of both production and returns associated with developing individual hypothetical oil and gas fields under different assumptions about the possible size of individual fields, the price of oil or gas and a number of other considerations. The results then are used to evaluate total production possible from a potential Georges Bank basin, e.g., a number of individual petroleum fields, under the low- and high-find scenarios.

In chapter 3 attention is given to investment demands, output and public revenues from hypothetical New England petroleum refinery activity. In addition, this chapter reviews the kinds of investment demands that can be anticipated from offshore oil and gas development. This information provides insights into the potential interactions of petroleum developments with the regional economy.

The results of chapters 2 and 3 provide the basis for estimating the direct and secondary regional economic effects of the potential petroleum developments in chapter 4. The assumptions and properties of the regional economic model are described in this chapter, and a summary of the impact results is presented. For each petroleum case considered, the estimates of offshore oil and gas production, petroleum refinery output, public revenues and petroleum-related investment demand for New England are used as input into the regional economy model. This procedure for each petroleum case evaluated generates estimates of the direct and secondary economic impacts from the potential introduction into New England of a variety of particular petroleum developments.

The results of chapter 4 are qualified in chapter 5 to reflect considerations regarding the cost of resources used in the region, and public revenues and public service costs. The discussion in chapter 5 also provides a perspective on possible social costs and planning issues associated with potential petroleum activities.

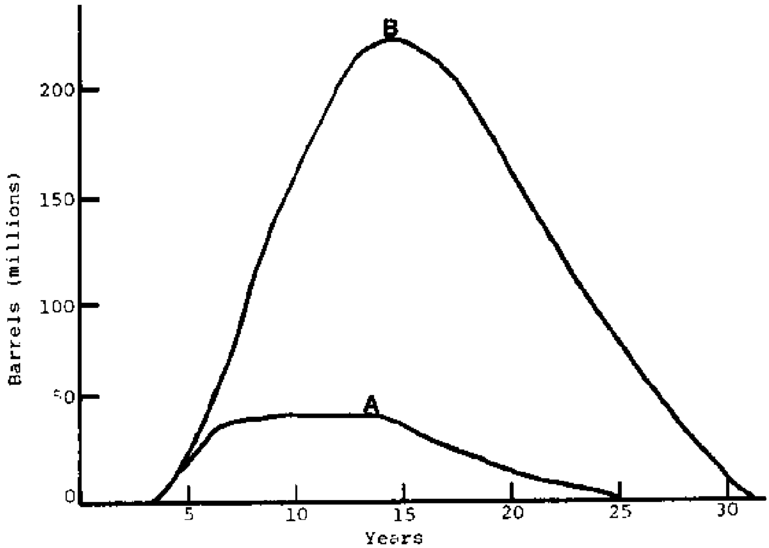


Figure 1.1. Potential annual production of oil from hypothetical Georges Bank fields -- low-find (A) and high-find (B) cases. A - Total Reserves: 400 x 10^6; No. of Fields: 2; No. of Fields Discovered/Year: 2. B - Total Reserves: 3 x 10^9; No. of Fields: 15; No. of Fields Discovered/Year: 2.

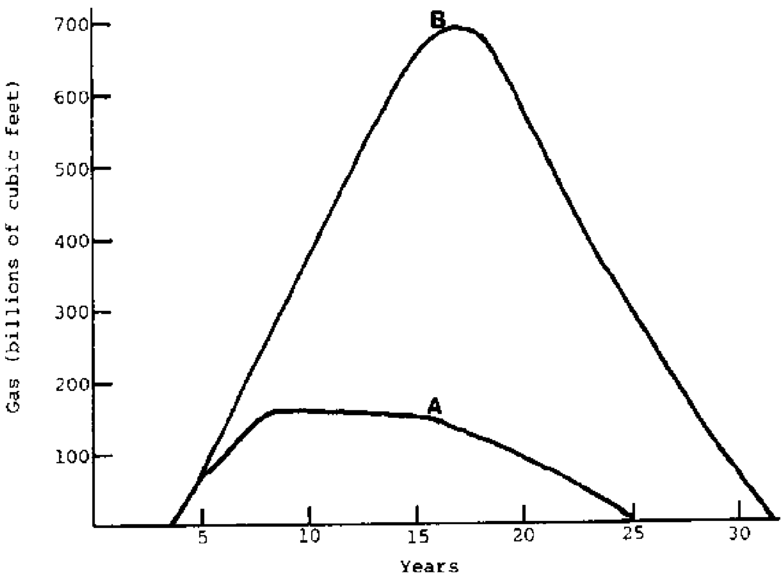


Figure 1.2. Potential annual production of gas from hypothetical Georges Bank fields -- low-find (A) and high-find (B) cases. A - Total Reserves: 2 x 10^{12}; No. of Fields. 2; No. of Fields Discovered/Year:1. B - Total Reserves: 10 x 10^{12}; No. of Fields: 10; No. of Fields Discovered/Year: 1.

Table 1.1. Summary of possible Georges Bank petroleum reserves and production and New England petroleum consumption in 1972.

	Oil	Gas	Total
High Case			
Reserves[a]	3 bill. bbls.	10 trill. cu.ft.	--
Number of fields[b]	15	10	25
Maximum annual production[c]	219 mill. bbls.	700 bill. cu.ft.	
Low Case			
Reserves[a]	400 mill. bbls.	2 trill. cu.ft.	--
Number of fields[b]	2	2	4
Maximum annual production[c]	29 mill. bbls.	148 bill. cu.ft.	--
New England Consumption of petroleum products in 1972[d]	438 mill. bbls.	260 bill. cu.ft.	--

[a]Recoverable reserves at a low landed price of $6/bbl of oil and $.75/Mcf of gas.

[b]Each oil field is assumed to contain 200 million barrels of reserves; gas fields each contain one trillion cubic feet of non-associated natural gas.

[c]Derived under the assumption that two oil fields and one gas field are discovered each year until all potential fields on Georges Bank have been discovered for the high and low cases.

[d]Based on Minerals Industry Survey information for 1972 published by the Bureau of Mines.

Table 1.2. Summary of offshore petroleum and refinery cases examined with the regional model.

Case	OCS Find[a]	Price[a]	Control	Refineries
1[b]	--	Low	--	0
1[b]	--	High	--	0
2	Low	High	Federal	0
3	High	Low	Federal	0
4	High	High	Federal	0
5	High	High	Federal	3

[a]To reduce the number of find-price combinations, the low and high classifications for field size and price refer to <u>both</u> oil and gas. Thus, the low find case assumes that Georges Bank contains the low reserve assumptions for <u>both</u> oil and gas used in the study; similarly, the high price case means that the study assumptions for the high price of oil and gas are in effect.

[b]Base cases, assuming no Georges Bank OCS development and no refineries in New England.

Table 1.3. Economic indicators of the regional impacts of example offshore petroleum cases averaged for selected years.[a]

Indicator	Low Find Federal Control No Petroleum Refinery 1977-79	1980-85	1985-90	High Find Federal Control No Petroleum Refinery 1977-79	1980-85	1985-90
Employment	3,015	1,115	1,375	6,295	7,135	7,575
Payrolls (in millions)	\$32.9	\$13.8	\$18.0	\$73.2	\$87.2	\$101.3
Income[b] (in millions)	\$39.4	\$14.0	\$25.7[c]	\$87.3	\$135.0	\$144.6

Source: Special application of the Harris regional forecasting model.

[a]The figures in each column represent an average, not a total, for the years indicated in the column heading.

[b]Regional income = earnings + transfer payments + property income - social security contributions.

[c]Adjusted to reflect the same income-to-earnings ratio as in 1985-90 high-find case.

Table 1.4. Economic indicators of the regional impacts of petroleum refinery alternatives averaged for selected years.[a]

Indicator	One 250,000 B/D Refinery[b]			Three 250,000 B/D Refineries[c]		
	1977-8	1980-85	1985-90	1977-8	1980-85	1985-90
Employment	2,900	2,630	2,650	8,220	6,000	6,825
Payrolls	$34.4	$34.3	$36.5	$94.6	$81.3	$96.3
Income[d]	$42.3	$41.5[e]	$40.6[e]	$118.	$98.4	$107.1

Source: Special application of the Harris regional forecasting model.

[a]The figures in each column represent an average, not a total, for the years indicated in the column heading.

[b]Calculated as the difference between the low find-state control-high price cases with and without a petroleum refinery.

[c]Calculated as the difference between the high find-high price-federal control case with and without three refineries.

[d]Regional income = earnings + transfer payments + property income - social security contributions.

[e]Adjusted to reflect the same income-to-earnings ratio as in the 1980-85 or 1985-90 three-refinery case.

Table 1.5. Estimated discounted New England earnings and personal income from alternative potential offshore oil and gas and petroleum refinery developments (in $ million).

A. Offshore Petroleum Cases Examined

Low-Find, High-Price, Federal-Control

Discount Rate	Earnings[a]	Personal Income[b]
.08	$196	$207
.11	150	155
.14	120	130

High-Find, Federal-Control

Discount Rate	Low-Price Earnings	Low-Price Personal Income	High-Price Earnings	High-Price Personal Income
.08	$871	$1002	$874	$1006
.11	632	739	641	751
.14	478	569	488	579

B. Regional Petroleum Refinery Cases Examined[c]

Discount Rate	One Refinery Earnings	One Refinery Personal Income	Three Refineries Earnings	Three Refineries Personal Income
.08	$324	$353	$923	$1169
.11	234	265	649	814
.14	177	207	483	600

[a]Throughout the table, earnings = payrolls.

[b]Throughout the table, personal income = earnings + transfer payments + property income - social security contributions.

[c]In the one refinery case, the example refinery location is Bristol County, Massachusetts. The three example refinery locations are Bristol County, Massachusetts; Newport County, Rhode Island; and Washington County, Maine.

Table 1.6. Discounted share of New England earnings and personal income from alternative potential petroleum developments that represents a gain in national earnings and income (in $ million).

A. Offshore Petroleum Cases Examined

Low-Find, High-Price, Federal Control

Discount Rate	Earnings[a]	Personal Income[b]
.08	$49	$60
.11	38	43
.14	30	39

High-Find, Federal-Control

Discount Rate	Low-Price Earnings	Low-Price Personal Income	High-Price Earnings	High-Price Personal Income
.08	$218	$349	$219	$351
.11	158	265	160	271
.14	120	210	122	213

B. Regional Petroleum Refinery Cases Examined[c]

Discount Rate	One Refinery Earnings	One Refinery Personal Income	Three Refineries Earnings	Three Refineries Personal Income
.08	$82	$109	$231	$478
.11	59	90	173	317
.14	45	74	120	238

[a]Throughout the table, earnings = payrolls.

[b]Throughout the table, personal income = earnings + transfer payments + property income - social security contributions.

[c]In the one refinery case, the example refinery location is Bristol County, Massachusetts. The three example refinery locations are Bristol County, Massachusetts; Newport County, Rhode Island; and Washington County, Maine.

Footnotes

1. There is a voluminous literature on the effects of oil on the environment and a less extensive, but rapidly growing, body of research that focuses on the environmental aspects of offshore oil and gas production and transportation, e.g., M.I.T. (1973), University of Oklahoma (1973), Council on Environmental Quality (1974).

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2. PETROLEUM PRODUCTION FROM GEORGES BANK

The field development model in this chapter is used to obtain estimates of the approximate cost necessary to develop, produce, transport to shore, and store oil or process gas from hypothetical offshore fields. Based on the field model, estimates also are obtained for oil and gas production, revenues, profits, and royalty and cash-bonus payments under a variety of possible alternative economic and policy developments. The model then is used to make some judgments about some of the implications of a buildup of a potential Georges Bank petroleum province or basin.

The results of this chapter provide the basis for developing in chapter 4 estimates of the kinds and scale of investment activity associated with OCS development. The information generated in this chapter and in chapter 4 is used in chapter 5 as input into a regional economic model to estimate the direct and secondary impacts of potential offshore development.

The approach adopted in developing the model of offshore field development is based upon a synthesis of industry practices in offshore areas. It is recognized, of course, that potential field operations on Georges Bank will not have the exact characteristics of the hypothetical fields discussed. However, the model presented here captures the major features of offshore petroleum development, and suits the purpose of the study: to estimate the regional economic consequences of a variety of possible offshore petroleum developments.

Simulation of the future development of Georges Bank necessarily involves a host of judgments and assumptions. In general, when there is difficulty in determining which of several cost estimates is most likely, the high cost is used. In addition, efforts are made to establish explicitly the assumptions used to generate the results in each of the cases examined below and to provide some sensitivity analyses for many of the important variables included in the study.

A Simple Representation of the Development of Individual Offshore Petroleum Fields

For convenience, the hypothetical offshore petroleum fields considered in this study are assumed to contain either oil or gas. That is, gas is produced from gas fields not associated with oil, and gas produced as a joint product with oil is either used for power on the platform or is flared.

The discussion in the text is in terms of recoverable reserves, i.e., the amount of oil or gas in place that will be recovered from a specified hypothetical field at alternative prices, given company costs and the existing state of technology. An increase in the price of oil or gas will lead to additional field development and larger recoverable reserves. The field supply elasticity used here is .25. Thus, it is assumed an increase in petroleum prices of ten percent will give rise to an increase of 2.5 percent in oil or gas reserves recoverable from a given field.[1]

Price Assumptions. High and low prices for oil and natural gas are used in the study. In light of the behavior of the world crude oil market in the past few years, since the emergence of the unified OPEC cartel, it is heroic indeed to speculate on the price of crude oil over the next year, let alone over 20 to 30 years. It also is risky to speculate on a long-run price or series of prices for natural gas, since the market for natural gas will depend on the price of oil as well as on federal regulatory policies. It is possible, however, to set reasonable upper and lower limits on a long-run price of crude oil and natural gas.

The high price of oil used throughout the study is $9 per barrel (bbl); it is unlikely that the price of crude oil could remain at a price greater than $9-10/bbl in the long-run. Prices at this level would discourage demand, or at least growth in demand, and encourage secondary recovery from existing fields, exploration of new fields, and the development of fields which, at lower prices, had been considered marginal or noncommercial. Moreover, alternative conventional (nuclear power) and nonconventional (solar energy, coal gasification) energy sources would be expected to substitute for traditional sources and uses of petroleum. Houthakker and Kennedy have argued recently that at a real (1973) price of $8/bbl the OPEC countries would price themselves out of the world market in the long-run. Under these conditions, the OPEC countries would need to reduce prices in order to increase export revenues (1974, pp. 20-22). Alternately, major OPEC production cutbacks might be called for in the long-run to maintain a world oil price of $8-9/bbl.

On the other hand, oil prices may not decline below, say, $6/bbl in the foreseeable future. It is interesting to note that domestic oil companies recently submitted a total of $210 million in winning bids to develop shale oil from a 5,120-acre tract in Colorado; similar offerings in the past have only elicited modest interest as reflected by very low bids (Anon., 1974, p. 30). Assuming $5-6 estimates of the cost of producing oil from shale are realistic, apparently a number of companies are willing to bet heavily that the domestic price will not fall below that level. Even if world oil market developments were such that in the long-run pressures developed to price oil at less than $5-6/bbl, it is not inconceivable that attempts once again would be made to maintain the U.S. domestic price above the world price to encourage domestic self-sufficiency and conservation. The low price used for this study is $6/bbl.

The price for natural gas from potential offshore fields will depend on the pricing policy applied to new gas. In a recent landmark decision, the Federal Power Commission (FPC) established a national uniform base rate for new gas and gas sales where old contracts have expired. The new national rate replaces the former system of setting ceiling rates for each producing area, and with the new pricing structure gas companies are allowed a base price of $.42 per thousand cubic feet (Mcf) at the wellhead. Adjustment factors (for gathering, transportation and Btu content) may result in a higher base price in some cases; moreover, annual escalations of one cent per year per Mcf are allowed (U.S., FPC, 1974, pp. 103, 110). In addition, companies developing offshore fields that can support higher cost claims will be allowed to petition the FPC for higher gas prices.

The new FPC pricing policy raises the field price of "new" natural gas substantially over the early 1974 area rates, which ranged from area maximums of $.20-.34/Mcf.[2] On the assumption the new FPC policy is maintained, a landed price of gas of $.75/Mcf is a reasonable average price for potential Georges Bank gas fields. This is the low-price estimate adopted for this study.

The high-price estimate for natural gas is $.95/Mcf. This price is somewhat higher than the 1980 equilibrium price of $.836 recently estimated by one source (M.I.T., 1974, p. 25), but is lower than the $.90-1./Mcf and even higher equilibrium price estimates which have been mentioned in some industry and government circles.

In summary, in postulating total recoverable reserves for individual Georges Bank fields, a hypothetical oil field with estimated recoverable reserves of 200 million barrels at the low price of $6/bbl will have recoverable reserves of 225 million barrels at an expected price of $9/bbl. Similarly, a hypothetical Georges Bank gas field with reserves of one trillion cubic feet of gas at a price of $.75/Mcf is taken to contain 1.07 trillion cubic feet of reserves at a price of $.95/Mcf.

<u>Major Field Development and Production Assumptions</u>. The possible timing of the major activities involved with the exploration, development and production phases of hypothetical Georges Bank offshore fields is indicated in figure 2.1. Based on prior geophysical exploratory activity, oil companies nominate tracts that they wish to see included in a lease sale. Individual offshore blocks may average 5,000 acres, about eight square miles, but by law a block may not exceed 5,760 acres.

Exploratory drilling from a mobile rig begins shortly after a lease sale. Support services are required to supply food, pipe, drilling mud, chemicals, cement, casing and other materials to the drilling rig. Up to three 180-foot supply vessels, each with a crew of 8 to 13 men, may be needed, one standby for safety, one in port, and one en route. Helicopter services (about 20 hours a month) are required to transport crews, visiting specialized personnel, and light equipment needed on short notice.

The exploratory drilling period continues for 14 to 16 months or until enough wells are drilled to indicate the commercial potential of the field and delineate its approximate geographic extent. If the field is found to be commercial, fixed platforms are ordered.[3] This occurs in the second year after the lease sale. The platforms are constructed, towed to Georges Bank and installed over an 18-month period.

Development drilling commences once the permanent platforms are installed and operational and a drilling rig is in place on the platform. While the production wells are being completed, pipelines are layed in sections by several specialized pipelaying barges operating simultaneously during fair weather.

Oil storage terminals will be located on or near the shoreline where there is access to deep water, unless the crude is stored offshore and directly loaded onto small tankers or possibly barges. Alternatively, the crude could be piped directly to a refinery located along the coast or inland. If natural gas is produced, a gas processing plant will be located close to the point where submarine pipelines come ashore. These plants are used to dehydrate gas and to strip ethane, propane, and butane before the natural gas (primarily methane) is marketed through the distribution system. Pipelaying and the construction of terminal and gas processing facilities are timed so that they are in place and operational when major production from the offshore fields is ready to begin.

Production from Georges Bank fields is assumed to begin during the fifth year after a lease sale. Field production reaches a peak four years after the production from the first completed well, or eight years after the lease sale. A seven- to eight-year average time-frame to develop a large field a considerable distance offshore in a frontier OCS area is reasonable and even somewhat conservative. With an accumulation of industry experience in operating in New England waters and the establishment of an onshore supply system, subsequent fields may take less time to develop. As a crude check, British Petroleum's giant Forties Field, 110 miles off the northeast coast of Scotland, was discovered in October, 1970. Initial production was scheduled to begin in late 1974, and maximum production is expected to be reached in 1977.

Peak field production is assumed to continue at a constant rate for seven years, after which the output declines gradually as the field is depleted and the natural pressure of the petroleum reservoir declines.[4] The exact amount of oil or gas produced during peak production years is determined by the size of the assumed field in the case being considered, subject to the constraint that the field will be economically exhausted at the end of its production life.[5]

Once developed, all the hypothetical offshore fields are assumed to have an "economic" life of 20 years. However, most of the production from a given field takes place within the first 12 years. Fields are shut down in year 25, that is, in the last year of field activity, all wells are cut off and plugged at the mud line, and the fixed platforms are dismantled and removed.

The capital costs required to develop a given field depend on the planned production from the field and a number of technical assumptions, including water depth, drilling depths, distance to shore, and the initial oil or gas flow from each production well. The technical relations used to describe the development and operation of offshore fields are described below, and the cost data that will be used to evaluate the returns from Georges Bank oil and gas development are presented in the next section.

Companies developing offshore fields expect to drill a number of dry holes. Only 8.4 percent of all onshore and offshore new-field <u>wildcats</u> were successful in 1968. That is, 10.77 dry holes were drilled for each producing well found in previously unexplored areas (American Petroleum Institute, 1971a, p. 28), although it is reasonable to expect higher success rates in new offshore areas. However, for <u>development</u> wells -- wells drilled to exploit a reservoir previously discovered by new-field wildcat drilling -- the success rate is much higher. In 1968, for example, of the 21,720 development wells drilled in the U.S., 16,319 were productive and 5,401 were dry holes (API, 1971a, p. 14). This 3:1 success ratio for development wells is assumed to hold for hypothetical Georges Bank fields.

