Chapter IV

DISCUSSION OF THE TECHNOLOGIES

INTRODUCTION

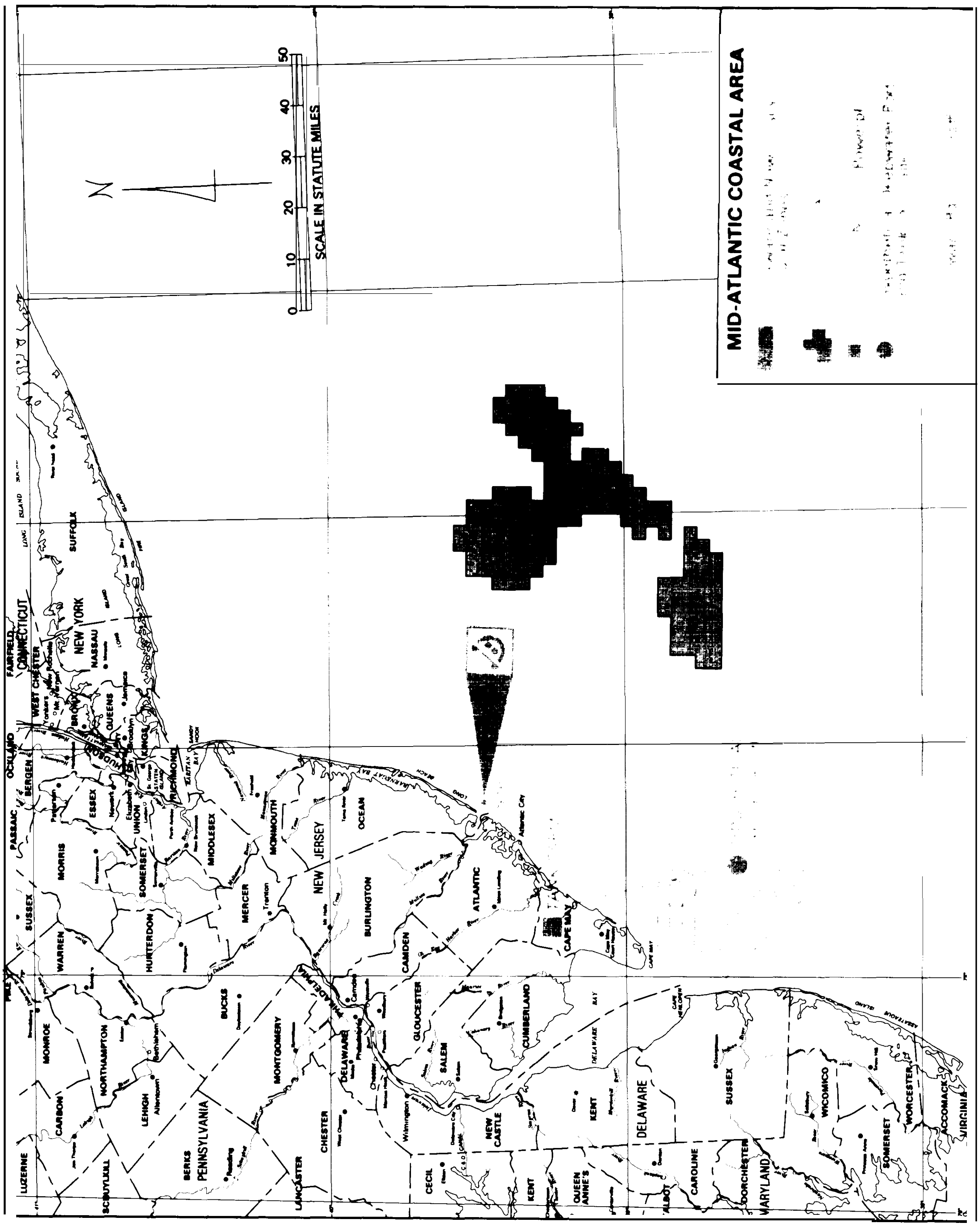
This OTA assessment deals specifically with three technologies and the potential impacts on New Jersey and Delaware of the deployment of any or all of the three in the ocean waters off the two States. Those two States, with their divergent energy and environmental needs, are described in this chapter.

The assessment involved detailed study of the equipment to be used as well as the State and Federal management systems which license, regulate, and generally oversee the deployment and operation of the three technologies. The equipment and the management systems are described and analyzed in this chapter in the context of the history, current status, and possible future development in the Mid-Atlantic of oil and gas resources, deepwater ports, and floating nuclear powerplants.

During the assessment, OTA made its own projections of deployment and resulting impacts of the technologies. Other projections have been made by industry, various executive agencies, and private study groups. In nearly every case, the differences between the many projections of impacts are the result of differences in the basic assumptions made by the various groups. Those impacts and assumptions made by OTA are specified here.

OTA also investigated what would happen if any or all of the three technologies were not implemented. The possible alternatives to oil and gas, deepwater ports, and floating nuclear powerplants and how these alternatives are being pursued are discussed in the final section of this chapter.

Figure IV-1. The coastal zones of Delaware and New Jersey



Source Off Ice of Technology Assessment, "Energy, 011 and the State of Delaware and "Inventory of New Jersey Coastal Area, 1975'

Description of the Study Area

Delaware and New Jersey—among the smallest and most densely populated of the 50 States—are a microcosm of the Nation's energy conflicts: burgeoning demand for petroleum and electric power accompanied by both a dependence on outside sources for energy and a continuing concern for the quality of life.

Wide Atlantic beaches that attract an estimated 100 million users annually[1] merge with coastal wetlands, marshes, and forests, then give way to intense industrialization farther inland.

Both States border the Atlantic Ocean; New Jersey with 126 miles of ocean coastline and Delaware with 28. Water along the ocean coast is relatively clean and most of the resort areas are located there. The States are separated from each other by the Delaware Bay, which is devoted mostly to boating, fishing, and shipping. Industrialization and pollution are heavy along the upper Bay and the Delaware River, which is at the southern end of an industrial corridor that stretches north to the Hudson River of New York.

Development in both States is clustered along the Delaware River Basin, a 300-mile long waterway which has attracted commerce and industry for three centuries.

In recent assessments of the Delaware River Basin, the Council on Environmental Quality has said the region is "at the cutting edge" of many of the environmental concerns facing America. Its water and air were among the first to be heavily polluted; its oldest cities were among the first to be changed by industrialization; its towns grew as a result of migration from Europe and from the Southern United States; its rural areas were among the first in the Nation to be urbanized by residential and industrial expansion; its mountains and beaches were among the most severely impacted by the recreation boom, With the energy shortage, it is a prime target for offshore energy systems and associated industrial development.[2]

The economic life of the two States is inextricably tied to divergent ventures: the energy-intensive manufacturing -refining - petrochemical complexes of the inland area and the tourist-recreation-fishing meccas of the coastal waters and beaches.

Both Delaware and New Jersey enacted laws to help deal with conflicts between industry and tourism. Delaware has a Coastal Zone Act which prohibits new heavy industries in the coastal zone. New Jersey has a Coastal Area Facility Review Act which sets up a permit procedure for new or expanding industry. In a further effort to plan for industrial growth, the urban sections of both States belong to regional planning commissions.

The demand for oil and electricity for increasing populations and the desire to avoid the adverse impacts associated with energy facilities in Delaware and New Jersey have produced pressures for clean sources of energy, new controls on existing energy systems and careful coordination of growth. The conflicts have posed severe planning and zoning problems and brought traditional State and local regulatory systems and land-use patterns into question. Both States are developing coastal zone management programs which may resolve some of the conflicts. They also are developing new State laws to deal with changing demands,

Neither State produces any oil or natural gas. Their energy needs are met with crude oil or petroleum product imports from foreign sources or from domestic wells along the Gulf of Mexico and natural gas from transcontinental pipelines.

Petroleum demand is expected to increase by nearly one-third by 1985. Electricity demand is projected to increase by at least one-half by 1985 assuming no change in the present growth pattern.

New Jersey, which has developed 29 percent of its total land area for housing, commerce, or industry, is the most heavily industrialized State in the Nations Increasing urbanization and industrialization are taking over New Jersey farmland at the rate of 40,000 acres a year. At the same time, New Jersey has more land in recreational uses than any other of the five Mid-Atlantic States.[4] Fourteen percent of New Jersey's land is recreational.

Delaware is predominantly a rural State with the highest percentage of wetlands and farmlands of any Mid-Atlantic State. Only 8 percent of its land is used for commerce, industry, or homes.[5]

New Jersey's recreational land serves the large populations of New York and Pennsylvania. Thirty percent of the demand for New Jersey recreational land is made by out-of-State tourists. Recreational demands are primarily for beaches and boating and are expected to almost double by the year 2000.[6] Tourism, or travel-related business, centers along the coast primarily in Atlantic and Monmouth Counties.

The tourist industry, which accounts for $3.5 billion of New Jersey's estimated $50 billion annual gross product, is second in economic importance only to the petrochemical industry. p

Petrocemicals, which depend on petroleum and natural gas byproducts for raw materials, account for $4 billion of the State's gross product. Eleven major plants are concentrated in Northern Jersey and along the borders with Pennsylvania and Delaware near a refinery complex that processes two-thirds of the crude oil refined on the east coast. [8]

When all manufacturing businesses are considered, more than 40 percent of New Jersey's 3 million workers owe their jobs to manufacturing. g Manufactured goods and petrochemical products are the primary exports from the two States.

About 31 percent of Delaware's 200,000 jobs are in the manufacturing sector.[10] The States largest industry is petrochemicals, with a complex of plants located in the Wilmington-Delaware City area at the northern tip of the State.

Tourism is ranked third among income sources in Delaware and annually generates $202 million worth of business,[11] located mostly in Sussex County. Most of the tourist business in Delaware involves fishing, swimming, and picnicking. With more than 16 million people living within a day's drive of Delaware, 87 percent of the increasing demand for sport fishing is from out of State.[12] Most of the visitors to Delaware are from the Baltimore-Washington area.

Despite the transportation demands made by both industry and tourism, neither State is amply supplied with major transportation facilities except where they coincide with the New York City to Washington, D. C., corridor. One major divided highway runs north-south through the coastal region of each State. Major rail service is limited to the metropolitan corridor and a freight service between Wilmington, Del., and Norfolk, Va., via a railroad ferry across the Chesapeake at Cape Charles. Mass transit systems are limited to the metropolitan areas.

Existing transportation probably could not support industrial and commercial activity that may result from any new large-scale development.

Two large ports serve Delaware and New Jersey. The Port of New York and New Jersey is the Nation's largest handler of imported general cargos. In 1973, the port handled nearly 218 billion short tons of cargo—primarily passengers, containers, grain, and petroleum. The petroleum terminals are mainly on the New Jersey side of the Port. The Delaware River Ports, centering around Philadelphia, have handled an increasing amount of cargo in recent years, more than 40 percent of it crude oil. Total tonnage through the ports in 1973 was 139 billion short tons.[13]

The wetlands of the two States—250,000 acres in New Jersey and 139,000 acres in Delaware—are crucial to coastal life. The areas are nursery and breeding grounds for much of the marine life in the ocean and bay. They provide nutrients which are carried by the tides into open waters to feed fish and other organisms. The wetlands provide shelter and food for waterfowl and migrating birds traveling one of the Nation's busiest flyways.[14]

In the coastal region of Maryland, Virginia, New Jersey, and Delaware, nearly 1 billion pounds of estuarine-dependent fish products are harvested annually with a wholesale value of almost $70 million. The important commercial species are menhaden, crabs, lobsters, clams, and oysters. More than a million sportmen fish in the same coastal areas annually and more than a half-million geese and ducks are harvested by sports hunters.[15]

In its final environmental impact statement on the proposed 1976 oil and gas lease sale in the Mid-Atlantic, the Department of the Interior indicated that the costs and risks associated with developing wetlands and sandy barrier islands can be very high and that destruction of the wetlands already has curtailed the productivity of some marine species.

The decline in the quality of commercial and sport fisheries in the region led to the passage of wetlands protection legislation in both New Jersey and Delaware.[16]

Behind the wetlands in New Jersey, a large and unique forest occupies most of the south central portion of the State. Known as the Pine Barrens, the area includes 1,500 square miles of sandy soil with stands of rare pine species and other plant and wildlife. Sparsely inhabited and virtually untouched by industrial development, the Pine Barrens covers a large untapped fresh water aquifer.

In this diversified area and off its shores, three new energy systems are now possible: production of oil and gas resources on the Outer Continental Shelf, construction of a deepwater port to handle petroleum imports by supertankers, and siting of the Nation's first floating nuclear powerplant. .

The offshore oil and gas leases run parallel to the southern half of New Jersey and the mouth of the Delaware Bay. The most promising site for oil and gas finds—as indicated by industry tract nominations—is located about 80 miles off Cape Henlopen, Del.

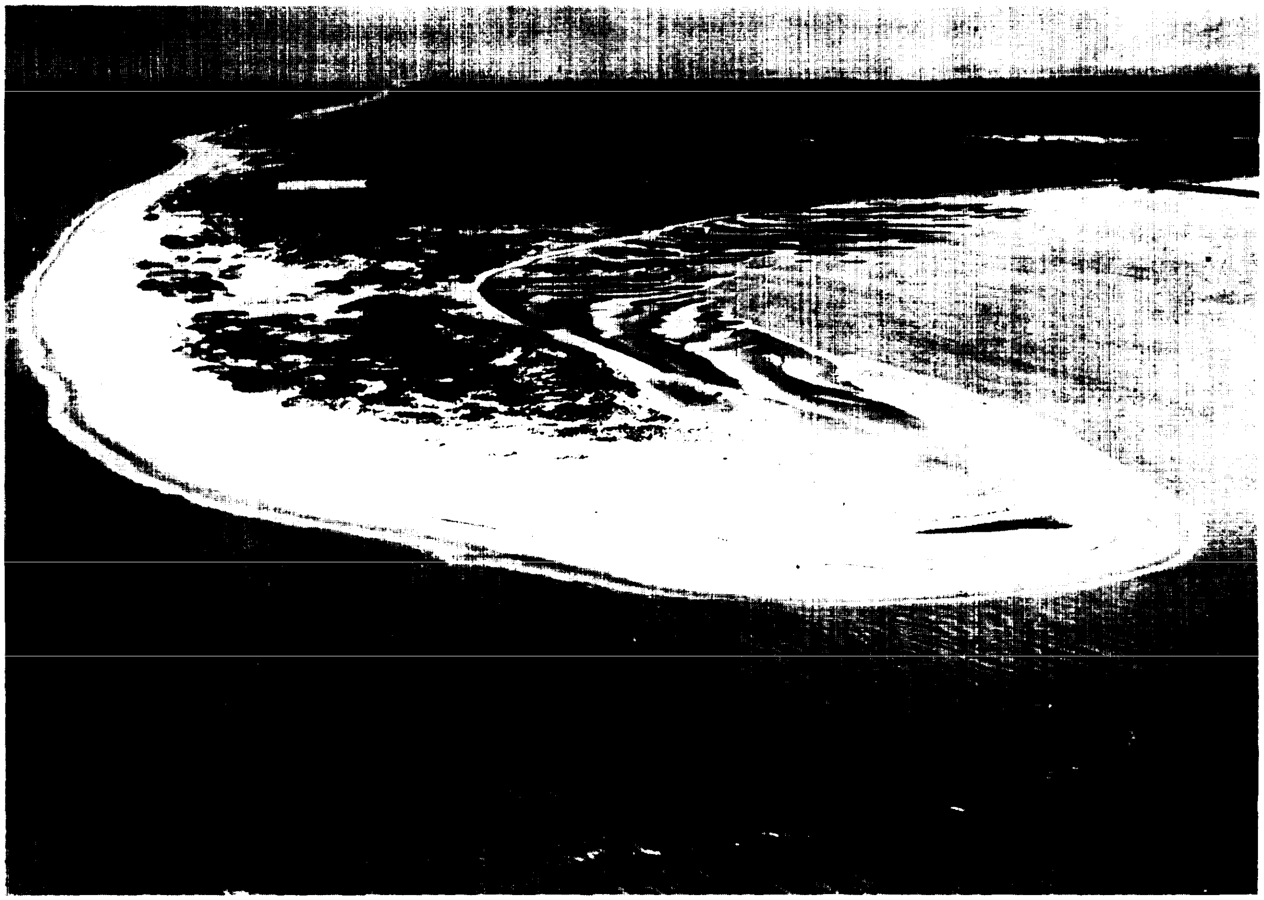
At present there is no serious proposal for a deepwater port outside the 3-mile limit of State waters in the Mid-Atlantic, but this study has determined that a likely site for an offshore deepwater port, should one be proposed, would be about 30 miles off Cape May County, N.J., across the mouth of the bay from the Delaware seashore.

The proposed site of the planned floating nuclear powerplant is off Atlantic County, N.J.

The citizens of the States reflect a wide range of views about the proposals. Industry representatives, labor, and the big city residents generally have favored the development of new energy systems off the coast of Delaware and New Jersey. Environmentalists, beach landowners, and tourist-oriented towns and businesses generally have opposed offshore development. The Governors of both States are on record in favor of exploration for offshore oil and gas if significant changes are made in the development process and Federal supervision. The Governor of New Jersey is on record in opposition to a deepwater port which would cause large-scale industrialization of rural areas, and Delaware has prohibited the port and pipeline landings by law. The Governors have taken no stand as yet on the proposed floating nuclear powerplant although New Jersey is currently investigating the risks of such a system.[17]

The position of each State in regard to the new energy systems is discussed in more detail in later sections of this chapter.

Figure IV-2. The beach at Cape Henlopen, Delaware State Park juts out into the water where the Delaware Bay meets the Atlantic Ocean. A few miles up the Bay, Lewes, Delaware, is a potential staging area for work crews and supplies that will be needed on offshore oil and gas rigs and platforms.



Source Delaware State Planning Off Ice

Development of Offshore Petroleum Technologies in the Mid-Atlantic

BACKGROUND

This study assesses the introduction of offshore petroleum development in the Mid-Atlantic region. Although the submerged Outer Continental Shelf (OCS) lands within this region were classified by geologists as a potential source of oil and natural gas in the late 1950's, they were not a priority target for development until 1974.

Initial notice of plans to develop petroleum resources on Federal lands off the Mid-Atlantic coast was given in a 5-year leasing schedule which the Department of the Interior first published in June 1971. However, in his energy message of April 18, 1973, the President announced that drilling on the Atlantic OCS and in the Gulf of Alaska would be deferred until a study of the environmental impact of oil and gas production in these areas could be carried out, The Council on Environmental Quality (CEQ) was instructed to conduct this study in consultation with the Environmental Protection Agency, the National Academy of Sciences, other Federal agencies, and the Governors, legislators, and citizens of the coastal States involved. The Council held public hearings, including hearings in cities on the Atlantic coast; established and met with an advisory committee comprised of representatives of the Governors of the coastal States; and consulted with representatives of environmental groups and industry.]

Development of the offshore petroleum resources of the Mid-Atlantic area was given high priority by the executive branch in 1974. This change in status followed the oil embargo imposed in October 1973 by the Organization of Petroleum Exporting Countries (OPEC). Accelerated development of the OCS, including the Mid-Atlantic, was one of the policies announced by the Administration for lessening U.S. dependence upon foreign sources. [2]

As initially announced, accelerated OCS development called for leasing 10 million acres in a single year, an amount roughly equal to all of the OCS land that had been leased during the 21 previous years. On the basis of its review of this decision, the General Accounting Office (GAO) reported that the decision to accelerate leasing was made "without carefully analyzing and considering several factors and problems affecting the decision's soundness."[3] The GAO concluded that the decision was hastily conceived by Interior and based on overly optimistic assumptions and inadequate data and that it was reached without considering environmental impacts, national-regional supply-and-demand needs, or alternatives to large-scale expansion of OCS leasing.

Despite the year-long CEQ study and the involvement of the State governments and citizens, OTA found that most affected parties in New Jersey and Delaware, including State and local officials, believe that the Administration's 1974 move to accelerate development off the Mid-Atlantic coast was made without giving them an opportunity to participate. They were, in part, reacting to the realization that the decision to develop the Baltimore Canyon Trough already has had significant social and political consequences for the States of New Jersey and Delaware and their coastal communities. They also were reacting to their dealings with the Department of the Interior in its role as manager of OCS resource development, Q experiences which led them to believe that few Interior Department officials recognize the magnitude and significance of the impacts that petroleum exploration and production may have on Mid-. Atlantic States and coastal communities.

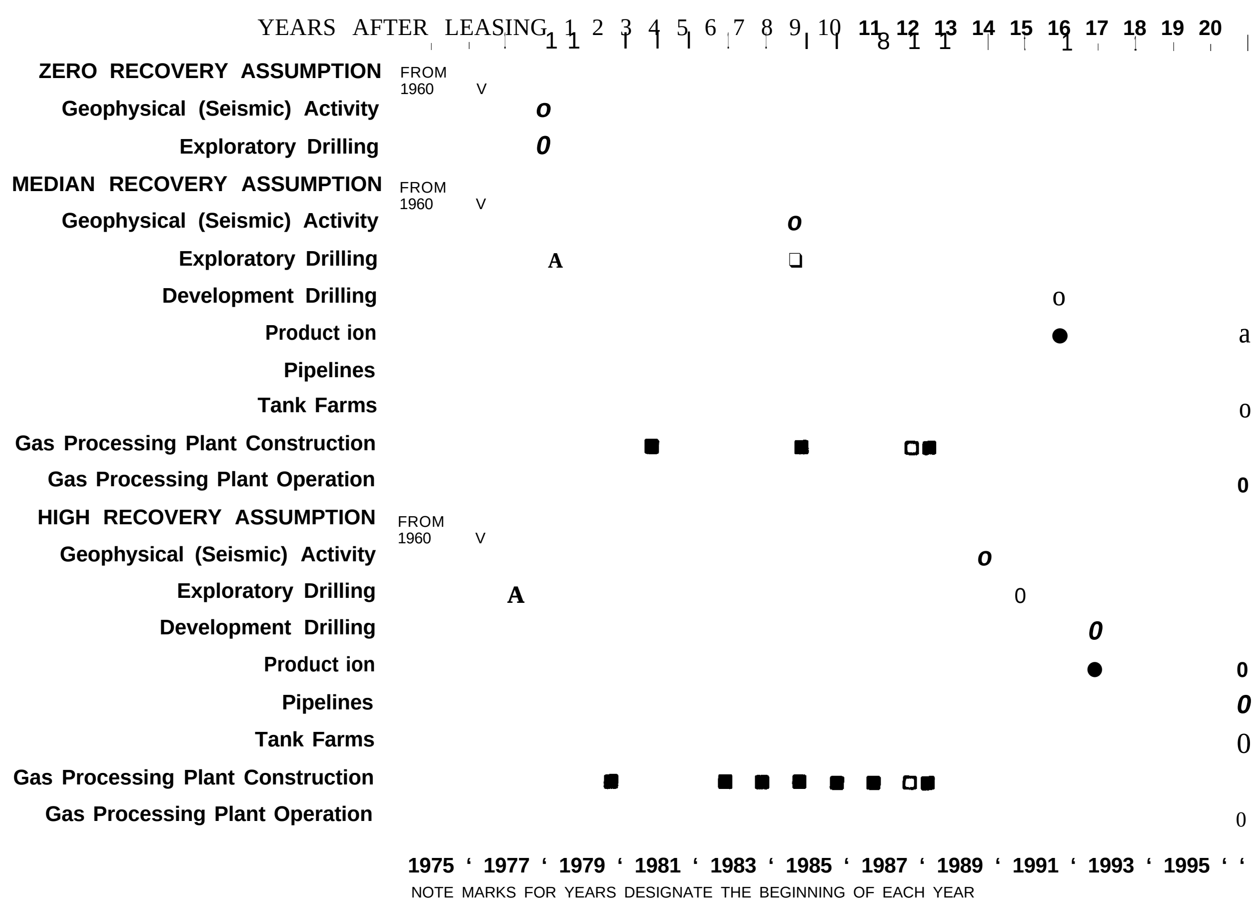
ACTIVITIES TO DATE

Seismic Surveys

Since about 1960 there has been active interest on the part of many U.S. oil companies in development of potential oil and gas resources on the Mid-Atlantic Outer Continental Shelf. The first technology which was deployed by industry to explore for potential deposits was that of seismic surveys.

Seismic survey ships have been tracing gridlines over the Baltimore Canyon Trough periodically since the early 1960's, using pneumatic or propane gas guns to generate sound waves which penetrate the rock of the sea floor and register their return to the surface on hydrophores which are trailed behind the survey ships. If petroleum exists in the Baltimore Canyon Trough, it is trapped in layers of porous rock which have been created over some 200 million years from soil, clay, and gravel which has washed to sea from the

Figure IV-3. Baltimore Canyon development activities by phase of development and by year



KEY: A First Major Discovery; ● Peak of Production; v Lease Sale; Construction; Operation;
❑ Termination of Activity; Gas Processing Plant on Line

Source Office of Technology Assessment

Appalachian highlands.[5] Because sound is reflected by different layers of rock through which it travels, the records of the sound-waves returning to the survey ships can be processed by computers to give an interpreter a detailed picture of the rock formations the soundwaves have penetrated.

A seismic survey is a rough and indirect measure of petroleum resource potential in a region and is most uncertain when it is used in a frontier area that has never been drilled such as the Baltimore Canyon Trough,

If oil is discovered in the amounts projected by geologists using seismic survey results these ships will continue to operate until 1990, overlapping the start of exploration and production drilling in an effort to outline possible areas where oil and natural gas might exist. Figure IV-3 summarizes the oil exploration and development activities that OTA has projected between now and 1995.

Although crude, seismic data is used to indicate the size and extent of potential oil fields. For this reason, the unsuccessful attempts of New Jersey and Delaware to obtain seismic data from the Government have been a source of irritation for many officials. The U.S. Geological Survey (USGS) itself has conducted some seismic surveys and the data, theoretically, could be transmitted to the States. The USGS also has various kinds of seismic data purchased or obtained from industry as a requirement for permits for seismic surveying. These data, however, are proprietary information and are not available to the States.

Delaware State Geologist Robert Jordan told OTA that, the States have been pushing USGS, without success, to make so-called "public" information available more quickly. If the USGS surveys were made available to the States 2 or 3 years in advance of a lease sale, he said, the States probably would have adequate information about the OCS for planning purposes.

Resource Estimates

It is common practice to use seismic survey data, measurements of magnetic fields, gravity and subsea geology as well as various indicators of past trapping of hydrocarbon deposits to make judgments of potential resources in a region. The oil industry invests substantially in surveys, data analysis, and expert judgments to make these estimates but does not publish specific results.

Based on seismic and other proprietary geophysical data, the U.S. Geological Survey has made several estimates of the resources in the Baltimore Canyon Trough. These estimates have changed several times over the past 2 years and even the methods of making estimates have been debated among geologists in industry and government.

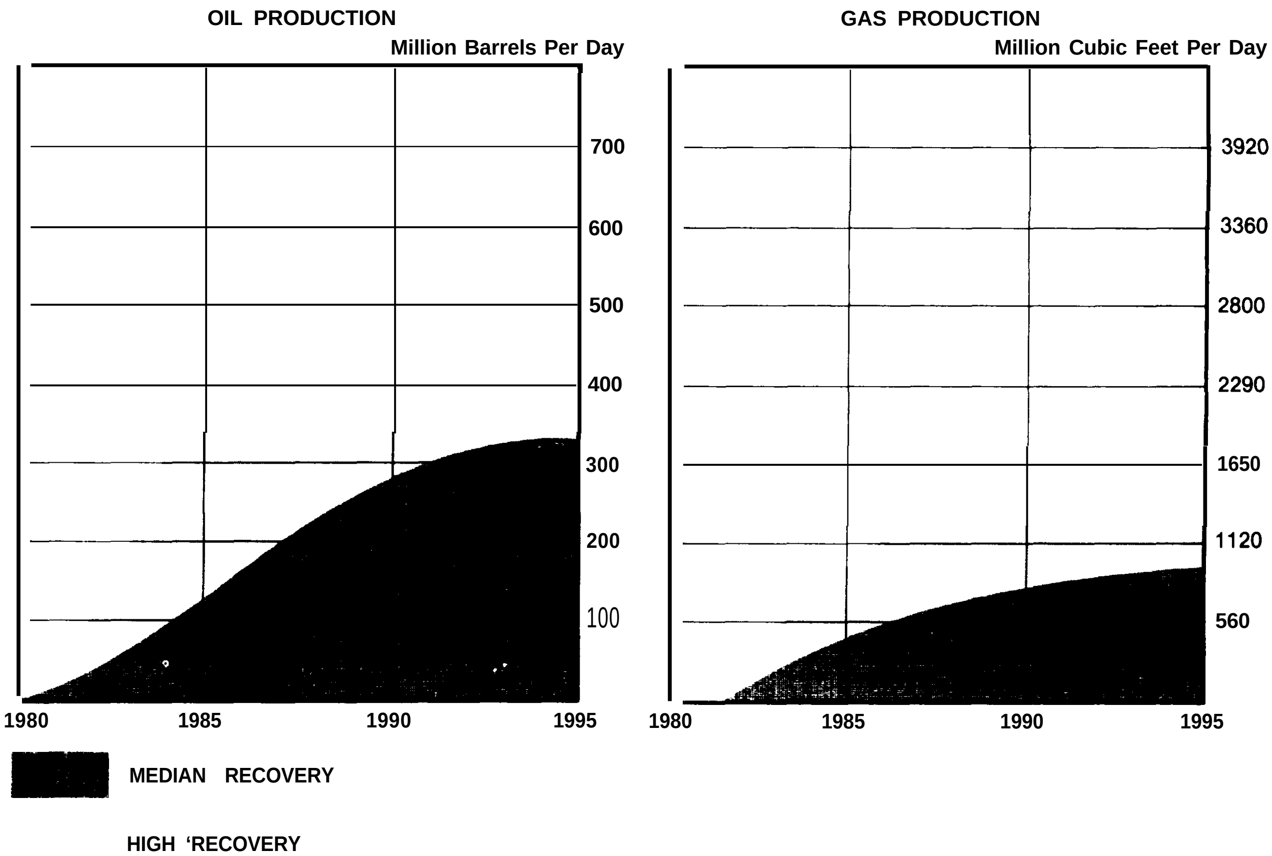
The USGS resource estimates for the Baltimore Canyon Trough were revised downward by about 50 percent in the last 2 years. The estimates are now given in terms of probabilities and ranges of possible discovery and recovery. The present estimate for the median of probable resource was announced for many OCS regions, including the Baltimore Canyon Trough in May 1975. The estimate was 1.8 billion barrels of oil and 5.3 trillion cubic feet of natural gas.[6] For the area which is being leased first, the USGS estimated in September 1975 that recoverable resources could range from 0.4 to 1.4 billion barrels of oil and from 2.6 to 9.4 trillion cubic feet of natural gas.

The continually changing nature of these figures indicates that they cannot be taken as any more than well-educated guesses about the amount of undiscovered resources.

Interior Department Preparations

Since the announcement that the Federal Government would accelerate the process of leasing Federal land on the Outer Continental Shelf for petroleum development, the Department of the Interior (DOI) and the Bureau of

Figure IV-4. Potential energy supply provided by Baltimore Canyon oil and gas development



Source U S Geological Survey resource estimates and Office of Technology Assessment development assumptions

Land Management (BLM)—Interior's leasing agency—have been preparing and proceeding with the many steps in the process. Leasing is carried out by BLM under the present system pursuant to the OCS Lands Act of 1953. A complete description of the present system is given in a March 1976 report prepared by the Congressional Research Service titled Effects Of *Offshore Oil and Natural Gas Development on the Coastal Zones.* Proposed changes as given by Senate and House bills to amend the OCS Lands Act are contained in Working Paper #l of this study. At present the Baltimore Canyon Trough region is one of more than a dozen OCS frontier areas now in the program for accelerated leasing which includes regions off the shores of all coastal States. As of this writing some of these areas have already been leased (deep portions of the Gulf of Mexico, Southern California, eastern Gulf of Alaska, and the Baltimore Canyon).

The steps up to leasing include:

- Planning and estimating the potential of a specific region;
- Selecting a lease area from industry and government-proposed targets;
- Preparing of Environmental Impact Statements and conducting environmental studies;
- Coordination of Coastal Zone Manage-

ment Programs and States' concerns for development impacts; and

- Final decision to lease, announcement of sale, and acceptance of bids from industry.

Although the Bureau of Land Management (BLM) had spent 2 years examining the possibility of accelerating lease programs before the 1973 proposal for a 10-million acre sale, they were not prepared for a sudden change of that magnitude.

In 1972, the BLM's OCS budget was $650,000 and 2 years before the Bureau had only nine staff members, some of them part time, in Washington to deal with offshore leases.[7] In the period since the acceleration program was announced, BLM has been chronically short of staff, particularly of specialists in urban land use, industrial

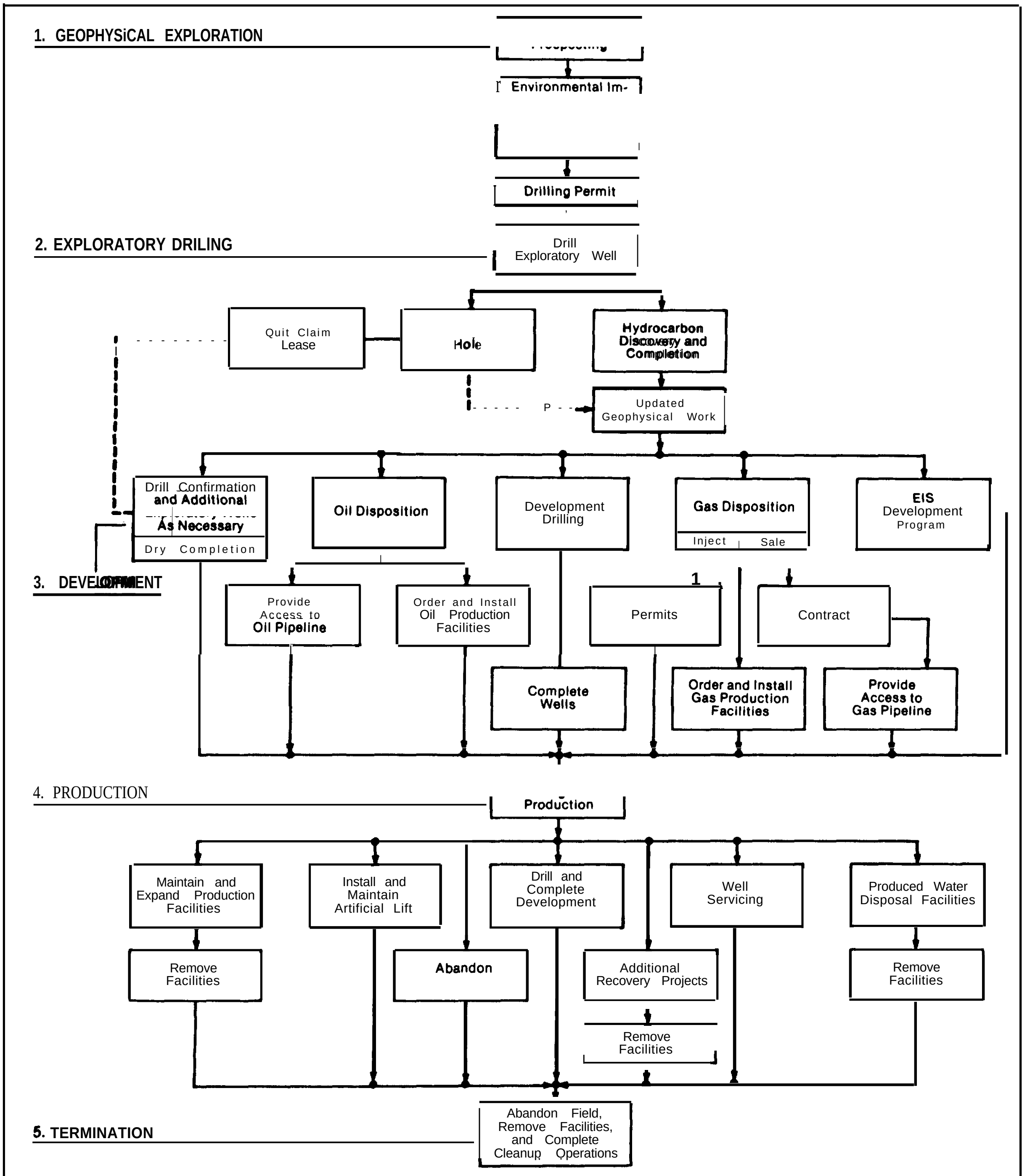
Figure IV-5. Estimates of undiscovered recoverable oil and gas resources(a) U.S. offshore areas

AREA	CRUDE OIL[b] (Billions of barrels)			NATURAL GAS (Trillions of cubic feet)		
Water Depths of 0-200 metres (includes state and Federal lands)	95% Probability (c) (e)	50/0 Probability (d) (e)	Statistical Mean (f)	95% Probability (c) (e)	5°70 Probability (d) (e)	Statistical Mean (f)
1. North Atlantic	0	2,5	0.9	o	13.1	4.4
2. Mid-Atlantic	0	4.6	1.8	o	14.2	5.3
3. South Atlantic	0	1.3	0.3	0	2.5	0.7
4. MAFLA (Eastern Gulf of Mexico)	0	2.7	1.0	0	2.8	1.0
5. Central Gulf of Mexico }(g) 6. South Texas	2.0	6.4	3.8	17.5	93.0	49.0
7. Southern California	0.4	2.1	1.1	0.4	2.1	1.1
8. Santa Barbara Channel	0.6	3.0	1.5	0.7	3.3	1.7
9. Northern California	0	0.8	0.4	0	0.8	0.4
10. Washington - Oregon	0	0.7	0.2	0	1.7	0.3
11. Lower Cook Inlet	0.5	2.4	1.2	1.0	4.5	2.4
12. Gulf of Alaska (h)	0	4.7	1.5	0	14.0	5.8
13. Southern Aleutian Arc	0	0.2	0.1	0	0.5	0.1
14. Bristol Bay Basin	0	2.4	0.7	0	5.3	1.6
15. Bering Sea	0	7,0	2.2	0	15.0	5.7
16. Chukchi Sea	0	14.5	6.4	0	38.8	19.8
17. Beaufort Sea	0	7.6	3.3	0	19.3	8.8
Water depths of 200-2500 metres ")						
4. MAFLA (Eastern Gulf of Mexico)	0	1.3	0.5	0	1.2	0.3
5. Central Gulf of Mexico }(g) 6. South Texas }	0	1.9	0.9	0	19.3	8.7
7. Southern California	0.2	2.9	1.2	0.2	2.9	1.2
8. Santa Barbara Channel	0.3	2.1	0.9	0.4	2.3	1.1

a) For assessment of maxlmurn anticipated enwronmental Impact, use of the 50/. probability resource estimate IS suggested.
'b) Natural gas Ilqutds not included. Total U S NGL resources to 200 metres water depth are calculated to be 28 billion barrels, based upon statistical mean estimates of undiscovered recoverable natural gas resources and an appropriate gas /oil ratio Information IS inadequate to warrant estimates for indlvidual areas
(c) 19 in 20 chances that *a?* least the amount estimated IS present. An estimate of O indicates that there IS less than 95%. probability of Commercial quantities **being** present Such estimates are made for frontier areas because the presence of 011 and/or gas has not yet been established by drilling
(d) 1 in 20 chance that *more than* the amount estimated IS present
(e) It IS statistically incorrect to sum either the 5°/0 or the 950/o probabtllty estimates for Indwldual areas to obtain totals for a region
[f) Mean estimates for lndwldual areas maybe summed for regional or U S totals
[g) Estimates for these two areas combined
[h) Includes Kodiak Tertiary Province
[II Estimates Ilmlted to areas where development IS underway or leaslng IS planned {n the Immediate future

Source U S Geological Survey (estimates)

Figure IV-6. Simplified flow diagram showing operations necessary for discovery, production, and abandonment of an oil field



Comply with Section 102(2)(C) of National Environmental Policy Act if Federal lease requires preparation and approval of Environmental Impact Statement **(EIS)**

NOTES: (1) Manpower requirements, while not detailed above, are substantial in all phases of the petroleum industry. All types are required, including technical, skilled and common labor.

(2) Not shown are requirements for permits and approvals by numerous Federal, State and local agencies throughout the life of the field.

Source National Petroleum Council

economics, and other skills and expertise required for analyzing coastal and other onshore impacts in States like New Jersey and Delaware.[8] Efforts have been made to remedy this and, as of early 1976, BLM had four regional offices and an OCS budget of $55 million; however, it was still short of staff in the specialty areas cited above.[9]

BLM officials were also unprepared for the reaction of Atlantic coastal States to the 1973 accelerated leasing proposal despite the reactions they had observed following events like the 1969 Santa Barbara blowout. Most of the leasing experience of BLM officials was based on development in the Gulf of Mexico, which had taken place during a time when attitudes and the social context were quite different than they were in 1974.

Frank A. Edwards, Assistant Deputy Director of Minerals and Management, BLM, said in an interview with OTA on January 30, 1976, that the Bureau "had total agreement and understanding with Texas and Louisiana. They were pro- oil and -gas and we just didn't realize at first that the other States would be so different. We didn't realize it would be so crucial to educate them and coordinate with them. "

William R. Moffat, former Director of Policy Analysis for the Interior Department, said in an interview on January 29, 1976, that the Department "had been operating in a benign environment in the Gulf. Louisiana and Texas didn't really care what we did out there. The whole ethos was different. They considered it a waste of time when we tried to coordinate with them. So, at the time, it was not obvious to anybody that we were in a whole new ball game. "

But, State and local officials in the Mid-Atlantic States responded to the leasing proposal more like Californians responding to Santa Barbara than like the people of Louisiana responding to similar accidents in the Gulf. The Mid-Atlantic States were less receptive to proposals to produce oil and natural gas off their coasts and were skeptical of assurances that the development would not disrupt existing patterns of life and land use.

Except for its Gulf of Mexico experience, BLM's background as a manager of public resources came from managing Federal mineral, timber, and grazing rights on some 450 million acres of land, mostly in the Western States and in Alaska, This background had not prepared it to meet the new challenges posed by the accelerated leasing program.

To obtain more people with the required skills, BLM has generally had to look outside the agency. This, in turn, has lengthened lead times both in terms of staffing and in terms of acquainting new staff members with Bureau activities. One result was that the New York City office, which was set up November 26, 1973, and drafted the Environmental Impact Statement for the Mid-Atlantic lease sale, still was short of its full requirement for professional staff members by 10 positions in March of 1976.[10]

The rush of events set in motion by the proposal to accelerate lease sales meant that BLM was playing "catch-up" during most of 1974 and 1975.

The net effect of BLM's experience and personnel limitations was to leave it ill-equipped to coordinate offshore development with States such as New Jersey and Delaware. In an effort to overcome these limitations and to deal with State concerns, the Assistant Secretary of Interior for Program Development and Budget was designated the OCS policy coordinator. Although State officials told OTA that the effort improved the flow of information from Interior, BLM officials said the arrangement did not always work well, partly because lines of communication between BLM and the OCS coordinator sometimes broke down.11

One such case involved an assurance by the OCS coordinator that State officials could review sections of the Environmental Impact Statement in advance of its publication. Because of standing orders within BLM, which were not rescinded after the assurance from the OCS policy office, State officials were also advised that they could review sections of the statement, but only in the New York office of BLM and only during certain hours of the day.

It was only after considerable complaining that changes were made in the BLM order and State officials were given easier access to information as it was being assembled. The misunderstanding eventually led to the adoption of internal guidelines for contact with the States through the EIS process at Interior.

The resulting guidelines, Instructional Memorandum No. 76, dealing with "Contacts with State governments through the OCS leasing process," requires that States be contacted to attend meetings during which activities like tentative tract selection are discussed, to participate in preparation of the EIS, and to review preliminary drafts of the EIS. Other procedures require that the States be informed of the EIS contents where appropriate, and advised of such activities as announcement of tentative tract selection, release of draft and final EIS, and notice of sale.

Line responsibility for OCS activities at Interior is divided between two bureaus, both of which have a wide range of other activities that overshadow their OCS responsibilities in terms of manpower and budget. The Bureau of Land Management is the lead agency in developing leasing programs and granting rights to offshore exploration and development. Once leases are signed, responsibility for supervising offshore activities passes to the U.S. Geological Survey (USGS), which is primarily a scientific agency with a limited regulatory role. The USGS is also responsible for topographic mapping, monitoring of domestic water resources, and locating and estimating the extent of deposits of all minerals under both public and private lands. The USGS drafts technical regulations for offshore equipment and operations and enforces those regulations. The regulations have been, and continue to be, more concerned with specific items of equipment than with relationships between the equipment and the total oil and gas development system.

During the 14 months ending January 1976, the former Assistant Secretary for Program Development and Budget, Royston S. Hughes, was responsible for coordination of OCS activities at the Interior Department. It was an assignment he combined with managing the Department's budget, supervising policy planning and analysis, doing economic analysis of Department programs, and dealing with environmental and natural resource policy issues.

Officials in New Jersey and Delaware and at the Interior Department said that Hughes' departure to join the White House staff disrupted progress toward opening a line of communications through which substantive issues could be argued to conclusion. State officials also insisted that the lines of communication depended on Hughes being in the position he held, not on the way in which Interior was organized to deal with the States.[12]

Despite the fact that the program to lease tracts off the Mid-Atlantic coast had moved through several crucial phases, the position of the OCS staff director was vacant from September, 1975 to March 1, 1976, when Alan Powers was hired to replace Darius Gaskins, who had returned to academic life. The position of OCS Coordinator/Assistant Secretary was vacant from the time of Hughes' resignation until May 21, 1976, when Ronald Coleman was confirmed to replace him. In the interim, the Deputy Assistant Secretary for Program Development and Budget, Stanley D. Doremus, acted as coordinator.

A plan for reorganizing the OCS offices was completed early in 1976 for consideration by the Secretary of the Interior.[13]

In general, it called for the Assistant Secretary for Program Development and Budget to continue combining OCS coordination with his other responsibilities. In addition, the plan called for a fulltime OCS director who would report to the assistant secretary. The office would be responsible for analyzing OCS policies, assuring the participation of States in decisions, resolving differences among Interior officials who have line responsibility for offshore oil development, and coordinating studies involving OCS activities.

The plan would not change line responsibility for any aspect of offshore oil development. It contained no recommendations as to the size of staff required to coordinate offshore development. The plan, in effect, continued the structure that existed before Assistant Secretary Hughes left Interior.

Based on experience of the 2 years since the Administration adopted a policy of accelerated offshore oil development and because of fragmented responsibility and lack of a single leader, the present structure probably will not be adequate to solve the problems of coordination with other Federal agencies and with the coastal States. These problems will intensify when offshore development begins in the Mid-Atlantic.

Selection of the Lease Area

For administrative purposes, the Outer Continental Shelf is divided into a chessboard pattern of tracts each containing a maximum of 5,760 acres or 9 square miles. Oil companies bid for leases by tract rather than by oil-bearing structures.

On March 25, 1975, the Bureau of Land Management, which acts as agent for the Interior Department in lease sales, called for nominations by the oil industry of tracts it would like to have offered for leases. Oil companies designated 557 tracts covering 3.1 million acres of the Outer Continental Shelf—about ha 1 f of the Trough area which runs roughly parallel to the Atlantic coast for 150 miles between New York and the north coast of Virginia, [14]

In August 1975, BLM selected 154 tracts covering 876,750 acres from among those nominated and tentatively scheduled a sale of leases for the tracts for May 1976. (See figure IV-7.) Some of the 557 tracts nominated by oil companies were eliminated because of concerns among commercial fishermen that oil operations would interfere with their activities. In other cases, BLM gave no reason for withdrawing nominated tracts from the lease sale.[15]

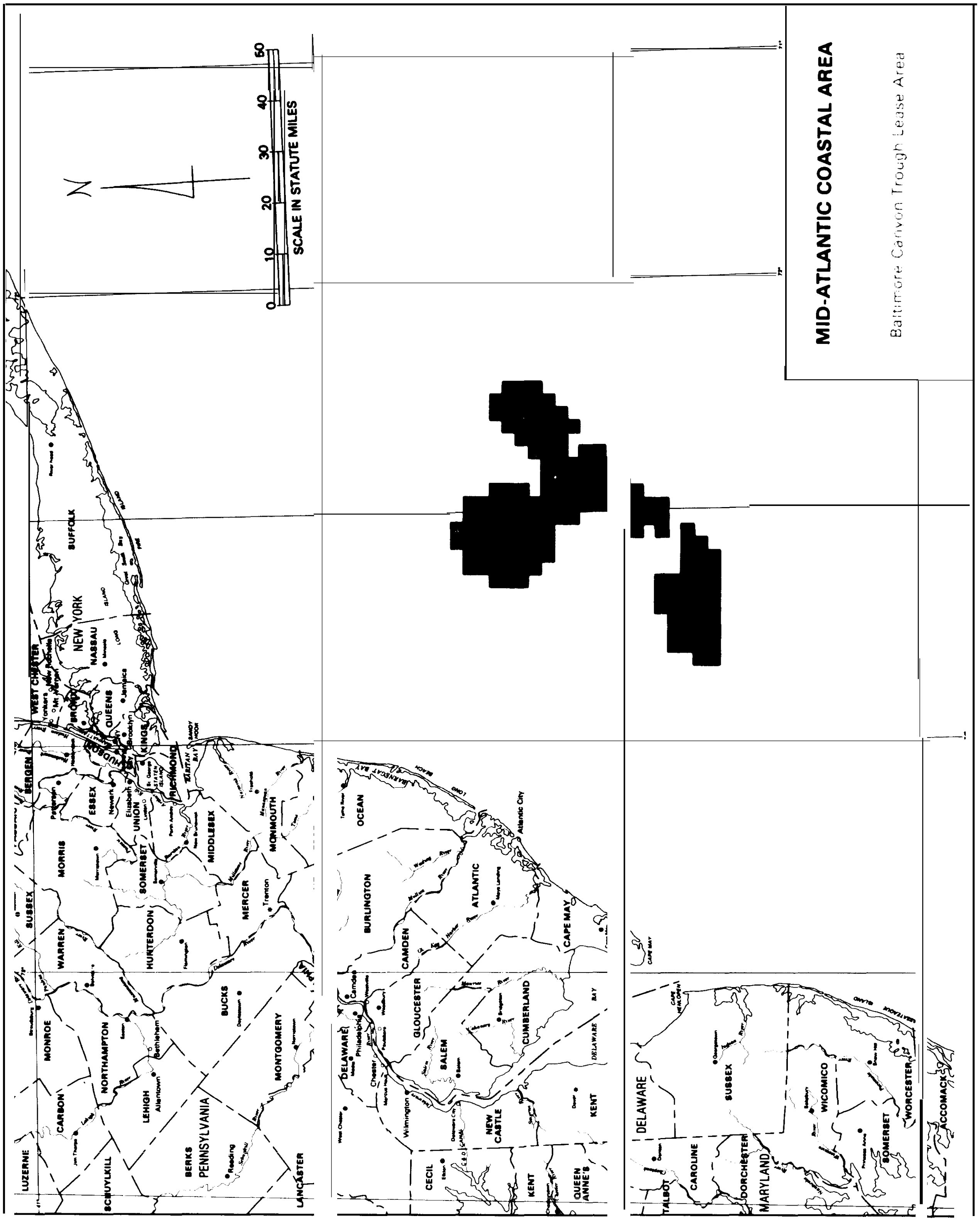
The final decision to hold the Mid-Atlantic Lease Sale #40 was made by Secretary of the Interior Thomas Kleppe late in June and the sale was finally held on August 17 in New York City.

Environmental Impact Statements

The most comprehensive packages of information which were provided to the States prior to the sale were the environmental impact statements (EIS) on the Baltimore Canyon Trough Lease Sale #40. The environmental impact statement is required by the National Environmental Policy Act (NEPA) for any Federal action that may have a “significant” effect on the environment.

Preparation of the document was largely the responsibility of the regional BLM office in New York. But staffing problems at the New York City office forced BLM to choose in early 1975 between meeting a deadline for the draft EIS and taking time to do research on coastal impacts at the county and local rather than the State level. BLM officials chose to rely on secondary data for such important data as tourist income to Cape May County and other New Jersey coastal areas. Although Interior claimed that contractor-prepared data was used for overall consistency among the tourist areas, in the case of Cape May County, the decision resulted in a basic conflict between the draft impact statement’s assessment that annual

Figure IV-7. Baltimore Canyon Trough lease sale area



Source Off Ice of Technology Assessment and U S Department of the Interior tourist receipts for the County were $33 million and County records that showed the receipts as $120 million.[16] After protests by Cape May County and the State of New Jersey, tourist income figures were revised in the final EIS to reflect the county's tabulation.

The draft EIS was issued December 10, 1975, and circulated for comments by Federal, State, and local agencies. Public hearings were held January 27–30, 1976, in Atlantic City, N.J., and the final impact statement was released May 26, 1976.

Both impact statements were prepared without benefit of recent updated guidelines or regulations as to content. The only applicable guidelines for preparation of EIS in Interior are contained in two manuals and an instructional memorandum. Neither manual is more recent than 1972.[17] No recent manuals implementing CEQ guidelines of 1973 have been issued, although BLM did say that a revised manual is currently in preparation.[18]

The environmental impact statement is supposed to guide the Secretary on the question of whether a lease sale should be held and which tracts should be leased after consideration of the proposed action, the consequences of that action, and the alternatives.

But State officials and some participants in the OTA public participation program expressed doubt that the impact statement for the Mid-Atlantic was adequate for that purpose.

The declared intent by BLM to "lease in all frontier areas by 1978," including the Mid-Atlantic, has led to an impression among New Jersey and Delaware officials that the EIS process was a procedural requirement unrelated to the actual leasing decision.[19]

Predicting the environmental consequences of any proposed action must, of necessity, involve some uncertainties and some guesswork. In the case of OCS development, some of the most specific and significant impacts cannot be predicted before exploratory drilling produces information on the quantity and location of OCS oil and gas. Despite these limitations, pre-lease environmental impact statements can be made more responsive to State needs by requiring that the EIS contain details of alternative "exploration plans, " including possible locations of onshore support facilities for exploration, complete sets of OCS orders and lease stipulations covering specific geographic regions. To insure that the EIS contains as much useful information as possible, BLM could be required to solicit—in advance of preparation of the EIS—written comments by affected States on information they wish to have developed and included. Joint Federal-State preparation of the EIS also could avoid some of the difficulties encountered in the Mid-Atlantic statement where States and localities found that information about their areas was either inaccurate or missing. An additional requirement could be imposed that would call for the draft EIS to be submitted to the affected States well before it is released, with release conditional upon State agreement that the draft contains accurate and relevant information about the States.

The basic decision as to whether an impact statement will be written is left to the Federal agency initiating the "major Federal action. " There are only departmental guidelines on what constitutes a "major Federal action" for purposes of NEPA, and Interior officials concede that ultimately the decision on whether a statement is required is "a judgmental one" made by "responsible Federal officials. "[20] In the case of OCS activities, Interior has determined that the major action is the decision to lease and prepares impact statements at that stage. Subsequent stages, such as exploration or development of the leases, are not considered major actions and separate impact studies are not made.

Presently, the State role with regard to NEPA procedures-consisting primarily of written comments and oral testimony on the draft EIS—is, at best, that of commentator. State comments on an EIS are not binding on a Secretary of the Interior when he is deciding whether to hold an OCS lease sale that would affect coastal States. State recourse to the courts is purely procedural. A State can prevail temporarily, and thus delay a lease sale, if it can argue successfully that the Interior Department has not fulfilled the obligations of the Act, but it cannot reverse a decision on the merits of its case.

States question whether the timing or the contents of recent EISs qualify as decision-making tools for the Secretary rather than as justifications for his decisions.

The National Environmental Policy Act gives the States 30 days to comment on the final EIS but Secretary Kleppe announced his decision to hold Lease Sale #40 Only 21 days after the final statement for the Mid-Atlantic was released and without waiting for all the comments to come in.

Environmental and Other Studies

The EIS is supposed to guide the Secretary on the question of whether a lease sale should be held and which tracts should be leased. But it can do that only if it contains some minimum information gathered through baseline studies which are completed before the EIS is written. Without such data a Secretary cannot decide which offshore and onshore areas are environmentally sensitive or are otherwise not suitable for drilling or for siting of exploratory support facilities. However, the environmental baseline study for the Mid-Atlantic area will not even be completed until February 1977—nearly 6 months after the lease sale.

Baseline studies are intended to provide information about the existing chemical and physical state of waters before oil operations begin so that monitoring in later years can provide scientists with data to use to determine whether changes in marine-life patterns are associated with oil production.[21]

The Bureau of Land Management presently conducts an environmental studies program in OCS regions under a general mandate to collect environmental baseline data and monitor environmental changes in offshore areas under development. Prior to initiating these studies, BLM determines the kinds and amounts of data needed in each OCS lease area, usually after consulting State and local groups and the OCS Environmental Advisory Committee and holding planning conferences and workshops to design the studies. BLM usually contracts with private or university groups for the studies or, in some cases, delegates the work to the Commerce Department's National Oceanic and Atmospheric Administration.[22]

NOAA is presently conducting a broad range of environmental studies for BLM. In the Mid-Atlantic, the Virginia Institute of Marine Science is under contract to BLM to conduct an offshore baseline study only. In all cases, lease sales are planned before any data from these studies are available and, therefore, the timing of the studies has been severely criticized.[23] It is evident that the environmental studies to date are useful neither for the EIS process or to affect a leasing decision because they are not completed in time to be used. It also is not clear whether later OCS management decisions could or would be affected by data from environmental studies. Certainly there is no firm requirement to utilize the data. Interior has even opposed legislation which would give it the power to cancel leases if serious environmental problems were identified by the studies.

Presumably, a monitoring program in an OCS region where oil is being produced may detect adverse environmental impacts. However, no formal procedures exist for using monitoring data to regulate production activities. Some State representatives claim that a formal method to tie environmental studies to management decisions is needed. Others claim that too much effort is being spent on these studies, that a minimum of critical baseline and monitoring data is needed at leasing time, and that only after a discovery is made should environmental studies receive serious attention .24

BLM also handles or regulates the collection and dissemination of other types of information in addition to that gathered in baseline studies and environmental monitoring.

One example is a contract for a comparison of costs and benefits of oil development as it relates to coastal areas. This contract was sent out for bids in February 1976, nearly a year after the call for nomination of tracts for leasing, despite the fact that the States had been expressing concern for more than 2 years that they might have to underwrite part of the costs of offshore development by providing new roads, new schools, and other public service to support an increase in population. [25]

Deadline for completion of the contract—assuming the deadline will be met—is June 1977, by which time exploratory drilling probably will be underway off New Jersey and Delaware.

Interior has explained the discrepancy in timing by saying that the study is not intended to turn out information that will be useful to the Mid-Atlantic. Rather, according to staff members in the office of the OCS Coordinator, it is intended to use the Mid-Atlantic as a model for developing a system of predicting costs and benefits for other frontier areas.[26]

In another effort to collect and distribute data, the Bureau of Land Management and the Office of Coastal Zone Management planned a series of field trips to coastal States in early 1976 to ask State officials what information they required to begin planning to cope with the onshore impacts of offshore oil and natural gas development.

However, no plans were made to guarantee that studies and analysis would be initiated to answer the questions which the States might pose to the joint teams since many departments and agencies could be involved in answering the questions. This action could further undermine State confidence in the seriousness of the Federal Government's attempt to assist them in planning for OCS development.

According to Interior staff members, the list of data needs identified by the BLM/OCZM survey will be distributed to all agencies with potential interest or responsibility in the OCS and coastal zone so that each agency can deal with the problems in its own way. In a final report, BLM will identify needs that are common to all States, needs that are common to each leasing region, and needs that are specific to certain States. This report, which will be distributed to the States and Congress as well as the agencies, is expected in late 1975.[27]

In interviews, Federal officials have emphasized the long lead-time involved in offshore development and said that they felt that the States were operating under a misapprehension that offshore development would occur suddenly. In fact, they said, platforms probably could not be installed off the New Jersey and Delaware coast before 1980 and development of the Baltimore Canyon Trough would be drawn out over a period of 20 years or more.

There is one aspect of the pattern of development, however, that could compress the lead times for offshore development. Oil companies contract with independent service companies for most of the goods and services involved in exploratory and production drilling. Some service companies would establish operations on the East Coast at the onset of exploration drilling, which could begin early in 1977. Service companies tend to cluster in the same area so that the first of these companies to establish an east coast base might very we]] make a long-lasting decision about the location of staging areas and other support facilities before either New Jersey or Delaware had completed a coastal zone management plan.

Coastal Zone Management

With the passage of the Coastal Zone Management Act of 1972, the 30 States eligible for funds under the CZM program gained a potential lever in their efforts to influence Interior Department policies. At present, however, the emphasis must be on the word "potential," because the key section of the Coastal Zone Management Act—the so-called "Federal consistency provision' '—has yet to become effective.

The Act made funds available to coastal States and territories to develop coastal zone management programs. The Act contains broad guidelines for developing such programs, but leaves a large degree of flexibility to the States to meet their particular needs. While participation is voluntary, all 30 coastal States and three of four eligible territories have chosen to participate.

On completion of a coastal management program, a State submits its program to the Secretary of Commerce who approves or disapproves the program, depending on his judgment as to whether it meets legislative requirements. If the Secretary approves a State's program, the State becomes eligible to receive funds for the implementation and administration of its program, The approval of a State program also triggers the "Federal consistency" provision.

That provision, found in Section 307 of the Act, reads, in part, as follows:

> After final approval by the Secretary of a State's management program, any application for a required Federal license or permit to conduct an activity affecting land or water uses in the coastal zone of that State shall provide in the application to the licensing or permitting agency a certification that the proposed activity complies with the State's approved program and that such activity will be conducted in a manner consistent with the program. At the same time, the applicant shall furnish to the State or its designated agency a copy of the certification, with all necessary information and data. . . . At the earliest practicable time, the State or its designated agency shall notify the Federal agency concerned that the State concurs with or objects to the applicant's certification. . . . No license or permit shall be granted by the Federal agency until the State or its designated agency has concurred with the applicant's certification or until, by the State's failure to act, the concurrence is conclusively presumed, unless the Secretary . . . finds . . . that the activity is consistent with the objectives of this title or is otherwise necessary in the interest of national security. (Emphasis added.)

During the summer of 1976, the Office of Coastal Zone Management (OCZM) drew up a draft of regulations for implementing the Federal consistency policy.

The philosophy behind the regulations centers on the mutual "cooperation" and "involvement" of Federal and State agencies and is summed up in the draft:

> . . . the consistency provisions are dependent upon the continuing cooperative, participatory and reasoned interaction of the coastal States and relevant Federal agencies set forth throughout the Act and highlighted in its legislative history. This one aspect of the many implementary activities States will undertake, will require the closest possible one-to-one involvement of the State and Federal community. The Secretary, and through him, NOAA and OCZM, will maintain responsibility for prudent administration of the Act and assuring that the views of the Federal agencies and the States are balanced within the framework of national CZM policies. In addition to its 'good offices,' NOAA will also utilize its

responsibility to evaluate the continuing performance of the States and its reporting responsibilities to the President and the Congress to assist in achieving the intergovernmental goals embodied in the Act and its consistency provisions.

The draft regulations also set up procedures for maintaining consistency of Federal projects, licenses, and permits with State coastal zone management programs. In the case of conflicts which cannot be resolved by the State and Federal agencies involved and the OCZM, the Secretary of Commerce makes final decisions "guided 'by a presumption of validity of the State agency's position except to the extent that the (Federal) applicant makes out a case for the proposed activity being either consistent with the purposes of the Act or necessary in the interest of national security or both. "

The Office of Coastal Zone Management has not finally defined "national interest" but has suggested that States meet the requirement for considering national interest by developing a policy statement concerning the national interest in their coastal zone.

The Secretary's decision on whether the Federal action shall be allowed is final, except that he is bound to report to the President and Congress on all activities and projects which are not consistent with an approved State management program.

There is some uncertainty about just how much leverage the Federal consistency provision would give a State over OCS-related activity. It is clear that having an approved coastal zone management program would give the State an additional vehicle for influencing the location of those onshore and nearshore facilities, such as pipelines, which require a Federal permit. However, because the State's objection to a proposed Federal action can be overturned by the Secretary of Commerce, Federal consistency does not provide an absolute veto over actions the State deems undesirable. Despite that limitation, the existence of the provision and the potential for delay that it gives a State should give a company seeking a permit, the permitting agency, and the Secretary of Commerce an incentive to work together to insure that State concerns are taken into account before any decisions about the location of facilities are made.

While the general relevance of the Coastal Zone Management Act to onshore and nearshore OCS-related facilities is clear, only under 1976 amendments to the Act was it specified that each Federal lease had to be submitted to each State with an approved coastal zone management program to determine whether the lease is consistent with the State program. The amendment specifically applies the consistency requirement to the basic steps in the OCS leasing process-exploration, development, and production—in an attempt to satisfy State needs for complete information, on a timely basis, about the details of the oil industry's offshore plans.

While the amendments give the States an important new point of access to the OCS decision process, they also will expedite OCS oil and gas development by specifying that once a lease is certified as consistent all individual activities described in detail in the leasing information submitted to the States also will be presumed consistent.

The leverage created by the "Federal consistency" provision is only potential at this time because no State has received approval for a coastal zone management program. In fact, the applicability of Federal consistency to OCS leasing was moot as far as New Jersey and Delaware was concerned because neither State had an approved management program at the time of the lease sale. Approved programs in both States are not expected until early 1977.

Grants to Delaware for coastal zone planning as of July 31, 1976, totaled $511,666, of which $102,000 was a supplemental grant to be used for work related to OCS development.

New Jersey grants total $1,082,750, including $377,000 in supplemental funds to be used by county planning offices to finance studies and planning for offshore development on a regional and more detailed scale than will be done by the State coastal zone planning office.

The 1976 amendments also intensify State needs for data about OCS activities and expected impacts because the amendments require that States plan for possible location of energy facilities in the coastal zone. The amendments also require that States show that they will be affected by energy facilities in order to qualify for planning grants and loans under the Act.

The Office of Coastal Zone Management (OCZM) could have a significant impact on offshore energy development when States begin to complete coastal zone plans. The Office has had a relatively minor role in offshore energy development to date. This could change when New Jersey and Delaware submit final plans and the Office- must make judgments about whether the plans make sufficient allowance for coastal zone activities that are in the "national interest" and whether, in turn, Federal activities in coastal zones are "consistent" with State plans.

State officials have expressed a hope that once coastal plans are completed the Office of Coastal Zone Management would- function as a clearinghouse for Federal activities and plans to help States sort out various Federal programs with coastal implications. They also have said they hope that once coastal plans are completed OCZM will assert authority to force coordination among Federal programs that involve coastlines.

With the passage of the 1976 amendments to the Coastal Zone Management Act, giving OCZM an additional $1.2 billion for grants and loans to coastal States, Congress has additional criteria for determining whether OCZM is adequately asserting its role as coordinator.

State Views.

The list of specific grievances which State officials say arise from existing laws and practices is long. For example:

- A decision was made within the Bureau of Land Management in January to postpone the sale of Mid-Atlantic OCS leases from May 1976 to August or later. State officials had not been advised of the decision as late as March, although the decision was common knowledge among State officials as a result of informal discussions with BLM personnel.
- The Interior Department has refused to share seismic data with State officials on the ground that it is proprietary information. State officials could purchase the data from individual seismic survey companies and pay geologists to interpret the data to give the States early warning about the possible location of major exploration activities and, in turn, about specific areas of coastal impact.[28] Delaware officials were told by the Office of Coastal Zone Management that they could use Federal grants to pay for the data and interpretation which the Interior Department declines to share with them.[29] As of August 1, the State had spent nearly $27,000 acquiring seismic data.
- The State of New Jersey proposed that the task of preparing an environmental impact statement be handled by the affected coastal States under contract to the Interior Department. The Interior Department said such an arrangement was not possible, but the Council on Environmental Quality advised OTA that it would be acceptable for the Interior Department to contract with a coastal State for data and informational support for Interior preparation of an EIS, including a State-oriented analysis of environmental impacts.

- State officials complain that there has been no single person or office within the Interior Department to which they could turn for answers to important questions about OCS development.
- They also say they have been forced to argue their right to information that should have been offered freely.
- State and county planners said that they had invested both money and manpower in gathering data to aid in assessing potential impacts of offshore energy development but that the draft EIS did not reflect the data that was forwarded to the Bureau of Land Management.
- Information which was supplied to the Bureau of Land Management about the importance of the tourist industry was not used in the environmental impact statement on the proposed Lease Sale #40 and was, in fact, replaced by inaccurate data which was obtained from other sources.[30]
- The Outer Continental Shelf Lands Act of 1953 does not provide for State involvement in offshore energy development decisions and the States claim that the Interior Department has stuck to the letter of the law.
- Some State officials feel Congress has missed the mark in efforts to provide State access to the offshore energy process. One State geologist said "The proposed legislation seems to want to shake up the system almost in a punitive fashion . . . but the States still would stand somewhat on the outside. Having more power pulled into Congress wouldn't help the States."

Under the present system, there are several stages in the process where a form of State participation is possible but not required. In a "fact sheet" dated December 1975, the Bureau of Land Management listed eight steps in the process (environmental study program, development of OCS orders, call for nominations, tract selection, draft of Environmental Impact Statement, public hearings and comments, decision by the Secretary, review of development plan) at which they note that there is "public participation."[31] The States participate at each of these stages by three basic methods: (1) serving on advisory bodies (e.g., the OCS Research Management Advisory Board); (2) reviewing and commenting on various documents (draft impact statement, development plan); (3) being "consulted" before various actions are taken (e.g., tract selection and offer of tracts for sale).

The BLM has instituted some changes in the past year "in an attempt to meet concerns expressed by the public and the States to improve the leasing program."[32] Included in the changes are provisions for State participation in the preparation of the final environmental impact statement and operating orders for leases off their shores. Interior has also issued a ban on joint bidding among major oil companies, cooperated with the States in securing access to proprietary geologic data from a stratigraphic test program for the Mid-Atlantic (although Interior officials told OTA they will not push industry to make similar information available in all cases), modified the bidding system, and proposed legislation for a loan program to deal with State needs for front-end money and a comprehensive oil spill liability and compensation plan.

Congress also is dealing with several pieces of legislation which will alter the processes involved in offshore leasing and development of oil and gas resources; establish ground rules for liability for oil spill damage; and place some aspects of energy development within the realm of the Coastal Zone Management Act of 1972.

No legislation, however, addresses the problems which the States view as most serious—problems that arise, by and large, from the way in which Federal-State relationships in OCS matters are now structured. State officials feel that they have no power to negotiate in a serious way decisions that affect their responsibility to State residents both to minimize harmful impacts that might result from OCS development and to assure supplies of energy that meet the needs of State residents generally and State industries in particular.

FUTURE ACTIVITIES

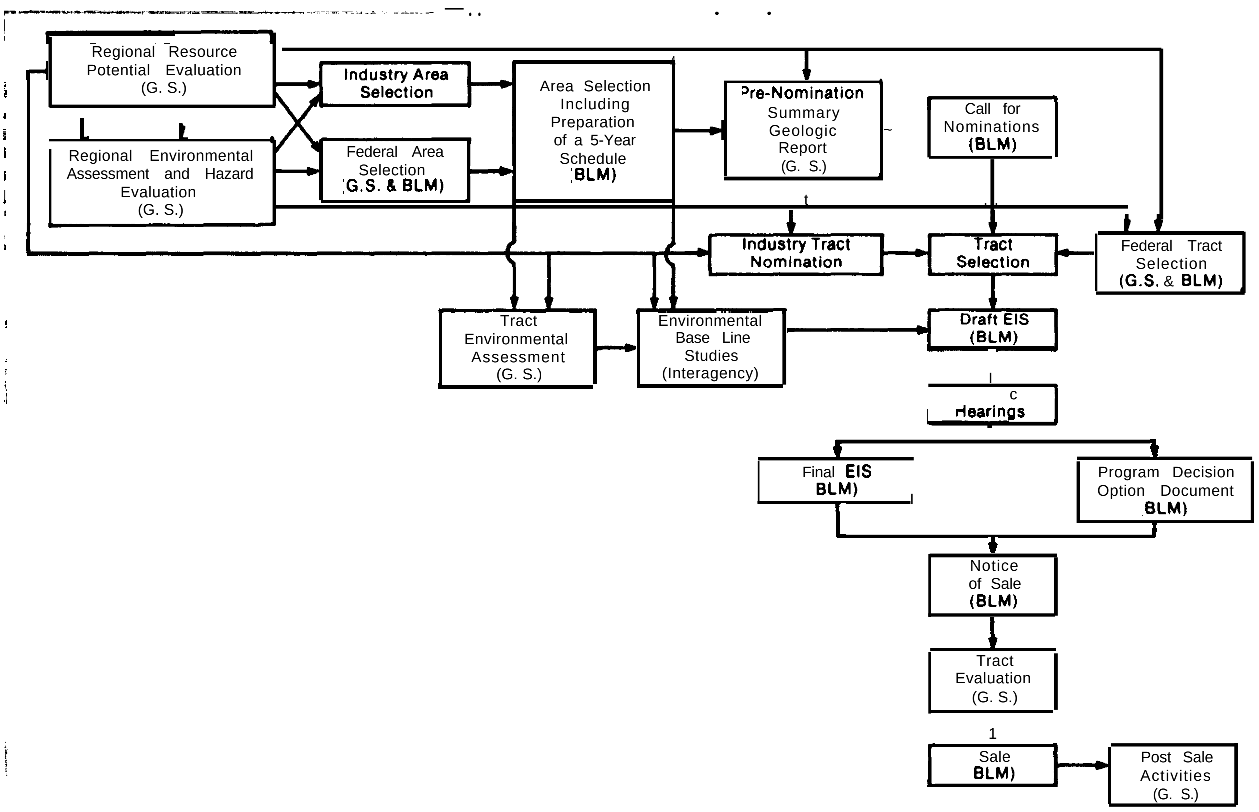
Lease Sale

The lease sale for the Mid-Atlantic frontier was held on August 17, 1976, in New York City while legislation dealing with the system for leasing and developing the potential oil and gas fields was pending in Congress.

Several U.S. Senators and Representatives asked Secretary of the Interior Thomas Kleppe to delay the lease sale until after pending amendments to the (3CS Lands Act became law.

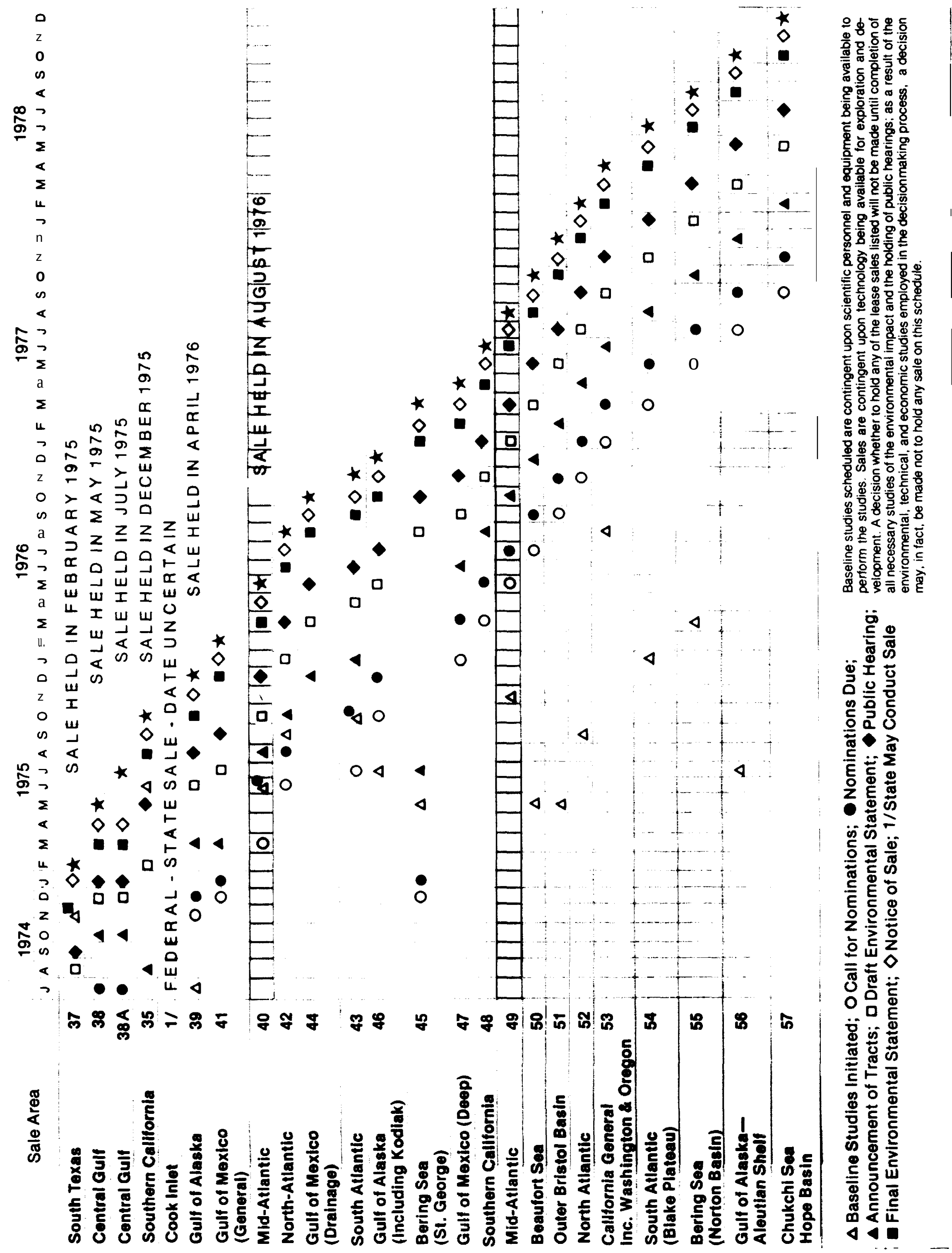
Kleppe responded that he felt "it would not be in the national interest" to delay because legislation had not yet been enacted and signd into law by the President and it was not clear that it would be.

Figure IV-8. OCS leasing procedures: information flow into decision points



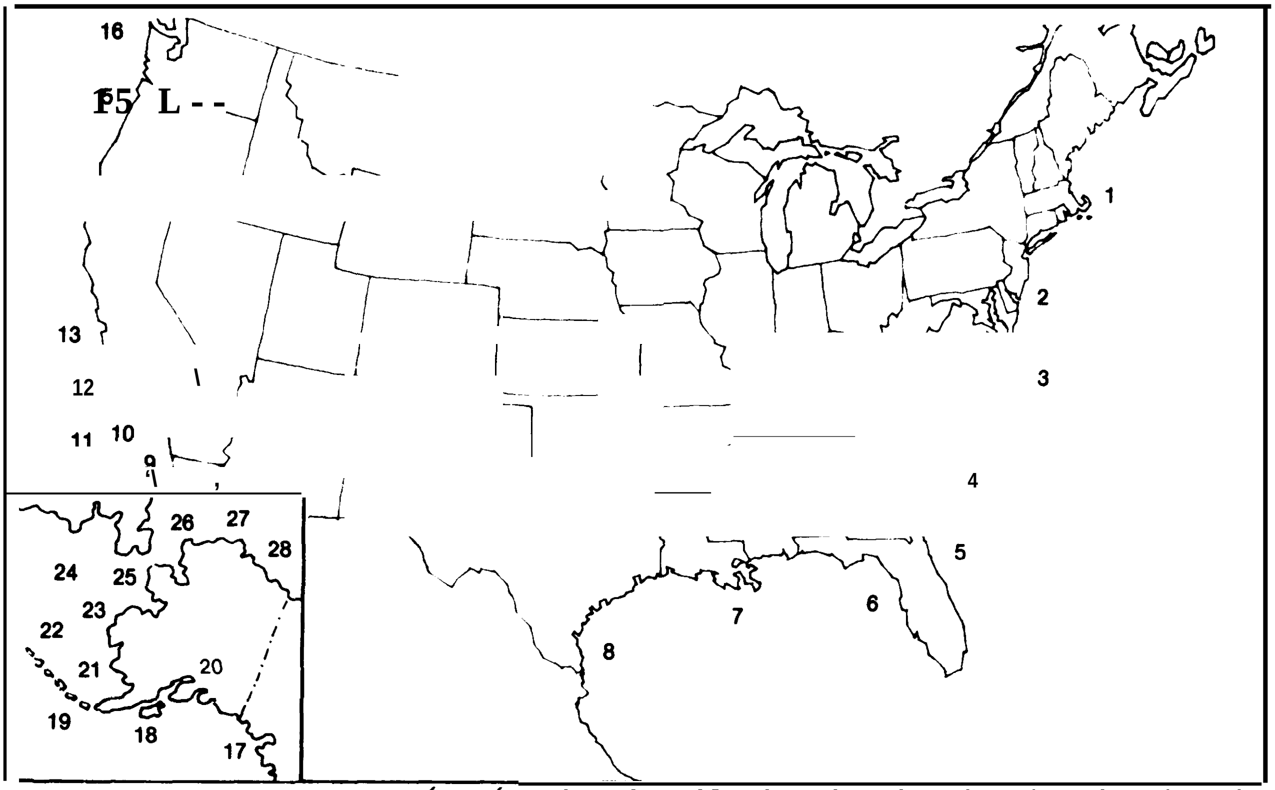
Source" Draft Environmental Impact Statement Proposed Geological Geophysical Expiration, Department of the Interior, May 1975

Figure IV-9. Proposed OCS planning schedule (June 1975)



Source U S Department of the Interior

Figure IV-10. Ongoing activities in U.S. offshore areas



Area	No.	Regional Studies	Reconnaissance Seismic	Basin Evaluation	Prospect Detection Seismic	Prospect Delineation Seismic	Prospect Evaluation	Tract Evaluation	Bid Preparation	Sale	Exploratory Drilling	Platform Construction	Development Drilling Completed	Production
Georges Bank Trough	1													
Baltimore Canyon Trough	2													
Cape Fear Arch	3													
S.E. Georgia Embayment	4													
Blake Plateau Trough	5													
Gulf of Mexico Eastern	6													
Central														
Western	8													
California Borderlands	9													
Santa Barbara Channel	0													
Santa Maria Basin	1													
Santa Cruz Basin	12													
Arena Bodega Basin	13													
Eel River Basin	14													
Astoria Basin	15													
Olympic Basin	16													
Gulf of Alaska	17													
Kodiak Shelf	17													
Aleutian Shelf	19													
Lower Cook Inlet	20													
Bristol Basin	21													
St. George Basin	22													
Bering Shelf	23													
St. Matthew Basin	24													
Norton Basin	25													
Hope Basin	26													
Arctic Offshore Basin	27													
Beaufort Basin	28													

Source Shell 011 Company

Kleppe said that in his opinion the present leasing program was not "seriously deficient" and the legislation under consideration would not clearly improve existing practices. In addition, he said, most of the provisions of the proposed legislation would be fully effective on Mid-Atlantic leases and others already issued.[33] However, a major section of the proposed legislation deals with State participation in the leasing decisions and with methods of leasing to insure competition among oil companies and participation of small firms. Those provisions, of course, could not be retroactive to leases which had already been sold.

Kleppe's determination to hold the lease sale on August 17 also ignored the fact that the State of New York, the Natural Resources Defense Council, Nassau County, N.Y., and Suffolk County, N.Y., had filed suit to halt the sale.

The sale set in motion events that will lead to at least some land and water impacts on Delaware and New Jersey whether or not oil and gas are discovered.

Virtually every phase of oil and gas exploration and development off the coast of New Jersey and Delaware would alter the physical, biological, and social environment to some degree. The biological environment could be affected by oil spills and other pollutants. The physical environment could be altered by the installation of platforms, the drilling process, the construction of pipelines, and the clearing of space for warehouse and service facilities. The social environment could be affected by expected increases in job opportunities, increases in population, and expanded need for public services.

Much of the information that is required to predict the degree to which the environment could be altered is unavailable. Much of what is available is based on resource estimates which may or may not be proved valid when actual drilling is undertaken. That situation cannot be changed but other types of data, such as that on the effects of oil spills, can be improved by additional research.

The moving force in leasing, exploration, and development is the oil and gas companies operating on the basis of developing maximum energy resources at minimum cost. Their actions are monitored, regulated, and guided by as many as 15 Federal agencies, two State governments, and a number of county and municipal governments.[34]

Top management of an oil company is involved in major decisions concerning Outer Continental Shelf activities at two points:

1. On the question of whether to bid for a lease on OCS tracts and at what price; and
2. On the question of whether to commit major funds for development on the basis of exploratory drilling results.

Most corporate decisions on bids are based on formulas that include such factors as a company's tax position, cash flow, and production costs and emphasize both the geological data available on a field and the price a company anticipates it will get for the oil once production has started.

Because offshore drilling platforms range in cost from $25 million to $50 million, depending on the depth of the water in which they are to be placed and many other factors, proceeding with development is a major management decision.

Other decisions during development of an OCS field are, by and large, technical and engineering decisions rather than policy decisions.

OTA studied the technology and deployment patterns that probably would follow the leasing of OCS land off New Jersey and Delaware as well as resulting impacts which could be projected through 1995. After Mid-Atlantic tracts are leased, the following actions will take place. The extent of each will depend on the quantity and location of oil and gas that may be discovered:

- Exploratory drilling of the most likely prospects for discoveries;
- Planning of production facilities for any fields located;
- Further development and delineation of oil or gas fields to determine actual production potential;
- Construction and installation of production platforms, pipelines to shore, and other offshore production facilities;
- Construction of shore facilities for processing, transporting, or utilizing any oil or gas produced;
- During all steps above—provision of offshore and onshore support: ships' personnel and equipment;
- Actual production of oil and gas for periods up to 20–30 years thereafter.

Many government and industry projections have been made of the number of drilling rigs, support equipment, personnel, and facilities that might be developed after a lease sale in the Baltimore Canyon Trough. During this assessment OTA projected certain deployment patterns for the New Jersey and Delaware study region. While some of the projections differed. from previous ones by industry or government agencies, the differences given were small compared with the great uncertainties associated with the oil exploration and production business.

The following sections dealing with future technology deployment and possible impacts are based on some major assumptions stemming from these OTA projections, as follows:

- Exploratory drilling will start by mid-1977.
- Total potential oil reserves in the Baltimore Canyon Trough range from a median of 1.8 billion barrels to a high of 4.6 billion barrels.
- Total potential gas reserves in the Baltimore Canyon Trough range from a median of 5.3 trillion cubic feet to a high of 14.2 trillion cubic feet.
- There is a one in twenty chance that no oil or gas in commercial quantities will be discovered.
- Given the above, OTA has, in turn, made assumptions about production levels, rig deployment, employment, and land use. These assumptions are shown in figure IV-11.

Exploration and Its Impacts

A final period of intensive seismic surveying probably would follow the signing of the first leases in the Baltimore Canyon Trough, after which exploratory drilling rigs would move onto station and begin drilling, probably within 6 months of the lease sale.

Based on current practice, industry probably would first move three rigs to the best lease prospects. If early exploration provided evidence that oil resources in the area were large, the number of exploratory rigs on station could grow to 10 during the first phase.

EXPLORATORY RIGS

Three classes of exploratory rigs, which are self-contained drilling platforms designed to be moved from area to area in an offshore development field, could be used in the Baltimore Canyon Trough area. They are drill ships, jack-up rigs, and semi-submersible rigs.

Jack-up rigs are large, complex platforms-up to 300 feet on a side-containing drilling equipment, crew quarters, and storage. They are support by massive steel legs that are lowered to the ocean floor and then used to jack the rig decks up 50 to 60 feet above the sea surface.

Semi-submersible rigs are similiar large platforms which are supported by steel legs that are mounted on submerged pontoons. When operational, the pontoons float below the sea surface and the legs extend through the surface to hold the platform 50 to 60 feet above the water. They are usually moored to the sea floor with large anchors.

Drill ships contain the same equipment, quarters, and supplies as semi-submersibles arranged instead aboard a large ship, thus providing selt-propulsion capability.

The arrival of exploratory rigs would start in operation a system of support that would expand as the field was developed.

The rigs normally carry a crew of more than 100 persons who work 12-hour shifts for 7 to 14 days. Such a system requires about 217 people, including some shore supervisors. If existing practice were followed, more than half of the crews of exploratory rigs would return to the Gulf of Mexico area when they were on leave. In addition, a large shore and workboat support force would be required, reaching a total of about 260 workers for 10 exploratory rigs.

Figure IV-11. OTA assumptions for oil and gas development in Baltimore Canyon Trough at peak production of median- and high-recovery projections (reached about 1992)

OIL AND GAS PRODUCTION

	Median Recovery	High Recovery
Oil Production (in million barrels per day)	313,000	650,000
Gas Production (in million cubic feet per day)	844	1,933

DRILLING RIG DEPLOYMENT

	Zero Discovery	Median Recovery	High Recovery
Exploration Rigs (from start to peak)	3	3-5	3-1o
Production Rigs (peak level)	0	25	52
Production Wells (peak level)	0	600	1,248

EMPLOYMENT FROM ALL OCS ACTIVITIES IN NEW JERSEY AND DELAWARE

	Median Recovery	High Recovery
Direct Employment (peak–reached about 1985)	4,500	9,000

LAND USE FOR ALL OCS ACTIVITIES PROJECTED

Activity	Land Required
Geophysical Surveys and Support	Docking space for one or two ships in coastal ports
Exploratory Drilling support	5 acres per rig in coastal ports
Platform Construction	500-1,000 acres for one major fabrication facility
Piatform Installation support	Docking space for tugboats and crane barges in a iarge port
Development Drilling support	5 acres per rig in coastal ports
Pipeline Construction support	Docking facilities and storage of 10-20 acres in large port
Oil and Gas Production support	½ acre per platform in coastal port
Pipeline Corridors	2 corridors: approximately 90 miles total onshore, 20 miles each in coastal zone, 7.5 acres/mile right of way
Tank Farms	2 sites near the coast; total 50-75 acres
Gas Processing Piants	100 acres per plant near the coast

NOTES:
- Gas processing plants will be built in the region to handle all gas produced but no new refineries are expected
- Onshore pipelines and tank farms will be the major permanent coastal facilities required to handle the transportation of OCS oil produced
- Support bases for exploration and development drilling will be located at coastal ports in the region such as Atlantic City, Cape May or Lewes, Delaware
- Construction of platforms and support for major operations such as pipelaying may take place partially in the major port areas in the region and partially at traditional construction sites outside of the region

Source Off Ice of Technology Assessment

On the average, each exploratory rig would require about 5 acres of onshore land for logistic support. The total land requirement for this activity would peak at 25 acres under the median recovery assumption and at 50 acres under the high recovery.

This land for logistic support, known as staging areas, would serve as supply centers for offshore drilling operations. The staging areas will be the flowthrough points for drill pipe, drilling mud, fuel, repair parts, food and other materials required to maintain round-the-clock drilling operations on offshore platforms. The staging areas may be located on the coast or at deepwater harbors.

Supply boats would transport materials, and helicopters would move crews to and from the rigs and staging areas and respond to emergency calls for small items of equipment.

REGULATIONS

The U.S. Geological Survey, principally through OCS orders and other lease stipulations, regulates OCS technology and related activities. Recent studies have concluded with recommendations for several changes, including more stringent regulation of oil spill prevention equipment and techniques, better equipment standards, and increased inspection and training.

These studies have been conducted by the National Aeronautics and Space Administration, the USGS, the General Accounting Office, the National Academy of Engineering, and the Council on Environmental Quality. Recommendations have been submitted to the Department of the Interior with some regularity since 1971 and a USGS Work Group was formed to review these and recommend action.[35]

Few of the substantive recommendations of these studies—which included development of comprehensive standards and specifications, improved training, and improved inspection and enforcement practices—have been reflected by changes in proposed OCS orders for the Mid-Atlantic or other regions such as Alaska. The USGS, in fact, debates the need to complete orders and inspection plans prior to a lease sale. The USGS has, on the other hand, instituted a number of the procedural recommendations of these studies and others are planned.[36]

The USGS decided that in the case of the Mid-Atlantic, orders on platforms and pipelines would not be issued until some unspecified time after the lease sale and that inspection procedures would be established only after exploration and development activities take place. (In the case of the Gulf of Alaska OCS sale, the Council on Environmental Quality recommended that OCS orders be developed and that the sale be delayed until they were issued, but the Department of the Interior proceeded with the sale without changing its procedures.)

Development Plans

There is no assurance that oil or gas will be discovered in the Baltimore Canyon; until it is, it is not possible to predict with any certainty what kind of platforms, well completions, pipelines, pumping stations, and processing equipment may be employed. If a discovery were made, however, specific planning would begin. Each offshore operator would be required to submit a development plan for approval to the Interior Department prior to any production.

Most development plans prepared for the Gulf of Mexico have been brief descriptions and have not covered any parts of the system which were not located on the lease block.

The fact that exploratory drilling must be conducted before definite information on the reserves and, therefore, on specific onshore requirements in the development phase are known has led States to advocate separation of exploration from development.[37] State officials say they are entitled to information about onshore impacts gained from exploration before a decision is made to permit development to proceed.[38]

On November 4, 1974, the Interior Department published a revision of 30 CFR 250.34 which requires offshore oil and gas operators to submit it to States both a technical devolopment plan and a description of activities that would be associated with development.

The regulation requires operators to deliver a development plan to the States 60 days before it is filed with the Interior Department and a supplemental description 30 days before the development plan is filed.

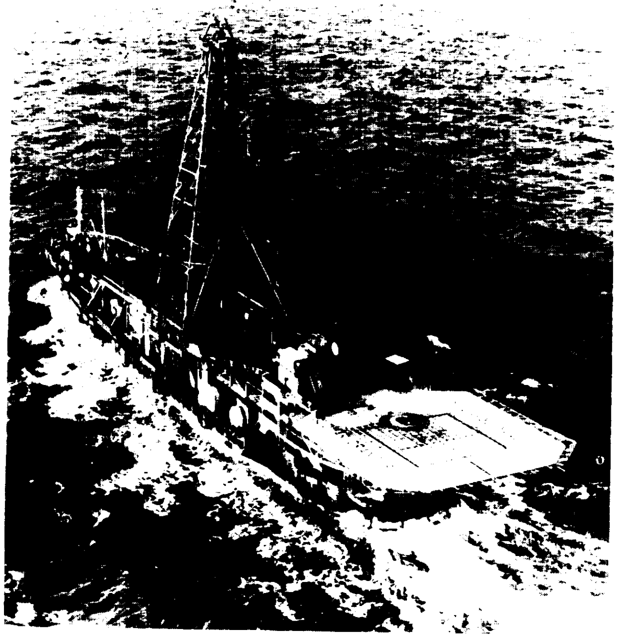
Governors would be invited to comment on development plans but final decisions on whether plans contained sufficient information to meet either the terms of the regulation or the needs of the States would be made by the USGS's area oil and gas supervisor.

While regulations on development plans do require the industry to provide certain information to the States and while officials at In-

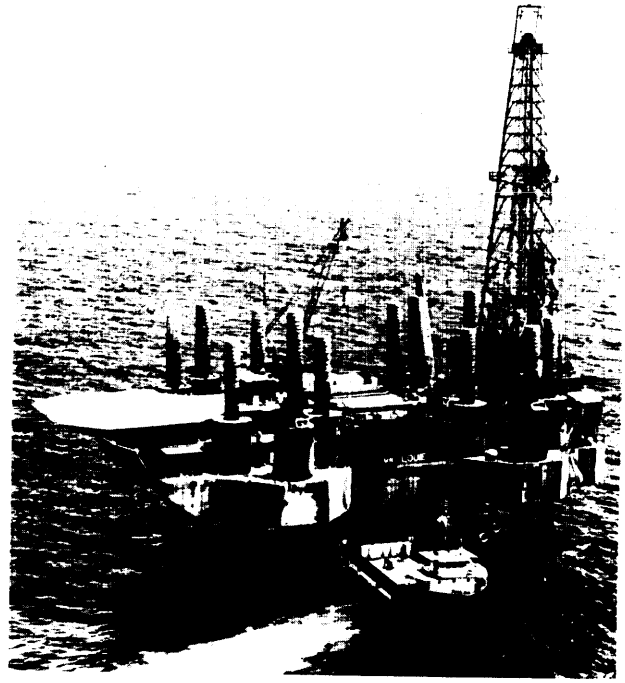
Figure IV-12. Drilling crews work with the drill string at an offshore well similar to those which will be put down in the Mid-Atlantic.

Source Shell 011 Company

Figure IV-13. Three exploratory rigs for possible use in the Mid-Atlantic



Drill ship — Source: Exxon Oil Company.



Jack-up rig — Source: Mobil Oil Corporation.

Semi-submersible **rig** — Source Marine EngineerIng/Log terior are now asking the States what information they believe should be included in development plans, there is no description in law or regulations that specifies information that is to be provided to the States in development plans or related impact statements.

information that could be required for inclusion in inidustry plans and in supplements to standard development plans include:

- description, quantity, and location of the resources discovered;
- complete description of the oil and gas production system, including platforms, gathering lines, pumping facilities, separation equipment, and pipelines;
- all operating procedures, including environmental and other safeguards and how these will be maintained;
- a detailed analysis of the site-specific environmental conditions for the offshore, nearshore, and onshore areas where oil and gas has been found and at which platforms and pipelines would enter; and
- a detailed description of the size, required land, personnel, and proposed sites for each onshore facility, including pipeline corridors, staging areas, supply boat docks, tank farms, gas processing plants, and transportation plans for all elements of the operation.

Figure IV-14. Assumed rates of exploratory drilling

Year	Zero Recovery Assumption		Median Recovery Assumption		High Recovery Assumption	
	Rigs	Wells	Rigs	Wells	Rigs	Wells
1977	3	12	3	12	3	12
1978	3	12	3	12	3	12
1979			5	20	6	24
1980			5	20	8	32
1981			5	20	10	40
1982			5	20	10	40
1983			5	20	10	40
1984			5	20	10	40
1985			5	20	10	40
1986					10	40
1987					10	40
1988					10	40
1989					10	40
1990					10	40
1991					10	40
Total Exploratory Wells		24		164		520

Summary of Assumptions

- Drilling Begins in 1977
- Each rig drills 4 holes/year
- Basis for drilling program
  - Zero Case: Stop in two years
  - Median: Explore 7 major traps plus additional exploration in intermediate traps
  - High: Explore 7 major 23 intermediate traps plus additional exploration

Source Office of Technology Assessment

The overall timing of the field development and production should be described, as well as the specific timing of each of the required facilities.

An EIS could be required to accompany development plans. The question of whether an EIS should be prepared is now left to the discretion of the USGS area supervisor (CFR 250.12). Such an EIS should incorporate all data gathered since the preparation of the draft EIS and throughout the exploratory phase as well as data to be gathered as soon as the industry begins to make proposals about specific aspects of the development plan. Included in this information should be:

- shallow geologic and oceanographic descriptions, including sediment behavior and identification of hazardous areas;
- biologic descriptions, including identification of sensitive areas;
- meteorological information; and
- information on other ocean uses in the area.

The EIS, which should be prepared jointly by the Federal agency and the affected States, should then compare various locations for each type of onshore and nearshore facility (including pipeline corridors) in terms of environmental and other consequences and should evaluate each set of alternatives with regard to consistency with the State's coastal zone management plan or comparable statements of State planning objectives for the coastal zone.

Production and Its Impacts

At peak production under the high-recovery assumption, the daily flow of oil and natural gas from the Mid-Atlantic would be 650,000 barrels a day. By comparison, the entire Gulf of Mexico, where proven reserves are dwindling, is now producing about 800,000 barrels a day.

The series of actions involved in production would have environmental, economic, and institutional consequences for New Jersey and Delaware. OTA has assumed, for the purpose of this section, no change in existing laws, regulations, or practices among oil companies or Federal, State, and local regulators.