For the offshore petroleum field results presented in this study, the initial oil production per well is set at 1,100 barrels per day (B/D), and gas produced from nonassociated gas fields is set at 10 MMcf/da. Given the initial production per well, the number of production wells and the expected number of dry wells depend on the recoverable reserves in a hypothetical field and the company's planned peak rate of production. For example, a company planning for annual peak production of 14.8 million barrels from a field with recoverable reserves of 200 million barrels would complete 37 production wells. The company also would expect to drill, on the average, 12 dry holes in the course of developing the field.

Successful oil and gas wells on Georges Bank are taken to be drilled to a depth of 10,000 feet, which is roughly in line with reported drilling experience at Sable Island, Nova Scotia. (See table 2.1.) It also is assumed that dry holes are drilled to 10,000 feet before the well is abandoned as noncommercial. The drilling depth for dry holes thus corresponds with the pay depth for successful wells, and it approximates experience in other offshore areas. In offshore Louisiana, for example, the average depth of a dry hole in 1970 was 10,742 feet (API, 1971b, p. 31).

Well workover or recompletion operations are assumed to be required for all Georges Bank fields. All production wells are worked over once, and the first wells are worked over beginning ten years after initial production from the field. One-seventh of the wells are worked over per year, beginning in year 10.

Secondary recovery operations, such as water or gas injection, are not allowed for in this study, and thus all oil production takes place from the reservoir's natural drive. Implicitly this means that the investment-production relations discussed in this section refer primarily to reservoirs characterized by a water drive as opposed to a less efficient gas cap, dissolved gas or combination reservoir drive.

The number of platforms for a given field depends on the number of planned production wells. Each field has a minimum of three eight-pile platforms, two field platforms -- one for production, one for living quarters -- and a third for an interim pumping station for oil or compressor station for gas. Additional field platforms are added when the number of wells per platform exceeds 20. Under these assumptions, the hypothetical oil field with reserves of 200 million barrels and 37 production wells mentioned above would have three field platforms and one platform for an interim pumping station.

The approximate investment costs to deliver oil and/or gas to shore, including onshore oil storage and gas processing, under a variety of alternative assumptions, are discussed in detail in appendix A. If the development of Georges Bank follows the pattern of the Gulf of Mexico, fields closest to shore, and perhaps in shallower waters, will be developed first. For the range of hypothetical oil fields used in this study, pipelines, rather than offshore storage and tankers (or perhaps barges), are used as the mode of transportation. The possibility of extended periods of rough seas, during which the offloading of oil would not be possible, would appear to favor pipelines over offshore storage and vessel shipment for Georges Bank oil, although for smaller fields considerable distances offshore, a tanker-barge system may involve a lower cost than a pipeline system (M.I.T., p. 114). Gas production comes ashore in pipelines.

Pipelines could be routed to Cape Cod, and buried and extended to a terminal or possible refinery in southeastern New England. However, the construction of a pipeline corridor through Cape Cod almost certainly would encounter strong resistance from environmental groups, residents and others. An anticipation of possible production delays as a result of extended hearings or legal suits could make a Cape Cod pipeline route less attractive than a submarine pipeline corridor to a terminal located elsewhere in southeastern New England. For the estimates generated in this study, the pipeline(s) is assumed to circumvent Cape Cod and extend to Bristol County, Massachusetts, implying a distance of about 160 miles. Should pipelines traverse Cape Cod, the associated capital costs could be lower than the estimates used in this study since, depending on right-of-way costs, it usually is far less costly to install and maintain an onshore pipeline.

Capital Cost Data Assumptions. Table 2.1 lists costs of selected capital items used as data to evaluate the economic returns for the potential development of Georges Bank petroleum fields. Other capital costs associated with exploration, field development and production are discussed below.

It is difficult to assign general exploration expenditures to particular fields. Nevertheless, it is assumed that the exploration cost which can be attributed to an individual field -- for seismic reconnaissance, interpretation and related items -- is $1 million. The drilling cost for dry holes in the 10,000-foot range used in this study is estimated to be $35 per foot.[6]

The capital cost of an oil and gas submarine pipeline system is estimated as follows. For each offshore petroleum field considered, an estimate is made of the capital and operating costs necessary to deliver peak field production to shore and store oil or process gas (see appendix A). The discounted cost of shipping a given volume of oil via pipelines of two different sizes is compared for each field production case, and the lower cost alternative is adopted. For gas the transportation subroutine picks the lowest cost pipeline-gas treatment system which can handle the peak gas flow from the offshore field. Capital costs are charged to the field when the pipeline, pumping and compressor equipment, pumping stations, and storage terminals or processing plants are installed.

Well workover, or recompletion, costs are taken to be $100,000 per well. This figure represents the costs of moving a large rig on and off the production platform, rig rental, and support and related services (Weaver, et al., 1974, pp. 20, 47). The cost of shutting down a field (plug and abandon wells, dismantle platforms, transport materials, etc.) in the terminal year is estimated at $1 million per platform (Weaver, 1972, p. 108).

Operating Cost Data Assumptions. Insurance costs amount to $500,000 per year for coverage against the physical loss of $12 million.[7] The oil or gas transportation operating costs include maintenance and inspection costs, pumping costs and oil storage facility or gas treatment plant operating costs. Transportation operating costs depend on the planned production rate for a given field, the size of the pipeline selected by the transportation subroutine and the distance to shore (see appendix A).

Other operating costs are estimated to be $4,500 per month per well. As an example, a field with monthly operating costs of $170,000 ($ 1972) -- excluding the costs of transporting oil or gas to shore -- could have the following specific costs:

Crew wages	$90,000[8]
Contract catering services	26,000
Transportation-communications	25,000
Materials and supplies	10,000

Repairs and maintenance	10,000
Well work	5,000
Fuel and power	4,000
	$170,000

Overhead, including payments to management, is charged to field operations at a rate of 30 percent of annual operating costs. The company working the field is, for convenience, assumed to pay an effective tax rate of 25 percent of taxable income throughout the life of the fields.[9]

In addition, companies are required to make a royalty payment on each unit of gas or oil production from federal offshore lands. The historic royalty rate has been set at a flat one-sixth of the value of production at the wellhead, and this rate is used in this study.

The representation of offshore field development and the cost assumptions described above provide useful insights into evaluating a number of economic aspects of the potential exploitation of offshore petroleum fields. In the next section oil and gas reserves are postulated for individual example fields, and based on the development and cost assumptions presented in this section, a summary of results is described.

Some Results for Individual Oil and Gas Fields. Selected results for the development of example Georges Bank oil and nonassociated gas fields are presented in table 2.2. The oil field example considered here is assumed to contain 112.5 million barrels of reserves, a medium-sized new oil field by offshore standards, and the onshore price of oil is assumed to be $9 over the life of the field. The example gas field is postulated to contain 1.07 trillion cubic feet of natural gas, a medium-large new offshore gas field, and the landed price of gas is taken to be $.95/Mcf. Each of the fields considered here (and others discussed below) are taken to be located in 180 feet of water 160 miles from the point where the pipeline comes ashore in southeastern New England. The cost of capital in both cases is 14 percent, which is in line with the FPC's recent findings regarding the cost of capital, including risk, to integrated oil companies for domestic ventures (U.S., FPC, 1974, pp. 59-63).[10]

Maximum annual production from the oil field is 8.3 million barrels and from the gas field, 79 billion cubic feet, and peak production is assumed to occur in years 8 through 14. The maximum annual royalty payments, of course, also take place during these years and amount to $11.2 million for the oil field and $9.1 million for the gas field. The Bureau of Land Management (BLM) historically has allocated federal offshore lands on the basis of a sealed bid system. The company, or group of companies in the case of a joint venture, submitting the highest bid for a block at a lease sale wins the right to conduct exploratory drilling and to develop the block, provided, among other considerations, that the bid exceeds the refusal bid -- the minimum acceptable bid set by the U.S. Geological Survey, based on its assessment of "fair value" for the block.

A company's bid will depend on the value of the field to the firm and the expected behavior of other companies competing for the lease. The value of the block may vary widely from firm to firm because of different assessments of the petroleum potential of the area; different expectations of future costs, prices, and regulatory policies; different aversions to risk among companies, and perhaps because of different degrees of vertical integration among the companies. Under competitive conditions, the winning bid will equal the expected, after-tax present value of the block.[11] The company would earn the market rate of return on its investment, plus an allowance for risk as reflected in its cost of capital.

For simplicity in the calculations below, the hypothetical winning company is assumed to bid the full expected present value of the lease. The company thereby earns a rate of return equal to its cost of capital, and all "excess returns," i.e., economic rents, are transferred to the federal government. For the example fields in table 2.2, the expected, after-tax present value, hence the <u>maximum</u> cash bonus bid, is about $87 million for the oil field and $53 million for the gas field.

The unit cost of oil and gas from the example fields, <u>excluding</u> any royalty or cash bonus payments, is $2.75/bbl and $.46/Mcf. Unit cost is defined as the minimum constant return per bbl or Mcf needed to cover all development and production costs, including a rate of return of 14 percent (but excluding royalty payments). Looked at another way, the unit cost could be regarded as a "contract price," that is, the minimum amount the government would have to pay a private company to induce it to develop an offshore field under contract. Actual company oil or gas costs per unit in any given case also would include at least a minimum cash bonus as well as royalty payments and other taxes.

The detailed field results (not presented here) used to generate the summary results in table 2.2 indicate the possible investment demands associated with the development of offshore fields. For the oil field considered in table 2.2, the investment in production platforms is approximately $10.5 million, plus the cost of at least one platform for an interim pumping station. The investment in a submarine pipeline-onshore storage terminal for the oil field is on the order of $27 million. The detailed results thus permit an estimate of capital development costs, by category, associated with developing hypothetical OCS oil and gas fields. This information, discussed in more detail in the next chapter, provides a basis for understanding some of the kinds of investment-related interactions OCS development can have with the regional economy.

The results of some sensitivity analyses are of interest.[12] For example, using the hypothetical oil field considered in table 2.2, if the firm expects a price of $6/bbl to prevail over the life of the field, as opposed to the $9 assumed in the results in the table, the present value of the field falls from $87 to $37 million (see table 2.3). If all real costs, excluding taxes, are expected to be 10 percent higher than those underlying the results in table 2.2, the present value of the oil field declines to $82 million. If production is not expected to begin until year 7 because of, say, anticipated skilled manpower or materials bottlenecks, the field's present value drops to $54 million. With a cost of capital down to 11 percent from 14 percent, the present value of the oil field increases substantially to $126 million.

Based on the sensitivity results, it appears that expectations regarding the future price of oil and the cost of capital are key parameters that would be considered by a company evaluating the present value of an offshore block. Anticipated delays in field production also would have a significant effect on a company's assessment of the present value of the field. However, moderate changes in estimating field development and operating costs do not appear to have a major impact on estimates of the present value of the example field.

Selected results for several oil field sizes and alternative prices and discount rates are summarized in table 2.3. It is apparent from a review of table 2.3 that there are noticeable economies to scale with larger offshore field operations, a finding that also has been noted by others (M.I.T., 1973, pp. 113-118). The cost of oil per present equivalent barrel, at a discount rate of 14 percent, declines from about $4.51/bbl for the smallest field considered in table 2.3, 50 million barrels, to $1.68/bbl for the largest field, 393 million barrels. One source of the declining unit cost with larger fields is the substantial scale economies inherent in offshore pipeline systems. In table 2.3, unit transportation capital and operating costs decline noticeably over the range of oil fields considered. In addition, although not measured as part of the field model discussed in this chapter, there may be other scale economies in developing either larger fields or more than one smaller field as a result of potential scale economies with onshore support operations, with field operation, maintenance and transportation activities, with possible common carrier pipelines for shipping oil or gas and with onshore terminals or gas plants.

Finally, it may be interesting to ask what would be the minimum-sized oil and gas field that would be developed at a given price and cost of capital? From a review of table 2.3, it appears that it would be only marginally worthwhile to develop a field as small as 50 million barrels of reserves if the expected price is $6/bbl, particularly if there is the expectation that real costs might be 10 percent higher than those in the base case. It is interesting that, based on the results for example gas fields, it may not be economically worthwhile to develop a gas field as large as 500 billion cubic feet at a landed price of $.75/Mcf under the field conditions assumed for this study. If these results are reasonably accurate and are substantiated by further research an implication would be that it is possible that some comparatively large gas fields considerable distances offshore or in deep waters might not be developed except at prices higher than those currently being considered by the FPC. However, even relatively high-cost gas fields may be developed at a cost per Mcf lower than the $1 to $2, and even higher in some cases, prices currently being paid by gas utilities in the Northeast.

Hypothetical Production from a Georges Bank Petroleum Province

The scale and rate of development of a potential Georges Bank petroleum basin will depend on a variety of factors, some of which are interrelated. These include: federal leasing policy; the size-distribution of oil and gas fields; the rate at which discovered fields are developed; the availability, hence rental rate, of drilling rigs and specialized equipment and manpower; and, in general, the economics of petroleum development.

On the one hand the new province could contain a few large or small oil or gas fields, although based on the discussion in the previous section, one can estimate roughly the minimum-sized field that will be economically worthwhile to develop under given conditions. On the other hand, of course, Georges Bank could prove to be a prolific petroleum-producing basin.

Available geological studies provide a wide range of assessments of the potential petroleum resources of the Atlantic Outer Continental Shelf. (See, e.g., Maher, 1971, p. 65; NPC, 1970, p. 100; Ahearn, 1973, pp. 9-10; U.S. Department of Interior, 1974.) Estimates of potential petroleum resources allow one to say with a good deal of confidence that some petroleum will be found under the Atlantic OCS; however, such estimates inspire little confidence as to how much oil and gas is likely to be produced. In this connection the oilman's cautious adage, "oil is where you find it," seems particularly relevant. Nonetheless, to gain some insight into the likely regional economic effects of potential petroleum production on Georges Bank we must assume to know the unknowable. The two widely different major offshore petroleum find hypotheses (table 1.1) allow conditional statements of the form, "if this turns out to be the case, the following is likely to be the effect," to be made. Inferences then can be made about possible intermediate cases.

Hypothetical oil and gas production over time from a Georges Bank petroleum province under the study low- and high-find assumptions are indicated in figures 1.1 and 1.2. Other and more detailed province results are given in appendix B.

For the purposes of estimating annual Georges Bank oil and gas production, it is necessary to make a host of assumptions regarding the size-distribution of individual fields, the rate at which fields are discovered, and the rate at which discovered fields are developed. Obviously, any number of combinations of these assumptions is possible. For convenience, it is assumed here that in the low-price case each oil field contains 200 million barrels of reserves and each gas field contains one trillion cubic feet of gas.[13] It is further assumed that two oil fields and one gas field are discovered each year until all potential fields on Georges Bank are discovered for the high and low cases. Thus, in the high-find case there are 25 oil and gas fields, while in the low-find case Georges Bank would contain only four fields (see table 1.1).

Under the high-find assumptions, peak oil production from offshore fields reaches about 219 million barrels some 15 years after the first lease sale. Gas production reaches an annual maximum of 700 billion cubic feet about 16 years after the first lease sale. If an initial lease sale were held in 1975, under the study assumptions peak Georges Bank production would occur by about 1990 and all fields would cease operation by 2010. On the other hand, under the low-find set of assumptions oil and gas production would peak about eight or nine years after an initial lease sale. Annual peak production would be roughly 30 million barrels of oil and 148 billion cubic feet of gas. If an initial Georges Bank lease sale were held in 1975, then maximum production could be reached by about 1984, and offshore fields would be shut down in 1998.

For perspective, the study assumptions regarding oil and gas reserves and production from Georges Bank are compared to the regional consumption of petroleum in 1972 in table 1.1. The results thus provide an indication of the extent to which potential petroleum production on Georges Bank could be expected to meet New England's energy demands, assuming of course that Georges Bank production is marketed in the region. Under the high-find scenario, for example, oil production from Georges Bank amounts to roughly 50 percent of New England's consumption of refined products in 1972. On the other hand, if only two oil fields are found, the low-find case, the maximum annual production would be on the order of 30 million barrels per year, 6.6 percent of regional consumption in 1972. Natural gas production from Georges Bank in the high-find case would exceed by a wide margin New England's consumption of gas in 1972, 260 billion cubic feet. In the low-find case, however, production from Georges Bank would be less than the amount of gas consumed by the region in 1972.

Thus, if the high-find case considered for Georges Bank turns out to be what in fact does happen, the region would not be self-sufficient in terms of oil supply. Indeed, even if Georges Bank should prove to be twice as prolific in terms of oil production as indicated in the table, New England still only would meet its 1972 demand. That is, even a six-billion barrel province would not be adequate to make the region self-sufficient in oil products when the peak production from Georges Bank would be reached, some 20 years from the initial lease sale.

On the other hand, the maximum annual gas production from

Georges Bank in the high case could be reached in 16 years and could make the region self-sufficient in gas and possibly an exporter. Whether or not this would prove to be the case would depend on the marketing strategy applied to Georges Bank gas production and the growth in regional demand for gas, which in turn are related to how gas from potential Georges Bank fields is priced relative to other sources of energy.

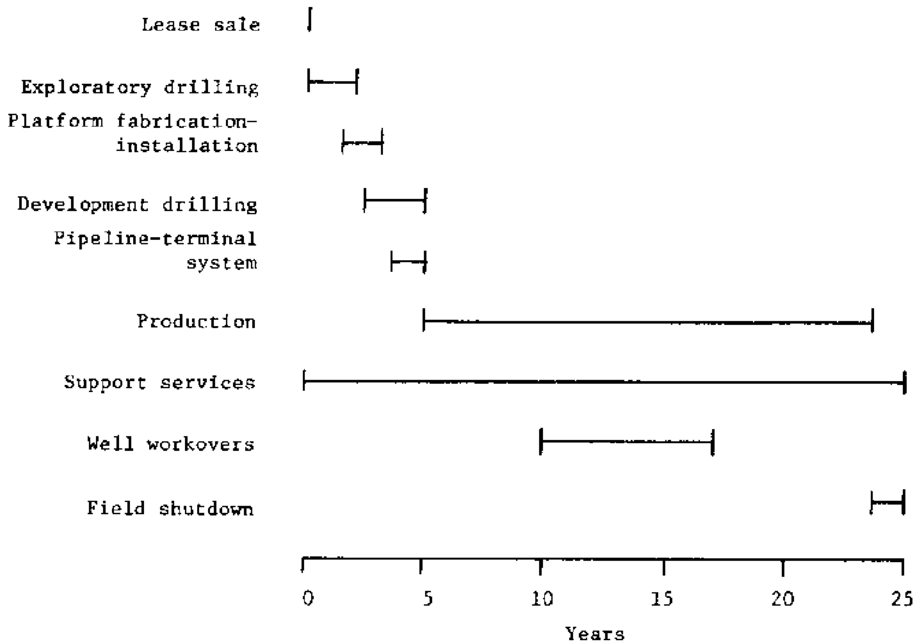

Figure 2.1. Representative timing of major development and production activities for OCS petroleum fields.

Table 2.1. Selected capital cost data used to evaluate potential Georges Bank offshore petroleum fields.

Cost per eight-pile platform[a]	$3,000,000
Cost of transporting each platform[b]	$ 250,000
Installation cost per unit[c]	$ 250,000
Living quarters with helioport	$ 100,000
Cost per completed well (depth: 10,000')[d]	$ 450,000
Water treating equipment[e]	$ 50,000
Power generators	$ 200,000
Flow lines between platforms	$ 250,000
Other production, processing and testing equipment	$ 300,000

[a]Letter from Mr. Griff C. Lee of J. Ray McDermott & Co., September 5, 1973. The approximate cost of an eight-pile platform, in 180' of water (allowing for 70'-waves) for the Gulf of Mexico is $2.0-2.5 million. This is rounded to $3.0 million to allow for possibly more difficult operating conditions on Georges Bank.

[b]Information based on interviews with industry officials. This is the approximate cost for two oceangoing tugboats to tow a platform from the Gulf of Mexico to Georges Bank.

[c]Based on an interview with industry officials.

[d]This figure covers drilling rig costs and completion costs, including electric logging, mud and casing, cement, tubing, Christmas tree, etc., but not the costs of the platform. Production costs are not included. See footnotes at the end of this chapter for the derivation of the cost per well.

Oil and gas wells at Sable Island, offshore Nova Scotia, have been completed at over 8,000 feet. See, Ocean Oil Weekly Report VIII, October 8, 1973, p. 2. The 10,000'-well depth figure used in the text thus is intended to allow for deep oil and gas pay zones in the Georges Bank area.