None of the information that has been gathered during the study leads OTA researchers to conclude that oil and gas development off the Mid-Atlantic coast would produce irreversible damage or changes in patterns of life in either State, provided that the technologies were properly planned and engineered and their operations were strictly monitored. State officials, including Gov. Brendan T. Byrne of New Jersey and Gov. Sherman W. Tribbitt of Delaware, have said publicly and privately that they have reached similar conclusions.[39] They also have said repeatedly that in view of the potential for damage to their coastal areas, which are valued both for their environment and for the tourist income that they produce, the governors have an obligation to satisfy themselves that offshore development would be conducted at least as prudently as the States would proceed if they had control over the process.

PRODUCTION PLATFORMS

Working decisions during the development of a field are made by the oil company chosen as operator of the field by the owners of leases over the oil trap. The operator would contract for engineering studies for a development plan for the Baltimore Canyon Trough area, including locations of platforms, design, and locations of pipelines and size and location of tank farms. It is not likely that all elements of the system would be included in a first plan for development. The operator also would oversee construction of platforms and pipelines. In most cases, goods and services involved in developing offshore oil are provided under contract by independent companies.[40]

Production drilling would follow roughly the same pattern, insofar as offshore activities are concerned, as exploratory drilling, except that the flow of men and materials would be substantially heavier.

Depending on size, location, and extent of possible field discoveries, between 25 and 52 production platforms, each standing as much as 650 feet above the ocean floor and 60 to 70 feet above the ocean surface, would be deployed offshore. Each platform would be capable of handling 24 producing wells. Assuming discoveries in the median range, the last of 25 production platforms would be in place 14 years after the lease sale, and the last wells would be drilled 17 years after the sale. If discoveries of closer to 4.6 billion barrels were made, 52 platforms would be placed offshore, the last one some 15 years after the lease sale.

The type of platform that is most common in the Gulf of Mexico and most likely to be used off the Mid-Atlantic coast is the conventional tower or "jacket" design, a four-cornered framework of large steel pipe with legs generally 4 to 6 feet in diameter. Once the platform was in place and secured to the ocean floor by pilings, drilling decks and crew quarters would be fastened atop the jacket, the entire process usually taking a few months.

Unlike exploratory rigs, production platforms are permanent fixtures fastened to the ocean floor by pilings and designed to drill wells, hold crew quarters, and remain in place until an offshore oil field has been exhausted.

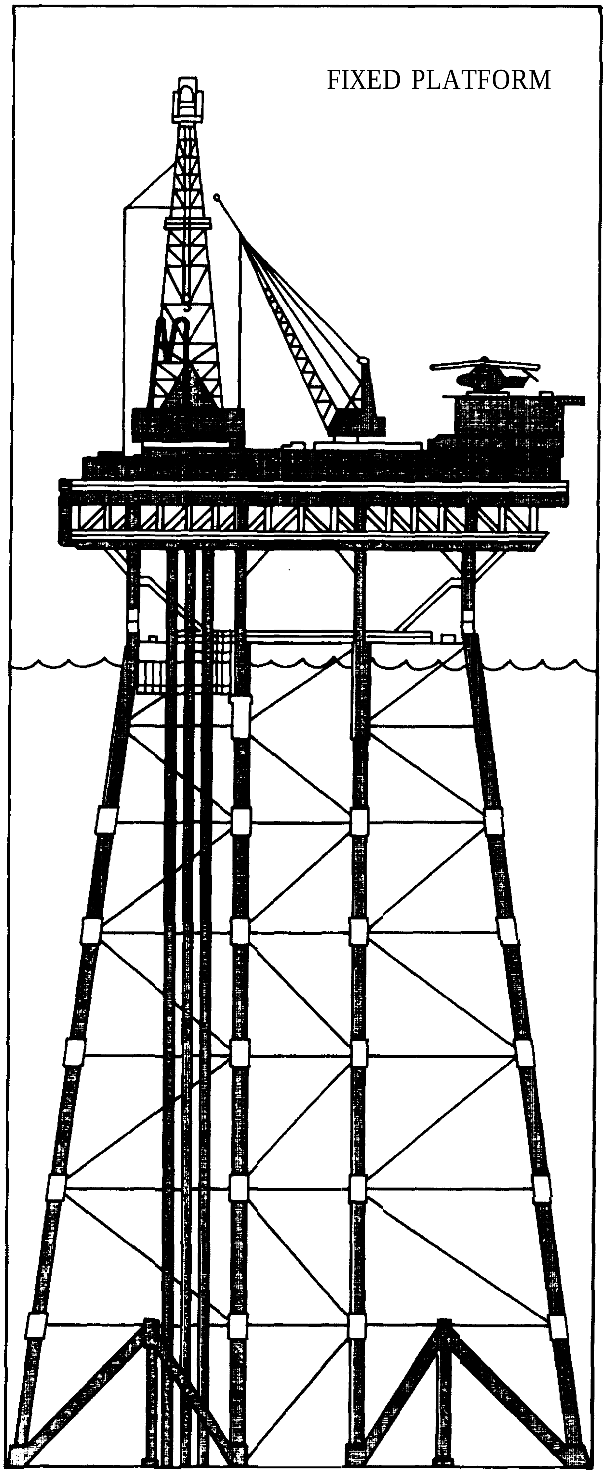
Portions of platforms could be fabricated in the Gulf of Mexico and towed to the east coast. They also could be assembled at a site in Cape Charles, Va., which was purchased in 1975 for that purpose by Brown & Root, Inc. (Rezoning for this facility has been approved, but approval of a detailed site plan is still pending.) The platforms could be fabricated at existing east coast shipyards. One large platform was constructed in a Baltimore shipyard in 1974 and towed to the Gulf of Mexico for use. Decisions on the source of platforms would be made, as would most hardware decisions, at the time the platforms were needed and on the basis of least cost to the operator. The decision would involve so many variables, such as workload in gulf assembly areas and the ability of east coast shipyards to compete for orders, that there is not enough data at this time to make a judgment about where Mid-Atlantic platforms would be fabricated.

Platforms other than those of conventional design could also be used in the Mid-Atlantic. Concrete platforms—reinforced concrete cylinders resting on submerged pedestals—are in use in sections of the North Sea. The legs and bases of such concrete structures double as offshore storage tanks which can serve both tankers and pipelines.[41]

Another possibility for oil production systems would be the use of partial or total subsea completions. With conventional platforms, drilling rigs and crew quarters are removed when all wells have been drilled. The wells are completed with systems of valves, pumps, separators, and other equipment that channel oil and gas toward collection points for shipment to shore either by pipeline or tanker. With subsea completions, a package of wellhead valves, pumps, and separators would be placed on the ocean floor rather than on a platform. A partial subsea system could also be used which combines underwater parts with a few platforms with some equipment above water.

During drilling operations to start production the "drill string" is composed of long sections of hollow pipe reaching from the platform to the bottom of the well, is suspended from a derrick. The pipe is rotated to spin the drill bit which digs each well. "Mud," a mixture of chemicals, clay, and water, is pumped through the hollow pipe of the drill string in a closed system that lubricates the bit, carries rock cuttings to the surface, and seals a well

Figure IV-15. Artist's drawing of production platform similar to those which might be used in Mid-Atlantic



Source Mobil 011 Corporation

against blowouts during the drilling process. In the Baltimore Canyon Trough, wells may be drilled to about 15,000 feet. "Storm chokes" or downhole safety halves are installed in producing wells after drilling is completed to seal off an oil flow if pressure rises suddenly and threatens a blowout. "Blowout preventers, " stacks of heavy valves, are inserted between a drilling rig and a well to control blowouts during the drilling process,

CREW REQUIREMENTS

Development and production drilling would require about the same number of platform crewmembers as exploration rigs, working 7 to 14 days and taking 7 to 14 days of leave. The flow of food, fuel, drilling pipe, casing, mud, and other materials to offshore platforms would be about the same as that required for exploratory drilling.

Once drilling was completed and wells were connected with a distribution network, maintenance crews would live on central platforms from which they would travel to producing platforms to pm-form routine repairs and inspection. On average, 50 personnel-mechanics, electricians, painters, and other maintenance workers-could service four producing platforms. Thus, offshore personnel requirements would drop, once drilling was completed, from more than 800 workers for four platforms to about 50 workers.

PLATFORM REGULATIONS

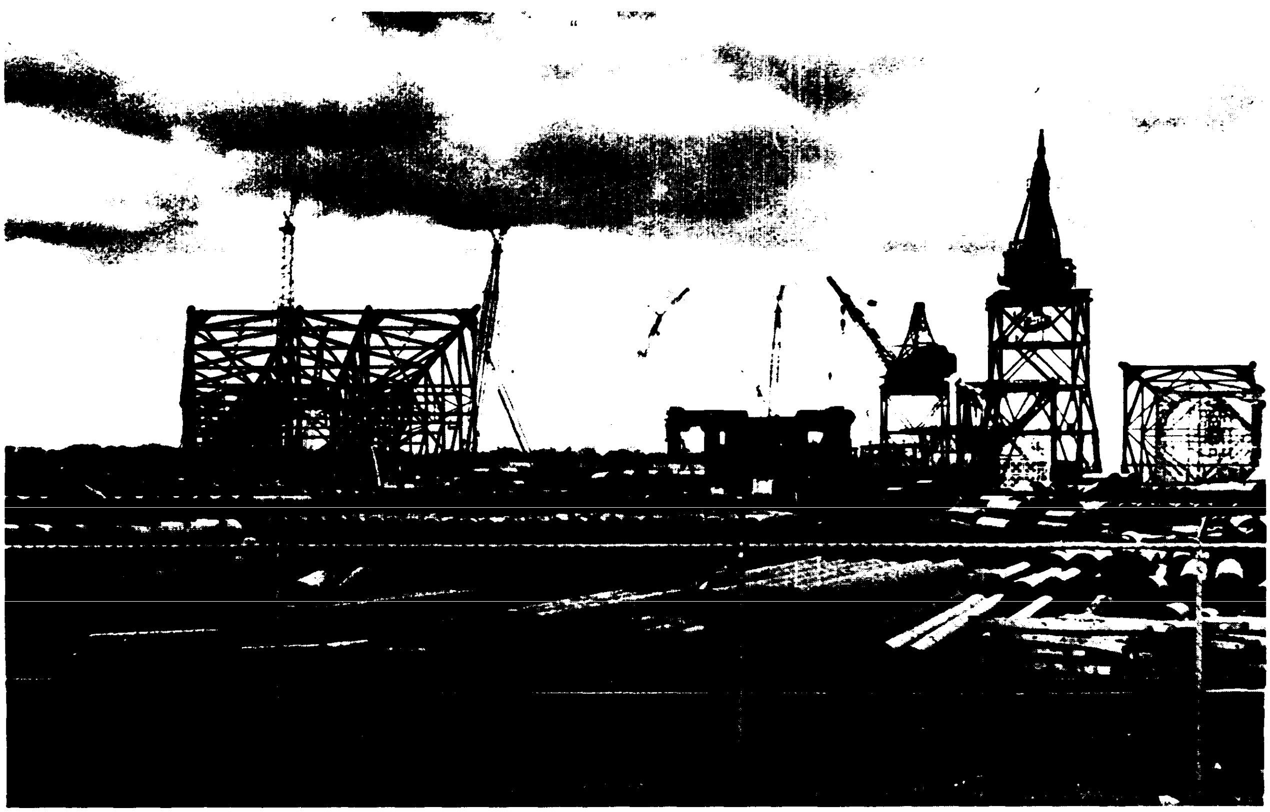
Oil production platforms are highly complex systems, subject to great uncertainties. The platforms are designed, built, and installed by oil companies under stringent, self-imposed guidelines. There is very little regula - tion of this technology. Most recognized industry standards at-c not required to be followed; the OCS order for platforms merely states that they shall be adequately designed and certified. Government inspections of construction, installation, and operations are not systematically planned.

The OCS order covering platforms for the

Mid-Atlantic was not issued before the lease sale. The EIS for the Mid-Atlantic states that "Major offshore structures are designed to withstand environmental stresses specified by the owner or operator. Typically, forces associated with the 100-year storm have been the specified stress." This is a major area of uncertainty: first, it is not known for sure that operators would design to a 100-year storm and regulations do not require it; second, the nature of a 100-year storm in the Mid-Atlantic is not known with any accuracy; third, the magnitude of many other interacting environmental factors such as temperature, waves, currents, and bottom stability is not known with any accuracy; and fourth, there are no recommendations as to safety factors a designer must use to account for uncertainties.

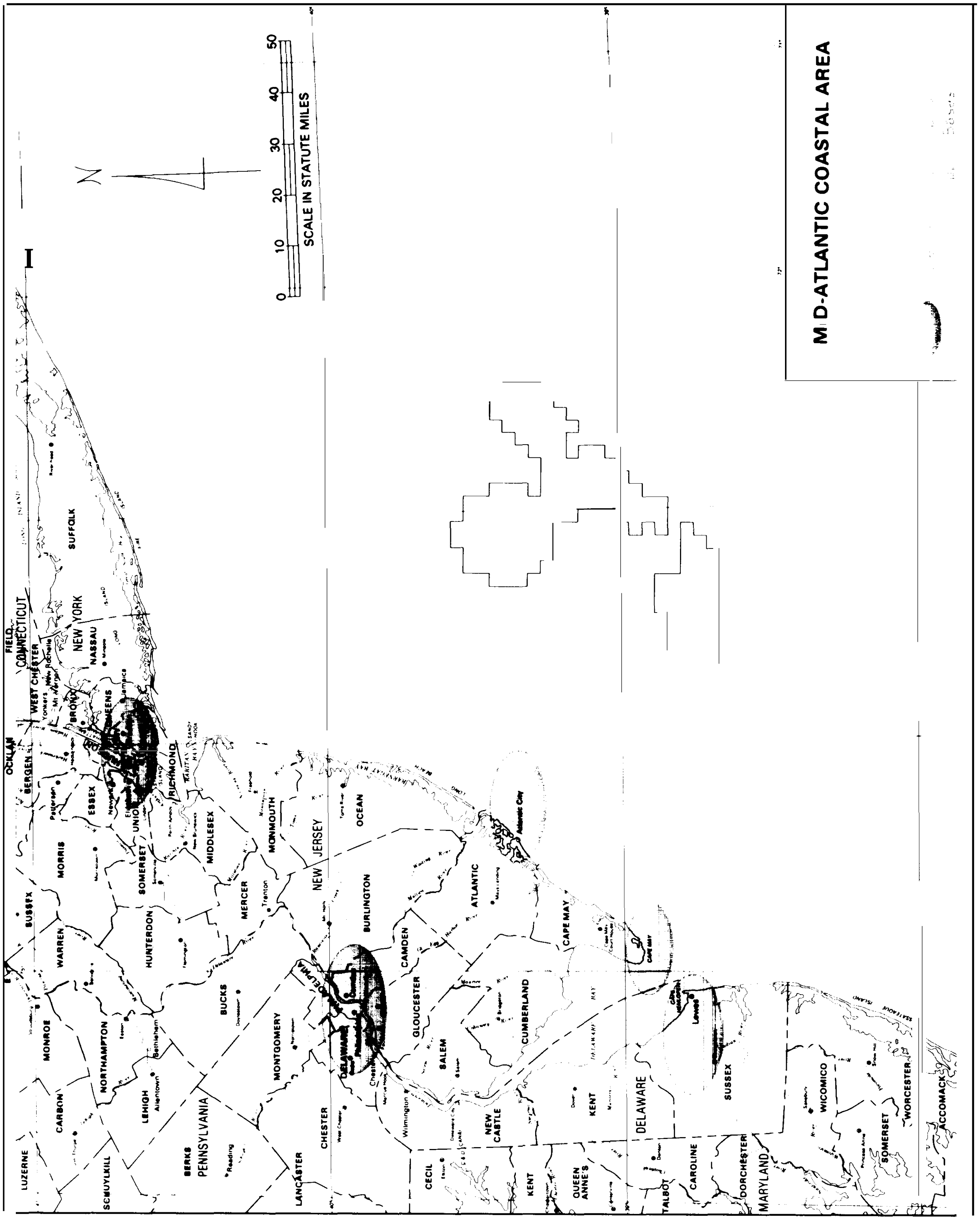
The American Bureau of Shipping, a private classification society which sets design standards and inspects offshore equipment for insurance companies, has developed specifications and inspection procedures for offshore platforms. The Bureau has certified the design and operation of over 200 floating drilling rigs (exploration rigs) and regularly works with the U.S. Coast Guard to certify ships and other floating equipment. The procedure includes publishing a book of design guidelines, completely reviewing and approving or rejecting all design plans, inspecting all materials and components as they are built, and finally, testing all major parts. The procedure has been in use in the United States for all ocean-going merchant ships for many years. Adoption of the principle by OCS regulatory agencies could increase the effectiveness of the present system immediately.

Figure IV-16. Platform construction yard outside Morgan City, Louisiana



Source Off Ice of Technology Assessment

Figure IV-17. Potential sites and land requirements for OCS support bases.



Source Office of Technology Assessment

Figure IV-1 7. continued

The total acreage given below is for onshore support bases which most likely would be located in coastal ports such as Atlantic City or Cape May, New Jersey, and Lewes, Delaware. The totals are for peak activity years, most likely between 1980 and 1985.

	Acreage for Median Recovery	Acreage for High Recovery
Exploratory Drilling Support	25	50
Development Drilling Support	55	120
Total Support	80	170

Source Office of Technology Assessment

It should be noted that the Coast Guard recently developed regulations for deepwater ports which, in many cases, cover technology and hardware similar or identical to that used in OCS operations. In fact, it is possible that two side-by-side structures—an OCS platform and a deepwater port platform—operating in the same environments and conducting operations with the same product at similar conditions could be regulated under quite different standards. The Coast Guard philosophy of regulation appears to be one of setting detailed, firm, and comprehensive rules for designing, building, and operating, and then carefully checking adherence to those rules. On the other- hand, the USGS philosophy appears to be one of asking for industry's best efforts and then making broad judgements about its adequacy.[42]

CONFLICTING OCEAN USES

The offshore region of New Jersey and Delaware is now used intensively for such traditional activities as commercial fishing, marine transportation, disposal of sewage sludge, and military operations. The most serious near-term offshore conflicts will probably be between proposed oil and gas operations and both commercial fishing and commercial shipping. Both coastal and trans-Atlantic traffic lanes from the major ports of New York and Philadelphia lead through or near the lease area. Many commercial fishing vessels operating out of New Jersey and Delaware and fishermen from other Atlantic coastal States also operate in the offshore waters, as do foreign fishermen. Increased marine traffic and manmade offshore structures resulting from oil and gas operations will increase the collision risk for all ship operators in the region. Offshore structures may also prevent access to some traditional fishing areas, fishing gear may be damaged by large debris accidentally dropped from oil support vessels and structures, and oil spills could cause temporary or long-term losses for fishermen.

In a letter to the Bureau of Land Management from the EPA commenting on the draft EIS for the Mid-Atlantic lease sale, the following statement was made about possible navigation hazards:

> We are concerned that the conflict between heavy vessel traffic in the Mid-Atlantic and the prescence of offshore platforms could, in the event of the lease sale, become serious. Five tracts are in the direct path of an existing shipping lane, six other tracts are considered most hazardous to navigation, and thirty-one additional tracts are in conflict with or in close proximity to commonly used shipping routes. Any accidents or collisions involving platforms and vessels, particularly during anticipated storms or fog, could pose a substantial threat of adverse environmental, social, and economic impacts on the shoreline communities where recreationl values of wetlands and beaches at-c high. Considering that adequate technology does not exist for containment of oil on the high seas, there is a probability that oil spills would impact the sensitive shorelines.[43]

SUPPORT BASES

Direct support for development drilling would require about 55 acres of staging land if the Baltimore Canyon Trough area were to yield 1.8 billion barrels of oil, and about 120 acres if the yield were 4.6 billion barrels. This land is in addition to that required for exploratory drilling, Figure IV-17 summarizes total land requirements for support bases likely in the region.

Five possible areas in the New Jersey-Delaware region could serve as staging areas for offshore development, three coastal sites and the port complexes of New York City and Philadelphia-Camden. All three coastal sites—Atlantic City and Cape May, N. J., and Lewes, Del.—would meet such staging area requirements as availability of good supply boat harbors with about 15 feet of water depth, accessibility by rail, proximity to lease sites, and availability of land for storage and service facilities. ‘

Service firms under contract to oil companies would choose staging areas on the basis of lowest overall operating cost, which cannot be evaluated in enough detail at this time to pet-m it determination of the most likely sites. Operating from coastal sites, supply boats would travel between 80 and 250 fewer miles on each round trip to the oil field than they would if they were based at either inland port. The resulting savings, however, might be offset by lower land prices at inland areas or by the cost of warehouse facilities which would have to be built if coastal sites were chosen.

Atlantic City, N. J., could provide enough acreage to meet all requirements for support development if median estimates of recoverable oil and natural gas are correct. If exploration activities expanded, additional staging areas might be required, such as Cape May and Lewes.

At present, State and local government control of land use provides the greatest leverage over OCS-related development. With State-to-State variations, the control of land through zoning and permit powers, including State powers relating to air and water pollution, is an effective tool for controlling development. Nonetheless, in the case of OCS development, States and localities find themselves limited to reacting to Federal decisions which set in motion chains of events that can affect population levels, employment patterns, requirements for State and local expenditures for public facilities and services, and social patterns. With key OCS decisions being made at the Federal level, States can only approve or disapprove location of refineries, platform construction sites, and service bases; or react favorably or unfavorably to genera] oil company efforts to build OCS-support facilities. They cannot participate in the process which leads to such decisions. Their only option is to try to exercise their legal rights to choose whether or not to approve OCS-related facilities after the fact of Federal decisions, oil company investments, and actual oil disco series.

CAPITAL INVESTMENT

Development of oil and natural gas off the New Jersey and Delaware coast could involve $2 billion to $4 billion in initial capital investments and could influence the U.S. balance of trade by as much as $50 billion over the life of the project, based on very rough figures for capital investment and discount over the life of the field.

Figure IV-18. Total new land requirements related to OCS development during years of peak activity (1 980 to 1990) in New Jersey and Delaware under high recovery assumptions

Activity	Acreage Required
Support Bases in Coastal Ports	170
Pipeline Corridors in Coastal Zone	150
Pipeline Corridors outside Coastal Zone	550
Tank Farms	75
Gas Processing Plants	700
Total Peak Land Requirement	1,645

Source Off Ice of Technology Assessment

Direct employment in New Jersey and Delaware would peak at about 9,000 workers if the high estimate of resources were correct and at about 4,500 workers if the median estimate of resources were correct. Capital expenditures would peak during the seventh year of development at approximately $1 billion. Peak land requirements are estimated to be 1,645 acres in New Jersey and Delaware. Of that, 320 acres would be coastal land and the remainder would be inland. Seven hundred acres would be required for pipeline corridors which probably would parallel existing highway or rail road lines. Figure IV–18 summarizes the total new land required.

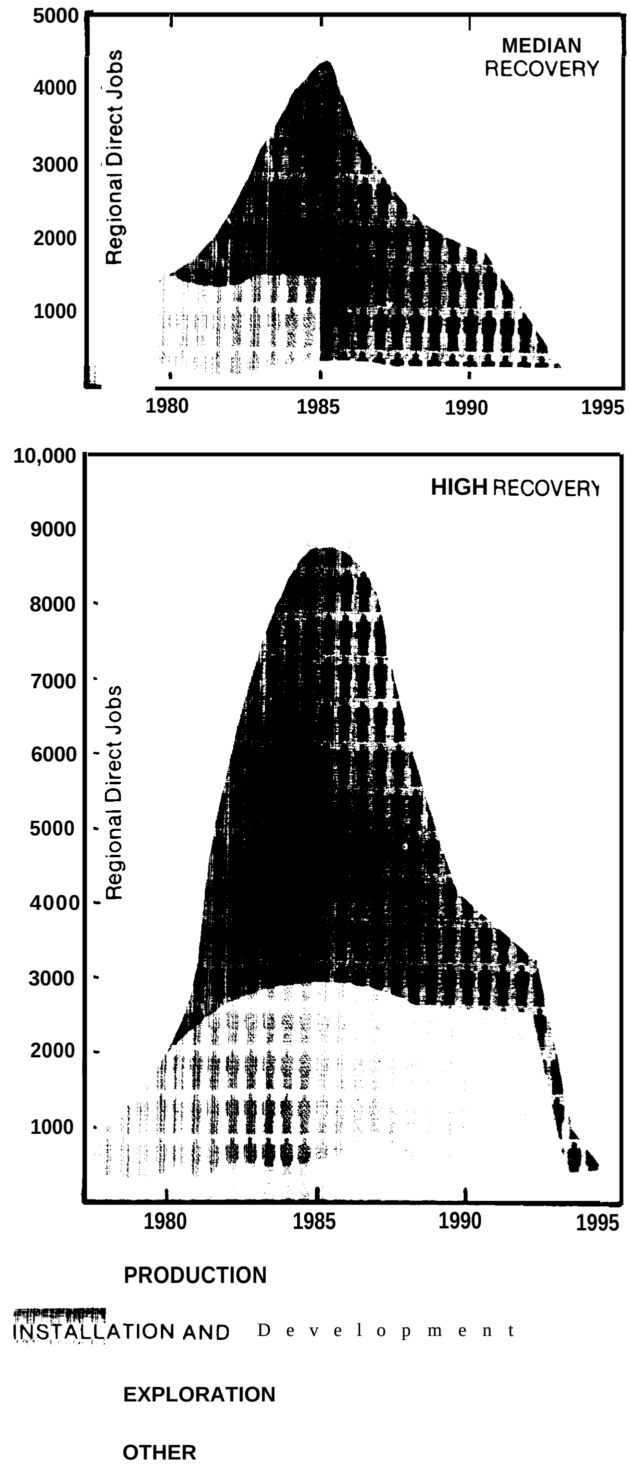
FISCAL EFFECTS

Analysis of the effects of offshore development on tax revenues in a wide variety of coastal States, including New Jersey and Delaware, shows that in States where major onshore facilities are located the per capita tax revenues from OCS activities probably would be significantly higher than from businesses and individuals in the rest of the State economy except during one time period. During the first 2 or 3 years of OCS-related development, very little revenue would be received from OCS-related businesses so that per capita revenues would be lower than the statewide average. Beginning in the fourth year, however, the net statewide fiscal impacts would become favorable as investments were made in capital-intensive onshore facilities needed during the production phase.[44]

OTA has prepared a fiscal analysis of costs and revenues from OCS activities in the States of New Jersey and Delaware assuming projected development associated with discovery of 1.8 billion barrels of oil in the Baltimore Canyon Trough.

The fiscal analysis concludes that, in general, per capita tax revenues from OCS-related activities would be considerably higher from the fourth year onward than statewide

Figure IV-19. Direct employment from all OCS activities under the high and median recovery assumptions



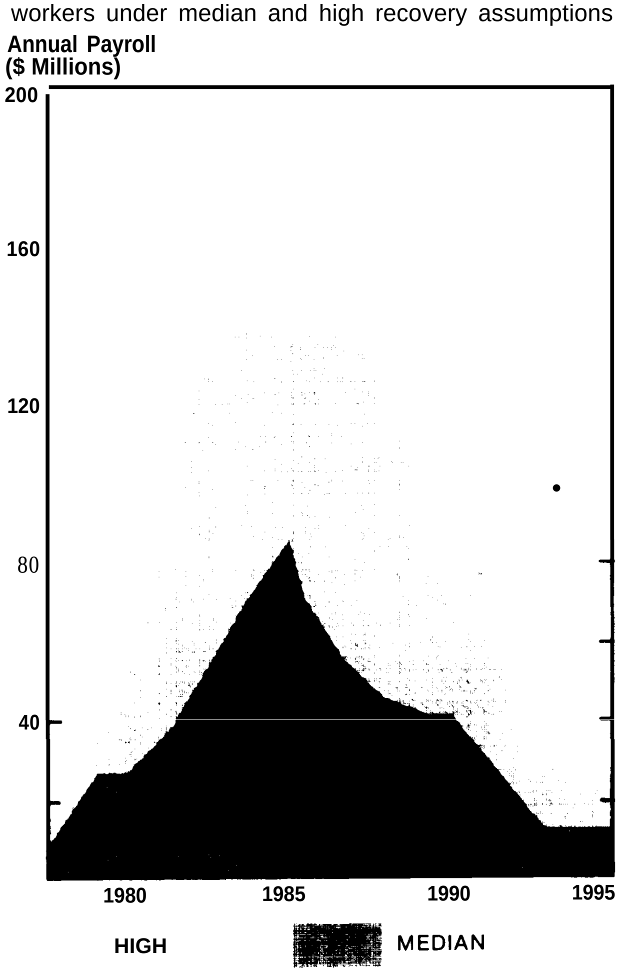
Source Off Ice of Technology Assessment

per capita revenues from other sectors under the assumptions of the study.

There is an important caveat to the conclusion. It assumes that public costs of supporting OCS bases and providing services to OCS-related workers and their families in one State would be offset by revenues from onshore investments in that same State. If, however, most of the support areas and OCS employees were located in one State and the landings of oil and natural gas were made in another, the results would be very different.

In 1972, per capita State and local revenues in New Jersey were $847. Before any major onshore investments occurred, revenues produced by OCS activities would be primarily those from taxes on individuals which average $512 per capita in New Jersey. Assuming that per capita expenditures for public services are about equal to total per capita revenues of $847, per capita expenditures to support OCS-related population would exceed the per capita revenues from OCS activities by about $335 during the first 2 years of development. The gap would decrease to $225 in the third year as some business taxes accrued.

Figure IV-20. Annual earnings of direct regional OCS workers under median and high recovery assumptions



Source Office of Technology Assessment

The picture would change in the fourth year when major onshore investments would be made for pipelines, tank farms, and . natural gas processing plants. In the year when these investments were made, the State would receive revenues from a real estate transfer tax and from its sales tax (or equivalent use tax). Since these are assumed to be concentrated in the fourth year, the per capita tax revenue is calculated to jump nearly $11,000 in that year in New Jersey. The jump would not be so pronounced in Delaware where there is presently no sales tax.

In subsequent years, the property tax would become the main source of revenues. Property tax revenues would decline on a per capita basis for a period because they would be divided among an increasing direct population engaged in offshore construction and development drilling, Finally, per capita property tax revenues would begin to rise in the ninth year when completion of construction would lead to a decrease in OCS-related population. For all years after the fourth year, per capita revenues from OCS activities would substantially exceed the statewide average.

If either business gross receipts or corporate income taxes are added, the per capita revenues accruing from OCS-related activities would be even higher after the sixth year or so as production was under-taken. The other un - certainty—that some components of onshore construction may be exempt from sales taxation—could reduce actual sales tax revenues below the calculated levels. However, this would not alter the conclusion that, for most States, the per capita tax revenues produced by OCS development should exceed the statewide average after the first 3 years of development.

There are important qualifications to these conclusions. First, higher than average per capita tax revenues from OCS development activities imply net fiscal benefits only if these activities do not require proportionately high or higher expenditures for public facilities and services. In some States, OCS development may require facilities such as roads in areas of unusually high construction costs. This could lead to a net negative fiscal impact in spite of relatively high per capita tax revenues.

Second, the analysis deals only with normal governmental expenditures and does not take into account such less easily quantified costs as environmental degradation and loss of recreational lands.

Thus, the conclusion that there may be net fiscal benefits does not imply that there are no uncompensated costs of development.

Third, while there may be a net fiscal benefit on a statewide basis, there could still be serious localized fiscal problems if development were concentrated in a small community. One of these problems is that during the first 3 years when revenues are low, a local government may not have the fiscal capacity to provide public services to the related population, and even in year four the major revenues are sales taxes which accrue primarily to the State rather than local government. It may also be the case that onshore investments subject to sales and property taxation are in one local government jurisdiction while a majority of the associated population resides in another. This same problem may occur between States if OCS exploration and development activities are supported from bases in a State different from the one in which the oil and/or gas is ultimately landed.

STATE ROLE IN DEVELOPMENT AND PRODUCTION

Because of the uncertainty, State officials have been increasingly insistent that they be brought into the development process as participants rather than observers. State officials have been, and continue to be, concerned that such critical decisions as choosing pipeline corridors, siting tank farms, and locating staging areas may be made without adequate consultation and that, in the end, States would have to accept the decisions or try to block development. The lack of State participation at early stages of the decision process therefore creates an adversary relationship in which the State's only option for controlling adverse onshore impacts is to obstruct, possibly through lengthy litigation, thus bringing about the very delay in OCS development that the Federal Government is trying to avoid.

The States and localities have several avenues for blocking OCS development. The most dramatic is simply to file suit to block a proposed lease sale. Neither New Jersey nor Delaware has threatened such action publicly. However, staff members of the Attorneys General of both States have explored courses of legal action open to them if the Governor of either New Jersey or Delaware were to decide at some future date that the State should try to block or delay offshore development.

States and localities also have some legal basis for intervening later in the development process to block decisions that they oppose. For example, they could refuse to permit the construction of pipelines in their coastal zones by invoking their rights under either the 10th Amendment or their own riparian laws. However, State and local officials are concerned about reliance upon such measures for several reasons:

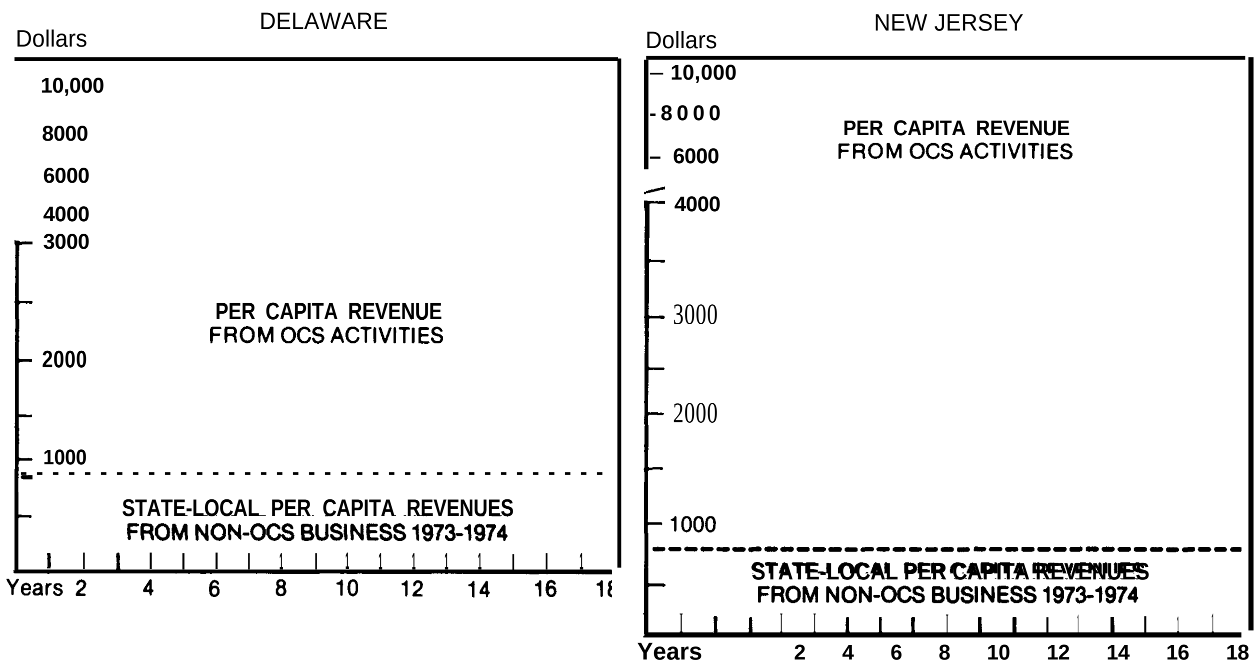
- There is some doubt about the effectiveness of these powers because they have not been tested under circumstances identical to those the States would face in confrontation with Federal powers.
- Neither State wants to block development of energy sources that may exist in the Baltimore Canyon Trough, particularly if it means fighting rearguard actions on technical points.[45]
- Some State and local officials fear that their concerns would be overwhelmed by the combined forces of the Federal Government and the energy industry joining in the search for new sources of energy. In August 1975, Thomas O'Neill, former assistant commissioner of Environmental Protection for New Jersey, said: "There is a fear among coastal residents and officials that they're not going to have any control. They see a combination of big Government and big oil coming down on them and you've got some poor commissioner in Wildwood, N. J., who feels like he's standing up there all alone against this juggernaut."

What State officials seemed to be seeking, as reflected in interviews with OTA researchers, is a new process that would require formal, effective channels for State participation that would satisfy State obligations to protect their coastlines and still assure adequate supplies of energy for State residents and the Nation as a whole.

Transportation and Storage and Their Impacts

The next phase in development of oil and gas off the coast of New Jersey and Delaware would be construction of a network to move oil and gas from platforms to storage tanks

Figure IV-21. State-local tax revenue per OCS employee and their families compared to revenue from non-OCS workers and their families



Source Office of Technology Assessment

and processing plants and from there to refincries and into the distribution system.

It is technically possible to lay pipelines to shore and build storage tanks on a schedule that would have them in place when commercial quantities of oil and natural gas begin flowing from the Baltimore Canyon Trough area. OTA has assumed for this description that pipelines and tank farms would be built. It is possible, however, that pipelines would not be built if:

- oil or natural gas were found in quantities too small to justify the approximately $1 million-per-mile cost of pipelines;
- oil companies decided that for market reasons they would refine Mid-Atlantic crude in some other location;
- oil companies decided that regulation of pipelines or refineries in either State would be too stringent to warrant pumping crude ashore in New Jersey or Delaware.

In any of these cases, crude oil could be pumped from platforms into offshore storage tanks and carried to refinery sites by tanker.

PIPELINES

If pipelines were laid, the work would be done by 175-man crews working on 300-foot "lay barges" which can assemble and drop to the ocean floor 1 mile of pipeline per day. The process involves welding 40-foot sections of steel pipe, coating them with asphalt paste or epoxy resin, bathing them in concrete to make them heavy enough to stay in place on the ocean floor, and trailing the assembled pipe over the side or stern. Smaller barges, dragging a "jet-sled" over the ocean floor, follow the lay-barges and pump water through nozzles on the sled to dig a trench into which the pipeline settles.

The environmental impact statement for the Mid-Atlantic lease sale states that the following lease stipulation will be applied: "Whenever technically and economically feasible, all pipelines . . . shall be buried to a depth suitable for adequate protection. . . ." It should be possible to specify burial depths where current and sand-shifting are high, where shipping lanes and anchoring grounds are located, where pipelines are traversing beaches, or where fish trawling or dredging takes place. The terms "suitable" and "adequate protection" could be defined more precisely.

Two kinds of pipelines would be laid on the ocean floor to transport oil to shore from offshore platforms. Gathering lines, usually 12 to 24 inches in diameter, connect individual wells to central platforms. Flow lines connect central platforms to shore. In the Baltimore Canyon Trough area flow lines probably would be more than 2 feet in diameter and extend 80 to 100 miles to shore.

Pipelines from offshore oil and gas production facilities might carry an initial installation cost in range of $100 million[46] for a 24- to 36-inch pipeline between New Jersey or Delaware and an offshore oil field.

Given the size of the investment, it is in the best interests of industry that pipelines be coated with corrosion protection coatings and properly weighted with concrete where necessary, be installed with care from pipeline barges, be adequately welded and inspected, be buried throughout most of the distance offshore as well as onshore, and be adequately tested prior to use.

PIPELINE REGULATIONS

Pipeline networks, however, have not been subject to stringent regulatory standards in the United States in the past and pipeline failures, with resulting oil discharges, have occurred in the Gulf of Mexico as well as other offshore development regions. According to the Coast Guard Pollution Incident Reporting System data on oil spills in 1974, a major source of discharge was from pipelines.

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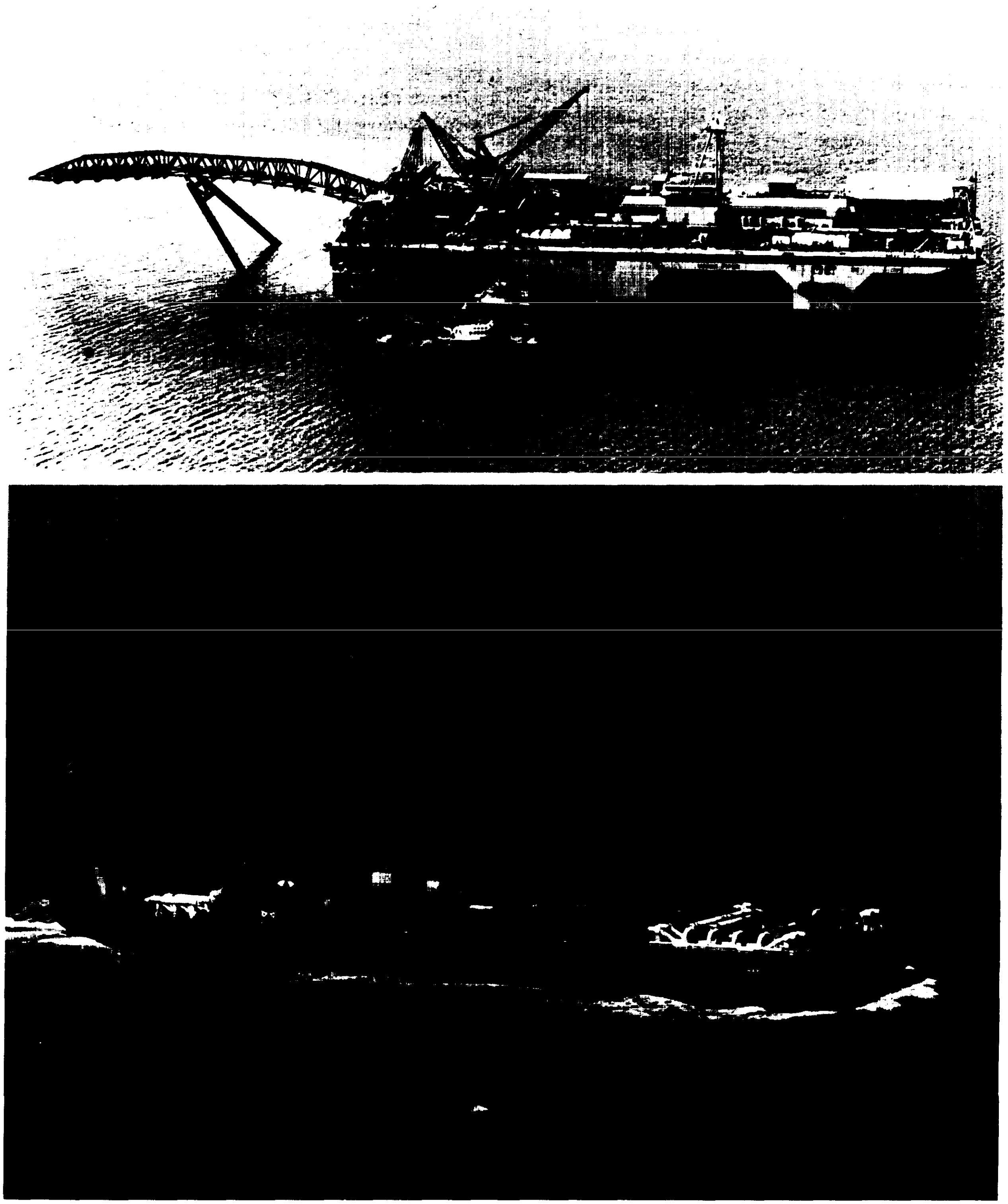
Figure IV-22. Typical pipelaying barges similar to those which could be used in the Mid-Atlantic



Source Marine Engineering/Log

Regulatory authority for setting pipeline design standards is now divided between the Office of Pipeline Safety (OPS) in the Department of Transportation (DOT) and the USGS in the Department of the Interior. The OPS standards apply to both offshore and onshore pipelines without differentiation or allowances for special seafloor conditions or stresses due to ocean installation.

OPS has proposed modifications to standards for offshore pipelines which are quite detailed and firm but the proposed rules were not in effect when the Mid-Atlantic lease sale was held. The USGS has developed an OCS order covering pipelines in existing areas such as the Gulf of Mexico but has not developed a similar order for the Baltimore Canyon Trough. A memorandum of understanding has been developed between OPS and USGS concerning pipeline regulations, but the formal process of translating an agreement into Federal regulations could take some months.

The memorandum sets out the responsibilities of each Department, basically giving DOT responsibility for pipelines from a production platform to shore and giving Interior responsibility for pipelines from the wells to the production platform. The two Departments will coordinate inspection and enforcement activities and will jointly be responsible for research, according to the agreement, and at least once a year will jointly review all existing standards, regulations, and operating practices concerning pipelines. (See figure IV-23.)

Specific design standards, installation practice specifications, and scheduled tests and inspections could readily be adopted for pipelines in the Mid-Atlantic region and in other OCS regions based on existing knowledge and technology. Such regulations do not require detailed knowledge of the regions or environmental conditions because specifications normally establish standards based on a formula which would accept a range of inputs and include safety factors for a specific design.

Much new technology is available to assure pipeline safety and could be incorporated in regulations, in some cases without additional research. Such technology includes:

- Standards for coating pipelines with corrosion protection materials that have been tested and proved to be effective over long periods of time.
- Standards for welding and inspecting welds and specifications for pipe materials and sizes including temperature characteristics which could assure an initially sound line.
- Procedures for installing and burying pipe which would protect the line from overstressing as water depths increase.[47]
- Pipeline inspection devices which could be used regularly over the life of a pipeline to detect any deterioration prior to a possible leak.[48] Some private firms are now using these devices to inspect offshore pipelines although few will make the inspection results public. As a regulatory tool the Government could readily perform its own inspections with these devices.

Another element of the system that would require particular attention is the placement of pipelines at coastal landfalls. Most biologists and other scientists agree that pipelines should be routed to avoid marshlands, a design that would be difficult to achieve along the Delaware or New Jersey coast. If marshlands cannot be avoided, biologists argue for ‘‘minimum disruption of such areas although there is no accepted definition of either “mini mum” or “disruption. “[49]

STORAGE TANKS

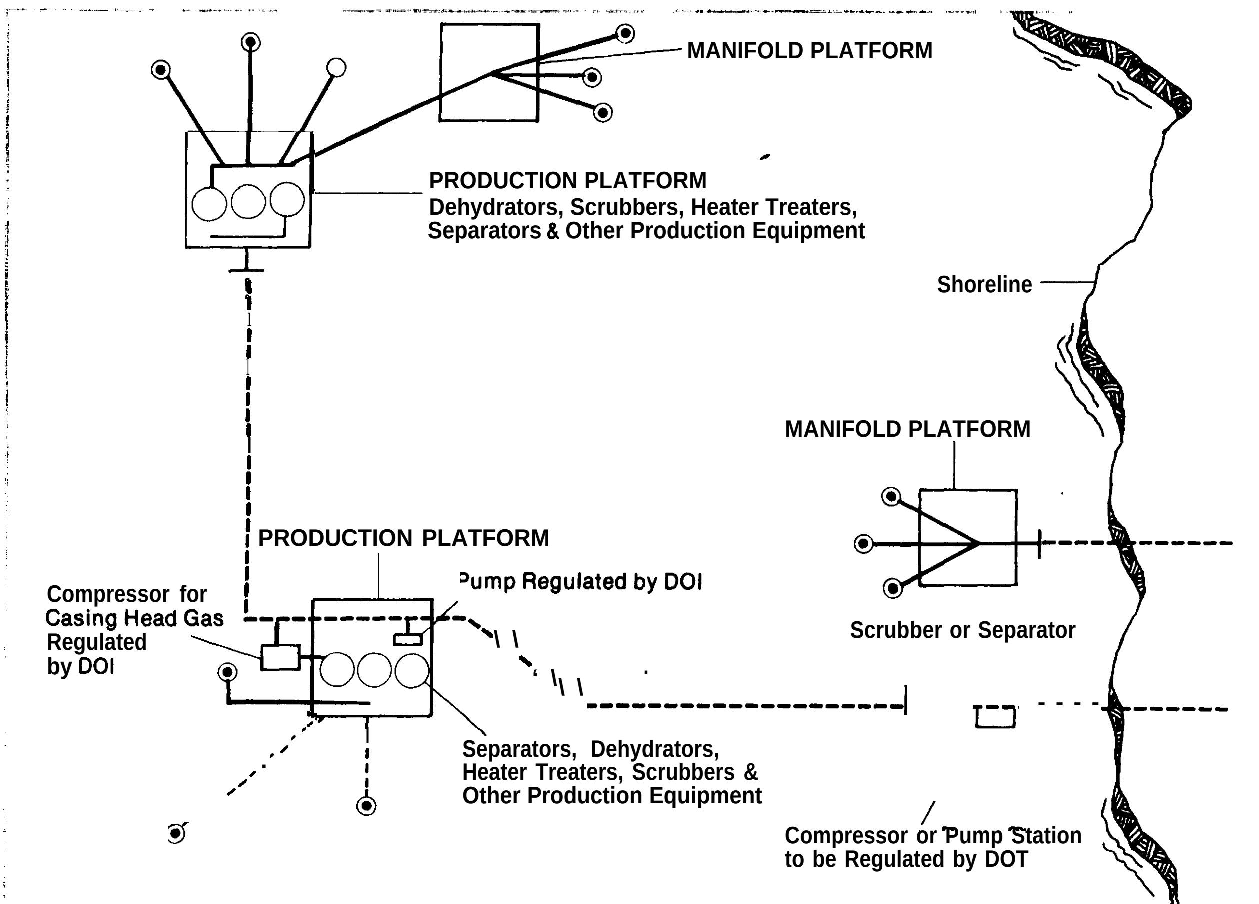
Oil coming ashore through pipelines probably would be stored temporarily in tank farms to provide a means of regulating the flow of oil to refineries. Natural gas would be piped ashore in separate pipelines to gas processing plants that probably would be located near tank farms.

The oil industry rule of thumb for such tank farms is that they would be able to hold 10 days production of oil or gas. At the median estimate of Baltimore Canyon Trough resources, this would translate to five storage tanks on about 50 acres of land which could be located close to shore or well inland. For the high recovery estimate, 75 acres would be required.

TANKERING

It is feasible and sometimes economical to transport oil produced at offshore fields directly to refineries by tankers rather than by pipelines. The practicality of such a system depends on many variables such as distance from the offshore field to the refinery, amount of oil produced, cost of pipelines, status of field development, number of wells and platforms producing, cost of offshore storage and loading terminals, gas mixture, and pollution potential. In the Gulf of Mexico all production from offshore wells is transported by pipeline

Figure IV-23. Responsibility of Federal agencies for pipelines



Wellhead; — Pipelines Regulated by the Department of the Interior (DO I);

--- Pipelines Regulated by the Department of Transportation (DOT)

Source DOI/DOT Memorandum of Understanding to refineries along the coast and inland. A major reason for this is that offshore production has been a gradual extension of producing areas on the coast and many wells are spread overwide areas in relatively shallow water. In some other major offshore producing areas very large fields were discovered which justified major pipelines. In other special cases, such as some North Sea fields, it was determined that offshore storage and tankering would be the best method of transporting oil ashore at least for some initial period of field development.

In the case of offshore New Jersey and Delaware, the potential fields are a substantial distance seaward (more than 80 miles) and pipelines may not always be economically justified, especially during initial development stages. It would be feasible to start producing into a storage tank and using tankers to ship the oil ashore. Of course, if major gas discoveries are made a pipeline would be required.

There are some advantages to tankering nominal quantities of oil when compared to the disruption that pipeline construction may cause. It should be noted, however, that oil pollution from tankers may not be as easily controlled as that from pipelines.

Oil Spills

In all stages of OCS development, oil spills are a major concern and pose the possibility of major impacts.

RISK ASSESSMENT

The possibility of oil spills is usually described in terms of risk probability. An OTA oil spill risk assessment indicates that there probably would be at least one major oil spill during development of the Baltimore Canyon Trough.

OTA projects that it is unlikely that there would be more than two spills of more than 24,000 barrels of crude oil each during the 30-year life of the Baltimore Canyon Trough field. The projection of oil spill risk assumes the high recovery estimate of the USGS of 4.6 billion barrels.[50] For a median recovery estimate of 1.8 billion barrels, oil spill risk figures are roughly cut in half. (Only high and median recovery estimates were used in the risk assess merit.)

This risk assessment concludes that the odds of an oil slick, even from a major spi 11 at a Platform 50 miles offshore, reaching the New Jersey or Delaware shore would be one-in-ten after the spill had occurred. If oil slicks did reach Mid-Atlantic beaches, however, they could hit any point along the coastline. Vague and general as these conclusions are, they represent the outer limits of judgments that can be made in view of such variables as wind force and direction, wave action, ocean currents, and size and location of a spill.[51]

This estimate of the range of probable oilspills as a result of Baltimore Canyon Trough development activities has been made based on statistics from offshore oil operations over the past 10 years, principally in the Gulf of Mexico. The greatest volume of oil has come from a small number of major spills. None of these offshore spills to date has been contained and cleaned up on site. OTA's estimate of a probable range of large oil spills, given OCS development follows the high recovery scenario, is from 5,000 to 860,000 barrels resulting from 1 to 40 spill incidents, with the most likely amount being 140,000 barrels and 18 spill incidents.[52]

Should a major oil spill occur during Mid-Atlantic OCS operations it is doubtful that the spill would be cleaned up. Depending on the season, the size of spill, and prevailing conditions, the shoreline could be severely impacted. An independent study conducted for OTA by the Coast Guard, indicated that during a stagnant summer high pressure system, the probability of an oil spill from OCS sites reaching the shore is very high.[53] On the other hand, a Chevron representative at the January 1976 Atlantic City EIS hearings stated that "we believe that there is no chance of oil reaching shore from the proposed (Baltimore Canyon Trough) OCS lease area."[54]

it has been pointed out by local officials in the States that if an oil spill were to reach the coast during a tourist season, the affected area could lose an entire season receipts.[55] Economic losses would be sustained not only by those whose property was directly damaged by oil but also by those who depend for income on the seasonal tourist industry. These could include owners and employees of hotels, restaurants, charter boat operations, and other tourist -oriented activities.

Commercial fishermen also could be adversly affected—in the short run as a result of fish kills or contain i nation and in the long run if damage to spawning and feeding grounds were to reduce the yield. The surf clam industry, which is economically important to New Jersey, would be vulnerable to oil spill damage.

Severe oil spills can cause major damage to marshlands if the spill reaches inshore, to waterfowl if large quantities of oil reach their habitat, to bottom-dwelling marine life if quantities sink and smother them, and to most fish, plants, and other biota if the concentration is high enough. What is not known and cannot be measured at this time is the severity of damage related to amounts and concentrations, the effects on the food web and ultimate consumer and the long-term effects of chronic discharges. Also unknown are many specific environmental conditions of each OCS region which may affect the dispersion, trajectory, chemical corn posit ion, and ultimate fate of any spill, Environmentalists argue that with so many unknowns, coupled with potential dangers, all efforts should be directed toward preventing o i1 spills whenever technically possible.[57]

OIL SPILL REGULATION

At the same t i me, however, Federal regulatory agencies, principally USGS, do not appear to employ the best available system for establishing standards and enforcing regulations dealing with oil spill prevention and cleanup. Recommendations contained in a GAO report of June 1973 covered the need for trained inspectors, improved inspection systems and standards for enforcement. Although USGS has advised Congress that it is proceeding with programs to meet the criticisms, no detailed descriptions of changes in procedure has been published.

The Federal Government, principally through agencies such as the Coast Guard and the EPA, has invested substantial resources in the research and development of oil spill surveillance, containment, and cleanup systems. Many of the more advanced systems have been produced and are available in the Coast Guard inventory. These include airborne oil spill detection systems which can locate and "fingerprint" discharges as well as high-seas spill containment and recovery equipment.[58] But the Coast Guard has no statutory authority over oil and gas development activities on the OCS. The Department of the Interior, through USGS, regulates OCS development and has a memorandum of understanding with the Coast Guard which provides that a Coast Guard coordinator will be available in the area for emergencies.

Mid-Atlantic OCS Order No. 7, the pollution and waste control order which was published in the Federal Register on July 12, 1976, places most of the responsibility for oil spill control and removal with the USGS. According to the order, "The primary jurisdiction to require corrective action to abate the source of pollution and to enforce the subsequent cleanup by the lessee or operator shall remain with the (USGS) Area Supervisor pursuant to the provisions of this Order and the memorandum of understanding between the Department of Transportation (U.S. Coast Guard) and the Department of the Interior

(U.S. Geological Survey) dated August 16, 1971."

According to Coast Guard instructions for implementing that memorandum of understanding, USGS has primary responsibility in any areas leased under the provisions of the Outer Continental Shelf Lands Act in recognition of USGS expertise with respect to abatement of the source of pollution at an offshore facility,

The instructions add, however, that the provisions of the memorandum of understanding will prevail only as long as removal of the pollutant is accomplished to the satisfaction of the Coast Guard on-scene coordinator. If cleanup is not satisfactory to the Coast Guard, the on-scene coordinator may take over under provisions of the National Oil Spill Contingency Plan.

In implementing its responsibilities, the USGS holds private offshore operators responsible for oil spill cleanup but has no check system to review the adequacy of the cleanup equipment available to operators.[59] OCS Order No. 7 requires only that operators inspect their own equipment regularly. Offshore cleanup is particularly troublesome because even the most advanced systems will perform only about 50 percent of the time in rough waters of the OCS.

The Coast Guard is responsible for a National Contingency Plan and has available a strike force for spill cleanup from any source. It appears that the Coast Guard would step in to clean up a spill in the Mid-Atlantic only after all other efforts failed.

On its own, the offshore oil industry apparently has developed a good safety record with regard to oil spill accidents, especially since the Santa Barbara spill in 1969.

Some oil companies have formed associations in active OCS regions for the purpose of providing oil spill cleanup systems and manpower. These are voluntary groups which are not required to use advanced technology which has been developed by the Coast Guard.

Sixteen oil companies interested in leasing tracts in the Mid-Atlantic have formed Clean Atlantic Associates and committed $1 million to purchase cleanup and containment equipment and to inventory existing equipment and expertise which could be used to supplement the group's resources.

By July, Clean Atlantic had named Haliburton as contractor for its cleanup operations and had contracted with Raytheon Corp. for studies to map coastal areas of unusual sensitivity, identify the bird population, and draw up a plan of action to be followed in the event of Mid-Atlantic spills.

Although a base of operations had not yet been formally chosen, O.J. Shirley, chairman of the group, said equipment and manpower would probably be located at Davisville, R.I., and at one of the oil company support bases which are expected to be located in either New Jersey or Delaware.

According to Shirley, Clean Atlantic would be procuring equipment throughout the summer and expected to be operational before exploratory drilling begins in the Mid- Atlantic. If commercial discoveries of oil are found, he said, additional gear may be purchasd.

Shirley has testified at hearings on the final EIS for the Mid-Atlantic sale that under normal conditions Clean Atlantic equipment could be operational at a spill site as far as 125 miles from its shore base within 12 hours.

POLLUTION RESEARCH

The OTA oil spill risk assessment also concludes that no less than 85,000 barrels of oil and no more than 1 million barrels of oil would be spilled as a total of major- platform or pipeline accidents, chronic discharge of oil from platforms, and inevitable leakage from

Figure IV-24. Clean Atlantic Associates initial equipment stockpiles

Item	Number
OPEN SEAS	
Fast Response Open Seas & Bay Skimmer Systems	2
Mini-Fast Response Units	2
Open Seas Containment Boom	2000 Ft.
Vikoma Sea Pack (1600 Ft. Open Seas Boom)	1
NEARSHORE/INLAND	
Helicopter Spray Units	2
Boat Spray Units	3
Dispersant	50 Drums
Collection Agent	10 Drums
BEACH PROTECTION & AUXILIARY EQUIPMENT	
Communication System	1
Automatic Propane Guns (Bird Scarers) Set of 12	2

Source Clean Atlantic Associates

Figure IV-25. Partial listing of presently available equipment in mid-Atlantic area

Item	Available
CONTAINMENT BOOMS	
Small (18" & Under)	62,600 Ft.
Large (19"-36")	28,000 Ft.
Extra Large (Over 36")	4,200 Ft.
SKIMMING APPARATUS	
Self-Propelled	1
Self-Powered & Other	141
OTHER EQUIPMENT	
Vacuum Barges	4
Vacuum Trucks	28+
Pumps	161 +
Boats (Over 15 Ft.)	93
Sorbents (Pillows & Bags)	35,000
(Boom)	10,000 Ft.
Storage	32+ Million Gallons
Ocean Going Barges	50
Automat ic Propane Guns (Bird Scarers)	12
Bird Rehabilitation Units	2
Earth Moving Equipment	Readily Available

Source Clean Atlantic Associates

pipelines over the 30-year life of a field. All estimates were the result of a statistical extrapolation of experience in the Gulf of Mexico and may not apply in the Mid-Atlantic if improvements in pollution control equipment and procedures should occur before the development of this potential offshore oil field.

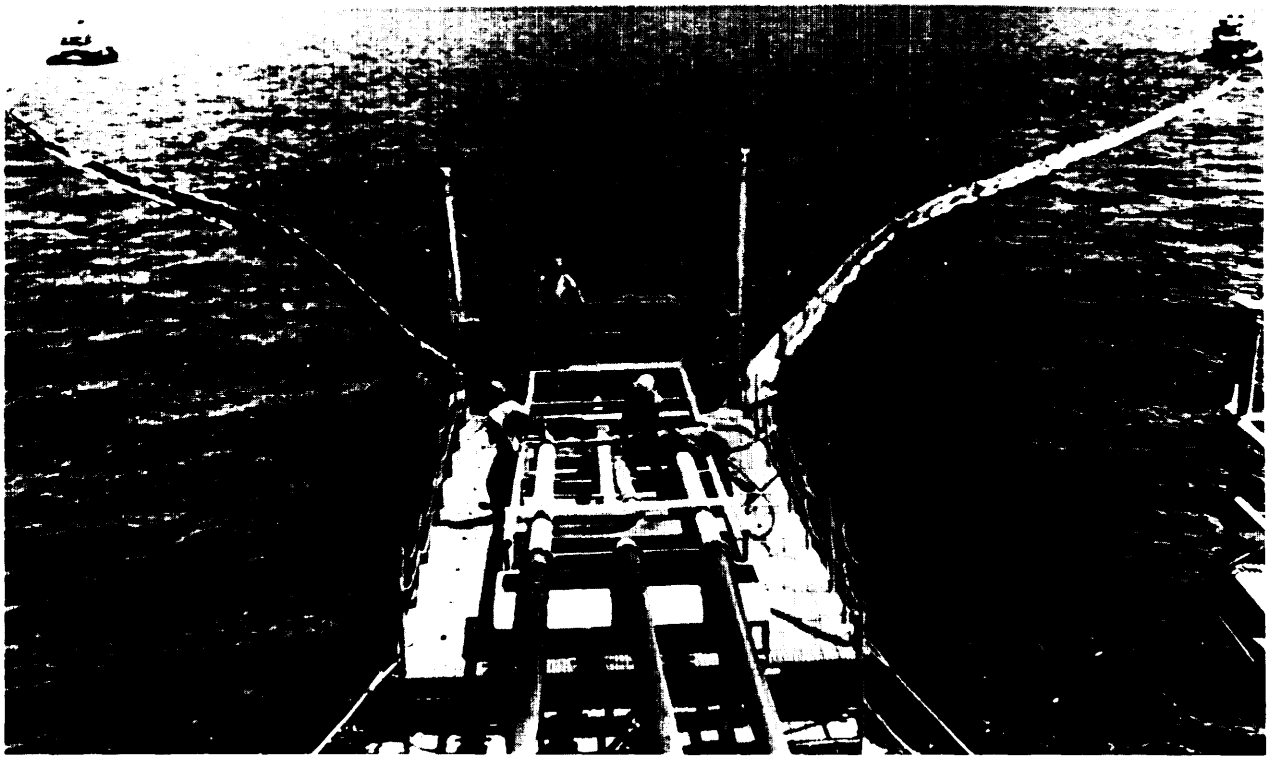
Oil companies state that the low-level discharge of hydrocarbons which result from chronic or routine discharges do not have a detrimental effect on the marine environment or the marine biota.[60]

The oil industry has sponsored a significant amount of research into the effects of oil pollution, including a study of the effects of oil operations on the marine environment off the Louisiana coast by the Gulf Universities Research Consortium.[61] In addition, the American Petroleum Institute, EPA, and USGS sponsor regular conferences on prevention and control of oil pollution at which many reports on research efforts are presented.[62] There appears to be no equivalent coordination of pollution research efforts among Federal agencies which share responsibility for OCS management.

The Report to Congress of the Secretary of Commerce on Ocean Pollution is one of the few examples of a coordinating effort.[63] The report describes oil pollution research efforts by the National Science Foundation, the Environmental Protection Agency, the Bureau of Land Management, the Fish and Wildlife Service, the U.S. Geological Survey, the National Oceanic and Atmospheric Administration, and others.

The Coast Guard has recently evaluated its

Figure IV-26. Oil cleanup equipment at work skimming spill from Gulf of Mexico



Source Clean Gulf Associates

Marine Environmental Protection (MEP) program which principally addresses oil pollution other than that related to OCS operations but which can serve as an example of analysis of causes and effects of spills. In this evaluation it is stated that oil explora - tion / production operations contributed only a million gallons out of the 15-million-gallon total discharges into U.S. waters during 1974. (See figure IV-27.) It is also stated that “the documented direct cost to society of all oil pollution incidents (from all sources) in the United States is about $50 million a year or in excess of $4,500 per incident. The estimate is undoubtedly low since it includes only the costs of cleanup and the value of the product discharged. ”

Processing and Refining and Their Impacts

Discovery of oil offshore would not necessarily y lead to the construction of new refinery capacity to process that oil. Because refinery construction and expansion decisions probably would depend more on regional demand than on local availability of crude oil supplies, it is likely that OCS oil would be processed in existing or expanded refineries and would replace higher priced crude from foreign sources by an equivalent amount. Throughput for refineries located in eastern Pennsylvania, New Jersey, and Delaware is projected to total 1.87 million barrels per day in 1985 compared with the current throughput of more than 1 million barrels per

Figure IV-27. Oil Spills in U.S. waters ranked by operation, calendar year 1974

Operation	Volume in Gallons	% of Total
1. Vehicle, Pipeline Transport	5,959,403	38.9
2. Vessel Underway	2,554,443	16.7
3. Vessel Facility Oil Transfer Operation	2,308,101	15.1
4. Unknown Operation	2,265,801	14.8
5. Natural Resources Exploration/Production	989,369	6.5
6. Vessel Mooring, Anchoring	385,487	2.3
7. Industrial Operations	290,643	1.9
8. Other Facility Operation	275,583	1.8
9. Vessel, Facility Fueling	113,037	0.8
10. Other Vessel Operation	47,104	0.3
11. Vessel Maintenance	36,658	0.3
12. Other Non Transportation Related Operations	34,130	0.2

Source U S Coast Guard, "Marine Environmental Protectlon Program Evaluation of Mission Per formance, " August 1975

day. Since this projected throughput exceeds the most optimistic estimate of peak Baltimore Canyon Trough oil production of 650,000 barrels per day by more than 1.2 million barrels per day, OCS crude could be processed in these refineries without further expansion.

If the rate of growth of existing markets for products of existing refineries in the New Jersey and Delaware areas were the controlling factor in decisions about building new refineries, then the demand could be handled by expansion of refineries already in place in the region. Refineries in the area now have a capacity of 1.3 million barrels of crude oil per day which could be nearly doubled without need for additional land. It is not clear, however, that growth in existing markets would be the controlling factor. For example, an oil company that had no regional refinery capacity might discover a significant deposit of OCS oil and choose to build a new refinery in the area to process it. Or, oil discovered in the Georges Bank area to the north could be tankered to the Mid-Atlantic refineries and lead to pressure for new construction.

If significant amounts of natural gas are found, the gas would be piped to processing plants where methane (the key ingredient of commercial natural gas) would be separated from ethane (which is used as a petrochemical feedstock) and other compounds. After treatment, natural gas would flow into gas distribution systems.

Gas processing plants would require about 100 acres of land each. For the high recovery estimate, seven plants and 700 acres would be required.

AIR QUALITY

The primary source of onshore air and water impacts (other than oil spills) associated with offshore oil and gas development would be new refinery capacity, if any refineries were built as a direct result of offshore discoveries. Analysis shows that the most important air quality impacts would result from hydrocarbon emissions while the most important water impacts would result from thermal pollution and from demands on regional water supplies.

Analysis of existing air quality in the study region indicates that environmental standards may be a significant constraint on either new or expanded refinery capacity. Under current regulations, these facilities are required to conform to the most stringent limits for each pollutant set by two basic types of standards imposed by Federal and State governments. Effluents emitted by each facility must meet certain quantitative standards with regard to pollutant content and, in addition, the ambient air quality must not be degraded below specific standards for the area by additional pollutant discharges.

Analysis indicates that in the study region the refinery pollutants of primary concern are nonmethane hydrocarbons, which react with nitrogen oxides in the presence of sunlight to form photochemical oxidant, an irritating secondary pollutant. It is estimated that a 250,000-barrel-per-day refinery emits about 40 tons of hydrocarbons per day (or 14,600 tons per year), of which 80 percent or more can contribute to the production of oxidants.

The area of study is, for the most part, at or over the oxidant and nonmethane hydrocarbon air quality standards. With any additional hydrocarbons from a new petroleum refinery or additional expansion of existing refineries, the air quality situation most likely would get worse. Even without the added pollutants, the New Jersey, New York, Connecticut, and Metropolitan Philadelphia Air Quality Control Regions total hydrocarbon emissions exceed air quality standards. In the first area, a reduction from 1971 levels of 67 percent, or 287,000 tons per year, is required. Therefore, if there is an air quality constraint on possible new or expanded refineries in the area, it would involve hydrocarbon emissions from refineries and tank farms.

WATER QUALITY

Analysis suggests that the concentration of waterborne pollutants from a new 250,000-barrel-per-day refinery effluent are relatively small and probably would not detrimentally affect the water quality of a receiving stream. The primary potential problem involves thermal impacts. The Delaware Bay and Newark Bay areas are both very close to the maximum permissible thermal load. Refinery cooling water would have some impact on these areas but technological alternatives such as the use of cooling towers could alleviate some of these problems.

As to water availability within the study area, potential problems could exist. If the various water supply regions within New Jersey are looked at in isolation and if the water demand increases up to 2,500 million gallons a day in northeastern New Jersey, a supply deficit could result. However, if the total region including the Hudson and Delaware Rivers is considered, the overall supply of water is more than adequate to meet projected demands. Ample potential supplies of water exist but control over the distribution system is fragmented and funds are not available to expand the system to take advantage of available supplies. Water from new sources would require the construction of transmission systems and water control facilities such as dams, may encounter considerable opposition.

Effects on Regional Energy Prices

Dramatic changes in regional energy prices are not expected as a result of OCS development. However, While no absolute price decreases are expected, the area receiving OCS oil and gas may have lower energy prices *relative* to some other regions which may pay premiums for higher transportation costs. Another factor would involve future policies on oil and gas price controls.[64]

The expected effects of natural gas discoveries in the Baltimore Canyon Trough on regional natural gas prices are highly dependent on assumptions concerning deregulation. In the case of complete deregulation, sales of intrastate gas in the Gulf Coast area suggest that prices of OCS gas would tend to follow the price of oil on a dollar-per-million Btu's basis, regardless of production costs. In the case of continued regulation, any price effects would depend on possible pass-through of relative cost savings resulting from reduced transportation costs compared to gas from the Gulf Coast, However, since transportation costs are a relatively small share of the delivered price of gas in the northeast, the possibility]' of offsetting increases in production costs makes large cost savings (relative to Gulf Coast gas) and price decreases unlikely.

Increasing curtailments of natural gas mean that increased availability of this clean-burning premium fuel from the OCS would be of greater importance than price savings to consumers. To the extent that deregulation is less than complete by the time that gas production begins from the Baltimore Canyon Trough, greater use of natural gas in lieu of higher priced oil would represent a cost savings to users due to a change in mix of fuel types.

Predictions of the effects of OCS oil discoveries on regional energy prices are more uncertain than for natural gas,

First, as is the case with natural gas, deregulation could have a major impact on the price of domestic oil.

Second, even under the high recovery assumptions, large quantities of imports will still be used in the region,

Third, OCS oil probably will tend toward a market price which is set by OPEC-controlled imports.

Fourth, the cost of producing Mid-Atlantic oil may be quite high, and

Finally, even if there were savings in costs, there would be little incentive to cut prices in order to achieve a larger share of a market because demand for secure sources of oil is greater than supply.

With this degree of uncertainty, any prediction of prices is necessarily contingent on assumptions concerning the future strength of the OPEC cartel and U.S. price controls.

Decommissioning

When production from a platform dropped after 15 to 30 years to levels that no longer justified its operation, the platform would be decommissioned. As the Baltimore Canyon Trough field became depleted, all platforms would be removed, pipelines would be abandoned, and tank farms and gas processing plants would be dismantled.[65]

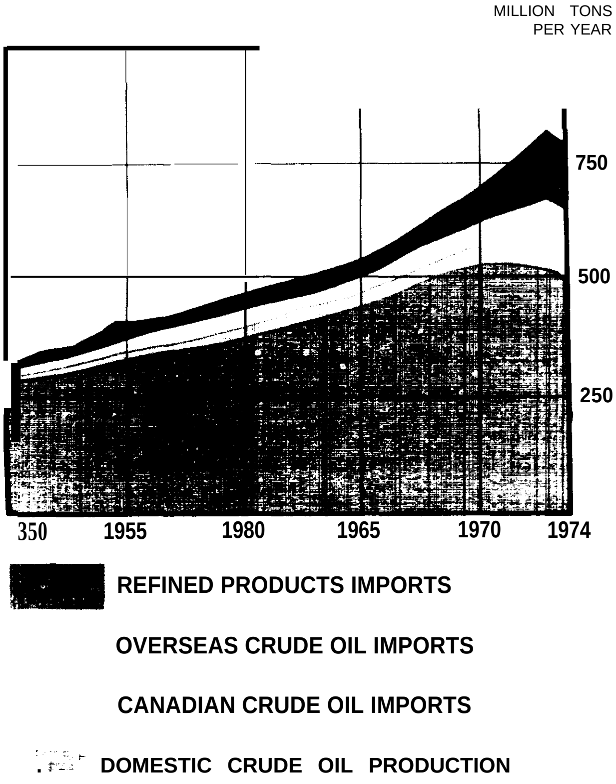
The Possibility of Deepwater Ports in the Mid-Atlantic

THE NEED FOR DEEPWATER PORTS

U.S. imports of crude oil nearly trebled between 1950 and 1970, reaching 1.3 million barrels a day just as domestic production began a steady decline from a peak of 11.2 million barrels per day of oil and natural gas liquids. (See figure IV-28.) To fill the increasing gap between demand and domestic supply, imports soared to 6 million barrels of crude and refined product between 1970 and 1973. Similar increases in oil imports took place in all industrial nations.

With the world oil industry seeking to cut the costs of moving increasing amounts of oil from producers to consumers, tankers grew in size through the 1950's and 1960's. Supertankers now in service range from 100,000 to 500,000 deadweight tons (dwt), which is a measure of their cargo capacity. Supertankers are among the largest ships afloat. Their cost advantage is demonstrated by comparison between a 250,000-dwt tanker and a 50,000-dwt tanker, which in the early 1950's was itself considered huge. Tankers of 50,000 dwt, a size that normally serves New York Harbor and Delaware Bay, average 750 feet in length, 100 feet in width, and 40 feet in draft. An average supertanker of 250,000 dwt is 1,100 feet long and draws 70 feet of water but it can carry five times as much oil as a 50,000-dwt tanker at about half the cost-per-barrel over long trade routes. [1]By 1976, supertankers of all sizes represented 55 percent of the world tanker capacity.[2]

Figure IV-28. U.S. oil supplies 1950/74



Source British Petroleum Statistical Review of the World 011 Industry

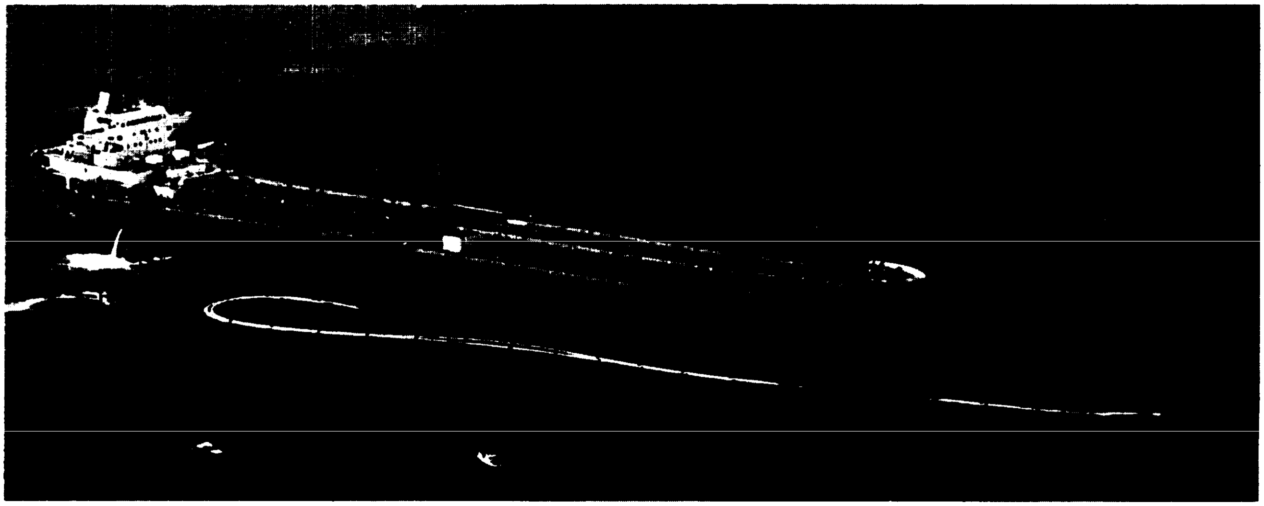
The growing dependence on super-tankers in the world distribution system in the 1960's prompted Federal officials and oil industry executives to press for deepwater ports in U.S. waters to handle this country's fast-growing imports.

Today only three U.S. ports can accommodate tankers of more than 100,000 dwt-Los Angeles, Long Beach, and Puget Sound. ? There are no deepwater ports in the Mid-Atlantic area where nearly all crude oil is imported by tanker, a degree of dependence on imported oil which is unique in the United States. (See figure IV-29.) Tankers presently deliver more than 1.2 million barrels of crude daily from the Middle East, Africa, and South America to nine Mid-Atlantic refineries.

The nine Mid -Atlantic refineries are clustered in two locations. (See figures IV-30 and 31.) More than two-thirds of the capacity is in Delaware and New Jersey where tankers

F gu e V 29 S

ANKER 252 000 DWT ESSO S NGAPORE DWP



CO

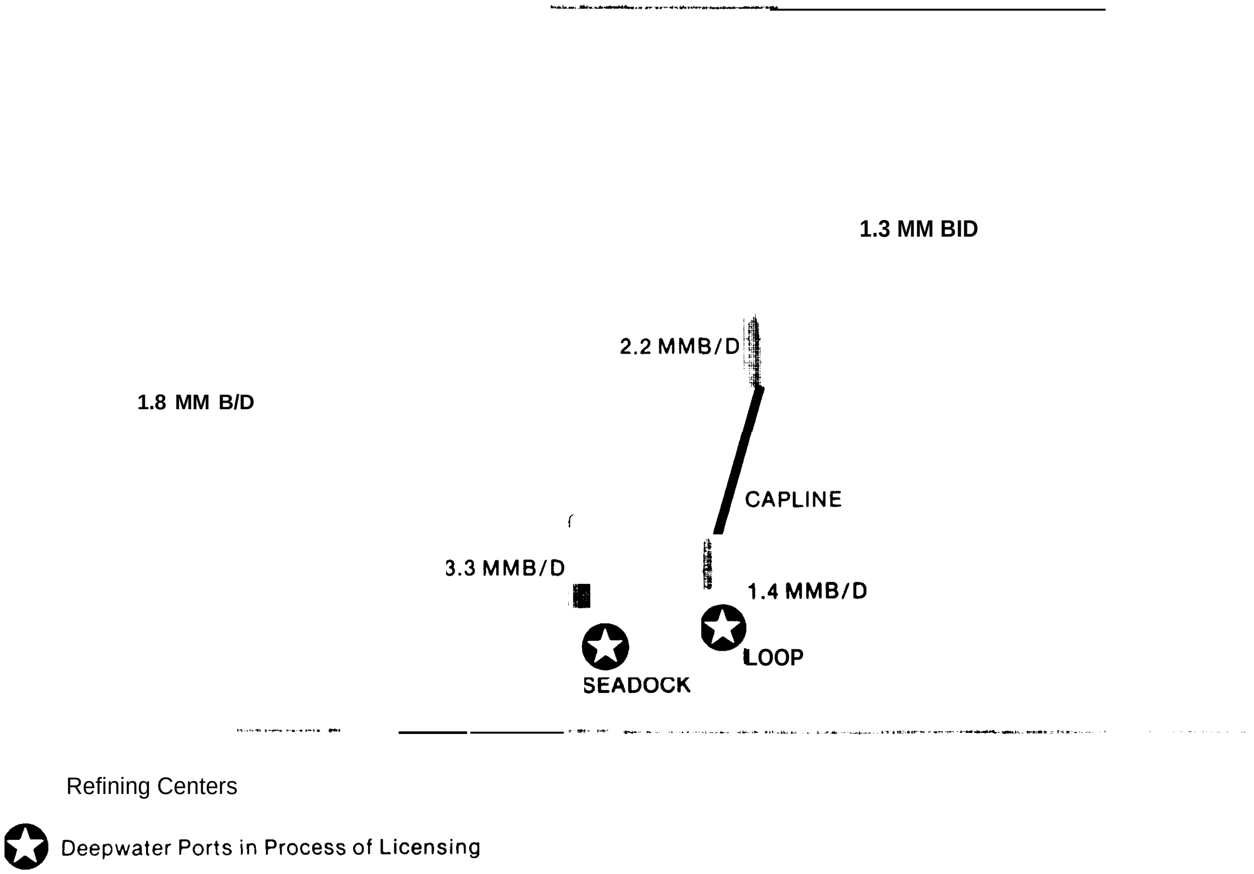
Under 50,000 Tons	50,000-75,000 Tons	75,000-100,000 Tons	100,000-150,000 Tons
San Francisco	Boston	Los Angeles	Long Beach
	New York	Portland, Maine	Puget Sound
	Delaware Bay		
	Baltimore		
	Norfolk		
	Houston		
	Galveston		

Source Office of Technology Assessment

must sail up the Delaware Bay and into the Delaware River to discharge their cargo. The other one-third of the capacity is in northern New Jersey near New York Harbor. Loaded tankers of more than 55,000 dwt—far smaller than supertanker class-draw too much water to reach the oil terminals at either location without being lightered. The controlling depth of the Delaware River channel is 40 feet. A fully loaded 100,000-dwt tanker requires 50 feet; the largest supertankers (480,000 dwt) require at least 100 feet of channel depth. Supertankers up to 150,000 dwt now anchor inside Delaware Bay, off Big Stone Beach, Del., and just outside of New York Harbor, to pump their oil into barges for final delivery to the refineries. Tankers can lighter their entire cargo, or when enough oil has been "lightered" to allow a tanker to ride higher in the water, the ship can proceed to a refinery terminal to discharge the remaining cargo.

In 1975, oil from 429 tankers was lightered to 1,055 barges in the Delaware Bay anchorage. Spillage reports on this lightering operation, run by Interstate Oil Transport Co. of Philadelphia, indicate it is exceptionally clean and free of accidents that lead to pollution. Officials of the lightening firm claim the operation was responsible for only 5 gallons of oil spilled into the bay during 1975. J This is not, however, an adequate measure of the

Figure IV-30. Major U.S. refining centers



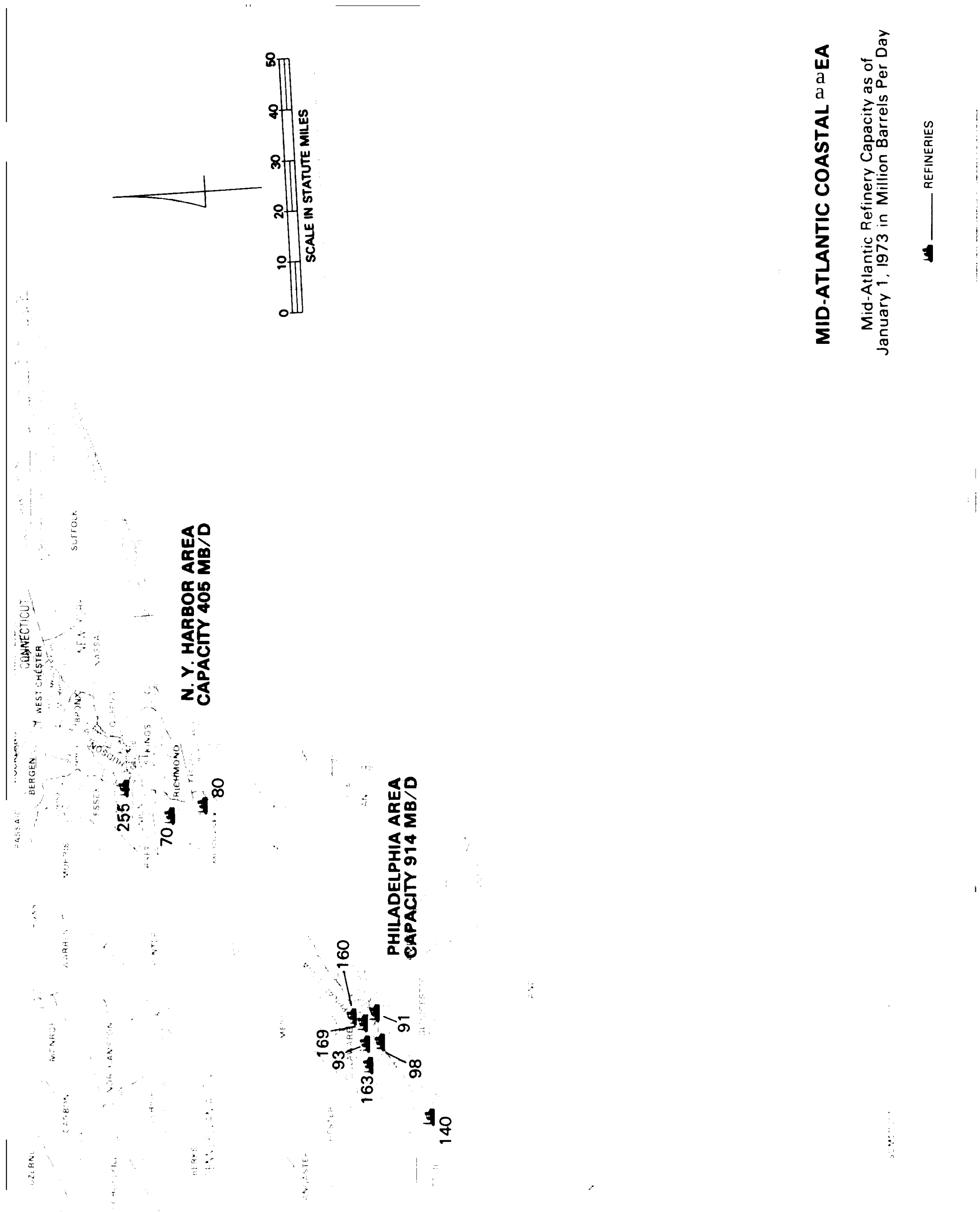
Source Office of Technology Assessment

risks of the present system because lightening operations force a substantial increase in barge and small tanker traffic, and these vessels themselves often are responsible for serious polluting accidents in world harbors. s

One comparison of the lightening system with a deepwater port system was provided by the president of the Philadelphia Maritime Exchange several years ago during testimony before the Delaware General Assembly:

> "On April 28, 1974," he said, "the largest tanker ever to enter the Delaware Bay, the 191,000-dwt Japanese tanker Yasutama Maru, arrived at the Big Stone Beach tanker anchorage and lightered her entire cargo of crude oil—1,283,865 barrels—using a small ship and barges to transport the oil upriver. The vessel sailed out of the bay in ballast on May 10, During the oil transfer operation, while in the bay, 15 separate lightening operations were needed. This involved a 25,000-dwt tanker which made 4 trips from the anchorage to the upriver refinery plus 11 barge voyages to and from Big Stone Beach anchorage. How much better and safer this could have been handled under the controlled conditions of a deepwater port which would permit a tanker to tie up to a platform, transferring its cargo into a pipeline, in a single operation, moving the oil via the pipeline direct to the refinery. "

Figure IV-31. Mid-Atlantic refinery capacity as of January 1, 1973



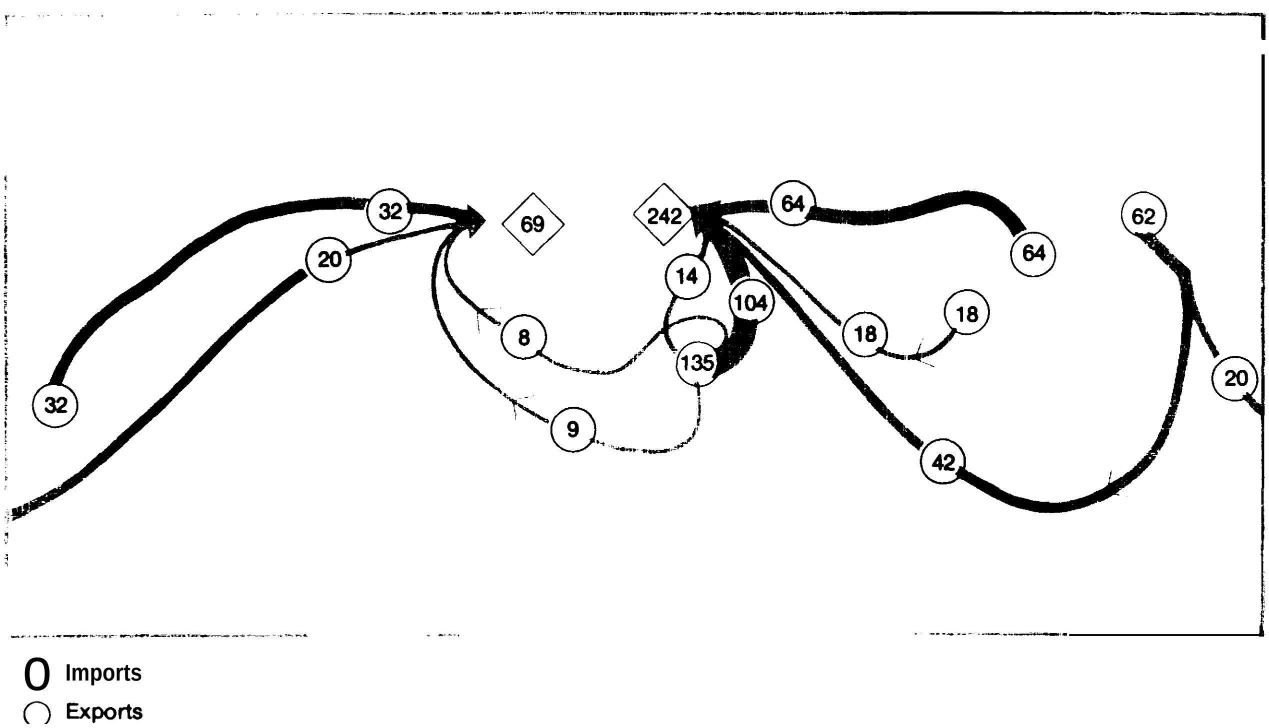
Source Office of Technology Assessment and EXXON Corporation

In 1973, tankers brought 870,000 barrels of crude oil a day to Delaware River ports and 410,000 barrels per day into New York Harbor.[6] The combination of increasing demand and dwindling domestic production in the early 1970's led the oil industry to plan new Mid-Atlantic refineries to be supplied by foreign crude. At that time, it appeared that crude oil demands could be met with relatively cheap and virtually unlimited supplies from the Middle East. (See figure IV-32.)

Several studies commissioned by the Federal Government and by private industry between 1968 and 1973 reached the general conclusions that:[7]

- Increasing volumes of oil shipped to the United States over the next 10 to 25 years would be carried by supertankers.
- Most of the crude imported by the United States would be shipped from the Middle East and Africa.
- The United States had a choice of installing deepwater ports to handle imports directly or relying on transshipment in smaller tankers from deepwater ports in Canada and the Caribbean.
- Transshipment would be more expensive than direct delivery of crude oil in supertankers to Mid-Atlantic deepwater ports.
- The economic and environmental costs of dredging existing channels in the Mid-Atlantic harbors to enable supertankers to reach existing dock facilities probably would rule out such an approach.
- Deepwater ports could be built in New England, the Mid-Atlantic, the South

Figure IV-32. Oceanborne crude petroleum to the United States— 1969 (millions of barrels per year)



Source Executive Summary, "Offshore Terminal System Concepts, " Maritime Administration

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Atlantic or the Gulf of Mexico without modifying the technology already in use in deepwater ports off the shores of other industrial nations.

. The need was greatest in the Mid-Atlantic region.

In the early 1970's, industry and Government sources talked of moving 2 million barrels of crude a day into Delaware River ports, which would mean an average of five arrivals each day of 55,000-dwt tankers, the largest ships that could navigate the Delaware River channels. If the crude came in one 200,000 dwt to 250,000 dwt, it would require lightening into 15 smaller vessels or into a deepwater port.

Many studies between 1970 and 1973 stressed the economic advantages of deepwater ports for the Mid-Atlantic. In general, they concluded that it would cost less to ship oil from Africa or the Persian Gulf to east coast refineries with supertankers and deepwater ports than with the existing system. A range of sites and systems were proposed. Savings, when compared to such alternatives as transshipping thru Caribbean ports, were estimated to be 5–15 cents per barrel (less than one-third-of-a-cent per gallon).[8] While this is a small unit cost, it translates to major savings for a transport system carrying nearly half-a-billion barrels per year to the east coast—between $75 million and $225 million a year.

DEEPWATER PORT PROPOSALS

Studies sponsored by Government and industry in the 1960's and 1970's produced a variety of approaches to construction of deepwater ports at specific locations on the east coast and in the Gulf of Mexico. All of the studies drew on experiences abroad, where deepwater ports were developed in the 1960's, principally to handle supertankers in the Persian Gulf-to-Europe and the Persian Gulf-to-Japan trade. More than 100 such ports are in use today, as shown in figure IV-33.

The kind of deepwater ports contemplated for various locations around the United States will have their principal use as terminals for very large tankers carrying crude oil to major refining centers from distant major producing fields such as the Persian Gulf.

Other products also can be or are proposed to be transported through offshore terminals, including ore slurries, but most of those are very special situations.

Deepwater ports are not usually justified for transferring refined products because smaller tankers are used to carry refined products, the products are widely distributed through small, scattered terminals, and the present transport system is geared to the use of the smaller tankers within existing harbors and waterways.

A study for the U.S. Maritime Administration by Soros Associates Inc. in 1972, concluded that a 500-acre artificial island could be built inside Delaware Bay off the southern tip of New Jersey, creating a port that would handle 6 million barrels of crude per day. The port would have berths for six supertankers. Storage tanks would be located on the island with the port.

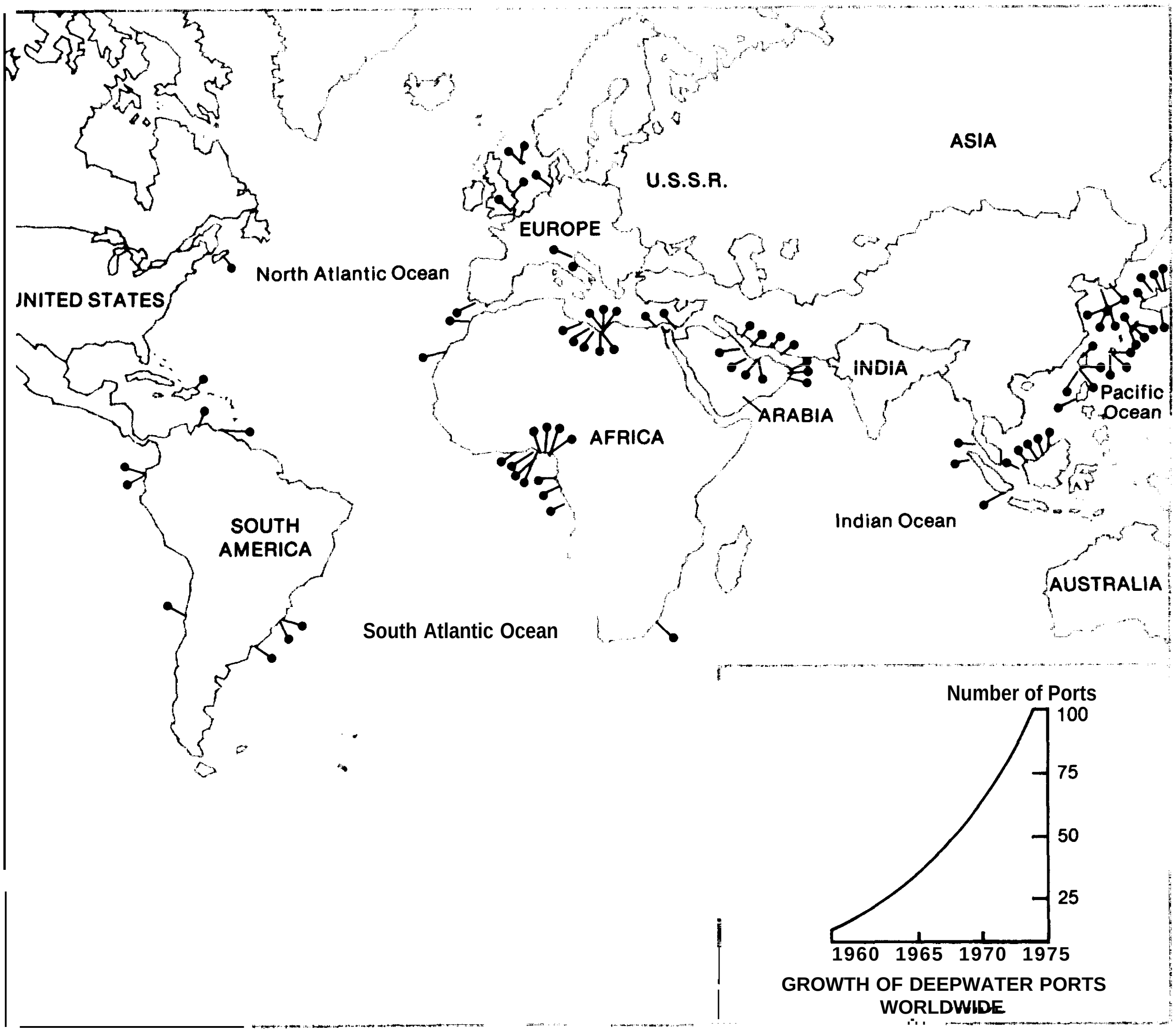
A study for the Council on Environmental Quality, prepared by Arthur D. Little Inc. in 1973, pictured a port in the Delaware Bay area transferring about 6.6 million barrels per day to new refineries in Cumberland and Cape May Counties of New Jersey. The report said that 14 square miles of the counties—which now are devoted to farming and resort activities—would be required for at least 9 new refineries and 13 new petrochemical plants. As a result of the port and associated industries, the two counties would become "a new industrial center" with employment doubling to 300,000 workers by the year 2000, the report said.

Industry's own private studies resulted in proposals for deepwater ports in the Atlantic off Long Branch, N.J., and in the Delaware Bay.

The Delaware Bay site was proposed by a consortium of oil companies which own refineries along the Delaware River.