[e]Skim tank, flotation cell, and miscellaneous associated equipment.

Table 2.2. Summary of results for example hypothetical offshore oil and gas fields.[a]

	Oil Field	Nonassociated Gas Field
Recoverable Reserves	112.5 million barrels	1.07 tril. cu. ft.
Price (landed)	$9/bbl	$.95/Mcf
Peak Annual Production	8.3 million barrels	79 billion cu. ft.
Peak Royalty Payments[a]	$11.2 million	$9.1 million
Present Value[b]	$87 million	$53 million
Unit Cost[c]	$2.75/bbl	$.46/Mcf

[a]Calculated at one-sixth of the value of production at the wellhead.

[b]At a discount rate of 14 percent.

[c]Resource cost, excluding royalty payment, per present barrel or Mcf equivalent.

Table 2.3. Selected economic indicators of the development of alternative-sized offshore petroleum fields.

	Field Size[a] (millions of barrels)							
	50		100		200		350	
	Price/bbl		Price/bbl		Price/bbl		Price/bbl	
	$ 6	$9	$6	$9	$6	$9	$ 6	$9
Expected Present Value ($$10^6$)								
i = .08	28.54	77.60	88.85	183.4	200.9	393.1	374.0	715.7
= .11	14.77	50.60	57.66	126.2	136.1	275.9	257.9	507.3
= .14	5.70	32.40	36.62	87.28	92.03	195.6	178.7	364.4
Transportation Cost ($/bbl)								
Capital Costs[b]								
i = .08	0.99	.88	0.54	0.48	0.36	0.32	0.26	0.23
= .11	1.23	1.09	0.67	0.60	0.45	0.40	0.32	0.28
= .14	1.50	1.33	0.82	0.73	0.55	0.49	0.39	0.34
Operating costs	0.35	0.32	0.23	0.21	0.20	0.18	0.17	0.15
Amount Recovered (10^6)	49.9	56.2	99.9	112.4	199.8	224.8	349.6	393.3
Cost of Oil/bbl ($)[c]								
i = .08	3.22	2.90	2.03	2.01	1.59	1.58	1.37	1.26
= .11	3.86	3.43	2.45	2.33	1.91	1.80	1.58	1.47
= .14	4.51	4.01	2.87	2.75	2.22	2.11	1.79	1.68

[a] The numbers in the column heading are millions of barrels of recoverable reserves at a price of $6/bbl. The actual amount recovered from a field depends on the price.

[b] Average capital cost = $\sum_t C_t (1+i)^{-t} / \sum_t X_t (1+i)^{-t}$

[c] Landed cost per barrel equivalent, including a rate of return equal to the cost of capital, but excluding royalty and bonus payments.

Footnotes

1. Increases in oil or gas prices are regarded as providing the incentive to drill extension wells which add to recoverable reserves from the field. The field supply elasticity of .25 is the lower-bound industry elasticity estimate used by Houthakker and Kennedy (1974, p. 20), and it is considerably below the industry long-run supply elasticities that have been reported by others.

2. An obvious implication of the new FPC pricing policies is that companies developing low-cost fields may earn rents unless such returns are transferred to the government as a result of the lease-bidding process.

3. A number of wells, particularly those planned for very substantial water depths, may involve subsea completions.

4. A "field," of course, may include one or more distinct oil or gas reservoirs.

5. For a field with known reserves, R, at a given constant expected price, and a four-year field development period, production at time t, x_t, is determined in the field model as follows:

$$
\begin{aligned}
x_t &= 0 & 1 \le t \le 5 \\
&= [(t-4)/4]\ cR & 5 \le t \le 8 \\
&= cR & 8 \le t \le 15 \\
&= [(25-t)/11]\ cR & 15 \le t \le 25
\end{aligned}
$$

subject to $\Sigma x_t < R$.

An industry rule of thumb is that peak annual production will be about 7 to 10 percent of recoverable reserves. Initially c is set equal to 10 percent and then iterated downward so that the recoverable reserve constraint is met over the imposed 20-year production life of the field.

6. Joint Association Survey (JAS) drilling costs for dry holes and producing wells are far more expensive offshore than onshore for the same depth interval, since offshore wells are assigned a portion of the cost of platforms and capital items peculiar to their operations. Capital equipment costs for offshore development are accounted for separately in this study so that an adjustment of the JAS statistics is required in order to arrive at a separate drilling cost per well. This is done below where an intermediate, and perhaps conservative, or high, figure is derived:

Calculation of per-foot costs of drilling dry holes and producing oil wells, 10,000-12,499 feet.

	Drilling Cost Per Foot		
Category	Offshore Wells	All Wells	Adopted For Study
Dry Holes	$50.36	$23.56	$35.00
Oil Wells	$57.78	$35.98	$45.00

Source: American Petroleum Institute. 1971. Joint Association Survey of the U.S. Oil and Gas Producing Industry. American Petroleum Institute, Washington, D.C., pp. 10-11.

7. The cost of insuring against a $6 million loss is on the order of $150,000 (U.S. Department of the Interior, Bureau of Mines, Weaver, Pierce, Jirik, 1972, p. 47). The firm is assumed to insure less than the full value of the field to take into account the depreciation in the value of its facilities. The working assumption is that the firm acquires coverage for $12 million at a cost of $500,000 per year.

8. This figure is based on a crew size of about 35 men working during the field development phase. Crews work 12 hours per day on a 7 days on-7 days off schedule. Two crews are on the platform at all times, and there is a total of 4 crews. The production phase of offshore petroleum operations is highly automated; hence, the $90,000 figure for wages, and the related expenses, are high estimates.

9. Cox and Wright (1973, pp. 12-15) have estimated that the (average) "neutrality" tax burden on a sample of 18 of the largest oil companies in 1970 was 14.7 percent. This figure was calculated by dividing the total tax due on U.S. income by the companies in 1970 by their approximate total domestic net income for that year. The authors point out, however, that an alternative calculation -- with which they disagree -- based on a cash flow rather than an accrual approach (which includes taxes paid in 1970 but assessed in prior years) increases the tax rate to 21.8 percent.

The 14.7 percent tax rate appears to be the more accurate measure of ("neutral") tax burden on oil industry net income in 1970. The rate, of course, is an average rate and may not apply to the returns from additional investments. The 25 percent effective rate used in this study, while necessarily somewhat arbitrary, appears to be reasonable in light of the Cox and Wright estimates.

10. The FPC concludes that allowable rates of return from 12 to 15 percent are in the "zone of reasonableness," although it adopted a 15 percent rate of return in its decision (U.S., FPC, 1974, p. 61).

11. In the absence of perfect competition in the bidding for leases, bidding strategies become a paramount concern for rational firms (see, e.g., Brown, 1969). Alternative leasing arrangements, e.g., royalty rate bidding with a flat, moderate cash bonus, reduces front end capital needs, hence company risk. Such leasing schemes may encourage more companies to compete for offshore blocks although even with minimal bonus payments exploration and field development costs can be major. Such arrangements, however, affect the marginal conditions of field operation and could lead to earlier field shutdown. A number of alternative leasing arrangements are available.

12. As noted earlier the model underlying the results summarized above does not have optimization features. Consequently, the results in the text must be regarded as very crude measures of the effects of changes in the selected economic parameters on the offshore field results.

13. The assumption that all oil fields and all gas fields are identical, while convenient, suffers from several shortcomings. This assumption implies that increments to offshore oil and gas production are available at constant costs. Even if fields are identical with respect to all important geological and technical parameters, one still would expect that additional fields could be developed at declining unit costs because of potential scale economies from spreading the cost of onshore facilities over more than one field; from crew-supply transportation; from inspec-

tion, operating and maintenance activities; and especially from common user pipeline systems to transport to shore oil or gas from more than one field.

In reality, however, fields in the province would follow a size-distribution, be at different water and pay depths, be different distances from shore, etc. A standard upward sloping supply curve for the province then could be constructed by plotting output against incremental development and lifting costs for individual reservoirs or wells (Bradley, 1967, pp. 26-27). The marginal field would be that field which it will just pay to develop, given costs, the prevailing and expected price, etc.

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3. POTENTIAL OFFSHORE PETROLEUM AND REFINERY INVESTMENT

The investment associated with developing offshore petroleum fields and constructing refineries will generate income in New England to the extent that otherwise unemployed regional resources are used or resources are attracted into the region as a result of the projects.

The purpose of this chapter is to provide estimates of the kinds of investment that could accompany the development of Georges Bank petroleum fields and the construction of one or more petroleum refineries. The results generated in this chapter will be used in chapter 4 as input into an economic model of the region to estimate the direct and secondary effects on New England of alternative petroleum developments.

Direct Investment Demands Associated with Potential Offshore Petroleum Development

The development of offshore oil and gas fields involves substantial capital costs. This section provides a brief review of the major capital costs associated with potential Georges Bank petroleum development, and judgments are made regarding the extent to which offshore-related investment may take place in New England.

Platforms. An eight-pile permanent production platform for Georges Bank, designed for 180 feet of water, could involve an investment of $3.5 million, installed. The low-find offshore scenario for this study involves four fields and 18 platforms; under the high-find assumptions there are 25 fields and as many as 115 platforms. Platform investment, therefore, could range from about $63 to $400 million. Estimates like these necessarily are very crude. The number of platforms for each scenario may be less since the production of oil and gas from different fields substantial distances offshore will, as in the North Sea and in the Gulf of Mexico, be shipped via common carrier pipelines, so that each field may not have an interim pumping or compressor station platform. Fewer, larger platforms may be used; and larger platforms, or platforms designed for fields located in the substantial water depths along the eastern edge of Georges Bank, could cost considerably more than $3.5 million. It is possible, moreover, that the use of subsea completions in deep waters will reduce the number of platforms used in Georges Bank production.

It is not evident that substantial platform investment for Georges Bank will take place in New England, particularly for the development of initial fields. Platforms for Georges Bank could be towed from the Gulf of Mexico or from facilities located elsewhere along the East Coast. Platform fabrication activity has been centered in the Gulf in large yards like that operated by J. Ray McDermott & Company in Morgan City, Louisiana, and Gulf Coast shipyard costs have been estimated to be about 4.1 percent lower than those at yards on the East Coast (U.S. Maritime Administration, 1972, p. 30).[1] If this figure is accurate, a $3-million platform in the Gulf would cost $123,000 more on the East Coast. This amount is less than the $250,000 cost of towing a platform from the Gulf; however, there does not appear to be a clear net economic advantage to manufacturing OCS platforms in New England when allowance is made for considerably higher energy costs in the Northeast, periodic yard shutdowns for extreme weather, possible "learning" and other investment costs involved with the initial construction of platforms, and, finally, platform transport costs from a regional fabrication site.

On the other hand, a major increase in the amount of OCS area leased for petroleum development -- if it leads to bottleneck problems and rising costs at existing platform fabrication yards -- might provide an incentive to construct offshore platforms for Georges Bank in New England. The assumption used in this study is that over the life of a Georges Bank petroleum province one-half of the investment in offshore platforms will be made within New England. This may be a generous estimate.

Drilling Rigs and Crew Supply Vessels. Unlike permanent production platforms, drilling rigs are designed to be mobile. No drilling rigs have been constructed in New England shipyards to date; and based on a recent survey of mobile rigs under construction, none currently is being fabricated in the region, despite an explosive rate of growth in offshore drilling worldwide and an excess demand for rigs (Ocean Weekly, 1974). Drilling rigs may be constructed in New England in the future, but this activity will depend on a number of factors -- e.g., drilling activity along the entire Atlantic OCS and in foreign waters, the availability and rental rate for rigs, comparative shipyard costs across regions, capacity constraints in shipyards from region to region, etc. -- in addition to developments on Georges Bank. No attempt is made here to assess such factors, and the assumption in this study is that the development of Georges Bank does not lead to construction of drilling rigs in the region.

New England could also become involved in the construction of crew boats and supply-utility vessels as a result of the development of Georges Bank. Blount Marine in Rhode Island, for example, has constructed offshore supply vessels intended for use in areas outside New England. Conceivably a moderate amount of investment in crew-supply vessels could take place in the region. However, as noted in the brief discussion of drilling rigs, a number of factors in addition to petroleum development on Georges Bank will explain this activity. No evaluation of the investment-locational factors relating to potential crew-supply vessel investment is made in this report, and it is assumed that Georges Bank development does not lead to any investment of this type in the region.

Regional ship and boat yards almost certainly will be used for investment activities like vessel repair and maintenance and to outfit old trawlers for use in supporting Georges Bank operations, e.g., for standby safety vessels for offshore rigs. However, the investment in vessel repair and conversion will be insignificant compared with that associated with other petroleum activities, and it is not considered in this study.

Other Investment Activities. The investment in submarine oil and gas transportation systems is one of the largest single potential capital costs in the development of Georges Bank oil and gas fields. The major components of capital costs for pipeline for sample Georges Bank oil and gas fields are indicated in table 3.1. These figures exclude the other elements of a transportation system, onshore storage and gas plants and interim offshore platforms, which are discussed elsewhere.

Pipelaying services, the major capital component of an oil or gas offshore transportation system, take place from mobile, highly specialized lay and derrick barges. Contracts for these services will go to firms based outside New England, like Brown and Root. On the other hand, pipeline preparation, the coating of pipelines with a granite-aggregate concrete, probably would take place within the region and use New England labor.

Relative to the other field development capital costs, the investment in pumps and compressor units used for gathering and shipping oil and gas is small. For example, pumping equipment for a hypothetical 225-million barrel oil field would be on the order of $1.7 million, and compressor units for a one-trillion cubic feet gas field would be roughly $1.9 million. A portion of the investment activity associated with the manufacture of pumps and compressors may accrue to New England-based firms. In generating the impact results, it is assumed that one-half of this investment demand will take place in the region.

The capital costs to store the production from a 225-million barrel field onshore would be over $3 million, and the investment required to construct an onshore gas plant capable of handling the daily production from a nonassociated gas field with one trillion cubic feet of recoverable reserves would be on the order of $6.5 million.[2] Onshore storage and gas processing investment may be comprised, roughly, of half materials and equipment cost and half labor. Steel materials are necessarily imports to the region; companies like Chicago Bridge and Iron specialize in the design and construction of onshore storage facilities. On-site labor requirements are likely to be met from the region's labor force, however.

In addition to the activities described above, onshore facilities will be needed to support offshore exploration and development activities. Depending on the size of a company's offshore operations, a single supply base could involve ten to twenty shorefront acres, and could contain one or perhaps two moderate-sized (15,000-20,000 square feet) warehouses and a small, relatively simple structure for office space. Pier facilities would be needed for two to three 180-foot crew-supply vessels. A larger facility, such as the Phillips Petroleum base in Stavanger, Norway, which is principally used to oversee development of the giant, one-billion barrel Ekofisk complex, could cover 75 acres and involve the construction of office space for about 100 professional and supporting staff during field development activities. Seven supply boats operate out of the Phillips' Stavanger base in addition to supply boats and barges out of Aberdeen, Scotland. A major center like Aberdeen will contain supply bases and facilities for a number of companies and may serve as a transportation center and headquarters in support of offshore operations.

In short, should Georges Bank prove to be an important petroleum producing province, there will be demands for marine transport facilities, warehousing and storage areas, office space, ground and air transportation and social services in strategically located coastal areas of New England. Depending on the capacity of such areas to meet these additional demands with existing capital, there could be subsequent investment in pier facilities and harbor improvement, roads, air facilities for expanded commercial traffic and helicopter flights, and perhaps other public services such as expanded municipal sewerage and water supply systems, schools, housing and fire and police services.[3] Major capital costs have been incurred in northeast Scotland for highways, port improvement and other infrastructure items in support of oil and gas operations in the North Sea (Scottish Office, 1973). This study, however, is not intended to address the set of micro-questions involved with assessing the detailed possible future demands for public and private services and investments of the sort mentioned above, and no attempt is made to include these activities in the impact estimates generated in the next chapter.[4]

<u>A Summary of Possible Offshore Petroleum-Related Investment Demands</u>. A summary of the major capital costs associated with the development of oil and nonassociated gas fields of our example on Georges Bank is contained in table 3.2. The figures considered here include development capital costs and do not include cash bonus payments made by firms to acquire the offshore blocks.

The total investment to develop the gas field is on the order of $79 million, and the oil field involves a total investment of about $90 million ($ 1973). The major components of total investment for the oil field are for well drilling and exploration ($29 million) and a pipeline transportation system ($28 million). Next most significant is offshore platforms ($16 million). For the gas field, on the other hand, the investment in pipeline transportation ($53 million) by far exceeds the investment in well drilling ($15 million) or platforms ($12.5 million).

The low-find assumption for this study involves two oil fields and two gas fields, and the high-find case assumes that Georges Bank contains 15 oil fields and ten gas fields. This information, together with the capital cost estimates for developing the fields in table 3.2, provides a basis for obtaining usable estimates of the total capital costs associated with the potential development of Georges Bank.

Total estimated investment, by major category, associated with the buildup of a hypothetical Georges Bank petroleum basin is presented in table 3.3 for the low-find case, and in 3.4 for the high-find case. It is evident from a review of the data contained in these tables that, despite a possible 30- to 40-year life of a productive new petroleum basin, the vast amount of investment-related activity associated with the development of offshore fields will take place over a comparatively short period. The major portion of development-related activity occurs within the nine years following the initial lease sale in the high-find case and over a shorter period in the low-find case. The results assume substantial Georges Bank acreages are opened for bidding, and fields are discovered in approximately the fashion hypothesized in chapter 2. Should an initial sale for Georges Bank be held in 1975, then one could expect, very roughly, the amount of annual investment demands indicated in table 3.4 would take place prior to 1990 and be concentrated in the period 1977-1985.

In general, the on-site labor component for each field development investment category is assumed to involve a substantial use of regional labor over the life of Georges Bank fields, although initially occupations requiring extensive industry-specific training -- for example, drilling foremen on offshore platforms -- will use imported labor. The only exception is for the on-site labor for laying submarine pipelines. Pipelaying barge crews, given the relatively short-run nature of individual projects, primarily will be comprised of non-regional labor.

Potential Refinery Activity Within New England

Except for a very small (7,500 B/D) asphalt refinery in East Providence, Rhode Island, there are no refineries in New England. Indeed, in the major U.S. coastal petroleum market extending from Sandy Hook in northeastern New Jersey, through Maine, there are only three major refineries, all in northeastern New Jersey. Together these refineries have a total capacity of 412,500 B/D, and can produce 169,400 B/D of gasoline, approximately 3.1 percent of the total U.S. refining capacity and 2.5 percent of U.S. gasoline refining capacity (table 3.5).

Several interrelated factors account for the economic incentive to locate refineries within New England. These include

(1.) the absence of refinery capacity within the region and the lack of refinery capacity within the North Atlantic states as a whole; (2.) national energy policy initiatives which have as a goal substantial U.S. self-sufficiency in refinery activity through the removal of the quantitative restrictions on crude imports, the imposition of import fees on refined products, and the exemption of new refinery capacity from the "license fee" on crude oil imports for a period of five years; (3.) an increasing reliance on oil imported from the Middle East; and (4.) potential production from the Atlantic OCS.

The investment cost of a grassroots refinery will depend on the planned capacity of the refinery, the planned product mix or "end products" and the characteristics of the crude oil to be processed. In general, refineries are characterized by important scale economies in process unit and ship unloading activities, and perhaps in such areas as the overhead work force and maintenance functions associated with particular refinery operations (Scherer, 1974, p. 18).

The industry trend has been toward constructing larger refinery units and refineries and enlarging or shutting down smaller refineries. Scherer, for example, has noted recently that significant scale economies in refinery activity persist to a capacity of at least 200,000 B/D for 1965-vintage refineries, and more recent technological advances may permit refineries to operate with decreasing unit costs considerably beyond that capacity (Scherer, 1974, p. 18). It is likely, therefore, that new refineries with a throughput capacity below this figure will be the exception rather than the rule. In fact, refineries recently proposed for New England have planned capacities of at least 200,000 B/D, although a small (65,000 B/D) specialized refinery was proposed for Tiverton, Rhode Island, in 1970. In the discussion below, attention is restricted to hypothetical refineries with a 250,000 B/D capacity.

The planned mix of refinery end products, given the capacity, will affect the amount of investment because of the specialized processing activities required for particular products. Gasoline production, for example, requires very large reformers and polymerization units, and a specialization in gasoline production thus would involve considerably more investment than a specialization in, say, heating oil.[5]

The planned refinery product mix, given the capacity of the various processing units, depends on the joint-product nature of the refining process and the relative prices of refined petroleum products. For example, a decrease in the price of gasoline relative to other petroleum products could create, ignoring inventories, an incentive for refinery operators to schedule the production of less gasoline and more distillates and jet fuel (Griffin, 1972, p. 54). The actual trend in refinery output has been toward higher yields of gasoline and jet fuels and lower yields of mid- and lower distillates, particularly residual oil. It is doubtful this trend will continue in light of recent dramatic developments in the world petroleum market and in U.S. energy policy.