The consortium, the Delaware Bay Transportation Co., purchased 1,800 acres of coastal land in Kent County, Del., for storage tanks, landside headquarters, and a supply base for the deepwater port. The companies planned to build their port 5 miles offshore but inside the bay. (See figure IV-34.) They planned a sea pier which could berth three super tankers of up to 250,000 dwt simultaneously and transfer crude oil into pipelines running first underwater to the tank farm and then overland to upriver refineries. The port capacity was to be 2 million barrels per day, an amount the consortium concluded would satisfy the needs of existing refineries (with expansion that was then planned) and one new refinery (which was then planned by Shell Oil Co.). The proposed port was to use a natural deepwater channel into the bay and require only "minimal" dredging to maintain a draft of 70 feet along the approaches to the

Figure IV-33. Worldwide single-point mooring installations—1 973



Deepwater Ports

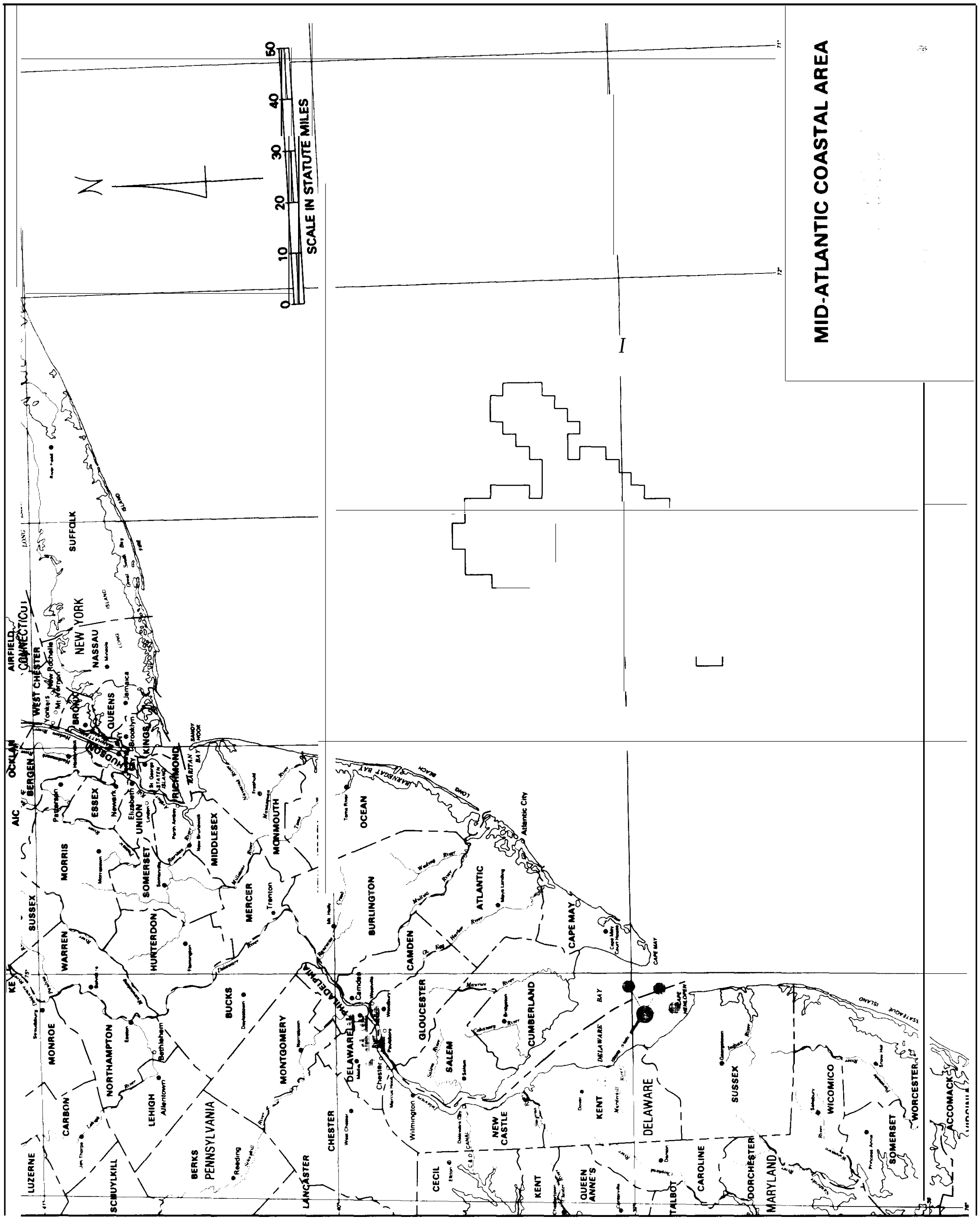
Source Off Ice of Technology Assessment

port and at the port itself. In the late 1960's, planners projected that construction would cost $193 million.[9]

Local opposition to the Delaware Bay port was strong. In 1971, Delaware's General Assembly approved one of the Nation's strongest pieces of land use and environmental legislation, the Delaware Coastal Zone Act, which prohibited the construction of any new heavy industry—including refineries, tank farms, pipelines, and bulk offshore unloading terminals—in the coastal area. Almost immediately after passage of the law, a campaign was organized to have the law repealed or amended. To date, those efforts have been unsuccessful.

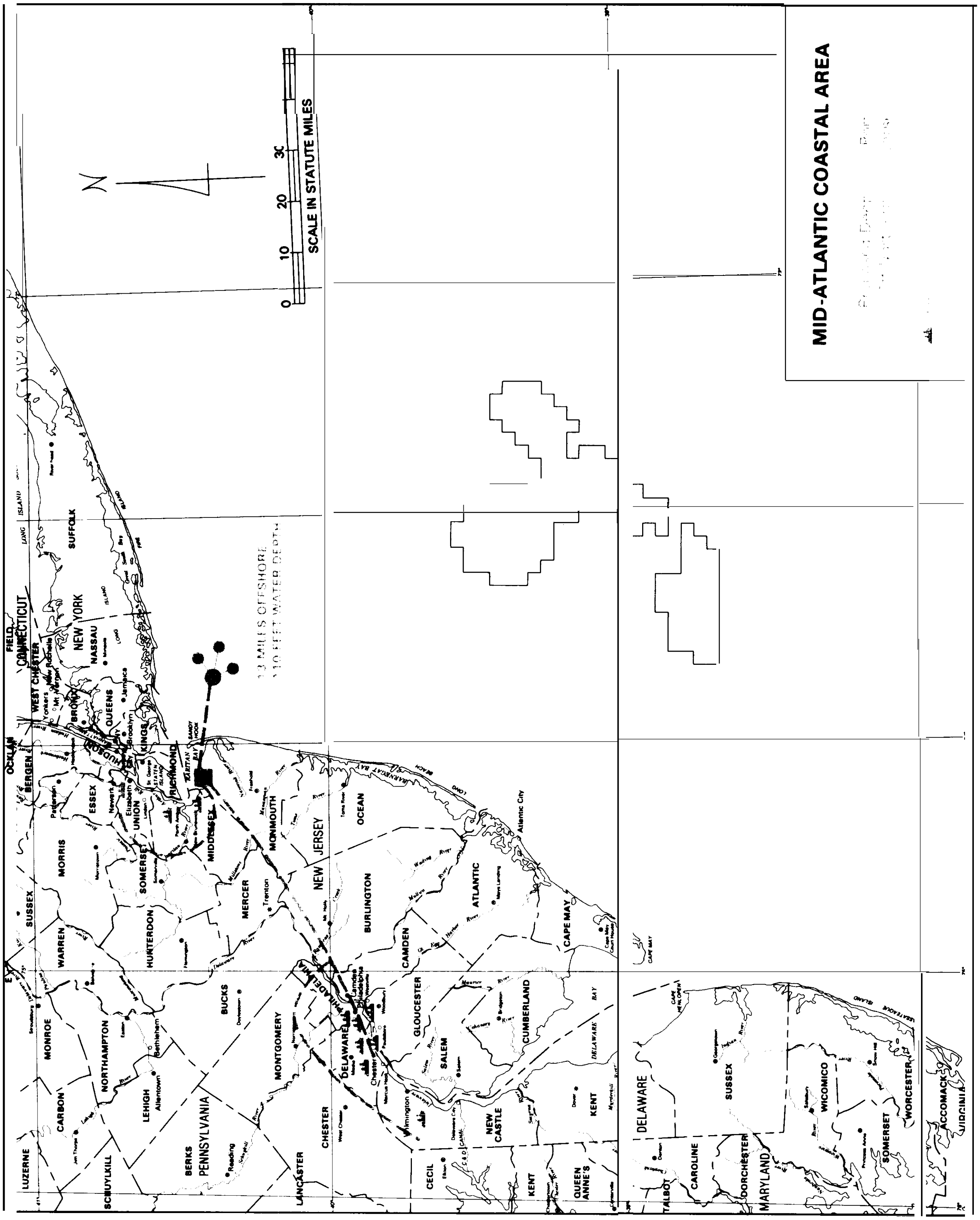
Before the 1973 Arab oil embargo, EXXON Corp. gave serious consideration to a deepwater port in 110 feet of water some 13 miles off the coast of Long Branch, N.J. (See figure

Figure IV-34. Proposed deepwater port site in Delaware Bay.



Source Of fice of Technology Assessment and Energy 011 and the State of Delaware

Figure IV-35. Deepwater port site offshore northern New Jersey, proposed by EXXON in 1973



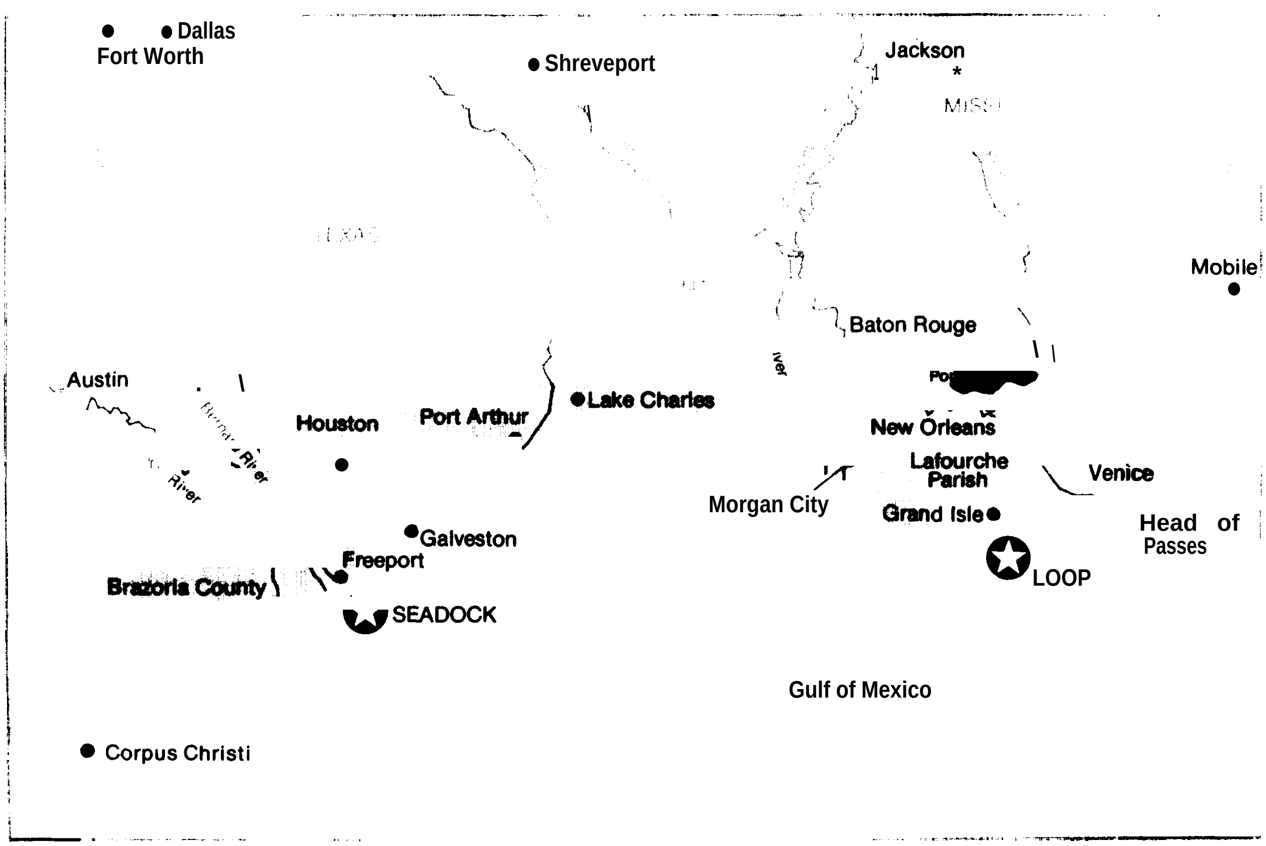
Source Off Ice of Technology Assessment and EXXON Corp.

IV-35.) The proposal no longer is an active plan. EXXON has chosen to expand its Baytown, Tex., refinery rather than its Bayway, N.J., refinery. Total refining capacity in northern New Jersey now is about 500,000 barrels, less than half of the capacity that one EXXON official said would be required to support a northern New Jersey deepwater port.

New Jersey residents, particularly in the south, opposed construction of deepwater ports off the southern shore and the massive industrialization which the Little study indicated might result. In 1973, the New Jersey Legislature declined to pass a formal ban on deepwater ports and related development, and instead made each energy facility proposed for the coastal area subject to individual review. The former Governor, Thomas Cahill, declared himself strongly opposed to plans for a deepwater port that would industrialize rural counties. The present Governor, Brendan Byrne, has taken a similar public position.[10]

Consortia of oil and petrochemical companies also proposed two deepwater port projects in the Gulf of Mexico off the coast of Texas and Louisiana. Both projects are still active. (See figure IV-36.)

Figure IV-36. LOOP and Seadock deepwater port sites in the Gulf of Mexico



Coastal Zone

Terminal Sites under Study

Source Arthur D Little, Inc

Seadock, the Texas terminal, was planned by a company made up of nine oil and chemical firms with plants in the area. They propose a port of three monobuoys anchored in 100 feet of water 26 miles off Freeport. Capacity will be 2,5 million barrels of oil per day by 1980 with an ultimate expansion capacity to 4 million barrels per day. The port plan also includes offshore pumping stations which will move crude oil at the rate of 125,000 barrels an hour from the monobuoys to inland refineries. In 1976, the cost of the system is estimated at $659 million.11

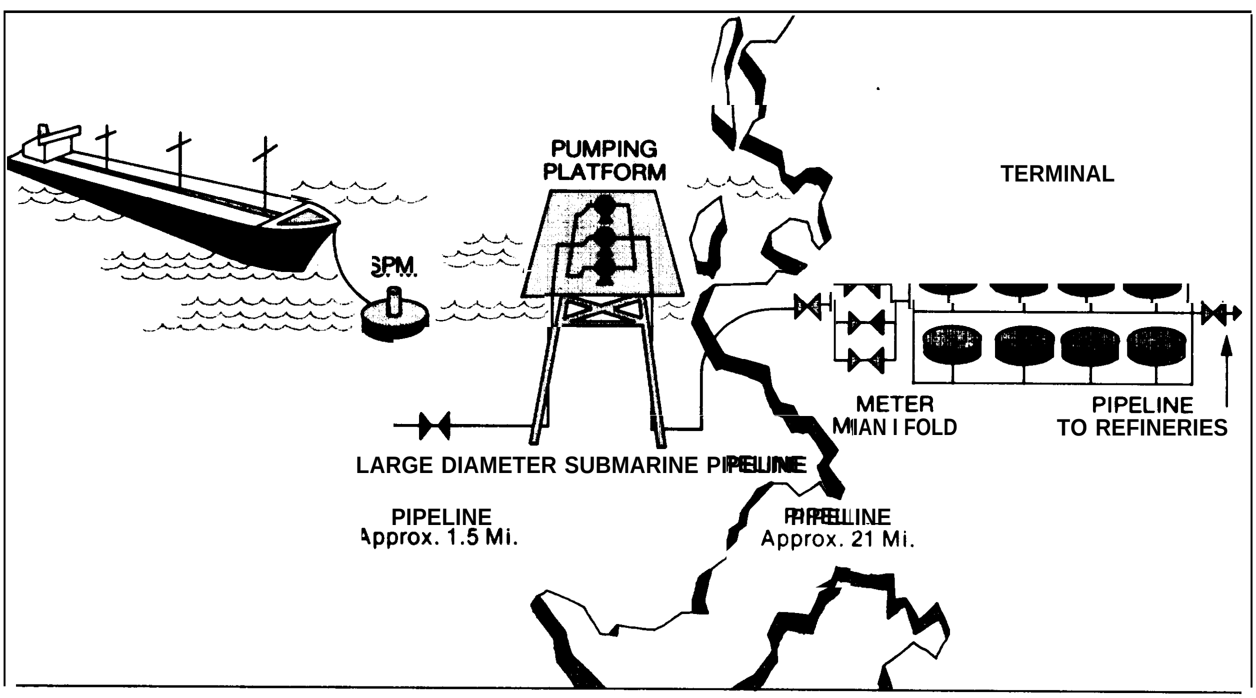
LOOP (Louisiana Offshore Oil Port, Inc.) plans a monobuoy port located in 100 feet of water 19 miles off the Louisiana coast. The port will start operation with a capacity of 1.4 million barrels a day and expand to a capacity of 3.4 million barrels a day by the year 2000. Cost of the LOOP system is put at $348 million for the early phase and $800 million for the expanded version. 12

It has been suggested that offshore deepwater ports could be utilized for mooring supertankers while offloading cargo into smaller tankers or barges for transport to refineries rather than through pipelines, as is a more common plan. It would be feasible to operate such a monobuoy lightening port and some advantages could be expected, such as employment of more small tankers and barges and a more flexible distribution to a variety of refinery locations.

The chief disadvantage is that the use of more small tankers and barges increases the risk of pollution.

It appears that industry plans for deepwater ports do not presently contemplate using the lightening system; however, offshore lightening has been used in the past and is part of a major project to supply the new 200,000-barrel-per-day "Ecos" refinery in Louisiana for the next 3 years. The plan is to offload super-

Figure IV-37. LOOP deepwater port layout



Source "Louisiana Offshore 011 Port, " LOOP, Inc , New Orleans, Louisiana tankers into smaller tankers of about 90,000 dwt while underway offshore. This system will be utilized until the LOOP deepwater port is ready to handle the oil.[13]

Faced with a growing number of specific proposals for deepwater ports, Congress enacted the Deepwater Port Act of 1974. The Act requires that the Secretary of Transportation license all ports located in Federal waters and that the Coast Guard write and enforce regulations for the construction and operation of the ports. Comprehensive Coast Guard regulations were published in the Federal Register on Nov. 10, 1975,11 along with proposed guidelines for developing design criteria for specific sites, guidelines for site-specific environmental impact statements, and guidelines for detailed operating procedures.

The Coast Guard is pursuing several research programs to develop design criteria on which to evaluate future port construction and operations. The principal concerns, which will receive priority research and development attention, are in the areas of oil spill response systems, oil spill consequences, inspection methods, and procedures. It appears that the Coast Guard approach to regulations and further research to improve regulations is reasonable and should provide for future contangencies.

Seadock and LOOP have both applied for licenses under the Deepwater Port Act. The Delaware Bay Transportation Co. would not need a license under the act because its proposed port is located in the State waters controlled by Delaware.

Deepwater ports in local waters require no license from the Transportation Department under the Deepwater Port Act, but they do require permits from the U.S. Army Corps of Engineers.

The Corps' jurisdiction over nearshore deepwater ports originates in two laws—the Rivers and Harbors Act of 1899, which prohibits obstructions to navigation and dredging in navigable waters without a permit from the Corps, and section 404 of the Federal Water Pollution Control Act of 1972, which requires a permit before dredged material can be deposited in navigable waters.

The Corps of Engineers is not bound by the Deepwater Port Act. It may issue permits on the basis of its own judgment of an applicant's design without regard to Coast Guard regulations for deepwater ports beyond the 3-mile limit. By the same token, the Corps could require ports under its jurisdiction to comply with construction and operation regulations promulgated under the Deepwater Port Act.

One port in local waters recently has been approved by the Corps. Permits for that port, a monobuoy facility to be located about 2 miles off the south coast of St. Croix in Canegarden Bay in water depths of 200 to 230 feet, were issued to the Virgin Islands Refinery Corp. on June 18. Construction of the port will begin immediately and completion is expected within 3 years.

The absence of any required coordination between the Corps and Transportation's Deepwater Ports Office could lead to problems in the future because there is no guarantee that ports in local waters would meet minimum safety and environmental standards set at the Federal level to protect the national interest and the interests of States other than the host State.

The Corps' Jacksonville division, which issued the permits for the Virgin Islands port, coordinated its activities with Transportation only by sending a public notice of the application to the Coast Guard and by contacting the Coast Guard on the environmental impact statement. The Jacksonville office also asked the Coast Guard to develop a vessel movement control system for the port, but made no effort to apply Federal safety or equipment standards to the port before approval of the permit.[15]

Presently another nearshore application is pending in the Virgin Islands, and at least two other ports in State waters are in early planning stages elsewhere off the east coast. These applications and the construction and operation of the ports will be useful in determining whether closer coordination of Corps and Transportation procedures and regulations is needed.

STATUS OF NEW JERSEY AND DELAWARE PLANS

A deepwater port probably will not be built to serve the Mid-Atlantic States during the next 10 years.

The Arab oil embargo and the cloud it placed over the reliability of imports was a major factor in the oil industry's decision to postpone deepwater port development. But it is only one of several factors, including State policies to discourage new refineries, Federal air quality regulations, which have the same effect, and sharply inflated construction costs. Another major factor is the oil industry's decision, faced with growing opposition to refineries and encouraged by Federal tax policies and import quotas, to develop an alternate system for supplying Mid-Atlantic oil products from Caribbean and Gulf Coast refineries. Industry is not likely to abandon the system as long as its costs are relatively close to the costs of refining oil on the Atlantic coast.

Oil consumption in the United States dropped in 1974 and then leveled off in 1975 at 16.3 million barrels a day, principally because of the 1974–75 recession. Recent forecasts estimate that consumption will climb to 20 million barrels a day by 1985.[16]

As much as half of the projected 1985 supply may be imported because domestic oil production has continued to drop since 1970. Even with production on Alaska's North Slope, domestic output is not likely to return to its 1970 peak of 11.2 million barrels, at least in the near future.

Oil consumption in New York, New Jersey, Delaware, and Pennsylvania is expected to climb to 3.8 million barrels a day by 1985, an increase of 1.1 million barrels a day over the 1975 levels. During that time, total imports of crude oil to refineries supplied through New York Harbor and the Delaware Bay may increase from 1975 levels of 1.2 million barrels a day to 2 million barrels a day only it there are expansions in refinery capacity,

Estimates in figure IV–38 were developed from a February 1976 forecast of demand by the Federal Energy Administration. Crude oil import figures assume that there will be some

Figure IV-38. 1976 projections of petroleum supply and **demand**

IN MILLIONS OF BARRELS PER DAY

A. UNITED STATES TOTAL

	1975	1985
Total Demand	16.3	20.0
Imports	6.0	10.0

B. MID-ATLANTIC REGION
(New Jersey, Delaware, New York, and Pennsylvania)

	1975	1980	1985
Total Demand	2.7	3.4	3.8
Total Imports	2.2	2.9	3.3
Crude Oil Imports°	1.2	1.5	2.0

'Likely to f low through any deepwater port

Source Federal Energy Administration, "National Energy Outlook, " 1976 (for 1965 reference case) and with present crude oil to total import ratio extrapolated

1' , 1,

refinery expansion so that area refineries will continue to supply about 55 percent of the region's petroleum products.

Increases in excess of refinery capacity in the Mid-Atlantic will be in product while crude oil moves to the Gulf Coast for refining and redistribution coastwise by small tankers or overland by product pipeline.

About one-third of all oil products used in the Mid-Atlantic in 1974 were residual fuels which were transshipped from the Caribbean for generating electricity. Although the Federal Energy Administration forecasts a shift of about 12 percent of electric power generation from oil-fired to nuclear or coal-fired plants over the next 10 years, its projections still imply a continued heavy reliance on residuals. [17]

In recent years, State land use and environmental policies have discouraged the construction of new refineries in coastal areas of New Jersey and Delaware.

The Delaware Coastal Zone Act flatly prohibits construction of refineries or pipeline landings in the coastal area. Existing Federal and State air quality regulations make construction of new refineries along the Delaware River and Bay unlikely in the foreseeable future although existing refineries may be expanded without exceeding pollution standards.[18]

Since 1970, an Amerada-Hess refinery in the Mid-Atlantic region has been closed; plans to double the capacity of a Mobil Oil Co. refinery in New Jersey have been canceled; and construction has not begun on a Shell Oil Co. refinery, originally planned for a site in Delaware and then for a site in New Jersey.

Because a decision to build a deepwater port would logically follow—and not force—a decision to build new refineries, a port is likely to be postponed at least until the Mid-Atlantic refinery picture changes.

Inflation also has worked against construction of a deepwater port, pushing the costs of a port inside Delaware Bay from $193 million to more than $400 million. The estimated cost of dredging some 15-million to 20-million cubic yards of bay bottom for a channel to the port that would handle 250,000-dwt tankers has increased in that time to more than $40 million. [19]

In 1971, the Delaware Bay Transportation Co. estimated that oil could be transferred through its proposed port for 12 cents a barrel. At the inflated construction costs, the price in 1975 would be closer to 25 cents and possibly as much as 39 cents if Delaware were to tax incoming oil at 1 percent of its market value.[20]

At those prices, most of the cost advantage of using supertankers would be lost and the port would provide an economic advantage only for tankers on the longest trips between the Persian Gulf and the Mid-Atlantic region. Even on that route, savings would be significant only with tankers of 250,000 dwt or more. There would be little or no cost advantage over lightening for tankers between 100,000 dwt and 200,000 dwt. Deepwater port transfer costs actually could be higher than lightening for small tankers or for large tankers on shorter runs from Africa or South America.

The increased transfer costs would eliminate much of the economic advantage which was perceived by New Jersey and Delaware residents to be a prime argument in favor of a deepwater port.

Citizens responding to OTA questionnaires said they believed the port would reduce the cost of petroleum products by providing a more efficient transportation system.

Not all oil industry officials agree with the cost figures cited in this study, which were generated by the PenJerDel Corp., an affiliate of the Philadelphia Chamber of Commerce, in a 1975 study. Industry officials do agree, however, that a Mid-Atlantic deepwater port would be marginally feasible in the near future,[21] particularly when its costs are compared with the 1975 lightening charge of 8 to 11 cents per barrel.

However, one change in the existing Delaware Bay system could revive interest in a deepwater port—for environmental rather than economic reasons.

There never has been a major lightening accident in Delaware Bay. One accident or a series of accidents could provoke political action to build a deepwater port not only to eliminate lightening but to reduce the number of tankers that will be required to carry growing supplies of imported crude oil to docks in the Delaware River.

Many people responding to the OTA public participation questionnaire said a reduction in the risk of lightening accidents is a major argument in favor of building a deepwater port.

DESCRIPTION OF DEEPWATER PORT TECHNOLOGY IN THE MID-ATLANTIC

If a deepwater port were constructed in the Mid-Atlantic, it would probably be a monobuoy port located off southern New Jersey.

The OTA study investigated a range of technical and siting options for a port under several demand assumptions. Because the capacity to expand refineries is substantially greater in the Delaware Bay area than in northern New Jersey, the study assumed the port would be oriented toward the Delaware Bay refineries and located 30 to 32 miles off the New Jersey coast. At such a site, the port would be in waters under Federal jurisdiction and would be located far enough from the coast to serve the largest supertankers in the world fleet, the 480,000 dwt, which require 110 feet of water depth for maneuvering. (See figure IV-39.)

Because of uncertainties about import projections and the low level of industry interest in any near term project, this description of port technology is confined to one logical-sized port and its impacts.

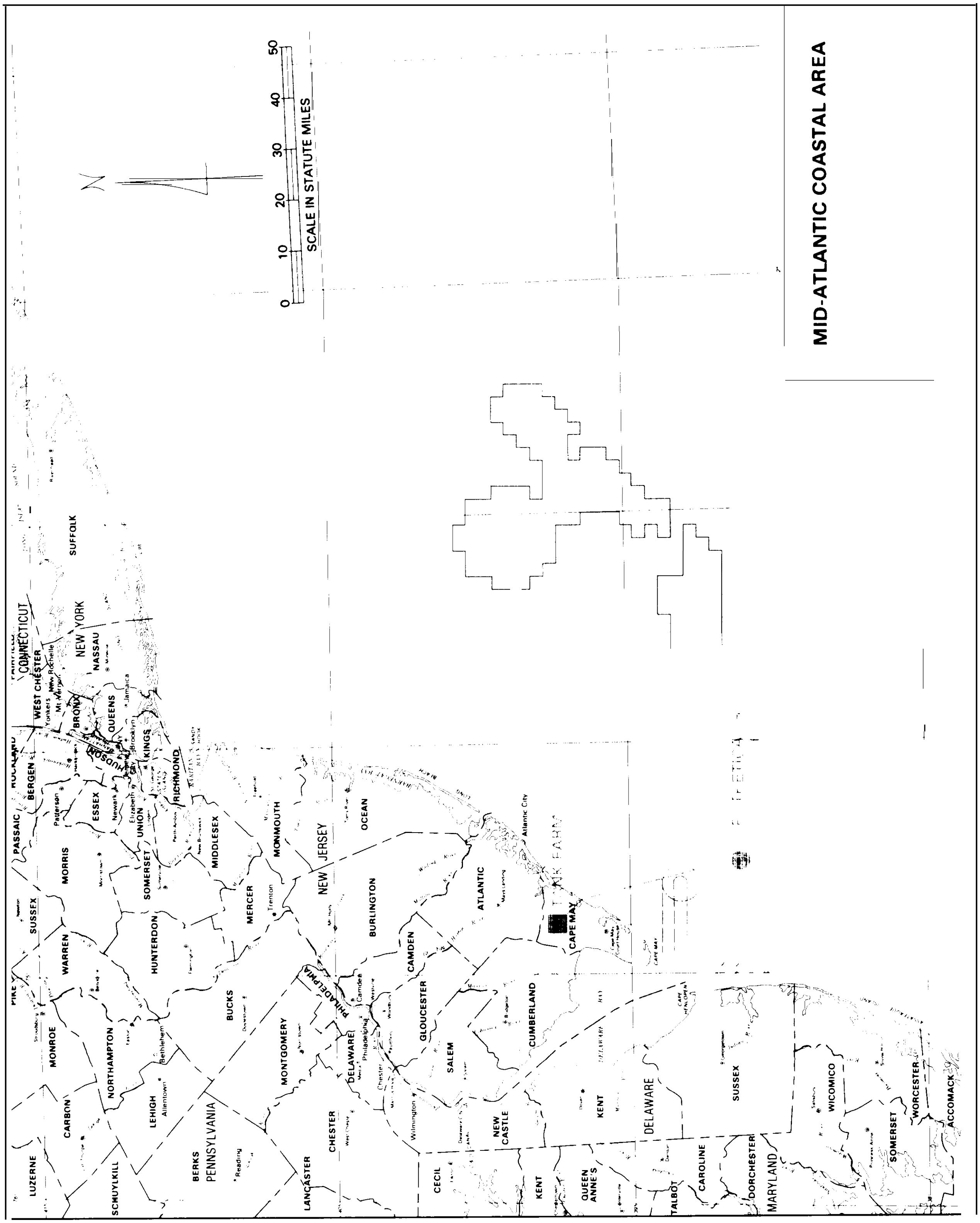
It should be emphasized that the site and type of port selected relate only to technical feasibility y. Basic changes in Government policy, the economics of oil distribution, and standards governing air pollution would be necessary before the events described in this report could actually take place.

Several general categories of deepwater ports now operating around the world could be adapted to the east coast, including the integrated, bulk cargo, island port—which would require much more detailed planning than has been done to date—and the structural pier built for alongside mooring of tankers—which would be a likely design for use inside the Delaware Bay.

The OTA study assumed that the choice would be a monobuoy, the least expensive and most versatile system in the present world network of more than 100 deepwater ports. This is essentially the same technology proposed for LOOP and Seadock in the Gulf of Mexico.

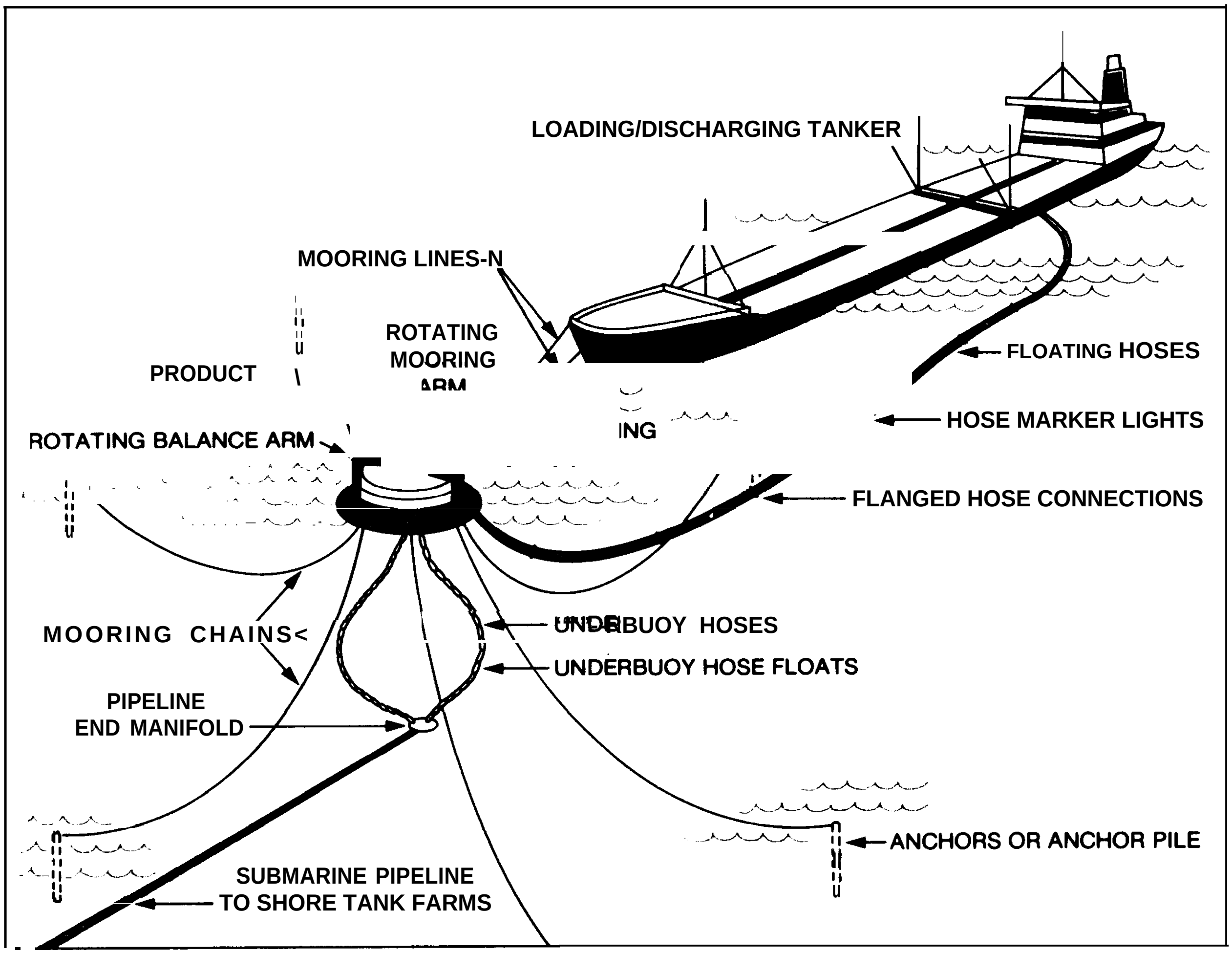
The technology for monobuoys has been m use since 1960. Foreign ports have demonstrated safe operations over several years of intensive use. Although it is true that the United States has no experience with the ports

Figure IV-39. Hypothetical deepwater port site offshore New Jersey coast



Source Office of Technology Assessment

Figure IV-40. Catenary anchor leg mooring (CALM)



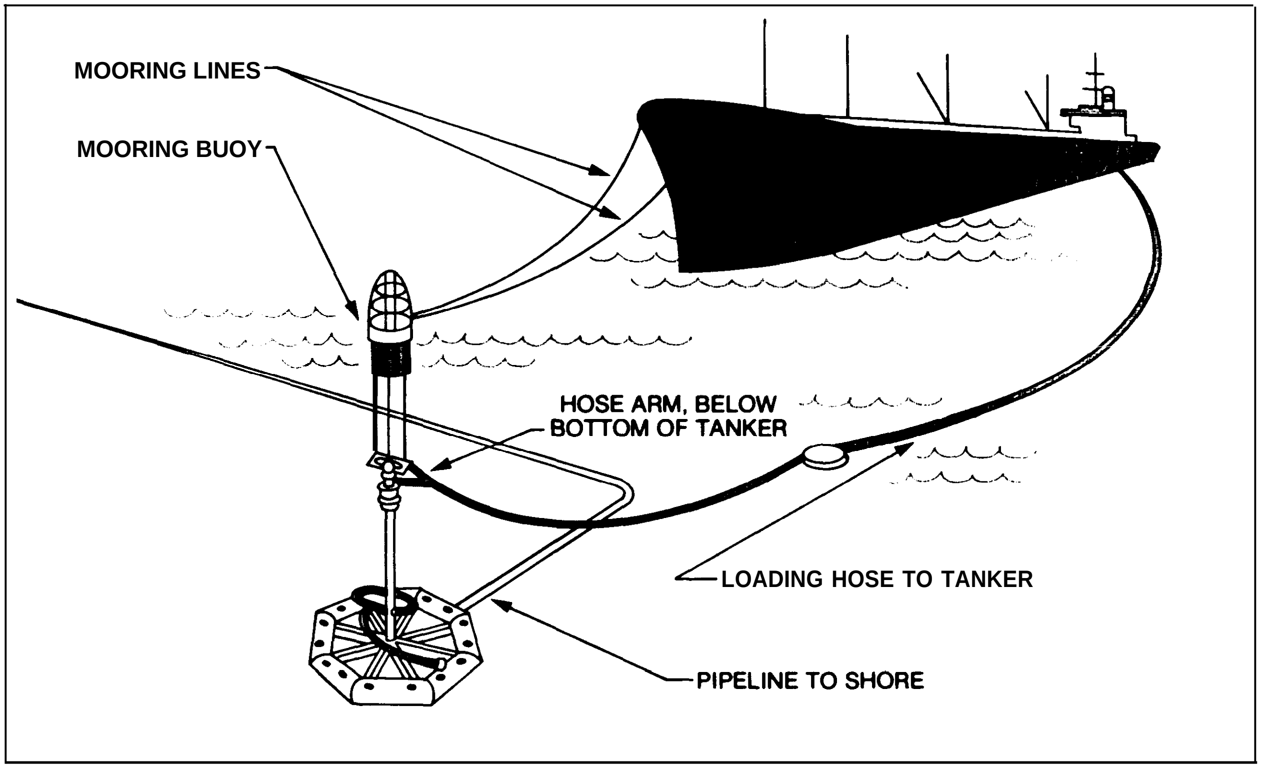
Source "Tankers and the U S Energy Situation, " Poricelli and Keith.

in its waters, many of the ports in the worldwide system are owned by the multinational oil companies which would be able to transfer their knowledge to American sites. In addition, the technology for component parts of the monobuoy system—the platforms, hookups, pumps, pipelines, and storage tanks—has been in use in offshore exploration and production, shipping, lightening, and distribution of oil in the United States for several decades.

Two types of monobuoys are presently in use and could be adapted to the Mid-Atlantic. The most common is the Catenary Anchor Leg Mooring system (CALM). (See figure IV-40.) The other, more recent, design is the Single Anchor Leg Mooring system (SALM). (See figure IV-41.)

The CALM is a floating steel cyclinder 30- to 50-feet across and 15 feet thick which is tethered to the sea bottom by 6 to 8 anchors and chains. Rubber hoses rise from a connection with a pipeline buried under the sea floor through the center of the buoy and float on the ocean surface. Tankers tie up to the CALM and launch crews guide floating hoses to the tankers, hoist the hoses aboard, and secure them to discharge manifolds. Crude is then

Figure IV-41. Single anchor leg mooring (SALM)



Source "Tankers and the U S Energy Situation, " Poricelli and Keith

pumped through the hoses, into the pipeline and on to shoreside storage tanks.

Because tankers can weathervane around the CALM and maintain a heading into wind and waves, there usually is no need for protective breakwaters even offshore. But because launches are required to help secure hoses to a tanker's manifold, mooring operations cannot be conducted in seas higher than 6 to 8 feet. Once moored, however, a tanker can discharge crude oil in waves as high as 10 to 12 feet and winds of up to 40 knots.

One drawback to the CALM is that there is a danger of tankers overriding the buoy and tearing the hose connections which are mounted on top of the buoy. The newer SALM system reduces that danger. In the SALM design, the steel buoy is tethered by one vertical anchor chain. Instead of rising through the buoy, the rubber hoses connect to a pipeline below the water at a point deep enough that the danger of a break in the hose-pipeline connection is reduced in the event a tanker collides with a buoy.

In addition to the monobuoy, the port complex would include one or more pumping stations to force the crude through the pipelines to shore. The stations would be mounted on structural-steep platforms fastened to the sea floor with pilings similar to those that support offshore oil platforms. One or more decks would be mounted to support pumps, a helicopter pad, and crew quarters. The pumping station would be located at least 8,000 feet from the monobuoy to reduce the danger of having it rammed by a tanker entering or leaving the port proper.

If a port off New Jersey were planned to handle 1.6 to 2 million barrels per day initially, it would consist of two monobuoys situated about 5,000 feet apart. (See figure IV-42.) The port could be expanded at intervals of 5 years to increase capacity to 3.5 million barrels per day to satisfy the area's needs for at least 20 years.

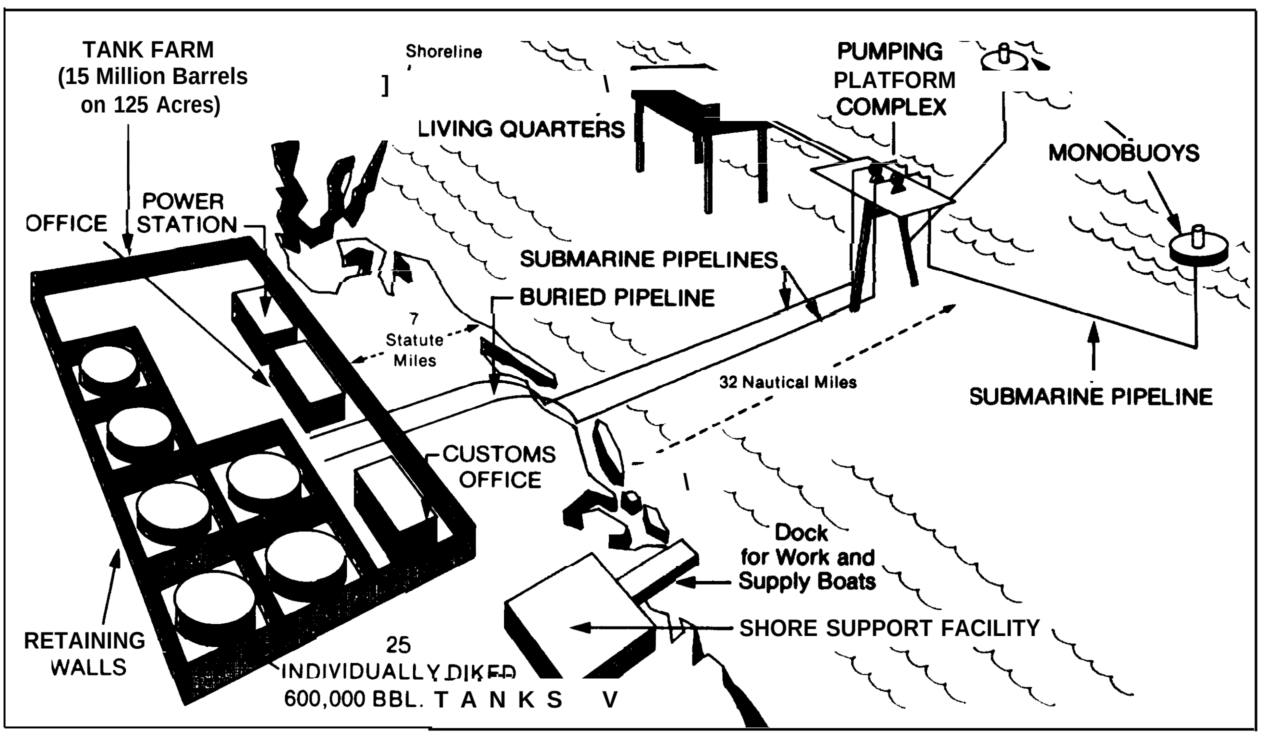
Several firms already supply monobuoys, which would be constructed at existing yards and towed or carried on barges to the Mid-Atlantic site to be anchored in place. Pumping platforms and other equipment are also supplied by existing specialty firms and shipyards so that, except for pipelines, the production of equipment probably would not generate employment for the Delaware/New Jersey region. Pipe could be fabricated on the east coast,

Construction of the offshore portions of the deepwater port would require about 2 years after a license was granted.[22] During the construction phase, about 20 acres of waterfront land would be required for support. Such support includes construction crew and equipment staging, repair, and pipeline supply. This land could be used for headquarters operations after the port was completed.[23]

Pipelines from port to shore would be put in place by lay barges using procedures identical to those for laying pipes for Outer Continental Shelf oil and gas production. The pipeline from a port off New Jersey could come ashore between Townsend's Inlet and Sea Isle City, N.J. If that occurred, a tank farm would be built in central Cape May County with the pipeline continuing overland to the Camden area and to the refineries,

Typically, tank farms for deepwater ports will store 10 times the port's daily capacity to assure refineries of a continuous supply of crude even if the port is shut down because of bad weather or an accident. A typical storage

Figure IV-42. Hypothetical deepwater port layout including onshore facilities



Source Off Ice of Technology Assessment

tank holds 600,000 barrels of crude; therefore, the initial two-buoy port discussed here would require 25 tanks on 125 acres of land to store a 10-day supply of 1.6 million barrels per day. If the port were expanded to 3.5 million barrels per day capacity, 58 storage tanks on 250 to 300 acres of land would be required.

If new refineries were built, distribution pipelines to these could be added from the tank farm.

There is substantial public concern over potential oil spills associated with deepwater ports, especially large spills which may reach New Jersey and Delaware beaches. But an oil spill risk analysis prepared for this study indicates that the likelihood of spills in rivers, harbors, and coastal waters out to 50 miles is reduced by about one-half if a supertanker/deepwater port system, rather than small tankers, is used to move oil.[24]

Two principal factors make the risks of oil spills from deepwater ports lower than the risk from small tankers., First, a deepwater port reduces the number of tankers that must be used to move a given quantity of oil. Second, if oil is spilled at a deepwater port, the distance between the port and the shoreline may reduce damage to the coastal areas.

The OTA oil spill risk analysis for a deepwater port of 1.6 million barrels per day capacity located about 30 miles off the New Jersey coast was based on data from regional and worldwide spills from ports and tankers of all sizes. The results of the analysis indicate that over a 15-year period there is a 50 percent chance that 150,000 barrels of oil will be spilled within 50 miles of shore by a deepwater port/supertanker system. During the same period, there is a 50 percent chance that small tankers will spill 310,000 barrels in the same area. Total spillage from the port system in the same time period and area could range from a low of 50,000 barrels to a high of 720,000 barrels. Total spillage from the small tankers could range from a low of 32,000 barrels to a high of 1.4 million barrels. The high estimates include the pessimistic assumption of a major tanker accident. (See figure IV-43.)

The statistical average of these estimates gives deepwater ports a two-to-one advantage over small tankers based on total spillage within 50 miles of shore.

When spills in the seas beyond 50 miles are considered, there is less difference between the two systems. This is because of two factors which are common to both systems: 1) most discharges from routine tank cleaning occur far at sea; and 2) most spills from major accidents such as structural failures have occurred far at sea.[25]

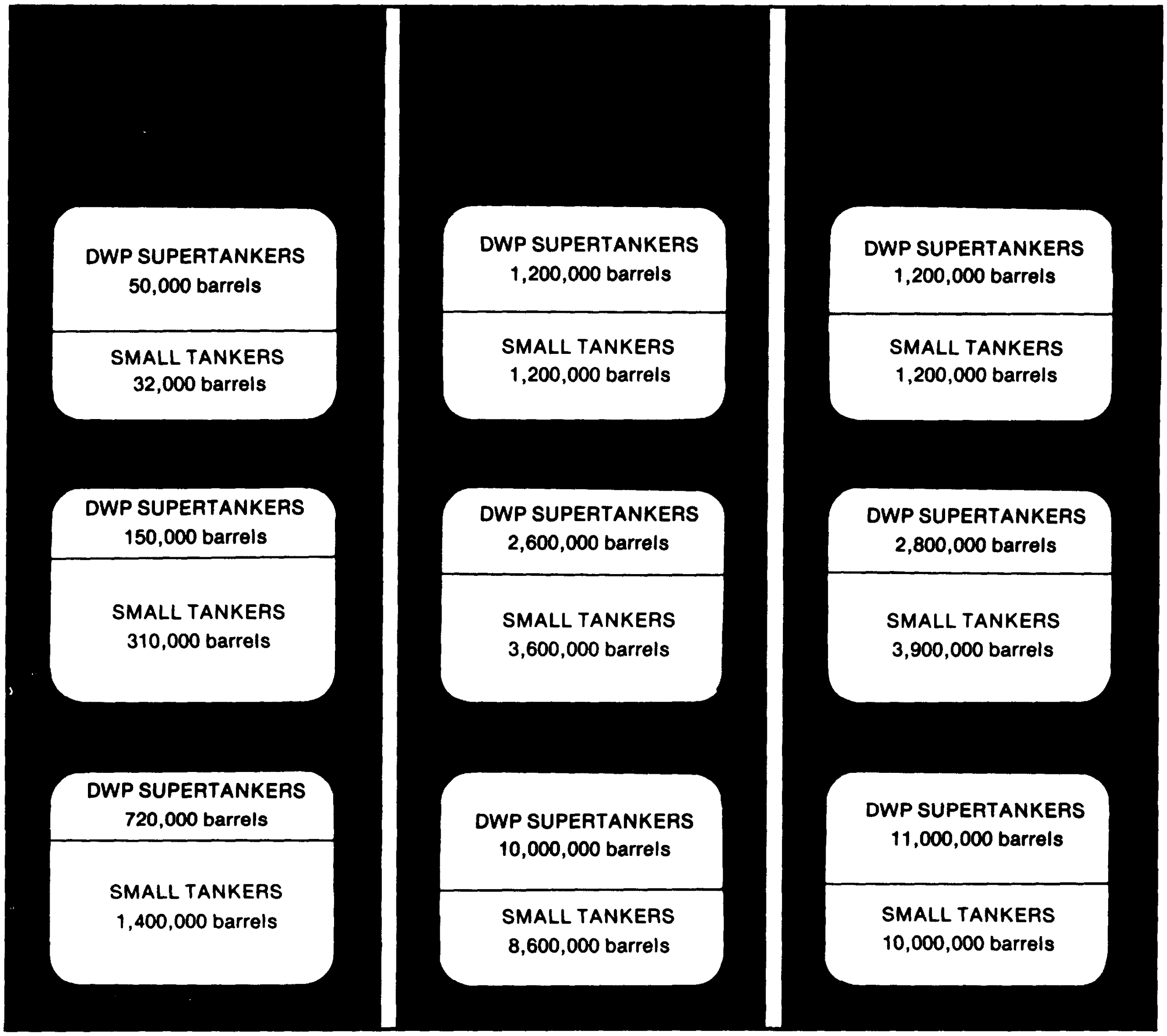
Because there are fewer supertankers and they have been in use a shorter time, the maximums used for the deepwater port/supertanker figure are higher and more uncertain than those for small tankers.

The OTA Working Paper on oil spill risk assessment describes the data and basis for estimating this potential oil spillage. From these spillage estimates, the study concludes that a deepwater port system would offer environmental advantages over small tankers in existing ports. This study assumes that pollution control technology and the tankers themselves utilizing deepwater ports will have safety features equivalent to the smaller tanker alternative.

The Coast Guard has prepared for OTA an analysis of potential oil spill movements should a spill occur at the deepwater port. The data indicates that with a stagnant summer high pressure system producing steady south to east winds, a spill could be expected to move ashore within 3 days.[26] Such projections are subject to great uncertainties because the state of knowledge about the movement of oil at sea is limited and little data is available.

Regulations recently issued by the Department of Transportation (DOT) for deepwater

Figure IV-43. Fifteen (15) year totals of oil spills from one 1.6 million barrel per day deepwater port compared to small tanker alternative



Source Off Ice of Technology Assessment, Working Paper #3

port operations require an operator to provide onsite oil spill containment and cleanup equipment for spills of less than 1,000 barrels which might result from malfunctions in port operations. In addition, the operator must have "readily accessible" equipment to clean up larger spills on a scale that might result from a tanker accident.

Equipment will be subject to approval based on port capacity, operating conditions, weather, experience of the operator, and availability of equipment. The operator will be required to prepare an operations manual describing procedures for use of his own resources as well as possible use of the National Contingency Plan.

The National Oceanic and Atmospheric Administration (NOAA) deepwater ports project office is responsible for evaluating environmental risks associated with deepwater ports and for relating those risks to specific States. A recent NOAA attempt to assess environmental risks to Florida, Mississippi, and Texas from the proposed LOOP and Seadock terminals, however, confirmed the shortcomings of existing data for use in quantifying and forecasting damage and costs. NOAA is exploring methods to improve both the data base and analytical techniques.

The situation off Florida, Mississippi, and Texas also surfaced another problem—the apparent confusion over which States should share in the benefits and protections of the Deepwater Port Act when a port is located offshore.

The. Deepwater Port Act gives “adjacent” coastal States a role in approving a license and benefiting from the protections and provisions of the law. But, except for those States directly connected by pipeline, the Secretary of Transporation makes the final determination of which States are adjacent to a proposed deepwater port.

Because of the benefits of adjacent status and the fact that there are a large number of States close together on the east coast, several States may ask to be designated as adjacent coastal States if a deepwater port should be considered for licensing off the coast of New Jersey and Delaware.

Recently, Florida asked to be declared an adjacent coastal State in connection with the licensing of LOOP and Seadock deepwater ports off Louisiana and Texas. The Florida case brought attention to an ambiguity in the law which may also figure in any applications for adjacent status made by Mid-Atlantic States.

Florida asked for adjacent status because it felt its beaches and coastal wildlife preserves and parks would be subjected to an added risk of oil spills as a result of tankers moving through the Florida Straits to and from the deepwater ports. The Florida request was denied by the Secretary of Transportation on a question of statutory interpretation.

The Secretary ruled that tankers in transit to and from the port should not be considered in determining the risks to States. That ruling has now been appealed in the courts.

Citizens who participated in the OTA study seemed satisfied that the existing technology and regulations for deepwater ports are adequate for safe operation. But there was concern that the supertankers using a deepwater port would be major sources of pollution,

A recent OTA report, “Oil Transportation by Tankers: An Analysis of Marine Pollution and Safety Measures, ” examines the evolution of tankers and the pollution and safety problems they cause.[27] It presents approaches for reducing pollution and improving the safety of operations and reviews the international and domestic regulation of these operations. The world fleet of tankers spill about 11.1 million barrels of oil into the seas every year: 7.5 million barrels during routine operations such as cleaning tanks and dumping ballast, 1.6 million barrels as a result of accidents, and 2.0 million barrels during drydocking operations.[28] This spillage accounts for nearly one-third of all ocean oil pollution.

Both the Coast Guard and international organizations are attempting to solve some of the problems of oil pollution of the seas by implementing stricter tanker standards.

In 1973 the International Conference on Marine Pollution drew up a treaty which required new tankers of 70,000 dwt or more to have a segregated ballast capability but the requirement has not been approved by all member nations. The concept of segregated ballast is that a tank vessel must have sufficient spaces set aside for carrying ballast water separately so that in all but unusually rough weather conditions it will not be necessary to introduce ballast water into cargo tank spaces. The concept has gained worldwide acceptance as offering major environmental benefits.[29]

The Coast Guard has implemented a similar requirement for U.S. tankers in domestic service and proposed the same for U.S. tankers in foreign service and foreign tankers visiting U.S. waters.

In addition, the International Conference on Marine Pollution recommended that governments undertake concerted efforts to reduce the discharge of oil from ships into the sea with a view to complete elimination of international pollution by the end of this decade.[30]

To follow up on that recommendation, the Coast Guard is now considering an extension of the segregated ballast concept to make it mandatory for all existing U.S. tankers of 70,000 dwt or more. The Coast Guard has asked for comments on the feasibility and economic impact of retrofitting U.S. tankers and has publicly said that the agency believes the retrofit is possible. According to a notice published in the *Federal Register* on May 13, 1976, the Coast Guard favors the change now because: 1) the present tanker tonnage surplus is expected to last for at least 5 years, allowing time for necessary shipyard alterations without much disruption in the transportation system; 2) most vessels will require only minor changes to the cargo and ballast piping systems; and 3) increases in consumer cost of oil as a result of the change will have only a minimum impact on the present inflationary trend because transportation costs are a relatively small part of the price consumers pay for oil products.[31]

The Proposal for a Floating Nuclear Powerplant in the Mid-Atlantic

BACKGROUND

The need for vast amounts of cooling water has ruled out many potential sites for nuclear powerplants around the Nation. Late in 1972, New Jersey's largest public utility company concluded that the answer to its own siting problems would be floating nuclear plants, moored off the coast where they would have virtually unlimited amounts of seawater for cooling. The company also concluded the floating plants could be built for less money and be less environmentally damaging than land-based plants. Access to cooling water was crucial to Public Service Electric and Gas Co., which generates more than 60 percent of the State's power. Its customers were using electricity at rates that meant doubling Public Service's generating capacity every decade or so and water supply problems were ruling out many potential sites for new generating capacity.

Today, after 3 years of analyzing the offshore power concept, staff members of the Nuclear Regulatory Commission (NRC) and some other Federal agencies have come to the same general conclusion about floating nuclear powerplants. These staff judgments are tentative and are not in any sense formal endorsements of the concept or the construction plans. The Public Service proposal still must work its way through a series of reviews, public hearings, and decisions by State and Federal agencies and meet challenges from environmental groups, New Jersey beach communities, and some nuclear scientists and engineers who say that the systems are unnecessary and may be unworkable or unsafe. Before an offshore nuclear plant can start generating power it must clear three separate stages of licensing. The first of these probably will not come before 1977.

The preliminary NRC staff reviews nevertheless have provided enough encouragement to the companies involved in the floating nuclear powerplants—the Atlantic Generating Station Units 1 and 2—that they have spent more than $120 million thus far for plans, environmental studies, and in tooling-up for production.

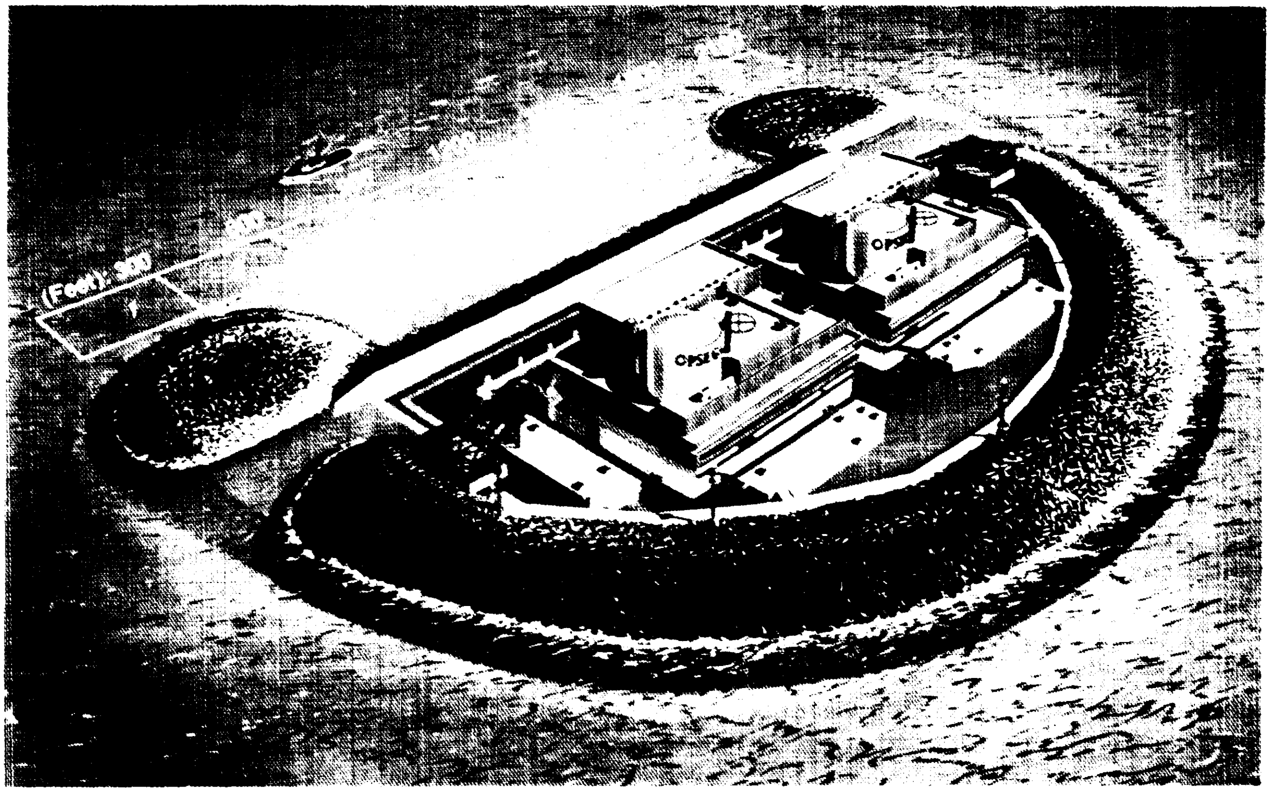
Nothing on the scale of the offshore complex of floating plants and protective breakwater has ever been built in ocean waters anywhere in the world. More cubic yards of rock and concrete will go into the breakwater that will create a lagoon of calm water for the plants and shield them from the pounding of ocean waves than went into many major dams in the United States. The gantry crane in the Florida shipyard where the plants will be built could straddle the dome of the U.S. Capitol.

The powerplants will be assembled by Offshore Power Systems, a subsidiary of Westinghouse Electric Corp., at a shipyard on a manmade island near Jacksonville, Fla., 8 miles up the St. John's River from the east coast.

The platform for each plant will be a steel barge measuring nearly 400 feet square and 44 feet deep, reinforced with bulkheads to form a honeycomb of watertight compartments. A pressurized water reactor (PWR) similar to Westinghouse reactors now operating in land-based powerplants will be mounted on each barge inside a 17-story domed containment structure with steam turbines, generators, and office buildings clustered around it.

The domed containment structure will rise nearly 18 stories above the ocean surface and from the shore will look much like the distant skyline of a small city.

Figure IV-44. Size comparison of proposed Atlantic Generating Station



Source Public Service Electric& Gas Company and Off Ice of Technology Assessment

While the floating plants are being built, construction workers will build the largest structure ever placed in ocean waters-a massive, curving breakwater of 5.6 million tons of stone and cast concrete that will span 49 acres of ocean floor and rise 64 feet above the water surface.

Powerplants will be towed at intervals of 2 years from Florida, moored, sealed in the breakwater with a wall of concrete caissons, and connected to 4 miles of underwater cable leading to shore and the power distribution grid, Public Service plans are to have the first plant operational in 1985 and the second in 1987.

Each plant is designed to generate 1,150 megawatts (MWe) of power, a supply that Public Service estimates will provide about one-third of the additional power it must be generating each year by 1987. The plants have a design life of 40 years, after which they may be shut down and decommissioned.

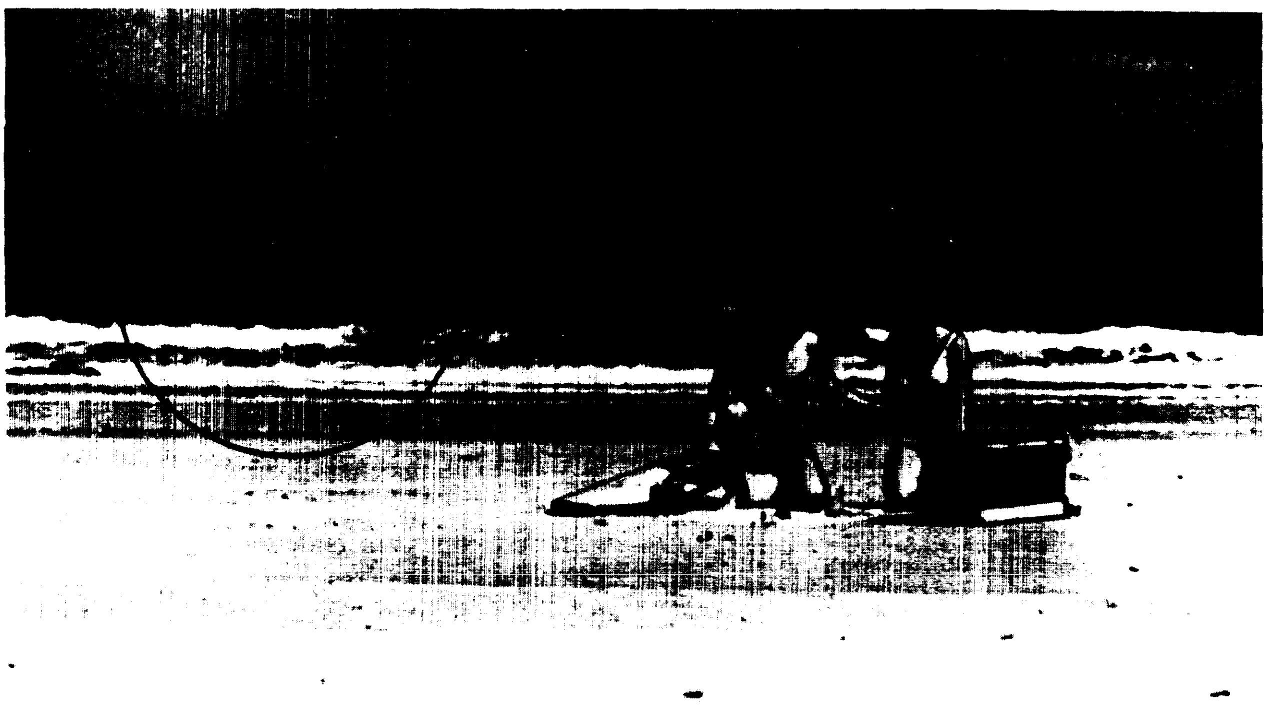
When Public Service began exploring the offshore plant concept in the late 1960's, electrical energy consumption in its service area had been increasing at an annual rate of nearly 8 percent.[1] The eastern blackout of 1965 still was a recent memory and there was strong pressure not only to keep up with rising demand but also to maintain reserves of power to prevent future blackouts and brownouts,

There were counterpressures as well. Public Service customers are in the most densely populated wedge of land in the most densely populated State in the Nation and the company had to compete with homes and other industries for both land and water.

By the early 1970's, environmental restric-

Figure IV-45. Visualization of a floating nuclear powerplant in comparison to the USS Franklin D. Roosevelt

Visualization of a floating nuclear powerplant



USS Franklin D. Roosevelt

Source Public Service Electric & Gas Company tions on air and water pollution also were taking effect, making the search for sites even more difficult and adding months and, in some cases, years to the lead times for powerplant construction.

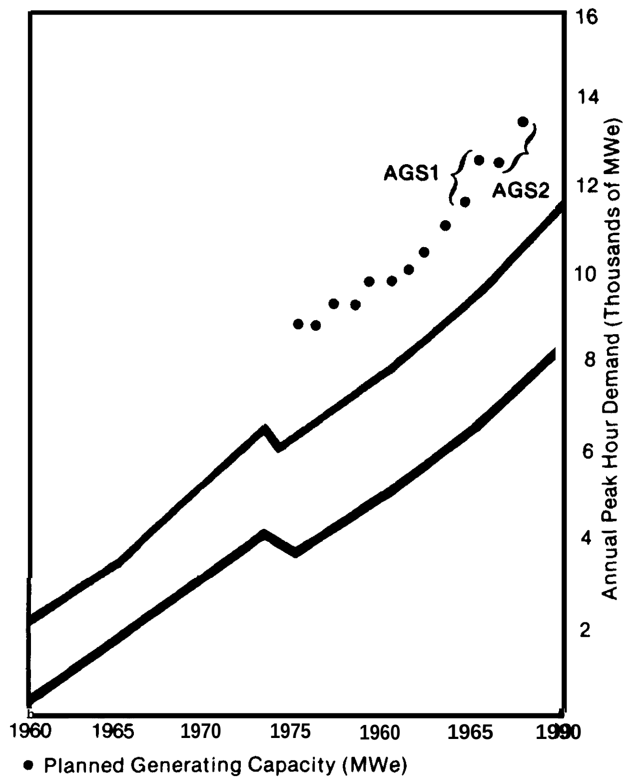
The 1973 oil embargo and four-fold rise in prices that followed the embargo took some of the pressure off Public Service. The price of electricity rose sharply with the price of oil, which was then being used to generate 77 percent of New Jersey's power. Higher energy prices coupled with a recession drove down consumption so that by 1976, Public Service estimated that the growth in consumption in its area would be only slightly more than 4 percent a year through 1985, about two-thirds of the preembargo growth rate. z

Even at this slower growth rate, New Jersey will need the equivalent of four new 1,150 megawatt powerplants for baseload power generation by 1995 in addition to the Atlantic Generating Station (AGS) and other new plants that are scheduled for operation by 1987.[3]

During the period of steep growth in demand in the late 1960's and early 1970's, the offshore plant was a critical element in Public Service's long-range plans for providing new generation facilities. Its construction schedule called for having large amounts of new generating capacity in place by the early 1980's. Two land-based nuclear plants near Salem, N.J., were running 5 years behind schedule. Construction of two more nuclear units was delayed when objections to the use of Newbold Island in the Delaware River forced Public Service to relocate the project to Hope Creek, just north of the Salem plants. Lead times for land-based plants elsewhere in the State were running between 8 and 12 years.

The sharp drop in electricity demand in 1974 and 1975 allowed the company to slip its construction schedules. But by 1976, with lead times for land-based plants expanding rather

Figure IV-46. Annual observed and forecast values for energy consumption and peak-hour demand, 1963-1987, for Public Service Electric & Gas Company area. The planned generating capacity is also shown for 1975-1987.



Source Draft Environmental Statement—Atlantic Gas Service

than shrinking, the AGS was seen by the company as its best hope of meeting projected demands for electricity with nuclear power.

The first design for a floating nuclear powerplant was commissioned in the mid-1960's by the Atomic Energy Commission (AEC) which was searching for a way to insulate nuclear plants from earthquakes.[4]

The concept was endorsed by the Energy Policy Staff of the President's Office of Science and Technology in August 1970. s The staff, in cooperation with an interagency task force, stated that, "The use of offshore siting adjacent to coastal cities would circumvent the problems of land availability, objections on esthetic grounds, and assure the adequacy of cooling water. "[6]

Public Service adapted the concept and asked the Nation's four reactor manufacturers to test its feasibility. Westinghouse, General Electric Co., and Babcock & Wilcox Corp. responded with proposals. In December 1970, a Westinghouse study team concluded that the floating plant could be built and the next year Offshore Power Systems was created as a joint venture of Westinghouse and Tenneco Inc. to manufacture floating plants. Tenneco withdrew from the venture in early 1975. In September 1972, after conducting its own site surveys off the New Jersey coast, Public Service contracted to buy the first two floating plants to be produced by Offshore Power Systems. In 1973, Public Service signed a contract for two more floating plants.

Several advantages of supplying electricity from offshore stations have been advanced in recent years by supporters and some analysts of the concept. Promoters of offshore plants take the position that:

- Unlimited supplies of cooling water are available at ocean sites and the environmental consequences of discharging heated water into the ocean will be minimal compared with the consequences of discharging heated water into rivers, lakes, and bays.

- Offshore construction eliminates the disruption of coastal marshlands and estuaries to a great extent.

- The floating powerplant concept moves in the direction of standardized nuclear plant designs, [a] goal the Nuclear Regulatory Commission (then the Atomic Energy Commission) set in 1972.

- Shipyard construction of plants will shorten the time required to put a nuclear plant in operation after a decision is made to build it.

- Volume production can cut costs and improve quality control.

Federal and State agencies have been reviewing the offshore powerplant proposal informally since late 1971 and formally since July 1973, when the AEC docketed an Offshore Power Systems application for a permit to build eight floating nuclear powerplants.

During that time, the AGS has received encouragement from the staff of the Council on Environmental Quality, which views the proposal with "guarded optimism."[7] The NRC's Office of Nuclear Reactor Regulation has declared the project "generally acceptable" as to environmental impact and risk. [8] The same office concluded in a Safety Evaluation Report published in September 1975 that with some modifications in design "there is reasonable assurance that . . . (the reactors could be installed) without undue risk to the health and safety of the public."[9]

On June 7, 1976, the NRC's independent Advisory Committee on Reactor Safeguards (ACRS) issued an interim report on the floating nuclear plant saying that if a number of issues were resolved "the floating nuclear plant units can be constructed with reasonable assurance that they can be operated without undue risk to the health and safety of the public."[10]

Several major contentions challenging some of these claims have been raised by intervenors[11] in preheating conferences since 1974. Among those admitted by the Atomic Safety and Licensing Board (ASLB) for further consideration are:

- The plant will be vulnerable to external hazards such as ship collisions, airplane crashes, and severe storms, and damage to the plant could result in dispersal of radioactive materials injurious to human health and aquatic life.

- Transportation and handling of radioactive fuel and wastes involve risks to human safety and health and to the marine and coastal environment.
- Evacuation in case of an accident will be difficult, especially in summer months, and there are no adequate plans or procedures for such emergencies.
- Fear of nuclear accidents will reduce the appeal of the area for recreational uses and have a detrimental effect on the region's tourist -based economy.
- Inadequate consideration has been given in the environmental cost-benefit balance to the adverse somatic and genetic consequences to marine, animal, and plant life.
- Inadequate attention has been given to the radiological impact on humans who may boat or swim in the vicinity of the facility and to the cumulative effects of radioactive substances injected along the food chain from plankton through humans.
- Operation of the plant will cause thermal pollution and under some circumstances could result in fish kills and other damage to marine life.
- The breakwater may cause changes in wave and tidal patterns and adversely affect the shoreline.
- Other impacts that could be adverse include industrialization of the ocean around the site, onshore support facilities, dredging, and defects in underwater electrical transmission lines.
- NRC should prepare a comprehensive, programmatic EIS on the construction of floating nuclear powerplants located offshore on or above the Continental Shelf.

Among other contentions raised by the intervenors but not admitted by the ASLB are:

- Radioactive discharges during the normal operation of the plant or from an accident would pose a risk to public health and safety and cause damage to marine organisms.
- The floating nuclear powerplant is an untested technology and the coastal area of Atlantic County will be a virtual testing ground near major population centers. One intervener urged full-scale prototype testing before any plant is installed.
- There is uncertainty as to the reliability of the safety systems, including the containment structure.
- There are risks from the corrosive effects of the marine environment on the plant's structure, and the effects of erosion and shifting of the ocean floor on the stability of the breakwater.
- The plant will be vulnerable to sabotage.
- There should be more thorough studies of alternatives to the plant.

The State of New Jersey, which has not sought official intervener status, has raised the following points in a May 4, 1976, letter to the NRC by Environmental Protection Commissioner David J. Bardin:

- The possible consequences of a "severe" accident should be considered in the licensing process.
- All safety risks from the plants should be addressed.

New Jersey and Delaware residents who took part in a public participation program carried out as part of this study are generally well aware that advantages and disadvantages must be weighed in deciding whether to build floating nuclear powerplants.

Information gathered in two regional

workshops, from 1,000 responses to an OTA questionnaire, and from press reports and statements at public hearings show that the public sees the disadvantages as involving questions of safety, environmental degradation, and high construction costs. The advantages include increased energy supplies with resulting economic expansion and cheaper power than would be possible with continued use of oil-fired generating plants. Safety concerns include a perception that floating nuclear powerplants are experimental and that there is limited experience on which to base estimates of risk and reliability.

Among the advantages cited in questionnaires and workshops are that nuclear powerplants are less polluting generally than fossil-fueled plants. In turn, participants saw advantages in floating plants over land-based plants in their distance from shore and the elimination of pressures on New Jersey water supplies for cooling water.

In this study, OTA has analyzed available information on costs, benefits, environmental impact, safety, waste disposal systems, transportation, and decommissioning activities associated with the floating plants, The study does not attempt to evaluate general controversies about the safety and performance of nuclear plants; these are beyond the scope of the coastal effects analysis. It concentrates, instead, on exploring differences between the designs of floating and land-based plants and comparing the advantages and disadvantages of each.

As a result of this comparative analysis, the study finds that:

- Although the costs of the first two floating nuclear plants, AGS 1 and 2, are about the same as the costs of a similar land-based plant, volume production and standardization eventually could slow down the rapid escalation of capital costs of nuclear powerplants.
- Offshore siting of nuclear plants would reduce thermal pollution and eliminate disruption of marshlands and estuaries that would be associated with land-based or shoreline nuclear installations.
- Routine operations would produce less air pollution than would routine operations of a coal-fired plant equipped with flue gas desulfurization and other advanced pollution control equipment.
- The NRC has not evaluated and does not plan to evaluate risks from accidents in floating nuclear plants comprehensively enough to permit either a general comparison of the relative risks from land-based and floating plants or an assessment of the specific risks associated with deploying Atlantic Generating Station Units 1 and 2.[12]
- Several technical problems of design and operation remain to be resolved, including procedures for transporting nuclear fuel to a floating plant and carrying radioactive wastes to shore, the process of decommissioning a floating plant, and the techniques of towing plants from Florida to the Mid-Atlantic coast.
- There do not seem to be any significant differences between land-based and floating powerplants as to releases of radioactive material and other pollutants during routine operations.
- Although the nuclear reactor steam supply and turbine generator systems and the floating barge are, separately, proven technologies, the combination is not. In addition, there are unique features including the barge-to-cable connection, the breakwater, and the mooring system that have not been tested by experience.

TECHNOLOGY

The operating principle of all steam electric plants is similar, whether the source of heat is coal, oil, gas, or a nuclear chain reaction. In all such plants, heat turns water to steam which powers turbines to drive electric generators. The steam is recondensed to water and pumped back through the steam-generating system.

In an AGS plant, the process will begin inside a reactor vessel, a steel tank five stories high and weighing 550 tons. When thousands of thin metal rods packed with uranium dioxide are clustered at the bottom of the reactor vessel, atoms of uranium-235 begin splitting in a chain reaction to produce the plant's heat source.

A closed loop of pipes—the coolant system—in which water is pumped under pressure through the reactor vessel and around the fuel rods serves two purposes. The water moderates the fission process and at the same time draws off the heat energy and carries it through tubing in four steam-generator tanks. The average temperature of water in the cooling circuit is about 600°F. The system is pressurized to prevent the water from boiling at that high temperature.

If all cooling systems failed, the core would rapidly overheat, reaching temperatures near 5000°F at its center within 30 minutes and falling in a molten mass to the bottom of the pressure vessel within hours. An emergency core cooling system (ECCS) is designed to prevent such a core-melt, which could produce an accident with large public consequences.

A second closed loop of water turns to steam when it flows along the hot tubes inside the generator tanks which are some seven stories tall and 22 feet in diameter. There are four steam-generators in the AGS plants.

In the final phase of the process, steam expands through turbines to drive generators and into a chamber where a stream of water, flowing through condensor tubes at a rate of 1 million gallons a minute, cools the expended steam and condenses it to water which then is pumped back through the steam-generating cycle.

The open ocean provides a virtually unlimited supply of water for cooling at least small numbers of offshore plants.

Nuclear Reactor

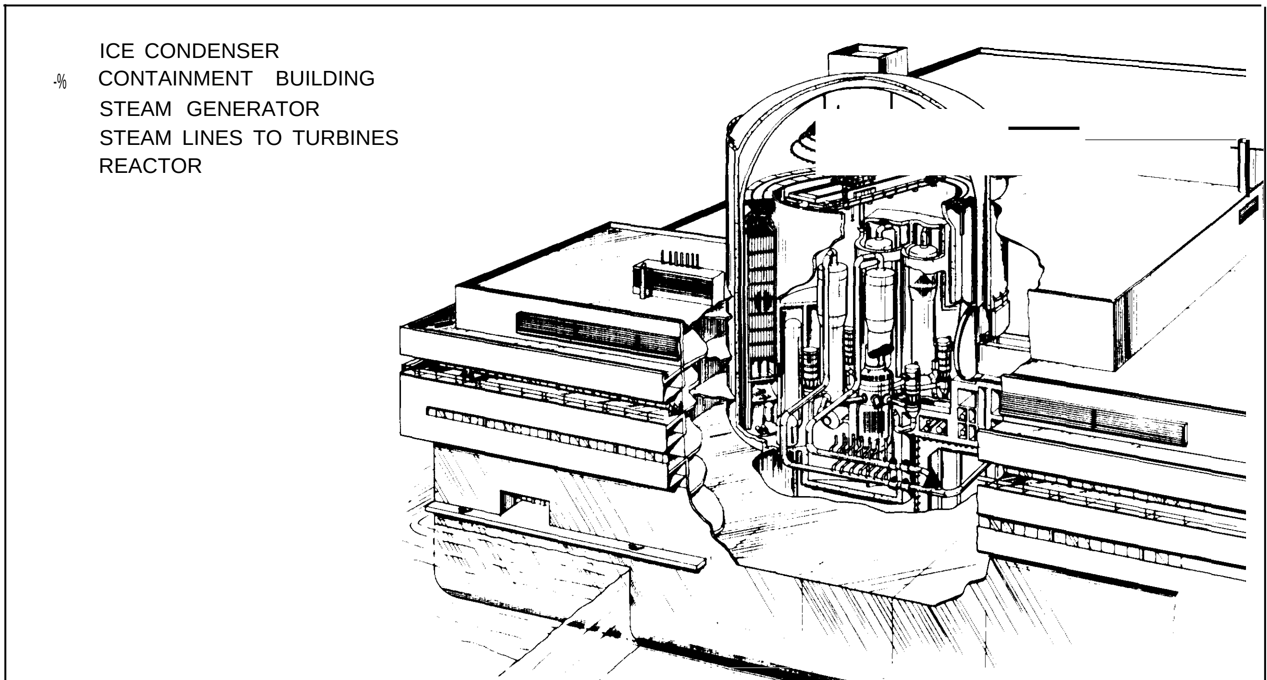
The reactor vessel and steam-generating tanks are enclosed in a steel-lined cylinder of concrete 3 feet thick that has a domed top and stands 169 feet tall—the containment structure. The domed containment building is designed primarily to prevent steam and radioactive materials from escaping into the atmosphere as the result of a major accident that might involve a rupture in the coolant-water loop or the steam-generating system. Each AGS containment building will hold 2.5 million pounds of ice designed to condense steam rapidly and reduce pressure on the walls of the containment building in the event of a major accident. One ice-condenser system already has been installed as part of an operating land-based plant; ice condensers will be used in nine other land-based plants now under construction. Between the reactor vessel and the containment building, steel and concrete shields are used to prevent the escape of radiation produced in the fission process.

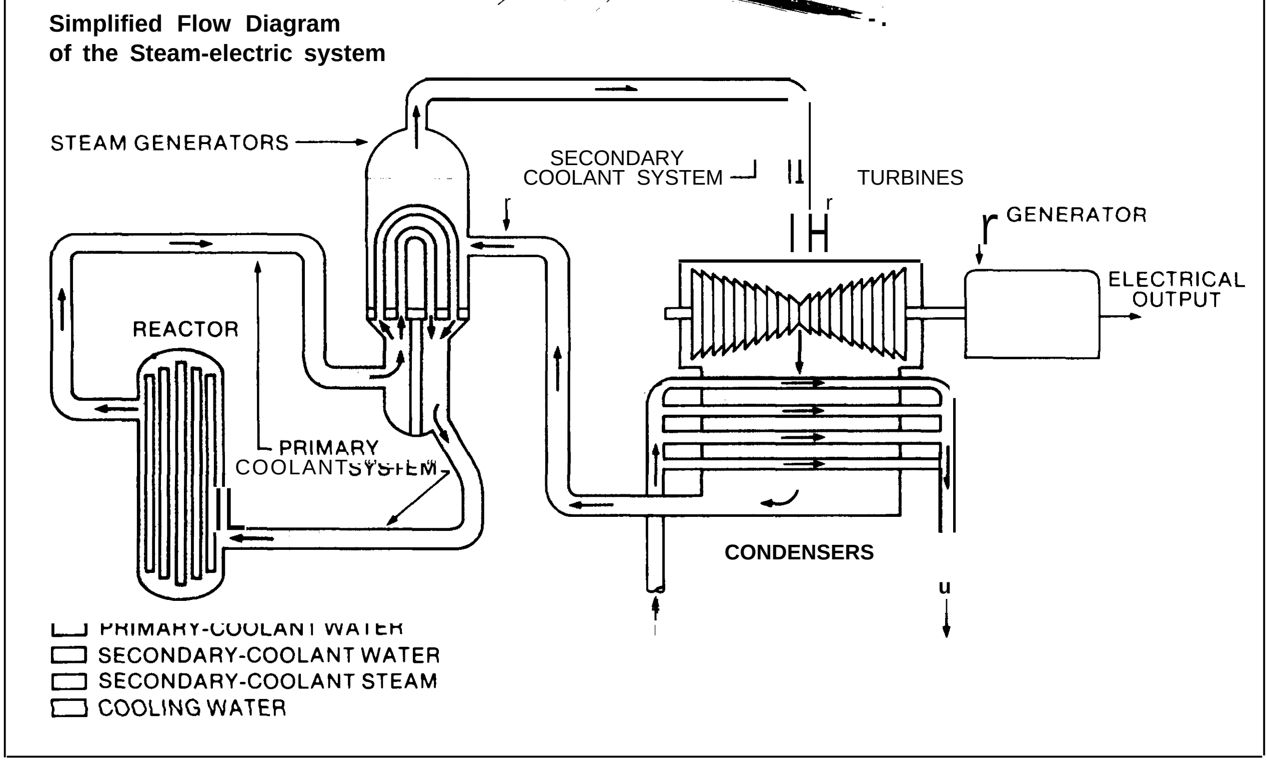
Steel buildings will be mounted on the platform around the containment structure to house turbines, generators, power-transmission circuits, the reactor control center, and office and living space for 120 plant personnel.

Platform

The powerplant is mounted on a steel barge nearly 400 feet square and 44 feet deep with watertight compartments, some of which

Figure IV-47. Cutaway diagram of a floating nuclear plant containment building





Source (Top Diagram) Offshore Power Systems

(Bottom Diagram) Pages 3-7, Part II, Draft Environmental Statement on the Manufacture of Floating Nuclear Powerplants can be filled or drained for use as trim tanks to keep the huge platform level,

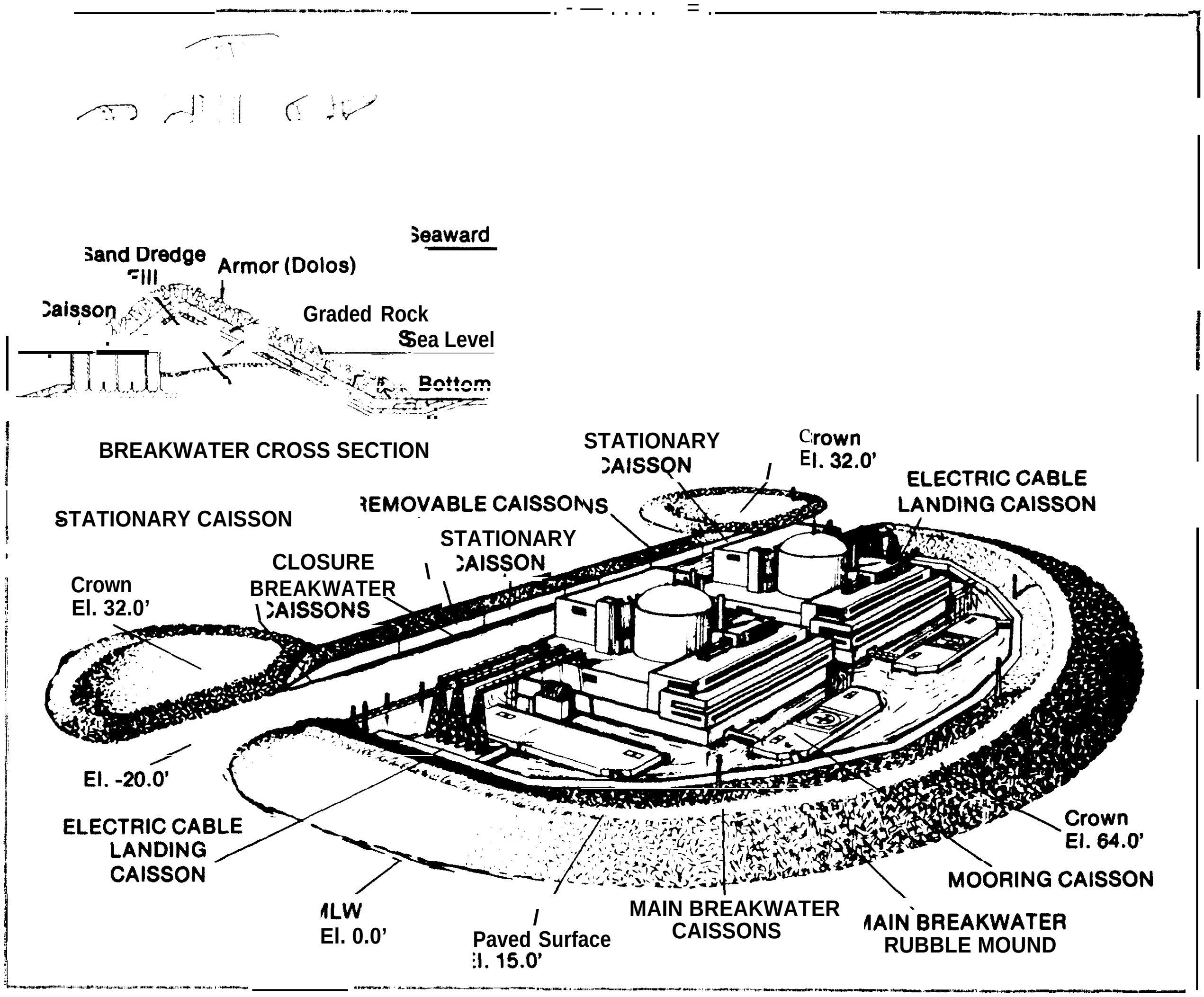
Cooling water is drawn through six intake screens on the landward side of the platform-each measuring 27 feet by 15 feet. A corrosion-prevention system using sacrificial anodes on the floor of the mooring basin will be installed.

Breakwater

One massive, D-shaped breakwater will shield both floating plants from ocean movement and from ships and will provide a basin of calm water in which the platforms will float.

In the first phrase of construction, 10 empty concrete caissons about 200 feet long, 100 feet wide, and 50 feet deep will be floated into a semicircle and filled with sand to sink them to the ocean floor. The caissons provide a base against which some 3.5 million tons of rock and a covering layer of 17,000 cast-concrete forms called dolos will be piled to form the seaward protection for the powerplants. Most

Figure IV-48. Offshore siting rubble mound breakwater, Atlantic Generating Station



Source Public Service Electric & Gas Company of the dolos weigh 42 tons; some range up to 62 tons. Before the powerplants are moored inside the semicircle, a straight line of seven caissons will be sunk to the bottom on the landward side of the mooring basin to complete the protective shield. Two of these will be removed to float each barge into place and then repositioned.

Power Transmission

The generating station's combined output of 2,300 megawatts of electricity, enough to meet the needs of a community of more than 1 million people, will be transmitted to shore through oil-cooled copper cables sheathed in plastic and a lead-alloy casing and buried 10 feet beneath the stable ocean floor.

DEPLOYMENT

The Public Service schedule for the AGS calls for one powerplant to start producing electricity in 1985 and a second to be online in 1987. Between now and then, eight Federal agencies and the State of New Jersey must approve one or another aspect of the project. The crucial clearances are those required from the NRC and the New Jersey Department of Environmental Protection.

The NRC will make three separate licensing decisions on the project. Clearance for construction of the barge-mounted plants will be shared by the Commission and the U.S. Coast Guard, which have signed a memorandum of understanding under which approval of both agencies will be required before a floating plant may be moved to a generating site. Approval also will be required from the U.S. Army Corps of Engineers, the Environmental Protection Agency, the Federal Aviation Administration, the National Oceanic and Atmospheric Administration, the Department of Justice, and the Department of the Interior at successive stages of the project.

Site

The minimum water depth for the floating plants of the AGS is 45 feet. Some dredging will be done to level the bottom to obtain this depth. With less than 45 feet of water, there is not enough clearance between the platform and the basin bottom to assure the barge will not be grounded in hurricane waves, a tidal wave, or a tornado.[13]

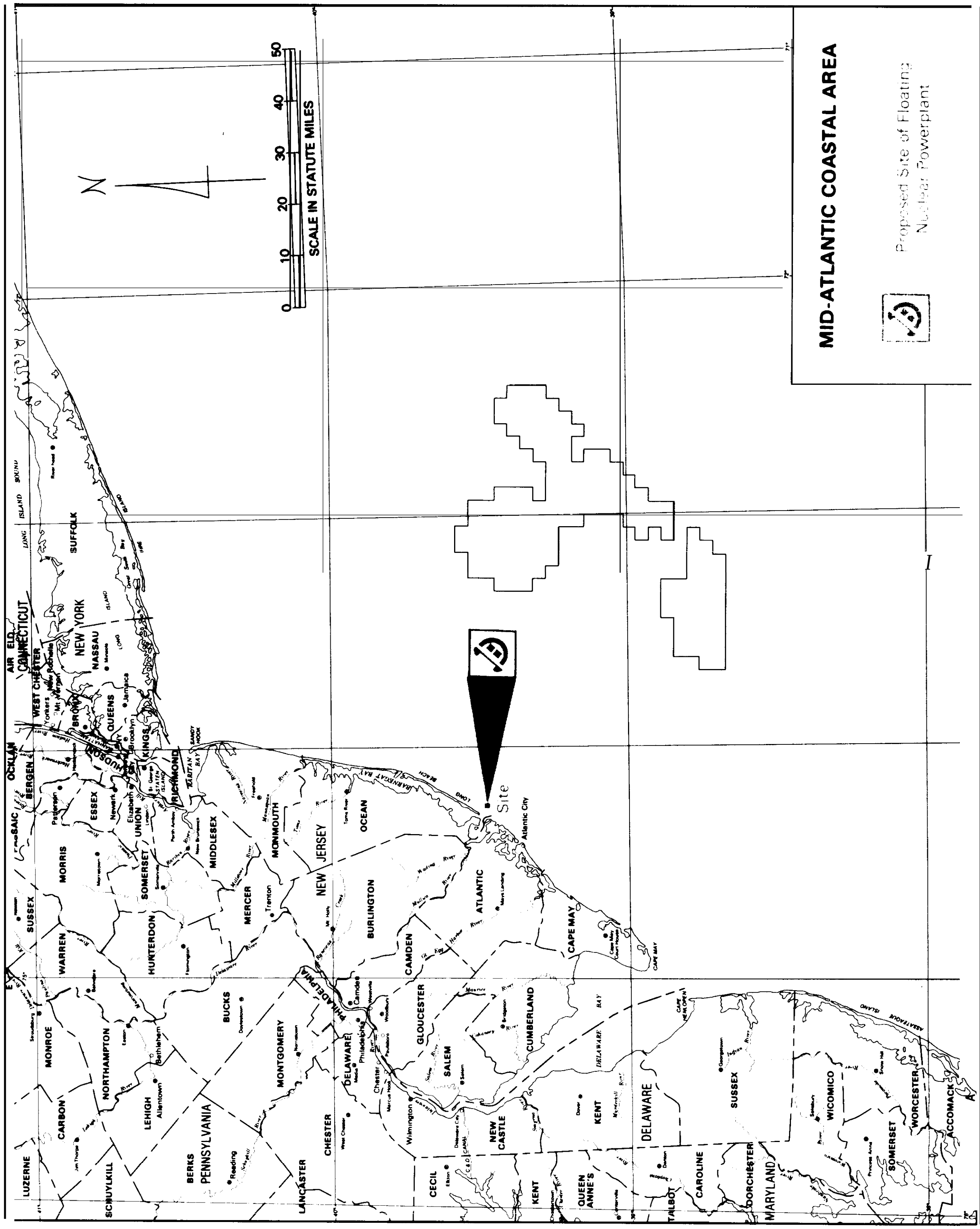
The AGS will be inside the 3-mile limit, which places the plants inside U.S. territorial waters and under Federal jurisdiction, and within the legal jurisdiction of the State of New Jersey. Both powerplants will be relatively close to existing transmission grids, which both limits the costs of new transmission facilities and reduces the amount of power lost in transmission. The generating station will be about 15 to 20 miles from major ship traffic in the Atlantic coastal shipping lanes. (Figure IV–49.)

Licenses

A series of more than 70 Federal, State, and municipal licenses and permits will be issued for the AGS in a review and decision process that will span 12 years.

A steering committee of Federal agencies, chaired by the NRC, has been created to monitor the licensing process and exchange information on various aspects of the project.[14] Represented on the committee are the Commission, the Coast Guard, the Corps of Engineers, the Council on Environmental Quality, the Department of the Interior, the Environmental Protection Agency, the Federal Aviation Administration, the Federal Energy Administration, the Federal Power Commission, and the National Oceanic and At-

Figure IV-49. Proposed site of floating nuclear plant



Source' Off Ice of Technology Assessment and Public Service Electric & Gas Co.

mospheric Administration.

The first-and the most important—Federal license is a permit to manufacture the floating powerplants. The Office of Nuclear Reactor Regulation has been reviewing environmental and safety aspects of the plants at the staff level since mid-1973. The ACRS, an independent panel of scientists and engineers appointed by the Commission, is conducting an independent appraisal of the project and reviewing the work of the reactor licensing staff. When these safety and environmental reviews are completed, an Atomic Safety and Licensing Board, also appointed by the Commission, will hold public hearings, review the record on the project and recommend for or against a license. The decision is subject to appeal before an Atomic Safety and Licensing Appeal Board and may ultimately go before the Commissioners for a final decision.

A license for Offshore Power Systems to manufacture eight plants would be issued under a policy adopted in April 1972 by the Atomic Energy Commission, now the Nuclear Regulatory Commission.[15] Before that time, all nuclear powerplant designs were reviewed in detail, even in cases where a new plant would be identical to designs that already had been cleared by the Commission. The 1972 policy was adopted to move the nuclear power industry toward a pattern of standardized powerplants to shorten the planning and review process and, in turn, the lead time for construction of nuclear plants. Under the policy, a design for a plant that has been approved by the Commission can be used repeatedly during at least a 5-year period without further detailed review. Twenty-one applications for approval of plants that duplicate earlier designs were on the Commission's docket as of December 31, 1975.[16]

The Coast Guard will review those aspects of a floating plant design that relate to the barge and must certify the barge as seaworthy before a completed plant can be moved from the Jacksonville shipyard to a permanent installation. Under a memorandum of understanding between the NRC and the Coast Guard, a floating plant will not be cleared to leave the shipyard without both Coast Guard and NRC approval.[17]

A second round of Federal permits is required for Public Services Electric and Gas Co. to construct a breakwater and prepare the site, The NRC must approve the site for a nuclear installation. The U.S. Army Corps of Engineers must approve dredging and other aspects of the project under the Rivers and Harbors Act of 1899 and other acts.[18]

The NRC site-review process is similar to that for a manufacturing license. A decision will be made by an Atomic Safety and Licensing Board after staff analysis of the plants and public hearings in the Atlantic City area. A decision is subject to appeal before an Atomic Safety and Licensing Appeals Board and—in some cases—to a final review and decision by the Commission itself. A Commission decision can, in turn, be appealed in Federal court.