Refineries tend to produce proportionately more gasoline during the spring and early summer months and relatively more heating oil during the fall and early winter. In general, however, East Coast refineries produce a higher yield of gasoline and distillate fuel oil and a lower yield of jet fuel than U.S. refineries in total (table 3.6). In contrast, the major petroleum product consumed in New England and the North Atlantic states -- New Jersey through Maine -- is residual fuel oil, which is primarily used by electric generating plants. Gasoline and distillate oil are, in order, the next most important products consumed in the region. Most of the residual fuel consumed in New England has been imported via refineries in Puerto Rico and the Virgin Islands.

The hypothetical New England refineries discussed below are assumed to produce, as seems likely, a full mix of refined products, possibly including some petrochemical feedstocks. The approximate percent yield of potential refineries is taken to be the following: gasoline, 35; distillate and gas oil, 30; residual fuel oil, 25; kerosene and jet fuel, 3; other, 7.

Thus, in view of the nature of the regional petroleum market and a national policy which encourages self-sufficiency in refinery capacity, hypothetical New England refineries are expected to produce a substantially higher yield of residual fuel oil than the current average for East Coast or U.S. refineries. New England refineries also may produce proportionately more distillate fuel oil and less gasoline than the current average refinery mix. The annual value of output from a 250,000 B/D refinery with the assumed above product mix would be on the order of $375 million at the refinery in 1969 product prices.

Storage costs are a major element of refinery investment. The average U.S. refinery in 1973, for example, had a storage capacity of 69 days of production, and storage investment costs for large tanks can range from $2 to $7 per barrel (Nelson, 1972, p. 173; 1973, p. 88). Other things being equal, the larger the refinery and the larger the number of end products that are produced (hence stored), the larger the amount of investment in storage capacity. Investment in storage capacity also will depend on the crude and product transportation system. For example, because of the periodic nature of vessel deliveries and shipments, a refinery operating on a tanker/barge system will use more storage capacity than a refinery with the same capacity and product mix but which is tied into a pipeline for crude delivery and/or product distribution. In fact, refineries tied into a pipeline system for both crude supplies and product distribution can essentially "run on stream"; that is, they will use very little storage capacity.

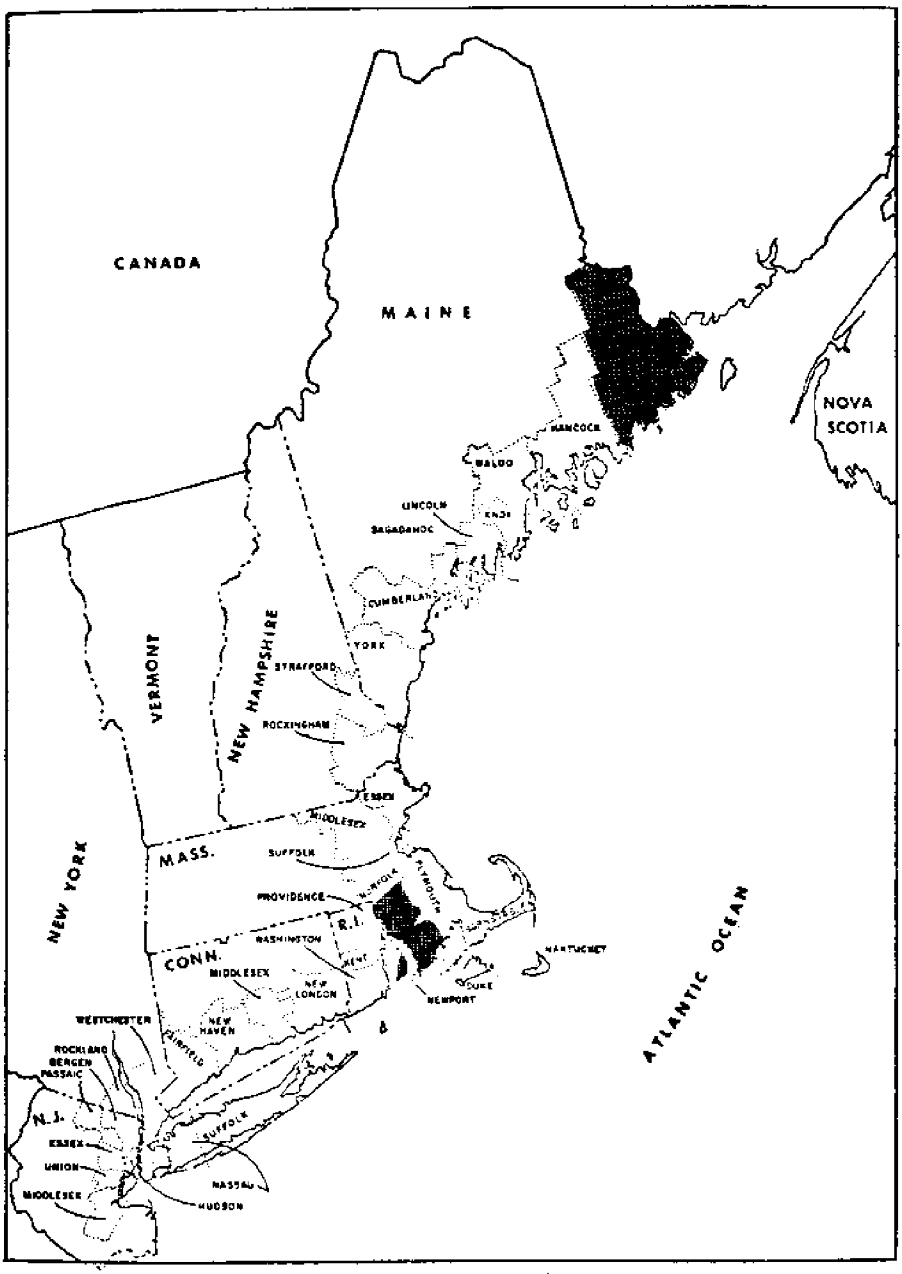
Based on an estimate by the National Petroleum Council (1971, p. 68), the average per-barrel cost of new refinery capacity is on the order of $1,800 ($ 1970). A hypothetical 250,000 B/D refinery thus would mean an investment of $450 million. This figure, however, is a gross average in that it ignores regional differences in construction wage rates and environmental constraints, and it abstracts from the transportation, storage, and produce mix decisions facing any particular refinery. New England refineries likely would be more costly than the average for several reasons: (1.) higher labor costs; (2.) possible storage capacity needs due to the number of products produced and the use of tankers/barges for delivering crude and distributing refined products; (3.) the cost of a deepwater terminal; (4.) the greater complexity of a regional refinery compared to the average new U.S. refinery; and (5.) stringent environmental standards. As a result of these reasons, a 250,000 B/D New England refinery could involve an investment cost in excess of $450 million, and in this study a figure of $475 million is used as a reasonable estimate of the cost of a refinery.

On the basis of rough estimates by industry officials (Moore, letter, 1972), one-half of refinery investment cost is for construction (direct labor, supervision, contractor, and engineering fees; materials handling equipment, concrete, etc.) and the remaining investment is for refinery equipment and processing units (towers, reactors, pumps, heat exchanges, piping and electrical systems, etc). With the exception of engineering design work and some contract fees, which may be for work done outside the region, the construction phase of the refinery can be expected to draw substantially on the region's labor force for welders, pipefitters, electricians, general laborers and the like. Perhaps as much as 80 percent of this component will involve New England labor. The major non-labor interactions of refinery construction activity with the regional economy would be via inputs from several sectors (table 3.7).

Two petroleum refinery hypotheses are considered. The low case is based on the assumption that one petroleum refinery is located in New England, while the high refinery case is based on three. A single 250,000 B/D refinery operating the equivalent of 350 days a year has an annual output of 87 million barrels. This is far more than adequate to handle the low-find oil case examined in chapter 2, which involves a maximum annual production of about 30 to 33 million barrels. The total annual throughput capacity of 262 million barrels with three, 250,000 B/D refineries is sufficient to handle the high-find scenario in which the maximum annual production is 219 to 247 million barrels (see table 1.1 and appendix B). However, three 250,000 B/D refineries would have an annual output equivalent to only slightly more than 50 percent of New England's total consumption of petroleum products in 1972. Thus assuming all the production from the refineries was distributed to regional markets, New England still would import considerably over one-half of its petroleum demands from other areas.

Three sample New England refinery locations have been selected based primarily on past or present industry interest in these areas as potential sites. These are Bristol County, Massachusetts; Newport County, Rhode Island; and Washington County, Maine (see map).

In selecting the refinery sites, the word "sample" is emphasized in that a number of additional areas have been proposed as potential locations for refineries, and local, state and regional economic and environmental considerations may preclude the location of a refinery in any or all of the sites used for this report. The representative refinery sites thus can best be regarded as indicative of what some of the consequences of refinery activity could be in areas similar to them.



North Atlantic coastal counties.

Table 3.1. Major components of pipeline capital costs for example Georges Bank offshore oil and gas fields ($ millions 1973).[a,b]

	Oil Field Reserves=$225X10^6$	Gas Field Reserves=$1.05X10^{13}$
Pipeline Costs		
Pipe Material	$ 6.48	$16.16
Pipe Coating	2.06	4.91
Pipe Laying	19.28	31.68
Pump Station Equipment	1.66	--
Compressor Station Equipment	--	1.87
TOTAL	$29.48	$54.62

[a]Excluding onshore oil storage and gas processing facilities and interim platforms for pumping and compressor equipment.

[b]See appendix A, tables A.2 and A.5 for the technical and economic assumptions underlying the above cost estimates.

Table 3.2. Possible development capital costs for example Georges Bank oil and gas fields ($ millions 1973).

Category	Oil Field (Reserves: 225 mill. bbls.)	Nonassociated Gas Field (Reserves: 1.05 trill. cu.ft.)
Platforms[a]	$16.0	$12.5
Pipeline	28.0	52.8
Well drilling and exploration[c]	29.0	15.0
Onshore storage terminals[d]	3.3	--
Gas processing plant	--	6.5
Pumps and compressors	1.7	1.9
Other machinery	.9	.9
TOTALS	$79	$90

Source: Based on the results generated in chapter 2 and appendix A.

[a]Includes field platforms and interim pumping or compressor station platform.

[b]Pipeline material, coating and laying costs.

[c]Includes $1 million for exploration work, the cost of drilling and equipping all wells and the cost of the estimated number of dry holes during development drilling.

[d]Allows for onshore storage of 14 days of field production.

Table 3.3. Estimated annual total investment, by major category, to develop hypothetical Georges Bank oil and gas fields under low-find assumptions ($ millions 1973).[a]

Years	Equipment			Pipe-lines	Other Construction[b]
	Plat-forms	Pumps and Compressors	Other Machinery		
1-2	$ 0	$ 0	$ 0	$ 0	$ 0
3	44.5	5.19	2.7	108.8	86.02
4	12.5	1.87	.9	52.8	21.5
Total	57.0	7.06	3.6	161.6	107.52

[a]All investment for each field is assumed to take place three years after the lease sale.

[b]Includes onshore oil storage and gas processing facilities and well drilling and exploration investment.

Table 3.4. Estimated annual total investment, by major category, to develop hypothetical Georges Bank oil and gas fields under high-find assumptions ($ millions 1973).[a]

Years	Plat-forms	Equipment: Pumps and Compressors	Equipment: Other Machinery	Pipe-lines	Other Construction[b]
1-2	$ 0	$ 0	$ 0	$ 0	$ 0
3-9	44.5	5.19	2.7	108.8	86.02
10	28.5	3.53	1.8	80.8	52.76
11-12	12.5	1.87	.9	52.8	21.5
Total	365.0	43.60	22.5	948.0	697.90

[a]All investment for each field is assumed to take place three years after the lease sale.

[b]Includes onshore oil storage and gas processing facilities and well drilling and exploration investment.

Table 3.5. Capacity of petroleum refineries in the Northeast, January, 1973 (measured in barrels per calendar day).

Area		Capacity Crude	Capacity Gasoline	Other Charact.
United States		13,454,471[a]	6,722,108[a]	
North Atlantic		412,500	169,400	
Northeastern New Jersey				
Port Reading	Almerada Hess Corp.	70,000	32,000	
Perth Amboy	Chevron Oil Co.	80,000	21,500	Asphalt
Linden	Exxon Co.	255,000	115,900	Asphalt
Rhode Island				
East Provid.	Mobil Oil Co.	7,500		Asphalt

Source: U.S., Department of The Interior, Bureau of Mines, Mineral Industry Survey, July 24, 1973, pp. 3,8,10.

[a]Operating capacity.

Table 3.6. Percent yield of major refinery products for the East Coast and the United States, April, 1973, and December, 1972.

	Percent Yield			
	East Coast		United States	
Refined Product	April 1973	December 1972	April 1973	December 1972
Gasoline[a]	49.6	47.5	46.7	44.6
Special Napthas	--	--	.7	.7
Kerosine	1.0	1.1	1.8	2.3
Distillate Fuel Oil	23.0	27.8	20.7	23.6
Residual Fuel Oil	7.8	7.1	7.2	9.0
Jet Fuel	2.9	2.3	7.3	6.5
Other	15.7	14.2	15.6	13.3
	100.	100.	100.	100.

Source: U.S., Department of The Interior, Bureau of Mines, Mineral Industry Survey, July 20, 1973, p. 9, and March 16, 1973, p. 9.

[a]Based on total gas output minus input of natural gas liquids and other hydrocarbons.

Table 3.7. Five major non-labor inputs per $1,000 of refinery (general industrial) construction activity.

Supplying Sector	Amount
Heating, plumbing and structural metals	$170
Stone and clay products	120
Business services	78
Transportation	66
Materials handling equipment	40

Source: Based on 1967 national input-output coefficient data provided by Curtis Harris.

Footnotes

1. Comparisons like those made by the Maritime Administration assume constant-cost conditions. Differences in supply responses from region to region make such comparisons tenuous in the long run.

2. Based on the estimates made in Appendix A.

3. In addition, based on a conversation with a regional gas company official, a major expansion in gas supplies to the metropolitan Boston area could require the laying of an additional pipeline and/or the expansion of the existing Algonquin-Tennessee supply system.

4. No attempt is made in this study to estimate the costs of onshore investment associated with or induced by offshore operations. However, the regional model used to generate impact results does allow for some induced effects on investment of changes in economic activity in an area. See Chapter 4.

5. Conversation with C.J. Wilson.

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4. THE REGIONAL ECONOMIC CONSEQUENCES OF POTENTIAL PETROLEUM DEVELOPMENTS

The regional economic impacts estimated in this chapter are measured by the difference in selected indicators of regional economic activity assuming Georges Bank development of one or more refineries as compared to a base case which assumes no petroleum developments. The results generated in this chapter provide some indication of how the economy of New England could be expected to differ as a result of primary and secondary impacts of petroleum development.

The major features of the regional economic model used in this study, the specific petroleum cases to be evaluated with the model, and the assumptions and data used are discussed. The selected results for the entire region and for an example coastal area in southeastern New England are summarized.

The Regional Model

The economic model used in this study to estimate regional economic impacts was developed by Curtis Harris at the University of Maryland. Described in considerable detail elsewhere (Harris, 1970, 1972, 1973), it is only briefly outlined here.

The Harris model, hereafter referred to simply as the regional model, is a multi-regional, multi-industry forecasting model. It makes use of input-output relationships to capture linkages among industries in the region, but it is not an input-output model. Autonomous changes in the components of final demand, e.g., business investment or government expenditures, or production as the result of the location of a new industry in a region, affect the output of regional industries based on national inter-industry coefficients. Changes in the demand for the output of regional industries lead to changes in regional payrolls and income, and to changes in the demand for retail trade and services. Induced changes in investment are also permitted in the model. For example, it is hypothesized that increases in industry output lead to additional investment in equipment, and increases in area personal income induce new construction for residences and public facilities.

Essentially, the logic of the model forecasts is as follows. The regional model finds the output of industries in a region, based on the existing structure of the area economy and on the economic theory explaining the location of industries. Estimates of employment, population, and earnings and personal income are derived next. Using the forecasts of employment earnings, income, and output, final demand sectors are forecast for personal consumption, government expenditures, investment and other categories. The model forecast for year t + 1 depends on the values of supply and demand data for year t; the forecast for year t + 2 similarly depends on year t + 1, etc.

The Harris model has properties that make it useful for undertaking long-run, regional-impact analyses. First, unlike many regional models, one can examine the effects of locating one or more new industries in a region. This property of the model makes it possible to estimate the impact on New England of new activities like offshore petroleum development and petroleum refinery operations. Second, the model attempts to capture the extent to which the growth in one industry may attract new activities or expand the output in existing industries, or the extent to which the location of one or more new activities may lead to a decline in some other activities because of a competition for resources.

A third property of the regional model is that it provides consistent results in two senses. First, national control totals can be established for employment and other economic variables in total and by industry. The regional model then allocates shares of the national values to geographic areas based on the historic structure of the area economy and estimated economic relationships. This procedure ensures that forecasts for the industries in an area are not independent of expected national and regional trends. Without this check there is always the risk that local analysts, operating from a narrow perspective, may misinterpret trends in the national economy and may be overly optimistic or pessimistic about the likely future position of local industries. Second, the model allows for consistent analysis from the point of view that the results of all the impact cases studied reflect the same assumptions regarding the economic behavioral relations in the model. Thus, there is a basis for a systematic comparison in evaluating, say, the regional economic consequences of petroleum refineries located in two areas because the assumptions and methodology are the same for both cases. This is an advantage when studying alternative development strategies from a regional or a national point of view.

Application of the Model to Georges Bank Development

Petroleum Cases Examined. Six runs are made with the regional model. Two of the runs provide the base case, no-petroleum-development forecast for New England.[1] One base-case run uses the low petroleum price assumption, and the second uses the high assumption. The four petroleum cases are designed to indicate the effects of the low- and high-find scenarios with either low or high oil and gas prices and with control of Georges Bank by the federal government. The petroleum cases studied also provide an estimate of the impact on the region as a result of the location of no, one or three petroleum refineries (see table 1.2). As mentioned previously, four state control cases were run with the regional model; but in view of the Supreme Court decision upholding federal control over Georges Bank, these cases were not developed in the text.

The economic impact of each petroleum case is measured by the model results using the indicated petroleum alternative less the appropriate (high or low price) base-case forecast.[2] The data and assumptions used to apply the regional model are explained in the following sections.

Specification of Investment. For each new or imposed industrial activity considered, investment is estimated for each year, by major category, e.g., offshore platforms, onshore storage facilities or refinery investment. The investment estimates serve two purposes. First, they provide an estimate of the capital used by industry in production activities. Second, they provide the basis for estimating the potential income effects on New England from the autonomous investment demand taking place in the region.

Once the total investment demands have been estimated by broad category and by year, the region's share is allocated to the corresponding sectors of the regional model. Of course, a fraction of each "round" of all respending effects will "leak" from the region, and the smaller the area for which economic impacts are measured, the more significant such leakages will be, and, the smaller the secondary effects within the area.

A 250,000 B/D refinery for New England, it was estimated earlier, will involve an investment of about $475 million. Construction of the refinery is taken to begin in 1977, and the refinery comes on stream during the third year after the initiation of construction, in 1979. The total capital costs over time, by major category, for Georges Bank offshore oil and gas field development were discussed in detail in chapter 3. The initial offshore lease sale is assumed to take place in 1975, and for convenience in generating the regional impact estimates, all development costs for individual fields are assumed to take place during the third year after a block is leased. The field development costs for a block leased in 1975 then are assumed to take place in 1977, the development investment for a block leased in 1976 occurs in 1978, etc.

The petroleum-related investment demands assumed to take place in New England are indicated in tables 4.1 and 4.2. Table 4.1 is based on the judgmental considerations discussed earlier,[3] and it contains the fraction of each equipment (nonlabor) category of total petroleum-related investment that is taken to be an increase in output of the regional economy. For example, 50 percent of the investment in production platforms for Georges Bank is assumed to be produced in New England. For petroleum refineries in New England, only ten percent of the non-labor investment is regarded as an increase in output of New England firms.

The estimated value of investment demand originating in New England is indicated in table 4.2. The figures in this table represent the share of the total investment to develop Georges Bank fields and construct one or more refineries.

Offshore Oil and Gas Production and Refinery Output. In order to estimate the regional economic effects of the introduction of one or more new industries, their annual output levels must be specified. The input-output relations in the model then provide an estimate of the linkages of the output of the new industries with other sectors of the area economy.

The estimated oil and gas production from Georges Bank under the low-find and high-find assumptions are based on the results in chapter 2 and appendix B. Production from the first oil and gas fields is assumed to begin in year 5, so that if a lease sale were held in 1975, initial production would begin in 1979.

Oil and gas from offshore fields are assumed to be landed in Bristol County, Massachusetts. This county was selected because use of the model requires that activity be assigned to a county, and Bristol County, given its location, is at least as reasonable a terminus for oil and gas pipelines as any other county. However, in order to determine the possible distribution of economic activity from offshore development and production among regional ports, offshore petroleum production in the model is assigned to three sample counties in southeastern New England: Bristol County, Massachusetts, 50 percent; Suffolk County, Massachusetts, 25 percent; and Washington County, Rhode Island, 25 percent.

Washington County and Bristol County are designated as potential support areas because of their relative proximity to potential offshore fields and the seeming suitability of existing facilities (Davisville, Rhode Island, and New Bedford, Massachusetts), with locational criteria for offshore supply operations. Suffolk County, Massachusetts, is included because of its location in relation to Georges Bank and because of Boston's role as a commercial, transportation and marine-service industry center.

Each refinery, consistent with the regional pattern of demand for petroleum products, produces the slate of end-products discussed in chapter 3. The refinery begins production in 1979, and the annual value of output of each refinery, in 1971 prices, is $396 million.

Estimation of Potential Public Revenues. The public revenues associated with the new activities must be estimated and then distributed in the model to reflect increased public expenditures (federal or state and local government) and/or reduced taxes with their accompanying increased consumer demand or savings.

The estimates of public revenues considered here include:

(1.) royalty payments on the production of oil and gas, (2.) cash bonus payments to acquire blocks on Georges Bank and (3.) property taxes on potential refineries and onshore facilities associated with offshore operations. The assumptions used to calculate and distribute the potential public revenues from Georges Bank petroleum and refinery development are discussed below and summarized in table 4.3.

No estimate is made of tax receipts from payrolls as a result of petroleum-related developments, since taxes on residents are a transfer and not an addition to total regional income. (Such revenues, however, may be of interest for public budgeting purposes for individual states.) Income tax revenue from non-residents would represent an addition to regional income, but a portion of the income earned by non-residents will be received by workers only temporarily in the region and possibly not within the taxing jurisdiction of New England states. Excluding possible income taxes received from non-residents may underestimate the income gain to the region; however, it is likely that taxes on income earned by non-residents will be roughly offset by additional public services, so that the net effect of ignoring income taxes on non-New Englanders is minimal.

Royalty payments are calculated at the rate of one-sixth the estimated wellhead value of Georges Bank oil and gas production. Royalty and cash bonus payments are based on the offshore field simulation results described in chapter 2, and it is assumed here that the winning firm bids the full after-tax, expected present value of the block. On this basis, the highest winning bid on the sample oil field would be on the order of $92 million at a low price of $6/bbl and $195 million at a landed price of $9/bbl. The winning bid for the gas field would be approximately $26 million at a landed price of $.75/Mcf and $53 million at a high price of $.95/Mcf.

The maximum amount of annual royalties in the high find-high price case would be received 15 years after the initial lease sale, 1990 under the study assumptions, and would be on the order of $426 million. Royalty revenue schedules for alternative Georges Bank oil and gas finds and prices are presented in appendix B.

The maximum amount of cash bonus payments in any year, assuming a high find-high price case, would be on the order of $445 million. Under the Georges Bank leasing-development assumptions used for this study, the cash bonus bids would be received early in the life of the province until all fields are discovered for the high- and low-find cases. If an initial lease sale were held in 1975 all cash bonus payments would be received by 1976 in the low-find case and by 1985 in the high-find case.

All royalty and cash bonus revenues would accrue to the federal government. The region shares in this gain only to the extent additional federal expenditures take place in the region.

Property tax revenues associated with petroleum developments are calculated for convenience at .875 percent (.00875) of the value of estimated onshore investment. This tax rate would apply, for example, if the market value of onshore petroleum facilities is calculated at 50 percent of investment cost, the assessed value at 70 percent of the market value and the tax rate at $25 per $1,000 of assessed valuation on all categories of investment. Clearly the actual amount of property taxes collected depends critically on local assessment practices and tax rates, which differ considerably among coastal New England areas. Moreover, within a given area, property tax rates may change over time as a result of development.

All the onshore capital associated with offshore operations (onshore storage terminals and gas processing plants) is assumed to be located in Bristol County, Massachusetts, so that this county receives all onshore property tax revenues. Property taxes on regional refineries, of course, accrue to the counties in which the refineries are located.

Under the assumptions outlined above the maximum annual property tax collections from offshore operations would be on the order of $170,000 for the low-find case and $1 million for the high-find. The annual tax revenues from a refinery would be $4.18 million. No estimate is made of throughput taxes which could be assessed on refinery activity or taxes which could be levied on landed production from offshore fields. Nor is any consideration given here to "tax holidays" or other special tax provisions which might characterize a specific refinery proposal.

In all the petroleum refinery cases studied, two-thirds of the property tax revenues are assumed to be used for additional state and local public expenditures. The remainder is distributed as reduced taxes, which then are used for additional consumption and savings by households in the particular counties. Real estate taxes on onshore terminal and gas plants are used for state and local government expenditures.

The cash bonus and royalty payments are distributed in the model among federal government final-demand categories, and they are distributed geographically based on the level of personal income and prior level of government expenditures, by category. New England's share in OCS federal revenues thus is based on the personal income in the region and the extent to which federal expenditures have taken place within the region in the past.

Table 4.4 contains information regarding the assignment of investment, output and public revenues associated with oil and gas developments to sectors in the regional model. Selected results of the economic impact on New England of potential Georges Bank development and the location of one or more petroleum refineries in the region are discussed below.

Selected Impact Analysis Results

Potential Georges Bank Development. The regional employment impact for high- and low-find Georges Bank cases are presented below, and the results are aggregated to 14 broad economic sectors. Selected results for a sample coastal area in southeastern New England, Bristol County, Massachusetts, are contained in a later section.

As discussed in chapter 1, an examination of any potential onshore or offshore conflicts between petroleum developments and activities like commercial fishing or recreation are outside the scope of this report. Consequently, the model results for the natural resources sector cannot be regarded as shedding any light on the issue of possible market or non-market conflicts between oil development and other marine activities.

The regional impacts associated with the development phase occur during the early years of potential Georges Bank operations and are a result of investments associated with the construction of oil terminals and gas plants, pipeline preparation-laying, platform fabrication, exploration-well drilling activities and equipment investment (pumps and compressors, instruments, and other equipment). The results are based on the assumption that a lease sale is held in 1975, and development investment for a given field for convenience is assumed to take place in the third year after the lease sale. Thus, the regional effects of development investment show up in tables 4.5 and 4.6 in 1977-78 for the low-find (four fields) and 1977-85 for the high-find (25 fields). In practice the field development period will be somewhat more extended than indicated here.

The major direct regional impacts from OCS field development take place in the industries placed here under the broad category "construction sector." This sector is an amalgam of all onshore and offshore construction activities including oil and gas well drilling and exploration, gas and petroleum pipeline, and other industrial construction (see tables 4.5, 4.6). With the high-find, offshore-related construction employment is about 2,500 from 1977-79 and declines thereafter. In the low-find case, construction employment relating to the development of offshore fields is on the order of 1,200 in 1977 and 1978 and drops off substantially in subsequent years.

The other major direct effects of offshore oil and gas development-related activities occur in two sectors. The first, metals, machinery and other manufacturing, includes such industries as stone and clay products (concrete); hardware, plating, and wire products; pumps and compressors, and instruments and clocks. The second major sector directly affected during the development phase of offshore oil and gas operations is shipbuilding. This sector also encompasses boat building and repair activities.[4] Under the assumption that one-half of the offshore platforms used on Georges Bank are fabricated in New England, shipyard employment increases during the field development years beginning in 1977. In addition, noticeable employment effects occur in the transportation sector, a very broad aggregation which includes marine, air, rail and highway transportation services.

The major indirect regional economic effects of the development phase take place in three sectors. Employment in trade and services increases as a result of the general increase in regional income. This sector is a grouping of wholesale trade, motels, and all retail trade and service activities. The federal government sector in New England also expands, reflecting the region's share of federal spending. The third major indirect effect is in the state and local government sector. Employment in this sector increases as a result of the general expansion in personal income and the regional public revenues. Smaller indirect effects of field development activities are evident in regional transportation activities, discussed above, and in the finance, real estate and business services and the petrochemical sectors.

Under the study assumptions, the production phase of Georges Bank oil and gas operations begins in 1979, and oil and gas production builds up gradually. The maximum employment directly associated with Georges Bank production is on the order of 155 in the low-find case in which there are four fields. Offshore production-related employment is as high as 950 with the high-find scenario. These aggregate employment figures are an average representation of direct employment during the production (not development) stage of field operations, and they include: the permanent production crew (production foreman, maintenance, gaugers, caterers); an apportionment of drilling crews for well workovers; onshore supply base operation; and operation of onshore terminals and gas processing plants. The employment estimates for offshore production do not include shoreside professional labor, e.g., petroleum and reservoir engineers; or additional labor for exploration activity; specialized services, e.g., diving, or any indirect oil company activities.

The types of employment activities involved with field production will vary over the life of the field and the province. For example, well workovers or recompletions occur later in the life of fields, and under the study assumptions drilling rigs and crews for well workovers are not used until ten years after field production begins. Also, support operations change over the life of offshore fields from those related to field development to those providing protection systems, specialized maintenance and welding services, and in general to services related to the inspection and maintenance of production platforms and submarine pipelines.

The relatively modest direct offshore petroleum employment estimate for the low Georges Bank find reflects the substantial automation capabilities of offshore production operations. For example, when developed, British Petroleum's giant, two-billion barrel Forties Field off the coast of Scotland may need a permanent crew offshore of only 20 to 30 men and possibly fewer (Findlay, interview, September, 1973). The high-find direct production employment estimate of about 950 is probably on the high side because, as noted in chapter 2, there may be scale economies to a company in developing large fields and to a company and the industry in developing more than one field.

In addition to employment associated with platform crews and onshore support, oil terminal and gas processing activities, other employment effects during the field production phase occur in the transportation sector. As noted earlier, this sector is an aggregate of all transportation categories, and the results in tables 4.5 and 4.6 include both direct, e.g., services demanded in direct support of OCS operations, and indirect transportation services demanded as a result of, say, an expansion in retail trade and services.

To summarize, many sectors of the regional economy, it appears, would be affected directly or indirectly by offshore production operations. However, the major indirect effects occur in wholesale and retail trade and services; transportation; federal government and state and local government employment; metals, machinery and other manufacturing; and construction. Smaller secondary effects take place in the utilities and communications, and finance, insurance and real estate sectors.

Aggregate regional impact results for selected economic variables -- employment, earnings, and personal income -- are presented in table 4.7 for various years. Regional earnings are defined as wages and salaries, proprietor's income and other labor income. Regional personal income includes earnings plus transfer payments (pensions, unemployment insurance payments, and welfare payments), plus estimated property income less employees' contributions to social insurance.[5]

<u>Potential Petroleum Refinery Activity</u>. The regional industry employment impacts from the construction and operation of a single 250,000 B/D integrated refinery are indicated in table 4.8. The results are based on the assumption that construction begins in 1977, and the refinery comes on stream in 1979. The first tax revenues are collected in 1979.[6]

Construction employment is about 1,650 in 1977 and 1978, and noticeable indirect impacts occur in the trade and services, metal, machinery, and other manufacturing, and state and local government sectors. Smaller secondary employment impacts take place in the transportation and financial, insurance, real estate and business services sectors. The total employment generated by refinery construction is on the order of 2,900, although the construction-related effects are short-run.

The refinery initially employs about 700 people, although employment declines over time as a result of continued technical progress. About 25 percent of the refinery work force would be administrative, e.g., accounting, employee relations, medical, etc., and technical. The remaining 75 percent of refinery employees would be in process and mechanical operations, and of these about 15 percent would be at the level of foreman or above (Moore, letter, 1973).

The effects on state and local government employment indicated in table 4.8 are a result of the increase in personal income from the general development of the area and the taxes assessed on the refinery. Regional employment in trade and services would increase as a result of the increase in earnings and a reduction in area property taxes (assumed to be equal to one-third the real estate taxes collected on the refinery) which would lead to higher consumer spending. Total regional employment as a result of the operation of the refinery could be as high as 2,600 over the period 1980-1990 but would decline thereafter.

Aggregate regional impact results for the one and three petroleum refinery cases for selected years are presented in table 4.9. With three refineries, average annual employment in the region during the refinery construction phase would be about 8,200. Direct and indirect employment during the 1980s could be as high as 6,800. In the one-refinery case, total average annual payrolls would be on the order of $34 to $36 million and annual regional personal income could be about $40 to $42 million. With three refineries, annual payrolls and personal income are somewhat less than three times that of the one-refinery case.

Regional Impact of Alternative Petroleum Developments: Discounted Earnings and Income. Table 1.5 contains a summary of the petroleum impact cases stated in terms of the aggregate discounted value of regional earnings and income resulting from each alternative. The cases presented under part A deal with the various Georges Bank oil and gas alternatives, while part B summarizes the results for the refinery cases. Three discount rates are used, but the discussion below is with reference to the eight-percent discount rate.

With the high-price assumptions, the present value of direct and indirect income to the region ranges from about $207 million to about $1 billion, depending on whether the low or high find proves to be the case.

Based on the results presented in table 1.5, the construction of a single petroleum refinery will lead to considerably higher regional earnings and income than the low-find case considered in this study. The three-refinery alternative has only a somewhat higher present value of income and earnings than the high-find case, but if each case is off by as much as five percent, the two potential petroleum developments are about the same in terms of their effects on total earnings and income in the region.

For either the low- or high-find case, the present value of regional income and earnings is somewhat higher in the high-price case, as opposed to the low-price case. The results in table 1.5 do not include the losses in the real income of the region because of higher petroleum prices. Instead, the results reflect earnings and income in the region with a particular alternative, given that the high or low set of prices prevails and is not affected by Georges Bank development.

Impacts on a Coastal Area: Bristol County, Massachusetts. Bristol County, Massachusetts, in this study is a sample coastal area in southeastern New England in which offshore petroleum-related activity is concentrated. A large fraction of the investment activities associated with the field development of Georges Bank operations is assumed to take place from the county. This includes support operations for well drilling and exploration activities and pipeline preparation and laying. All oil and gas from Georges Bank is assumed to be landed in Bristol County, and all storage terminal and gas plants are located there. It also has been assumed that one-half of all regional offshore production operations take place from Bristol County. The county also is used as a sample location for a petroleum refinery in those impact cases which include regional refinery activity.

In brief, a very substantial portion of all potential regional petroleum activities is located within this county, and an examination of the impact results for this area provides insights into the magnitude and kinds of impacts offshore oil and gas operations and petroleum refining can have on particular coastal areas that are central sites for petroleum activities.

Table 4.10 summarizes the impact results for Bristol County for two cases, the high find-high price Georges Bank case with and without a refinery.

In the high find-no refinery case, construction employment related to offshore operations during the development phase of Georges Bank, 1977-1985, could range from about 1,100 to 1,400. County employment directly associated with offshore production would range from 200 to 475 over the life of the province. Overall Bristol County employment could range from 2,400 to 3,600 during different periods of offshore oil and gas activity. The location of economic activity in the county leads to a population increase which could be as high as 6,600.

The employment-population impacts with the high find-one refinery case are summarized in the bottom section of table 4.8. Some 1,600 to 1,700 workers are involved with the construction of the refinery in 1977-1978, and the remaining construction employment is primarily related to offshore operations. Refinery employment is on the order of 750 and declines over time. Total direct and indirect employment in Bristol County associated with petroleum activities in the high find-one refinery case ranges from about 4,500 to a high of 5,900. The population in the county could increase by as much as 11,500. The employment-population figures in table 4.10 in fact may somewhat overstate the effects on Bristol County since not all the labor associated with the petroleum developments, e.g., tanker crews or production-drilling crews for offshore platforms, may live within the county. Offshore drilling and production crews work a seven days on-seven days off schedule, and as in the Gulf of Mexico, it is reasonable to expect that crew members commuting twice a week may be willing to travel considerable distances.

As stated in chapter 1 in the context of the existing size and structure of the economy of the area, the expansion in Bristol County employment and economic activity as a result of petroleum-related developments will not lead to a large increase in annual per-capita income (more than, say, $50 per person) and may not substantially reduce area unemployment rates.[7]

Population and employment changes in Bristol County as a result of the petroleum-related developments considered in this study could amount to a two to three percent increase for the county as a whole over the non-development case in a given period. However, as explained in chapter 1, this kind of comparison can be misleading. Offshore petroleum and refining activities are particularly marine-oriented, so that in terms of distribution, much of the development activity in the county will be concentrated along the coastline. The obvious and subtle consequences of development occur, except they may be within a telescoped time frame given that companies may develop offshore blocks quickly once a lease sale is held. The high-find refinery impact scenarios indicated here, then, imply noticeable changes for coastal areas which become central sites for petroleum operations in terms of population and economic activity and the general level of development.

Table 4.1. Assumed regional share of petroleum-related investment, by category.

Petroleum investment category	Fraction of total investment that is an output of the region
Petroleum refineries	10%
Platforms	50%
Pipeline	16.7%
Well drilling and exploration	16.7%
Onshore storage terminals	40%
Onshore gas plants	40%
Pumps and compressors	50%
Other machinery	50%

Table 4.2. Value of petroleum-related investment, by year and by category, that is taken to be an output of the New England economy ($ millions).

I. Offshore Petroleum Cases

Year	Plat-forms	Pipe-lines	Well drill. & explor.	Onshore storage terminals	Onshore gas plants	Pumps and compressors	Other machinery
			A Georges Bank Development--Low Find				
1-2	0	0	0	0	0	0	0
3	22.25	18.13	12.17	2.61	2.60	2.59	1.35
4	6.25	8.80	2.5	0	2.60	0.94	0.45
			B Georges Bank Development--High Find				
1-2	0	0	0	0	0	0	0
3-9	22.25	18.13	12.17	2.61	2.60	2.59	1.35
10	14.25	13.47	7.33	1.30	2.60	1.76	0.90
11-12	6.25	8.80	2.50	0	2.60	0.94	0.45

II. Petroleum Refinery Cases

A One Refinery

Year	Plat-forms
1-2	0
3	$11.9
4	$11.9

B Three Refineries

Year	Plat-forms
1-2	0
3	$35.7
4	$35.7

Table 4.3. Summary of the calculation and distribution of public revenues from Georges Bank petroleum development and refineries.

Category	Basis of Calculation	Distribution Assumed to Measure Regional Economic Impacts
Royalty payments	One-sixth the value of production at wellhead	Federal civilian government
Cash bonus payments	After-tax present value of fields	Federal civilian government
Real estate taxes: petroleum refinery	.00875 of the cost of investment	2/3 to state and local government, 1/3 to consumer expenditures, revenues accrue to example refinery locations
Onshore terminals and gas plants	.00875 of the cost of investment	State and local government, Bristol County

Table 4.4. Assignment of petroleum activities to regional model sectors.

Activity	Model Industry Sector (S.I.C. Number)[a]
Investment:	
Platforms	Ships, Trains, Trailers, Cycles (373-9)[b]
Pipelines	
Construction	Gas and Petroleum Pipelines[c]
Equipment/Materials	Stone and Clay Products (324-9)[b]
Well Drilling and Exploration	
Construction	Oil and Gas Well Drilling and Exploration[c]
Equipment	Oil and Gas Wells[d]
Onshore Storage Terminals	
Construction	Industrial Construction[c]
Equipment	Hardware, Plating, Wire Products (342, 347-9, 3491)[b]
Onshore Gas Processing Plants	
Construction	Industrial Construction[c]
Equipment	Hardware, Plating, Wire Products (342, 347-9, 3491)[b]
Pumps and Compressors	General Industrial Machinery (356)[b]
Other Machinery	Instruments and Clocks (381-2, 384, 387)[b]
Refinery	
Construction	Industrial Construction[c]
Equipment	Petroleum Refining[d]
Output:	
Oil and Gas	Petroleum Mining (13)[b]
Pipeline Transportation	Transportation (40-42, 44-47)[b]
Refining	Petroleum Refining (29)[b]
Federal Government	Federal Civilian Government[e]
Regional Government	State and Local Government[e]

[a]The S.I.C. number is the Standard Industrial Classification Number that, where appropriate, corresponds with the Harris regional model industry sectors.

[b]Output sector.

[c]Construction sector.

[d]Equipment purchasing sector.

[e]Extra labor sectors.