A third Federal permit, an operating license, is required before fuel can be placed in a reactor vessel to prepare a plant for operation. Public Service will initiate this final review for the AGS about 3 years before its first plant is scheduled for completion by submitting a Final Safety Analysis Report (FSAR) and an Environmental Report. The Office of Nuclear Reactor Regulation will conduct one more analysis of the project, as will the Advisory Committee on Reactor Safety. A public hearing is mandatory if one is requested by citizens in the construction region, The Atomic Safety and Licensing Board will approve or disapprove startup of the plant if there is a hearing. If there is no hearing, NRC staff issues the operating license. The same avenues of appeal are available in the operating-license process as in the site-approval process.[19]

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More than half of the licenses and permits for the AGS must be issued by State and local government in New Jersey.

The State of Florida must approve dredging the St. John's River that would link the shipyard to the sea. It has approved water and air quality control systems for the manufacturing plant site. The City of Jacksonville already has issued permits for construction of the manufacturing facility, which was underway in 1976.

Permits for construction of the AGS breakwater and burying of transmission cables to shore must be issued by the Department of Environmental Protection in New Jersey which administers New Jersey riparian lands, the State's Wetlands Act, and the Coastal Area Facilities Review Act.

The Department also must issue permits for transmission lines that cross streams and for any construction of onshore facilities in the State's coastal area.

The New Jersey Department of Labor and Industry must issue a permit for construction of the breakwater and installation of floating powerplants. Local governments must approve onshore support facilities and laying of underground cable between the coast and a Tuckerton, N. J., switchyard. The State must grant riparian rights to PSE&G for the site, which may require the passage of special legislation.

The New Jersey Department of Environmental Protection also must issue a permit as part of the final licensing process for loading nuclear material into the floating plant's reactor vessel.

Public Role in Licensing

Any citizen or group of citizens who can demonstrate economic, environmental, or other interests in the outcome of a licensing case may petition for status as interveners. Intervenors, who also may include government agencies, may petition either to support or oppose an application, and are present throughout formal hearings, cross-examining witnesses and presenting expert testimony of their own. Interveners are selected from the list of petitioners by the ASLB after a series of preheating conferences on the basis of specific areas of concern which they describe in their petitions. A rejection of a petition to intervene may be appealed to the Atomic Safety and Licensing Appeals Board or to the courts.

Six interveners were chosen for hearings on the Offshore Power Systems manufacturing license after preheating conferences that lasted from February 1974 to December 1975.

Formal hearings began in March 1976, in Jacksonville, Fla., the site of the shipyard where the floating powerplants would be built. Because the licensing process for floating plants is unique in that plants will be built in one location and installed in another, the hearing was continued the following week in Atlantic City, N.J.

In all formal hearings, the general public is permitted at the outset to make brief statements either for or against a license. After these opening statements, public participation is limited to formal interveners.

Although the Atlantic City hearings were technically confined to the environmental effects of building floating plants in Florida, Board Chairman Thomas Reilly opened the Atlantic City hearings to a broad range of questions and statements by the general public.

Hearings on the manufacturing license will proceed in four stages. The first hearings were held in Jacksonville in late March. These hearings covered environmental aspects of the manufacturing facility. Following the hearings in Jacksonville, two days of special hearings were held in Atlantic City to enable the citizens of that area to make limited appearances before the ASLB.

The second phase of hearings was in progress in Bethesda, Md., in mid-1976 covering radiological, safety, and health issues. The third phase will also cover safety issues and will follow the Nuclear Regulatory Commission's publication of its final Safety Evaluation Report. The final hearings will cover general environmental questions, including the findings of a Liquid Pathways Generic Study in which the NRC will discuss the environmental impacts of a severe accident at the Mid-Atlantic Ocean sites which include the Atlantic Generating Station. These hearings will begin in late fall of 1976 or early the following year after the Liquid Pathways Generic Study has been released.

A similar series of hearings will be held in or near Atlantic City on the Public Service application to prepare an offshore site for two floating nuclear plants (the Atlantic Generating Station). These hearings will probably not begin before June of 1977.

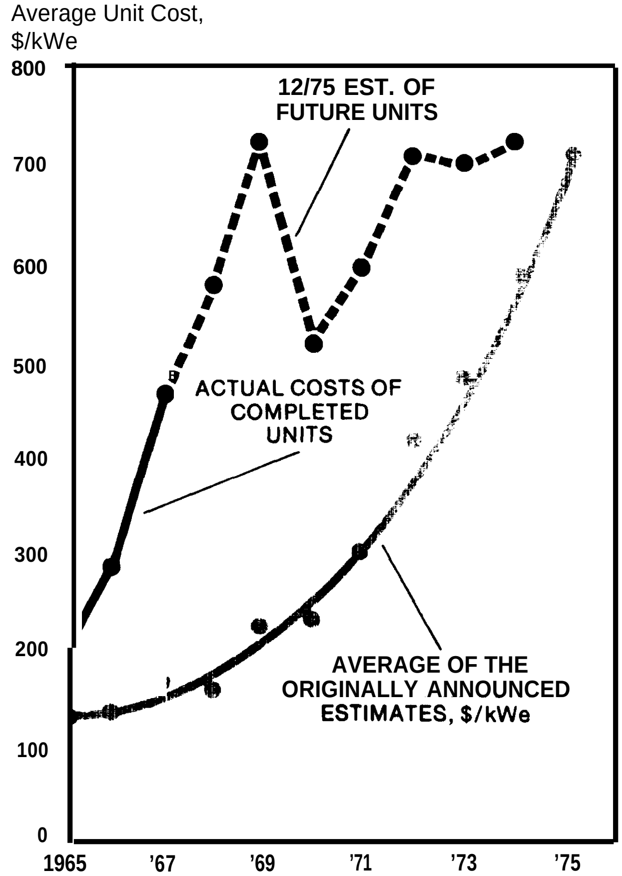
Interveners in the manufacturing license hearings are the Natural Resources Defense Council, the Atlantic County Citizens Council on the Environment, Atlantic County, N. J., the city of Brigantine, N.J., the State of New Jersey, which so far has not adopted a position for or against the license, and Ken Walton, a resident of Brigantine.

Interveners in the application by Public Service for a license to prepare a site off the New Jersey coast will include the six intervenors in the manufacturing license case as well as a seventh, Ocean County, N.J.

costs

One argument in favor of floating nuclear plants has been that the use of standardized design and a centralized work force could reduce the capital cost of floating plants below that of land-based plants. However, any cost advantages will be offset to some extent by the additional expenses associated with a floating plant, most importantly the massive break-

Figure IV-50. Cost estimates of nuclear units at time of order vs. actual finished cost or estimate as of December 1975



Source F.C Olds, "What Happened to the Nuclear Plant Program in 19757, " *Power Engineering, 4/76,* pp 83-85

water and buried transmission lines required for an offshore site. Since the costs of constructing a land-based plant and of siting an offshore plant depend heavily on specific sites, it is difficult to make generalizations about the possible overall cost advantages of the floating plant.

An analysis for OTA concludes that the capital costs of the AGS and a land-based plant of identical capacity would be comparable.[20] Assuming no unforeseen delays or overruns in either case, the AGS is expected to cost $1.9 billion and a 'comparable land-based plant to cost $2.0 billion—a difference of about 5 percent in a floating plant's favor. The possibility of error in forecasting could change either or both of these figures as well as the floating plant's cost advantage.

The analysis also concludes that because of the fixed-price contract that Public Service has signed with Offshore Power Systems, delays or overruns in construction costs would widen the price advantage for the floating system to about 10 percent.

About 80 percent of the total cost of the AGS is represented by the floating plants. Offshore Power Systems, and not Public Service, will be responsible for cost overruns in plant construction. In the standard land-based construction contract, a utility company has only about 20 percent of its total costs fixed by contract and is responsible for any overruns in the remaining 80 percent of the total cost.

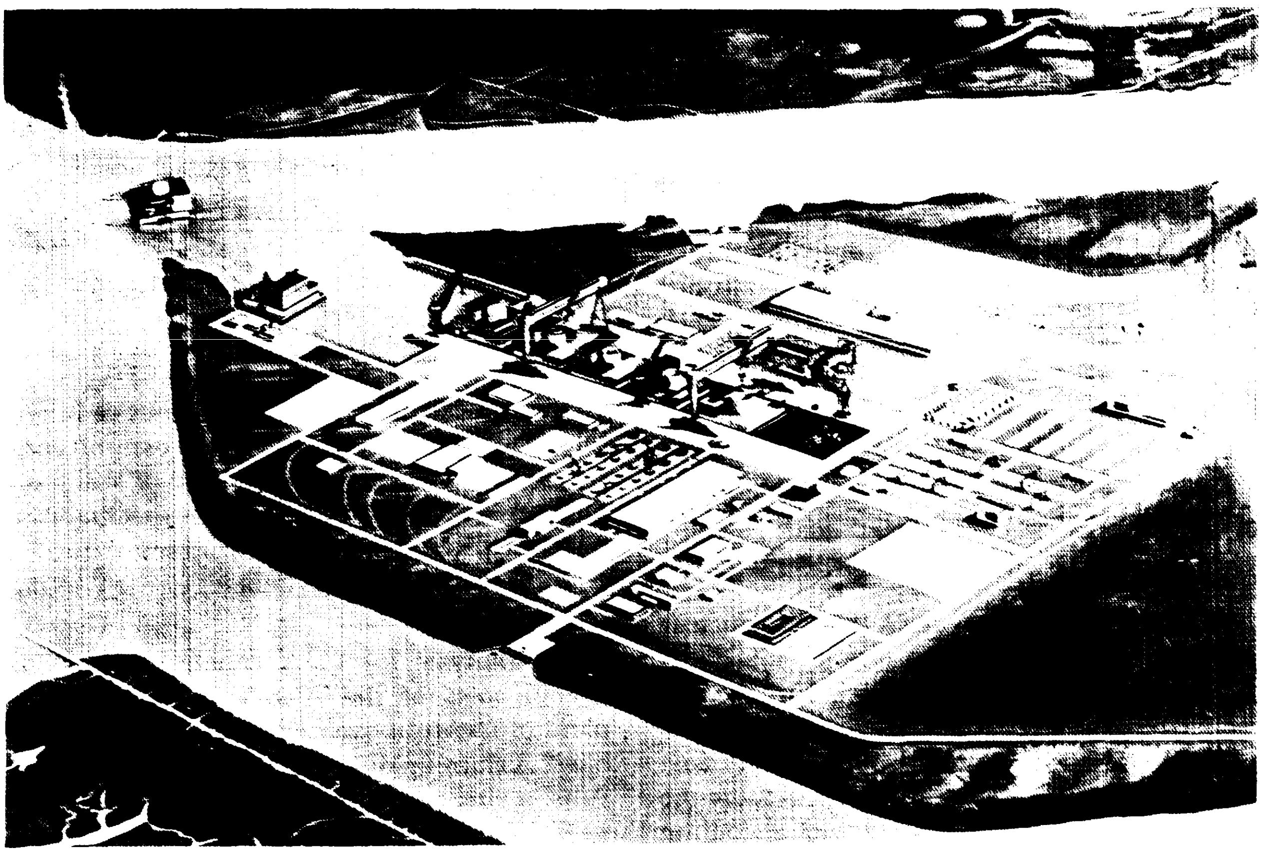
The largest additional costs that could be associated with the AGS are for the breakwater and underwater power cables, which are now estimated at $250 million without escalation or overruns. Public Service would be responsible for overruns on these items. However, the floating plants would compare favorably with land-based plants even if the costs of a breakwater were to exceed the budget by 50 percent.

Under the worst circumstances, the analysis shows, the costs of the AGS probably will not be higher than the costs of a comparable land-based plant.

Assembly

Offshore Power Systems has completed

Figure IV-51. Floating nuclear powerplants manufacturing facility, Jacksonville, Florida



Source Offshore Power Systems, Inc

several buildings at its Jacksonville, Fla., shipyard and begun dredging a graving dock or drydock and a slipway some 415 feet wide which will be the center of the assembly procedure for floating nuclear powerplants,

Fabrication of each floating plant begins with construction of a barge in the graving dock at the upper end of the slipway that runs between a series of production shop areas. When the barge is completed, it is floated, towed along the slip, and moored at successive production areas where workers assemble and mount elements of the powerplant on the barge. The final stage of construction takes place at the lower end of the slip where the powerplant is tested, certified, and towed down the St. John's River.

Offshore Power Systems estimates that the first plant will take about 4 years to build but that at peak production the facility could turn out four to five plants a year with an average construction time of 27 months per plant and a peak work force of 13,800.[21]

Before a floating plant leaves the Jacksonville shipyard, it will be tested under NRC supervision to verify that it meets design standards. Coast Guard inspectors will inspect the barge to certify its seaworthiness. Electrical systems, controls, and steam-generating systems will be tested under simulated operating conditions. No nuclear fuel will be placed aboard a floating plant until it is moored inside its breakwater.

Breakwater Construction

It will take a crew of about 350 offshore workers 4 years to build the breakwater, working around the clock in 8 hour shifts. Less than half of these workers will actually work at the site. On an average, two barges will arrive each day from quarries in New Jersey or New England, carrying rock for the breakwater.

Dredges will prepare the breakwater site by cutting away nearly 1 million tons of ocean floor to expose more stable sediment than now exists at the site, A layer of rock over the dredged area will form the bottom of the mooring basin. Mooring caissons will be placed inside the breakwater before the first floating plants are installed. To complete the shield, a line of seven concrete caissons—ranging in length from 100 to 300 feet—will be floated into position behind the first powerplant and filled with sand to settle them to the bottom. Two caissons later will be emptied, refloated, and moved out of the way to allow installation of the second floating plant.

A gap of about 180 feet between the rock breakwater and the landward line of caissons will permit a flow of cooling water to the powerplant intakes and access for service ships.

Transmission System

About 100 workers will be involved over a period of more than 2 years in building a link between the breakwater and Public Service's distribution network.

Fifteen cables will be laid between the breakwater and the shore, buried 10 feet beneath the stable ocean floor with jetting devices that carve a trench in bottom sediment with high pressure streams of water and compressed air directed through nozzles. Jetting is a device commonly used in burying communication cables and pipelines. Between the coast and a switchyard at Tuckerton, N. J., a distance of about 7 miles, the cable will be buried under Great Bay Boulevard. Overhead transmission lines will carry the AGS power from Tuckerton to Forked River where it will be directed into the distribution network.

Plant Installation

After the breakwater and transmission system are completed, the first floating plant will start north from Jacksonville, towed by four seagoing tugs at a speed of about 3 knots. The trip, which will take 10 to 14 days, will be supervised by the Coast Guard in consultation with the National Weather Service to reduce the risk of encountering storms.

The final phase of preparing plants for operation will involve mooring them to concrete caissons inside the breakwater with metal struts about 72 feet long which have double-action hinges at each end. Eight struts run between the sides of a barge and the caissons. The hinges permit the struts to hold the barges in position but still accommodate a rising and falling motion inside the breakwater.

When the barges are moored, six outfall pipes-each nearly 8 feet in diameter and curving at right angles to the barge platform—will be positioned over catchment basins built inside the breakwater. Cooling water will be discharged through the pipes, into the catchment basin, and will flow into the open sea around the breakwater through a culvert built through the central closure caisson.

Operation

The procedures that will be followed in putting the floating plants into operation will be similar to those used for land-based nuclear plants.

Nuclear fuel will be placed aboard floating plants after they are secured inside the breakwater and after final clearance from the NRC and the New Jersey Department of Environmental Protection. Arranging fuel rods to produce a critical mass of uranium within the reactor vessel takes 4 to 6 months and is monitored step-by-step by NRC inspectors.

During operations, two full crews, totaling 87 employees among the two plants, will be aboard the floating plants for periods of 3 days, one manning the plant and the other on standby, Personnel normally will commute from shore by boat, although the breakwaters or an adjacent site may have helicopter pads to permit shuttling personnel or equipment by air,

Key powerplant personnel are licensed by the NRC and any member of the plant crew who will manipulate any of the reactor controls must pass a written NRC examination before being licensed.

Fuel Supply

About 30 metric tons of fresh fuel will be carried to each floating plant annually to replace some 30 metric tons of spent fuel, which will be temporarily stored on the plant platform, and then carried to shore to be stored until U.S. reprocessing plants are back in operation.

The fission process which powers a nuclear plant occurs when an atom of uranium-235 is split apart (fissioned) by a slow neutron, discharging an average of 2.5 new neutrons, which can in turn split other U-235 atoms to continue the chain reaction and produce heat for steam generation. Plutonium is created as a byproduct of fission when slow neutrons are captured by U-238 atoms rather than U-235 atoms, the only fissionable uranium isotope.

Over a period of a year, the fission process in a reactor core depletes the U-235, much as a burning coal becomes encased in ash, to the point that one-third of the rods must be replaced. The spent fuel rods are removed and replaced with fresh rods.

Because a fuel rod continues to generate heat, even after removal from a reactor core, spent fuel is kept in storage pools of circulating water for several months until radioactive isotopes have decayed enough to reduce the output of heat. Spent fuel rods then should be packed and shipped to reprocessing plants where residual uranium-235 and plutonium are removed for recycling into new fuel pellets.

As of early 1976, no reprocessing plants were operating in the United States. A new plant in Barnwell, S. C., was nearing completion. A second plant in West Valley, N. Y., had been closed since 1972 for modification and expansion and was not scheduled to reopen before 1978.[22] Future operations depend on a final decision on whether to recycle plutonium.

Recent practice has been for nuclear plants to hold spent fuel in storage basins at the plant site until such time as the Barnwell and upstate New York reprocessing plants are open. In its 1975 annual report, the NRC said that as many as 10 nuclear plants would fill their holding areas to capacity by 1978.[23] Land-based plants generally have the space to expand storage facilities, but a floating plant would have limited space for expansion even though storage pool capacity can be trebled if storage racks are placed closer together.

An implicit assumption appears to have been made in planning for floating nuclear plants that the reprocessing system will be in operation by 1985 and that the question of space for long-term storage of spent fuel from a floating plant will be moot. If, on the other hand, no central storage area has been approved by the time the floating nuclear plants are in operation, the storage question could present an obstacle to operational licensing.

Waste Handling

Waste handling practices aboard a floating nuclear plant will be similar to those required by the NRC at land-based plants.

In addition to spent fuel, a nuclear powerplant with a capacity of 1,150 MWe will produce about 1,000, 55-gallon drums of other radioactive waste a year. Bombardment of a reactor vessel and its coolant system with neutrons creates radioactive isotopes, particularly in material that enters the coolant through wear or corrosion and is carried through the fuel core. Radioactive gases also are created in the coolant cycle. Other radioactive particles lodge in tools, laboratory glassware, and protective clothing.

Radioactive particles are continuously filtered from the coolant and steam-generating systems. Radionuclides with long lives are separated from waste water and mixed with cement and vermiculite to form a sludge which is packed into 55-gallon drums for shipment to shore and storage underground.

Figure IV-52. Annual shipments of radioactive materials to and from the two-unit Atlantic Generating Station

OPERATION	APPROXIMATE NUMBER OF SHIPMENTS PER YEAR	
	Barge	Land
Fresh (unirradiated) fuel:[a]		
1. Fuel fabrication plant to shore transfer point.		12 trucks[b]
2. Shore transfer point to offshore power-plant.	2 to 4 barges[c]	
Spent (irradiated) fuel:[a]		
1. Offshore powerplant to shore transfer point.	4 to 10 barges[c]	
2. Shore transfer point to fuel reprocessing facility.		120 trucks or 20 rail cars
Solid radioactive wastes:		
1. Offshore powerplant to shore transfer point.	4 to10 barges[c]	
2. Shore transfer point to licensed radio-active waste disposal facility.		92 trucks or 22 rail cars

[a]The shipment of empty fuel casks and casks for irradiated fuel will require essentially the same number of shipments as when loaded. However, the radioactivity hazard will be negligible.

[b]Initial loading of reactor requires about 18 truckloads of unirradiated fuel. Shipment of unirradiated fuel by rail is usually ruled out because of length of transit time.

[c]Number depends on capacity of barge.

Source Atlantic Generating Station, Draft Environmental Statement

Water containing radionuclides with short lives is stored in holding tanks until the particles have decayed and then is discharged into the sea. Contaminated gases go through a similar filtering and holding process. Contaminated clothing and other solid material also are packed into 55-gallon drums for shipment to storage areas ashore.

Even with these filtering systems, trace amounts of radioactivity remain in some of the liquid discharged from nuclear powerplants. For example, tritium, a radioactive form of hydrogen, is released from nuclear facilities after it combines with oxygen in the form of water.

Tritium has a half-life of 12.3 years. It is extremely difficult to separate out from ordinary water because water formed with tritium is chemically indistinguishable from ordinary water.

Nuclear fuel will be loaded into the floating nuclear powerplants after each unit has been towed to the AGS site, properly installed within the protective breakwater, prepared for operation and licensed to operate by the NRC. All handling of fuel and radioactive waste material within the plant and transportation to and from the plant is the responsibility of Public Service Electric and Gas Co. and regulated by NRC.

The potential environmental impact of transporting fuel and radioactive wastes to and from land-based nuclear powerplants has been evaluated by NRC.[24] As a result of that study, major emphasis is placed on packaging of radioactive materials because radioactive materials could be involved in accidents between shore and an offshore plant. All packaging must meet the regulatory standards established by NRC, DOT, and State government. There are memoranda of understanding between NRC and other government organizations, drafted to avoid unnecessary duplication of standards.

The potential environmental impact of transporting fuel and radioactive waste to and from the floating nuclear plant site is evaluated in similar language in environmental impact statements for both the manufacturing license of Offshore Power Systems and the construction permit of the AGS.

The standards and tests required by NRC for shipping containers are both rigorous and exhaustive. However, NRC has not specified unique design and test requirements for casks and drums for floating nuclear powerplants in particular. Nor has it outlined special procedures for handling these casks and drums. A sample survey of environmental and safety operating license documents issued by NRC for land-based nuclear powerplants finds that hardware design criteria and procedural requirements are not described in more detail than language in the NRC study of transport of radioactive materials, which states that:

> Safety in radioactive materials transport is achieved through design standards on packaging and implementation of a quality assurance program, including proof-testing and independent reviews, to assure conformance, to correct problems, and to help assure continued satisfactory (design) performance over the lifetime of the package under normal and accident conditions.[25]

The draft environmental impact statement for the AGS describes a most likely pattern for the fuel and waste handling system.[26] The casks and drums will be similar to those currently in use with land-based nuclear powerplants. Each shipment to or from AGS is expected to be by barge or ship. Current Coast Guard requirements mandate that irradiated fuel be carried in a type-A, or double-walled and “less likely to sink” vessel. Casks must be secured aboard a vessel so they will be easier to find and recover in case the vessel sinks. Ships and barges carrying radioactive wastes are restricted—to the extent possible—to operations where water depths do not exceed 150 meters. NRC regulations require a cask design that will withstand an external pressure equal to the pressure at a water depth of 50 feet, but most designs will withstand pressures at greater water depths.

About 30 metric tons of fresh nuclear fuel, 30 metric tons of spent nuclear fuel, and several hundred drums of solid radioactive wastes must be transported annually either to or from each floating reactor. The transfer of nuclear fuel and radioactive materials to and from floating plants will involve the transfer of loaded casks to a barge or ship. A shore facility or transfer point also will be required. These transfer conditions are different from those at land-based nuclear powerplants where transportation is by truck or rail. Except for the transfer, shipments to a fuel reprocessing plant or to a waste disposal facility will follow the same pattern as those for land-based nuclear powerplants.

The estimated number of shipments annually to and from AGS appears in figure IV-52. The total number of shipments by vessel range from 10 to 24 per year, depending on the capacity of the vessel. The number of truck and/or rail shipments depends upon the method of transportation. Coast Guard statistics are used in the NRC reports to estimate the probability of a barge accident, but it is unclear how these may apply to the open ocean site because those accident statistics are based largely on inland waterways traffic. However, the NRC conclusion is that there are only small differences in the accident probabilities among truck, train, and barge. The radiological impact on the general population of transporting fuel and waste from the AGS is expected to differ little from that associated with a land-based plant.

OTA supplemented the NRC analysis by making a detailed comparison of fuel-handling operations between AGS and two 1,150 MWe land-based nuclear powerplants—the D.C. Cook and Sequoyah plants—that are similar in many respects to the proposed offshore plants.[27] Topics included in the comparison were fuel type and radioactive inventory, transportation of new and irradiated fuel, fuel handling in the plant, new fuel storage, spent fuel storage, and fuel handling accidents. No differences were found among the three plants in terms of the amounts of fuel handled or general fuel handling procedures. There are specific differences in fuel and cask handling associated with the transfer of a shipping cask from land to a transfer boat or barge and between a barge and a nuclear platform. There are differences, too, in handling fuel on a floating plant under a condition of one-half degree combined pitch and roll.

There is insufficient information to verify whether loading and unloading features unique to the floating plant pose significantly greater risks than fuel handling at a land-based nuclear plant, However, engineering judgment suggests that cash transfers and the other fuel-handling operations can be designed and performed without undue risk.

Transportation of materials to and from land-based nuclear plants involves trucks and railroads. With a floating nuclear powerplant, barge transportation will be added to the logistic pattern.

There appears to be no inherent reason why water transportation would involve greater risks than truck or railroad transportation provided that handling procedures are analyzed and specified in advance. However, no detailed procedures or system designs have been prescribed for the segment of transportation of materials for floating nuclear plants that will involve barges. The Department of Transportation has responsibility to formulate regulations for transportation of radioactive materials.

This study concludes, however, that the

step-by-step analysis of transferring materials from truck to barge or boat at a waterfront site and the precautions that might be necessary to protect a barge enroute to a floating nuclear plant has not been made. By the same token, there are no procedures that specify steps to be taken, for example, in transferring spent fuel from a floating plant to a barge and from a barge to a truck or railroad car on shore.

Decommissioning

Earlier studies of methods for decommissioning a floating nuclear powerplant suggested that a plant might be sunk or mothballed for 50 years until highly radioactive elements of the plant could be removed manually.

The OTA analysis indicates that neither of these options would be workable under present guidelines and that the plant's radioactive elements probably would have to be removed with remotely controlled equipment on the site.

The fuel elements are the only radioactive material in a nuclear reactor when it begins operations. However, bombardment by the neutrons released in the nuclear fission process make other components of the reactor, particularly the reactor vessel and its internal parts, highly radioactive during the course of operation. Because these levels of induced radioactivity are dangerously high, the owner of a nuclear powerplant must take steps to ensure that public health and safety are protected after the end of the plant's useful life.

Forty years is the maximum period for which a license to operate a nuclear plant is issued by NRC.[28] An operator then must renew the license for an additional period or apply for termination of the license and for permission to dismantle a plant and dispose of the radioactive components.[29] If technical, economic, or other factors dictate, the operator may elect to terminate operations earlier than the expiration of the operating license. The applicant must demonstrate when he applies for the original operating license that he possesses "or has reasonable assurance of obtaining the funds necessary to cover the estimated costs of permanently shutting the facility down and maintaining it in a safe condition.''[30] The activities of shutting down operations and dismantling the plant-or maintaining it in a safe condition—are referred to as "decommissioning."

Current NRC positions also require maintenance of a "possession-only" license for as long as there is significant residual radioactivity in a decommissioned facility.[31] The conditions of the license require plant protection for public health and safety.

The NRC now acknowledges three basic modes of decommissioning—mothballing, entombment, and dismantlement.[32]

Mothballing is sealing to prevent radioactive releases from the pressure vessel, the biological shield, or other buildings. Protective maintenance is required as long as levels of residual radiation within the plant exceed specified criteria.

Entombment is a much more complete sealing, accomplished by encasing the pressure vessel and all other residual activated materials within a poured concrete structure integral with the biological shield. The primary difference between mothballing and entombment is the degree of protection needed. The mothballed plant may require a full-time protective force until residual radiation no longer poses a health and safety hazard. The entombed plant may or may not require a protective force.

For dismantling, activated components are cut up within the biological shield (including the pressure vessel and its contents) and deposited in a licensed burial site. A completely dismantled facility has no licensing requirements because it no longer contains radioactive materials that could pose a hazard

Figure IV-53. Probable actions to be taken in decommissioning a floating nuclear powerplant by various methods

PLANT COMPONENT	METHOD 1. Permanent lay-up[a]	METHOD 2. Dismantling and onshore disposal[b]	METHOD 3. Decontamination and sinking[b]
Barge	Seaworthiness must be maintained	Seaworthiness must be maintained until plant is at dismantling site	Seaworthiness must be maintained until plant is at sea dumping site
Biological shield	Sealed to prevent access and loss of radioactive materials and to reduce deterioration of contents	Sealed during transit from offshore-site to dismantling site	Surfaces coated where necessary to prevent loss of radioactive material[c]
Equipment within biological shield	Pressure vessel sealed with inert gas or other means to prevent corrosion; all other equipment treated to prevent corrosion and deterioration	Sealed during transit from offshore site to dismantling site	Pressure vessel probably filled with concrete and sealed to prevent exposure to seawater at depth; all other equipment treated to reduce corrosion rate and deteriorate ion
Rest of plant on the barge	Individual buildings sealed with provisions for maintenance access; equipment treated to reduce corrosion and deteriorate ion	Some equipment may be salvaged or scrapped at offshore site; remainder of plant tied down for transit to dismantling site	All salvageable material removed while plant is in breakwater; nonsalvageable material likely to float made sinkable

[a] If lay-up is at offshore site, the entrance to the breakwater would probably be closed. Additional structures might be installed on the barge to protect the plant from sea and storm action

[b] Breakwater has to be partly dismantled to permit barge egress

[c] Adequate protection against loss of radioactive materials after dumping may require extensive modification of the biological shield and will have to be balanced against the almost negligible hazard of radioactivity released by rusting reinforcing steel in the shield

Source Atlantic Generating Statlon, Draft Environmental Impact Statement.

to the public health.

Three primary alternatives for decommissioning the floating plants have been proposed: permanent layup (mothballing), dismantling (with onshore disposal of the radioactive materials), and decontamination and sinking. A fourth option—a 50-year layup followed by dismantling—also has been suggested.

Figure IV–53 summarizes the NRC's view of the actions that might be taken for each of the three basic options, which are subsequently discussed in turn.

Decommissioning Alternatives

NRC studies suggest that all of the decommissioning options listed here may be possible. However, OTA's brief analysis discloses uncertainties about all alternatives except that of dismantling and removing the radioactive components on-site. It is the most expensive of the options. The NRC environmental impact statement is based on an Offshore Power System analysis which did not directly calculate the radioactive inventory that would be found in the plant at the end of its life. It simply used estimates derived by extrapolating the results from decommissioning small (less than 50 MWe) power reactors.

PERMANENT LAYUP

A floating plant could be decommissioned by placing it in permanent storage, either within its breakwater or in an estuary or river. A possession-only license would be required as long as radioactive parts posed a public health and safety threat. If the internal equipment were sealed and not entombed, this option would require protective custody for the duration of a possession-only license.

If layup were undertaken at the original breakwater site, the cost would include maintenance of the breakwater as well as a protective force. However, if the barge were seaworthy at the end of the life of the plant, it could be towed to a specialized shore facility (perhaps the original construction facility modified to handle radioactive materials) where the plant could be permanently stored under surveillance.

Simple layup of a plant would not be reasonable under present guidelines because some long-life isotopes could be present which would require guaranteed plant security for not only the several hundred years required by Ni^{63}, but possibly for as long as the 500,000 years that Ni^{59} would pose a health hazard.

Layup with in-place entombment of the internals does not appear feasible either because the integrity of the entombment structure containing the radioactive materials for such extended periods cannot be assured.

Past experience indicates that 200 years may be the limit for structural integrity of an entombed plant. For example, in entombing one reactor that had been active for far less than 40 years, a portion of the core internals had to be removed and disposed of at a burial site due to excessive Ni^{63} activity which would have required structural integrity of the entombment for a period exceeding 200 years. Consequently, some degree of dismantling appears necessary for decommissioning power reactors of the size scheduled for floating plants.

DISMANTLING AND ONSHORE DISPOSAL OF RADIOACTIVE MATERIALS

Unlike the layup option, dismantling would entail removal of radioactive components, their disposal at a licensed burial site onshore and salvaging or scrapping the remainder of the plant. The NRC environmental impact statement suggests that this could be done for a floating plant at less cost than for a land-based plant if a specialized onshore disassembly facility were available and if the floating barge were seaworthy enough. However, it also appears technically and economically. feasible to dismantle and remove radioactive components at the original plant site inside the breakwater before towing to a drydock for disassembly, this option probably would not cost less than decommissioning a land-based plant.

Immediate dismantling and removal of radioactive components for disposal at a licensed burial site appears to be a viable alternative for decommissioning floating plants. It would require the same type of tooling development as required for any land-based light water reactor—the development of remotely operated equipment such as a plasma torch manipulator for cutting up the pressure vessel and its internal parts. There appear to be no unique risks or engineering requirements associated with dismantling an FNP as compared to a land-based plant. Equivalent land-based disposal sites would be required. OTA has compared recent cost analyses for this option and concluded that the cost of dismantling each floating nuclear plant would be under $50 million.[33]

Technically speaking, dismantling could be done either at the original plant site, or at a specialized shore-based facility, as suggested by the Offshore Power Systems. However, dismantling at a location other than the plant site would require towing the radioactive plant which would, in turn, entail the risk that the plant might sink enroute with all the radioactive components in place.

The plant would be sealed before towing, but even a completely entombed plant could pose a hazard if sunk because of the long half-lives of some elements in the radioactive inventory. Thus, there may be some risk associated with any of the options in which the radioactive plant is towed. However, the NRC environmental statement on the AGS concludes that it is most likely that decommissioning would be done at a site other than the operating site.

The risks involved in towing a plant to a nearby shore site may be small, but they could be much greater if it were towed back to the original construction facility in Jacksonville, as has been suggested. The removal of the radioactive components in place before towing the barge elsewhere for salvage appears to be the most viable option until the level of risk is properly assessed.

DECONTAMINATION AND SINKING

One possible option for decommissioning floating plants not available for land-based plants has been suggested by Offshore Power Systems. It involves on-site salvage of all materials of value and removal of all radioactive materials except the pressure vessel and its internals. All remaining radioactive piping and vessels then would be sealed and the plant would be towed to a deepwater site and sunk. Projected costs for this option are by far the lowest, and land-burial site requirements are much lower.

The problem of guaranteeing the integrity of an entombed plant long enough for radioactivity to decay to safe levels applies to the sinking option as well. The problem may be more severe with sinking because of the additional corrosive effect of seawater on the entombment structure.

NRC has not yet established any special decommissioning criteria for the FNP. It is not clear whether integrity would have to be maintained as long for a sunken plant as for an onshore plant. The plant would automatically be isolated from human contact and would be shielded by the water, but other problems may result from corrosion of radioactive components if the seals were breached. These uncertainties would have to be resolved before sinking could be considered a viable option.

FIFTY-YEAR LAYUP FOLLOWED BY DISMANTLING

A combination of mothballing and later dismantling could reduce the overall decommissioning cost by cutting dismantling costs. The plant would remain intact in the breakwater or at another site for about 50 years by which time Offshore Power Systems projects that induced radioactivity would have decayed enough to considerably reduce the difficulty in dismantling.

The Offshore Power Systems analysis indicates that a 50-year layup period would allow the levels of radioactivity in the reactor to decay enough to simplify the process of dismantling which would, in turn, reduce the cost of decommissioning.

OTA's analysis, based on the study of the actual end-of-life inventory that could be expected in a reactor of the size used in a floating plant, indicates that dismantling would be a relatively simple operation only after a layup period of about 110 years.

Under the combination layup-and-dismantling, the plant would be moved from a storage site at the end of the layup period to a facility where the barge and nonradioactive parts of the plant could be scrapped or salvaged (after dismantling the radioactive components).

The extended layup period may present a problem because of the difficulty of maintaining the barge in seaworthy condition for a total of 150 years (40 years of operation plus 110 years of storage). Consequently, it appears that immediate dismantling may be more feasible, even though the cost is somewhat higher.[34]

In summary, there is doubt about some of the principal options proposed for floating plant decommissioning because of the size of the end-of-life radioactive inventory of the reactor and the very long half-lives of some of the particular isotopes in the inventory. The extremely long protective storage period that is required before radioactive pressure vessel internals decay to safe levels rules out permanent storage. Intentional sinking or alternatives that run the risk of accidental sinking of the activated plant during towing may not be acceptable because of the difficulty of guaranteeing the structural integrity of seals for more than 200 years or so, far less than the time required for radioactivity to decay to acceptable levels. However, the option of simply dismantling the radioactive internals at the plant site and disposing of them appears to be technically feasible and economically viable.

River and Bay Sites

A floating nuclear powerplant can be located in a river, lake, bay, or inland lagoon as well as at sea as long as there is a channel to the site. An access channel must be at least 500 feet wide and 35 feet deep. This could require dredging that would cause more environmental damage than would installing a plant in the open ocean.

Installing a barge-mounted powerplant near shore or in a lagoon would mean giving up the advantage of unlimited supplies of cooling water that an ocean site provides. If cooling towers are required for a land-based plant, they will be required for a floating plant in the same general area.

Dredging will be necessary to tow a floating nuclear plant to any near-shore site in Delaware Bay.

A breakwater probably would be required, but it will cost substantially less than a breakwater off the Atlantic coast. In many areas, a causeway can provide access to a near-shore floating plant as well as a base for overhead transmission cables.

Licensing procedures for a near-shore or lagoon-based plant are similar to those for an offshore plant. One exception in Delaware Bay is that the Delaware River Basin Commission will be added to the list of licensing agencies. EPA guidelines may require cooling towers for all nuclear steam-electric plants in Delaware Bay estuaries.

Conventional Nuclear Plants

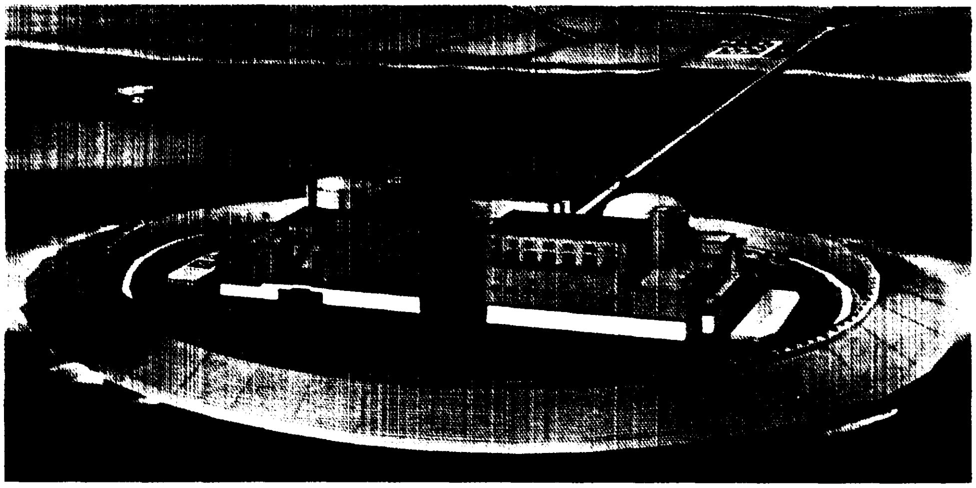
New Jersey's three major public utilities are building or awaiting approval of six land-based nuclear powerplants, the last of which would come on-line in 1984.

Two Salem County plants are scheduled for completion by 1979. Two other plants are to be built at Hope Creek, near the Salem plants, the second plant to begin generating power in 1984. Jersey Central Power and Light Company is building one nuclear plant at Forked River, N.J., on the Atlantic coast north of Atlantic City. It is sharing the cost of building a plant at Three-Mile Island in the Susquehanna River near Harrisburg, Pa. Both are scheduled to start operating in 1982.

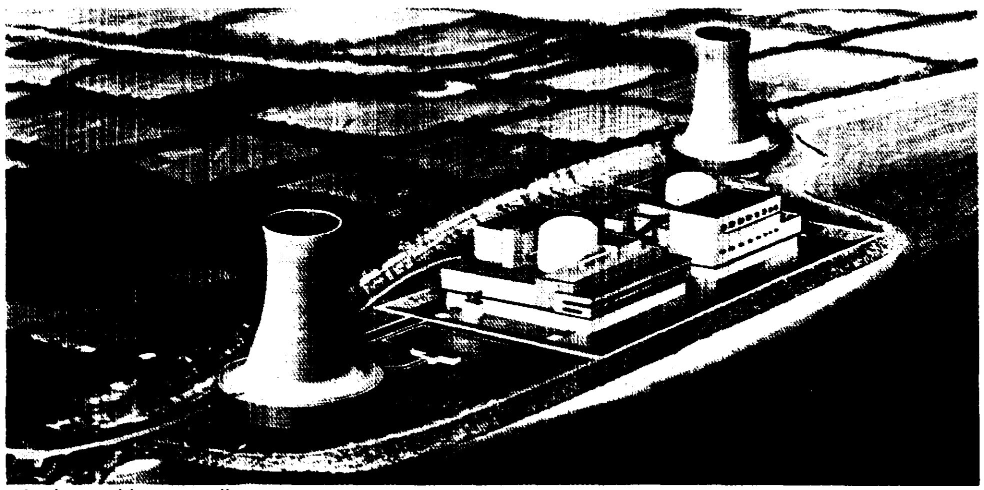
Population densities and limited water supplies in northern New Jersey probably will dictate southern sites for any nuclear plants built in addition to the six already planned.

Public Service and Atlantic City Electric jointly own 5,400 acres of land near the community of Bayside about 10 miles south of the Hope Creek site. In theory, the acreage could accommodate at least four, 1,500 megawatt, nuclear generating Plants.

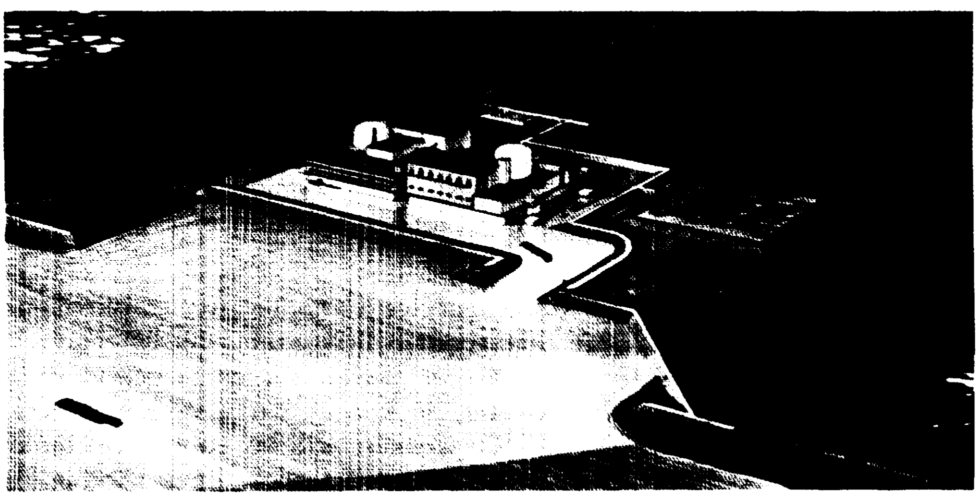
Figure IV-54. Three siting alternatives for floating nuclear plants



1. Nearshore siting-open-cycle cooling



2. Inshore siting—cooling towers



3. Riverine siting-open-cycle cooling

Source Offshore Power Systems, Inc

COASTAL EFFECTS

During this study, OTA analyzed the technical, safety, and environmental reports on offshore nuclear plants published by Offshore Power Systems, NRC, Council on Environmental Quality, Public Service Electric & Gas Co., and others, and the comments of intervenors in the licensing process.

This critical review has been supplemented by additional research on issues which earlier studies did not explore in sufficient depth or about which there were substantial differences of opinion between interveners and nuclear specialists.

This section discusses the effects of installing and operating offshore nuclear plants in two categories: 1.) areas in which there seems to be general technical agreement about the con sequences o f installing offshore powerplants, and 2.) areas in which OTA research raises questions about some aspects of published studies.

The first category includes such areas of concern as the effects of an AGS on land use, water supply, job opportunities, the ocean environment, traditional uses of the ocean, and the New Jersey energy supply. It also includes economic benefits which may occur from the floating nuclear plant concept.

The second category includes issues of safety, fuel handling, decommissioning, and the particular relationship between AGS and the coastal communities that depend heavily on tourists for their livelihood.

NRC published a draft environmental statement in April 1976 covering the proposed AGS project. The environmental statement includes a comprehensive analysis of energy and economic benefits, monetary costs, and environmental costs of the proposed projects. The statement concludes that the project "will have accrued economic and social benefits that outweigh the economic, environmental, and social" costs. " Figures IV–55 and IV–56 are reproduced from this environmental statement,

Direct Benefits

The direct benefits estimated by NRC from the proposed AGS include the production of 15.7 billion kilowatt-hours of electricity annually, divided about equally among residential, industrial, and commercial users.[35] Indirect benefits include employment of about 850 local workers with a $100 million payroll during construction and 250 with a $5 million payroll annually during operation of the plants, taxes of about $80 million annually distributed to municipalities, and about $10 million annually of local material purchases.

Construction of barge-mounted nuclear plants offshore will provide substantially fewer direct construction jobs in the New Jersey region than would land-based plants. As with any new generating plant, however, the additional electricity would support existing jobs and make new job opportunities available in the State.

The NRC uses a peak-employment figure for land-based plants of slightly more than 2,000 employees.[36] Peak local employment for a floating nuclear station off Atlantic City estimated by Public Service is about 500 workers, few of whom will be the kinds of skilled workers, like welders and electricians, who are needed for construction of a land-based plant.

Public Service estimates for employment are that about 350 workers will be required over a 4-year period for construction of a breakwater, including barge crewmembers. About 100 workers will lay cables and build the overhead transmission lines. About 50 workers will be required to build a staging

Figure IV-55. Benefits from the proposed Atlantic Generating Station

DIRECT BENEFITS	
Electrical energy generation	
Capacity	2300 MWe
Annual electrical energy generation (millions of kilowatt-hours)	
At 0.78 plant factor	15,700
At 0.6 plant factor	12,100
Proportional distribution of electrical energy	
PSE&G	
Residential	27%
Industrial	4170
Commercial	31 %
Other	1%
State of New Jersey	
Residential	32%
Industrial and commercial	66.570
Other	1.570
INDIRECT BENEFITS	
Employment	
Construction (excluding FNP manufacture)	850
Operation	200-300
Payroll, millions of dollars	
Construction (total)	100
Operation (annual)	5
Taxes collected by State and distributed to municipalities annually, millions of 1995 dollars	69-90
Local material purchases, millions of dollars	
Construction (total)	15
Operation (annual)	10

Source Table 104, Draft Environmental Statement on the Atlantic Generating Station

area. Other workers will be required to work in a dolos casting yard which may be also located in New Jersey.

If all of the expanded generating capacity of New Jersey were to be provided by offshore powerplants between now and 1995, the State could lose workers of certain skills to other States in which land-based plants were being built. On the other hand, there is presently a shortage of certain skills such as welders in New Jersey and other States today.

Economics

Figure IV–56 displays NRC's estimates compared to Public Service estimates of capital and operating costs for the AGS. The economic consequences of these costs compared to those of an equivalent land-based plant were analyzed by OTA and are discussed in staff working paper No. 10. The conclusion of this analysis follows.

An absolute reduction in electricity prices from nuclear reactors remains a hope rather than an accomplishment because of continuing increases in the capital costs of nuclear powerplants. The trend of actual capital costs of land-based plants as the units come into operation is consistently much higher than original estimates. Costs of three times original estimates have not been uncommon.

Cost increases for nuclear plants have consistently exceeded overall inflation rates. Although the nuclear industry and even recent Government publications maintain that this trend will not continue, there is no evidence that the constant dollar costs of nuclear

Figure IV-56. Monetary costs of construction and operation of the Atlantic Generating Station

IN MILLIONS OF DOLLARS

	Applicant [a]	Staff [b]
Capital costs, 1985	2285	2300
Annual operating and maintenance costs (O&M) [c]	15.6	26.7
Annual fuel costs [c]	53.4	149
1985 present worth of fuel and O&M costs	649	1659
Total 1985 present worth	2934	3959

[a] Computed by the staff from data in the Environmental Report
[b] Derived independently by the staff
[c] Operation at 0.78 plant factor

Source Table 105, Draft Environmental Statement on the Atlantic Generating Station

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powerplants have begun to stabilize. In fact, all available evidence points clearly to further constant dollar increases in nuclear plant capital costs.

As noted earlier, the floating plant concept may help resolve the problem of escalating costs if the pattern of fixed-price contracts that has been established for the AGS is extended to all floating plants. By the same token, some fixed-price contracts could probably be applied to all nuclear plants. They have in the past, by means of turn-key projects, but vendors lost a great deal of money because of cost overruns.

Environmental and Social Effects

The NRC summary of environmental effects is displayed in figure IV–57. These effects include the categories of land use, water use, impacts on marine ecology, impacts on land ecosystems, local community impacts, and radiological impacts on man and other life.

LAND USE

The largest requirements for onshore land are for a 100-acre switchyard at Tuckerton, N.J., and for 1,870 acres[37] for rights-of-way for overhead transmission lines through the Pine Barrens between Tuckerton and Forked River, some 22 miles to the north. However, Public Service plans to build both of these transmission facilities to move power from its Salem and Hope Creek nuclear plants and the land would be needed whether or not the AGS is built.

Public Service anticipates that a 4-acre waterfront site will be required for a staging and support area during construction of the offshore facility and for office space after the plant is in operation.

A corridor through about 5.5 miles of salt marsh between Great Bay Peninsula and Tuckerton will be required for buried cables to transmit power from the offshore plant to the switchyard. Most of this land, however, will be under Great Bay Boulevard and will not involve additional disturbance of the marsh area.

WATER USE

The once-through cooling system proposed for the AGS will circulate more than 2 million gallons of seawater per minute through the two plants.

All 1,150-MWe plants run roughly 1 million gallons per minute through their condensers. Cooling towers make it possible to recycle the cooling water and reduce thermal pollution, but about 10,000 to 20,000 gallons per minute is lost in cooling towers through evaporation.[38]

Discharge of cooling water at 16.1 degrees above the intake water temperature will heat surrounding ocean waters above normal in a plume extending 200 or 250 feet from the breakwater. Beyond 1,750 feet, mixing that results from jet diffusion as well as wind and wave action will dilute the plume to three degrees- or less above normal temperatures.