Table 4.5. Estimated average annual regional employment associated with the development and production of Georges Bank petroleum fields, selected years.

Case: Low-Find, High-Price, No-Refinery.

	Average Annual Employment			
	Field Development	Production		
Economic Sector	1977-9	1980-5	1985-90	1990-2000
Offshore Petroleum	30	115	155	75
Agric., For., Fish., Min.	--[a]	--	--	--
Construction	1,200	50	60	20
Petrochemicals	20	--	--	--
Petroleum Refining	--	--	--	--
Shipbuilding	190	10	10	10
Food, Textile, Lumber	--	5	15	25
Metal, Mach., Other Mfg.	400	90	150	300
Transportation	125	375	420	140
Utilities Commun.	5	20	35	50
Fin., Ins., R.E., Bus. Serv.	90	20	30	40
Trade and Services	650	160	260	300
Fed. Gov., Hous., Milit.	75	120	120	20
State and Local Government	230	150	120	--
TOTALS	3,015	1,115	1,375	980

Source: Special application of the Harris regional forecasting model.

[a]The symbol (--) denotes no change or no significant change. As stated in the text, environmental effects and possible conflicts among marine activities are not considered in this study.

Table 4.6. Estimated average annual regional employment associated with the development and production of Georges Bank petroleum fields, selected years.

Case: High-Find, High-Price, No-Refinery.

Economic Sector	Average Annual Employment			
	Field Development	Field Development and Production		
	1977-9	1980-5	1985-90	1990-2000
Offshore Petroleum	30	400	950	700
Agric., For., Fish., Min.	--[a]	--	--	--
Construction	2,500	1,900	700	280
Petrochemicals	40	20	--	-10
Petroleum Refining	--	--	--	--
Shipbuilding	450	300	100	50
Food, Textile, Lumber	--	15	45	90
Metal, Mach., Other Mfg.	790	700	470	590
Transportation	225	1,250	2,250	1,500
Utilities, Commun.	--	50	110	160
Fin., Ins., R.E., Bus. Serv.	130	150	150	175
Trade and Services	1,150	1,200	1,400	1,600
Fed. Gov., Hous., Milit.	750	700	750	550
State and Local Government	225	450	650	600
TOTALS	6,290	7,135	7,575	6,285

Source: Special application of the Harris regional forecasting model.

[a]The symbol (--) denotes no change or no significant change.

Table 4.7. Economic indicators of the annual regional impacts of example offshore petroleum cases averaged for selected years.[a]

Indicator	Low Find No Petroleum Refinery			High Find No Petroleum Refinery		
	1977-79	1980-85	1985-90	1977-79	1980-85	1985-90
Employment	3,015	1,115	1,375	6,295	7,135	7,575
Payrolls (in millions)	$32.9	$13.8	$18.0	$73.2	$87.2	$101.3
Income[b] (in millions)	$39.4	$14.0	$25.7[c]	$87.3	$135.0	$144.6

Source: Special application of the Harris regional forecasting model.

[a]The figures in each column represent an annual average, not a total, for the years indicated in the column heading.

[b]Regional income = earnings + transfer payments + property income - social security contributions.

[c]Adjusted to reflect the same income-to-earnings ratio as in 1985-1990 high-find case.

Table 4.8. Estimated average annual regional employment associated with a 250,000 B/D petroleum refinery, selected years.[a]

Economic Sector	Average Annual Employment: Construction 1977-9	Production 1980-5	Production 1985-90	Production 1990-2000
Agric., For., Fish., Min.	--[b]	--	--	--
Construction	1680	130	130	90
Petrochemicals	--	--	--	--
Petroleum Refining	--	700	720	670
Shipbuilding	--	--	-15	-30
Food, Textile, Lumber	--	70	60	50
Metal, Mach., Other Mfg.	250	15	15	-30
Transportation	75	90	90	70
Utilities Commun.	--	50	75	100
Fin., Ins., R.E., Bus. Serv.	60	50	80	125
Trade and Services	620	750	870	830
Fed. Gov., Hous., Milit.	10	170	130	30
State and Local Government	220	500	450	190
TOTALS	2915	2525	2605	2095

Source: Special application of the Harris regional forecasting model.

[a]Calculated as the low-find, state-control case with a refinery less the low-find, state-control case without a refinery.

[b]The symbol (--) denotes no change or no significant change.

Table 4.9. Economic indicators of the annual regional impacts of petroleum refinery alternatives averaged for selected years.[a]

Indicator	One 250,000 B/D Refinery[b]			Three 250,000 B/D Refineries[c]		
	1977-8	1980-85	1985-90	1977-8	1980-85	1985-90
Employment	2,900	2,630	2,650	8,220	6,000	6,825
Payrolls	$34.4	$34.3	$36.5	$94.6	$81.3	$96.3
Income[d]	$42.3	$41.5[e]	$40.6[e]	$118.	$98.4	$107.1

Source: Special application of the Harris regional forecasting model.

[a]The figures in each column represent an annual average, not a total, for the years indicated in the column heading.

[b]Calculated as the difference between the low find-state control-high price cases with and without a petroleum refinery.

[c]Calculated as the difference between the high find-federal control-high price case with and without three refineries.

[d]Regional income = earnings + transfer payments + property income - social security contributions.

[e]Adjusted to reflect the same income-to-earnings ratio as in the 1980-85 or 1985-1990 three-refinery case.

Table 4.10. Estimated average annual impacts associated with selected petroleum developments, Bristol County, Massachusetts, selected years.

Category	1977-8	1980-5	1985-90	1990-2000
Case: High-Find, High-Price, No-Refinery				
Employment:				
Offshore Petroleum	--	200	475	370
Agric., For., Fish., Min.	--[a]	--	--	--
Construction	1,450	1,130	470	130
Petrochemicals	20	10	--	--
Petroleum Refining	0	0	0	0
Shipbuilding	--	--	-10	-25
Food, Textile, Lumber	--	--	--	--
Metal, Mach., Other Mfg.	320	225	30	-100
Transportation	100	650	1180	780
Utilities Commun.	--	25	50	70
Fin., Ins., R.E., Bus. Ser.	70	90	100	160
Trade and Services	630	760	780	700
Fed. Gov., Hous., Milit.	25	140	170	100
State and Local Govn't.	90	360	390	275
Total Employment	2,705	3,590	3,635	2,460
Population	4,370	6,289	6,590	5,850
Case: High-Find, High-Price, One-Refinery				
Employment:				
Offshore Petroleum	--	200	475	370
Agric., For., Fish., Min.	--[a]	10	--	--
Construction	3,225	1,225	570	250
Petrochemicals	20	10	--	--
Petroleum Refining	0	750	740	635
Shipbuilding	--	-10	-20	-50
Food, Textile, Lumber	--	70	40	15
Metal, Mach., Other Mfg.	650	240	-70	-325
Transportation	170	750	1,250	850
Utilities Commun.	--	70	125	175
Fin., Ins., R.E., Bus. Ser.	160	120	170	290
Trade and Services	1,270	1,430	1,525	1,525
Fed. Gov., Hous., Milit.	35	300	265	190
State and Local Govn't.	320	720	725	600
Total Employment	5,850	5,885	5,795	4,525
Populations	10,900	11,550	11,450	9,500

Source: Special application of the Harris regional economic model.

[a]The symbol (--) denotes no change or no significant change.

Footnotes

1. No estimate is made here of the regional real income changes associated with different oil and gas prices. The argument for this treatment is that the region has no effective control over the price of crude oil and natural gas. Estimates by others (M.I.T., 1973) indicate the major effects that changes in petroleum prices will have on the real income of the New England region.

2. In all applications the base-case regional model data were adjusted at the outset to reflect dramatic declines in military-related employment in Newport and Washington Counties, Rhode Island, and Suffolk County, Massachusetts. Based on telephone discussions with Public Affairs Officers, military-related employment was reduced by 90 percent in Washington County and 50 percent in Newport and Suffolk Counties.

3. See chapter 3.

4. The term "shipyard," of course, is a catch-all since platforms could be fabricated at new, specialized facilities or possibly at some existing yards. The major New England yards, unless they invested in new facilities, might not be able to construct platforms in the near future because of a backlog of orders for LNG carriers, tankers, and submarine construction and/or assembly projects.

5. In the Harris model, earnings or payrolls by industry are a function of estimated employment and the equipment investment in the industry. Total earnings, of course, is the sum of all payrolls for all industries in the region. Transfer payments are estimated as a function of population and the level of unemployment. Property income, a large proportion of which is rental income, is estimated as a function of area earnings. Social security payments are estimated by applying the prior year's ratio of social security payments to civilian persons employed to the current year's civilian persons employed (Harris, 1974, pp. 28-29).

6. Tax collections may in fact begin sooner since many communities tax facilities under construction.

7. Local unemployment problems conceivably could be exacerbated in the short-run. This could occur if prospective employees, operating with imperfect information, are attracted to the area or if labor imported to work on the development of offshore fields or the construction of a refinery are not mobile when the projects are completed.

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5. THE REGIONAL ECONOMIC CONSEQUENCES OF POTENTIAL PETROLEUM DEVELOPMENT: ADJUSTMENTS

The purpose of this chapter is to adjust and qualify the regional impact results presented in chapter 4. Total regional impact results are adjusted to reflect the cost of resources used in the region as a result of hypothetical petroleum activities. This adjustment provides an estimate of the part of the total regional earnings and income impacts that constitutes an increase in national earnings and income.

Another section contains a brief discussion of some of the public-sector consequences of petroleum developments. These include the potential regional costs of social services and public management activities associated with OCS oil and gas development and refineries. Also included are some qualifications of the earlier estimates of regional public revenues.

An assessment of the many environmental aspects of offshore oil and gas development is outside the scope of this report. Extensive studies of the environmental dimensions of the petroleum activities examined in this work may be found in several major studies, including those by M.I.T. (1973), the University of Oklahoma (1973) and the recently published assessment by the Council on Environmental Quality (1974).

The only quantitative adjustments actually made in this chapter are in the next section, dealing with the cost of resources used in the region. In all other cases the adjustments are primarily qualitative, although an effort is made to provide an appreciation of some of the quantitative elements of each needed adjustment.

Adjustment of Total Regional Impact Results to Reflect Resource Costs

The regional impact estimates presented in chapter 4 indicate the total effects on the New England region of each of the hypothetical offshore petroleum and refinery developments. The results, with the exceptions to be noted below, correspond with what one would expect to see reflected in a system of economic accounts measuring employment, earnings, income, output, and other variables, if the region maintained a unified set of accounts. A region understandably may wish to measure the total impacts of prospective economic developments. However, it also is of interest, in terms of national goals, to provide estimates of the extent to which increases in regional earnings and income represent an increase in national earnings or income or instead a mere transfer of resources and income into the region (or even among sections of the region).

In general, unless the introduction of offshore petroleum and refinery activity will draw upon otherwise idle labor and capital, the use of the resources diverts them from alternative activities and thus is at the cost of what they would have produced elsewhere. If at least some otherwise unemployed resources are used as a result of the new activities, however, the real cost of the resources will be less than the market costs, and the difference represents a gain in income to society. The base-case runs with the regional model were based on the assumption that national full employment policies were in effect over the life of the potential petroleum developments, and national controls on employment were established on this basis. A full employment assumption is reasonable in the long-run; however, in view of the existing substantial unemployment rates, the impact results are adjusted to allow for possible increases in national earnings and income as a consequence of the use of resources which could otherwise be unemployed. The approach used to make this adjustment is discussed below.

The extent to which the labor and capital demands imposed by offshore oil and gas and refinery developments are met out of unemployed resources will depend on the pattern of resource demands directly and indirectly resulting from the particular activities as well as the level of unemployment by occupation and idle capacity by industry within New England. The higher the level of regional unemployment in the types of labor and capital demanded by petroleum activities, the greater the likelihood that the resources used will be drawn from the unemployed. Based on a detailed examination of these factors, inferences can be made regarding the extent to which an activity will make use of unemployed resources or merely will divert employed resources from alternative activities.

No attempt is made as part of this study to undertake the detailed calculations necessary to estimate the real cost of resources as suggested above. Fortunately, however, a good idea can be gained of how large an adjustment for resource costs might be called for by examining the results of an earlier, major study specifically designed to address this issue. Haveman and Krutilla (H-K), in a very comprehensive 1968 study, attempted to refine benefit-cost calculations by taking into account the likely use of unemployed labor and idle capital in the construction phase of selected water resource projects. The H-K study considered five types of representative public water resource expenditures and divided the U.S. into ten regions, one of which was New England. Estimates were made of the composition and geographic distribution of direct and indirect resource demands resulting from hypothetical undertaking of the public projects in each region. It was assumed that the public expenditures took place in 1960, a year of comparatively high (5.6 percent) national unemployment.

Based on the H-K analysis of the labor and capital demands associated with each representative project, estimates were derived of the social cost of the resources used to construct the public projects in each region. For New England it was found that the social labor cost, i.e., the real resource cost of labor, ranged from 82 to 88 percent of the market labor cost for the five projects located within the region. Total social costs for the projects located in New England were estimated to range from 84 to 89 percent of the total expenditures (1968, pp. 82, 88).

The pattern of resource demands imposed by petroleum-related construction activity surely is not the same as that resulting from the water resource projects considered in the Haveman-Krutilla study, except that on-site construction activities are an important component of both types of investment. Nonetheless, the H-K estimates can be used to establish a reasonably lower limit on the real cost of regional resources used in offshore oil and gas and petroleum refinery activity. It is most unlikely, for example, that the real cost of resources used in the region will be less than 80 to 85 percent of the market cost of the resources used in petroleum-related developments, particularly in view of the age-skill requirements associated with offshore petroleum and refinery activity. As has been argued by others, the workers employed in these activities are likely to be younger and more skilled than average and can be expected to be adaptable and mobile -- and therefore, would be unlikely to be unemployed for any length of time (M.I.T., 1973, pp. 170-172).

On the other hand, recent regional and national unemployment rates have been in the vicinity of seven percent. The higher the level of unemployment, the greater the chance new activities will make use of unemployed resources. Also, an increase in state and local government revenues as a result of new activities creates the potential to employ and train workers who might otherwise be unemployed, perhaps for substantial periods, and state and local government activities are notably labor-intensive. Clearly, the real importance of this last point for regions like New England will turn on whether or not the coastal states can share directly in the cash bonus and royalty revenues from offshore operations, and the extent to which state and local governments can capture the potential returns from petroleum refinery operations. The retail trade and services sector also is comparatively labor-intensive.

Taking into account the range of direct <u>and</u> indirect activities associated with petroleum-related developments, it is highly unlikely that real resource costs would be less than 75 percent of the market cost. Based on this reasoning, the following adjustment is made for resource costs to estimate the share of total regional earnings and income that represents an increase in national earnings and income. For each impact case examined for New England in chapter 4, all payments to labor are adjusted to reflect the real cost of the labor used in the region under the assumption that at most only 25 percent of the direct <u>and</u> indirect payments to labor over the life of all petroleum activities represents a gain to society. No adjustments are made for returns to the region's industrial capital, which assumes that without the petroleum activities in question the capital used in these activities would be idle. These are very conservative adjustments, and they almost certainly result in higher estimates of national earnings and income than would be estimated with a comprehensive study along the lines of Haveman and Krutilla. The results of these adjustments are summarized in table 1.6.

The effect of the adjustments for resource costs is to bring into sharp focus the difference between estimates of the total "regional development impacts" experienced by a region -- essentially the results in table 1.5 -- and estimates of the increase in national earnings and income associated with the petroleum activities taking place in the region, as indicated in table 1.6. For example, at a discount rate of eight percent, the total or unadjusted regional earnings and income in the low find-high price-federal control case are $196 million and $207 million, respectively (table 1.5). These figures represent an estimate of the direct and indirect impacts on the region of this offshore find scenario, and the estimates would be reflected in a system of regional economic accounts for New England. However, when adjusted for resource costs, the share of regional earnings and income that is a contribution of the activity in the region to national earnings is $49 million and to total national income is $60 million. Similarly, the total discounted earnings and income accruing to the region with one refinery is on the order of $324 million and $353 million, respectively. The component of regional income and earnings that represents a gain in national earnings and income, however, is about $82 million and $109 million, respectively.

In summary, both the total regional impact results and the total results adjusted for resource costs are of interest. There is, however, a substantial difference between the two measurements of regional economic effects. The total effects include the use of unemployed regional and non-regional labor and regional capital, the location effects of a transfer of resources and income into the region, and perhaps a re-allocation of resources among activities and areas within the region. The total results adjusted for resource costs, on the other hand, provide an estimate of the share of the total earnings and income accruing to or taking place in the region that represents an addition to national earnings and income, after subtracting the opportunity costs of the resources used in the region as a result of the introduction of the petroleum activities.

Fiscal Adjustment Considerations

Public Revenues. Real estate or property tax revenues from onshore petroleum investments (ignoring public services temporarily) are treated as a gain to the region, although such revenues are transfers from the point of view of society as a whole. Under the study assumptions all onshore petroleum investments for oil terminals, gas plants and petroleum refineries are assumed to generate annual real estate tax revenues equal to .00875 of the cost of investment, irrespective of the location of the facilities. Higher and lower effective tax rates can be found in coastal communities that could be affected by offshore petroleum and petroleum refinery alternatives, so that the .00875 tax revenue coefficient is probably a reasonable, though necessarily crude, figure. On this basis, the annual tax revenues from the estimated investment in a refinery is $4.18 million. Property tax revenues from onshore oil storage and gas processing facilities associated with offshore fields could eventually range from approximately $170,000 in the case of a low-find to perhaps as much as $1 million with a high-find.

The property tax revenues estimated above and included in the results of this report can best be described as the "gross" or "overstated" estimates. In reality the land will have alternative uses, and the actual property tax revenue gain is the difference between the revenue from the refinery less the revenue which would be received from the next best (highest return) use of the land. For example, except for utilities, few single-alternative activities would involve the major capital investment associated with a refinery, perhaps $475 million. If the "next best" use of the land for one or more activities involves an investment of, say, $75 million, the annual public revenue gain to the area with the refinery, all other things equal, would be $3.5 million, or $475 less $75 million times .00875.

Whatever the value of the next best alternative investment in any particular case, calculations like the one described above provide a lower limit to the public revenues gained from allowing one form of development rather than another. The upper limit is the difference between the public revenues from the petroleum facility less the tax on idle industrial land.

On the other hand, the regional income estimates in this study may be understated to the extent that the petroleum developments generate revenues not considered in this study, for example, a tax per-unit of refinery throughput or ad valorem taxes. Needless to say, the public revenue implications in a given situation will depend upon the particulars of development proposals agreed to by all parties and the applicable state and local laws and assessment practices. These detailed considerations cannot be addressed in a study of this scope, but they clearly would be of central interest in a site-specific, comprehensive study of particular alternatives.

Perspectives on Public Services and Expenditures: Refinery Activity. The construction of a refinery over a two-year period may involve on the order of 1,700 construction employees. Roads and traffic control devices may have to be improved in nearby areas as a result of additional traffic and the trucking of heavy materials and equipment. Depending on commuting patterns and the availability of labor with the requisite skills in the area concerned, a number of the workers involved with the construction of the refinery and their families may be attracted to the area. As a consequence of these developments and the indirect effects on retail trade and services and other activities (see table 4.8), additional social services will be required. These effects primarily would be short-run.

Once on stream the refinery will require obvious direct public services such as police and fire protection and sewerage disposal. Continuous monitoring will be needed to ensure that state-federal environmental standards are adequate and are being maintained. In connection with a 1970 proposal for a 65,000-B/D refinery for Tiverton, Rhode Island, for example, it was estimated that an environmental monitoring system could cost \$100,000 per year (Mlotok, 1970, p. 11). It is reasonable and perhaps conservative to expect that an environmental monitoring system for a 250,000-B/D refinery might cost \$200,000 to \$300,000 a year. Unless regulation costs are assumed by the refinery operators or federal authorities, the costs would have to be borne by state and local taxpayers.

Contingency plans to deal with spills of crude oil or products would have to be developed by state, federal and company officials. Containment devices, one or more oil recovery vessels, possibly chemical dispersants and qualified personnel will need to be available in the event of an accident. Some of these services and equipment typically will be provided by the refinery operators. However, the design of an area-wide oil transportation system and spill contingency plan will impose costs on the state.

In addition to the above public services, a refinery operation creates major demands for water, primarily for cooling purposes. The water demands will depend on the capacity and complexity of the refinery, the technology used, and the cost of water either from public water supply systems or the company's system, and perhaps on other factors.[1] Existing information and studies provide a wide range of estimates of water intake for a 250,000-B/D integrated refinery, but a reasonable lower figure for water intake by a hypothetical New England refinery would be nine million gallons per day (MGD). Lower refinery water demands have been reported. For example, ARCO's new 100,000-B/D refinery at Cherry Point, Washington, uses about 3.5 MGD of water (Aaland, 1972, p. 90), which is proportionately the equivalent of 8.7 MGD for a refinery with a throughput of 250,000 B/D. However, this figure probably is unrealistically low for other sections of the United States, particularly New England, because the ARCO refinery uses electricity-intensive air cooling techniques. Electricity costs in the U.S. are lowest by a wide margin in Washington state and highest in New England and the Northeast.

A reasonable upper-bound water demand estimate is 18 MGD.

This figure is considerably below the water demand estimates for comparable refineries from some sources, and it is based on the assumption that New England refineries would adopt state-of-the-art water conservation techniques to achieve the major reductions in water use reported in the industry literature (Exxon, 1974, p. 12; Lieber, 1973). Regional water pricing and discharge policies also could work to influence potential refinery water demands.

Some appreciation can be gained of the extent to which the introduction of a refinery could increase the demands on public water systems and area freshwater supplies by looking at U.S. Census figures on water use by all petroleum refineries. In 1968 over one-half, 57 percent, of the raw water used by refineries was fresh water; the remaining 43 percent was from brackish sources. Of the freshwater demands, 22 percent was withdrawn from public water systems and the rest from company water systems (U.S., 1968, pp. 7-42, 43). If these U.S. average figures are regarded as reasonably representative of what could be expected with a New England refinery, the refinery would demand some 1.1 to 2.2 MGD from municipal sources and a total of 5.1 MGD to 10.2 MGD from area freshwater stocks (table 5.1). These figures make no allowance for indirect water demands as a result of the secondary effects on the area as a consequence of the location of a refinery.

The figures in table 5.1 provide a basis for a particular community to assess the adequacy of the existing supply capacity and water pricing policies and the cost of augmenting the water supply, if necessary. For example, one hypothetical refinery site is Newport County, Rhode Island. The calculated dry-weather yield for the reservoirs serving Newport, Middletown and Portsmouth is 12.6 MGD, but based on the 1964-65 drought, the safe yield of the system is only about 9.5 MGD. Average daily pumpage for the system in 1972 was 8.03 MGD (Malcolm Pirnie, 1972, pp. 4, 7). The low estimate of direct refinery water demand from a public system, 1.1 MGD, would come close to the safe yield of the system, and higher withdrawals from the public system would exceed the safe yield. In view of the likely future water supply needs and management problems in Rhode Island (Martel, 1973; Malcolm Pirnie, 1972), the public policy aspects of the introduction of a major water-using industry like petroleum refining clearly require a comprehensive examination on a site-specific basis.

Once in operation the refinery will give rise indirectly to a range of social services. Based on the estimates provided in chapter 4, the refinery initially will employ about 700 people, a number of whom can be expected to move into the community. The refinery will attract such activities as retail trade and services, transportation and state and local government activities (see table 4.8). Many of the families migrating to the area will be of prime working age and hence will have children who will need to be provided with educational services.

The above considerations suggest that the location of a refinery will lead to substantial indirect demands for a range of business and social services. Detailed planning considerations are not within the scope of this study, but clearly questions should arise at the local level regarding the extent to which the existing social capital, taxing provisions and planning mechanisms are appropriate in light of the direct and indirect consequences associated with the construction and operation of a refinery. The general type of development-related issues raised here are not new; they are faced by communities all the time. What is different, however, is the need to evaluate and plan for the introduction over a short period of time of a major industry with which the area has little or no experience (and which has been characterized by uncertainties in the environmental area) as opposed to the more typical situation of planning for gradual or incremental development.

Offshore Petroleum. Should the states assume an active role in overseeing the development of Georges Bank, New England will incur management costs for coastal planning efforts and for research on oil-related issues. Regional, state and local authorities will be called upon to address a variety of onshore issues. These will include studies and hearings to evaluate alternative landfalls and pipeline corridors for offshore oil and gas; site selection for the location of oil terminals and gas processing plants; the adequacy of existing port facilities to accommodate offshore support vessels; and the possible conversion of some coastal lands to support offshore development and production activities.

No attempt is made here to assess the community and societal costs, potential onshore conflicts and planning issues that can arise as a result of the development of offshore oil and gas fields. It is tempting to make comparisons between the coastal development problems that might take place in New England as a result of offshore petroleum activity and recent experiences with offshore oil and gas development in the North Sea. In northeast Scotland, for example, major public investments have been made in road improvements to handle the transport of heavy materials, harbor expansion and improvement to meet the specific berthing and storage needs of support operations, expansion of airport and rail services, and a variety of other community services including housing, water supply and sewerage facilities (see e.g., Scottish Office, 1973, pp. 12-15). However, broad comparisons with the North Sea only indicate the kinds of regional planning problems that can arise with OCS petroleum development and are of limited value for concrete planning purposes for New England.

The results generated in this study provide an indication of the scale and kinds of direct and secondary effects from the leasing and development of Georges Bank, and hence some of the development pressures that will confront coastal areas. Additional work is called for, however, to examine in detail the activities and demands that are likely to be made on coastal areas as a result of alternative offshore scenarios, and to inventory the stock of port, transportation, social service and other facilities and resources. Assessments then can be made of the extent to which potential OCS petroleum developments might encounter constraints or bottlenecks in coastal sections of the region and the adequacy of existing leasing arrangements and coastal planning mechanisms to deal with these problems. This kind of a planning strategy would, among other things, provide guidance in dealing with potential planning problems, including a possible ranking of particular ports and coastal communities in terms of, say, lowest social cost of accommodating OCS development and socio-economic conflicts. Specialized studies of the potential onshore effects of OCS developments also would provide more refined measures of the true social gains from offshore development and would indicate the onshore costs of petroleum developments to coastal regions. This kind of information provides a rational foundation for examining the existing federal OCS leasing arrangements in which all offshore public revenues accrue to the federal government irrespective of the costs borne by coastal areas in support of offshore oil and gas operations.

Table 5.1. Potential range of new water demands by a hypothetical 250,000 B/D integrated refinery (in MGD).

Source	Low	High
Freshwater	5.1	10.2
Public Water System	1.1	2.2
Company Water System	4.0	8.0
Brackish Water	3.9	7.8
Total	9.0	18.0

Source: Based on the refinery water demand estimates discussed in the text and census information on the percentage breakdown of water intake by source for petroleum refineries (U.S., 1968, Pp. 7-42, 43).

Footnotes

1. For an analysis of the economic-technical substitutions that a petroleum refinery can make in the context of a residuals management framework, see Russell (1973).

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Appendix A: Estimates of Offshore Oil and Gas Pipeline Transportation Costs*

In this appendix capital and operating costs are estimated for an offshore pipeline system for transporting oil and gas to New England from hypothetical fields on Georges Bank. The results are intended to provide order-of-magnitude estimates of offshore petroleum transportation costs for alternative-sized oil and nonassociated gas fields.

The transportation subroutine provides cost estimates for each oil and gas field assumption considered in the main program. Variations of offshore oil or gas field parameters influence the transportation cost estimates. For example, as discussed in Chapter 2 an increase in the price of oil increases the total and peak amount of oil recovered from a given field and thereby raises transportation capital and operating costs. An increase in the interest rate also can influence the selection of the oil pipeline system and will raise discounted costs and, accordingly, the average transportation costs.

Oil Pipeline Transportation Costs

The oil pipeline costs considered in this appendix include those from the intake side of the production platform pumping equipment to the discharge from the first land storage depot. The major elements of transportation cost considered below are:

1. Capital Costs

   a. Pipeline material
   b. Pipeline coating
   c. Pipeline laying
   d. Pumping equipment at the production platform and interim stations
   e. Interim pump station(s) -- ocean platform costs
   f. Onshore storage facility costs

2. Operating Costs

   a. Costs for operating and maintaining the pipeline

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*This section was written with Edward Carapezza.

(including patrolling and inspection costs)

b. Miscellaneous interim pump station(s) operating costs (including overhaul, repair, operating supplies, etc.)
c. Pumping energy costs
d. Storage facility operating costs
e. Oil heating costs

In order to estimate the elements of transportation costs listed above, a number of simplifying assumptions are made to reflect the interrelationships of the various cost elements. For example, a pipeline transportation system designed to carry a flow of x gallons of oil per minute could be handled with a number of different pipe sizes. If a relatively large pipeline is used, pressure losses in the pipeline would be small, and therefore the pumping station horsepower requirements would also be small. A large pipeline thus reduces horsepower-dependent costs as 1d, 2b, and 2c described above relative to the costs of a smaller pipeline. However, large pipelines lead to an increase in those costs which depend on the size of the pipeline, namely, 1a, 1b, 1c, and 2a.

On the other hand, for a given flow,operating costs always are higher for a smaller line. The only exception is for the costs of patrolling, inspecting, and maintaining the pipeline and pumping stations. These costs tend to increase with the size of the pipeline (see table A.3).

Clearly a number of transportation possibilities exist, and in a more specific engineering-economic study other alternatives would merit detailed examination within an optimization context. For the purposes of this study, however, the following approach is adopted. The discounted cost of shipping a given volume of oil via two pipeline sizes is compared for each field production case, and the lower cost alternative is adopted in each case. For gas the transportation subroutine picks the lowest cost pipeline-gas treatment system which can handle the peak gas flow from the offshore field. Capital costs are charged to the field when the pipeline, pumping stations, and storage terminals or processing plants are installed.

Oil Field Size and Production Assumptions

The offshore field sizes considered in this study range up to 600 million barrels of recoverable reserves. Only a fraction -- typically less than one-half -- of the oil in place is recovered over the life of the field. The exact amount recovered depends on the reservoir mechanics of the field, the price of oil, and related factors. As is discussed in Chapter 2, the field produces oil over a 20-year period. Maximum annual production cannot exceed ten percent of "recoverable reserves" and is reached during the fourth year of production from the field.

The program is designed to choose between two pipeline sizes so as to pick the system with the minimum, discounted total costs, with the restriction that the transportation system must handle the peak volume of production from the field. The maximum flow in barrels per day (B/D), then is:

$$B/D \leq [RR\ .1]\ [358^{-1}]*$$

Thus, once the recoverable reserves (RR) are specified, the maximum flow in B/D is known. The actual oil flow depends on the production rate selected in the field representation model described in detail in the text section.

Major Oil Field Engineering Assumptions

The major engineering assumptions in table A.1 are used to derive the transportation investment and operating cost estimates.

Capital and Operating Costs for Offshore Oil Transportation

Capital cost estimates for selected pipeline sizes and flow rates are presented in table A.2, and operating costs are contained in table A.3.

Gas Transportation Costs

The gas costs considered in this section include those from the compressor at the production platform through the onshore gas processing plant. The major elements of cost for the gas transportation system considered below are:

1. Capital Costs

   a. Pipeline material
   b. Pipeline coating
   c. Pipeline laying
   d. Compressor equipment at the production platform and interim stations
   e. Interim compressor station -- ocean platform costs
   f. Onshore gas process plant costs

2. Operating Costs

   a. Costs for operating and maintaining the pipeline (including patrolling and inspection costs)
   b. Miscellaneous interim compressor station operating costs (including overhaul, repair, operating supplies, etc.)
   c. Compression energy costs
   d. Gas gathering and processing costs

The gas transportation cost estimates, like the oil es-

*The pipeline is assumed to be capable of pumping at its design rate for 358 days per year. For computational purposes transportation costs are based on flows in gallons per minutes.

timates, are based on industry cost data and a specific set of simplifying engineering and production assumptions. The assumptions are discussed below.

Nonassociated Gas Field Size and Production Assumptions

Offshore gas fields are assumed to contain nonassociated natural gas. The size of fields considered ranged from 500 billion to two trillion standard cubic feet (scf) of recoverable reserves.

It is assumed, consistent with the discussion in Chapter 2, that the field produces over a 20-year period. The maximum annual production is not allowed to exceed ten percent of the recoverable reserves, although the actual flow from a field is based on the field production assumptions discussed in Chapter 2.

The gas transportation program is designed to select the set of transportation costs for a system that can handle the maximum flow rate from the particular field being considered.

Major Gas Field Engineering Assumptions

The major engineering assumptions in table A.4 were used to derive the gas transportation investment and operating cost estimates.

Capital and Operating Costs for Offshore Gas Transportation

Capital cost estimates for selected pipeline sizes and flow rates are presented in table A.5. Operating cost estimates are contained in table A.6.

Table A.1. Major engineering assumptions for estimating offshore oil transportation costs.

Average Well Depth:	10,000'
Water Depth Range:	150-200'
Temperature:	
Average temperature of flowing oil:	140°F[a]
Average temperature of surface seawater:	40°F

Interim Pump Station (IPS):
An IPS is required when the oil pipeline downstream pressure reaches 200 p.s.i.g. (pump efficiency = 60%)

Major Crude Oil Characteristics:

Type:	32 degree (API)

Temperature-Viscosity:

Temp.	Absolute Viscosity Centipoise	Kinematic Viscosity Centistoke	Density[b] lb/ft^3	Saybolt Universal Visc. (sec.)
120°	7.0	8.0	52.6	52.0
150°	5.0	5.8	51.8	45.0

Pipeline Characteristics:
Pipe material: Coated, low-carbon steel (API-5 pipe)
Operating pressure:

Maximum	2500 p.s.i.g.
Minimum	800 p.s.i.g.

Maximum elevation head plus valve, bend, fittings, and opening losses = 300' pressure drop
Oil flow velocities considered ranged to 10 ft/sec.
Design flow rates are based on the assumption that oil flows for only 51 wks/yr.
Engineering calculations for flow rate, pressure drop, and pumping power required (brake horsepower = BHP) based on equations in Crane Co. (1970).

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[a]Based on the industry "rule of thumb" that there will be a 1° temperature increase over surface water temperature per 100 ft. of well depth.

[b]Density at elevated temperatures = specific gravity at elevated temperatures x 62.4. See Crane Co. (1970).

Table A.2. Capital costs for selected offshore oil pipeline system.

(1) Pipe Size/ Flow Rate (in./ (thou. B/D)	Pipeline Costs ($/mile)[a] (2) Pipe Material ($/mile)	(3) Pipe Coating ($/mile)	(4) Pipe Laying ($/mile)	(5) Pump Station Cost[b] ($)	(6) Pump Station Eqmt. Costs[c] ($/mile)	(7) Storage Facility Costs[d] ($)
6"/15.4	29,600	8,850	91,000	1,500,000	6,550	863,000
8"/15.4	31,500	10,000	98,500	1,500,000	1,770	863,000
8"/25.7	31,500	10,000	98,500	1,500,000	7,080	1,440,000
10"/25.7	33,100	11,100	106,000	1,500,000	2,200	1,440,000
10"/41.1	33,100	11,100	106,000	1,500,000	7,900	2,310,000
12"/41.1	40,500	12,900	120,500	1,500,000	3,780	2,310,000
12"/58.3	40,500	12,900	120,500	1,500,000	10,400	3,260,000
14"/58.3	47,550	13,950	131,250	1,500,000	6,760	3,260,000
14"/72.0	47,550	13,950	131,250	1,500,000	10,900	4,040,000
16"/72.0	54,600	15,000	142,000	1,500,000	6,200	4,440,000
18"/111.1	62,400	20,700	142,200	1,500,000	9,800	6,210,000
18"/145.7	62,400	20,700	142,200	1,500,000	28,000	8,140,000
20"/145.7	70,500	26,600	142,800	1,500,000	15,550	8,140,000

Footnotes, table A.2.

[a]Based on Brubaker (1968), updated to 1973 by using the offshore pipeline price index in O'Donnell (1973, p. 76).

[b]Judgment, based on platform cost figures discussed in table 3.1.

[c]Based on pump station costs per brake horsepower (BHP) required, calculated at \$400/BHP as extrapolated from figures presented in Crane Co. (1970, pp. A-7 and 3-2) at 150°.

[d]From National Petroleum Council (1970, p. 7), average capital costs for a storage facility are \$3-3.50 per barrel stored. It is assumed that the facility allows for 14 days storage. The amount stored, S, in barrels, depends on the flow rate from the offshore field, measured in gallons per minute. Thus:

$$\begin{aligned} S &= (\text{GPM})\ (1440\ \text{min/day})\ (14\ \text{days})\ (1/42) \\ &= \text{GPM}\ (480) \end{aligned}$$

Using a per-barrel storage capital cost of \$4/bbl in 1973 total storage costs, C, for a given field are:

$$\begin{aligned} C &= \text{GPM}\ (480)\ (4) \\ &= \text{GPM}\ (1920) \end{aligned}$$

Table A.3. Operating costs for selected offshore oil pipeline system.

(1) Pipe Size/ Flow Rate (in./ (thou. B/D)	(2) Patrolling Inspecting Maint. & Operating Pipeline[a] ($/yr/mi)	(3) Pump Station Operating & Maint. Costs[b] ($/yr/mi)	(4) Pumping Energy Costs[c] ($/yr/mi)	(5) Shore Storage Facility Cost[d] ($/yr)
6"/15.4	4,650	1,310	1,890	180,000
8"/15.4	6,200	352	508	180,000
8"/25.7	6,200	1,420	2,040	300,000
10"/25.7	7,750	440	632	300,000
10"/41.1	7,750	1,580	2,280	480,000
12"/41.1	9,300	755	1,085	480,000
12"/58.3	9,300	2,040	2,930	680,000
14"/58.3	10,850	1,350	1,940	680,000
14"/72.0	10,850	2,170	3,130	840,000
16"/72.0	12,400	1,240	1,780	840,000
18"/111.1	13,950	1,910	2,750	1,295,000
18"/145.7	13,950	5,460	7,850	1,710,000
20"/145.7	15,550	3,040	4,360	1,710,000

[a]According to Withers (1973), it costs on the order of $775/mi/yr to maintain, inspect, and operate a 3-in. equivalent, onshore pipeline system. The $775 figure was increased by a factor of 3 for our offshore cost estimate for a 3-in. equivalent pipe.

[b]Includes overhaul, repair, and operating supplies costs for the interim pump station calculated at $80/BHP from Withers (1973).

[c]Based on the assumption that it costs approximately $.021/kwh for offshore generators for the pump station. The electric motor efficiency for the pump drives is assumed to be .85. For a 24-hour day, 358-day operation, this works out to $115/BHP/yr.

[d]Storage facility operating costs have been estimated (National Petroleum Council, 1970) to be $.05/bbl for maintenance and $.65/bbl for overhead. This is increased to $.83/bbl to allow for 1973 costs. As derived in note d, table A.1, storage capacity depends on the design flow rate: S = GPM(480). Total operating costs for a land storage facility, therefore, would equal: GPM(480) (.83) or GPM(400).

Table A.4. Major engineering assumptions for estimating offshore gas transportation costs.

Average Well Depth:	10,000'
Water Depth Range:	150-200'
Temperature:	
Average temperature of flowing gas:	120°F
Average temperature of surface seawater:	40°F
Interim Compressor Station (ICS):	
An ICS is required when the gas pipeline pressure reaches 200 p.s.i.g.	
Gas Characteristics:	
Specific gravity	0.65
Gas compressibility factor	0.95
Pipe material: Coated, low-carbon steel (API-5 pipe)	
Operating pressure:	
Maximum	1200 p.s.i.g.
Minimum	800 p.s.i.g.
Maximum elevation head plus valve, bend, fittings, and opening losses = 300 ft.	
Design flow rates are based upon the assumption that gas flows for only 51 wks/yr.	
Engineering calculations for flow rate/pipe size and pressure drop based upon equations in Crane Co. (1970, pp. 3-2 and 3) and Mouser (1973, pp. 66-67).	

Table A.5. Capital costs for selected offshore gas pipeline systems.

Pipe Size (in.)/Flow Rate (MMscf/da)[a]	Pipeline Costs[b] Material ($/mile)	Coating ($/mile)	Laying ($/mile)	Cap. Cost, Gas Proc. Plant ($ thou)[c]	Compressor Station Cost/mile[d]	Compressor Station Platform Cost($ thou)[e]
14"/40	$47,550	$13,950	$131,250	$1,200	$1,760	$1,500
14"/50	47,550	13,950	131,250	1,500	2,200	1,500
14"/60	47,550	13,950	131,250	1,800	2,640	1,500
16"/70	54,600	15,000	142,000	2,100	3,070	1,500
16"/80	54,600	15,000	142,000	2,400	3,520	1,500
18"/90	62,700	20,800	142,500	2,700	3,960	1,500
18"/100	62,700	20,800	142,500	3,000	4,400	1,500
20"/115	70,500	26,600	142,800	3,450	5,070	1,500
24"/190	92,400	29,000	185,500	5,700	8,370	1,500
24"/210	92,400	29,000	185,500	6,310	9,240	1,500
26"/265	101,000	30,700	198,000	7,950	11,680	1,500
30"/380	115,000	33,000	218,000	11,400	16,750	1,500

Footnotes, table A.5.