The NRC's draft environmental impact statement estimated that under the worst plausible conditions of wave and current, a plume could reach the Great Bay Estuary at temperatures 1 degree higher than ambient water temperatures.

WATER USE CONFLICTS

The most important conflict which the breakwater will pose with present ocean uses is for shipping. Although Public Service estimates that there is only slightly more than 1 chance in 1,000 that a large ship would ram the breakwater in any year, the breakwater does represent a new potential for collision. The Public Service estimate is based on comparisons of ship collision data in the Gulf of Mexico near offshore oil platforms and traffic in the New York area.[39]

The area in which the generating station is to be built is a popular sport and commercial fishing area. Because the breakwater will preempt a relatively insignificant amount of waters available for fishing and because reefs tend to attract fish, the area around the breakwater eventually may increase fishing opportunity.

The NRC analysis (see figure IV–57) concludes that increased water surface traffic associated with construction results in minor constraints on other users.

The NRC summary estimates of environmental and community impacts from construction and normal operation of the AGS are also given in figure IV–57.

Routine discharges of radioactive gas, liquids, and solids are similar for both barge-mounted and land-based nuclear powerplants. As has been noted, the filtering systems are the same for both designs.

Chlorine, chromates, phosphates, acids, hydroxide, hydrozine, and morpholine would be used in various parts of floating plant systems, but discharges into the open sea would be at levels within standards imposed by EPA regulations.

MARINE LIFE

The NRC environmental impact statement estimates that about 287 tons of fish production will be lost each year—roughly 0.3 percent of the New Jersey catch—as a result of zooplankton and larvae being caught (or entrained) in the cooling water system.

Breakwater construction will destroy about 100 acres of burrowing marine life, and the laying of transmission cables will disrupt marine life over a 127-acre corridor of the ocean floor. The NRC estimates that about 0.2 percent of the New Jersey commercial surf clam fishery for 1974 will be destroyed but that recolonization will take place 12 to 18 months after construction is completed. The NRC reported that samples in the area showed that the lowest density of surf clams was at the breakwater site.

OTA has prepared an independent analysis of the environmental effects of floating plants, particularly the effects on marine life. The purpose of this analysis was to determine whether floating plants would have environmental effects significantly different from those of shore-based plants with ocean, lake, or river cooling. This analysis indicates that floating plants located nearshore or in estuaries would have effects similar to those of land-based plants in the same areas, with the exception of the dredging required to bring a floating plant to its site, while offshore breakwater siting could reduce the environmental impacts.[40]

MONITORING

The NRC requires a plant operator to monitor specific discharges and the general environment for radioactivity in the region around a nuclear plant. The New Jersey Department of Environmental Protection conducts independent monitoring for radioactivity.

NRC and EPA inspectors visit nuclear powerplants an average of four times a year to appraise both safety systems and environmental conditions. Monitoring includes sampling fish, milk, and plant life in regions where a nuclear plant is operating to measure concentrations of radioactive particles.

Figure IV-57. Environmental costs of the proposed Atlantic Generating Station

Effect		Summary description
LAND USE		
Land required for station	Table 3.1, Sect. 4.4	47 acres of ocean surface and ocean bottom, 2.8 miles from shore, removed from natural use
Land required for underwater transmission lines	Sects, 3.12,4.4	127 acres of ocean bottom disturbed in a 582-acre right-of-way
Land required for underground transmission lines and switchyard	Table 3.1, Sect. 3.12	68 acres for cables: temporary disturbance and vegetation changes; 100 acres for switchyard: improves a former disturbed area
Land required for overhead transmission lines	Sect. 3.12	1870 acres altered, 95 acres cleared; primarily wooded
Land required for personnel	Table 3.1, Sect. 4.1	A few acres in urban area
WATER USE		
Once-through cooling and and auxiliary water requirements, two units	Table 3.1	4600 cfs (2,060,000 gpm)
Thermal discharge to ocean, two units	Sect. 3.4	15.5 X 10 Btu/hr at full power
Temperature rise	Sect. 3.4	16,1 F“
Thermal plume description from physical model	Sect. 5.2, Table 5.3	
1 F temperature rise		Does not impinge on shore
3 F° temperature rise		Distance from discharge 1750 ft; area affected, 525 acres
5 F° temperature rise		Distance from discharge, 650 ft; area affected, 46 acres
Chemical discharge to ocean	Sect. 5.3	
Chlorine		0.1 ppm total residual for 2 hr/day per FNP unit. Acceptable environmental impact: meets EPA standard
Copper		Less than 7 ppb increment added to available 5.5 ppb average seawater concentration. No environmental effect expected due to rapid dilution
Nickel		Less than 1 ppb increment with no expected environmental effect
Use of surface	Sect. 4.2	Increased water surface traffic associated with AGS construction results in minor constraints on other users. This is localized, temporary, and dispersed
IMPACTS ON AQUATIC ECOSYSTEMS		
Construction		
Dredging	Sect. 4.4	Destruction of some blue mussels and surf clams, 339,000 lb valued at $6000: less than 1 % of annual surf clam harvest in New Jersey
Sedimental ion	Sect. 4.4	Little effect on benthic organisms
Turbidity	Sect, 4.4	Temporary; insignificant impact on finfish
Operation		
Impingement	Sect. 5.3	An occasional operational problem because of schooling fish but will not affect fishery
Entrainment	Sect. 5.3	Loss of less than 0.5% of plankton, fish e s, and fish larvae will not alter aquatic population dynamics o f New Jersey coastal zone
Thermal effects	Sect. 5.3	Little or no effect on finfish or benthic communities
Cold shock	Sect. 5.3	Expected occurrence of once per year. Impact on ecosystem is negligible
Chemical discharges	Sect. 5.3	Very little effect
Breakwater existence	Sect. 4.4	Increased finfish production and diversity because of reef environment; potential benefit of more than 14 tons per year of increased finfish production

Source Draft Environmental Impact Statement, Atlantic Generating Station,

Figure IV-57. Continued

Effect		Summary description
IMPACTS ON TERRESTRIAL ECOSYSTEMS		
Construction		
Shore support facility	Sect. 4.3	Negligible if in urban or industrial area
Underground transmission cables	Sect. 4.3	Destroys less than 0.1% of spartina marsh habitat within 10 miles. Temporary loss of bird nesting habitat. Alters upland habitat with little impact on animal life
Switchyard	Sect. 4.3	May improve abandoned sandpit by stabilization of pit slopes and planting of vegetation
Overhead transmission line	Sect. 4.3	Clearing corridor destroys some forest habitat but increases grass andshrub habitat. Potential loss of rare white cedar bog environment
Operation		
Underground transmission cable	Sect. 5.1	Little or no impact unless oil leak occurs; then, impact depends on leak rate and quantity and speed of repair
Switchyard		Negligible
Overhead transmission line	Sect. 5.1	No herbicides will be used. Maintenance activities will use existing roads, No ozone at ground level. Bird losses are not expected to be severe
COMMUNITY IMPACTS		
Housing		Very little
Schools		Very little
Hospitals		None
Municipal services		Very little
Highway use		intermittent local congestion near shore support facility; moderate congestion along Great Bay Boulevard during underground cable installation activi ties
Economy		Slight increase due to local purchases of materials and input of new worker incomes
RADIOLOGICAL IMPACT ON MAN		
Cumulative population	Sect. 5.5	C 14 man-rems compared with 125,000 man-rems due to natural environment
Radioiodine and particulate dose to thyroid from all pathways	Sect. 5.5	Adult at nearest residence, 0.05 millirem; child using milk from nearest dairy farm, 0.2 millirem
Occupational	Sect. 5.5	900 man-rems
RADIOLOGICAL EXPOSURE TO AQUATIC ORGANISMS		
Barnacle on FNP hull	Sect. 5.5	20 rads/year
Organisms in discharge plume	Sect. 5.5	<1 millirad/year
RADIOLOGICAL EXPOSURE TO TERRESTRIAL ANIMALS		
Birds feeding on food in discharge plume	Sect. 5.5	<1 millirad/year
Animals on shore	Sect. 5.5	Approximately the same as for man

RISKS AND SAFETY

Accident Risks

The most serious accident possible in an operating nuclear powerplant is overheating that causes the fuel core to melt. If the upper containment of a powerplant were to rupture as a result of a core-melt, the radioactive materials released into the atmosphere could have severe health and economic impacts. No core-melt accident has occurred in any commercial light water reactor and the 1975 *Reactor* Safety Study (WASH- 1400),[41] commonly known as the 'Rasmussen Report, estimated the probability of such an accident in a land-based reactor as 1 in 20,000 years of reactor operation. WASH-1400 also concluded that only about one in six pressurized water reactor core-melt accidents would lead to the release of significant amounts of radioactive materials to the open air.

Under current NRC policy, the possible consequences of core-melt accidents are not considered in reviewing and approving either plant designs or proposed sites, although less severe accidents are considered. The rationale for this policy is the contention that the probability of severe accidents is judged to be so small that the total risk from such accidents (the probability of an accident multiplied by the expected consequences of the accident) is extremely low, so low that they can be safely ignored even though the consequences could be far worse than those of other malfunctions. The low level of risk from core-melts calculated in WASH-1400 has been cited by the Commission as a justification for concluding that no immediate changes in its safety and environmental regulations are required. [42]

The validity of the conclusions of WASH-1400 concerning the accident risks in nuclear powerplants is a matter of controversy, as is the subject of reactor safety generally.[43] Any resolution of the general debate would be far beyond the scope of this study of the onshore effects of offshore energy systems. Recognizing that there is disagreement over whether the risks associated with land-based plants are fully understood, OTA focused on the question of whether there are significant *differences* in the risks associated with floating nuclear powerplants and land-based plants, either on a generic basis or as far as deployment in the study area is concerned.

To determine whether there is adequate information available for such an analysis, OTA commissioned a preliminary study which compared the floating nuclear powerplant with the pressurized water plant (the Surry plant) examined in *WASH-1400*.[44] This comparison was designed to evaluate the applicability to the floating nuclear plant of WASH-1400'S conclusions about the probabilities and consequences of core-melt accidents. In addition, the preliminary study assessed the methodology being used in a Liquid Pathways Generic Study, a comparison of the radiological consequences of release of radioactive materials into water at land-based and floating plants being conducted by the NRC as a result of concern by the ACRS about the unique safety issues posed by floating nuclear plants. In examining both *WASH- 1400* and the Liquid Pathways Generic Study, OTA focused on their applicability either to a generic comparison of the relative risks from land-based and floating nuclear plants, or to an assessment of the specific risks from deploying floating plants in the study area. The results of the analysis are summarized below.

Probability of Core-Melt Accidents

Comparison of the floating nuclear powerplant with the land-based pressurized water plant studied in *WASH-1400* reveals three areas of difference which could affect the relative probabilities of core-melts in the two plants:

- *External hazards,* The floating plant will face several unique external hazards, such as the risk of ship collisions, which could increase the probability that an accident sequence would be initiated. At the same time, it will be less sensitive to hazards posed to land-based plants by floods and earthquakes.
- *Marine environment.* Floating plants located in offshore breakwaters will be subjected to continued low-level stresses from operation in the marine environment, such as platform motion and corrosion from salt spray and air. In addition, floating plants may be subjected to unusual stresses while they are being towed from the Florida manufacturing facility to their operating sites,
- *Design.* The reactor system used in the floating plant incorporates new features, such as the ice-condenser pressure-suppression system, some of which could decrease and others increase the probability of a core-melt.

A more detailed discussion follows of the areas of difference between floating and land-based plants which were addressed in the OTA analysis.

EXTERNAL HAZARDS

Because floating plants may be located at sea, they may be exposed to stresses that could not occur on land. The most obvious hazards are ship collisions, buffeting in storms, and disturbance by tidal waves. NRC has dealt with these hazards by establishing performance criteria for the plant and breakwater designed to reduce the possibility that any unusual stresses could trigger malfunctions in the reactor system. OTA's analysis indicates that if the design criteria are met, such hazards do not appear to have a significant potential for initiating core-melt accidents.[45] At the same time, because *WASH- 1400* indicated that earthquakes and floods are negligible contributors to core-melt probabilities, the fact that floating plants are less subject to these hazards than land-based plants would not lead to any significant reduction in core-melt probabilities for the floating plant.[46]

EFFECTS OF THE MARINE ENVIRONMENT

Floating nuclear powerplants will be subject to ocean-induced stresses both during towing to their sites and during the 40 years of operation. They will be exposed to salt water and spray which could degrade the reliability of exposed components such as external valves, the links with the underwater cables, and the mooring system. This exposure could also adversely affect the electronic equipment, even though there are provisions to limit the exposure. They also will experience more or less continuous motion because of wind and currents. While the breakwater must be designed to keep these motions within the design limits of floating plants, they will be subjected to open ocean conditions while being towed from the manufacturing facility to its site. The stresses of towing, combined with the cumulative effect of the small stresses of normal operation, may be sufficient to affect the reliability of crucial parts of the system. For this reason, the ACRS has recommended that instruments be installed in the plant to monitor and record stresses in order to verify structural behavior during towing operations.[47]

WASH-1400 concluded that the probability of a core-melt is relatively insensitive even to substantial variations in the reliability of individual components. However, exposure to the marine environment could reduce the reliability of enough components simultaneously to increase the probability of an accident. As with other features of floating plants, this question cannot be answered without an extensive risk analysis.

DIFFERENCES IN REACTOR DESIGN

The reactor design for floating powerplants is different in several significant details from the Surry plant on which WASH-2400'S conelusion about pressurized reactors was based.

Of the eight differences considered by OTA, seven are also incorporated in land-based ice-condenser plants using Westinghouse reactor systems. Hence, they are relevant only to determining the applicability of *WASH– 1400's* conclusions to the floating plant, rather than to analyzing general differences in accident probabilities between floating plants and land-based plants.

OTA evaluated the implications of each design difference by analyzing more than 60 accident sequences that could contribute to a core-melt and then factoring the floating plant's design differences into each sequence to the extent possible with the information at hand. This evaluation indicates that these design differences do not produce any significant difference in the probability of a core-melt in the floating nuclear plant as compared to the Surry plant.

After OTA had completed this analysis, an additional safety issue was raised at the beginning of the formal hearings on the manufacturing license for floating nuclear powerplants. Mr. Ernst Effenberger, a former employee of Offshore Power Systems, alleged that the turbine-generator on the floating nuclear powerplant was the most dangerous piece of equipment onboard and could disintegrate during destructive overspeed (180 percent of operating speed) thus producing missiles that would tear the plant apart. In response to these allegations, OTA conducted a survey of the issue. The turbine missile problem in general has been recognized by Offshore Power Systems, the Nuclear Regulatory Commission, and the Advisory Committee on Reactor Safeguards. In most ways, there is no difference between land-based and floating nuclear powerplants in terms of the relative dangers. For land-based plants, the production of turbine missiles is not considered to be a significant contributing factor to the probability of a core-melt. For the floating plant, missile barriers and special speed control mechanisms have been designed so that the probability of a safety system being damaged by the turbine-generator during destructive overspeed is within the low levels prescribed by NRC. Specific responses to Effenberger's allegations will be made during the* September 1976 hearings by Offshore Power Systems and the Nuclear Regulatory Commission. Based on the information to date, it does not appear that the production of turbine missiles is an important issue that would change the conclusion of OTA's analysis.

Taking all the differences that might alter the probability of a core-meltdown into account, OTA's preliminary analysis indicates that the probability of a core-meltdown accident in a floating nuclear powerplant is comparable to the value of 1 in 20,000 per year of reactor operation that was calculated for land-based plants in *WASH–* 1400, although substantial additional effort would be required to validate that conclusion. The effects of a towing and continued operation in a marine environment were not analyzed in detail because that would require an examination of. individual component failure rates that is beyond the scope of this study.

Consequences of a Core-Melt

The most serious consequence of a core-melt in a land-based nuclear plant is the release of radioactive materials to the atmosphere. According to the analysis in WASH-1400, even if a core-melt occurs in a land-based PWR plant, it will rupture the upper containment structure and permit radioactive materials to escape into the atmosphere only about one in seven times. How such a release would affect public health and safety would depend on weather conditions, population density around a plant, the effectiveness of evacuation plans, and other factors.

The human consequences range from deaths that would result within a matter of days from direct exposure to relatively intense radiation to deaths and illnesses over a period of years as a result of low-level residual radioactivity y. There also can be economic losses, such as the costs of evacuation, loss of contaminated crops, and loss of productive use of lands placed under quarantine for extended periods.

The OTA analysis indicates that the consequences of a core-melt on a floating nuclear plant may be significantly different from those for a land-based plant. One reason is that in the case of a core-melt on a floating plant the core eventually would melt through the bottom of the barge hull and release large quantities of radioactive material directly into the ocean, where it could contaminate beaches and be taken up into the food chain. While a core-melt in a land-based plant could also lead to waterborne contamination, e.g., if the core entered an aquifer after melting through the bottom of the containment, such effects were not considered in detail in *WASH- 1400.* Concern about this type of release prompted the Advisory Committee on Reactor Safeguards to request a special study of the effects of accidental releases of radioactive materials into water as part of its review of floating nuclear powerplants. The NRC subsequently decided to conduct a Liquid Pathways Generic Study to analyze the effects of such releases from both land-based and floating nuclear plants.

A second reason to expect different consequences for a floating plant is that it appears that in case of a core-melt a release of radioactive materials to the atmosphere is about seven times more likely with the reactor system used in the floating plant than with the WASH-1400 land-based PWR plant. On the other hand, this may be offset to some extent by design features of floating plants which could reduce the amount of radioactive material released in case of an accident.

The following discussion will summarize OTA's critique of the methodology of the Liquid Pathways Generic Study and the scope of its coverage, and an analysis of the atmospheric releases that could be expected from a core-melt in a floating nuclear plant.

Liquid Pathways

The Liquid Pathways Generic Study is being conducted jointly by Offshore Power Systems and the NRC staff in an attempt to compare the consequences of accidental releases of radioactive materials into water for various representative land-based and floating nuclear powerplant sites.

The study was initiated by the Advisory Committee on Reactor Safeguards to answer a series of questions and concerns that were raised during the Committee's review of the design concept and of plans submitted to support Offshore Power System's application for a manufacturing license for eight floating nuclear powerplants.

In the first phase of the study, the Advisory Committee asked Offshore Power Systems to analyze the dispersal patterns of radioactive material that might be released into the open ocean as a result of a number of postulated nuclear accidents on a floating powerplant. After analyzing the OPS study, NRC decided to conduct a generic study of the environmental effects of the release of radioactive materials into water from either land-based or floating plants.

The NRC staff is concentrating on land-based plants sited near rivers, the Great Lakes, estuaries, and desert areas. The OPS staff is continuing its study of hypothetical sites for floating plants, including sites off the Mid-Atlantic States and the Gulf of Mexico. Both the' NRC and OPS studies are examining possible methods of mitigating potential negative impacts.

The results of the Liquid Pathways Generic Study will be incorporated into the licensing processes for the manufacture of eight floating nuclear plants and for construction of the AGS in several ways. The analysis of the consequences of radioactive releases resulting from so-called "design-basis accidents,"[48] which must be considered in environmental and safety reviews and which exclude core-meltdowns, will be included in new environmental statements for each licensing action. In addition, the NRC will publish a separate report containing the analysis of severe accidents (core-meltdowns) as well as design-basis accidents.

Because the study has not been completed, OTA has reviewed only the methodology being used by NRC and Offshore Power Systems. The methodology appears to be valid and based on conservative assumptions which, if anything, will tend to overestimate the consequences of a release. Furthermore, the study is being subjected to extensive review by a wide range of experts prior to release. As a result, OTA expects the study to produce adequate analysis of the questions it has addressed.

Nevertheless, the Liquid Pathways Generic Study has serious limitations in the range of questions it addresses. Specifically, it does not consider the full range of consequences analyzed in *WASH-1400.* First, while it does calculate the radiological-dose-to-population resulting from releases into liquid pathways, it does not translate the dose into health effects such as illnesses and deaths. Second, it does not attempt to estimate the economic consequences of such releases, even though these may be very great. A core-melt at an offshore floating nuclear powerplant could prohibit commercial and recreational fishing for a wide area around a plant. It could lead to an extended quarantine of nearby waters and beaches for recreational uses, which could have extremely serious economic consequences for Atlantic and Ocean Counties in New Jersey. While NRC is sponsoring a survey intended to estimate both positive and negative effects of a nuclear powerplant on tourism at various locations in the United States including the Atlantic City area, it is studying only the effects of the fear of an accident as a negative effect and is not assessing the reduction in beach visitors that could result if an accident actually occurred.

These restrictions in the scope of the Liquid Pathways Generic Study mean that it will permit only a partial comparison of the consequences of accidental releases of radioactive materials into water pathways in land-based and water-based nuclear powerplants. The range of consequences considered would have to be expanded if the study is to be used in a comprehensive comparison of the overall risks associated with the two kinds of plants.

One additional feature of the Liquid Pathways Generic Study limits its usefulness, in its present form, in a comprehensive comparison of risks. Specifically, the study assumes that all of the radioactive material that *WASH-1400* indicates might be released into the atmosphere if the containment fails during a core-meltdown would, with a floating plant, be released directly into the water. While this assumption gives a conservative estimate of the consequences of liquid pathway releases, it does not readily fit into a realistic assessment of overall expected consequences of a core-melt, which would have to take into account the probabilities and consequences of atmospheric releases as well. The question of atmospheric releases will be considered in the next section.

ATMOSPHERIC RELEASE

The Liquid Pathways Generic Study assumes that the consequences of the release of radioactive materials into the atmosphere are comparable for land-based and water-based plants. This assumption may not be valid. Even if a given quantity of radioactive material would have roughly the same consequences whether it escaped to the air onshore or offshore, it is not reasonable to assume that the expected magnitude of atmospheric releases would be the same for onshore and offshore plants. Because there are significant design differences between the reactor system used in the floating nuclear plant and the plant analyzed in *WASH-1400,* OTA examined these differences to determine whether they would significantly limit the applicability of WASH-1400'S conclusions to floating plants. This examination suggests that the probability of atmospheric releases from a core-melt in a reactor system of the design used in the floating nuclear powerplant would be significantly greater than for the land-based PWR plant considered in WASH-2400. At the same time, the consequences of a release may be less severe because lower amounts of radioactivity may escape. For these reasons, the conclusions of WASH-2400 about the expected consequences of atmospheric releases cannot be directly applied to floating plants without modification.

The source of these differences is the ice-condenser, pressure-containment system used in the floating nuclear powerplant, as well as in one plant in operation and nine under construction onshore. This system, which uses 2.5 million pounds of berated ice as a heat sink to condense steam and thereby reduce containment pressure in case of an accident, allows the use of a smaller and lighter containment building, a distinct advantage for a floating plant. OTA's comparison of this design with the Surry plant indicates that the smaller pressure containment used in the floating plant ice-condenser system is about seven times more likely to rupture in the case of a core-melt than is the larger and heavier containment of the onshore plant analyzed in the Rasmussen Report. In fact, it appears that every core-melt sequence on a floating plant is likely to lead to a rupture of the containment above the water line, while only one in seven core-melt sequences in the Surry plant would produce an above-ground containment failure, The reason for this difference is that the smaller volume and lower design-pressure resistance of the floating plant containment structure would make it much more vulnerable to the pressure pulses that would occur at various points during any core-melt sequence as the molten core fell into various pools of water within the containment, and ultimately reached the water under the plant. This higher probability of an atmospheric release from a core-melt on a floating plant would tend to make the expected consequences of a core-melt proportionately greater for a floating plant than for an onshore plant similar to the Surry installation.

Despite the higher probability of a containment rupture, the ice-condenser system has certain features which would tend to reduce the amount of radioactive material released to the air from the failed containment. The ice-condenser itself would trap radioactive iodine, one of the more dangerous radioactive materials, while the higher ratio of surface area to volume in the containment structure might increase the amount of vaporized core material that is deposited on surfaces within the containment. These tentative conclusions also require validation.

It should be emphasized that these findings indicate that the analysis of atmospheric releases in *WASH- 1400* would require modification before it could be applied to any ice-condenser plant, whether located onshore or offshore. These findings do not imply that there is a generic difference between floating and land-based plants as far as atmospheric releases from containment failures are concerned, because Westinghouse ice-condenser plants are under construction, and in one case in operation, onshore. A comprehensive comparison of risks of floating and land-based plants would have to examine differences between the same type of plants located in the two environments.

While such a comprehensive analysis was beyond the scope of this study, several generic differences between floating and land-based plants can be identified. First, in the case of a core-melt in a floating plant the core would eventually melt through the bottom of the platform and contact the water on which the plant was floating, This probably would produce large quantities of steam because boiling conditions could be expected to exist at the surface of the core for a day or more after melt through,[49 50] This steam could in turn transport into the atmosphere significant quantities of radioactive material, including fine particles produced in the interaction of the molten core with water.[51] While the possible interaction of a molten core with groundwater is a potential mechanism for similar secondary atmospheric releases in some land-based plants, there are some factors that may lead to differences in the effects of such releases on the generic risks of floating plants as compared to land-based plants. For one thing, the potential for such releases exists for all plants located on water, and only for some land-based plants, depending on the site. In addition, the release would occur later in time after initiation of a core-melt sequence in a land-based plant because of the thicker containment base mat that the core would have to melt through before encountering groundwater; this could reduce the population at risk by allowing additional time for evacuation. However, since WASH-1400 did not consider this type of release, further analysis would be needed to determine whether the potential for such secondary releases leads to a difference in the generic risks of land-based and floating plants.

A second possible generic difference between land-based and floating plants is the fact that floating plants can be located away from shore, which guarantees a permanent zone of zero resident population for several miles around the plant. This could reduce the expected consequences of an atmospheric release compared to some onshore sites. However, this difference applies only to offshore sites, and would not affect nearshore sites as compared to land-based plants located near the coast.

In summary, OTA's preliminary analysis indicates that the conclusions of WASH-1400 about the expected consequences of atmospheric releases cannot be directly applied to the floating nuclear powerplant. Furthermore, substantial additional analysis would be required to enable a generic comparison of the types and effects of atmospheric releases resulting from core-melt accidents in land-based and floating nuclear plants.

Accident Risks in the Study Area

Because the objective of this study was to assess the three offshore technologies by examining the potential impacts of their deployment in a specific geographic area, New Jersey and Delaware, OTA's analysis of the safety of floating nuclear plants considered the risks from an accident at the AGS, as well as the generic risks of floating plants.

Several unique aspects of the AGS site could lead to more severe consequences in the unlikely event of a core-melt accident than would be the case with many land-based plants or floating plants at other sites. The first of these is the fact that the economy of the area around Atlantic City depends heavily on summer recreational use of the nearby beaches and ocean. An accident that released large quantities of radioactive materials into the ocean could have a severe regional economic impact.

The influx of summer tourists also greatly increases the number of people who could be exposed to radiation in case of an accident. For example, the year-round population of Atlantic City, which is estimated by city officials to be 43,000, increases to around 400,000 on some summer weekends.[52] The population of Long Beach Island, whose southern tip is 2.8

miles north of the AGS site, increases from 10,000 to a summer daytime peak of more than 100,000.[53] In the unlikely event that a severe accident occurred on a July weekend, some 500,000 people, few of whom could be expected to know emergency evacuation procedures, could be in the area.

Finally, the prevailing winds in the Atlantic City area are from the south from April through August, and could be expected to carry atmospheric radioactive releases from the AGS directly towards Long Beach Island.[54] Because the winds average about 10 miles per hour in those months,[55] an accidental release could be carried to populous beach areas on the island within an hour. Furthermore, the island is connected to the mainland by a single four-lane bridge, which can delay motorists leaving the island by as much as *2* hours in traffic jams under normal summer conditions. This suggests that evacuation procedures would be only of limited usefulness in reducing the consequences of an accident during the daytime in the summer.[56]

These peculiar aspects of the AGS site lead to the conclusion that both the Liquid Pathways Generic Study and WASH-1400 have only limited applicability in assessing the overall risks from deploying floating nuclear powerplants in the study area. As noted earlier, the Liquid Pathways Generic Study is not considering economic impacts, While WASH-1400 did analyze economic impacts, its calculations of the expected consequences of accidents are based on site characteristics developed by averaging the characteristics of 68 sites expected to be in use by 1981. The averaging technique makes it impossible to determine from WASH-1400 the effects of peculiarities of particular sites such as the AGS. For this reason, WASH-1400'S conclusions do not appear to be directly applicable to analysis of the risks from locating a floating nuclear powerplant at that site. A comprehensive risk assessment of the AGS would require some modification of existing analytical techniques, since neither WASH-1400 or NRC procedures for analyzing the consequences of design-basis accidents take into account correlations between wind direction and seasonal population peaks.

CONCLUSION

OTA's review of NCR studies related to the risks from accidents in floating nuclear powerplants indicates that these studies are not comprehensive enough to provide either a generic comparison of the relative risks from land-based and floating plants or an assessment of the specific risks from deploying floating plants in the study area.

While substantial additional effort would be required to perform these analyses, a review of relevant literature indicates that there exists a substantial amount of information applicable to assessing the consequences of a core-melt in a floating nuclear powerplant, and that research programs are underway to provide additional relevant information.[57]

Alternatives To Offshore Technologies

The Coastal Effects study has been concerned to this point with the consequences of deploying any or all of three offshore energy systems proposed for the waters off New Jersey and Delaware.

This phase of the study examines the consequences of not deploying the offshore systems, with particular attention to the question of alternative sources of energy for New Jersey, Delaware, and other Mid-Atlantic States.

Although the analysis includes a discussion of a range of alternatives, it concentrates on those that are judged to be realistic options during the period 1976-90.

Based on analysis of existing and potential energy sources and possibilities for reductions in energy consumption, this assessment finds that:

- Even if offshore Mid-Atlantic oil and natural -gas systems and nuclear powerplants are producing at presently projected levels in the 1980's and 1990's, the Mid-Atlantic States still will depend on other sources for at least 80 percent of their energy.
- It may be possible to develop conservation programs that would make up the energy lost if the offshore systems are not deployed, but such programs would need strong national leadership and would have to begin at once.
- Without strong national programs to conserve energy and develop alternative resources, the Mid-Atlantic States will be locked into existing energy patterns well into the next century.
- Utility managers will choose existing and tested technologies that are most apt to match the consumption levels in their forecasts and will assign reliability of power supply a higher priority than cost.
- The most promising alternatives for stretching out supplies of fossil fuels are programs to improve insulation of homes and offices, changes in automobile design to increase mileage, and the use of existing technologies to increase the amount of power generated per unit of fuel.
- Coal is a potential substitute for every basic fuel in the United States and supplies could last for more than a century, even if consumption were to quadruple without improvements in mining techniques. However, massive conversion to use of coal would entail such major changes as transportation networks, some changes in air quality standards, new mining techniques, and new miner training and safety programs.
- Utility companies and other energy suppliers in Mid-Atlantic States will not factor supplies of oil and natural gas from the Baltimore Canyon Trough into their future plans until exploration establishes likely production levels.
- No single new technology or change in the way existing technologies are used is likely to provide more than a small percentage of total energy requirements for New Jersey and Delaware before the end of the century. Solutions to energy problems will be found by putting together many relatively small conservation and supply programs.
- Given existing laws, regulations, fuel supplies, and technologies, New Jersey utilities would favor building floating nuclear powerplants as their first choice. If these are not permitted, the utilities would opt for shoreline floating plants,

land-based nuclear plants, and coal-fired plants, in that order.

- Solar programs will not contribute much to energy supplies before the end of the century unless Federal programs to cut solar installation costs and private plans to market solar products are given higher priorities than they now enjoy.

CONSTRAINTS ON ALTERNATIVES

Without strong national leadership in conservation and fuel supply programs, the most likely course for the Mid-Atlantic region over the next 20 years is to expand and extend the energy system that is already planned or in place, including floating nuclear plants.

One likely sequence that emerges from an examination of the study region is as follows:

In the case of electric power, only extensive conservation is likely to reduce the growth in consumption below predicted levels. Lacking assurance that growth in demand will be slowed down by new national policies, utility executives will schedule construction of new generating capacity according to their own forecasts, which factor in relatively modest changes in consumption growth rates. Because of the long leadtimes for planning and building large power-generating plants, this sequence tends to lock regions into existing technologies for many years into the future. For example, Public Service Electric & Gas Co., New Jersey's largest public utility, signed a contract in 1973 for two floating nuclear powerplants it did not intend to put into operation for 12 years. [1]

In scheduling construction of new generating plants, utility managers choose technology that is both available and time-tested. For at least the next 15 years, that inclination is likely to limit the choices to nuclear or coal-fired powerplants for baseload generators.

Several options to present plans for expanding central generating capacity are being studied in New Jersey and Delaware. With each alternative there are uncertainties as to performance, questions about cost, or legal or institutional barriers.

A June 1976 report concluded that enough electricity could be generated in New Jersey as a byproduct by producing steam or heat for industrial purposes to postpone for 10 to 15 years a need for new baseload powerplants. [2] The report noted that 29 percent of the electricity in West Germany is generated as a byproduct of industrial operations and that only 2 percent of the power supply in New Jersey involves joint production of steam and electricity. However, there has been no detailed study of the cost of expanding joint production in New Jersey. There is no inventory of plants that could be converted and, therefore, no estimate of the potential output for the State.

In theory, about 5 percent of baseload power in the Public Service Electric & Gas Co. service area could be generated by burning municipal refuse. But the only attempt to build a refuse-burning powerplant in New Jersey has been delayed for more than a year by problems of site selection, transportation, and guarantees of delivery of refuse in sufficient quantities to keep a plant operating. [3]

New Jersey and Delaware utilities could increase purchases of power from the Pennsylvania-New Jersey-Maryland (PJM) Interconnection as an alternative to building new central powerplants in either State. The Interconnection is a power pool that links 11 power companies and permits them to operate as a single, integrated system.4 Beyond some point, however, other Mid-Atlantic States might balk at increasing their generating capacity to supply New Jersey and Delaware on the grounds that both States would be taking the benefits of power without paying the potential costs of pollution.

ENERGY PATTERNS IN THE MID-ATLANTIC STATES

Present plans call for a steep increase in nuclear-generating capacity and a drop in the share of energy supplied by petroleum to bring basic changes in Mid-Atlantic energy patterns over the next 20 years.

According to a 1976 Bureau of Mines forecast, the share of energy supplied by petroleum in the Mid-Atlantic States—New York, New Jersey, and Pennsylvania—will drop by the year 2000 from a present 57 percent, which is well above the national average (46 percent), to just over 40 percents During that time, nuclear generating capacity is planned to increase by about 85 percent. By the turn of the century, nearly half of the region's total energy would be supplied by nuclear and coal-fired powerplants.

The forecasts make several assumptions about consumption and availability of fuels.

Because States in the Northeast and Mid-Atlantic are much more dependent on foreign oil than are States in other regions, forecasts probably are least reliable where they are based on assumptions about availability of petroleum. Sharp price increases, embargos, or decisions by producing nations to cut back output all could change the energy picture for the Mid-Atlantic States more drastically than for the Nation as a whole.

As with oil forecasts, several assumptions in the projections of growth in nuclear-generating capacity are open to question.

New Jersey utility companies plan to use nuclear power for virtually all of the increase in their baseload generating capacity between now and 1987.[6] By 1987, about 70 percent of the baseload capacity in New Jersey is expected to be nuclear powered, compared with some 40 percent in 1975.

However, escalating costs, scarcity of capital and questions about the availability of uranium have held back completion of nuclear plants to about two-thirds of the levels that were forecast as recently as 1974. Recent studies also raise questions about how close nuclear plants come to operating at their rated capacity. T Design changes in new plants now under construction may increase on-line generating time but there is no experience to support a judgment.

Despite these potential problems, New Jersey utilities have concluded that nuclear power is the least expensive technology at hand and have scheduled expansion accordingly.

OFFSHORE OIL AND GAS ALTERNATIVES

The only direct substitute for oil and natural gas from the Baltimore Canyon Trough during at least the next two decades is an increase in imports.

For the near term, conservation programs could reduce the rate of growth in foreign imports. Over a longer period of time, an accelerated switch from the usc of oil and gas to heat buildings to the use of solar power could achieve dramatic reductions in petroleum consumption,

Based on present estimates of offshore resources, substantial increases in oil imports will be necessary over the next 20 years in addition to offshore production if nothing is done to reduce projected increases in congumption.[8]

There are alternatives that could reduce demand for oil in Mid-Atlantic States without a need for new technologies. None of these can alleviate the problem by itself, but in combination they could ease the strain on energy supplies in New Jersey and Delaware, OTA is assessing the potent i a 1 for conservation programs in residences for a report to be delivered to Congress in early 1977. The assessment includes an examination of technology and institutional barriers to deploying the technology. The following are some examples of such programs:

Insulation

About 32 percent of the oil consumed in Mid-Atlantic States in 1974 was used for heating space and water.[9] That represented about 400,000 barrels of oil per day.

The promise of energy savings through widespread insulation programs so far exists largely on paper. No definitive studies of net energy savings have been done. No workable program to accelerate insulation on a national scale has been devised. But there is at least one program that seems to be working without national leadership and using accepted marketing techniques. That program, run by Washington Natural Gas Co. of Seattle, could serve as a model for other regions.

The results of that program indicate that consumption of energy for heating single-family homes can be cut by more than 50 percent with better roof and sidewall insulation.

Washington Natural Gas Co. found that attic insulation cut the fuel requirements for heating a single-family home by 22.7 percent and that wall insulation cut fuel requirements by another 28 percent.[10] The firm also found that appeals to conserve fuel were less effective than a marketing approach based on promises of lower home-heating bills. In April and May of 1974, while an insulating subsidiary of the company was stressing conservation, its crews insulated 17 homes. In the same 2 months of 1976, after the company began emphasing lower fuel costs in its advertising, it installed insulation in 1,404 homes.

It is not possible to compare the Washington experience with the potential for New Jersey and Delaware without a detailed study of insulation in those two States, but i f the pattern of uninsulated homes in New Jersey and Delaware is comparable to that in Washington State, a widespread insulation marketing program could cut consumption of oil and gas for heating purposes by 24 to 40 percent.

Solar

Solar heating systems probably could replace many of the oil and gas systems now used to heat Mid-Atlantic homes, apartment houses, office buildings., and stores. But the statistics that are emerging from research and demonstration projects indicate that the use of solar energy for heating will spread too slowly to make a significant contribution to total energy supplies before the turn of the century.[11]

Automobile Efficiency

Another alternative to offshore oil production and increased imports lies in increasing the energy-efficiency of automobiles. In 1974, more than 40 percent of petroleum products sold in the Mid-Atlantic were used for transportation.[12] Changes in design of automobiles could double the number of miles per gallon of fuel. Congress has moved in that direction by setting standards for automobile mileage in the Energy Policy and Conserve - tion Act of 1975.

FLOATING NUCLEAR PLANT ALTERNATIVES

Interconnection

The Pennsylvania-New Jersey-Maryland (PJM) power pool is a clear alternative to construction of floating nuclear powerplants or to shoreline or inland plants in New Jersey and Delaware.

New Jersey already imports about half of its electric power, either from PJM companies or from powerplants located outside the State but partially owned by New Jersey utilities. Public Service plans to buy 650 megawatts (MWe) of power from the pool in the early 1980's to meet forecast demands until it can bring new nuclear plants into operation.

The power pool includes 11 members and affiliates, operating in five States and the District of Columbia. The members and affiliates serve 21 million customers with a peak generating capacity of 43,000 MWe. The power pool's 117 generating plants are linked by 5,293 miles of transmission lines and are controlled from a central computer complex in such a way that power demands from anywhere in the system are met by activating the least-costly unit elsewhere in the system that is not already operating at capacity.

Utility executives do not flatly rule out the PJM power pool as an alternative to new generating plants offshore or in the State. However, their plans for new generating plants are based, in part, on a conclusion that lower operating costs of scheduled nuclear plants will make it possible to reduce power costs in the State, which now run about 60 percent higher than the national average.

Conservation

Neither insulation programs or solar-heating systems would reduce electrical demand in the Mid-Atlantic region significantly because only about 1 percent of all homes are heated electrically.

Estimates of savings in consumption that could be achieved by reduced levels of lighting, higher efficiency of electrical appliances, and improved building design are largely extrapolated from a relatively small base of actual experience.

Reduction in electrical consumption also will come slowly because of the long lead-times for replacing existing equipment and appliances with more energy-efficient equipment. The Energy Policy and Conservation Act of 1975 requires that most appliances sold in 1980 and thereafter be 20 percent more efficient than similar appliances sold in 1972. However, the replacement cycle for some appliances is 16 years or more.

The California Energy Resources Conservation and Development Commission voted on September 15, 1976, to require air-conditioners sold in the State* after 1979 to be 30 percent more energy-efficient than the average existing models.[13]

Technology is not a barrier to higher efficiency in air-conditioning. Several models now on the market will meet the new California standards. But air-conditioning manufacturers oppose higher standards because they mean higher price tags for air-conditioners and a possible decrease in sales volume.

After a recent study, one New Jersey utility company concluded that standards similar to those set in California would reduce the company's need for peak power-generating capacity in 1990 *by 7* percent.[14] Peak power is generated largely with the most expensive fuels-ail and natural gas—and its costs are five to six times as high as baseload electricity.

The New Jersey company tried to persuade the State legislature to write higher energy-efficiency standards into law. Air-conditioning manufacturers in the State opposed the law and the proposal was abandoned.[15]

Cogeneration

Cogeneration of electricity refers to generating both electricity and heat for manufacturing processes in a single plant. This dual use of energy is not a new concept in the United States. About 4 percent of the Nation's electricity is generated by steam which is then used in manufacturing.

A preliminary assessment of the potential for cogeneration in New Jersey concludes that somewhere between 10 and 90 percent of the State's electricity could be produced by plants that already generate steam for industrial use.[16] The actual number of plants that could generate electricity as a byproduct would depend on the number of plants that could convert to cogeneration and projections of future needs for steam or heat in manufacturing processes. The preliminary assessment prepared by the Princeton University Center for Environmental Studies recommends an in-depth survey of industry to determine the potential for cogeneration.

A prime argument for cogeneration, according to the report, is that fuel costs for electricity could be about half those for power generated in central stations because fuel efficiency would be 62 percent compared with an average 32 percent in existing powerplants. The higher efficiency results from the fact that one unit of fuel is used to perform two functions, power generation and production of steam or heat for industrial use.

The study did not anlayze the costs of installing dual-purpose steam generators on a large scale. Nor did it include a detailed study of water and transportation needs that would be involved in cogeneration on a large scale.

A common type of cogeneration already in use involves piping waste steam from powerplants to factories within a mile or so where the steam is used for industrial purposes. Advocates of cogeneration propose to reverse the process so that electricity would become a byproduct of industrial steam and heat generation.

Coal

Coal is a potential substitute for every basic fuel in the U.S. energy system-oil, natural gas, and uranium. There is enough coal in the United States to last well over a century, even if consumption were to quadruple and there were no improvements in mining technoiogy.

However, any such increase in coal production would require major investments in new mines, new transportation networks and equipment, adjustments in air quality stan - dards, new mining techniques, and improved safety systems.

Coal can be converted to fuels like oil and gas but existing technology for conversion is relatively primitive and expensive and has not been perfected for widespread commercial use. OTA is assessing the coal technologies that are or will be available between now and 1990 and evaluating methods of reducing environmental impacts of increased utilization of coal. A report on the assessment will be made to Congress in early 1977.

For at least a decade, coal could be used as a substitute for offshore energy resources by burning in conventional powerplants or for heating homes and commercial buildings. It is, in fact, the last of the fallback fuels on the lists of New Jersey utilities which are investing in offshore nuclear powerplants.

According to the most recent estimate of the Energy Research and Development Administration, new coal technologies that will burn fuel much more efficiently and with far less pollution will not be tested on a commercial scale before 1990. By that time, construction may already have begun on the last of four floating nuclear plants which PSE&G has agreed to buy.

The coal technology most likely to serve as an alternative to any of the proposed offshore systems during the next 10 to 15 years is a conventional powerplant. The capital cost of a conventional plant currently is between $700 million and $900 million, including advanced pollution control equipment. A 1,000 megawatt (MWe) plant would require about 1,000 acres of land and take some 4 years to build.

RESEARCH

The foregoing examination has concentrated on near-term alternatives, those likely to be available for widespread commercial deployment within the 20-year time frame of this assessment. They include alternatives that would involve changing the patterns of energy use and distribution and alternatives which would adapt existing technology to new uses.

Longer term alternatives could cover a much broader range of possibilities and many depend on research on new and promising technologies. The research is now being conducted on many levels in government and private industry.

Major federally sponsored research is being conducted on thermonuclear fusion as a generator of electricity and many expect the research will show fusion to be capable of providing long-term, environmentally safe energy in large quantities. Other research is directed toward more efficient conversion systems for coal such as the magnetohydrodynamic generator.

Still other research efforts are directed toward more effective use of solar energy, the most plentiful and long-lasting fuel known.

Technology already exists for using solar energy to heat water and space. Similar technology is under development to power cooling systems that now are operated largely by electricity y.

An OTA analysis has found that neither public nor private programs in solar energy are likely to lead to large-scale deployment of solar equipment in the next 20 years unless they are expanded and intensified.

The Energy Research and Development Administration estimates that at the present pace of development less than 6 percent of the heating and cooling systems in U.S. homes will be solar powered by the year 2000. The OTA analysis concludes that the potential for solar power is large enough to warrant more emphasis on development and marketing. The OTA study, which will be sent to Congress early in 1977, focuses on barriers to more widespread use of solar energy to generate electricity for individual residences and small cities and examines possible courses of action for removing the barriers, The stakes for solar power in New Jersey and Delaware are high in energy terms. As ha's been noted, about 32 percent of all oil and about 63 percent of all natural gas now consumed in those States is used for space heating and water heating. A major shift to solar power would make possible significant savings in both scarce fuels and in the need for future imports.

The OTA analysis of energy alter-natives is continuing beyond this and other studies.

One assessment now underway involves an investigation of renewable ocean energy technology, including methods of extracting useful energy from ocean tides, waves, winds, currents, and thermal differences in water-layers.

The study will assess the amount of research necessary to make such technology commercially feasible and the consequences of developing renewable ocean energy systems. A preliminary assessment is to be completed early in 1977.

CONCLUSION

No new alternative technology is likely to provide a significant share of energy supplies in the Mid-Atlantic States between now and the end of the century. The alternatives to the proposed offshore energy systems in that time- frame are, by and large, restricted to extending the existing pattern of oil and gas imports and land-based coal and nuclear powerplants.

Two courses of action that are open to the States, with or without Federal support, offer-some hope of reducing the rate of growth of oil imports and slowing the pace at which new powerplants are built.

- Conservation n programs, including widespread improvement of insulation of homes, could reduce the rate at which oil and natural gas imports grow over the next 20 years.
- Cogeneration of electricity as a by-product of industrial steam or heat could reduce the rate at which new central powerplants would be built.

Conservation and new uses of existing technology such as cogeneration are important because they could buy time for New Jersey and Delaware, in which new energy options may become available for both States.

A very important policy question involves alternative energy sources for easing the problems of transition from existing energy systems to more efficient and less polluting systems. That transition can be difficult because of the long lead times and the long operating lives that are involved in existing energy systems, particularly in electric power generators.

New Jersey public utilities have contracted for four floating nuclear powerplants to be installed off the Mid-Atlantic coast. * The last of these plants is scheduled for completion in 1992 and designed to operate for 40 years, until the year 2032. Four land-based nuclear plants already are under construction in New Jersey, all of which would be operating past the turn of the century.

The more central powerplants that are built using existing technology in the next 10 to 20 years, the more difficult it will be to replace

*Two floating plants are in the licensing process. No application for a site license has yet been filed for the second pair of plants them with new technology that may be more efficient and less polluting than may be commercially feasible after 1990. An analogy exists in the case of older coal-fired powerplants that now are used primarily for generating intermediate loads of power in the two States. Newer coal-fired systems already exist that are more fuel efficient and less polluting. But it is not economic to shut down the older plants and replace them with new plants because the older plants, most of them located near urban areas, still have many years of operating life.

Similar transition problems will exist in the future as new technologies come online while it is still economical to operate existing systems. Conservation, cogeneration, and other alternatives would ease the transition problem and make it possible to put new technologies in place with less delay and difficulty when they are ready.

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...ffshore Oil Study Defines ...ms, Solutions

... and New ... with taxes, ... serve the ... according ...

The OTA report concluded ... the odds of an oil spill ... the shore are only ... if the accident happened at a drilling or production platform. A pipeline ... near the shore, ... of course, increase ... Under the first ...

The dismal chances are ... in a new congressional study that both ... problems in the drilling program ... definite ...

weeks ... Senate ... that would ... money to absorb the ... supplying services such as housing and police to the drilling communities.

Numerous congressional bills have been drafted to deal with the problem of oil spill liability and also will be concluded within the coming months. The OTA suggested in its report that a fund could be set up to which claims could be made directly. Those liable for the spill damages would have to repay the fund. That way, compensation would be speedily received.

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NEWARK STAR-LEDGER/September 3, ...

Cong... your... offs...

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"It is," he contends, ... information is obtained ... interested and affected ...

What the OTA speci... know is "What effects w... for yourself, your comm... if offshore energy syst... veloped off the coasts of ... Delaware?" "Do you thi... would be generally positi... "What comments do y... alternatives?"

To receive copies of th... and questionnaire, writ... gress' Office of Technolo...

By GORDON BISHOP

Every resident of New Jersey has an opportunity to participate in the decision-making process that will largely determine the direction and impact of America's energy policies.

Congress wants to know the implications of proposed new energy technologists off the shores of New Jersey and Delaware. And Congress is calling on the citizens who live, work and play in coastal states to share in the shaping of energy policies as they relate to offshore resources.

other complex ... fice of Technology ... (OTA) was ... search arm of the ... legislature.

Established ... 92-481, OTA ... in January ... it has been ... to undertake ... such vital ... oceans, health ... sources, food ... technology and ...

OTA's basic ... help Congress ... plan for the ... technological ...

ASBURY PARK EVENING PRESS, September 2, 1975

Oil Drilling Opinions Sought of N.J. Residents