[a]Millions of standard cubic feet per day.

[b]Based on Brubaker (1968), updated to 1973 by using the offshore pipeline price index in O'Donnell (1973, p. 76).

[c]From National Petroleum Council (1973, p. 637) investment costs for a gas plant for processing nonassociated gas is $\$30/10^3$ scf/da.

[d]Calculated at $300/BHP (O'Donnell, 1973, p. 73).

[e]Judgment, based on platform cost figures discussed in table 3-1.

Table A.6. Operating costs for selected offshore gas pipeline systems.

Pipe Size/ Flow Rate (MMcf per day)	Patrolling, Inspecting, & Maintaining Pipeline[a] ($/yr/mile)	Compressor Station & Maintenance Costs[b] ($/yr/mile)	Compressor Energy Costs[c] ($/yr/mile)	Gas Gathering & Processing Costs[d] ($/yr)
14"/40	10,850	470	673	214,000
14"/50	10,850	587	840	268,000
14"/60	10,850	700	1,020	322,000
16"/70	12,400	820	1,180	376,000
16"/80	12,400	940	1,350	429,000
18"/90	13,950	1,055	1,520	483,000
18"/100	13,950	1,175	1,680	536,000
20"/115	15,500	1,350	1,930	616,000
24"/190	18,600	2,230	3,210	1,020,000
24"/210	18,600	2,460	3,540	1,130,000
26"/265	21,500	3,120	4,480	1,425,000
30"/380	23,200	4,460	6,420	2,040,000

[a]Based on a (conservative) estimate of three times the on-land figure of $775/yr/mi. of 3-in. equivalent pipe/in. (Withers, 1973).

[b]Based upon $80/yr/BHP (Withers, 1973).

[c]Based upon a value of $115/BHP/yr (Withers, 1973).

[d]Costs for nonassociated gas gathering and processing estimated to be $0.015/Mscf or $15/MMscf (National Petroleum Council, 1973, p. 637).

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Appendix B: Estimates of Possible Georges Bank Production and Royalties

This section contains estimates of possible Georges Bank oil and gas production, revenues and royalties for the high- and low-find and high- and low-price study assumptions. The value of production and royalty estimates contained in this appendix were used as inputs into the regional model, as described in Chapter 4.

Two major find possibilities are postulated. In the high-find case, Georges Bank is assumed to contain recoverable reserves of three billion barrels of oil and ten trillion cubic feet of gas, while in the low-find case reserves are 400 million barrels of oil and two trillion cubic feet of gas.

As described in Chapter 2, an expected higher oil or gas price leads to additional field development activity and additional reserves. The high oil and gas prices used in the study are \$9/bbl and \$.95/Mcf and the low prices are \$6/bbl and \$.75/Mcf. The field supply elasticity response is set at .25, so that as the expected price of oil increases from \$6 to \$9, the planned amount of oil production increases by 12.5 percent. Similarly, as the expected price of gas increases from \$.75 to \$.95/Mcf, additional field development takes place, and the amount of gas produced from a field increases by 6.6 percent.

Georges Bank Oil and Gas Production, Revenue and Royalty Estimates

Reproductions of the printouts for each Georges Bank oil and gas find case are presented below. Each case lists the major assumptions used. For example, the first case is the low oil find, 400 million barrels.* There are two separate fields, each with 200 million barrels of oil, and following the discovery-development assumptions discussed in detail in Chapter 2, both fields are discovered in the first year after

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*Note that on the printout sheets the notation E followed by a number indicates 10 raised to the power of that number, e.g., E 09 = 10^9. The number .4 E 09 is read ".4 times 10^9," which equals 400 million. As another example from the first printout, .2398 E 10 = 2.398 billion.

a lease sale. The price is \$6/bbl. Offshore activity takes place over a 24-year period, and company revenue over the life of both fields is \$2.398 billion. Royalty payments, based on the value of production at the wellhead, total \$362.3 million over the 24-year production period.

The second case presented is the same low-find oil case, but now the price is \$9/bbl. Following the study assumptions, the amount recovered increases, and total oil revenues and royalty payments (as well as cash bonus payments, not shown here) increase correspondingly. Other oil and gas find-price combinations are presented below.

Possible Georges Bank oil reserves, production, and royalties.

Assumptions

Recoverable reserves in basin = 0.4000E 09
Recoverable reserves per field = 0.2000E 09
Number of oil fields = 2
Number of oil fields discovered each year = 2
Price of oil = $6.00

PERIOD	QUANTITY	REVENUE	ROYALTY
1	0.0	0.0	0.0
2	0.0	0.0	0.0
3	0.0	0.0	0.0
4	0.0	0.0	0.0
5	0.7400E 07	0.4440E 08	0.6710E 07
6	0.1480E 08	0.8880E 08	0.1342E 08
7	0.2220E 08	0.1332E 09	0.2013E 08
8	0.2960E 08	0.1776E 09	0.2684E 08
9	0.2960E 08	0.1776E 09	0.2684E 08
10	0.2960E 08	0.1776E 09	0.2684E 08
11	0.2960E 08	0.1776E 09	0.2684E 08
12	0.2960E 08	0.1776E 09	0.2684E 08
13	0.2960E 08	0.1776E 09	0.2684E 08
14	0.2960E 08	0.1776E 09	0.2684E 08
15	0.2691E 08	0.1615E 09	0.2440E 08
16	0.2422E 08	0.1453E 09	0.2196E 08
17	0.2153E 08	0.1292E 09	0.1952E 08
18	0.1884E 08	0.1130E 09	0.1708E 08
19	0.1615E 08	0.9687E 08	0.1464E 08
20	0.1345E 08	0.8073E 08	0.1220E 08
21	0.1076E 08	0.6458E 08	0.9759E 07
22	0.8073E 07	0.4844E 08	0.7320E 07
23	0.5382E 07	0.3229E 08	0.4880E 07
24	0.2691E 07	0.1615E 08	0.2440E 07
TOTALS	0.3996E 09	0.2398E 10	0.3623E 09

Possible Georges Bank oil reserves, production, and royalties.

<u>Assumptions</u>

Recoverable reserves in basin = 0.4000E 09
Recoverable reserves per field = 0.2250E 09
Number of oil fields = 2
Number of oil fields discovered each year = 2
Price of oil = $9.00

PERIOD	QUANTITY	REVENUE	ROYALTY
1	0.0	0.0	0.0
2	0.0	0.0	0.0
3	0.0	0.0	0.0
4	0.0	0.0	0.0
5	0.8325E 07	0.7492E 08	0.1180E 08
6	0.1665E 08	0.1498E 09	0.2360E 08
7	0.2497E 08	0.2248E 09	0.3539E 08
8	0.3330E 08	0.2997E 09	0.4719E 08
9	0.3330E 08	0.2997E 09	0.4719E 08
10	0.3330E 08	0.2997E 09	0.4719E 08
11	0.3330E 08	0.2997E 09	0.4719E 08
12	0.3330E 08	0.2997E 09	0.4719E 08
13	0.3330E 08	0.2997E 09	0.4719E 08
14	0.3330E 08	0.2997E 09	0.4719E 08
15	0.3027E 08	0.2724E 09	0.4290E 08
16	0.2724E 08	0.2452E 09	0.3861E 08
17	0.2422E 08	0.2180E 09	0.3432E 08
18	0.2119E 08	0.1907E 09	0.3003E 08
19	0.1816E 08	0.1635E 09	0.2574E 08
20	0.1514E 08	0.1362E 09	0.2145E 08
21	0.1211E 08	0.1090E 09	0.1716E 08
22	0.9082E 07	0.8173E 08	0.1287E 08
23	0.6054E 07	0.5449E 08	0.8580E 07
24	0.3027E 07	0.2724E 08	0.4290E 07
TOTALS	0.4495E 09	0.4046E 10	0.6371E 09

Possible Georges Bank oil reserves, production, and royalties.

Assumptions

Recoverable reserves in basin = 0.3000E 10
Recoverable reserves per field = 0.2000E 09
Number of oil fields = 15
Number of oil fields discovered each year = 2
Price of oil = $6.00

PERIOD	QUANTITY	REVENUE	ROYALTY
1	0.0	0.0	0.0
2	0.0	0.0	0.0
3	0.0	0.0	0.0
4	0.0	0.0	0.0
5	0.7400E 07	0.4440E 08	0.6710E 07
6	0.2220E 08	0.1332E 09	0.2013E 08
7	0.4440E 08	0.2664E 09	0.4026E 08
8	0.7400E 08	0.4440E 09	0.6710E 08
9	0.1036E 09	0.6216E 09	0.9393E 08
10	0.1332E 09	0.7992E 09	0.1208E 09
11	0.1628E 09	0.9768E 09	0.1476E 09
12	0.1887E 09	0.1132E 10	0.1711E 09
13	0.2072E 09	0.1243E 10	0.1879E 09
14	0.2183E 09	0.1310E 10	0.1979E 09
15	0.2193E 09	0.1316E 10	0.1988E 09
16	0.2139E 09	0.1284E 10	0.1940E 09
17	0.2059E 09	0.1235E 10	0.1866E 09
18	0.1951E 09	0.1171E 10	0.1769E 09
19	0.1816E 09	0.1090E 10	0.1647E 09
20	0.1655E 09	0.9929E 09	0.1501E 09
21	0.1467E 09	0.8799E 09	0.1330E 09
22	0.1265E 09	0.7588E 09	0.1147E 09
23	0.1063E 09	0.6377E 09	0.9637E 08
24	0.8611E 08	0.5166E 09	0.7807E 08
25	0.6593E 08	0.3956E 09	0.5978E 08
26	0.4844E 08	0.2906E 09	0.4392E 08
27	0.3364E 08	0.2018E 09	0.3050E 08
28	0.2153E 08	0.1292E 09	0.1952E 08
29	0.1211E 08	0.7265E 08	0.1098E 08
30	0.5382E 07	0.3229E 08	0.4880E 07
31	0.1345E 07	0.8073E 07	0.1220E 07
TOTALS	0.2997E 10	0.1798E 11	0.2717E 10

Possible Georges Bank oil reserves, production, and royalties.

Assumptions

Recoverable reserves in basin = 0.3000E 10
Recoverable reserves per field = 0.2250E 09
Number of oil fields = 15
Number of oil fields discovered each year = 2
Price of oil = $9.00

PERIOD	QUANTITY	REVENUE	ROYALTY
1	0.0	0.0	0.0
2	0.0	0.0	0.0
3	0.0	0.0	0.0
4	0.0	0.0	0.0
5	0.6325E 07	0.7492E 08	0.1180E 08
6	0.2497E 08	0.2248E 09	0.3539E 08
7	0.4995E 08	0.4495E 09	0.7079E 08
8	0.8325E 08	0.7492E 09	0.1180E 09
9	0.1165E 09	0.1049E 10	0.1652E 09
10	0.1498E 09	0.1349E 10	0.2124E 09
11	0.1831E 09	0.1648E 10	0.2596E 09
12	0.2123E 09	0.1911E 10	0.3008E 09
13	0.2331E 09	0.2098E 10	0.3303E 09
14	0.2456E 09	0.2210E 10	0.3480E 09
15	0.2467E 09	0.2220E 10	0.3496E 09
16	0.2407E 09	0.2166E 10	0.3411E 09
17	0.2316E 09	0.2084E 10	0.3282E 09
18	0.2195E 09	0.1975E 10	0.3110E 09
19	0.2043E 09	0.1839E 10	0.2896E 09
20	0.1862E 09	0.1676E 10	0.2638E 09
21	0.1650E 09	0.1485E 10	0.2338E 09
22	0.1423E 09	0.1281E 10	0.2016E 09
23	0.1196E 09	0.1076E 10	0.1695E 09
24	0.9687E 08	0.8718E 09	0.1373E 09
25	0.7417E 08	0.6675E 09	0.1051E 09
26	0.5449E 08	0.4904E 09	0.7722E 08
27	0.3784E 08	0.3406E 09	0.5363E 08
28	0.2422E 08	0.2180E 09	0.3432E 08
29	0.1362E 08	0.1226E 09	0.1931E 08
30	0.6054E 07	0.5449E 08	0.8580E 07
31	0.1514E 07	0.1362E 08	0.2145E 07
TOTALS	0.3372E 10	0.3034E 11	0.4778E 10

Possible Georges Bank gas reserves, production, and royalties.

Assumptions

Recoverable reserves in basin = 0.2000E 13
Recoverable reserves per field = 0.1000E 13
Number of gas fields = 2
Number of gas fields discovered each year = 1
Price of gas = $0.75

PERIOD	QUANTITY	REVENUE	ROYALTY
1	0.0	0.0	0.0
2	0.0	0.0	0.0
3	0.0	0.0	0.0
4	0.0	0.0	0.0
5	0.1850E 11	0.1387E 08	0.1564E 07
6	0.5550E 11	0.4162E 08	0.4692E 07
7	0.9250E 11	0.6937E 08	0.7821E 07
8	0.1295E 12	0.9712E 08	0.1095E 08
9	0.1480E 12	0.1110E 09	0.1251E 08
10	0.1480E 12	0.1110E 09	0.1251E 08
11	0.1480E 12	0.1110E 09	0.1251E 08
12	0.1480E 12	0.1110E 09	0.1251E 08
13	0.1480E 12	0.1110E 09	0.1251E 08
14	0.1480E 12	0.1110E 09	0.1251E 08
15	0.1413E 12	0.1060E 09	0.1194E 08
16	0.1278E 12	0.9586E 08	0.1081E 08
17	0.1144E 12	0.8577E 08	0.9669E 07
18	0.1009E 12	0.7568E 08	0.8532E 07
19	0.8745E 11	0.6559E 08	0.7394E 07
20	0.7400E 11	0.5550E 08	0.6257E 07
21	0.6054E 11	0.4541E 08	0.5119E 07
22	0.4709E 11	0.3532E 08	0.3981E 07
23	0.3364E 11	0.2523E 08	0.2844E 07
24	0.2018E 11	0.1514E 08	0.1706E 07
25	0.6727E 10	0.5045E 07	0.5688E 06
TOTALS	0.1998E 13	0.1498E 10	0.1689E 09

Possible Georges Bank gas reserves, production, and royalties.

Assumptions

Recoverable reserves in basin = 0.2000E 13
Recoverable reserves per field = 0.1067E 13
Number of gas fields = 2
Number of gas fields discovered each year = 1
Price of gas = $0.95

PERIOD	QUANTITY	REVENUE	ROYALTY
1	0.0	0.0	0.0
2	0.0	0.0	0.0
3	0.0	0.0	0.0
4	0.0	0.0	0.0
5	0.1973E 11	0.1875E 08	0.2282E 07
6	0.5920E 11	0.5624E 08	0.6845E 07
7	0.9866E 11	0.9373E 08	0.1141E 08
8	0.1381E 12	0.1312E 09	0.1597E 08
9	0.1579E 12	0.1500E 09	0.1825E 08
10	0.1579E 12	0.1500E 09	0.1825E 08
11	0.1579E 12	0.1500E 09	0.1825E 08
12	0.1579E 12	0.1500E 09	0.1825E 08
13	0.1579E 12	0.1500E 09	0.1825E 08
14	0.1579E 12	0.1500E 09	0.1825E 08
15	0.1507E 12	0.1432E 09	0.1742E 08
16	0.1363E 12	0.1295E 09	0.1576E 08
17	0.1220E 12	0.1159E 09	0.1410E 08
18	0.1076E 12	0.1023E 09	0.1245E 08
19	0.9328E 11	0.8862E 08	0.1079E 08
20	0.7893E 11	0.7499E 08	0.9126E 07
21	0.6458E 11	0.6135E 08	0.7467E 07
22	0.5023E 11	0.4772E 08	0.5808E 07
23	0.3588E 11	0.3408E 08	0.4148E 07
24	0.2153E 11	0.2045E 08	0.2489E 07
25	0.7176E 10	0.6817E 07	0.8297E 06
TOTALS	0.2131E 13	0.2025E 10	0.2464E 09

Possible Georges Bank gas reserves, production, and royalties.

Assumptions

Recoverable reserves in basin = 0.1000E 14
Recoverable reserves per field = 0.1000E 13
Number of gas fields = 10
Number of gas fields discovered each year = 1
Price of gas = $0.75

PERIOD	QUANTITY	REVENUE	ROYALTY
1	0.0	0.0	0.0
2	0.0	0.0	0.0
3	0.0	0.0	0.0
4	0.0	0.0	0.0
5	0.1850E 11	0.1387E 08	0.1564E 07
6	0.5550E 11	0.4162E 08	0.4692E 07
7	0.1110E 12	0.8325E 08	0.9385E 07
8	0.1850E 12	0.1387E 09	0.1564E 08
9	0.2590E 12	0.1942E 09	0.2190E 08
10	0.3330E 12	0.2497E 09	0.2815E 08
11	0.4070E 12	0.3052E 09	0.3441E 08
12	0.4810E 12	0.3607E 09	0.4067E 08
13	0.5550E 12	0.4162E 09	0.4692E 08
14	0.6290E 12	0.4717E 09	0.5318E 08
15	0.6778E 12	0.5083E 09	0.5730E 08
16	0.7013E 12	0.5260E 09	0.5930E 08
17	0.6996E 12	0.5247E 09	0.5915E 08
18	0.6727E 12	0.5045E 09	0.5688E 08
19	0.6391E 12	0.4793E 09	0.5403E 08
20	0.5997E 12	0.4490E 09	0.5062E 08
21	0.5516E 12	0.4137E 09	0.4664E 08
22	0.4978E 12	0.3734E 09	0.4209E 08
23	0.4373E 12	0.3279E 09	0.3697E 08
24	0.3700E 12	0.2775E 09	0.3128E 08
25	0.3027E 12	0.2270E 09	0.2560E 08
26	0.2422E 12	0.1816E 09	0.2048E 08
27	0.1884E 12	0.1413E 09	0.1593E 08
28	0.1413E 12	0.1060E 09	0.1194E 08
29	0.1009E 12	0.7568E 08	0.8532E 07
30	0.6727E 11	0.5045E 08	0.5688E 07
31	0.4036E 11	0.3027E 08	0.3413E 07
32	0.2018E 11	0.1514E 08	0.1706E 07
33	0.6727E 10	0.5045E 07	0.5688E 06
TOTALS	0.9990E 13	0.7492E 10	0.8446E 09

Possible Georges Bank gas reserves, production, and royalties.

Assumptions

Recoverable reserves in basin = 0.1000E 14
Recoverable reserves per field = 0.1067E 13
Number of gas fields = 10
Number of gas fields discovered each year = 1
Price of gas = $0.95

PERIOD	QUANTITY	REVENUE	ROYALTY
1	0.0	0.0	0.0
2	0.0	0.0	0.0
3	0.0	0.0	0.0
4	0.0	0.0	0.0
5	0.1973E 11	0.1875E 08	0.2282E 07
6	0.5920E 11	0.5624E 08	0.6845E 07
7	0.1184E 12	0.1125E 09	0.1369E 08
8	0.1973E 12	0.1875E 09	0.2282E 08
9	0.2763E 12	0.2624E 09	0.3194E 08
10	0.3552E 12	0.3374E 09	0.4107E 08
11	0.4341E 12	0.4124E 09	0.5019E 08
12	0.5131E 12	0.4874E 09	0.5932E 08
13	0.5920E 12	0.5624E 09	0.6845E 08
14	0.6709E 12	0.6374E 09	0.7757E 08
15	0.7229E 12	0.6868E 09	0.8359E 08
16	0.7481E 12	0.7107E 09	0.8649E 08
17	0.7463E 12	0.7090E 09	0.8629E 08
18	0.7176E 12	0.6817E 09	0.8297E 08
19	0.6817E 12	0.6476E 09	0.7882E 08
20	0.6386E 12	0.6067E 09	0.7384E 08
21	0.5884E 12	0.5590E 09	0.6803E 08
22	0.5310E 12	0.5044E 09	0.6140E 08
23	0.4664E 12	0.4431E 09	0.5393E 08
24	0.3947E 12	0.3749E 09	0.4563E 08
25	0.3229E 12	0.3068E 09	0.3733E 08
26	0.2583E 12	0.2454E 09	0.2987E 08
27	0.2009E 12	0.1909E 09	0.2323E 08
28	0.1507E 12	0.1432E 09	0.1742E 08
29	0.1076E 12	0.1023E 09	0.1245E 08
30	0.7176E 11	0.6817E 08	0.8297E 07
31	0.4305E 11	0.4090E 08	0.4978E 07
32	0.2153E 11	0.2045E 08	0.2489E 07
33	0.7176E 10	0.6817E 07	0.8297E 06
TOTALS	0.1066E 14	0.1012E 11	0.1232E 10